Asia-Pacific | Europe | North America

Energy - Discussion Paper

Options for network charges with decentralised power generation

Abstract

Power generation in Europe is being transformed by environmental concerns and innovation: rapid improvements and cost reduction in renewables (solar, wind) and battery technology. Domestic and industrial consumers now have increased incentives to generate their own power on-site (also known as "off-grid" or "behind the meter") as an alternative or in combination with power from the network. However, this trend may create concerns for those consumers unable to afford such facilities, that they could end up paying a disproportionate share of total network costs. This is because network operators typically recover the costs of the network through volume-dependent charges although the total costs of the network do not vary with total consumption; they are mainly capital costs. Thus "low" consumption by some consumers may cause higher charges for others. In this paper, we describe possible regulatory changes that may address this challenge.

Introduction

The costs of renewable technologies such as solar panels, windfarms, waste-to-energy and batteries and have fallen considerably over time, reducing the need for government subsidies. Such trends have made it increasingly attractive for consumers (domestic and industrial) to install their own power generation on-site (also known as "off-grid" or "behind the meter").

The deployment of such on-site facilities will be enhanced by further improvements in battery technology and economies of scale. We identify some of the issues associated with this trend.

In Europe, power network charges are predominantly met by consumers (through retail prices) and, to some extent, by generators. In France, Germany and the Netherlands, almost 100% of the charges are levied on consumers. In contrast, in the UK, generators pay a third of the charges. The ratio between charges levied on volumes (variable) and capacity (fixed) varies across Europe, although volume-based charges represent the largest share in most countries, as can be seen on Figure 1.[1]

By using on-site generation, consumers reduce the volume they take from the network and consequently the variable part of their payments. Lower consumption reduces network costs through, for example, fewer power line losses, which can account for 8-15% of the power transmitted and distributed.[2] However, a large share of the network costs are capital costs which do not vary with usage. Therefore, the current trend towards on-site facilities creates the concern that network users who cannot afford the on-site

[1] ENTSO-E (2017) Overview of Transmission Tariffs in Europe.

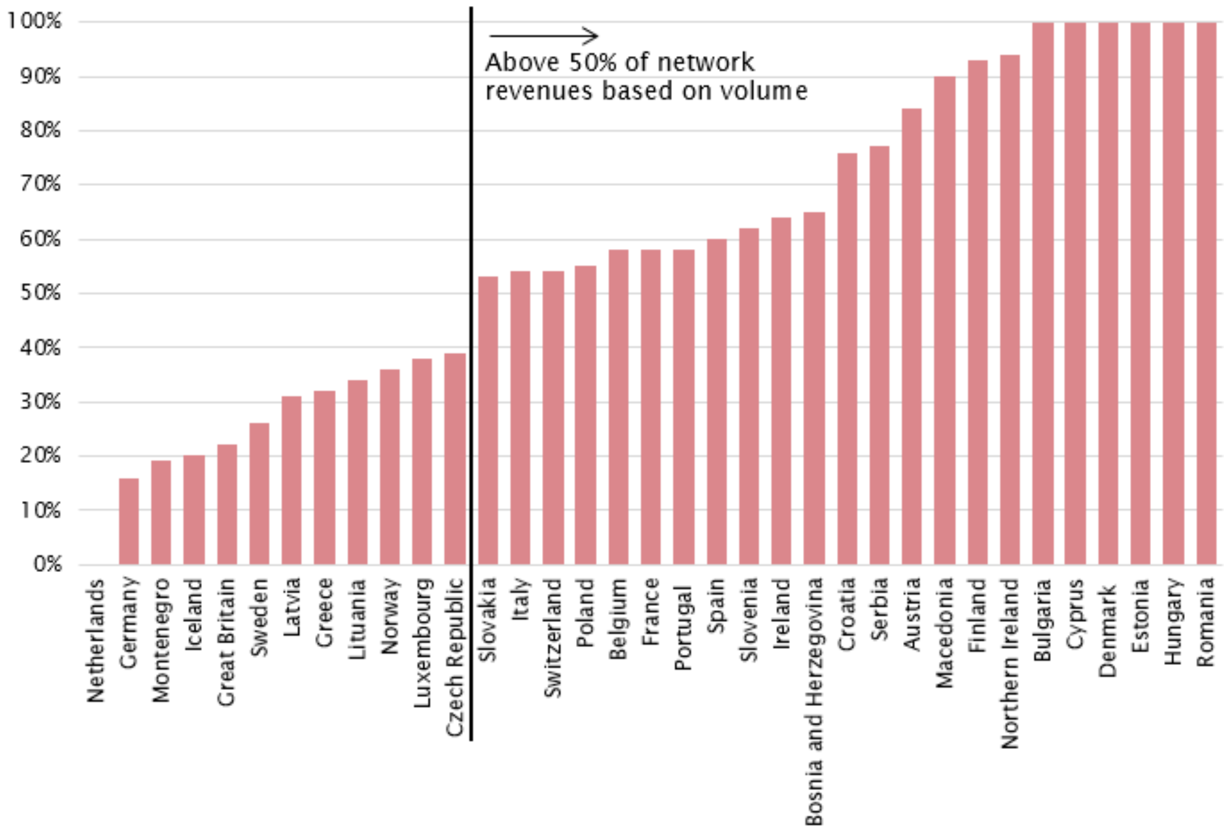
[2] https://blog.schneider-electric.com/

