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International Review of Tariff Structures

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Contents

1 Introduction

Europe Economics, TNEI and Delta-EE have been commissioned by the Commission for Regulation of Utilities (CRU) to conduct an international review of electricity network tariff structures. This paper reviews tariff structures in eight other jurisdictions: Australia, Germany, Great Britain, Italy, the Netherlands, Norway, Portugal, and Spain.

The motivations for choosing these jurisdictions are varied. Most are inside the European Union and consequently subject to the same European regulatory constraints as Ireland. Some of the jurisdictions have transmission networks that, like Ireland, are largely self-contained with limited scope to access energy from elsewhere, e.g. Australia and Great Britain. Others, like Portugal, are part of a wider single electricity market that may have parallels with the Irish Single Electricity Market. There have been important changes in the way that networks are used in many cases, such as the roll out of smart meters. Similar to Ireland, policy goals to realise decarbonisation are an important consideration for energy regulators in many of these jurisdictions, such as the UK with its targets for 600,000 heat pumps by 2028 and no new diesel cars by 2030. Many jurisdictions have recently completed or started workstreams reviewing the structure of network tariffs (e.g. in Spain the competition authority was relatively recently given responsibility for setting tariffs and commenced a review).

None of the jurisdictions included is a perfect comparator for Ireland. Nor do the selections we have included in this chapter imply that there are not useful lessons that could be learned from other jurisdictions.

Three thematic conclusions that might be drawn from these case studies are:

1. It is unusual for tariff structures not to change for a couple of decades. Many of the jurisdictions have seen relatively recent changes to the structure of charges and have ongoing consultation exercises concerning possible further changes. In some cases, this may be required by domestic legislation which defines the frequency with which a regulator has to review the structure of charges. Even where such legislation does not exist, many regulators have chosen to intervene and consider changes to the structure of tariffs fairly frequently. This does not necessarily result in regular wholesale reform of the structure of tariffs. In some cases, the changes will entail tweaks to the existing structure that only affect a subset of consumers (although the effects for these individuals may be significant).
2. Decisions on the appropriate tariff structure often depend on judgements about how to trade-off policy goals relating to fairness and efficiency. The recent trend has been towards tariffs that recover more from capacity charges rather than energy usage charges. This often reflects a judgement that such changes will send better price signals to customers, incentivising decisions that are more guided by the true costs that the customers' actions will impose on the network. Nevertheless, such changes will often mean higher network tariff for customers with low energy usage. This may be seen as unfair, and even raise concerns about how the proposed charges will affect affordability. It is not unusual for regulators contemplating such changes to have a transitionary period. Different regulators will have different views on the appropriate trade-off between the policy goals of efficiency and fairness (and/or affordability), and this will influence the choices they make about the structure of network tariffs.
3. More generally, the case studies suggest that there is not an agreed optimal structure of charges. Differences in policy goals is just one reason why different jurisdictions may have a different structure of network tariffs. It is not the only factor. The networks are not all the same, such that any cost-based charges may look different. Furthermore, differences in the uptake of smart meters, self-generation and the roll-out of EV, to give just three examples, will all affect the appropriate design of

tariffs, with implications for the extent to which certain tariff structures are either feasible or necessary to incentivise behavioural change. Even the current structure of tariffs may influence what structure is deemed suitable in the future (for example, it will influence who wins and who loses from any given reform). Finally, the case studies illustrate the multiple different potential factors that regulators have to consider when thinking about tariff design. The exercise is complicated, and there will not be a single ‘right’ answer that everyone agrees is the optimal structure even if there is agreement on the policy objectives.

The detailed case studies from the eight jurisdictions presented in the chapters below follow the same structure, with the analysis divided into five sections for each. The five sections cover:

- The issues that the distribution network or transmission network is facing that are relevant to Ireland.
- Reviews of network tariff structures that the regulatory body has conducted, or is currently conducting.
- Potential methods proposed by the authority to solve any issues identified by their reviews.
- Changes to network tariff structures that have been implemented to help solve the issues identified.
- A summary of key findings from the case study.

2 Australia

2.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

As in Ireland, and many other jurisdictions, the electricity supply industry in Australia is anticipating significant changes in patterns of energy supply and demand that are both rapid and complex. The drivers and anticipated issues are like those expected elsewhere, including a reduction in the capacity of fossil-fuel power stations, a rapid expansion of variable renewable generation, and mass adoption of technologies like electric vehicles, rooftop solar PV, smart-meters, and domestic batteries. For example, the smart-meter rollout is essentially complete in the state of Victoria.

The Australian Energy Market Operator (AEMO) has projected that, by 2040, the system might have 80 per cent of generation provided by renewable sources for almost 10 per cent of the time. In its 2020 Integrated System Plan (ISP),[1] AEMO identified several transmission projects that will help to secure this energy transition, including additional interconnection between the states of South Australia, Victoria and New South Wales.

These changes are introducing new challenges for system operation. For example, in September 2016, 850,000 customers in the state of South Australia lost their electricity supply during a storm. The AEMO has also declared shortfalls of system strength and of inertia in the state, in 2017 and 2018 respectively, which historically would have been provided by traditional fossil-fuel generators.[2]

2.2 Reviews of network tariff structures

The Australian Energy Market Commission (AEMC) introduced changes in 2014 to the National Electricity Rules which required Distribution Network Service Providers (DNSPs) to introduce more cost-reflective tariffs. This followed concerns about the impact that new tariff structures might have on customers – for example, in Victoria, a three-and-a-half-year moratorium was introduced on introducing time-of-use tariffs, between 2010 and 2013.[3] In this case, the concern was driven by the possible impact that time-of-use tariffs could have on customers when combined with smart meters.

However, tariff reform has been an ongoing process, and is still evolving, with the focus increasingly shifting to consider how to integrate distributed energy resources. The new rules, introduced in 2014, require each DNSP to include within their regulatory submissions a strategy for progressing reform of network tariffs, which is included in their "tariff structure statement" (TSS). The Australian Energy Regulator (AER) expects DNSPs to start planning trials of more innovative tariff approaches within their TSS. AER has been assessing these TSS submissions since 2015.

2.3 Potential methods to solve any issues identified

In 2014 AEMC introduced a new objective for setting network tariffs: "that the network prices that a distribution business charges each consumer should reflect the business' efficient costs of providing network services to that consumer". There are many additional principles that DNSPs have to comply with, including:

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1 AEMO (2020) "2020 Integrated System Plan" [online] p.14
2 Electranet (n.d.) "Power Systems Strength" [online]
3 Smart Energy Network (2010) "Moratorium on time-of-use pricing in Victoria" [online]

- "Each network tariff must be based on the long run marginal cost of providing the service", although the rules allow for flexibility in how the DNSPs determine this long-run marginal cost (LRMC);
  - In its final determination, the AEMC stated that "consumers will be able to make more efficient consumption and investment decisions by comparing the value they place on using the network against the cost of providing network services".
  - The determination also references evidence and analysis from consultants that show the possible benefits of cost-reflective tariffs. AEMC's conclusions about the impacts demonstrated in this analysis were that while some customer bills will increase and others will decrease in the short-term, in the long-run all network prices should be lower due to the reduction in network expenditure.
- The overall revenue allowed by the regulator in the control must "be recovered in a way that minimises distortions to price signals", although again DNSPs are given freedom to determine the method used to achieve this; and
- DNSPs must "consider the impact on customers" of changes in network prices, and must make sure these are "reasonably capable of being understood" by their customers.

The rules also allow for DNSPs to transition customers to new tariff structures gradually over several years, to help manage customer impacts. For example, initially cost-reflective tariffs were offered to customers on an "opt-in" basis, but are now increasingly being offered on an "opt-out" basis. AER forecast that the number of residential customers to face cost-reflective tariffs will increase significantly by 2025, although the magnitude of the increase varies by DNSP.[4]

2.4 Changes to network tariff structures to help solve the issues identified

As described above, each DNSP can propose its own tariff reforms as parts of its TSS submission to the regulator, and this is expected to be an ongoing and evolving process.

As an example, consider the AER's draft decision on the TSS submitted by SA Power Networks for the period 2020-25,[5] which was the second TSS submitted since the new rules were introduced in 2014. SA Power Network's proposed tariff reforms included:

- Continuing to move customers to cost-reflective tariffs by making these mandatory for new connections, upgraded connections, or customers who receive a smart meter;
- Moving customers onto time-of-use tariffs;
- Introducing specific tariffs to encourage consumption during periods of high solar PV generation (called a "solar sponge" period from 10am to 3pm); and
- Introducing some locational tariffs for non-domestic customers.

The AER recommended some further development that could help SA Power Network to strengthen its proposals, with interesting comments about how marginal costs are determined, including:

- The treatment of replacement capital expenditure, which AER does not consider should be included within LRMC estimates;
- Noting that there is a perception that the costs derived by the AIC approach are "not the best representations of long run marginal costs", but that this is outweighed by its low cost of implementation;
- An observation that, within SA Power Network's network, there is no locational element to the cost reflective tariffs, which limits their effectiveness; and

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4 AER (n.d.) "Network Tariff Reform" [online], first graph.

5 AER (2019) "Draft Decision - SA Power Networks Distribution Determination 2020 to 2025. Attachment 18, Tariff Structure Statement" [online]

- Many of the Australian DNSPs – including SA Power Networks – use the Average Incremental Cost[6] method with a 20-year horizon.

In general, the increasing adoption of cost-reflective tariffs suggests that the rule changes are having the intended effect. However, it is clear that in Australia tariff reform is seen as an ongoing process rather than a single outcome, and some aspects of the regulatory change to date – such as the obligation to produce TSS – have reflected this.

2.5 Key findings

Decarbonisation and the switch to renewables is an important feature of the Australian energy market.

Tariff reform is viewed as an ongoing process. The network companies are expected to include strategies for reforming their tariff structures within their regulatory submissions with an expectation from the regulator that they should plan trials of more innovative structures.

The trend is towards tariffs based on long-run marginal costs, with the regulator requiring networks to recover revenues that minimises the distortions to price signals. Individual networks have discretion in the methodologies used to determine these costs-reflective tariffs. There are examples of time-of-use charging, including charges that encourage electricity use when renewable energy (solar) in abundant, and locational charging. At the same time, the regulator requires DNSPs to consider the impact of network prices on customers, and transitioning to new tariff structures over a number of years is permitted.

[6] The average incremental cost method is based on determining the average cost of providing an increment of capacity per unit of new demand which requires that increase in capacity.

3 Germany

3.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

In Germany, the so-called 'Energiewende' remains a key pillar of energy policy. Over the last decade its effects are most clearly visible in the electricity generation sector. Of a total installed generation capacity of around 214GW close to 60 per cent (around 128GW) are made up of renewable energy sources today.[7] Onshore wind and solar PV make up the bulk of the renewable capacity. In 2010, coal (especially lignite) still made up close to half of Germany's gross power production.[8] While coal is still being used today, government plans are in place to phase out the fuel.

Germany's transmission system consists of four TSOs: Amprion, TenneT, 50Hertz and TransnetBW. In addition, there are over 800 DSOs in Germany, and most of them have less than 100,000 customers; the smaller DSOs have around 30,000 customers on average.[9]

The German transmission system serves as an important hub in the European electricity market as well.[10] Amprion is responsible for the Northern part of the European UCTE (Union for the Coordination of the Transmission of Electricity) interconnected system (Belgium, Bulgaria, Germany, the Netherlands, Austria, Poland, Romania, Slovakia, the Czech Republic, and Hungary). TenneT also operates cross-border interconnectors between Germany and the Netherlands, Denmark, Sweden, Austria, and the Czech Republic. In 2021, it launched a first direct current subsea cable link to Norway (NordLink).

