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Pricing on electricity networks

Conference report

Conference organised by the French Association for Energy Economics (FAEE) in cooperation with the Centre of Geopolitics of Energy and Raw Materials (CGEMP), the Chair Governance and Regulation and the Chair European Electricity Markets (CEEM) of the University Paris-Dauphine.

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DEBATE


CHAIRE EUROPEAN
ELECTRICITY MARKETS
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What are the right economic signals for the energy transition?

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Although they represent nearly half of the bill facing consumers (ex-tax), electricity network rates – and in particular electricity distribution rates – have received relatively little attention from energy economists, who have so far focused their studies on questions relating to electricity production, particularly in terms of security of supply and ways to develop renewable energy or "decarbonise" electricity production.

This conference highlighted the need to adapt TURPE's[1] structure to the changes introduced by the energy transition legislation. We are already seeing new behaviours and uses, which can now be expected to develop considerably: wind and solar energy production and tools providing increased flexibility, particularly in terms of storage and load management. Some actors have called for an increase in the proportional share of TURPE relating to power, for example by separately billing the costs representing the different services made available by the network. In any case, the rates applied must continue to send out signals that reflect costs, as this is the only way to ensure the expenditure needed to develop the networks is controlled in the long term.

1 Public electricity network user rates

Public electricity network user rates (TURPE): the challenges going forward

Dominique Jamme
Director of networks, French Energy Regulatory Commission (CRE)

The pricing structure for the use of electricity networks is governed by two key objectives:

1. *economic:* send out effective and transparent signals to users in order for them to adopt behaviours that can minimise network costs;
2. *legal:* ensure non-discriminatory access to the network.

In order to address both of these objectives, rates must be developed in such a way that they reflect the cost of running the network for each category of users. Beyond these objectives, the regulator endeavours to respect two principles: the "postage stamp" principle (rates do not depend on distance from the point of supply) and the standardisation of rates at a national level.

Added to this are various criteria that do not necessarily converge:

- *transparency and simplicity,* in order to send out a clear signal to consumers;
- *consistency and continuity,* in order to ensure a certain stability in pricing;
- *feasibility,* given that a rate may be optimal from a theoretical perspective but impossible in practical terms, or may require a lengthy implementation period;
- *acceptability,* given that a change in the pricing structure implies higher bills for some consumers and lower bills for others.

Economic efficiency is therefore not the only pricing criterion. To account for all of the criteria at play, the regulator works in collaboration with stakeholders. The next public consultation to address these issues will be held in April 2016. A decision will be made in late 2016, and TURPE 5 is due to come into force in mid-2017.

How does the energy transition affect the pricing structure?

The development of wind and solar energy production, which is largely connected to the distribution network, is well underway and can be expected to gather pace. This will lead to a fall in electricity drawdown, but not necessarily with a proportional decline in peak demand, particularly where transmission is concerned. This sector, which interfaces with distribution, could see a significant decrease in its drawdown in years to come. We are also seeing an increase in flexibility, which has an impact on storage and load management. Finally, the deployment of more advanced electricity meters and smart grids will improve our knowledge of the network and consumption, as well as an exponential increase in the quantity of available data. TURPE's structure must evolve to account for these general trends.

TURPE 5: the main challenges

- ***Hourly network costs: marginal cost vs. Shapley value***

The year is not made up of hours with an even load, so how should hourly network costs be determined? This question is particularly poignant in France, where the electricity system sees much higher peak demand in winter than in most neighbouring countries.

Pure economic theory suggests that the most effective signal for consumers is based on the principle of marginal cost. This would mean asking those users who draw down energy at critical times to bear the entire cost of developing the network. In practice, however, hourly rates based on this principle would be unacceptable as they would heavily penalise customers with electrical heating, which represents the bulk of demand on the network. It would also be difficult to explain that users who did not consume electricity during peak hours would not be required to pay to access the network. In order to strike the right balance between the efficiency and acceptability criteria, the CRE chose a methodology derived from the Shapley value to determine hourly network costs under TURPE 4.

Rates are then established by looking at the curve representing the costs induced by each consumer, based on the duration of usage, whereby this curve is determined by combining hourly network costs with user load curves.

Any significant change in network usage modifies the underlying cost function in respect of rates. This means that consumption heavily concentrated around peak periods results in a high proportion relating to power and a lower energy value, whereas for consumption that is more regular throughout the year the most suitable signal is a higher energy-based rate. This is how pricing adapts to changes in the electricity system, by looking for the best way to reflect costs

- ***Breakdown of power and energy proportions***

Overall pricing comprises a proportion relating to power (expressed in kW) and one relating to energy (expressed in euros per kWh). One might intuitively think that the energy proportion represents variable costs and that power represents fixed costs. Yet such an approach would be mistaken, not only because it reflects quantifiable costs and not necessarily the costs of using the network, but also because the power proportion is not fixed: it varies in accordance with subscribed demand. It would be economically justifiable to invoice customers for a fixed proportion independent of their consumption and of their subscribed demand, but in practice this sum must be low for reasons of acceptability: the lowest consumers of electricity must not be penalised.

A rate based only on energy or power would be inappropriate. Only one that perfectly reflects the costs associated with each hour in the year could get around this problem: there would be a balance between energy and power. For practical reasons, it is necessary to establish periods that include similar hours of the day. Intuitively, one may wish to price each period based only on energy by looking at its average hourly cost. But this would not reflect the diversity of consumer behaviour

within each period. A customer who draws down energy only during the most expensive hour would be under billed. Similarly, a rate calculated on power alone could encourage some customers to consume more, thereby reducing disparity in user demand. An energy component is needed to discourage them from this, especially given that there is a very high level of disparity in electricity consumption due to the considerable diversity of electricity usage.

The power proportion therefore depends on the more or less differentiated nature of unit costs and the heterogeneity of consumer behaviour within each period, as well as the level of precision in defining these periods: the more rates are divided into different periods, the greater the homogeneity from one hour to another, and the greater the energy proportion. Where consumption is unchanging, a precise pricing structure based on periods of the day and seasons will therefore reduce the power proportion. Such an approach sends out a highly effective signal to encourage consumers to consume less during peak periods.

