energies

Article

Implications of Growing Wind and Solar Penetration in Retail Electricity Markets with Gradual Demand Response

Chin Hui Hao [1], Presley K. Wesseh, Jr. [2,3,4,*], David Iheke Okorie [3,5,6,7,8] and Hermas Abudu [9]

1 College of International Business and Trade, Xiamen Ocean Vocational College, Xiamen 361005, China; haochinhui@xmoc.edu.cn
2 School of Management, China Institute for Studies in Energy Policy, Collaborative, Innovation Center for Energy Economics and Energy Policy, Xiamen University, Xiamen 361005, China
3 Center for African Development Strategy (CFADS), Monrovia 1000, Liberia; okorie.davidiheke@gmail.com
4 Graduate School of Climate Change and Environmental Studies, University of Liberia, Monrovia 1000, Liberia
5 University of Waikato Joint Institute, Hangzhou City University (HZCU), Hangzhou 310015, China
6 Waikato Management School (WMS), School of Accounting, Finance and Economics (SAFE), University of Waikato, Hamilton 3240, New Zealand
7 Centre for the Study of the Economies of Africa (CSEA), Abuja 900108, Nigeria
8 SD Consulting Agency (SCA), Abuja 900108, Nigeria
9 College of Overseas Education, Chengdu University, Chengdu 610106, China; 17720170155924@stu.xmu.edu.cn
* Correspondence: presley@xmu.edu.cn

Abstract: Time-of-use pricing in retail electricity markets implies that wholesale market scarcity becomes easily communicated to end consumers. Yet, it is not well-understood if and how the price formation process in retail electricity markets will help to reward the demand for operational flexibility due to growth in intermittent generation. To contribute to this discussion, this paper develops a partial equilibrium model of the retail electricity market calibrated to Chinese data. The paper finds that tariffs in this market may not be significantly suppressed by growth in near-zero costs renewable sources when controlling for flexibility restrictions on thermal generation assets and when a significant curtailment of variable renewable resources exists in the market. In addition, it shows that the price formation process in retail electricity markets which controls for flexibility restrictions on thermal generation while allowing for consumers to respond slowly to price changes is a feasible strategy to reward the demand for operational flexibility. Finally, the paper reveals that while integrating intermittent generation beyond levels which the available storage capacities can accommodate may result in losses to producers, benefits to consumers may offset these losses, leading to overall welfare gains.

Keywords: time-of-use pricing; demand response; operational flexibility; intermittent generation; welfare

Citation: Hao, C.H.; Wesseh, P.K., Jr.; Okorie, D.I.; Abudu, H. Implications of Growing Wind and Solar Penetration in Retail Electricity Markets with Gradual Demand Response. *Energies* **2023**, *16*, 7895. https://doi.org/10.3390/en16237895

Academic Editors: Sonia Leva, Emanuele Ogliari and Alessandro Niccolai

Received: 11 October 2023
Revised: 26 November 2023
Accepted: 30 November 2023
Published: 3 December 2023

1. Introduction

Fossil-driven energy consumption is creating adverse environmental changes globally, and these changes are presumed to have a disproportionate impact on developing countries [1–3]. Since these countries are expected to experience a major growth in their energy use due to industrialization, increased use of transportation facilities, and growth in electrification, transitional economies could make a significant contribution toward climate change mitigation, especially if they invest in less carbon-intensive energy systems relative to their developed counterparts. Interestingly, the huge innovation in renewable energy technologies and storage devices over the past decade has led to a significant decline in the associated capital costs and has raised optimism about variable renewable energy expansion and mitigation prospects [4–6].

At the same time, and despite being an essential element of any development-oriented energy policy, the shift toward renewable sources will not only bring about a huge uncertainty in electricity supply but will also create the need for an increase in the flexibility of power generation, increase in transmission capacity, as well as increase the need for a more efficient system operation [7]. This increased need for operational flexibility on the grid leads to more frequent fluctuations in net demand (i.e., electricity demand minus variable renewable energy generation like wind and solar power). Low and middle-income countries that already suffer from unstable supply and frequent load shedding may find it difficult to manage large-scale renewable energy integration, leading to security of supply issues. This becomes problematic, since an energy policy that promotes development should not only minimize the external costs of energy consumption but should also maximize energy access.

With the adoption of dynamic tariffs in the form of time-of-use (TOU) pricing (or even real-time pricing) in retail electricity markets, wholesale market scarcity becomes easily communicated to end consumers. This creates the need to understand the impacts of variable renewable energy expansion in the bulk electricity system on retail markets. Yet, it is not well understood if and how the price formation in retail electricity markets will help to reward the level of flexibility that is required for expansion in variable renewable energy sources.

Therefore, based on the marginal costs theory, this paper aims to employ data of the Fujian grid of China (As part of efforts to mitigate climate change [8–11], almost all provinces in China (including Fujian) have adopted TOU pricing [12]) to explore how the TOU price formation process is affected by growing wind and solar penetration in a retail electricity market where consumers' response to prices happens gradually. (The slow consumer response over their billing period may be attributed to factors such as habit, imperfect information about the market [13], etc.) It also seeks to investigate the extent to which price formation in the retail market can incentivize storage utilization and ensure gains to producer and consumer welfare. The results obtained represent a major break with the literature (see Section 5) and help to advance understanding of the conditions under which the price formation process in retail electricity markets can reward the provision of operational flexibility on the grid.

Following this introduction, the remainder of the study proceeds as follows. Section 2 reviews the relevant literature. Section 3 describes the methodology employed in the research. Section 4 presents the data and calibration of parameters. Section 5 documents and discusses the main results obtained. Section 6 draws the conclusions.

2. Review of Relevant Literature

A major step toward scaling up universal energy access in developing countries is to achieve price formation that can ensure that the returns on investments in energy are sufficient for firms, households, and these societies at large [14]. A discussion of the literature dealing with how variable renewable energy expansion suppresses prices in wholesale electricity markets is provided in [15,16]. Some studies have suggested that the price formation process in wholesale markets does not adequately reward the demand for operational flexibility [17–19].

In retail electricity markets, a rate reform from fixed tariffs to the dynamic pricing of electricity is gaining momentum as consumers become increasingly equipped with new technologies to participate as active players in the electricity system. While a number of different pricing schemes exist (see [20–24]), three approaches to retail pricing have gained popularity in the literature. These include: (1) a time-of-use (TOU) pricing scheme in which prices vary only at certain intervals of the day (e.g., off-peak or peak periods) [25–32], (2) a real-time pricing (RTP) scheme, which provides a more accurate price signal to consumers [33–40], and (3) a critical peak pricing that extends a TOU pricing scheme to incorporate a certain number of critical peak hours within a year [41–44].

The impacts of dynamic pricing in consumer-centric electricity markets have also been studied across several dimensions including impacts on load and demand response [45–51], impacts on variable renewable energy expansion [52,53], impacts on the environment [54–56], and impacts on social welfare [57].

With regard to TOU pricing schemes in particular, several studies now exist on TOU pricing in retail electricity markets focusing mainly on how consumers respond to TOU tariffs (e.g., [58,59]), the structural design of TOU schemes (e.g., [60,61]), effects of TOU rates (e.g., [62]), and how TOU pricing models interact with distributed power resources (e.g., [63,64]). However, the impacts of growth in variable renewable energy expansion on the TOU price formation process in the presence of consumer demand response has not been studied. It also remains largely unclear how the TOU price formation process can interact with variable renewable energy expansion to enable or constrain electrical energy storage utilization and welfare levels.