3.1.1 Renewable electricity generation

Two key trends have marked the German electricity generation system in the past decade.

- Firstly, the country has seen a stark growth in renewable generation capacity, in large parts from onshore wind and solar PV technologies, which now make up more than half of installed capacity (as noted above). This was driven by strong policy support, especially in the form of feed-in-tariffs.
- The second trend is a noticeable reduction in nuclear generation, sparked by the government's phase out plans (to remove nuclear generation by end of 2022). Since 2011, ten nuclear power plants with a net capacity of 11 gigawatts (GW) have been shut down.[11] The share of generation has fallen from around 30 per cent in 2011 to around 10 per cent today (2021). The bulk of this drop has been cushioned by a rollout in renewable electricity generation.

A key challenge the German electricity networks face is the supply & demand imbalance between the North and South.[12] Most wind capacity is in Northern Germany, whereas most demand comes from cities and industrial areas in the South and West of the country. Due to increased generation from wind and solar, network constraints preventing transmission from the North to the South, delays in grid expansion, and the fact that Germany has only one bidding zone,[13] Northern states are facing power surpluses and Southern

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7 Bundesnetzagentur (2021) "Power Plant list" [online]
8 Clean Energy Wire (2020) "Germany's energy consumption and power mix in charts" [online]
9 IEA (2020) "Germany 2020 Energy Policy Review" [online] p.130
10 IEA (2020) "Germany 2020 Energy Policy Review" [online] p.130
11 IEA (2020) "Germany 2020 Energy Policy Review" [online] p.196
12 IEA (2020) "Germany 2020 Energy Policy Review" [online] p.14
13 A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation. Bidding zones in Europe are currently defined according to differing criteria.

ones are experiencing deficits. This situation is expected to worsen, as the last of the country's nuclear power plants in the South and Northwest close and wind comes online in the North. The imbalance has resulted in "re-dispatch" measures in the South (where grid operators order power stations to ramp up output to compensate for procured electricity that cannot make it South) and curtailment in the North (where grid operators order generators to shut down to avoid congestion). This challenge is expected to cost consumers hundreds of millions of euros annually.

Looking forward, Germany also plans to phase out coal generation (proposal not before 2038).[14] Renewables – and to a smaller extent natural gas-fired generation – are set to make up for some of the lost capacity from the coal and nuclear phase outs. However, the capacity will not be replaced like for like, as currently there not only is an excess in generation capacity, but Germany will be driving for greater energy efficiency in the coming decades. Overall, the country is aiming for 65 per cent renewables share in power consumption by 2030 and 100 per cent by 2050.[15]

3.1.2 Electrification of heat, transport and building sectors

Whilst Germany has made good progress in decarbonising its electricity sector, much more progress is needed in decarbonising heat and transport in order to meet its carbon reduction targets. Electrification will play a major role in Germany's decarbonisation.

There were over 400,000 Electric Vehicles (EVs) in Germany by 2020, making Germany Europe's biggest EV market.[16] It is also the fastest growing EV market in Europe with high uptake expected across the next decade. This growth in EVs will have major impacts on the electricity networks.

Heating buildings in Germany is currently dominated by fossil fuels such as gas and oil. Only a small proportion of heating systems are electric and only 2 per cent of homes have heat pumps.[17] Policies in Germany will mean a shift away from fossil fuels – for example, current regulations mean the removal of old oil boilers and increasing share for renewable energy. The decarbonisation of heat in Germany is likely to be met through the deployment of a variety of technologies, such as biomass, district heating, combined heat and power (CHP) and fuel cells. Electrification will also play a role, although this is currently limited due to high costs of electricity, making electric heating less attractive. Electricity costs are high due to levies, charges and taxes and there are discussions that the Erneuerbare Energien Gesetz (EEG) surcharge that subsidises renewables generation may be removed over the coming years, enabling a greater role of electrification by reducing household bills. The heat pump market is currently small but expected to multiply in size by 2 – 3 times by 2030.[18]

3.1.3 Smart meters, smarter tariffs and electricity prices

Smart meter rollout in Germany is in the very early stages. Germany is not officially rolling out smart meters for all residential properties. From 2017, large consumers with annual consumption in excess of 10,000 kWh were required to install smart meters. This was lowered to 6,000 kWh in 2020, affecting around 15 per cent of households (average household consumption is 3,500 kWh).[19] Households with annual electricity consumption of over 6,000 kWh will receive a digital meter and communication hub enabling consumption data to be processed and shared with households. Consumption data is stored in the device and sent to the metering point operator on a monthly basis, who shares with stakeholders, such as the supplier and grid

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[14] IEA (2020) "Germany 2020 Energy Policy Review" [online] p.12
[15] Clean Energy Wire (2021) "Germany's greenhouse gas emissions and energy transition targets" [online]
[16] Delta-EE Electric
[17] IEA (2020) "Germany 2020 Energy Policy Review" [online] p.51
[18] Delta-EE
[19] Delta-EE Energy

operator. However, consumers can also choose tariffs that require more frequent metering and data transmission. For households with annual electricity consumption of less than 6,000 kWh, smart meters are optional with the meter operator being the decision maker. Smart meters are mandatory in new builds.

Germany has one of the highest shares of non-energy related price components. Rigid taxes and charges, including a surcharge to support renewable energy developments, make up over half of the electricity bill. Up to seven different taxes and surcharges are applied to the German Electricity bill.[20] An energy tax and a 19 per cent VAT are applied to the energy consumption. Several other surcharges are in place to cover for different renewable energy technologies ("EEGUmlage") in general and specific taxes to support CHP ("KWK-Umlage") and offshore wind ("Offshore-Haftungs-Umlage"). Other surcharges cover funding to local governments ("Konzessionsabgabe") and interruptible load agreements ("AbLaVUmlage"). No differentiated taxing of the different tariff terms exists, and the use of the network is not taxed. With regards to smart tariffs, although customers have the choice between different contracts, dynamic pricing contracts are practically non-existent, due to the lack of smart meters today.

3.2 Reviews of network tariff structures

The four TSOs and over 800 DSOs in Germany each charge different tariffs depending on their internal cost structures. Lack of transparency in network tariffs is regarded as a major issue in Germany today. A study by German think tank Agora Energiewende describes network tariffs in their current design as a "blind flight through the fee system".[21] The authors suggest that the grid costs and grid fee structure is currently so non-transparent that it is de facto impossible to efficiently regulate grid expansion and grid costs.

Not only are tariff structures lacking transparency, but the charges can vary significantly from one network to the next – and data on average rates are not available.[22] A key contributor to this situation is supply & demand imbalance between the North and South. While the North (and East) are relatively sparsely populated, those are the areas requiring the most grid expansion / reinforcement, due to the steep growth in wind deployment. Consequently, the network charges per customer have been steadily increasing for years relative to other regions.

In order to even out these regional tariff differences and to mitigate the opacity of charges, the German Federal Government passed a law on 25 April 2018 to introduce more uniform national network tariffs, which will be introduced gradually from 2019 until 2023.[23] Regions with previously very expensive grid fees will benefit from this - regions with previously low grid fees, however, will probably have to pay more, especially in the low-voltage range relevant for household and small business customers.

3.3 Potential methods to solve any issues identified

The German Federal Government passed a law on 25 April 2018 to enable more uniform national network tariffs – "Gesetz zur Modernisierung der Netzentgeltstruktur (NEMoG)".[24] The regulation includes the following key reforms:

- So-called 'avoided' network tariffs for intermittent electricity generation plants (i.e. wind and solar energy) will be removed in three steps from 2018 to 2020. 'Avoided' network tariffs are payments for decentralised feed-ins that are financed from grid costs. 'Avoided' network tariffs were introduced on the assumption that locally generated electricity would also be consumed locally, without having to use

20 Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.55
21 Agora Energiewende (2019) "Ntezentgelte 2019: Zeit für Reformen" [online] p.10
22 Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.54
23 Next Kraftwerke (n.d.) "Was ist das Netznutzungsentgelt?" [online]
24 BMWi (n.d.) "Regulierung der Netzentgelte" [online]

a higher-level grid structure and thus reducing overall grid costs. However, as noted above, this assumption is becoming less accurate, as decentralised fed-in wind and solar power must instead be transported from the North to the centres of consumption in the South and West, for which grids are needed. The mitigation of the ‘avoided’ network tariffs is supposed to help reduce regional differences in grid charges and so also in electricity prices for end customers.

- The costs of connecting offshore wind farms and installing underground cabling of the transmission grid are being adjusted. From 1 January 2019, the offshore connection costs will no longer be included in the network tariffs, but in a newly formed offshore grid levy. In September 2018, the Federal Ministry for Economic Affairs and Energy (BMWi) presented a draft bill that will further specify the calculation method for the offshore network levy.

In addition to unifying the network tariffs, as described above, the German government is planning billions of euros in subsidies for network tariffs from 2023.[25] It is planning to participate in the financing of network tariffs for private and commercial electricity consumers from 2023 onwards, based on a proposal by the Coal Commission.[26] The proposal, made in autumn 2019, envisages reducing network tariffs by an amount of around two billion euros per year. The plan would bring immediate relief to large customers such as industrial companies, and end consumers at the distribution grid level.

3.4 Key findings

The German electricity system faces challenges of increased renewable capacity on the networks and increased electricity demand due to electrification. A key challenge if the supply and demand imbalance between the North and South: most wind capacity is in Northern Germany, whereas most demand comes from cities and industrial areas in the South and West of the country.

Tariff structures in Germany are currently going through some changes. Firstly, this will address the lack of transparency in network charges and even out regional differences. At the moment, tariffs vary widely between regions with those in the North facing the highest charges due to reinforcements required due to large quantities of wind generation in this region. The changes will also reduce network costs to the benefit of large customers and end users on the distribution networks.

[25] Next Kraftwerke (n.d.) “Was ist das Netznutzungsentgelt?” [online]

[26] To reach a broad social consensus on the coal phase-out plan, the federal government established a Commission on Growth, Structural Change and Employment in June 2018. Source: Next Kraftwerke (n.d.) “Was ist das Netznutzungsentgelt?” [online]

4 Great Britain

4.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

Great Britain has three Transmission Network Operators (TNOs): National Grid for England and SPEN (Scottish Power Energy Networks) and SSEN (Scottish and Southern Electricity Networks) for Scotland. The TNOs own, maintain and operate the transmission network infrastructure. The National Grid Electricity System Operator (ESO) is the only system operator for Great Britain and is responsible for balancing and managing constraints on the network in real time. The National Grid ESO operate the system but are not responsible for the infrastructure – although it may make recommendations to the TNOs about where reinforcements on the networks may be needed to reduce system costs.

There are 14 licensed distribution network operators (DNOs) in Great Britain, and each is responsible for a regional distribution services area. The 14 DNOs are owned by six different groups: Electricity North West Limited; Northern Powergrid; Scottish and Southern Energy; Scottish Power Energy Networks; UK Power Networks and Western Power Distribution.

