Please cite this article in press as: Schittekatte et al., Reforming retail electricity rates to facilitate economy-wide decarbonization, Joule (2023), https://doi.org/10.1016/j.joule.2023.03.012

Joule

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Commentary

Reforming retail electricity rates to facilitate economy-wide decarbonization

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Impacts of economy-wide decarbonization on power systems

Deep decarbonization of the economy depends heavily on the decarbonization of the electricity sector and the electrification of several key end-use sectors.

Decarbonization of the electricity sector requires replacement of most dispatchable fossil generation with wind, solar, and storage. Wind and solar have high capital costs and nearly zero marginal operating costs. The transition of the electricity sector will lead to a fundamental change in the distribution of prices and marginal operating costs at the wholesale or bulk power level. There will be increased volatility, many hours of near zero prices, and more hours of very high prices.[1] Figure 1 shows recent wholesale price variability in Texas (ERCOT) and California (CAISO), where the combined share of solar photovoltaic (PV) and wind generation stood at 24% and 32% in 2021 versus the US national share of 13%.[2] The top panels show that there are a few hours each year with very high prices, signaling system stress conditions. The bottom panels show that within the day, there are fairly consistent price patterns indicating when it is relatively more or less costly to the system as a whole to

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https://doi.org/10.1016/j.joule.2023.03.012

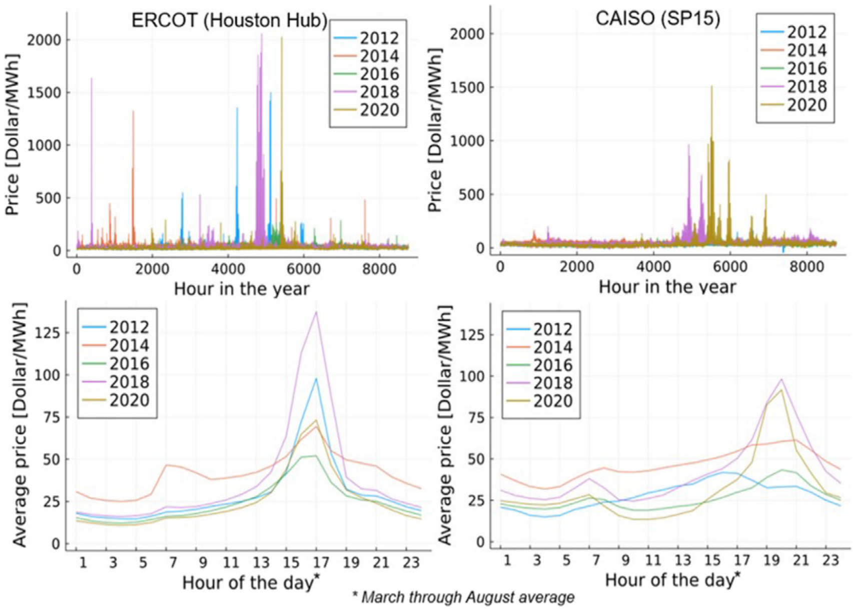

Figure 1. Illustrations of volatility in spot markets for electricity
Top: Day-ahead price series for the Houston Hub in ERCOT (left) and Southern Hub (SP15) in CAISO (right) for selected years. Bottom: averaged daily day-ahead prices from March through August for the same systems and years.

provide electricity. Especially in the case of CAISO, today there is already a strong impact of solar PV generation on the volatility of price patterns. These trends in volatility will continue as wind and solar penetration increases.

The electrification of end-use sectors will lead to a large increase in electricity demand. In the International Energy Agency's (IEA's) "Net Zero by 2050 Scenario," for instance, global electricity consumption increases by more than 2.5 times by 2050.[3] Increases in electricity demand will in turn lead to large increases in required investments in transmission and distribution (T&D) networks. Figure 2 shows that the IEA expects annual grid investment to increase by more than 200% compared to 2020 levels by 2030, with the main driver being the rise in electricity consumption. Figure 2 also indicates that the need to connect enormous amounts of wind, solar, storage, and other low- or zero-carbon-generating technologies will also lead to increased grid investments. For the US, the National Renewable Energy Laboratory projects 2050 electricity demand 29% above the 2018 levels in their reference scenario but 81% above the 2018 level under high electrification.[4] In short, we will move from a world in which electricity demand was static or falling accompanied by modest incremental network investments to a world in which electricity demand and network investments are increasing very significantly.