3. Methodology

3.1. Model Overview

The model framework in this paper is graphically presented in Figure 1, which shows the interaction between producers seeking to minimize their costs of power generation and storage (i.e., pumped hydro storage) on the one hand and consumers seeking to reduce their payments for electricity by responding slowly to price changes. The equilibrium tariffs and storage levels arising from this interaction are determined endogenously by the model under different degrees of wind and solar penetration, and these results are subsequently used to calculate different metrics for assessing the extent to which marginal costs pricing in the retail electricity market can reward the demand for operational flexibility as variable renewable energy grows.

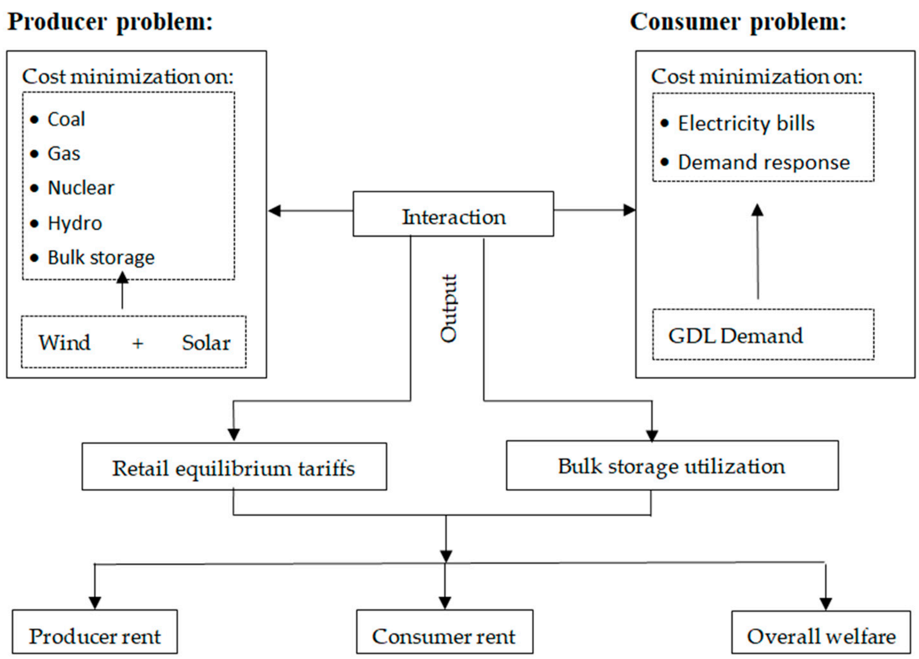

Figure 1. Graphical presentation of the model.

The model developed in this paper is based on partial equilibrium theory (see [65]) and builds on the frameworks in [32]. In particular, it refines the approaches in these papers by modeling the interaction of power generation and electricity storage, and evaluating outcomes of growing wind and solar penetration.

3.2. Producer Problem

On the supply side of the market, the objective is represented by a cost minimization problem for producers who seek to minimize their total generation cost (Z) from conventional generation assets i (i.e., coal, gas, nuclear, hydro, and storage) in each hour (h) of the month (t) for demand block j (i.e., peak or off-peak in our case). The objective function is given by

$$Min\ Z = \sum_{t}\left(\sum_{i,j,h} vg_i * E_{t,i,j,h} + \sum_{j,h} v_s * SG_{t,j,h} - SL_{t,j,h}\right) \tag{1}$$

where vg and v_s are variable costs of generation and storage operation, respectively. E, SG, and SL are energy flows, storage discharging, and storage loading, respectively. To optimize their behavior, producers face constraints (2) to (9).

$$E_{t,i,j,h} - \overline{E}_{t,i} \leq 0, \qquad \forall t,i,j,h \quad \left[k_{t,i,j,h}\right] \tag{2}$$

$$E_{t,i,j,h} - E_{t,i,j,h_{-1}} - \lambda_i^{up}\overline{E}_i \leq 0, \quad \forall t,i,j,h \quad \left[{w^{up}}_{t,i,j,h}\right] \tag{3}$$

$$E_{t,i,j,h_{-1}} - E_{t,i,j,h} - \lambda_i^{down}\overline{E}_i \leq 0, \qquad \forall t,i,j,h \quad \left[{w^{down}}_{t,i,j,h}\right] \tag{4}$$

$$SL_{t,j,h} - \overline{SL} \ \leq 0, \qquad \forall t,j,h \quad \left[{\aleph^{Stin}}_{t,j,h}\right] \tag{5}$$

$$SG_{t,j,h} - \overline{SG} \ \leq 0, \qquad \forall t,j,h \quad \left[{\aleph^{Stout}}_{t,j,h}\right] \tag{6}$$

$$\sum_{\varphi=1}^{h} SG_{t,j,\varphi} - \sum_{\varphi=1}^{h-1} SL_{t,j,\varphi}\varepsilon_S \leq 0, \qquad \forall_{t,j,h} \quad \left[{\aleph^{Stlo}}_{t,j,h}\right] \tag{7}$$

$$\sum_{\varphi=1}^{h} SL_{t,j,\varphi}\varepsilon_S - \sum_{\varphi=1}^{h-1} SG_{t,j,\varphi} - \overline{S} \leq 0, \qquad \forall_{t,j,h} \quad \left[{\aleph^{Stup}}_{t,j,h}\right] \tag{8}$$

$$E_{t,i,j,h}, SG_{t,j,h},\ SL_{t,j,h} \geq 0, \qquad \forall t,i,j,h \tag{9}$$

Constraint condition (2) is the generation capacity constraint that ensures that power generation is not more than the installed capacity $(\overline{E})$. Condition (3) is the generation ramp-up restriction that ensures that between any two subsequent periods, generation is raised only to a certain extent based on the technology-specific ramp-up parameter (λ_i^{up}). Similarly, condition (4) corresponds to the ramp-down constraint that ensures that generation can be reduced only by a certain amount depending on the ramp-down parameter (λ_i^{down}). Condition (5) is the storage loading constraint ensuring that energy stored in the pumped hydro-reservoir (Note that in our paper, we have incorporated four different constraints on pumped hydro storage. The first two constraints (i.e., Equations (5) and (6)) deal with the condition of the pump, and the remaining two constraints (i.e., Equations (7) and (8)) deal with the condition of the reservoir. In an economic sense, constraints on the reservoir can represent capacity constraints while constraints on the pump, as well as the efficiency factor (ε_S), can be used to capture drainage constraints and water dynamic balance limits. This approach reduces the complexity of the model and has been applied in a number of economic studies (e.g., [66–68]) cannot exceed the loading capacity of the pump ($\overline{SL}$). In the same manner, condition (6) guarantees that energy discharged from the pumped hydro reservoir is not more than the discharging capacity of the pump ($\overline{SG}$). Condition (7) is the lower reservoir capacity constraint that ensures that storage discharge in any period is not more than the net of inflows and outflows in the previous period considering efficiency losses (ε_S). In a similar manner, condition (8) is the upper reservoir capacity constraint requiring that the pumped hydro storage reservoir does not overflow. Finally, condition (9) ensures that values for energy flows and storage operation are at least zero. The dual variables in brackets represent the shallow price of various constraints.

3.3. Consumer Problem

For demand, a geometric distributed lag (GDL) functional form is adopted to capture the situation wherein consumers may respond slowly to price changes due to habits or imperfect information, and this is given by

$$d_t = \alpha_t (p_t)^{\beta} (d_{t-1})^{\gamma} \tag{10}$$

where d, p, and α are electricity demand, prices, and non-price factors, respectively. β and γ represent the constant price and lag elasticities, respectively. For a double commodity case (where the demand for electricity comes from both peak and off-peak blocks), the GDL demand is given by

$$\boldsymbol{D}_t = \boldsymbol{A}_t (\boldsymbol{P}_t)^{\boldsymbol{B}} (\boldsymbol{D}_{t-1})^{\boldsymbol{C}} \tag{11}$$

where $\boldsymbol{D}$, $\boldsymbol{P}$, and $\boldsymbol{A}$ represent vectors of electricity demand, prices, and non-price effects, respectively. $\boldsymbol{B}$ represents the matrix of elasticities (i.e., is own- and cross-price), while $\boldsymbol{C}$ represents lag elasticities (diagonal matrix).