Ofgem is GB's independent energy regulator and sets price controls for the transmission and distribution networks. These set out the allowed revenue that can be earned by network operators over the length of a price control period – revenues are set at a level which covers the companies' costs whilst delivering value for consumers.

4.1.1 Electricity generation mix

In 2019 the UK government passed laws which require the country to reduce all greenhouse gas emissions to net zero by 2050 with further announcements to achieve reductions of at least 68 per cent by 2030 and 78 per cent by 2035. To meet these ambitious targets, an uptake of generation from renewable energy and a move away from fossil fuels is necessary, with the UK planning to phase out all coal-fired electricity generation by 2025. This also has an impact on energy distribution and storage, which will need to adapt to accommodate this shift, alongside carbon capture and storage (CCS). Natural gas-fired generation still provides most of the electricity in the UK, but renewable power in total at times has taken the lead spot in the generation mix towards the end of 2020.

4.1.2 Renewable electricity generation

Renewable energy sources broke records throughout 2020 for their contribution to UK's overall power mix, providing a 40 per cent share in power generation for the first time in Q1 2020 and remained above this level until the end of Q3 2020. Wind power was the primary factor in driving the record share of generation. According to the Department for Business, Energy & Industrial Strategy (BEIS), wind offshore facilities increased their share of the mix in Q3 2020 by 13 per cent compared to Q2 2020.

More intermittent and decentralised electricity generation are increasingly making its way onto the GB distribution system, which have an unprecedented impact on the distribution networks. Like Ireland, Great Britain is an island electricity system. The issues facing GB are similar to Ireland, perhaps less acutely, whereas countries in continental Europe are not yet facing these issues due to the interconnected nature of the European electricity system.

In Great Britain, the DNOs must increasingly manage distributed energy resources which are increasingly unpredictable by nature, alongside growing electricity demand caused by trends such as electrification of heat and transport through the uptake of electric vehicles (EVs) and heat pumps.

To manage this situation, a greater strategic coordination and increased investment in network infrastructure, storage and other flexibility services is needed. Overall electricity demand will increase, but also peaks of demand could be magnified if not managed correctly. In addition, generation could become less flexible due to the nature of the move to decentralized generation dominated by renewables, which is less controllable than conventional fossil-fuelled power plants. Flexibility is vital because the challenge posed by increased electrification of heating and transport is not only an increase in overall demand, but heightened peaks of demand. A more volatile demand schedule increases the risk of under-utilisation of conventional generation assets. Furthermore, traditional sources of flexible generation, such as coal-powered generation, will have to reduce their capacity in line with decarbonisation targets. This will reduce the overall flexibility of the generation mix unless replacement sources are found. A recent report from Carbon Trust and Imperial College London for BEIS found that the UK could save between £17-40 bn across the electricity system from now to 2050 by deploying flexibility technologies, against a counterfactual where flexible technologies are not introduced.[27]

Therefore, one option to help manage this is to make it easier and more attractive for consumers to shift electricity demand from peak periods, and to increase the provision of energy storage (e.g. using EV batteries, smart charging, and home energy systems as well as grid scale storage). System operators and network owners will have to integrate a higher number of small-scale and inflexible sources of generation while maintaining high standards of security of supply.

The increasing number of distributed energy resources have created a challenging situation for network operators. One way to deal with this – on both the transmission and distribution networks – has been to offer flexible connections, allowing generators to connect with the condition that the network operator can curtail them (without compensation). Generators that do not want a flexible connection will have to pay higher costs for a connection to cover reinforcement costs.

Nevertheless, a lack of clarity around firmness of ‘standard’ connections has been identified by Ofgem, while there is also a need to improve clarity of access to the transmission network for small, distributed generation. There is an intrinsic link between access rights and tariff charges because terms of access essentially define what a generator is buying when paying a tariff. Therefore, clear and well-defined access rights are important for facilitating optimum decision making.

During a recent review Ofgem was advised that the current arrangements do not provide sufficiently refined access choices and forward-looking charging signals to generation on the distribution system regarding the impact at different points on the network, nor a good signal for where investment in new network capacity would be beneficial. This includes ensuring sources of flexibility are provided with the signals needed to determine what benefit they can have to the network. Ofgem has since carried out a Targeted Charging Review (completed in 2019) aiming at adapting the network tariffs to the new energy landscape where renewable energy resources (RES), distributed energy resources (DER) and flexibility services play an important part. Ofgem is also seeking to address the separation between arrangements for transmission and distribution access and charging, which could be distorting competition between different sizes and types of projects. Further detail on this is given below.

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27 Carbon Trust & Imperial College London (2016) “An analysis of electricity system flexibility for Great Britain” [online] p.5

4.1.3 Other key decarbonisation trends

The UK Government has set ambitious targets around electrification, both in buildings and transport, which will have a significant impact on electricity networks.

The sale of new petrol and diesel cars will be banned from 2030, resulting in a major shift to EVs and thousands of charge points installed across the UK. The Government has also outlined a target to install 600,000 heat pumps per year by 2028 – a significant increase from current installation rates. Both of these trends will require major changes to the electricity networks, including reinforcement programmes and/or flexibility approaches (e.g. using assets such as batteries and thermal storage). Ofgem believe that network access and charging arrangements need to provide better signals about the costs and benefits of using the network at different times and locations, and are in the process of reviewing the current arrangements with a Significant Code Review, discussed in section 4.2.2.

4.1.4 Smart meters

Great Britain had a target to reach 100 per cent smart meter penetration for households and small businesses by the end of 2020. Energy suppliers had to take 'all reasonable steps' to rollout meters to their customers by this date but problems have been faced with customer uptake, and technology and software issues. The COVID pandemic negatively impacted the rollout in early 2020 and by June 2020 only 31 per cent of GB homes had a smart meter. The government announced that the deadline for completing the smart meter rollout would be pushed back to June 2024 – when energy companies need to have installed smart meters in 85 per cent of their customers' homes. Reasons given by suppliers for this delay included challenges with: customer engagement, third-party contracts, remote upgrades of faulty first-generation smart meters (SMETS1) and the transition to second-generation meters (SMETS2).[28] The pandemic led to a further deadline extension of one year, now set at June 2025. High voltage connected customers already have smart metering capabilities. Most of the smart meters installed can offer 30-minute measurements.

4.2 Reviews of network tariff structures

For most customers, including domestic customers, the current network tariff design focuses on volumetric and fixed costs. The volumetric charge varies by time-of-use to achieve better cost-reflexivity. The absence of a capacity charge means that peak kW demand (the biggest contribution a consumer makes to network costs) is not reflected in the tariff charge.

Ofgem is undertaking a series of reforms to the structure of the UK energy system, recognising that electricity is being both generated and used in different ways, at different times and in different locations than has historically been the case.[29] Within this is a comprehensive evaluation of electricity network charging comprising two reviews; the first examining the residual, non-signalling component of electricity network charges while the second review looks at the forward-looking component. The final decision and impact assessment for the former was published in 2019. The final decision for the latter is due to be published later this year (2021).

4.2.1 Review of residual charging

The Targeted Charging Review (TCR) was a Significant Code Review launched on the 4th August 2017 that focused on "residual" charges in electricity network tariffs.[30] Residual charges are designed to recover the

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[28] Ofgem (2019) "Smart Meter Rollout: Open letter on energy suppliers progress, future plans and regulatory obligations" [online]

[29] Ofgem (2019) "Targeted Charging Review: decision and impact assessment" [online] p.12

[30] Ofgem (2017), "Targeted Charging Review – Significant Code Review Launch Statement" [online]

remaining network expenditure that is not picked up by the forward-looking component of tariffs, which itself reflects the marginal cost to the network of electricity consumption. Unlike forward-looking charges, which are discussed in Section 4.2.2, residual charges are not designed to send signals to consumers for how networks should be used. They are necessary because forward-looking charges do not tend to fully recover network companies' allowed revenue in full.[31]

Prior to the review, residual charges levied on network users were largely based on the user's consumption from the grid. Some consumers or businesses are able to generate their own electricity and therefore avoid paying some or all of these charges, but still benefit from the ability to draw on the grid as and when they need. However, the total revenue operators can recover is essentially limited by the price control, and therefore the total residual charge is a fixed amount each year.[32] The costs avoided by users that can invest in reducing their network usage fall to users who are unable to take similar action. The increased price they face sends a distortionary signal to these consumers about their network use. This signal was deemed inappropriate by Ofgem as "there is no associated reduction in system costs through responding to the signals sent through residual charges".[33]

Advances in technology are allowing more and more users to invest in methods of reducing their use of electricity from the grid, meaning an increasing amount of the residual charge is being cross-subsidised by users who cannot or do not invest in reducing their network use. This prompted the review into how residual charges are set.

The review was shaped around three core questions on residual charge design[34]:

1. Who should pay - generation, final demand or a combination of both?
2. What mechanism should be used to collect charges? For example, should it be based on volumes used or other means, such as a fixed or capacity charge?
3. How should charges be implemented – by voltage level, user group, ability to respond to signals, or a combination of these?

The assessment of potential changes was driven by three principles summarised below:

- Reducing harmful distortions - Residual charges should be designed to minimise their impact on user's investment or operational decisions. Users adjusting their behaviour because of residual charges leads to inefficient network use, as users' decisions to consume an additional unit of electricity should (ideally) be based on the marginal cost of that additional unit (reflected in the forward-looking component). Furthermore, if some users decide to avoid residual charges by reducing consumption, it increases the residual charges on other users, further distorting their decisions. Any residual charging will inevitably cause some amount of distortion, but large distortions should be avoided.
- Fairness - This principle comprises five criteria: equity and equality,[35] simplicity, transparency, justifiability[36] and predictability. Similar users should pay similar residual charges.

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[31] Forward-looking charges do not usually wholly recover network costs because they merely reflect the marginal cost to the network of a user consuming an additional (marginal) unit of energy. Since a significant fraction of the costs of providing electricity are fixed (i.e. do not vary with consumption) they are not captured by the forward-looking component. Therefore, the residual charges recoup the left-over, or "residual", costs.

[32] Though not directly set by price controls, total residual charges for operators are the difference between their price-controlled allowable revenue and forward-looking charges.

[33] Ofgem (2019) "Targeted Charging Review: decision and impact assessment" [online] p.14

[34] Ofgem (2017) "Targeted Charging Review: update on approach" [online] p.8

[35] The equity concept is that those that use the network more (thus imposing more costs) should pay more. The equality concept relates to Ofgem's principle that residual charges should be set in a way that reduces any distortions to user's behaviour. See paragraph 1.3 of Annex 1, TCR Principles [online]. Ofgem recognises that at times these are conflicting concepts. They determined that a balance of equity and equality is needed for residual charges.

[36] Meaning any change to charging regimes must be founded on strong logic and procedural fairness in the decision-making process, so that it is more likely to be accepted by users.

- Proportionality and practical considerations – The disruption costs of proposed changes to residual charging should be in proportion to the benefits the change will deliver. Practicality involves assessing considerations such as metering requirements and data calculations that proposed changes may entail.

4.2.2 Review of forward-looking charging

The Network Access and Forward-looking Charging Review (NAFCR) is an ongoing significant code review launched by Ofgem on the 18th December 2018 that focuses on user's access to electricity networks and the forward-looking component of electricity tariffs.[37] The goal of the review is to improve the efficiency and flexibility of the UK's electricity networks in response to changing technologies and the transition towards decarbonisation.