We believe that without fundamental reform of retail electricity rates, the costs of this massive transformation will be substantially higher than necessary, harming consumers and putting essential political support at risk.

How traditional retail rate designs discourage decarbonization

To stimulate efficient electrification of end-use sectors, we need to provide consumers with better incentives to adopt and utilize electric appliances and equipment. Properly designed retail rates charged to consumers (perhaps along with other incentives or requirements) can provide appropriate incentives. However, current retail rates cannot do this job. Historically, electricity supplied to residential and many commercial customers was priced everywhere on an almost flat volumetric rate; i.e., a constant price per kWh of electric energy consumed determined most of the bill, plus a small fixed charge ($/connection). Very roughly, the volumetric price was determined by dividing the total costs the local utility had to cover in some period—including fuel and other marginal operating costs of current generation and charges (such as interest on debt, depreciation, and a return on equity investment) fixed in the short run and reflecting past investments—by expected kWh demand in that period. The latest estimates from the US Energy Information Administration (EIA) state that less than 10% of US consumers are enrolled in rate plans deviating from that structure.[5] In this commentary, we mainly focus on the US, but a similar situation prevails in most of the rest of the world.

For decades, economists have pointed out two problems with these traditional retail rate structures. Deep decarbonization of the electricity sector and the associated dramatic changes in the distribution of wholesale prices and massive electricity infrastructure investment needs will make these problems more costly than in the past and will thus make fundamental rate reform more urgent.

First, as we have noted, the wholesale spot price, reflecting the marginal operating cost of supplying electricity, will vary much more than in the past, but under traditional rate designs, consumers have no incentive to shift their demand to periods when electricity is relatively cheap to produce. Since low-cost hours generally involve relatively high renewable production, shifting demand away from high-cost to low-cost

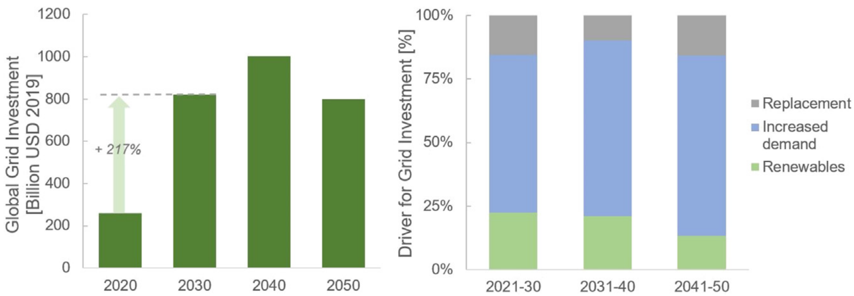

Figure 2. Global investment in electricity networks and drivers for the IEA 2050 Net Zero Emissions scenario

IEA, 2022; CC BY-NC-SA 3.0 IGO.[3]

periods will lead to less curtailment of renewables and less need to invest in back-up technologies such as peaker plants or batteries. Failure to substitute demand-side flexibility for investment would raise the cost of electricity, making grid decarbonization and electrification more costly and putting political support for decarbonization at risk.

Second, the generation, transmission, and distribution capacity necessary to meet consumer demand in any period at any location is not determined by average energy demand (in kWh) during that period. Precisely determining the cost drivers of such investments is complicated, especially at the bulk power system level. For distribution and sub-transmission investments, which represent an important share of the bill for residential and small commercial consumers, it is generally agreed that an important portion of the costs is driven by aggregate peak power demand (in kW).[6] Under traditional rate structures, these investment costs are recovered primarily through flat volumetric rates. Consumers then have no incentive to reduce their contributions to the aggregate peak demand. Electrification to support decarbonization makes this problem worse simply because it will entail massive network investment. A failure to provide incentives to consumers to shift their consumption away from peak demand periods will lead to excessive network investment requirements. This will significantly increase the cost of electricity as retail rates rise to cover growing network investments cost, again making grid decarbonization and electrification to support economy-wide decarbonization costlier.