Defining θ as the share of hourly demand in each demand block for a given month, condition (12) links the hourly generation of the market with the monthly demand.

$$d_{t,j,h} = \theta_{t,j,h} d_{t,j}, \qquad \forall t, j, h \tag{12}$$

Equilibrium in the retail market requires that energy flows plus storage discharge and wind and solar feed-in minus storage loading should be sufficient to satisfy demand. The equilibrium condition is given by Equation (13) where the dual variables $\left[p_{t,j,h}\right]$ represent the marginal cost of hourly demand. (The market clearing condition adopted in our study follows from previous economic literature (e.g., [13,66,67]). And even though there may be multiple solutions, our model simulations have produced only one optimal equilibrium solution, which we report in our study).

$$d_{t,j,h} - \sum_i E_{t,i,j,h} - SG_{t,j,h} - wind_{t,j,h} - solar_{t,j,h} + SL_{t,j,h} \le 0, \quad \forall t, j, h \quad \left[p_{t,j,h}\right] \tag{13}$$

$$p_{t,j} = \sum_h \theta_{t,j,h} p_{t,j,h}, \qquad \forall j \tag{14}$$

Condition (14) is necessary to ensure the producers meet their revenue requirement by supplying electricity to each demand block. From marginal cost pricing and applied equilibrium theory, $p_{t,j}$ represents the efficient TOU tariffs in the retail market.

The model in this paper is formulated as a mixed complementarity problem (MCP). To do this, using Equations (1)–(14), the Karush–Kuhn–Tucker (KKT) conditions are derived (see Appendix A).

After obtaining solutions for the MCP, we calculate power sector emissions in each month using Equation (15), where CF_i is the technology-specific emissions factor.

$$M_t = \sum_{i,j,h} CF_i * E_{t,i,j,h} \tag{15}$$

We also obtain producer rent in each month (PR_t) as the difference between revenue and costs given by Equation (16).

$$PR_t = \left(\sum_i p_j * d_{t,j} \right) - \left(\sum_{i,j,h} vg_i * E_{t,i,j,h} + v_s * SG_{t,j,h} \right) \tag{16}$$

Similarly, since the demand function is non-integrable, we estimate the change in consumer rent (ΔCR_t) from different model specifications given by

$$\Delta CR_t \cong \sum_j \left(p_{t,j} + \frac{1}{2}\Delta p_{t,j}\right)\Delta d_{t,j} - \left[\left(p_{t,j} + \Delta p_{t,j}\right)\left(d_{t,j} + \Delta d_{t,j}\right) - p_{t,j}d_{t,j}\right] \quad (17)$$

4. Data and Application

This paper simulates data for the retail electricity market in Fujian Province, China. Capacities of conventional generation assets and bulk storage, levelized cost of electricity generation, ramping parameters, and emissions factors in this market are reported in Table 1. We assume only 80% availability of storage for arbitrage purposes considering that some amount of the storage capacity will be kept for black start and backup. We set the round-trip efficiency of pumped hydro storage (ε_S) at 0.80 based on efficiency values that have been reported in the literature for pumped hydro storage technologies [69,70].

Table 1. Generation and storage parameters in Fujian market.

Generation	Capacity in 2018 (MW)	Cost (RMB/MWh)	Ramp Up (λ_i^{up})	Ramp Down (λ_i^{down})
Coal	25,649.6	496.5	0.11	0.03
Gas	5630.4	556.1	0.23	0.18
Nuclear	8710	436.9	0.05	0.09
Hydro	13,220	463.4	0.35	0.28
Pumped hydro storage capacity:				
Loading/discharging $(\overline{SL} = \overline{SG})$ (in MW)	1200	0.002		
Volume of storage reservoir $(\overline{S})$ (in MWh)	1,900,000			
Emissions factor (Metric ton per MWh)				
Coal	0.9426			
Gas	0.4838			
Nuclear	0			
Hydro	0			

Source: [32].

To achieve the objectives of this study, load data in Fujian retail electricity market are also needed. Accordingly, this paper adopts the representative workday data of net demand (i.e., electricity demand minus wind and solar generation) reported in [32], which corresponds well to the peak periods (between 8:00 and 22:00) and off-peak periods (between 23:00 and 8:00) stipulated in Fujian TOU pricing policy. (The peak and off-peak periods in Fujian TOU policy adopted in this paper are sourced from the Fujian Price Bureau (Document No. 241) and the Fujian Development and Reform Commission (Document No. 669).) The representative workday data have the advantage of reducing the size of the model (and limiting the model complexity) by using averages. In this way, each month of the year is represented by the average 24 h within that month amounting to a total of 288 h within the year. Despite the advantage of this approach, it does not allow for capturing seasonal effects. Notwithstanding, since our focus in this study is on general impacts rather than absolute numbers, the main conclusions of this study are valid.

To obtain hourly wind and solar load data for Fujian, we follow the approach in [12] by applying hourly weights of wind speed and solar radiation data (obtained from the Meteonorm 8.2.0 software) to monthly wind and solar utilization data for Fujian collected from the national bureau of statistics of China and the wind database. For simplicity, we use the first 24 h of each month to represent the wind and solar utilization in that month (Figure 2).

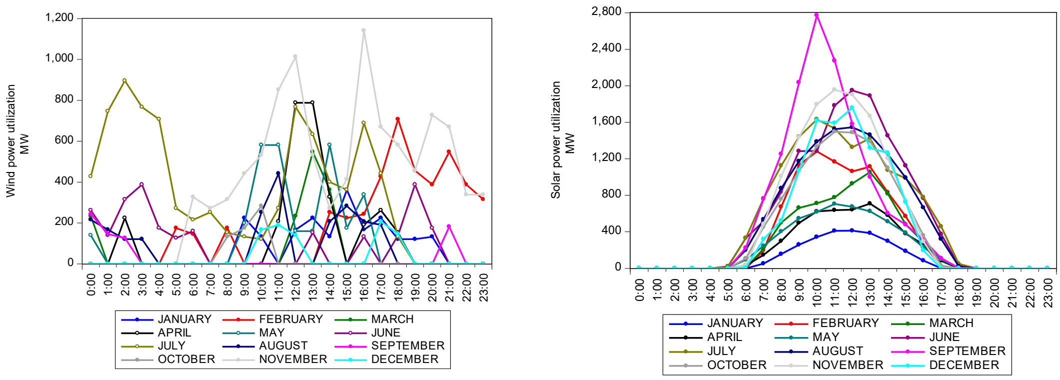

Figure 2. Representative wind and solar power utilization in Fujian for a typical year.

As may be seen from Figure 2, solar power utilization is zero during the night and then tends to increase through the morning, peak in the early afternoon, and decrease through the late afternoon. Wind power utilization, on the contrary, does not show any regular pattern and remains largely volatile. The wind and solar data reported in Figure 2 are treated as the benchmark scenario in this paper. We evaluate outcomes of higher variable renewable energy integration by scaling the hourly benchmark so that wind and solar, combined, can account for 30% (15% wind and 15% solar) and 60% (30% wind and 30% solar) of total demand in a typical year. These percentages represent the share of electricity demand in megawatt hour (MWh) that could potentially be met by wind and solar energy.

Other parameter values such as hourly weights of a demand block ($\theta_{t,j,h}$), price elasticities ($\beta_{j,s}$ and $\gamma_{j,j}$), and constants of non-price effects ($\alpha_{j,t}$) are the same as in [32]. A summary of all sets, parameters, and variables employed in the model is provided in Table 2.