Let us consider the case of self-production. The greater the proportion of energy (i.e. the energy proportion in TURPE, supply and taxes) in the price of electricity, the more profitable investment in self-production and storage becomes. Inversely, an artificially low energy proportion in TURPE may slow the development of such practices. The regulator's intention is to send out neither encouraging nor discouraging signals in this regard, but to remain neutral. Pricing based on periods of the day and seasons sends out the right signal when it encourages self-producers to be absent from the network during peak periods. The development of advanced meters represents a move towards such an approach and will reduce the windfall effect whereby self-producers mainly present on the network during peak periods are "subsidised".

- ***Energy injection and drawdown***

There is no mathematical solution for the challenge of finding the right balance between energy injection and drawdown in establishing a pricing structure. Provided a market functions effectively, the relative weighting of these components has no real effect, as producers pass the injection component onto consumers through the prices on the electricity market. The drawdown component in TURPE is currently massive, while the injection component is very low. Some parties have called for the latter to be strengthened based on the cost of infrastructure.

There are several ways of doing this:

- *introduce an injection power component,* although this would run counter to the objective of having a market with the capacity to finance the power installed;
- *introduce an energy component,* although this would offset the merit order in Europe by penalising producers, who would be taxed to the amount of a few Euros each time they injected energy into the network;
- *introduce localised pricing signals,* which is the most effective solution from an economic perspective but would involve a highly complex

market design that is out of reach in the short term and would run the risk of competing with the geographic signals being sent out by France's regional schemes to connect to the network of renewables (S3RENR).

- ***4-index pricing and low-voltage mobile peaks***

The roll-out of the Linky meter (35 million units between late 2015 and late 2021) will make it possible to measure consumption during four different periods for all low-voltage consumers. It will provide more refined knowledge of the consumption structure and allow more detailed and effective signals to be sent out to customers. The current segmentation between peak and off-peak hours, which has proven highly effective, could be complemented by a winter/summer segmentation. Although there is now consensus support for such an approach, there is ongoing debate about the pace with which this 4-index system should be introduced: either as an option in line with the roll-out of Linky, or at the end of its deployment in late 2021. The CRE recommends gradual implementation, as this would allow the network to benefit immediately from the advantages of Linky, but also to spread out the cost increases that will inevitably have to be borne by some consumers.

With regard to mobile-peak pricing options – encouraging willing customers to avoid consuming during peak periods, having been notified the previous day, in exchange for lower prices for the rest of the year – analysis shows that they may be appropriate in the case of medium- and high-voltage customers. The CRE favours this approach. However, in the case of low voltage, adopting this at a national level could potentially be counter-productive given that peak demand carries a significant local dimension. This question requires further studies to consider the best way to mobilise local flexibility resources.

Economic criteria underpinning pricing methods

Anna Creti
CGEMP, CEEM and Chair Governance and Regulation, University Paris-Dauphine

The economic literature reveals that there is a wide variety of possible choices when it comes to pricing on electricity networks, depending on which criteria one wishes to focus on: efficiency, acceptability, fairness, etc. For once, the theory is not as normative as one might expect. This is due in particular to the fact that distribution rates lie at the interface between transmission networks on the one hand, and on the other consumers whose behaviour is becoming increasingly complex and diverse. There are many different theoretical principles and the possibilities for implementation are even more numerous – and in some cases counter-productive.

The new roles of distributors

Under the effect of the energy transition, the construction of the European energy market and climate and energy security policies, distributors have seen their historical role take on new objectives: energy efficiency, the development of distributed generation, a flexible system, etc. ACER-CEER now predict that by 2025 distribution network operators will act as "network facilitators".

A theoretical kaleidoscope

How can efforts to determine pricing take these various objectives into account? In this regard, the reference theory is that of the natural monopoly. However, the problem is that the principle of marginal cost does not work for networks as there is an imbalance between revenue and costs. In order to allocate residual costs, one solution may be to adopt a "Ramsay-Boiteux" approach where the revenue of the network operator is taken into account and maximised within the constraints of its budgetary balance. It is also possible to set prices in two parts, accounting not only for the network operator's revenue but also that of the consumer. Part of the applicable rates covers marginal costs and another covers fixed costs.

Other possible methods include the distributed cost model, which is based on rules for attributing and sharing costs between the different categories of consumers. Shapley values are an illustration of this, based on cooperative game theory. Other approaches that are more operational and simpler to implement include the "postage stamp" approach and rates based on individual contracts or distance. As for locational marginal pricing (LMP), which is attractive in the context of liberalising the energy markets, this is no more than the application of nodal prices, which requires an environment of perfect competition, perfect information and the perfect consumer.

The ambiguities of locational marginal pricing

Imagine a standardised framework in which the objective is to encourage the average consumer to invest in solar energy. The price carries an element of variability linked to the intermittence of solar production, and the variable costs of solar production do not apply. Depending on the pricing method adopted, consumers must solve one of the

following equations:

- In the case of LMP, they reason on the basis of the expected value of the nodal price (subject to variability), multiplied by the capacity of their solar installation, less fixed costs;
- In the case of pricing averaged out over time, the price of consumption is fixed but profits will depend on production variability.

These equations make it possible to determine the weight of an efficient investment in solar energy. There is a constraint, however, since this weight must be determined by market conditions. This means there continues to be a random variable, which adds an element of complexity. The efficiency of the investment is also subject to certain conditions: it requires solar production to be low or to present little correlation with the price of energy on the market. Yet in reality there is a strong and negative correlation between the capacity of solar energy and the price of energy on the market, which results in over-encouragement to invest in solar energy. It should be noted that this demonstration does not take incentive mechanisms into account.

This example shows that one of the possible pricing strategies on distribution, which is in fact the closest to the market, can lead to distortions in its implementation.