The NAFCR is reviewing both distribution and transmission Use of System (UoS) charges. This involves reviewing the methodology for the network cost models used to set the charges, the extent of locational granularity and the basis on which users are charged (e.g. agreed capacity versus time-varying charges).[38] These are all elements that affect the accuracy of the signals sent to consumers.

The three guiding principles of the NAFCR are:[39]

- Supporting efficient use and development of network capacity – Ofgem believe a key element of this principle is supporting decarbonisation at the least cost to consumers.[40]
- Reflecting the needs of consumers as appropriate for an essential service – Small users in particular are identified as needing protection from welfare-harming arrangements.
- Practicality and proportionality – This is the same as the principle for the TCR, above.

4.3 Potential methods to solve any issues identified

4.3.1 Residual Charges

The 2017 working paper for the TCR set out seven possible options for residual charging mechanisms.[41] This was narrowed down to four basic options through workshops with stakeholders in 2018; fixed charges, gross volumetric charges, ex-ante capacity charges and ex-post capacity charges.

[37] Ofgem (2018) "Network Access and Forward-looking Charging Review – Launch Statement" [online]
[38] Ofgem (2020) "Network Access and Forward-looking Charging Review – Open Letter" [online] p.4
[39] Ofgem (2018) "Network Access and Forward-looking Charging Review – Launch Statement" [online] p.7
[40] Ofgem (2020) "Network Access and Forward-looking Charging Review – Open Letter" [online] p.1
[41] Ofgem (2017) "Targeted Charging Review: update on approach" [online] p.15

Table 1: Summary of four basic options for residual charges from Ofgem's TCR "minded-to view" paper

Basic Option	Description	Challenges	Possible Variations
Fixed Charges	All individuals within each customer segment levied the same fixed charge, based on historical contributions of that segment to network costs.[42]	Using historical contribution to determine fixed charge doesn't reflect changing use of the grid in the future.	Alternative methods for calculating the fixed charge. Add a variable element to the fixed charged.
Gross Volumetric Charges	Per kWh charge based on all user's consumption	Current metering technology incapable of calculating for most users. Could be seen as an invasion of privacy (collecting "behind-the-meter" data).	Only apply to large, non-domestic users
Ex-ante capacity charges	Charge based on agreement with individual customer on connection capacity	Incentivises capacity reduction to avoid residual charges (distortionary since residual charges shouldn't incentivise behavioural changes).	Hybrid option with variable element
Ex-post capacity charges	Charge based on an individual's peak usage, whenever this occurs each year	Incentivises peak usage reduction (distortion) Metering technology not currently capable of such a charge for most users.	Hybrid options with fixed element

Source: Ofgem (2018) "Targeted charging review: minded to decision and draft impact assessment" [online] p.26

A "minded-to view" paper published in 2018 outlined Ofgem's position that all final demand users who benefit from the electricity network should pay towards its upkeep in a fair manner. Two leading options for residual charges were presented for consultation:

- A fixed charge, with the charge for customer segments set by net consumption volume and Line Loss Factor Class.[43] See Figure 1 for an explanation of the mechanism for setting these fixed charges. Unlike the initial proposal of using historic contributions, this refined option updates the split of the residual between segments on an annual basis.
- Agreed capacity charges, using deemed levels for households and small businesses and explicitly agreed levels for larger businesses

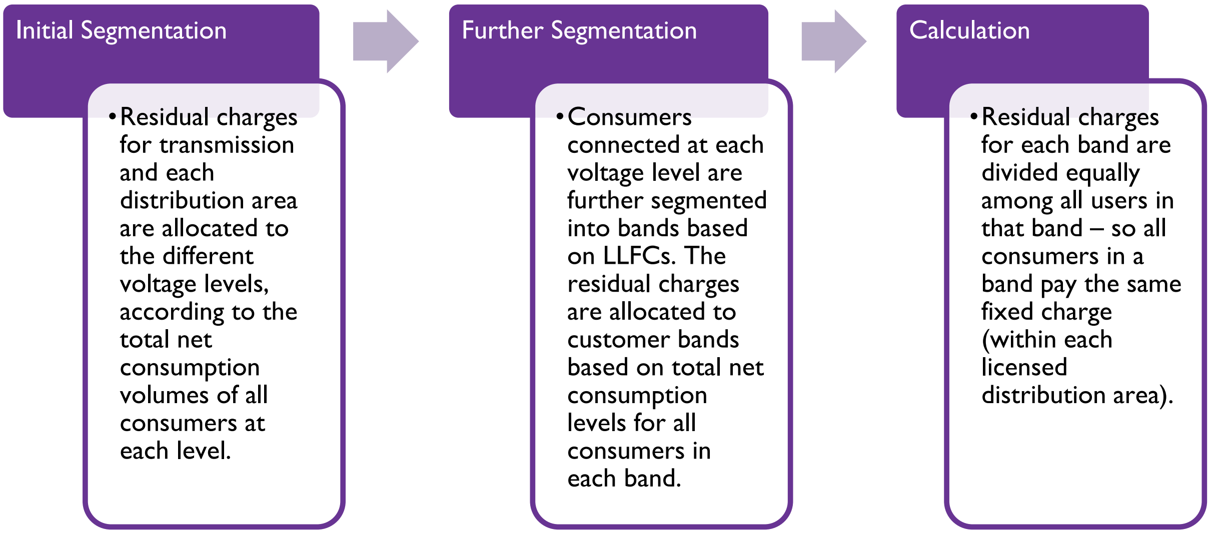
These two options were chosen because they were viewed as most likely to reduce distortions and distributional impacts. Of the two, fixed charges were viewed as the fairest, based on the criteria of simplicity, transparency, justifiability, equity and predictability.[44]

[42] Using segments' "historical" contribution to costs to determine fixed charges means the split of the residual between customer segments does not update over time. Contribution to costs is based on net consumption volumes of each segment.

[43] LLFC is a classification of distribution charges that reflects both the amount of distribution infrastructure used to supply the exit point and the amount of energy lost through heating of cables, transformers, etc.

[44] Ofgem (2018) "Targeted charging review: minded to decision and draft impact assessment" [online] p.32

Figure 1: Mechanism for setting the fixed charge under Ofgem's preferred option



Source: Ofgem (2019) "Targeted Charging Review: decision and impact assessment" [online] p.36

4.3.2 Forward-looking charges

Some of the options that have been taken forward for further consideration by Ofgem under the NAFCR are listed in Table 2.

Table 2: Selection of proposed changes to distribution and transmission UoS charges in the NAFCR

Option Area	Description of different options
Distribution	
Methodology for network cost models	• Charges based on forecasted need of reinforcement to the Extra High Voltage network. • An "Ultra long-run" or allocative cost model. Signals to users that an additional unit demanded will, at some point in time, require investment in reinforcing or replacing network infrastructure.
Locational Granularity	• Splitting the 14 distribution licensed areas into smaller zones, based on primary substations. • Varying time-of-use bands by location to reflect variation in peak demand times. • Varying credits for embedded generation by location and charging generators in "generation-dominated areas" that contribute to costs (currently receive credit as default).
Basis on which users charged	• More accurate time of use bands (seasonal). • Agreed capacity as basis for charges.
Transmission	
Locational Signals	• Embedded generation – Distribution-connected generation pay similar/identical local transmission charges to larger generators
Basis on which users charged	• More accurate time of use bands (seasonal) • Agreed capacity as basis for charges

Source: Ofgem (2020) "Network Access and Forward-looking Charging Review – Open Letter" [online] p.4

There are other options under consideration outside of those listed in Table 2, as well as a series of proposed reforms to network access rights which Ofgem are reviewing in parallel, believing they are currently poorly defined or lacking in choice for both small and large users, limiting the information to network users about where usage might contribute to costs.[45] This includes reviewing when users can import/export electricity from/to the network, and how much.

4.4 Changes to network tariff structures to help solve the issues identified

4.4.1 Residual Charges changed to a fixed charge

The outcome of the TCR, published in 2019, was that Ofgem decided residual charges will be levied as fixed charges on final demand users, with the mechanism slightly refined from the 2018 outline. For domestic users, there will be a single transmission residual charge and a single distribution residual charge within each of the 14 licensed distribution areas in the UK. The reform is being introduced incrementally to mitigate distributional impacts and help with predictability of charges for consumers. The fixed transmission residual charge is coming into effect this year and the distribution charging regime is due to begin in 2022.[46]

Fixed charges benefit from being the least distortionary mechanism for residual charging, because they can only be avoided by user's disconnecting from the grid entirely (an unlikely course of action). Under the new system, all domestic consumers in a distribution network operator (DNO) area, of which there are 14 in the United Kingdom, pay the same charge. For non-domestic users, there is further segmentation by voltage level and by either net consumption volume, as shown in Figure 1 or by agreed capacity where possible (this will be larger consumers.

4.4.2 Forward-looking charges

Ofgem is yet to publish its minded-to decision paper for the NAFCR, initially due in late 2020. This will be followed by a final decision and impact assessment. The most recent publication on forward-looking charging reforms is a request for information from industry stakeholders on the potential costs of the currently shortlisted options seen in Table 2.[47]

4.5 Key findings

In Great Britain there are ambitious targets for decarbonisation, and increased electrification of heating and transport will have important implications for demand. Against this background, the regulator Ofgem is keen that decarbonisation of the network should be promoted at the least possible cost to consumers. An important element of the net-zero transition is seen to be well-defined network access rights that offer choices to network users on how they connect to and use the network.

Forward-looking charges should send accurate signals to users about the contribution to network costs their consumption has. To achieve this, Ofgem is considering proposals such as increased locational granularity, seasonal time-of-use charging and an "Ultra long-run" cost methodology.

To the extent that forward-looking charges will not allow the networks to recover costs, Ofgem allows residual charges. The intention is that these charges should have the minimum effect on behavioural decisions by users. Ofgem sees a fixed charge as the best way to achieve this.

[45] Ofgem (2018) "Network Access and Forward-looking Charging Review – Launch Statement" [online] p.4
[46] Ofgem (2019) "Targeted Charging Review: decision and impact assessment" [online] p.8
[47] Ofgem (2020) "Request for Information for Access and Forward-Looking Charging Review" [online]

5 Italy

5.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

Terna SpA - Rete Elettrica Nazionale (Terna) is the Italian transmission system operator, while Terna Rete Italia owns and manages most transmission assets in Italy. Terna deals with high-voltage electricity transmission. The main distribution companies in Italy are e-distribuzione, Unareti, Areti, and Ireti.

The Italian electricity sector has been evolving rapidly due to energy transition, focused on achieving sustainability goals and improving system security. The most significant elements are the integration and management of renewable energy, energy efficiency, grid digitalisation and storage systems.

In 2017, the Italian government approved the National Energy Strategy setting out future policy goals for the electricity sector. The objective was to make the national energy system more competitive, more sustainable, and more secure. Italy had already achieved its 2020 renewable energy targets by 2015. This was backed by generous government subsidies and resultant capital investment, but these are not available anymore and due to the absence of subsidies, projects could largely be exposed to volatile merchant prices.

The country also continued to progress in terms of market liberalisation and infrastructure development, notably in the electricity market where transmission improvements between North and South, as well as market coupling, have resulted in price convergence throughout the country.