Table 2. Sets, parameters, and variables of the model.

Item	Description	Unit
Sets		
H	Hours, $h \in H$, $\varphi \in H$	Hours
I	Power generation technologies, $i \in I$	
J	Load, $j \in J$, $s \in J$	
T	Time period, $t \in T$	Month
Parameters		
vg_i	Variable generation costs	RMB/MWh
v_s	Variable storage costs	RMB/MWh
$\overline{E}_i$	Generation capacity	MW
$wind_{t,j,h}$	Wind power feed-in	MWh
$solar_{t,j,h}$	Solar power feed-in	MWh
CF_i	CO_2 emissions factor	Mt/MWh
λ_i^{up}	Ramping up parameter	
λ_i^{down}	Ramping down parameter	
$\overline{SL}$	Loading capacity of storage	MW
$\overline{SG}$	Discharging capacity of storage	MW
$\overline{S}$	Reservoir capacity of storage	MWh
ε_S	Efficiency of storage	
$\theta_{t,j,h}$	Hourly weights	
$d_{t-1,j}$	Lag demand	MWh
$\alpha_{t,j}$	Non-price effects	
$\beta_{j,s}$	Own- and cross-price elasticities	
$\gamma_{j,j}$	Lag elasticities	

Table 2. *Cont.*

Item	Description	Unit
Variables		
$E_{t,i,j,h}$	Energy flows	MWh
$SG_{t,j,h}$	Generation from pumped hydro storage	MWh
$SL_{t,j,h}$	Loading of pumped hydro storage	MWh
$p_{t,j}$	Marginal costs (monthly)	RMB/MWh
$p_{j,h}$	Marginal costs (hourly)	RMB/MWh
$d_{t,j}$	Monthly demand in each block	MWh
$d_{t,j,h}$	Hourly demand in each block	MWh
$k_{t,i,j,h}$	Shadow price of generation capacity constraint	RMB/MWh
$w^{up}{}_{t,i,j,h}$	Shadow price of ramping-up constraint	RMB/MWh
$w^{down}{}_{t,i,j,h}$	Shadow price of ramping-down constraint	RMB/MWh
$\aleph^{Stin}{}_{t,j,h}$	Shadow price of storage loading capacity constraint	RMB/MWh
$\aleph^{Stout}{}_{t,j,h}$	Shadow price of storage discharging capacity constraint	RMB/MWh
$\aleph^{Stlo}{}_{t,j,h}$	Shadow price of lower storage capacity constraint	RMB/MWh
$\aleph^{Stup}{}_{t,j,h}$	Shadow price of upper storage capacity constraint	RMB/MWh
M_t	Emissions	Mt
CR_t	Consumer rent	RMB
PR_t	Producer rent	RMB

5. Results and Discussion

This section presents the results of equilibrium outcomes in the retail electricity market. These results show how different levels of wind and solar penetration influence tariffs and storage utilization in this market. The results also document the extent to which retail rates based on marginal costs pricing can ensure welfare gains for producers and consumers.

5.1. Impacts of Variable Renewable Energy Expansion on TOU Tariffs

Equilibrium tariffs in the retail market (TOU rates) are reported in Figure 3. As expected, peak prices are higher than off-peak rates for the most part (the notable exceptions occur in the months of January and February). In the benchmark case (first panel), off-peak rates range between 1.31 and 1.43 RMB per kWh, while peak rates stand between 0.84 and 7.0 RMB per kWh with the highest prices occurring during the summer months when demand is especially high. Equilibrium rates are different for different months, suggesting that retail tariffs should be adjusted periodically to reflect changes in demand and supply. Note that these rates appear to be by far higher than those implemented by regulatory bodies in Fujian, which is understandable, since we have controlled for the costs of inflexibility of thermal generation assets as stipulated in the constraint conditions represented in Equations (3) and (4). For instance, [31] show that by imposing ramping restrictions on thermal generators, equilibrium TOU rates increased from 0.129 to 0.308 RMB/KWh for off-peak periods and from 0.332 to 0.571 RMB/KWh for peak periods. Therefore, to address the political economy issues associated with high retail tariffs arising from the increased use of inflexible generation assets, scaling the use of flexible generation sources (like wind and solar) will present opportunities.

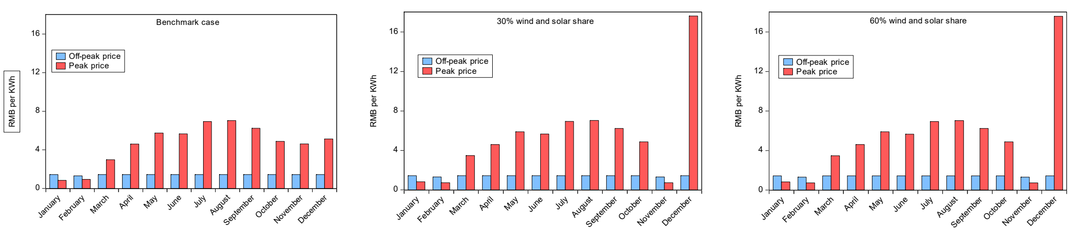

Figure 3. Equilibrium TOU rates in the retail market.

Moving to the second panel of Figure 3, where wind and solar generation increases to supply 30% of electricity demand, peak prices do not change significantly (with exceptions in November and December). For the most part, the increase in wind and solar generation suppresses peak prices only marginally. In some cases (e.g., March, May, and December), a rise in peak prices is observed. (The rise in peak prices to around 17 RMB per kWh in the month of December represents a clear case of an outlier in the model. We argue that this happened because gas-fired plants (with the highest operating cost in the model) reached their full capacity.) These results represent a major break with findings in wholesale electricity markets which point to evidence that large-scale penetration of near-zero costs variable renewable energy sources significantly suppress peak prices (see [15,71]). Against this backdrop, the key insight from our modeling of the retail market is that the low price benefits, to consumers, of near-zero costs wind and solar generation is almost eroded when accounting for the demand for operational flexibility, and associated costs, needed to accommodate their penetration. A further increase in wind and solar generation to serve 60% of demand leads to similar conclusions.

5.2. Variable Renewable Energy Expansion and Bulk Storage Utilization

Figure 4 shows generation from storage under different levels of wind and solar penetration. Under moderate levels of wind and solar penetration in the benchmark case, storage plays a major role in serving peak demand as monthly generation from storage stands between 1271 and 2659 MWh. As generation from wind and solar increases to supply between 30 and 60% of demand, the role of storage in serving peak demand vanishes. Accordingly, storage discharge declines to off-peak levels at around 900 MWh per month. This seems to suggest that variable renewable energy sources are important resources for peak load serving. However, further analysis is required to justify the decline in storage discharge under highly variable renewable energy penetration.

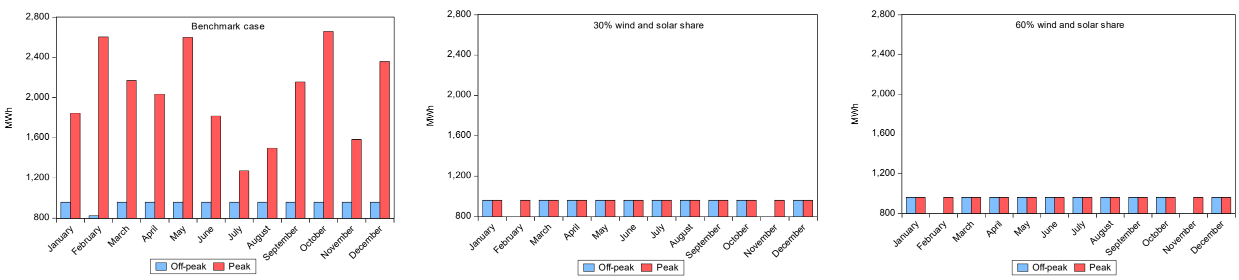

Figure 4. Storage generation.