Conflicting principles

Various pricing vectors structure the implementation of economic theoretical principles: breakdown of fixed/variable share, lack of time, differentiating between consumers, long-term incentives, ex ante or ex post regulation, etc. Combining these vectors leads to pricing configurations that differ in terms of criteria relating to location, time, fixed/variable components, payment method, service type and consumer profile.

One might think that the differences observed in practice, if only between European countries, could be explained by the different weighting of these criteria. In reality, however, it is difficult to establish such causality links as rates are determined in respect of nation-specific choice criteria (acceptability, economic efficiency, consumer protection, etc.). The most common approach is to weigh up cost against simplicity or stability, or to adopt the Ramsay-Boiteux principles and the objective of non-discrimination. But there may be synergies between other criteria, economic efficiency and innovation for example.

A review of several different countries that have significantly invested in renewable energies does not reveal a standard pricing solution. Practices differ as much in terms of connection methods as in the use of system charges, connections to the network and network usage. Connection charges can be “deep” (which cover the consumer’s specific costs and part of the infrastructure costs but are shared between users) or “shallow” (which only cover costs not shared by other consumers). But both approaches lead to the same balance, and the regulator recognises these costs as falling to the distributor.

In a world in which pricing diversity is set to continue, it is important to base rates on criteria that can be rationalised and reflect the energy mix in different countries. A benchmark is needed to achieve this.

Benchmark for distribution network pricing practices

Fabien Roques, CGEMP, CEEM and Compass Lexecon
and Charles Verhaeghe, Compass Lexecon

Network pricing has produced an abundant literature but which is partly outdated and does not specifically address electricity distribution and the changes brought about by the energy transition. Even the "first best" solution of marginal cost pricing raises real difficulties in the case of networks: are we talking about incremental cost, and should it be understood in the short, medium or long term? Furthermore, marginal cost pricing alone does not allow the network operator to cover all of its costs. A residue remains. The Ramsay-Boiteux approach makes it possible to cover this residue and stray as little as possible from the economic optimum, but raises the question of fairness. The alternative methods put forward by Anna Creti, which are characterised by a diversified hierarchy of objectives and constraints, need to be seen in light of a stream of literature that has been developing for a few years, particularly in Spain, in relation to benchmark network models. This approach considers the principles of causality with regard to costs by exploring the costs associated with the different services provided by the network.

Fixed/capacity proportion in distribution network pricing

The question of the fixed/capacity proportion in network rates illustrates the diversity of current practices in Europe. Approaches vary depending whether customers are residential or professional. The energy proportion represents an average of 70% of network prices for households in European countries, with a few notable exceptions (the Netherlands, Spain and Sweden, where it is lower than 25%). For industry and companies operating in the tertiary sector, the energy proportion represents 55% of network prices, but with significant variability from one country to another. By comparison, France has one of the highest energy proportions: over 70% for industrial customers and companies, and 80% for residential customers.

The current trend in Europe is towards a higher proportion reflecting power. Italy recently decided to treble its power proportion and increase its fixed proportion for residential rates. Spain increased its power proportion from 32% to 60% between 2013 and 2014. The Netherlands introduced a pricing system based solely on power in 2009. The regulators in Austria and the United Kingdom are currently considering the possibility of increasing their fixed/capacity proportions.

Across the board, the debate surrounding power, capacity and fixed proportions has proved complex, particularly with regard to the underlying method to apply.

Focus on Spain, the Netherlands and the United Kingdom

These three States provide an illustration of different approaches and methods that can be observed in Europe.

- ***United Kingdom***

The chosen method in the UK is partly a reflection of economic theory. Rates are calculated in a transparent manner based on the incremental costs reported by each network operator. However, one might question whether the finer calculations used in this method take account of current realities: for example, one of the parameters used to determine the breakdown between energy and power in electricity rates has not been revised since 1984. And despite its much vaunted transparency, the calculation of the incremental cost of producing low-voltage electricity remains a "black box" in the hands of network operators, even though the main principles underpinning this method are defined by the regulator. In practice, this method tends to produce a much higher energy proportion than a capacity or fixed proportion. This is mainly due to the ad hoc parameter mentioned above, which attributes most costs, including residual costs, to the energy proportion without any theoretical justification.

- ***Spain***

In 2004, the Spanish regulator published a methodology based on the concept of benchmark network models. The objective is to simulate the reconstruction of the network and try to reflect cost causality step-by-step. This procedure involves two phases. First, it regroups connection costs and the cost of guaranteeing a certain power output, and constructs a minimal network to meet these requirements. The corresponding costs are accredited to power. It then distributes energy throughout the network and meets the determined quality criteria. The corresponding costs are attributed to energy. Overall, this leads to a very high capacity and fixed proportion of costs and a relatively low energy proportion.

However, it is difficult to judge the implications of this new method. In Spain, the regulator determines the method for calculating network rates, and the Minister then sets the access rates, which includes the network rates and all taxes, including the Spanish equivalent of France's contribution to public electricity services (CSPE). This portion of the cost is significant and is higher than the network charges, which effectively drowns out the pricing signal from a network perspective. Furthermore, the minister does not necessarily apply changes to network rates and can maintain the same tariff by carrying out transfers from one portion to another. In fact, publishing the regulator's method did not bring about any significant change in the pricing structure. In contrast, in the previous year the minister chose a breakdown that rebalanced the pricing structure: he allocated a higher proportion of the costs to power so that customers who were heavily reliant on self-production nonetheless contributed taxes and helped finance the network.

- ***The Netherlands***

In 2009, the Netherlands made the relatively radical decision to attribute 100% of costs to the fixed proportion and to power in the case of all small consumers (households and SMEs). There is therefore no longer any rate proportional to energy to cover network charges. This decision was based on two primary motivations: first, the regulator felt that the vast majority of costs were fixed and that it was

preferable to reflect them onto the fixed or power proportions of rates; second, this decision simplified operations and administration and generated quite substantial savings, thus enabling the transition to the new tariff approach to be financed. Customers were informed that this new method could have a significant impact on their energy bills. Most of them had the option to reduce their subscribed demand without changing their habits or seeing an increase in their bills. Other customers benefited from an implicit subsidy over a two-year period to allow them the time to gradually cope with the increase in their energy expenditure.