5.1.1 Electricity generation mix

The country has experienced high growth in the renewable energy sector and has been successful in integrating large volumes of variable renewable generation in its electricity system. By 2015, Italy had 17.5 per cent of its total energy consumption from renewable energy sources in comparison with the 17 per cent target set for 2020. By 2019, natural gas was still the main source for generating electricity, accounting for almost half of electricity generation but hydro accounted for 16 per cent, solar 8 per cent and wind 7 per cent. According to the National Energy and Climate Plan submitted to the European Commission earlier this year, by 2030 Italian solar capacity is forecast to increase from 21 GW at end-2018 to 50.9 GW. Wind capacity is set to increase from 11 GW to 18.4 GW. Italy has the second-largest solar PV installed capacity in Europe and is targeting to make headways in the offshore wind segment.

The Italian government has put energy and climate at the centre of its political agenda, setting very ambitious targets for renewables by 2030; aiming for renewables to reach a 30 per cent share in energy consumption and a 55 per cent share in electricity generation.[48] The expansion of renewables will help to meet the Government's ambition to meet net carbon neutrality by 2050. Renewable capacity, excluding hydropower, is estimated to reach 60 GW by 2030 from the current 36 GW, growing at a compound annual growth rate (CAGR) of 4.5 per cent. This continued growth in renewables will have major impacts on the ability of the electricity grids.

5.1.2 Other key decarbonisation trends

Italy is an important market for heat pumps (mainly reversible air-air, but also hydronic), but as the country is on track to meet its ambitious decarbonisation targets, the focus is now firmly on decarbonisation of

[48] IEA (n.d.) "Countries – Italy" [online]

heating via electrification. There is a large stock of dwelling with gas heating, although reversible heat pumps will continue to be popular in milder climate regions.

Another important trend was the traditionally very slow uptake of battery EVs in Italy, a very traditional car segment of Europe. Until 2020, sales of EVs were marginal, but during 2020, sales of EVs grew strongly from a very low base. The Italian motorways will have a massive infrastructure upgrade with ambitious plans for high-power chargers to be installed across the network's petrol stations, which can contribute to further growth in battery EV sales.

The growing electrification of heat and transport will have impacts on the capacity of the electricity networks to cope with increasing loads.

5.1.3 Smart meters

Italy was one of the first countries to start the smart meter installations across the EU beginning in the early 2000s with the country reaching 100 per cent coverage before 2017. However, most of the smart meters from the first roll-out are now at the end of their life and are not of a standard to offer the same services as modern smart meters. The installation of second-generation smart meters, with the necessary functionalities required by the new EU Regulation, has begun. By the end of 2019, 13 million second generation smart meters were planned to be installed with a target to equip all households with these by the end of 2026. Until these smart meters are in place, there is a limit to the role retail time-of-use tariffs and associated services can have in Italy.

5.2 Reviews of network tariff structures

Tariff setting methodologies are fixed for 8-year periods in Italy and are set by the regulator Autorità di Regolazione per Energia Reti e Ambiente (ARERA). The most recent methodology covers the period 2016-2023.

5.2.1 Brief overview of tariff structure

The general structure of Italian network tariffs is unusual. For most network users (low voltage households) the network tariff has three components: [49]

- a volumetric charge;
- a capacity charge; and
- a fixed charge.

The volumetric term is predominant, and the capacity term is based on the size of connection rather than measurements. The volumetric component essentially represents transmission costs, and is charged on a kWh basis. Prior to reforms announced in 2016, this was a progressive charge where the unit cost of electricity (€/kWh) increased in bands as consumption increased. Distribution costs are mostly recovered through a capacity charge based on a peak load (€/kW) that is selected by the user, like the Maximum Import Capacity in Ireland. Together, the volumetric or "energy" charge and the capacity or "demand" charge cover the network costs. There is then a fixed charge that covers metering and measurement costs (and a very small amount of distribution costs).

Prosumers, with a cumulated power generation below 500 kW, have the option to use net-metering ('scambio sul posto'), to measure their injection and consumption from the grid. If net-metering is not used, they also have the option to participate through a feed-in-tariff to guarantee a minimum price through a

[49] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.40

programme called 'ritiro dedicato'. This allows prosumers, at regulated administrative costs and simplified imbalance costs, to sell energy produced at an hourly market price. Alternatively, they can stipulate a bilateral agreement with a counterpart (i.e. a trader), to sell the energy produced.

Tariffs are formulated in reference to an "ideal" tariff that is also calculated by ARERA but not actually charged to any consumers. It is designed to be a fully cost-reflective tariff, using an average cost approach, that the actual tariffs are intended to evolve towards over time.[50]

5.2.2 Reforms for regulatory period 2016-2023

In 2013, ARERA initiated the preparation for updating the tariff setting methodology for the upcoming 8-year regulatory period, 2016-2023. There then followed a series of consultations and deliberations with industry and consumer group stakeholders. The objectives of the procedure were:[51]

- Alignment of network tariffs with service costs;
- Rational use of resources;
- The promotion of energy efficiency initiatives and the development of renewable sources;
- Significant simplification of billing documents; and
- Increased transparency of billing documents.

On top of this, legislation set out by the Italian government in 2014 called for electricity tariff reform that removed the progressive structure of tariffs with respect to domestic user's consumption.[52] This objective was thus combined into the ongoing review of network tariffs.

5.2.3 Progressivity

Italian electricity network tariffs were designed since the 1970's so that the more a user withdrew from the grid, the more expensive the next kWh of electricity became (organised as bands of consumption).[53] The result of this structure was households with low consumption paid below the "ideal" tariff level and households with high consumption paid above the ideal level. This was designed to address equity concerns around applying purely cost-reflective tariffs to all households.[54] Network tariffs and metering costs for households under 1,800 kWh were reduced and could account from less than 25 per cent of the bill. This rose to 57 per cent for consumers consuming more than 4 MWh each year.

With the 2018 reforms, a move towards a less progressive tariff was implemented, with the objective to have the same tariff applicable to all consumers by the end of 2019. The motivation to move away from the progressive structure was that it introduced "two significant distorting and anti-historical effects"[55]. The first was cross subsidisation between different domestic users, which in 2015 was estimated as a total of at least 1 billion euros.[56] The second was penalising certain technologies related to improving energy efficiency, specifically end customer technologies such as electric heat pumps that represent an alternative to fossil fuels. Further to these criticisms, ARERA no longer considered the equity concerns underlying the historic progressive structure valid, because low consumption (the user bracket that is favoured by the redistribution of the structure) does not correspond with low income, especially given factors such as family size are not accounted for in the structure.[57]

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[50] CEPA & TNEI (2017) "International review of cost recovery issues" [online] p.39
[51] ARERA (2015) "Consultation Document 293/2015" [online] p.4
[52] Legislative Decree 102/2014 [online] Article 1, paragraph 3
[53] ARERA (2015) "Consultation Document 293/2015" [online] p.43
[54] CEPA & TNEI (2017) "International review of cost recovery issues" [online] p.38
[55] ARERA (2015) "Deliberation 582/2015" [online] p.3
[56] ARERA (2015) "Deliberation 582/2015" [online] p.3
[57] ARERA (2015) "Consultation Document 293/2015" [online] p.31

5.2.4 Electric vehicles

Another issue the consultations addressed was the promotion of energy efficient initiatives, and this included facilitating the increased uptake of electric vehicles (EVs). Charging EVs draws on the distribution system and can potentially contribute to network efficiency through smart charging and possibly discharging of EV batteries. Equally, they may also increase the capacity requirements in distribution networks and therefore the costs.[58] As such a rise in the usage of EVs means their treatment in tariff structures grows in importance.

ARERA has expressed concerns that a proliferation of dedicated charging points risks becoming an inefficient network investment if subsequent technological changes lead them to rapidly become obsolete.[59] The charging infrastructure required for EVs is unlikely to be the same in five- or ten-years' time as it is now, with EV range steadily improving and other advances (e.g. automation) possible too. Short term gains in promoting decarbonisation with investment in recharging infrastructure may lead to under-utilised assets in the long term, to the cost of consumers. The principles ARERA adopts in tariff design relating to electric mobility are:[60]

- To avoid introducing distortions to the general principle of adherence of tariffs to service costs;
- Not to induce an unjustified and inefficient increase in costs for network services;
- To stimulate the use of efficient and as "technologically neutral" approaches as possible; and
- To limit the risk that abuses may arise, thus limiting the administrative costs for monitoring/enforcing compliance.

5.3 Potential methods to solve any issues identified

The initial consultations led to the development of four possible new tariff structures to replace the unwanted progressive structure that was currently in place and limit the redistributive impact of network tariffs, summarised in Table 3.

Table 3: Options considered for the structure of network tariffs in the regulatory period 2016-2023 for domestic users

Option	Description
T0	Entirely consisting of a variable charge, but not with a progressive structure. Corresponds to the "ideal" tariff.
T1	Fifty-fifty split between a variable charge and a demand (capacity) charge.
T2	The same as T1, but with differentiation between residents and non-residents when calculating the demand charge.
T3	The same as T2, but the variable/demand split is 75:25

Source: ARERA (2015) "Consultation document 34/2015" [online]

Option T0 is the reference tariff. T1 entirely removes cross-subsidies between domestic user groups, while the second two options retain cross-subsidisation but only between residents and non-residents (spare homes, which account for 20 per cent of Italian households) [61] who would face higher capacity charges.

A criticism from some stakeholders against the T1 and T2 options, which both had a fifty-fifty split between capacity and volumetric charges, is that it would give little economic reward for reductions in usage by consumers.[62] They argued price signals sent to consumers would be far weaker than those sent by T0 and even weaker than the those sent by the prevailing progressive structure. Such a reform would risk

[58] CEER made similar points on electric vehicles in its papers on Whole Systems Approaches and on Electricity Distribution Tariffs Supporting the Energy Transition.

[59] ARERA (2019) "Consultation document 318/2019" [online] p.36

[60] ARERA (2019) "Consultation document 318/2019" [online] p.37

[61] CEPA & TNEI (2017) "International review of cost recovery issues" [online] p.39

[62] ARERA (2015) "Consultation Document 293/2015" [online] p.11

disincentivising the natural evolution of the market towards technological solutions characterised by greater environmental sustainability, as it lessens the reward for reducing the amount of electricity withdrawn from the grid (including through increased self-consumption). The increased weight of variable charges in T3 goes some way to addressing this concern.

The benefit of capacity charging, based on either contractual power or actual peak kW demand, is that it allows recovery of fixed network costs better than any other mechanism, because peak load demand is the largest driver of an individual's contribution to network costs.[63] ARERA sought to increase the weight of the capacity charge in the tariff structure, and the granularity of power levels to increase the choice available to customers as to how much contractual power they could select.[64] This is facilitated by smart meters which are installed in all Italian homes, so the maximum load can be remotely adjusted if a household requests a change.

5.4 Changes to network tariff structures to help solve the issues identified

From 2016 the progressive element of Italian network tariffs was gradually removed so that by 2019 all low voltage users faced the same unit cost (€/kWh) of electricity regardless of their net volume consumed. This addressed the distortionary impacts of the redistribution of the previous structure and increased the share of capacity charges in the overall tariff relative to the previous structure, although not as dramatically as other options considered. The removal of progressivity led to low-consumption users paying higher tariffs and high-consumption users paying less. ARERA's impact assessment of the change was (for resident households):[65]

1. An increase in annual costs of €69 for low-consumption (<1,900 kWh/year) users;
2. This tends to zero at approximately 2,800 kWh/year of consumption; and
3. Savings approaching €300/year for high consumption users (>5,000 kWh/year).