The rate of storage loading corresponding to the monthly discharge is reported in Figure 5. For the most part, the pumped hydro storage reservoir attracts higher loading during peak periods than off-peak periods, since intermittent renewable energy resources appear to be largely available during this time. In all cases, the storage capacity is loaded at a by far higher rate than discharged. In the moderate renewable energy penetration benchmark case, for instance, monthly storage loading during peak periods ranges between 4550 and 12,104 MWh. This can be compared to the monthly peak discharge rates of between 1271 and 2659 MWh in the benchmark case reported in Figure 4. When wind and solar penetration increases to supply between 30 and 60% of demand, monthly storage loading declines significantly, which is intuitive since the corresponding discharge turns out to also be significantly low. Since the installed capacity of storage does not increase in the model, these results suggest that the available storage capacity may be insufficient to accommodate additional loading due to higher intermittent renewable energy penetration. Hence, a significant amount of wind and solar curtailment may occur as a result of inadequate storage. This artificial waste of wind and solar resources can also be confirmed by the fact that prices do not change by a significant margin, moving from 30% to 60% variable renewable share. While the question of how much storage would be required for large-scale renewable energy utilization appears to be an interesting one for further research and model improvement, the interesting insight from these results is that the large-scale penetration of intermittent sources like wind and solar may not suppress prices where a significant curtailment of these resources exists in the market.

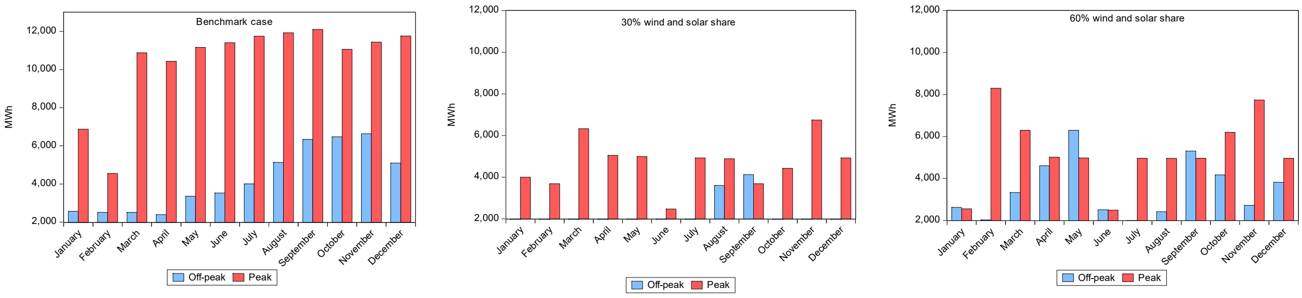

Figure 5. Storage loading.

5.3. Variable Renewable Energy Expansion and Welfare Changes in the Retail Electricity Market

The changes in the producer rent, consumer rent, and overall social welfare of participants in the retail electricity market from growth in intermittent renewable energy sources compared to the benchmark case are reported in Figure 6. Beginning with the first panel where wind and solar account for 30% of demand relative to the benchmark case, producer rent either remains unchanged or increases in all cases. The only exceptions occur in January and November where producer rent declines by 4.9 million RMB and 2330 million RMB, respectively. This huge decline in producer rent in the month of November can be attributed to the significant decline in peak prices in the same month to 0.73 RMB per kWh compared with 4.62 RMB per kWh in the benchmark case (see Figure 3). Summing over all twelve months, the results show that producer rent increases by 8390 million RMB for the entire year in general when wind and solar generation increases to supply 30% of electricity demand compared to the benchmark scenario. This suggests that the price formation process in retail electricity markets which controls for flexibility restrictions on thermal generation while allowing for end consumers to respond slowly to price changes is a feasible strategy to reward the demand for operational flexibility arising from growth in intermittent generation sources.

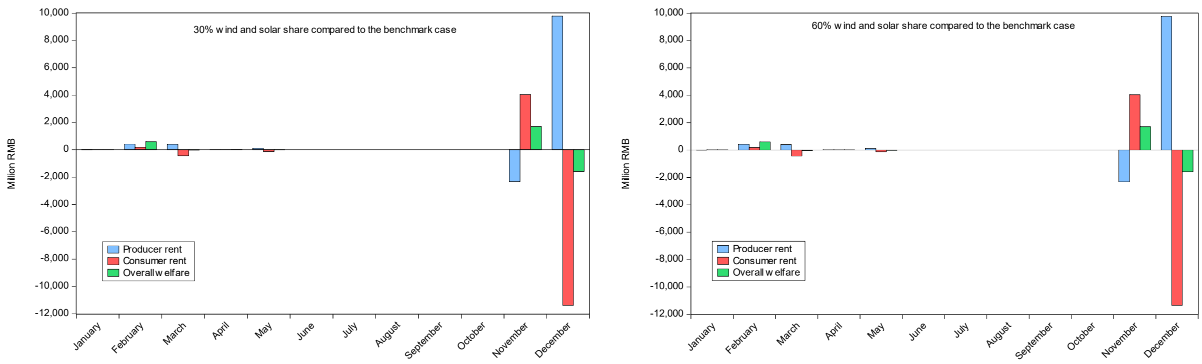

Figure 6. Welfare changes in the retail market.

On the demand side of the market, the first panel of Figure 6 shows that consumer rent increases in some cases especially when prices fall due to growth in wind and solar generation (such as in the months of January, February, April and November), and it falls in others when prices rise (such as in the months of March, May and December). When changes in consumer rent are summed over all months, the results show that consumer rent for the entire year declines in general by 7700 million RMB. Even though the gains to producer rent (8390 million RMB) less losses to consumer rent (7700 million RMB) would result in overall social welfare gains of 688 million RMB to market participants for the entire year, the losses to consumer rent present political economy issues that may appear to undermine the price formation process suggested in this paper.

Turning to the scenario where wind and solar share further increases to supply 60% of demand relative to the benchmark case as indicated in the second panel of Figure 6, the results suggest an increase in producer rent of 8370 million RMB (compared to 8390 million RMB in the 30% renewable case), a decrease in consumer rent of 7664 million RMB (compared to 7700 million RMB in the 30% renewable case), and an increase in overall welfare of 706 million RMB for the entire year (compared to 688 million RMB in the 30% renewable case). Clearly, a further increase in the wind and solar share to account for more than 30% of electricity demand results in losses to producers. On the contrary, consumers benefit from the excess wind and solar penetration, which lowers their losses and leads to an improvement in overall social welfare. These findings suggest that even though integrating intermittent renewable sources beyond levels which the available storage capacities can accommodate may result in losses to generation profits, benefits to end consumers may offset these losses, leading to overall welfare gains.

6. Conclusions and Policy Implications

This paper applies the marginal costs principle and partial equilibrium theory to explore how a retail rate formation of time-of-use (TOU) pricing is affected by growing wind and solar penetration in a retail electricity market where end consumers' response to price changes may occur over a period of time. It also evaluates the extent to which this price formation can reward conventional generators and end consumers as intermittent renewable energy sources like wind and solar increase. To achieve these objectives, the paper simulates data for the Chinese electricity market of Fujian, which serves as a compelling case.

On the main results, the paper finds that high tariffs in the retail market may not be significantly suppressed by growth in intermittent renewable sources when controlling for flexibility restrictions on thermal generation assets and when a significant curtailment of variable renewable resources exists in the market. In addition, it shows that although inherent political economy issues from losses to consumer rent may exist, the price formation process in retail electricity markets which controls for flexibility restrictions on thermal generation while allowing for end consumers to respond slowly to price changes is a feasible strategy to reward the demand for operational flexibility arising from growth in intermittent generation. Finally, the paper points to evidence that while integrating intermittent renewable sources beyond levels which the available storage capacities can accommodate may result in losses to generation profits, benefits to end consumers may offset these losses, leading to overall welfare gains.