In addition, not having the opportunity to take advantage of more frequent low-price periods and embedding generation, transmission, and distribution capacity costs in volumetric rates inflates the costs of electric technologies with demand-shifting capabilities. Users of many electric technologies—including electric vehicles (EVs), water heaters, clothes washers and dryers, and some heating, ventilation, and air conditioning (HVAC) systems—can already shift electricity demand to hours when the cost of providing electricity is low or spread out their usage better to limit future network investment needs if they had incentives to do so. The penetration of EVs and heat pumps must increase over time to meet decarbonization goals. Typically, these technologies substantially increase total household electricity consumption while having important load-shifting capabilities. Improved rate design would not only incentivize a more grid-friendly utilization of these technologies but also make their adoption more economically attractive. For example, a recent study using 2019 US data finds that residential off-peak time-of-use (TOU) charging would reduce average EV charging cost by 24%.[7] Another study using data on gas and electricity usage for residential customers of a US large investor-owned utility found that by reforming the traditional rate design, the operating cost gap between heat pumps and natural gas heating flips for all considered consumers from positive to negative.[8]

In short, because of the importance of economy-wide decarbonization, retail electricity rates should be reformed so that they encourage, rather than work against, cost-efficient electrification while not ignoring considerations related to equity, consumer acceptability, and the recovery of reasonable costs incurred by utilities. In what follows, we discuss particularly promising directions of reform to deal with the two problems just discussed.

Designing retail rates to provide appropriate demand-shifting incentives and achieve regulatory balanced budget constraints: Overview

There are now effectively no important technical barriers to adopting rates that vary with the marginal operating cost of supplying electricity at different times. Historically, the most significant barrier to adopting rate plans with time-varying prices has been the absence of economical metering technology capable of recording consumption with high frequency. The rapid diffusion of so-called smart meters with at least hourly recording and remote communications capabilities has removed this barrier in areas where they have been introduced. As of 2021, there were over 111 million advanced meters with these capabilities installed in residential (97 million) and commercial (13 million) locations in the US.[9] Unfortunately, only a small fraction of these meters are presently being used to support more effective retail rates of the type we discuss here.

Retail rate reforms should reflect three primary considerations. First, rates per kWh consumed should reflect wholesale prices (adjusted for losses and including negative externalities such as emissions of greenhouse gases), which will vary more widely from hour to hour in the future. This is sometimes referred to as real-time pricing (RTP) or dynamic pricing. Second, retail rates should provide consumers with incentives to shift their peak kW demand away from peak periods to conserve on network investment costs. This will require some type of forward-looking per-kW peak demand charge, as we discuss further below. Third, T&D network companies are typically subject to cost-of-service regulation, and regulators need to set rates that give them an opportunity to recover their total costs. The revenues produced by forward-looking capacity charges may be inadequate to cover total network costs. The "residual costs," if any, should be recovered in ways that do not distort consumers' electricity-related decisions, as we discuss briefly below.

Dynamic, TOU, critical peak pricing per kWh, and voluntary load management options

While retail rate design reforms are especially urgent as we decarbonize the electricity and certain end-use sectors, they have been suggested before. However, dynamic pricing per kWh consumed appears to be especially unpopular among consumers and regulators. One reason is that adjusting demand to frequently changing electricity prices takes consumer effort, and electricity typically only represents a small percentage of household spending in wealthy nations. Thus, the benefits from frequently reacting to price information might rarely be worth the effort involved. On the other hand, failure to pay attention can occasionally be very costly. The business model of Griddy, a now defunct Texas retailer, was based on dynamic pricing, leading, most of the time, to low bills even if consumers didn't react to price changes. In February 2021, however, wholesale spot prices in ERCOT were at their maximum for 4 straight days. When the crisis hit, Griddy urged its 29,000 customers to switch to alternative suppliers with flat, lower rates, but fewer than one-third did so. In May 2021, the Texas legislature outlawed this type of dynamic pricing. Not only will increased spot price volatility mean that the overall costs of time-invariant rates will grow, but after Griddy, dynamic pricing will be even less attractive to consumers, regulators, and politicians than before because of higher perceived bill risk.