The granularity of contractual power levels (the capacity charges users can select) was also increased, from 6 levels ranging between 1.5 kW and 15 kW prior to 2016 to 14 levels over the same range after the reform.[66]

ARERA has previously taken steps to reduce the cost of EV charging to incentivise more drivers switching to EVs. Publicly available EV charging points in Italy can opt into a special electricity tariff that is based solely on a volumetric charge, with no fixed annual component. This has been the case since 2011.[67]

5.4.1 2019-2021 strategic framework

Although the next regulatory period is not due to begin until 2024, there are ongoing procedures reviewing the current electricity tariff structures. The issues under review are set out in ARERA's strategic framework for the period 2019-2021.[68] These include; reviewing the criteria for allocating network costs to different types of users (including producers, with regard to reverse power flows); integrating the current cost recognition approach that differentiates between operators' capital costs and operating costs into a single total expenditure measure; and development and deployment of second generation (2G) smart metering systems. Further, ARERA is currently considering reducing the cost of private (at home) EV charging by doubling contractual power (peak kW) for EV households at night free of any capacity charge.[69]

[63] Brattle Group (2014) "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs" [online] p.39
[64] ARERA (2015) "Resolution 654/2015" [online] p.27
[65] ARERA (2015) "Consultation Document 293/2015" [online] p.20
[66] ARERA (2015) "Consultation Document 293/2015" [online] p.
[67] ACER (2021) "Report on Distribution Tariff Methodologies in Europe"[online] p.52
[68] ARERA (2019) "Quadro Stratego 2019-2021" [online]
[69] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.67

5.5 Key findings

There are regular reviews of the tariff structure in Italy, with tariffs set for eight-year periods.

ARERA use (agreed) capacity charges to recover a significant portion of fixed network costs. It recently increased the weight of capacity charges in overall network tariffs and the number of peak kW power options available for consumers to select from. ARERA does not consider low energy use to automatically correlate with low income, reducing the trade-off between distributional and efficiency goals.

Italy has ambitious decarbonisation targets, and investment in network infrastructure is an important aspect of the transition, but ARERA is wary of creating incentives to undertake large-scale investment that might be rendered obsolete by changes in technology in the near future. Specific tariffs relating to public Electric Vehicle charging points have been in place in Italy since 2011, designed to reduce EV charging costs. ARERA has considered adding to this by doubling contractual power at night, free of charge, for consumers that charge EVs at home.

6 Netherlands

6.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

The Netherlands is currently behind most other EU countries in the production of energy from renewable sources. In 2019, only 8.4 per cent of energy used in the Netherlands came from renewable sources, missing the EU requirement of 14 per cent by 2020.[70] As a result, the Netherlands is aiming for a rapid transition to a low-carbon economy and has placed ambitious greenhouse gas (GHG) reduction targets at the centre of energy and climate policy. The 2019 Climate Act sets targets to reduce GHG emissions by 49 per cent by 2030 and by 95 per cent by 2050 (versus 1990 levels) and for 100 per cent of electricity to come from renewables. Natural gas is the most important energy source in the Netherlands, and to meet the energy transition targets, several polices have been implemented to promote a low carbon-economy that relies more on electricity for heating and mobility.[71]

Investment in offshore solar and wind are also being planned. Onshore, various challenges hinder the deployment of wind and large-scale PV, for example onshore wind faces barriers relating to public acceptance, grid connections and land fees. Similar delays have affected large-scale PV projects particularly grid constraints. Addressing such grid constraints can take a long time, but the government is considering options for getting large-scale PV deployed sooner but allowing the networks to curtail it when necessary.[72]

The electricity network in the Netherlands has been described as "overcrowded" and a shortage of transmission capacity exists in several locations on the grid due to growing demand. The capacity constraints are expected to continue for another 5 – 10 years due to project investment lagging projected demand.[73]

6.2 Reviews of the network tariff structures

The National Regulatory Authority in the Netherlands is the Authority for Consumers & Markets (ACM). The ACM reviews the network tariff structures every five years and supervises compliance of the tariff calculation by the seven DSOs with the tariff methodology. The same methodology applies to all the DSOs. Distribution tariff values are updated annually in line with the methodology.

A review of distribution network tariffs was carried out in 2008, and a review of transmission charges in 2015. New energy policy is currently being developed, with a plan for this be introduced in 2022, which might affect network tariffs. As well as considering grid issues, it is expected that new policies will consider price signals within the energy market in general, as well as more specific issues such as "double charging" of energy storage.

70 IEA (n.d.) "Data Browser – The Netherlands" [online]

71 IEA (2020) "Country Report – The Netherlands 2020" [online]

72 IEA (2020) "Country Report – The Netherlands 2020" [online]

73 Authority for Consumers and Markets (2020) "Investment plans of system operators demonstrate shortage of transport capacity due to growing demand" [online]

6.3 Potential methods to solve any issues identified

The Netherlands has adopted capacity-based tariffs for all its customer categories as a way for electricity tariffs to be more cost-reflective and so that the following costs can be recovered:[74]

- Return on capital of electricity distribution investment;
- Depreciation of electricity distribution investment;
- Operational expenditures for electricity distribution;
- Costs of managing the switch between suppliers (e.g. related administrative costs);
- Costs of purchasing ancillary and flexibility services by the DSO; and
- Costs of distribution losses.

For customers who do not have a defined capacity, the size of their fuse is used instead as a stand-in for the maximum capacity that the customer could use.

6.4 Changes to network tariff structures to help solve the issues identified

6.4.1 2008 Distribution network tariff review

The Dutch government launched a review of tariff structures in 2008 to reform the supply model around energy retailers, and to simplify the billing process and improve consumer interfaces as at that time consumers received separate bills from suppliers and from the network companies. Aligning distribution charging (which accounted for 20-25 per cent of the typical retail bill) approaches with network cost drivers was a secondary objective (with this proportion perhaps giving some indication of the relative importance of this driver).

The outcome of the review was to remove the combinations of volumetric and capacity tariffs and introduce flat capacity charges for household consumers. This was considered to better reflect the peak demand driver of network costs, which is strongly linked to capacity requirements. It also had benefits for simplifying the retail market arrangements, simplifying billing arrangements for end consumers as well as between retailers and DSOs.

The capacity tariff was implemented in the retail market in 2009 for all electricity customers. Transitional impacts due to increased network charges were compensated through changes to the "energy tax", which had been introduced in 1996 to promote energy efficiency. This energy tax included a variable volumetric (€/kWh) component, such that higher consumption led to higher tax. The tariff methodology change was accompanied by a fixed tax reduction on the energy bill so that the typical bill for households would not change.

The main driver of this policy was simplifying and streamlining the retail market, and this appears to have been successful with a reduction in administrative costs in the energy sector and increased transparency for consumers. In addition, the change did not have any measurable negative impact on the efficiency of the system, which may be due to the continued use of a volumetric energy tax. The change also had the benefit of increasing revenue certainty for DSOs.[75]

6.4.2 2015 Transmission charging review

Similar to the charging reforms at distribution level, transmission tariff charges were also reviewed, and changes made for reasons of simplification and greater cost-reflectivity. New charges were implemented in 2015 which, for residential and small industrial customers, are based on:

[74] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.75
[75] EDSO for Smart Grids (2015) "Adapting distribution network tariffs to a decentralised energy future" [online] p.2

- An annual contracted peak capacity (kW); and
- Monthly measure peak demand (kW).

Consumers that use the grid for loading in less than 600 hours of the year receive reduced tariff rates and pay a tariff for kW maximum per week, whereas consumers that withdraw more than 600 hours per year pay a tariff for kW maximum per month. Customers pay for the costs of voltage levels they use, including those "upstream" of their own voltage level of connection. Transmission tariffs only include a small lump sum component (1 per cent), making the Netherlands the only European country that applies a combination of a power-based component and lump-sum component in its transmission tariffs.[76]

6.4.3 Current tariff methodology 2017-2021

The current distribution tariff methodology builds on the changes implemented in 2009. Tariff classes are defined by customer types, as set out in the table below. As described above, capacity charges are used extensively, and for customers without a defined capacity this is essentially converted to a fixed charge based on the size of the fuse.

Table 4: Charges applicable to different user types

Customer type	Fixed	Capacity	Volume
Residential	✓	✓	
Small industrial		✓	
Large industrial		✓	✓

Source: Tennet (n.d.) "Dutch Tariffs" [online]. Full breakdown of tariff charge available (in Dutch) online.

The capacity tariff is based on the size of the connection provided and increases from 0.05 for the smallest capacity connection (1 x 6A) to 50 for the largest (3 x 80A).

Approximately 30 per cent of a typical residential customers electricity bill is for network costs. These costs fund the DSO and the TSO (TenneT), with roughly 5 per cent of the total electricity bill of the household attributable to the use of the TSO's network and 25 per cent for the DSO's. Around 42 per cent of the bill goes towards energy costs, the cost of the electricity itself, and the remaining 28 per cent is taxes such as VAT and energy tax.[77]

Net-metering of small-scale PV

A net-metering scheme on retail tariffs (of which network costs represent a proportion) is available to support PV deployment. This allows credits for excess generation exported into the grid, accounted for annually. However, it is expected that after 2023 the tariffs will start to reduce by 9 per cent a year, with net-metering tariffs ending completely by 2031.[78]

Smart meters and time-of-use pricing

Smart meters can enable dynamic, time-of-use pricing contracts and, like many countries, the Netherlands is pursuing widespread smart meter adoption, with more than half of Dutch households currently having smart meters. However, as of March 2020, there is very little use of time-of-use pricing in residential energy supply, except for day/night metering. In addition, the benefits of time-of-use pricing for network tariffs will be limited due to the use of fixed charges.

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[76] ACER (2019) "Report on Transmission Tariff Methodologies in Europe" [online] p.26
[77] Tennet (n.d.) "Dutch Regulation" [online]
[78] IEA (2020) "Country Report – The Netherlands 2020" [online]

6.5 Key findings

Tariff structures are reviewed every five years.

Network tariffs for most users, including all residential users, have not included a volumetric charge for a number of years. Simplification of the tariff structure was a primary motivation for the most recent changes in distribution and transmission tariff structures, although in both cases the regulator also had a secondary goal of making the charges more cost-reflective.

The decision to use capacity (kW) based tariffs (which better reflect the peak demand driver of network costs) is noteworthy, particularly when volumetric charges are common in most jurisdictions. However, this may limit the prospect for time-of-use pricing, and these are not currently widely used despite the large roll out of smart meters.

7 Norway

7.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

Electricity generation in Norway is dominated by renewable sources: hydropower accounts for about 88 per cent of Norwegian production capacity with wind accounting for about 10 per cent.[79] The total hydro storage capacity corresponds to 70 per cent of annual Norwegian electricity consumption.[80] More than 75 per cent of Norway's production capacity is flexible.[81]

Statnett (a state-owned enterprise) is the sole TSO in Norway. There are over 100 DSOs in Norway with the 10 biggest DSOs having about 66 per cent market share. DSOs are typically owned by municipalities or county authorities with a small number being owned by private companies. Regulation has stated that, by 2021, all grid companies must undertake legal unbundling in both electricity generation, transmission and/or trading.[82]

The Norwegian power system is closely integrated with other Nordic systems, both in physical terms and through market integration. Furthermore, Norway has a large number of interconnectors, namely with: the Netherlands, Germany, the Baltic states, Poland, the UK and Russia.