The results of this study have important implications for public policy not only for regulatory bodies in the Chinese province of Fujian but also for developing countries in general as they seek to increase the use of market mechanisms in their electricity sectors. Based on the results of this study, the following recommendations can be put forward: (1) Retail tariff reforms should take into account the flexibility of power plants, as these constitute a significant component of the cost structure. (2) Because demand response is found to be a good strategy to reward conventional generators, end consumers should be provided with the right incentives to participate actively in the electricity market. (3) Measures should be taken to ensure that overall welfare gains in the electricity market do not come at the expense of losses to some market agents.

In additional to economic policy, the results of this paper are also of value to the scientific community especially in terms of widening the debate on how the price formation process in electricity markets can adequately reward the demand for operational flexibility due to growth in intermittent generation.

Even though the contributions of this paper are meaningful, further work could benefit from a more comprehensive modeling of unit commitment constraints on the generation side to account for individual power plants. Doing this would make it possible to address more specific questions as to how much storage is required to accommodate growth in intermittent generation. A more comprehensive model of drainage constraints and water dynamic balance limits of pump hydro storage would also present opportunities. Furthermore, implementing the models on a whole year dispatch covering 8760 h would prove meaningful.

Author Contributions: Conceptualization, C.H.H.; Methodology, C.H.H., P.K.W.J. and D.I.O. Software, C.H.H., P.K.W.J. and D.I.O. Validation, P.K.W.J., D.I.O. and H.A.; Investigation, H.A.; Resources, C.H.H. and P.K.W.J.; Data curation, P.K.W.J.; Writing—original draft, C.H.H., P.K.W.J. and D.I.O.; Writing—review & editing, P.K.W.J. and H.A.; Visualization, D.I.O. and H.A.; Project administration, P.K.W.J. and D.I.O. All authors have read and agreed to the published version of the manuscript.

Funding: This project is supported by the Natural Science Foundation of Xiamen, China (Grant No. 3502Z20227310) and the Natural Science Foundation of Fujian Province, China (Grant No. 2023J01167).

Data Availability Statement: The main data used have been presented in Section 4 of the manuscript.

Conflicts of Interest: Presley K. Wesseh, Jr. was employed by the Center for African Development Strategy (CFADS). David Iheke Okorie was employed by the Center for African Development Strategy (CFADS), the Centre for the Study of the Economies of Africa (CSEA), and SD Consulting Agency (SCA). The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

Appendix A. The Mixed Complementarity Problem (MCP)

In the MCP, we seek to determine $E_{t,i,j,h}$, $SG_{t,j,h}$, $SL_{t,j,h}$, $p_{j,h}$, $k_{t,i,j,h}$, ${w^{up}}_{t,i,j,h}$, ${w^{down}}_{t,i,j,h}$, ${\aleph^{Stin}}_{t,j,h}$, ${\aleph^{Stout}}_{t,j,h}$, ${\aleph^{Stlo}}_{t,j,h}$, ${\aleph^{Stup}}_{t,j,h}$, $d_{t,j}$, $d_{t,j,h}$, and $p_{t,j}$ that satisfy conditions (A1) to (A14). Note that Equations (A1)–(A3) are the first-order conditions of the objective function (Equation (1)) with respect to power generation, storage discharge, and storage loading, respectively.

$$0 \leq vg_i - p_{t,j,h} + k_{t,i,j,h} + {w^{up}}_{t,i,j,h} - {w^{up}}_{t,i,j,h+1} - {w^{down}}_{t,i,j,h} + {w^{down}}_{t,i,j,h+1} \\ \perp E_{t,i,j,h} \geq 0, \quad \forall t,i,j,h \tag{A1}$$

$$0 \leq v_s - p_{t,j,h} + {\aleph^{Stout}}_{t,j,h} + \sum_{\varphi=h}^{H} {\aleph^{Stlo}}_{t,j,\varphi} - \sum_{\varphi=h}^{H-1} {\aleph^{Stup}}_{t,j,\varphi+1} \\ \perp SG_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A2}$$

$$0 \leq p_{t,j,h} + {\aleph^{Stin}}_{t,j,h} - \sum_{\varphi=h}^{H-1} {\aleph^{Stlo}}_{t,j,\varphi+1}\varepsilon_S + \sum_{\varphi=h}^{H} {\aleph^{Stup}}_{t,j,\varphi}\varepsilon_S \\ \perp SL_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A3}$$

$$0 \leq \sum_i E_{t,i,j,h} + SG_{t,j,h} - SL_{t,j,h} - d_{t,j,h} \quad \perp p_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A4}$$

$$0 \leq -E_{t,i,j,h} + \overline{E}_i \quad \perp k_{t,i,j,h} \geq 0, \quad \forall t,i,j,h \tag{A5}$$

$$0 \leq -E_{t,i,j,h} + E_{t,i,j,h_{-1}} + \lambda_i^{up}\overline{E}_i \quad \perp {w^{up}}_{t,i,j,h} \geq 0, \quad \forall t,i,j,h \tag{A6}$$

$$0 \leq -E_{t,i,j,h_{-1}} + E_{t,i,j,h} + \lambda_i^{down}\overline{E}_i \quad \perp {w^{down}}_{t,i,j,h} \geq 0, \quad \forall t,i,j,h \tag{A7}$$

$$0 \leq -SL_{t,j,h} + \overline{SL} \quad \perp {\aleph^{Stin}}_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A8}$$

$$0 \leq -SG_{t,j,h} + \overline{SG} \quad \perp {\aleph^{Stout}}_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A9}$$

$$0 \leq -\sum_{\varphi=1}^{h} SG_{t,j,\varphi} + \sum_{\varphi=1}^{h-1} SL_{t,j,\varphi}\varepsilon_S \quad \perp \aleph^{Stlo}{}_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A10}$$

$$0 \leq -\sum_{\varphi=1}^{h} SL_{t,j,\varphi}\varepsilon_S + \sum_{\varphi=1}^{h-1} SG_{t,j,\varphi} + \overline{S} \quad \perp \aleph^{Stup}{}_{t,j,h} \geq 0, \quad \forall t,j,h \tag{A11}$$

$$d_{j,t} = \exp(\alpha_{t,j}) \prod_{s} \left[(p_{t,s})^{\beta_{j,s}} \right] (d_{t-1,j})^{\gamma_{j,j}} \qquad \forall t,j \tag{A12}$$

$$d_{t,j,h} = \theta_{t,j,h} d_{t,j}, \qquad \forall t,j,h \tag{A13}$$

$$p_{t,j} = \sum_{h} \theta_{t,j,h} p_{t,j,h}, \qquad \forall j \tag{A14}$$

where $\alpha_{t,j}$, $d_{t,j}$, and $p_{t,j}$ represent the jth elements of vectors $\boldsymbol{A}_t$, $\boldsymbol{D}_t$, and $\boldsymbol{P}_t$, respectively. In the same way, $\beta_{j,s}$ and $\gamma_{j,j}$ are the elements of matrix $\boldsymbol{B}$ and matrix $\boldsymbol{C}$, respectively.