Popular "second-best" rate designs that embody some of the time-varying nature of spot wholesale prices are TOU rates and critical peak pricing (CPP). TOU rates are predefined, e.g., at least a year ahead, and calibrated on historical price data. Typically, TOU rates differ by season, type of day (workdays or weekends), and/or time of day (e.g., peak, shoulder, or off-peak). While TOU rates are currently not widely used in the US, consumers are increasingly offered TOU rates that they can opt in to. Several state regulators, notably those in California and Hawaii, have recently adopted default TOU rates from which consumers may opt out.[10]

CPP programs provide extra incentives to reduce consumption during a handful of hours with the highest wholesale prices. An alternative to CPP is for consumers to agree for an *ex ante* bill credit to allow for remote demand management (which they can override at a cost) during CPP events. Thus, system operators are given the ability to reduce customer demand when system capacity is heavily stressed. These programs, when available, are generally well-subscribed in US jurisdictions. For example, many US utilities offer air conditioning cycling options that give the utility the ability to cycle the customer's air conditioner for a maximum number of days and hours per day during the summer. As wholesale spot prices become more variable with decarbonization, the value of some CPP-like options to cope with stress at the system level will increase.

Some of the existing academic literature has been skeptical of TOU rates, typically finding that they capture only about one-fifth of the cost savings that would be produced by RTP with alert consumers.[11] This literature mostly focused on demand characterized by independent hourly demand functions and thermal-dominated generation. In recent work, we introduce alternative assessment criteria that are tailored to a context with high volumes of intraday shiftable demand.[12] Using historical data from three US markets, we find that while TOU rates are obviously not good at predicting scarcity events or *absolute* spot price levels, they are reasonably good at predicting within-day *relative* price differences, which are what matter to stimulate load shifting. If TOU rates are adjusted relatively infrequently, consumers should be able to develop efficient usage habits and regularly take advantage of the ability to reduce costs by intra-day demand-shifting based on relative price differences. For example, a recent empirical study investigating in-home EV charging behavior under TOU rates found that EV households respond to electricity pricing signals by increasing their charging in lower-priced off-peak hours.[13]

Capacity pricing per kW to reflect the costs of growing network investments

As noted above, all projections indicate that investments in T&D will need to increase substantially in coming decades because of electrification. To provide incentives to reduce the need for additional network investment, the authors of the MIT "Utility of the Future" study propose to rely heavily on individualized capacity charges (in \$/kW).[6] In

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theory, each individual customer's capacity charge would reflect the impact of increases in their peak kW demand on the need for future investment in the system's capacity. Besides the technical challenges involved in computing theoretically correct consumer-specific capacity charges, however, serious issues of fairness would arise if nearby customers' charges differed substantially. That would conflict with the long-standing regulatory principle of charging the same prices to all consumers in the same rate class on the same network.

Nonetheless, we agree with the core idea that it is crucial to design capacity charges that are *forward looking* rather than *backward looking*, i.e., charges that signal *future* investment cost rather than simply collecting *past* investment costs. This idea also lies at the core of the ongoing network charge review that is currently performed by Ofgem, the British regulator.[14] We believe it is possible to link capacity charges approximately to pressures on investment in distribution network capacity without raising intractable equity issues. Capacity charges based on an individual customer's peak demand within particular time windows will not perfectly reflect the aggregated peak demand, but one can expect a significant correlation as long as the consumption patterns of customers within a distribution grid area are fairly homogeneous. Further, consumers' maximum kW usage is surely positively related to their ability to pay and to the benefits they derive from the power system.

While capacity charges, often also referred to as demand charges, are rare in the US for residential and small commercial consumers, 13 of the 27 member states of the European Union had capacity charges in place in 2021.[15] In fact, in Spain, capacity charges have been in place for decades. Currently, consumers contract for maximum kW usage in two time windows. Capacity in the midnight to 8a.m. time window during weekdays and the entire weekend is nearly free, while the price per kW in the day-time window during weekdays costs 22.4 €/kW per year in 2023. Such a subscription approach requires consumers to think through how they will use electricity and conserve on capacity charges. In the supplemental information, we provide more background information on the Spanish, French, and Flemish rate designs.