The Energy Act of 1990 provided for the liberalisation of the power market.[83] Norway is part of a common Nordic power market and is integrated with the power market in Europe.

7.1.1 Renewable electricity generation

Norway is in a unique situation when it comes to the energy transition as the electricity networks are already set-up for 100 per cent renewable energy generation. However, Norwegian energy demand is expected to grow due to population growth, the electrification of heat, transport and industry and an increasing number of interconnectors (the regulatory framework is expected to change so that not just the state-owned TSO Statnett may own and operate interconnectors). Consequently, it is expected that electricity generation capacity will increase. This is likely to be predominantly in the form of wind power (a development that is Government driven with the introduction of a national framework to ensure the long-term development of profitable wind-power in Norway)[84] and hydro power as Norway has capacity to further increase the production of hydro power.

7.1.2 Electrification of heat, transport and building sectors

In order for Norway to meet its ambitious climate targets, emissions reductions need to come from somewhere other than the power sector. This has resulted in Norway targeting the decarbonisation of

79 Ministry of Petroleum and Energy (2016) "Renewable energy production in Norway" [online]
80 Energy Facts Norway (2021) "Electricity Production" [online]
81 Energy Facts Norway (2021) "Electricity Production" [online]
82 Energy Facts Norway (2021) "Electricity Grid" [online]
83 Ministry of Petroleum and Energy, Act no. 50 of June 29,1990 (translation) [online]
84 NVE (2018) "Nasjonal ramme for vindkraft på land" [online]

transport, industry and buildings with electrification expected to play a big role.[85] This increased electricity demand (about 30-50 TWh per year) will result in increased renewable energy generation.

Statnett expects that this consumption growth will have a moderate effect on the transmission network if the volume comes gradually over a long period of time and is geographically dispersed (this is not an unlikely scenario given the existing penetration of electric heat, transport and industry in Norway – for example, in 2020 Norway became the first country in the world where the sale of EVs, at 54 per cent, outstripped the sales of combustion vehicles).[86] Increased power consumption from industry will often require local upgrades in the transmission network, but rarely need more capacity in the transport channels between the regions. Higher power consumption from the transport sector to a small extent increases the need for grid developments in the transmission grid, but can accelerate many investments. The consequences are greater for the distribution network as there are weak grids in some parts of the LV system.

The increased electricity generation and demand and the distributed nature of it, creates challenges that the (over 100) DSOs must deal with. These challenges relate to the creation of a smarter and more flexible power system that accommodates cost-efficient integration of new renewables as well as electrification of new loads. It is therefore believed that DSOs need a better understanding of technologies such as battery storage systems, demand response, smart meters and ICT (information communication technology).[87]

Whilst the above paragraph is true, Norway's LV grid is relatively well-prepared for the increased electricity generation and demand and the distributed nature of it. For example, modelling EV uptake in Norway to 2040, the impact on the LV grid (if smart charging is implemented) is almost negligible.[88] This is also the reason for the lack of development of DSO flexibility as the DSOs have stated that 'currently or in the near future, there is no need for DSR as the grid capacity is already sufficient'.[89]

7.1.3 Smart meters, smarter tariffs and electricity prices

Since January 2019 Norway has completed its smart meter roll-out with a 100 per cent penetration across all customer types. Dynamic time-of-use tariffs are common in Norway. Electricity prices in Norway are among the lowest in Europe. Currently, the traditional mix of a volumetric and fixed term network tariff is still applied to many consumers. Around one third of the network costs is a fixed charge and the remaining two thirds are a volumetric/energy charge -. However, a move towards a more capacity-based tariff is planned for 2021 to make the network tariffs more cost reflective and result in existing grid capacity being used more efficiently.

7.2 Reviews of network tariff structures

Network tariff design in Norway is currently transitioning into a new structure that will put the focus on a capacity-based tariff based on regular measurements.[90]

Each network company (DSO) sets its own network tariff within the limits of the regulation. DSOs' income from network tariffs covers costs related to the operation of and investments in the grid. This principle will not change. DSOs total income is strictly regulated through the yearly income cap set for each company by

[85] UN Framework Convention on Climate Change (2020) "Norway's Long Term Low Emission Development Strategy" [online]

[86] Life in Norway (2021) "Norway Sets Global Electric Car Record in 2020" [online]

[87] Nordic Council of Ministers (2017) "Demand side flexibility in the Nordic electricity market" [online]

[88] Reuters (2019) "Electric vehicle push in Norway could add $1.3 billion to power bills by 2040: study" [online]

[89] Nordic Council of Ministers (2017) "Demand side flexibility in the Nordic electricity market" [online]

[90] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.7

NVE-RME (Norwegian Energy Regulatory Authority). The proposed new tariff design does not change the current regime for setting the income cap. As such, DSOs' return on invested capital will not be affected.

On February 5th 2020, NVE-RME published a public consultation document, proposing changes to the design of network tariffs in the low voltage distribution grid, i.e. tariffs for households, vacation homes, and smaller commercial customers. The consultation proposed that most changes enter into force from 2022, but with several transitional periods.[91] Changes to the energy charge are to be phased in gradually, with an energy charge equal to the short-term marginal cost of utilizing the network from 2027. For larger commercial customers with the current capacity-based tariff design, NVE-RME suggest a transitional period for the capacity charge lasting until 2025.

7.3 Potential methods to solve any issues identified

The design of network tariffs is seen as an important instrument in ensuring the efficient operation, utilisation and development of the grid as well as facilitating a reasonable cost distribution among network customers.[92] As the consumption of electricity in Norway is increasing and more of this consumption is happening at the same time, the current capacity of the network will be challenged, and could, if it is not met by new policy instruments, lead to an increasing need for investments. Therefore, the changes to the network tariff are intended to contribute to the efficient operation, utilisation and development of the grid, resulting in the provision of network services at least cost, thus limiting the customer's future bill. Finally, a new network tariff design will be better suited for further electrification, which is an important prerequisite to achieve Norwegian climate targets.

For example, today, most household and smaller commercial customers' network tariffs are based on the total electricity consumption throughout the year. The consumption pattern, during a day, a week, or the year in total, does not affect the network bill. The cost of transporting electricity through the grid constitutes approximately 10 per cent of total network costs and the remaining 90 per cent are made up of capital costs and O&M costs.[93] Therefore, given that 90 per cent of costs are largely unrelated to the yearly transportation of electricity through the grid, the structure of the current network tariff is not sufficiently cost-reflective.

There are three overall principles for this future design of network tariffs[94]:

- The energy charge shall be equal to the cost of marginal losses when there is excess capacity in the grid;
- The price of utilizing the network should be higher than the cost of the marginal losses when capacity is constrained; and
- Network tariff design should provide a reasonable distribution of fixed network costs, through a differentiation of fixed costs based on the customer's demand for capacity.

Based on the above, there are three possible tariff designs:

- Measured capacity;
- Subscribed capacity; and
- Fuse size.

7.4 Changes to network tariff structures to help solve the issues identified

The above changes are intended to make the network tariffs more cost-reflective and result in existing grid capacity being used more efficiently. Perhaps most importantly, the network tariffs incentivise customers to

[91] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.14
[92] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.8
[93] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.8
[94] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.15

use new technology to manage the consumption of electricity. The alternative to these changes is a growing number of customers not paying for the capacity they demand, which implies a higher network tariff for the remaining customers. Therefore, the changes to the network tariff will ensure the efficient operation, utilisation and development of the grid and the provision of network services at least cost.

Today, the average household pays around one third of the network costs through a fixed charge and the remaining two thirds through an energy charge.[95] The changes to tariff design affect the division of cost elements in the network tariff, meaning that the energy charge will reduce and the fixed charge will be replaced by a larger fixed and capacity charge. In the short term, the total bill for an average electricity customer will not change. Over time, the proposal will contribute to avoiding unnecessary investments, implying that network costs will be lower than they would have otherwise been.

7.5 Key findings

Norway's electricity networks are unusual for Europe given that they have been designed to cope with 100 per cent renewable electricity, due to Norway's high share of hydro capacity. Regardless, Norway's population is rising, and the electrification of sectors means that electricity generation will need to also increase.

As total electricity consumption increases the current capacity of the networks will be increasingly challenged. Changes to network pricing structures are required to ensure that existing grid capacity can be used more efficiently and that costly reinforcement can be avoided as far as possible.

To achieve this, network tariffs will move to a more capacity-based tariff from 2021, making charges more cost-reflective. Currently, customers pay around one-third of their network costs as a fixed charge and two-thirds through an energy charge – and most are based on total electricity consumption throughout the year. This structure will change so that the energy charge is proportionately lower, and the fixed charge will be replaced by a larger fixed and capacity charge. These changes will incentivize customers to use new technology to manage the consumption of electricity.

[95] NVE (2020) "Proposed changes to the design of network tariffs for low voltage grid users in Norway" [online] p.6

8 Portugal

8.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

Rede Eléctrica Nacional SA (REN), under a public service concession with the Government, is responsible for the operation, planning and maintenance of the national transmission grid (RNT) and for technical management of the National Electricity System (SEN). In mainland Portugal, the main DSO in Portugal is EDP - Distribuição SA. There are also some low voltage distribution operators. Networks in the Portuguese island regions are operated by other DSOs: Electricidade dos Açores in the Azores and Empresa de Electricidade da Madeira in Madeira. The Regulatory Entity for Energy Services (ERSE) is an autonomous public organisation that acts as the electricity regulator in Portugal. ERSE sets out tariff regulations.

8.1.1 Renewable electricity generation

One of the key challenges facing electricity networks in Portugal is the rapid development of renewable electricity generation. Portugal has an abundance of natural resources it can exploit to generate renewable electricity and help meet decarbonisation targets. Over half of Portugal's electricity is now met by renewables, with wind power presenting the greatest share. It already has a large amount of hydro capacity and solar capacity is rapidly growing.[96] For example, the installed capacity of solar is expected to increase from around 1.9 GW in 2020 to 8.1 – 9.9 GW in 2030.

8.1.2 Growing need for system flexibility and network reinforcement

Reinforcement of the electricity networks is required to allow the connection of increasing numbers of renewable assets and provide sufficient capacity on the networks. Most (95 per cent) renewable installations are connected to the distribution networks[97] and a programme of reinforcements are planned on these by 2030. The TSO is also currently undergoing a series of reinforcement programmes (2018 – 2027).[98]

In addition to reinforcing the networks, there will be a growing need for flexibility and storage to deal with the increasing share of intermittent renewable electricity. Diversifying energy sources and flexibility between vectors (electricity and hydrogen) could play a role in managing this. A national objective to increase storage capacity by 2030 will largely be met through reversible pumped hydro and battery technology.[99] System flexibility and dynamic management will play an important role. By 2022, any generation installations over 1MW of installed power need to have means of communication to receive real time interruption or reduction instructions from the system manager.