References

1. Wesseh, P.K.; Lin, B. Refined oil import subsidies removal in Ghana: A 'triple' win? *J. Clean. Prod.* **2016**, *139*, 113–121. [CrossRef]
2. Wesseh, P.K.; Lin, B. Options for mitigating the adverse effects of fossil fuel subsidies removal in Ghana. *J. Clean. Prod.* **2017**, *141*, 1445–1453. [CrossRef]
3. IPCC. *IPCC Special Report: Global Warming of 1.5 °C*; IPCC: Geneva, Switzerland, 2018.
4. IRENA. *Renewable Power Generation Costs in 2018*; IRENA: Masdar City, United Arab Emirates, 2018.
5. Abudu, A.; Wesseh, P.K.; Lin, B. Climate pledges versus commitment: Are policy actions of Middle-East and North African countries consistent with their emissions targets? *Adv. Clim. Chang. Res.* **2022**, *13*, 612–621. [CrossRef]
6. Abudu, A.; Wesseh, P.K.; Lin, B. Are African countries on track to achieve their NDCs pledges? Evidence from difference-in-differences technique. *Environ. Impact Assess. Rev.* **2023**, *98*, 106917. [CrossRef]
7. Joskow, P.L. Comparing the costs of intermittent and dispatchable electricity generating technologies. *Am. Econ. Rev.* **2011**, *101*, 238–241. [CrossRef]
8. Xu, L.; Chen, N.; Chen, Z. Will China make a difference in its carbon intensity reduction targets by 2020 and 2030? *Appl. Energy* **2017**, *203*, 874–882. [CrossRef]
9. Sheldon, T.L.; Dua, R. Effectiveness of China's plug-in electric vehicle subsidy. *Energy Econ.* **2020**, *88*, 104773. [CrossRef]
10. Lin, B.; Wesseh, P.K. On the economics of carbon pricing: Insights from econometric modeling with industry-level data. *Energy Econ.* **2020**, *86*, 104678. [CrossRef]
11. Wesseh, P.K., Jr.; Zhong, Y.; Hao, C.H. Electricity Supply Unreliability and Technical Efficiency: Evidence from Listed Chinese Manufacturing Companies. *Energies* **2023**, *16*, 3283. [CrossRef]
12. Lin, B.; Chen, J.; Wesseh, P.K. Peak-valley tariffs and solar prosumers: Why renewable energy policies should target local electricity markets. *Energy Policy* **2022**, *165*, 112984. [CrossRef]
13. Çelebi, E.; Fuller, J.D. Time-of-use pricing in electricity markets under different market structures. *IEEE Trans. Power Syst.* **2012**, *27*, 1170–1181. [CrossRef]
14. Lee, K.; Miguel, E.; Wolfram, C. Experimental evidence on the economics of rural electrification. *J. Political Econ.* **2020**, *128*, 1523–1565. [CrossRef]
15. Bublitz, A.; Dogan, K.; Fichtner, W. An Analysis of the Decline of Electricity Spot Prices in Europe: Who Is to Blame? *Energy Policy* **2017**, *107*, 323–336. [CrossRef]
16. Daraeepour, A.; Dalia, P.-E.; Conejo, A.J. Economic and Environmental Implications of Different Approaches to Hedge against Wind Production Uncertainty in Two-Settlement Electricity Markets: A PJM Case Study. *Energy Econ.* **2019**, *80*, 336–354. [CrossRef]
17. Garces, L.P.; Conejo, A.J. Weekly Self-Scheduling, Forward Contracting, and Offering Strategy for a Producer. *IEEE Trans. Power Syst.* **2010**, *25*, 657–666. [CrossRef]
18. Papavasiliou, A.; Yi, H.; Svoboda, A. Self-Commitment of Combined Cycle Units Under Electricity Price Uncertainty. *IEEE Trans. Power Syst.* **2015**, *30*, 1690–1701. [CrossRef]
19. Daraeepour, A.; Larson, E.D.; Greig, C. Investigating price formation enhancements in non-convex electricity markets as renewable generation grows. *Energy J.* **2022**, *43*, 161–179. [CrossRef]
20. Joskow, P.L.; Wolfram, C.D. Dynamic pricing of electricity. *Am. Econ. Rev.* **2012**, *102*, 381–385. [CrossRef]
21. Hu, Z.; Kim, J.-H.; Wang, J.; Byrne, J. Review of dynamic pricing programs in the U.S. and Europe: Status quo and policy recommendations. *Renew. Sustain. Energy Rev.* **2015**, *42*, 743–751. [CrossRef]
22. Eid, C.; Koliou, E.; Valles, M.; Reneses, J.; Hakvoort, R. Time-based pricing and electricity demand response: Existing barriers and next steps. *Util. Policy* **2016**, *40*, 15–25. [CrossRef]