While the exact implementation of such forward-looking capacity charges can be gradually refined over time, this basic approach, tailored to system-specific conditions, seems to us a reasonable compromise between the provision of economic incentives, simplicity, and equity. For example, secondary markets for subscribed capacity can be developed or complementary CPP-like programs can also be introduced that can be of use at times of tight local network conditions, which can occur on short notice. Finally, there is also an interaction between potential local overloads due to simultaneous ramping up of consumption at the start of off-peak TOU energy prices (creating a so-called "peak shifting" issue). Well-designed forward-looking capacity charges can help to mitigate such impacts by encouraging spreading of consumption over the entire off-peak period.

Pricing to recover residual costs to meet regulatory balanced budget constraints

As noted, T&D services are provided by regulated T&D companies based on cost-of-service principles that include a so-called balanced budget constraint. That is, a proper regulatory system must give T&D companies a reasonable opportunity to recover their total costs, which, as we noted, consist of costs of past investments as well as current operations. The revenues produced by capacity charges reflecting (long-run) marginal T&D investment costs may not be adequate to satisfy the balanced budget constraint, leaving "residual costs" that need to be covered in other ways. One reason for this is that T&D companies often incur the cost of social programs like energy efficiency subsidies. If electrification is a priority, the costs of such programs should not be covered by making electricity more expensive. If "residual costs" are positive for whatever reason, they should ideally be recovered through fixed customer charges that are independent of consumers' decisions to consume electricity. As discussed by colleagues from Berkeley,[16] income distribution considerations must play a role in the design of such fixed charges. If "residual costs" are negative because future investment costs substantially exceed the costs of past investments, the excess revenues produced by forward-looking capacity charges should be placed in some sort of escrow account until they are needed for network investments. The necessary changes in regulatory arrangements do not seem overly complex. Such an approach would improve rate stability. This would not be the case when excess revenues would be immediately refunded, which would also potentially confuse consumers.

Conclusions and recommendations

Getting retail electricity rates right is crucial to affordable and cost-effective economy-wide electrification, which in turn is essential to economy-wide decarbonization. As we have argued, current nearly entirely time-invariant, volumetrically based electricity rates will make electrification slower and more expensive than it should be.

Considering our recent results,[12] along with the simplicity and low bill risk that makes TOU rate designs more attractive than dynamic pricing to risk averse consumers, TOU rate designs deserve more attention from researchers and regulators. We need to learn what sorts of designs are both acceptable to consumers and effective in inducing cost-reducing demand shifting. In the longer run, experience with TOU rates may reduce resistance to dynamic pricing. Also, under deep decarbonization, the incremental value of transitioning from TOU to dynamic pricing might increase due to potentially harder-to-anticipate price patterns. The lack of price predictability under dynamic pricing can be mitigated with the development of mass markets for appliances that include communications and control capabilities that facilitate a high degree of automation in electricity consumption, and bill stability can be guaranteed by complementing dynamic pricing with hedging or insurance products.

While there has been substantial experience with CPP programs in the US, the need to cope with the increased volatility of decarbonized power systems makes clear the potential value of increasing the coverage and effectiveness of these programs. Besides being valuable at moments of system-level stress, CPP programs can also be increasingly of use at times of tight local network conditions.

Finally, the issue of the recovery of costs that are fixed in the short run can be divided in two. First, instituting capacity charges that reflect future T&D investment costs is increasingly important because of the substantial investments ahead. The European experience indicates that cost-reflective capacity-based charges can be politically acceptable. The value of testing and further developing this proposition in the US, including the empirical analysis of residential consumer response to capacity charges, could be substantial. Second, if forward-looking capacity charges are inadequate to meet the balanced budget constraint, the remaining residual costs should ideally be recovered through fixed customer charges that reflect ability to pay. If forward-looking capacity charges yield excessive revenues, the excess should be put in some sort of escrow account until needed to pay for investments in network capacity.

ACKNOWLEDGMENTS

The authors would like to acknowledge the MIT Energy Initiative's Future Energy Systems Center study for research support.