installations will have to pay a disproportionate share of total network costs.

Regulators are considering a range of solutions to avoid such an issue. These include charges that are capacity-based only, i.e. no volume-related charge, meaning customers may continue to pay roughly the same network costs as now, if they all remain connected. Regulators have also considered other options such as a proportion of the fixed fees varying by broad groups of customers' connected capacity (e.g. large, medium and small). Again, under this option, customers may broadly pay what they are paying now for network charges.

In this paper we present some alternative solutions that consider the power market in its entirety, rather than as separate components: the network; power generation; and consumption. These are based on the views of the stakeholders involved: consumers; network operators; and power generators.

Figure 1 Volume-related component of transmission charges in Europe



Sources: ENTSO-E, CEG analysis

Possible solutions

Retail pricing could reflect the extra-value provided by the network

Because of the recent technological advances, consumers are increasingly getting a range of options for their power supply. Options include:

- 100% from the network.
- 100% from on-site facilities.
- Some combination of both.

Moreover, consumers that have on-site facilities may also sell power to the network.

The choice of whether to store or sell power to the network will be driven by the relative prices and the user's aversion to black-outs. Consumers with on-site facilities are exposed to the risk of power loss if generation facilities fail at times of power storage shortage. Black-out risk-averse consumers will therefore tend to maintain access to the network and the security of supply provided by centralised power production.

The power network is analogous to a service with time-specific value. Similar services include gas storage, insurance and other financial products. Tools and models are available to place a value on time-critical benefits.

For example, both gas storage and financial derivatives (power-related or not) often rely on option pricing theory (these yield fair price asset valuations). Equity options such as a call option (giving the right but not the obligation to buy an asset) are typically priced based on stochastic models such as the Black-Scholes formula. More generally, finance practitioners use reputable forward-looking models to value assets with uncertain pay-offs.

Access to the network can also be viewed as insurance against black-outs. It is possible to allocate probabilities (odds) to failure events happening (the risk is therefore "quantifiable"). As such, it is therefore possible to calculate an insurance premia for protecting against this risk using similar models as the ones commonly used in the insurance industry. It makes sense for risk-averse consumers to pay the premia as they get rid of the uncertain risk of failure for a certain price.

Funding centralised generation and storage as insurance products

Renewable energy "crowds-out" fossil power plants (the merit-order-effect), but does not deliver the same level of security of supply. Renewable intermittency would need to be offset by storage batteries to ensure reliable supply.