Lessons from the European benchmark

There is a lack of transparency in Europe when it comes to the principles and methods used to develop pricing structures, and there is significant diversity in the approaches adopted. Some countries have no fixed proportion, others do not provide the option to charge for subscribed demand (particularly in the case of households), while others do not use different rates for different periods. To take two extreme cases, the Germans allocate 99% of charges to energy in the case of professionals, whereas in the Netherlands 100% of charges relate to the fixed proportion or capacity. It should be noted that the fixed and power proportions are generally lower in France than in other European States, including those that offer different rates at different times of the day. A certain number of regulators are now considering increasing the proportion of costs relating to power, especially in countries where it is relatively low.

In most European countries, the economic foundations for the method used are relatively limited and have gone unchallenged over the years. The relevance of the economic signals sent out and the incentives put in place are not the subject of much analysis. Finally, there are considerable constraints in terms of implementation, whether they relate to the processing of data and the robustness of calculations, or questions of acceptability and energy transition management.

This European benchmark does not point to an optimal method from an economic perspective. However, it does underscore the need to work more on the economic method adopted and the signals being sent out by network rates in order to lead the energy transition in the most cost-effective way and with greater levels of commitment on the part of consumers.

Changes in the regulatory framework for new services and uses

Leonardo Meeus
Director of the Energy Centre, Vlerick Business School

European countries do not share a consensus on the exact definition of a distribution network, any more than they are converging towards a shared solution when it comes to allocating network costs. In a text published in July 2015, the CEER recognised that a certain number of emerging activities are in a "grey zone": some people believe they are part of distribution while others see them as part of the market.

Market or distribution network operator (DNO)?

European regulators perceive these new activities in different ways. Examples include charging terminals for electric vehicles, batteries and energy storage.

- ***Electric vehicle charging terminals***

The charging terminals for electric vehicles can either be seen as a competitive market or as an extension of the distribution network. Before reaching a decision on the issue, the Swedish regulator initially decided to give the market a chance. Similarly, the regulator in the Netherlands will only intervene if the market shows persistent flaws. However, Dutch cities see this issue differently, favouring competition when it comes to accessing the market rather than market competition per se. Amsterdam issued a call for tenders for 200 charging terminals.

Ireland, which included the development of electric vehicles in its energy policy objectives, adopted the opposite approach. The Irish regulator authorised the DNO to finance the initial deployment of charging terminals through a separate company, but using the budget and R&D of the DNO. In a few years, the regulator can decide to allocate this infrastructure to the DNO or to put it on the market.

- ***Batteries and energy storage***

Several European countries see energy storage installations as means of production. But given that this technology can lead to new uses of existing facilities, they could be assimilated to the distribution or transmission network. Germany provides subsidies for the purchase of batteries for residential storage. At the other end of the spectrum, Italy gives distribution and transmission network operators the chance to present the case that storage falls under their ambit. In the United Kingdom, small batteries can be assimilated to the distribution network, and a few pilot schemes are currently being tested.

- ***Is the DNO a market facilitator?***

The transmission system operator (TSO) is usually considered to be a market facilitator, but what about the DNO at a time of decentralised resources? In this regard, it is essential to identify who operates the data platform generated from advanced meters. Belgium has entrusted this role to the DNOs, who have even created a joint-venture to form a single hub. In the UK and Italy, this function has

been attributed to a third party. Like Belgium, France appears to be committed to a DNO model, and Austria has just formally adopted this approach. In Denmark, the TSO is responsible for the hub, and it would appear that the other Scandinavian countries as well as Germany are following the same path.

What role for the regulator?

- ***The regulator's role under the market-based approach***

In countries like Belgium and the Netherlands, where there is a complete split between the different activities on the electricity network, what would happen if a DNO entered the so-called "grey zones" to develop a commercial activity? In terms of market organisation, there are two main options: competition for accessing the market and market competition. But even countries that adopt a market-based approach are likely to impose a universal service on their market players. Another market correction mechanism is to introduce incentives for the deployment of new technologies, like the residential batteries used in Germany. Indeed, the involvement of DNOs can be seen as a type of market correction, one that could even become permanent.

- ***The regulator's role under the DNO-based approach***

The DNO-based approach may be favoured by States looking for pragmatic solutions and the rapid roll-out of new mechanisms. One way to limit the DNO's monopoly is to restrict the scope of its intervention in respect of infrastructure and/or services. In the UK for example, DNOs are authorised to invest in batteries and use them for network-related purposes, but the residual capacity of these batteries must be put up for auction. The regulator can also impose service quality requirements on emerging activities: intelligent meter functions, efficient data transmission, etc. Belgium also operates in this way. Finally, if we intend to assign a role to DNOs in the emerging markets, we must ensure they have sufficient resources to innovate and offer them incentives in this regard.

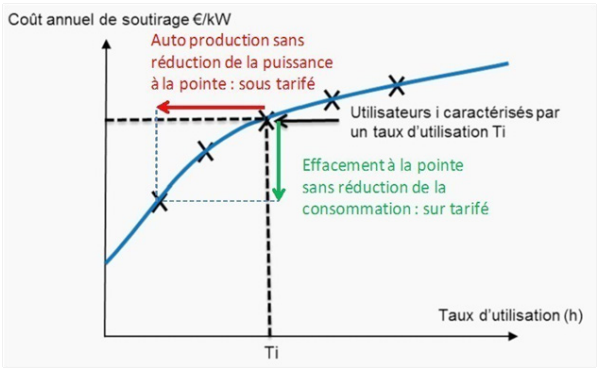
Challenges from the distributor's perspective