DECLARATION OF INTERESTS

P.L.J., serves, until April 24, 2023, on the Board of Directors of Exelon Corporation, a US public utility holding company. Exelon played no role in the financing, preparation, or review of this commentary, nor does Exelon necessarily subscribe to any of its analysis or conclusions.

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Supplemental information

Reforming retail electricity rates to facilitate economy-wide decarbonization

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Supplemental experimental procedures

Here we describe in more detail the regulated tariffs in Spain and France that contain capacity charges and the novel Flemish distribution network tariff design that is largely based on capacity charges.

Spanish regulated PVPC 2.0TD tariff

In Spain, while there is retail competition for all consumers, consumers who have a subscribed capacity lower than or equal to 10 kW are on the regulated tariff. Consumer can opt-out these regulated rates and freely contract with any supplier. In January 2023, 8.8 million consumers or about 32% of all residential and small commercial consumers were on the regulated rate in Spain.[17]

Since 2014, the component of the regulated rate reflecting the energy procurement costs has been a direct pass-through of the hourly wholesale prices. While the regulated rate has been the most competitive tariff for many years[18], the direct pass-through of wholesale prices has led to public acceptability issues during the European energy crisis that initiated in the summer of 2021. As a reaction, the Spanish Ministry of Energy has proposed to gradually cover part of the energy costs by future contracts (up to a maximum of 55% of the total consumed volume in 2025).[19]

The network charges (both distribution and transmission) consist of a TOU energy component and a TOU capacity component.

The TOU energy component has three periods per day (weekends and holidays are always off-peak, no seasonal differentiation). In 2023, the volumetric components of the TOU network charges are 2.9 c€/kWh during the peak period (10am-2pm and 6pm-10pm), 1.9 c€/kWh during the shoulder period (8am-10am, 2pm-6pm, and 10pm-12pm), and 0.1 c€/kWh during the off-peak period (midnight until 8am).[20]

The TOU capacity charges have two periods per day (weekends and holidays always off-peak, no seasonal differentiation). The capacity is "as subscribed", consumers decide how much capacity they want to contract ex-ante. Originally the contracted capacity was linked to a circuit breaker to impede consumers to withdraw power beyond their contracted capacity (measured averaging over 15 minutes). Currently, maximum power usage is controlled by a smart meter. Consumers can adjust their contracted capacity at any moment but there is a cost associated to such changes as the idea is that capacity contracting also provides a long-time planning perspective to the utility. For 2023, the capacity charges including both distribution and transmission costs were 22.4 €/kW per year for the peak period (8am-12pm) and 1.2 €/kW per year for the off-peak period.

French regulated blue tariff

In France, while there is retail competition for all consumers, consumers who have a subscribed capacity lower than or equal to 36 kVA have access to regulated tariffs. These regulated rates are offered by the incumbent EDF or one of the 162 local distribution companies and often referred to as "blue tariffs".[21] In July 2022, 63.6% of French households (21.6 million) were on the regulated rate.[22] These are integrated tariffs, i.e., including the cost for energy, the network, and taxes. There are three types of blue tariffs, all three consist of a capacity (€/kW) and an energy component (€/kWh).[23] It is not made explicit how network and energy costs are allocated to the energy and capacity components.

The capacity component is "as subscribed" (no time differentiation) and the price per kW goes down with more kWs contracted. A consumer cannot use more kW than it has subscribed to. This is ensured by a circuit breaker at the interface with the public grid or controlled by the smart meter. The magnitudes of the capacity charge differ to a very limited extent between all three regulated tariff offers. The main difference between the three rate plans lies in the time-differentiation of the volumetric component, which is determined as follows:

- Base tariff: a per kWh charge without any time differentiation (17.4 c€/kWh)
- Off-peak hours tariff: a per kWh charge with two TOU periods (no seasonal differentiation). The exact division between the peak and off-peak hours can slightly vary per the region within the country. What is common is that the off-peak period always lasts 8 hours per day. A typical schedule is having the peak period from 6am to 10pm (22,28 c€/kWh), with the other hours being off-peak (16,15 c€/kWh)
- Tempo tariff: This tariff is more complicated and described below. It could be categorized as a rate containing TOU and CPP elements. The tariff coefficients for the year 2023 are shown in Table S1.[3]