23. Matisoff, D.C.; Beppler, R.; Chan, G.; Carley, S. A review of barriers in implementing dynamic electricity pricing to achieve cost-causality. *Environ. Res. Lett.* **2020**, *15*, 093006. [CrossRef]
24. Patnam, B.S.K.; Pindoriya, N.M. Demand response in consumer-Centric electricity market: Mathematical models and optimization problems. *Electr. Power Syst. Res.* **2021**, *193*, 106923. [CrossRef]
25. Rahman, M.; Hettiwatte, S.; Shafiullah, G.; Arefi, A. An analysis of the time of use electricity price in the residential sector of Bangladesh. *Energy Strategy Rev.* **2017**, *18*, 183–198. [CrossRef]
26. Asadinejad, A.; Tomsovic, K. Optimal use of incentive and price based demand response to reduce costs and price volatility. *Electr. Power Syst. Res.* **2017**, *144*, 215–223. [CrossRef]
27. Venizelou, V.; Philippou, N.; Hadjipanayi, M.; Makrides, G.; Efthymiou, V.; Georghiou, G.E. Development of a novel time-of-use tariff algorithm for residential prosumer price-based demand side management. *Energy* **2018**, *142*, 633–646. [CrossRef]
28. Yan, Q.; Qin, C.; Nie, M. Designing household retail electricity packages based on a quantile regression approach. *Energy Strategy Rev.* **2019**, *25*, 1–10. [CrossRef]
29. Li, X.; Yang, H.; Yang, M.; Yang, G. Flexible time-of-use tariff with dynamic demand using artificial bee colony with transferred memory scheme. *Swarm Evol. Comput.* **2019**, *46*, 235–251. [CrossRef]
30. Daruwala, F.; Denton, F.T.; Mountain, D.C. One size may not fit all: Welfare benefits and cost reductions with differentiated household electricity rates in a general equilibrium model. *Resour. Energy Econ.* **2020**, *61*, 101160. [CrossRef]
31. Wesseh, P.K.; Lin, B. A time-of-use pricing model of the electricity market considering system flexibility. *Energy Rep.* **2022**, *8*, 1457–1470. [CrossRef]
32. Wesseh, P.K.; Dogah, K.E. Dynamic Tariffs and climate policy interaction: An economic analysis of welfare implications in retail electricity markets. *Energy Res. Soc. Sci.* **2022**, *90*, 102679. [CrossRef]
33. Siddiqi, S.N.; Baughman, M.L. Reliability differentiated real-time pricing of electricity. *IEEE Trans. Power Syst.* **1993**, *8*, 548–554. [CrossRef]
34. Tanaka, M. Real-time pricing with ramping costs: A new approach to managing a steep change in electricity demand. *Energy Policy* **2006**, *34*, 3634–3643. [CrossRef]
35. Conejo, A.J.; Morales, J.M.; Baringo, L. Real-Time Demand Response Model. *IEEE Trans. Smart Grid* **2010**, *1*, 236–242. [CrossRef]
36. Salies, E. Real-time pricing when some consumers resist in saving electricity. *Energy Policy* **2013**, *59*, 843–849. [CrossRef]
37. Yang, J.; Zhang, G.; Ma, K. Matching supply with demand: A power control and real time pricing approach. *Int. J. Electr. Power Energy Syst.* **2014**, *61*, 111–117. [CrossRef]
38. Seok, H.; Kim, S.P. Incentive-based RTP model for balanced and cost-effective smart grid. *IET Gener. Transm. Distrib.* **2018**, *12*, 4327–4333. [CrossRef]
39. Mamounakis, I.; Efthymiopoulos, N.; Vergados, D.J.; Tsaousoglou, G.; Makris, P.; Varvarigos, E.M. A pricing scheme for electric utility's participation in day-ahead and real-time flexibility energy markets. *J. Mod. Power Syst. Clean Energy* **2019**, *7*, 1294–1306. [CrossRef]
40. Tsaousoglou, G.; Efthymiopoulos, N.; Makris, P.; Varvarigos, E. Personalized real time pricing for efficient and fair demand response in energy cooperatives and highly competitive flexibility markets. *J. Mod. Power Syst. Clean Energy* **2019**, *7*, 151–162. [CrossRef]
41. Herter, K. Residential implementation of critical-peak pricing of electricity. *Energy Policy* **2007**, *35*, 2121–2130. [CrossRef]
42. Joo, J.-Y.; Ahn, S.-H.; Yoon, Y.T. Enhancing price responsiveness of end-use consumers' loads: Dynamically administered critical peak pricing. *Eur. Trans. Electr. Power* **2009**, *19*, 113–126. [CrossRef]
43. Zhang, X. Optimal scheduling of critical peak pricing considering wind commitment. *IEEE Trans. Sustain. Energy* **2014**, *5*, 637–645. [CrossRef]
44. Cappers, P.; Spurlock, C.A.; Todd, A.; Jin, L. Are vulnerable customers any different than their peers when exposed to critical peak pricing: Evidence from the U.S. *Energy Policy* **2018**, *123*, 421–432. [CrossRef]
45. Schwarz, P.M.; Taylor, T.N.; Birmingham, M.; Dardan, S.L. Industrial Response to Electricity Real-Time Prices: Short Run and Long Run. *Econ. Inq.* **2002**, *40*, 597–610. [CrossRef]
46. Simshauser, P.; Downer, D. Dynamic Pricing and the Peak Electricity Load Problem. *Aust. Econ. Rev.* **2012**, *45*, 305–324. [CrossRef]
47. Woo, C.-K.; Horowitz, I.; Sulyma, I.M. Relative kW Response to Residential Time-Varying Pricing in British Columbia. *IEEE Trans. Smart Grid* **2013**, *4*, 1852–1860. [CrossRef]
48. Yalcintas, M.; Hagen, W.T.; Kaya, A. Time-based electricity pricing for large-volume customers: A comparison of two buildings under tariff alternatives. *Util. Policy* **2015**, *37*, 58–68. [CrossRef]
49. Nguyen, T.T.K.; Shimada, K.; Ochi, Y.; Matsumoto, T.; Matsugi, H.; Awata, T. An Experimental Study of the Impact of Dynamic Electricity Pricing on Consumer Behavior: An Analysis for a Remote Island in Japan. *Energies* **2016**, *9*, 1093. [CrossRef]
50. Dong, C.; Ng, C.T.; Cheng, T.C.E. Electricity Time-of-Use Tariff with Stochastic Demand. *Prod. Oper. Manag.* **2017**, *26*, 64–79. [CrossRef]
51. Qiu, Y.; Kirkeide, L.; Wang, Y.D. Effects of voluntary time-of-use pricing on summer electricity usage of business customers. *Environ. Resour. Econ.* **2018**, *69*, 417–440. [CrossRef]
52. Nakada, T.; Shin, K.; Managi, S. The effect of demand response on purchase intention of distributed generation: Evidence from Japan. *Energy Policy* **2016**, *94*, 307–316. [CrossRef]

53. Krishnamurthy, C.K.B.; Vesterberg, M.; Book, H.; Lindfors, A.V.; Svento, R. Real-time pricing revisited: Demand flexibility in the presence of micro-generation. *Energy Policy* **2018**, *123*, 642–658. [CrossRef]
54. Holland, S.P.; Mansur, E.T. Is Real-Time Pricing Green? The Environmental Impacts of Electricity Demand Variance. *Rev. Econ. Stat.* **2008**, *90*, 550–561. [CrossRef]
55. Cochell, J.E.; Schwarz, P.M.; Taylor, T.N. Using real-time electricity data to estimate response to time-of-use and flat rates: An application to emissions. *J. Regul. Econ.* **2012**, *42*, 135–158. [CrossRef]
56. Nilsson, A.; Stoll, P.; Brandt, N. Assessing the impact of real-time price visualization on residential electricity consumption, costs, and carbon emissions. *Resour. Conserv. Recycl.* **2017**, *124*, 152–161. [CrossRef]
57. He, Y.; Zhang, J. Real-time electricity pricing mechanism in China based on system dynamics. *Energy Convers. Manag.* **2015**, *94*, 394–405. [CrossRef]
58. Khanna, N.Z.; Guo, J.; Zheng, X. Effects of demand side management on Chinese household electricity consumption: Empirical findings from Chinese household survey. *Energy Policy* **2016**, *95*, 113–125. [CrossRef]
59. Dehnavi, E.; Abdi, H. Optimal pricing in time of use demand response by integrating with dynamic economic dispatch problem. *Energy* **2016**, *109*, 1086–1094. [CrossRef]
60. Zhao, G.; Zhan, T.; Xi, H. Time-of-use price optimizing model and its solving method. In Proceedings of the International Conference of Civil, Transportation and Environment (ICCTE, 2016), Guangzhou, China, 30–31 January 2016.
61. Monfared, H.J.; Ghasemi, A. Retail electricity pricing based on the value of electricity for consumers. *Sustain. Energy Grids Netw.* **2019**, *18*, 100205. [CrossRef]
62. Liu, Z.; Zhang, X.; Yang, D. Policy target achievement between pure time-of- use tariff and time-of-use block tariff. *J. Quant. Tech. Econ* **2015**, *6*, 120–134.
63. Nayak, C.K.; Nayak, M.R. Technoeconomic analysis of a grid-connected PV and battery energy storage system considering time of use pricing. *Turk. J. Electr. Eng. Comput. Sci.* **2018**, *26*, 318–329. [CrossRef]
64. Wang, B.; Xie, M.; Zhang, T.; Wu, M. Research on the sharing mode of distributed optical storage systems based on dynamic tariffs considering the fairness of income. *Power Syst. Technol.* **2021**, *45*, 2228–2237.
65. Ventosa, M.; Bafllo, I.; Ramos, A.; Rivier, M. Electricity market modeling trends. *Energy Policy* **2005**, *33*, 897–913. [CrossRef]
66. Schill, W.-P. Electric vehicles in imperfect electricity markets: The case of Germany. *Energy Policy* **2011**, *39*, 6178–6189. [CrossRef]
67. Schill, W.-P.; Kemfert, C. Modeling strategic electricity storage: The case of pumped hydro storage in Germany. *Energy J.* **2011**, *32*, 59–87. [CrossRef]
68. Wesseh, P.K.; Benjamin, N.I.; Lin, B. The coordination of pumped hydro storage, electric vehicles, and climate policy in imperfect electricity markets: Insights from China. *Renew. Sustain. Energy Rev.* **2022**, *160*, 112275. [CrossRef]
69. Breeze, P. *Power Generation Technologies*; Elsevier Ltd.: Amsterdam, The Netherlands, 2019.
70. Mongird, K.; Viswanathan, V.; Balducci, P.; Alam, J.; Fotedar, V.; Koritarov, V.; Hadjerioua, B. *Energy Storage Technology and Cost Characterization Report*; U.S. Department of Energy: Washington, DC, USA, 2019.
71. Ekholm, T.; Virasjoki, V. Pricing and competition with 100% variable renewable energy and storage. *Energy J.* **2021**, *42*, 215–231.