Notwithstanding the price and efficiency of batteries, centralised generation and storage (such as pumped storage hydro) will remain valuable. This is an important point, with implications for the insurance value of centralised generators. By way of example, consider a power user that wants to install a second on-site facility to back up the first. The full cost of the second plant will need to be met, yet the plant may only be used a few times each year. Furthermore, there remains the risk that both facilities may fail at the same time. Alternatively, the user could rely on back-up from a network of connected generation plants. The risk that all connected plants fail at the same time is much lower than the risk of failure of one plant. Customers therefore can "diversify away" some of the black-out risk by having access to a network of connected plants.

Although they would need to ramp-up quickly, centralised plants providing back-up power would need to operate only for a few hours a year. This increases the need for well-functioning short-term, or 'flexibility' power markets, as system operators are increasingly recognising. It is still possible that long-term investments in fossil-fuelled plants may further decrease due to reduced actual and expected profitability. This may affect security of supply and network operators risk needing to adopt costly measures to maintain the system balance.

Generators that contribute to reducing the risk of on-site facility failure may thus need to receive capacity-based payments. One option may be to combine renewable generation with the opportunity to contract back-up capacity (e.g. battery power or centralised fossil fuel power plants). In addition to the effect on expected profitability, such fixed payments may contribute to reduce the perceived volatility of revenues from power plants. This typically reduces the cost of financing (cost of debt and equity) of new power plants and reduces overall system costs.

Nodal pricing may improve investments in the network but hinder wholesale trading

Nodal pricing is a method to manage network congestion. In short, prices rise at times and places of congestion. Congestion occurs when there is a shortage of transmission capacity to supply consumers with the cheapest source of power available. This is due to redispatching, i.e. transporting power from more expensive sources. Some States in the USA employ partial nodal pricing (for generators only; zonal prices apply to suppliers) and New Zealand has a full nodal price system.

A switch to nodal pricing would provide a signal to consumer-producers (“prosumers”) to inject power into the network at times of congestion. This system aims to benefit the network by increasing supply and reducing demand at the right time.

The ability to determine prices for the network that depend on location (location marginal prices) can also provide more information to network operators and investors on the most valuable investment opportunities in network and generation.

However, nodal pricing is beneficial only if certain conditions are met. In particular, power plants must be able to increase or decrease their outputs quickly and smoothly. Full benefits also require that transmission investments are made in varying scales to meet actual needs. However, transmission lines are generally only available in standard capacity sizes.

Moreover, nodal pricing adds an administrative burden for power plants, suppliers and traders. Nodal pricing can create a difference in price depending on the location and multiply the number of pricing points . It can become more difficult to find a counterparty for a trade in these new areas as the volumes corresponding to each price would be lower than in a larger zone. By multiplying the number of pricing locations, liquidity for hedging products at those locations would be limited. This applies to Europe generally and stakeholders from the Nordic countries have emphasised this issue.

Another issue is that managing the risks that arise from locational variation in price (which does not exist in a single pricing zone) increases the costs and complexity of participating in power markets: it can deter new entrants and affect competition.

Finally, balancing costs may be higher due to more stringent physical constraints on a single point than a wider area. Also, what is true for short term maturities is even more so for longer terms ones, which are of importance for supply portfolios or project managers.

How the three approaches fit into one coherent market view

The three approaches discussed thus far (retail pricing reflecting the value of centralised generation brought by failure risk diversification, maintaining centralised generation and nodal pricing at the network level) can be incorporated into one end-user tariff. The tariff could reflect both hedging costs (or insurance premium) and congestion costs.