Jean-Baptiste Galland
Director of Strategy, ERDF

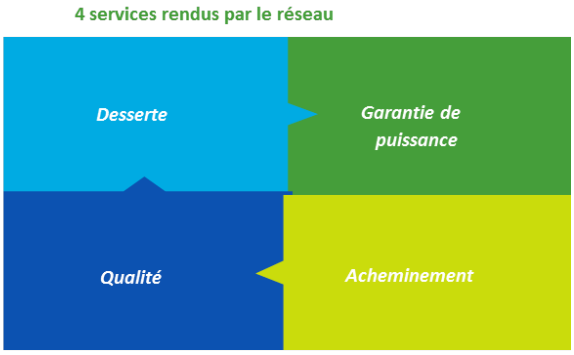
The energy transition represents a shift towards a new economic and social model, a model of sustainable development that is revising the way we consume, produce, work and live together in order to face key environmental challenges, whether climate change or the scarcity of resources. France could reach 47 GW of renewable energy by 2030, which would represent four times the current production of renewables connected to the distribution network. We could have 7 million electric vehicle charging terminals by 2030, and 35 million intelligent meters will be installed between now and 2021. At the same time, digital technologies and data management must be tackled. The energy transition requires the network operator to take into account not only changes in the energy mix but also in the economic model used to manage the electricity system. As we head towards TURPE 5, ERDF reasserts the importance of two objectives: a method that can ensure a pricing structure that is stable, economically relevant and legally robust and transparent; and coordinated action by the relevant players with a view to effecting changes in the pricing structure that will prepare for the future and safeguard the economic efficiency of their interactions with one another.

Adapting rates to the new modes of consumption

Although the dual pricing system (power and energy) has so far enabled automatic selection between consumers, it is becoming less and less appropriate at a time when the consumption behaviour of our customers is increasingly diversified. Let us consider the concave curve which current rates approach and examine, for example, self-production and load management at peak times. Self-producers use a low percentage of their power but are not necessarily absent during peak demand – indeed they are highly present. This means they may represent a significantly higher cost than that for which they are billed under current rates. Inversely, customers who are able to decrease their energy drawdown at peak times without modifying their energy consumption are at risk of being disproportionately charged.



This situation requires reflection on pricing changes beyond simple parameter adjustments: we need to look at all 4 services that the network provides to consumers. In order to understand these services, let us consider an analogy between a self-producer of electricity and someone who plants organic tomatoes in his garden in order to control the quality of what he consumes. In the event of unexpected production difficulties such as a mildew epidemic, our tomato grower will simply go to the supermarket. But he will need to find one close by; this is far from straightforward



if all of his neighbours also grow their own vegetables. This is the first service provided by the network: if the network fails, the self-producer cannot satisfy his needs elsewhere. And if all the neighbours have been affected by the mildew epidemic and turn to the supermarket, perhaps the stock of tomatoes will dry up. We can be certain that our gardener would like to be sure he can access tomatoes whenever he wants. This is the second service provided by the network: the guarantee of a certain amount of power. If production is abundant, the tomato grower may be tempted to sell his surplus of tomatoes. But to do this he must be able to distribute them; this is the third service – energy distribution. Finally, tomatoes grown in an individual vegetable patch will not always be of the same quality. Things are different on the network, whose fourth service is the consistent quality of its energy provision.

In the past, customers have wanted to benefit from these four services together, but in the future some may prefer to access them separately. This is a new problem facing economists.

Meeting diverse public service expectations

Consumers are expressing an increasing variety of demands to which the distributor can provide innovative responses using advanced meters, digital technology and data management. There are already proposals to put in place data platforms, satisfy demands for tertiary modularity using the Linky system, and experiment with shared production in an eco-neighbourhood.

Rolling out these options requires additional resources for which the cost will have to be allocated to the relevant customer categories.

Emphasis on flexibility

The emergence of renewables requires more significant adjustment of the system based on demand – and no longer by relying primarily on supply as in the past. The energy transition makes it imperative to actively manage the network and assigns distributors a key role in this respect. The flexibility options associated with the public distribution network – load management in particular – appear to be one way to achieve this adjustment.

This would mean that distribution network operators would take on three primary functions:

1. Understanding and anticipating the impact of flexibility options on the way in which the distribution network is managed;

2. Facilitating market operations;
3. Purchasing flexibility options to manage the constraints of a smart grid environment.

Flexibility raises questions relating to format (duration, time intervals, notice period?) and the coordination of energy demands (it can be used to serve the distribution system but also the transmission and power systems).

It is with this in mind that ERDF is studying the possibility of a TURPE based on mobile consumption periods. We believe that in the context of high-voltage electricity supply, such a TURPE with a national governance structure would be of low network value. It would however help maintain the current potential for flexibility (1 GW). Using a signal with an option for governance at a local level by the distributor could be more useful – even though this cannot be implemented at this stage – and could increase the value of flexibility.

With regard to managing the low-voltage network, we believe that a TURPE with mobile consumption periods and a national governance structure does not offer any value for TURPE 5. Nonetheless, ERDF proposes to keep this option open for possible implementation following the roll-out of the Linky meters.

Changes in the TURPE 5 pricing structure: key points

These significant changes in energy supply must therefore lead to a revision of the applicable rates in order to steer the decision-making process towards the search for new balances.

In order to keep up to speed with the energy transition and the latest technological developments (renewables, storage, electric vehicles, actively managing demand), ERDF therefore recommends changes to the pricing structure beginning with TURPE 5.

The company's recommendations are divided into **3 categories of measures** which we are confident will be adopted as long-term practices:

- ***Adapt rates to the new modes of consumption*** by rebalancing the drawdown component in favour of the power/fixed proportion and with a 4-index option for the C5 tariff (residential and professional customers);
- ***Respond to diverse public service expectations by passing on the cost of services to those who require them*** using a "public service" component for each client segment to replace the current management and metering components, and by drawing up conditions to regulate the "AccesAccess Smart" scheme;
- ***Meet the distributor's flexibility needs*** by maintaining the peak/off-peak pricing signals (which are useful for water heaters as well as charging electric vehicles in the home) and by introducing the option of local governance of a TURPE with mobile consumption periods in the case of high-voltage electricity supply.