Table S1: Tempo tariff coefficients for 2023

Subscribed capacity (kVA)	Monthly cost capacity (€/month)	Price per kWh (c€/kWh)					
		Blue day Off-peak	Blue day Peak	White day Off-peak	White day Peak	Red day Off-peak	Red day Peak
9	14.82	8.62	12.72	11.12	16.53	12.22	54.86
12	18.21	8.62	12.72	11.12	16.53	12.22	54.86
15	20.65	8.62	12.72	11.12	16.53	12.22	54.86
18	23.33	8.62	12.72	11.12	16.53	12.22	54.86
30	35.16	8.62	12.72	11.12	16.53	12.22	54.86
36	41.18	8.62	12.72	11.12	16.53	12.22	54.86

For the Tempo tariff, each day (at 5pm day-1) EDF announces the “colour” of the next day. There are three colours and depending on the colour of the day different TOU rates apply. For all three colours, the TOU rates have two periods with the same partitioning as in the off-peak tariff option. For example, on January 3rd at 5pm EDF notifies that the next day is a red day. This means that for a consumer on the Tempo tariff on the 4th of January from e.g., 6am to 10pm the volumetric price is 54,86 c€/kWh and from 10pm that same day to 6am the next day the volumetric price is 12.22 c€/kWh. Importantly, the maximum number of red and white days is predefined in advance:

- 22 red days from 1st November to 31st March, Monday through Friday (Saturdays, Sundays and holidays are never red and no more than 5 consecutive red days are allowed).
- 43 white days spread throughout the year, but never on Sundays.
- The remainder of the days are blue days.

Consumers that opt-out from the regulated rate can freely contract with a supplier offering different rates for the energy part of the bill. In 2022, these consumers could choose between five regulated distribution network tariff options.[24] The options range from e.g., the “short-use” network tariff with a rather low capacity charge (8.52 €/kVA per year) with a relatively high volumetric network charge (3.71 c€/kWh, not time-differentiated) to the “long-use” network tariff with a high capacity charge (76.44 €/kVA per year) and a very low volumetric charge (1.04 c€/kWh, not time-differentiated).

Newly introduced Flemish distribution network charge

In Flanders all consumers must freely contract with a supplier offering different rates for the energy part of the bill except for energy poor households who have access to a social tariff.[25] On 01/01/'23, the Flemish regulator has introduced a new distribution network tariff design that replaced the entirely volumetric network charges (with a different volumetric rate during the day vs night).

The new distribution network charge consists of a capacity charge plus a significantly smaller flat volumetric charge. The exact network tariff coefficients vary slightly from one region to another. We report here the charges for the Fluvius West region.[26] In 2023, for households with a smart meter (which represent about 1 out of 3 households at the end of 2022[27]), the capacity charge is 38.8 €/kW and the volumetric charge for distribution 1.0 c€/kWh (not time-differentiated). The capacity charge is not "as subscribed" but based on a measurement that goes as follows:

- The "power peak" that matters for the network charge is the maximum average power over a 15-minute interval within a month, independent of the exact timing of that power peak.
- To soften the impact of an exceptional power peak in a month, the monthly paid network charge is calculated based on the average monthly peak power over the last 12 months (rolling window)
- Each household pays for at least for 2.5 kW.

Consumers without a smart meter pay a fixed charge which equals the capacity charge multiplied by 2.5 kW and a higher volumetric network rate.

A brief comparison of the capacity charge in Spain, France, and Flanders

In Table S2 we provide an overview of the three different capacity charges according to four dimensions: measured or contracted capacity, time differentiation in the capacity prices, the price per kW per year, and the existence of a discount per kW with increasing capacity.

Table S2: Overview of the three different capacity charges

	Spanish regulated tariff	French regulated tariff	Flanders distribution network charge
Measured or contracted	Contracted	Contracted	Measured
Time differentiation	Yes, two periods with substantial price differences	No	No
Price per kW per year	23.6 €/kW (adding up on and off-peak)	19.8 €/kW (for 9 kW contracted)	38.8 €/kW (for region Fluvius West)
Discount of the price per kW with increasing capacity (within the residential segment)	No	Yes, quite substantial	No

Supplemental references

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