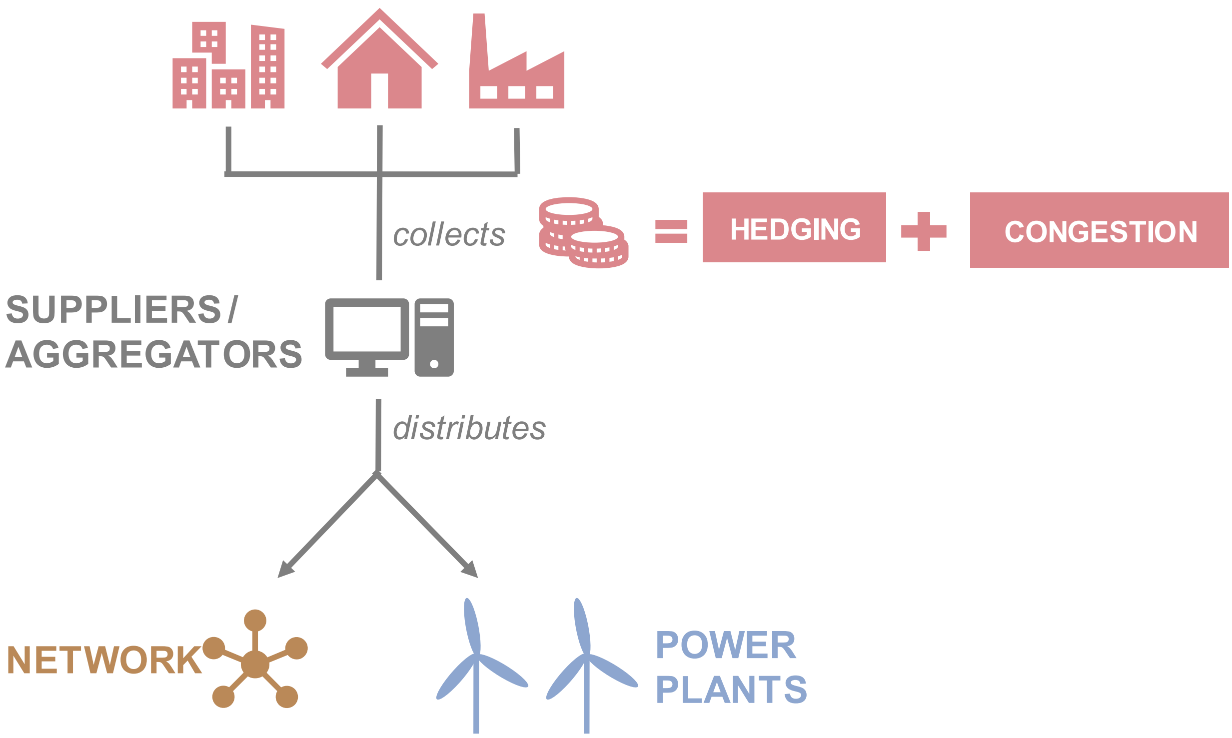
The hedging cost is the value of lost load multiplied by the probability of on-site facility failure. The value of lost load is the value consumers attribute to unsupplied energy, and while this is difficult to estimate, it tends to be a substantial sum for industrial users.

The congestion cost is the additional cost of dispatching higher-cost plants due to transmission constraints. This can be calculated at each node of the network.

Businesses will need to collect these payments from customers. (Suppliers currently provide this function.) It is likely that some parties will also propose to arrange the management of power generated by *prosumers* on their behalf. These "aggregators" could be the historic suppliers as they already have established relationships with customers and recognised brands. Aggregators would distribute the payments to centralised generators and network.

Figure 2 illustrates how the three components can fit into a coherent pricing formula.

Figure 2 How the three approaches can fit together



Source: CEG

Conclusion

Decentralisation of power generation may require a revision of network charges in Europe. Otherwise, some consumers could end up contributing a disproportionate share of the network costs.

This challenge presents an opportunity to modify network charges but also to conduct a comprehensive review of the pricing and funding of power markets: consumers, networks and generation.

Indeed, as innovation is impacting the generation market, there is an opportunity for regulators, consumer-facing businesses and network operators to develop innovative approaches in the way they offer and price their services. These new approaches better reflect new needs and simultaneously alleviate regulators' concern around transfers of costs between customer groups.

While innovation in renewable energy and batteries is impressive, renewables alone cannot currently deliver the required security of supply. The analogy of centralised power generation and distribution as an insurance product could enable the adoption of new forms of pricing. A nodal pricing approach for network charges is also worthy of consideration. Capacity payments to generators may play an important role in the future. Another interesting option for renewable energy suppliers could be to contract back-up capacity, either from battery power or centralised power plants.

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