Challenges from the transmission system operator's perspective

Vincent Thouvenin
Director of the regulation, tariffs and finance department, RTE

The revenue generated by providing access to the French electricity transmission network of RTE is worth €4 billion annually, most of which comes from users drawing down energy (distributors, industry and rail networks). The rate is calculated based on the load curves, i.e. how the network is used rather than how consumers use the electricity distributed to them. A dual pricing structure is used (based on power and energy) with varying consumption periods (winter/summer and peak/off-peak hours) and price differences with a range of 1 to 3.

A highly changing context since the previous TURPE on transmission

- ***The energy transition is underway***

Medium-term forecasts relating to the changes in electricity consumption in France have been revised downwards in recent years, although a slight increase is still anticipated. With regard to the figures for electricity drawdown from the supply terminals in the public transmission network, the forecasts are for stability or even a fall in demand depending on the hypothetical scenarios considered. The development of decentralised production partly compensates for the rise in consumption.

These trends, which provide clear indications that the energy transition is underway, raise questions with regard to pricing. Does the pricing structure accurately reflect the new ways in which the network is being used? If electricity drawdown or consumption prove to be lower than the forecasted levels, what impact will this have on customer bills?

- ***Efforts needed to integrate intermittent renewable energies***

The network is a pre-requisite for the large-scale deployment of decentralised renewable energy production, especially in terms of achieving a balance in real time. Given the significant unpredictability of intermittent energy sources on power lines, it would be difficult to maintain service quality at a local level without benefiting from the advantages, assets and externalities of the network.

Accommodating such decentralised energy production initially requires sustained investment. For example, connecting a 500 MW offshore windfarm to the grid represents a cost of €200 million that must be paid by the producer. In the case of decentralised on-land production that falls under France's S3RENR schemes, RTE anticipates the investment of 300 to 400 million euros by 2020. In some areas, the network's capacity depends both on peak consumption demand and the capacity of the production facilities in place. Current scenarios are more complex than in the past, and the requirements in terms of strengthening the network are determined on a case-by-case basis.

- ***The network is seen as a comprehensive guarantee by an increasing number of actors***

The assurance provided by the network is an increasingly important factor in the way it is used. Decentralised solar energy production, which is guaranteed in times of sunshine, has had a significant impact on the energy drawdown being recorded by RTE at its supply terminals. For this reason, the unpredictable nature of production due to varying levels of sunshine and wind conditions is taken into account in the curves that represent energy drawdown on the public electricity transmission network.

Finally, the diversity in the way the network is used and the development of decentralised energy production have added greater uncertainty to the economic model for energy transmission, which had previously remained stable. This raises fresh questions about how best to approach the pricing structure.

How should the cost of accessing the network be adapted to account for the energy transition?

When it comes to adapting the pricing structure, there is a risk of failing to adequately reflect the cost of usage, and in particular the value of the network's ability to provide certain assurances, and therefore of causing charges to be transferred between user invoices. Self-producing users will benefit from a particular energy-based rate; but the costs for which they are not billed must be transferred to other users who do not produce their own energy.

Over time, decentralised energy production facilities must absorb part of the rise in consumption being recorded at supply terminals. If the base rates being charged fall or remain very stable, costs will not decrease at the same speed. This will raise a problem of price variation: the fall in base rates will have to be compensated for by a higher increase in overall prices.

In light of this, RTE has suggested greater balance between the power and energy proportions. This is based on three approaches:

1. ***A study of the provisioning needed for a "minimal network"***. This involves connecting all users of the energy transmission system, with further provisioning to satisfy maximum power demands, and adding the costs of provisioning to transport the corresponding energy. This results in a pricing structure with a power proportion of slightly more than 50%.
2. ***Cooperative game theory*** (allocating costs to a "user grid" Shapley value). This approach differs from that of the CRE in just one respect: it does not use uniform blocks but instead includes the usage curves of those concerned, given that some users are not free to break down their load curves in order to spread out their consumption. Here, too, the power proportion is over 50%.
3. ***A study of the impact of decentralised production on energy drawdown and user bills***. At the level of the national grid, drawdown is falling or stable. The average scenario in RTE's forecast is one of stable energy drawdown between 2015 and 2020 (-0.7%). The ambitious scenario of a rise in the number of

decentralised renewable energy facilities forecasts a fall in drawdown of around 5% to 7%, requiring a change in the pricing structure to make up for the decline in the base rate. When intermittent local energy producers connect to a supply terminal downstream of the transmission system, an energy-based rate will result in a pro rata decrease in their bill to reflect the locally produced energy. With rates based on power, which will be much less averaged out than energy (for example, solar energy cannot be used at 7 pm during the winter), the impact on bills will be significantly lower.

This means that a pricing structure with an excessively high energy proportion does not adequately reflect the “assurance” value of the network, a value that is set to increase over time. In terms of the transmission system, the development of renewable energy production adds an additional dimension of unpredictability (wind conditions and sunshine) to those that already exist.

This value of the network that is partly based on its ability to provide consistency should be reflected in the pricing structure applied to users in order to avoid transferring charges between those who benefit from decentralised production or self-production and other users. It is reasonable and desirable to gradually balance out the power proportion, perhaps targeting a value of 50% over time. RTE is hoping this question will be more directly addressed in future consultations on TURPE 5. Yet this is not the only issue that must be addressed if we are to ensure that the future pricing structure sufficiently reflects the underlying changes in the energy transition.

Rates as energy policy tool

Virginie Schwarz
Director of energy at the French Ministry of Ecology, Sustainable Development and Energy, General directorate of energy and climate

While rates have mainly been considered from an economic perspective since TURPE 1 (coverage and breakdown of costs, investment incentives, etc.), economists now recognise that the network pricing structure is not being met with a straightforward or shared response. This admission reinforces the view that rates are also – and perhaps above all – energy policy tools.

We need to account for the consequences of the energy transition, and in particular the fall in consumption and the rise in renewable energy, in the network pricing structure. Indeed, the rates applied can have a favourable influence on the ongoing transition, not only in terms of the amount charged but also through the breakdown of the proportions attributed to power and energy. This debate lends structure to the discussions on the next TURPE. Wouldn't a proportional increase in the power proportion discourage customers from controlling their consumption? And as for flat-rate electricity charges, wouldn't they have an even more dissuasive effect?

Network rates also serve as an incentive to shift consumption times and as an instrument to control peak demand. In this respect, the Ministry favours the rapid implementation of the 4-index TURPE provided it is optional. As for the proposed mobile-peak TURPE, it benefits from relatively broad consensus in the case of high-voltage energy supply but is the subject of greater debate when it comes to low-voltage electricity, with some parties adopting an essentially economic approach and arguing that it would provide no network value. But doesn't its value in terms of energy policy justify its implementation, given that one of the conditions for its effectiveness is that it should be localised? If this objective cannot be achieved in the short term, how can we move towards this goal?

We believe consultations are needed to advance steadily on this issue.

It should be added that the energy transition legislation acts as a powerful incentive by authorising a pricing approach which, in proportion to the objective of controlling peak demand, departs from a precise reflection of the network costs incurred by users. The extent of this latitude remains to be determined, in a way that does not undermine the principle of fairness for all consumers. At the same time, how can we send out sufficiently strong signals so that customers will adapt their consumption accordingly?

The network pricing signals must also better account for the emerging usage behaviours (self-production, load management, storage and electric vehicles), which provide an indication of the increasing diversity in consumer profiles and expectations with regard to the network.

The overall objective is to firmly establish the new role of distribution network operators in accompanying the energy transition. There is increasing awareness at a European level of the role of market facilitators that they are required to take on.

One issue deserves to be explored in greater depth: timescale. Energy networks are marked by extremely long investment periods, just as pricing processes take place over the long term. The new TURPE will take us beyond 2020, to a world in which the energy transition objectives will already have significantly changed our electricity systems. How can the network rates anticipate these changes and adapt to them with flexibility in a way that supports and stimulates the transition rather than simply catching up with emerging trends? This is a delicate task but one that is crucial if we are to adopt the right approach, ensure the smooth running of the electricity system and achieve the energy transition objectives.

Discussion

A response from an energy supplier (EDF)

For energy suppliers, the key question is about correctly reflecting costs both in terms of amount and structure, providing a firm basis that offers predictability, enables a long-term approach and the development of new offers, and facilitates a form of competition that is in the general interest. This applies in particular to the inclusion of decentralised self-production in the system, as well as quality incentives for consumption modularity. This of course affects the structure of network rates, but also that of supply rates and their consistency (especially with regard to regulated retail prices). Pricing levels are not an issue that can be neglected if we are to achieve consistency between investment and pricing. Furthermore, the pricing signals sent out must also be both appropriate from an economic perspective and practicable. This dual requirement raises key questions and explains the significant diversity in pricing systems.

The available studies and analysis of the cost structure for low-voltage electricity customers suggest the need to inverse the breakdown between the subscription and energy proportions, although the exact procedure for this remains to be determined. With regard to mobile peak periods, it would appear necessary to explore in more detail the value (or lack thereof) that such a signal would represent for the network. As for differentiating between summer and winter rates, which would provide a more accurate reflection of costs, this would be a transparent approach for consumers equipped with Linky meters. However, if this optional solution is chosen, we will have to be aware of the problems of adverse selection that may arise – not to mention the lack of fairness between those with Linky meters and those without. It would be better to plan for implementation at a time when all users are equipped with these devices as part of a gradual but mandatory roll-out.

The injection vs. drawdown debate

In the debate on the breakdown between energy injection and drawdown, the preferred solution so far has been not to charge costs to producers on the basis that in a perfect market energy producers would pass the costs on to consumers. But the electricity market is far from perfect: it has a small number of players and is marked by the intervention of the public authorities when it comes to renewable energies, which skews the way they operate. Would it not therefore be better to rely on traditional economic theory, especially with regard to surpluses (both consumer and producer surpluses) when analysing the respective proportions that these parties should have to bear?

Dominique Jamme

Should we adopt the hypothesis that because the market is imperfect producers cannot pass on to consumers any charges relating to their injection of energy? If we

really decided to move towards such an approach, we would run the risk of seeing producers leaving the market. This is hardly desirable given the energy capacity problems facing France and Europe.

Virginie Schwarz

European integration changes the stakes in the injection versus drawdown debate. When it comes to the breakdown between producers and consumers, if both share the same closed national electricity system, then costs are distributed without causing any real change. As soon as the borders are open, interconnections are put in place and costs are distributed between French and foreign players, this changes the nature of the equation and the question deserves fresh consideration.

Charles Verhaeghe

European integration may be problematic with regard to the implementation of an injection charge, but there are other possible approaches, for example the introduction of such a charge based on power. In particular when referring to geographic zones, we can send out positive signals to support the energy transition and which would be useful for the energy supply system.

Standardised rates

As our understanding of the pricing structure and metering systems and the signals being sent out to consumers become increasingly refined, doesn't it make sense to replace the national rationale of the old order with a local rationale? And doesn't this require us to challenge the dogma of standardised rates?

Dominique Jamme

We are undeniably seeing the development of a certain amount of optimisation and flexibility at a local level, in some cases with incentives for actors to come together and form private networks. But do these phenomena justify challenges against a system of standardised rates that carries huge advantages in terms of redistribution, social justice and simplicity? Our reflections have not pointed to such a vision.

Virginie Schwarz

The government has reasserted its commitment to the principle of standardised rates insofar as it brings fairness and social justice. There is no justification for discriminating between consumers on the basis that they live in a rural area or overseas territory. However, the option of taking different situations into account cannot be excluded. For several years there has been recognition of the notion that producers of renewable energy who are connected to the network must bear different costs depending on their region. They are free to choose where to locate their facility, and this generates varying costs for the network which they must pay for. While respecting the principle of fairness, there is nonetheless a certain margin to consider taking local elements into account, particularly where they are favourable for consumers. This is a trend that should be developed, but

without putting in place a nodal pricing structure.

Should we adopt the Swedish model?

The Swedish model appears to apply the principles of economic theory more than any other. If this is the case, could France take inspiration from its best practices?

Charles Verhaeghe

The model that would be closer to economic theory is that adopted in the United Kingdom. In Sweden, each DNO applies its own method. The national regulator only deals with questions relating to levels and incentives. It is therefore difficult to assert that the Swedish model represents best economic practice.

Generally speaking, network operators try to reflect costs, which are for the most part fixed. Around 15 years ago, Sweden considered the implementation of benchmark network models, not to construct a pricing structure that would offer incentives to consumers or network users, like recently in Spain, but to introduce incentives relating to the level of network operators' revenue by benchmarking them in order to penalise or reward them depending on their results. The experiment proved that this method suffered from too much unpredictability and was legally challenged, and Sweden had to abandon it between 2005 and 2009.

Marcel Boiteux

It is important not to confuse fixed charges and fixed costs. The reality is that customers bear full responsibility for their connection to the network. They are part of a semi-collective network in which the power they draw down partly influences the power of the network segment that serves the few users around them. Beyond that, power no longer comes into play. The fixed rate is not therefore designed to cover fixed charges but to pay for that part of the nearest network for which the customer is responsible. As a result, the question of fixed and proportional charges is linked to the network and in no way linked to the notion of fixed charges and proportional costs.

Paying for energy transmission

There is maximum disparity in wind energy supply, with non-correlated production (e.g. Spain–Germany, Spain–Ireland and Ireland–Denmark). From the French perspective, these appear as wheeling transactions. Can we continue to avoid considering the need to pay for this energy transmission?

Vincent Thouvenin

In the relatively short term, the differences in the energy production mix between France, Germany or Spain lead to significant differences in the national market prices, thereby generating interconnection revenue through the existing infrastructure. This revenue is supposed to be used for further investment in interconnections. For the moment, it is reinserted in the transmission rate at the

time of an annual basis. In the longer term, we must determine the appropriate level for the injection rate, which can only be tackled on a European scale.

Dominique Jamme

Wheeling is not free, it is billed via interconnection bids. This trade-off is on the whole very favourable for French consumers: for the last 10 or 15 years, annual revenue generated by interconnections have largely exceeded the costs incurred by developing them. This revenue is used either to finance further investment or to reduce rates.

Conclusions

Dominique Finon
CEEM, International environment and development research centre (CIRED)

Changes in the electricity system are made necessary by the penetration of intermittent renewable energy outside of the market, which is having a particular impact on distribution networks. This is accentuated by the increasing need for products that can provide a balance between the different systems or market integration. The CRE's consultation document on TURPE 5 does not appear to contain the innovation necessary to support this shift. In reality, it is far from straightforward to design a progressive pricing structure within a system that is undergoing transformation, especially as efforts must be made at the same time to ensure transparent and relatively stable rates.

To what extent does the emergence of active distribution networks run counter to the principles of standardised rates and non-discrimination? Greater inter-regional differences, especially in terms of distribution, could encourage the development of active networks, smart grids in particular. The capacity to invest and innovate is there. The energy transition legislation enables independent players to push forward their offers of flexibility services. Shouldn't ERDF get on board too? This would require additional investment profitability in terms of innovation. It also appears essential to clarify the relationship between distribution network and transmission system operators in the context of local governance. Finally, if ERDF were to adopt a more region-specific grid system, perhaps it could help further stimulate the development of smart grids.

Eric Brousseau
Academic director of the Chair Governance and Regulation

These exchanges have provided a useful reminder of the fact that there is neither neutrality nor objectivity in the existing pricing structure, all the more so since the methods used to calculate costs clearly lack transparency. In reality, the chosen pricing structure, like markets more generally, is above all the result of political decisions. As Fabien Roques and Anna Creti pointed out, any pricing formula depends on the hypotheses used to establish it. These hypotheses reflect both national specificities and priorities (for example in terms of the energy mix), which is of course why rates can differ from one country to another and evolve over time.

Given the multifaceted and fast-paced transformations that mark the current period – affecting energy production methods as much as market structures or consumption models – the challenge is to ensure dynamic management of the changes in the electricity system as a whole and not to optimise just some of its components. In other words, the network pricing structure is not just about optimising the network. The right signals must be sent out to all stakeholders,

including users, in order to manage the ongoing transition. Any changes in price affect the breakdown between stakeholders. We must ensure that the changes introduced are acceptable economically, politically and socially. Added to this is the significant technical complexity of implementation.

These problems are made all the more complex by the high level of uncertainty surrounding future trends. This makes it essential to hold an ongoing debate to clearly identify the constraints facing each stakeholder and the way in which these evolve, as well as the costs incurred and how they should be distributed. We also need to explore alternative avenues for all parties to adapt to the new circumstances and manage the necessary changes to the approaches ultimately adopted.

It is also worth pointing out the potential changes in the roles of distribution network and transmission system operators, who can be expected to behave more like commercial intermediaries. We cannot rule out the possibility that in the future the roles played by intermediaries between the supply and demand for electricity will be divided up – for example into matching, transmission, supply quality management and market balance – and priced in isolation from one another. It will therefore be necessary to determine how to reorganise an optimum (and reliable) system in such a context and how to regulate those responsible for structuring the market.

Lastly, digital technologies could lead to the development of pricing instruments that are at once complex – far beyond the proposed 4-index system – and acceptable for consumers. This of course requires technologies that enable consumers to optimise their own consumption (and, where applicable, their ability to store, restore or produce energy). It would be regrettable if innovation in this respect were constrained ostensibly due to reluctance on the part of users.

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