Interconnection capacity with other countries can also play a role in increasing system flexibility. Portugal has an electricity sector target of 15 per cent interconnections by 2030 and a number of projects are underway

[96] IEEFA (2020) "Renewable energy provided 51 per cent of Portugal's electricity needs in 2019" [online]
[97] EU-Sysflex (2018) "'The key word is flexibility'. A DSO perspective on EU-SysFlex by EDP Distribuição CEO João Torres" [online]
[98] European Commission (2018) "Portugal: Integrated National Energy and Climate Plan 2021-2030" [online] p.27
[99] European Commission (2018) "Portugal: Integrated National Energy and Climate Plan 2021-2030" [online] p.24

to meet these targets.[100] It sits within a High-Level Group for interconnectors in Southwest Europe which includes Portugal, Spain and France,[101] and also has an interconnection with Morocco.

8.1.3 Electrification of heat, transport and industry

One of Portugal's main routes to decarbonisation will be electrification. Electricity is already the main fuel for heating and cooling. Further electrification will take place, amplified by increased demands due to thermal comfort changes. Heat pumps will be a key technology and have already seen large growth rates: by 2019 there were around 1.6 million heat pumps in Portugal in 2019, growing from fewer than 200,000 in 2014.[102] Likewise, whilst rollout of EVs is at an early stage in Portugal, it is expected to rise significantly by 2030. It is estimated that the renewable electricity contribution for the transport sector will increase by more than ten times between 2020 and 2030.

This extensive electrification across multiple sectors will place additional demands on the electricity networks in a relatively short space of time. As with the growing number of renewable electricity assets, major network reinforcements and increased flexibility will be required to enable this. ERSE is aware of the potential role of networks tariffs and has stated, for example, an intention to monitor and assess whether network tariff design adjustments are required to support the expansion of EVs.[103]

8.1.4 Smart tariffs and smart meters

The potential for a smart tariff design and time of use tariffs in Portugal is currently limited. Portugal is behind with its smart meter rollout, with only around half of residential and SME customers expected to have received smart meters by 2020. Energy retail prices are amongst the highest in Europe due to high taxes and levies: the energy component is one of the lowest in Europe. Network tariffs account for around 22 per cent of the typical Portuguese household electricity bill and 27 per cent for industrial customers.[104] These factors mean that there has been limited opportunity to alter the network tariffs to impact customer behaviour. However, trials of time-of-use tariffs with industrial customers have taken place (see below).

8.2 Reviews of network tariff structures

ERSE fixes the tariff methodology for a regulatory period of three years. The current regulatory framework was applicable for the period 2018 - 2020 but was extended till 2021 due to the COVID-19 pandemic. ERSE defines tariff values at the start of the regulatory time period but updates them annually on the basis of the pre-defined methodology.

The tariff design in Portugal has a mix of capacity, fixed and volumetric terms. There is one network tariff for the whole country, including the mainland and islands. The only differentiating factor is the five different voltage levels according to the connection point, and no differentiation according to technology. All grid users that only generate energy must pay generation-charges (G-charges), except for those connected to the low-voltage grid.

The "Tariff Regulation of the electricity sector"[105] (RT) for the 2018 – 2020 regulatory period sought to achieve three objectives:

[100] European Commission (2018) "Portugal: Integrated National Energy and Climate Plan 2021-2030" [online] p.79
[101] European Commission (2018) "Portugal: Integrated National Energy and Climate Plan 2021-2030" [online] p.16
[102] Statista (2021) "Number of heat pumps in operation in Portugal 2013-2019" [online]
[103] Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.73
[104] Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.75
[105] Translated from Portuguese: "Regulamento Tarifário do setor elétrico".

- To incorporate improvements and adaptations necessary for the evolution of the regulatory framework to reflect the then current electricity sector;
- To give ERSE an opportunity to update its regulatory models on incentives, maintain strategic orientation and to allow regulated companies to develop the most efficient processes and make economically rational decisions in order to reduce costs and improve quality; and
- To incorporate innovations identified as best practices for responding to the challenges of the internal energy market, related to demand management and incentives for energy efficiency, such as the pilot projects for dynamic tariffs and improvement of tariff structure.

ERSE also introduced seasonality in the prices of active energy in the tariffs for access to network and principles that allowed to reinforce the traceability and reliability of regulatory information. This was done to guarantee a greater rigor in the evaluation of financial and economic information resulting from the tariff process.

8.2.1 Brief overview of tariff structure

Distribution tariffs are segmented on the basis of a cost cascading principle. This means that a low-voltage (LV) user (both commercial and non-commercial) pays a separate distribution tariff for each voltage level which it utilises following a cost-cascading principle. However, a user connected through high-voltage (HV) only pays a single distribution tariff, which corresponds to the use of HV distribution grid.[106]

For each distinct distribution tariff (i.e. HV, MV[107] and LV), the billing variables are as follows:

- contracted power;
- peak power;
- active energy; and
- reactive energy.

For small consumers who are connected to the LV grid (≤ 41.4 kVA), peak power is not applied and the following simplified structure applies: contracted power and active energy.

ERSE divides investments into "central" and "peripheral" assets and uses price signals from average Long Run Incremental Cost (LRIC). Central assets are shared by many users and are designed for the system peak not individual peaks. The cost driver for these assets is peak power i.e. "average power in peak period during last month". Whereas, peripheral assets are close to end users and are designed to withstand peak of individual end-users. The cost driver for peripheral assets is contracted power i.e. "max power in 15-min during last 12 months".[108]

In its methodology it calculates the average LRIC as net present value of investments (CAPEX + related OPEX) due to increments in the cost driver divided by the net present value of increments in the cost driver (peak power, contracted power).[109]

8.2.2 Tariff design pilots

Portugal is exploring new network tariff designs and it has done so mainly through pilot projects. Two year-long pilot projects were carried out in 2018 - 2019 for dynamic time of use tariffs in mainland Portugal. These were voluntary for 100 industrial customers on the very high, high and medium voltage networks. The aims of the projects were to test new tariff scheme and time periods proposed by ERSE to promote demand response and encourage more efficient use of network amongst customers on the medium and high voltage

[106] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.38
[107] MV means medium-voltage i.e. voltage greater than 1 kV and equal to or less at 45 kV.
[108] ERSE (2019) "Distribution tariff setting methodologies in Portugal" [online] p.16
[109] ERSE (2019) "Distribution tariff setting methodologies in Portugal" [online] p.18

grids. The first project introduced a price differentiation in peak periods and defined new time periods. The second project tested the introduction of a dynamic tariffs for grid access to encourage users to shift their consumption to periods with lower prices. Users are given short notice of the high-priced periods (at least 48 hours).

8.3 Potential methods to solve any issues identified

The adoption of dynamic tariffs is one of the key reforms first discussed by ERSE and relevant stakeholders in 2011. The focus towards dynamic tariffs was discussed as a way to cater to the demand flexibility due to the growing weight on renewable production.

Subsequently, in 2014, it was decided that the concessionaire of the electricity distribution network in HV and MV in Mainland Portugal and the concessionaires of transport and distribution of electricity in the autonomous Regions of Madeira and the Azores were to submit implementation plans to ERSE for the pilot projects on implementation of dynamic tariffs. ERSE approved rules for the implementation of the pilot projects, including the DSOs conducting a preliminary cost-benefit analysis. A 2016 cost-benefit analysis commissioned by the DSOs indicated a net benefit from introducing dynamic network tariffs for a demand response of 5 per cent.

In 2018, ERSE approved the rules for two pilot projects. These pilot projects were aimed to look at tariff structure improvement and dynamic tariffs for network access on the very EHV, HV and MV lines in mainland Portugal. The primary objective of the first pilot project was to examine the benefits associated with the improvement of network access tariffs. In doing so it tested issues such as price differentiation within the peak period and the definition of new tariff periods more suited to transferring network costs. For the second pilot project, ERSE intended to test the introduction of a new dynamic network access tariff. ERSE was not able to reach its target samples of 100 consumers per pilot. For Pilot 1 it reached 20 candidates and for Pilot 2 it reached 82 candidates. It therefore decided to only progress with Pilot 2 which started in June 2018.[110]

Through the second pilot study ERSE intended to look at the possible ramifications of introducing a flexible tariff (i.e. dynamic network access tariff) for industrial consumers. In the pilot study, the participating consumers were notified a few days in advance of the occurrence of critical periods in the networks, to which higher prices were associated. This, in turn, encouraged them to transfer their consumption to periods with lower prices. Through this, ERSE also intended to encourage a more efficient use of the electricity system, generating benefits for the entire system and for all consumers.

The pilot study also tested elements, such as, the definition of a narrower peak period (super peak) and the application of time-of-use schedules differentiated by geographic area. In addition to these elements, the study also looked at whether ERSE should maintain its injection charge or remove it like Spain, given that it was only introduced in the past to ensure a level playing field for generators operating on the Iberian Peninsula.

8.3.1 Critical Peak Pricing

The key element of the pilot study was the introduction of critical peak pricing. Critical peak pricing means that higher prices are associated to critical hours, when there is either a higher demand level for network capacity or lower supply due to external reasons.

Through the introduction of dynamic tariffs ERSE divided peak hours for electricity consumption into two subcategories:

- super tip (≈ 333 h/year), and
- normal tip (≈ 667 h/year).

[110] ERSE (2019) "Distribution tariff setting methodologies in Portugal" [online] p.19

By doing this ERSE differentiates between normal peak hours and super peak hours and encourages industrial consumers to use electricity more efficiently.

8.4 Changes to network tariff structures to help solve the issues identified

As discussed earlier, through the pilot study ERSE identified that the prices charged to consumers should consider consumption in both the normal peak hours and the super peak hours. It therefore changes the structure of the tariff through the introduction of a new billing variable:

Additional power in critical peak hours – additional payment (compensation) is required when the average power during peak critical hours is higher (lower) than the average power during non-critical peak hours.

The introduction of this new variable seeks to reflect the different cost implications during the critical peak hours and the non-critical peak hours and reflect this in the prices. During the pilot study, ERSE charged 198.6 € / MWh during the super peak hours and 98.7 € / MWh during the normal peak hours.[111]

8.5 Key findings

ERSE fixes the tariff methodology for a regulatory period of three years.

The current tariff structure use average LRIC estimates to determine price signals. The variables that can influence a tariff are contracted power, peak power, active energy and reactive energy.

Distribution tariffs are uniform in nature and segmented on the basis of a cost cascading principle, so that MV consumers, for example, pay distribution tariffs for HV and MV (but not LV).

ERSE is exploring new network tariff designs and has made use of pilot projects to help develop its thinking on both the effectiveness of new structure and design issues. The focus has been on dynamic tariffs. From the pilot studies, ERSE has chosen to differentiate between normal peak hours and super peak hours and encouraged industrial consumers to use electricity more efficiently.

[111] ERSE (2019) "Distribution tariff setting methodologies in Portugal" [online] p.25

9 Spain

9.1 Issues faced by the Distribution network or Transmission network that are relevant to Ireland

The Spanish electricity network has undergone a series of regulatory and pricing changes and reforms over the last decade. One of the biggest challenges faced is connecting large numbers of renewable electricity generation assets, as detailed below. Other trends to decarbonise the energy system in Spain will also mean further changes are needed to the networks and their tariff structures.

The transmission network in Spain is operated by one TSO, the Red Eléctrica de España (REE). There are five main DSO groups in Spain.[112]

The electricity market in Spain is part of MIBEL, the Iberian Electricity Market, together with Portugal. This was created in 2007 to benefit customers in terms of equality, transparency and objectivity.[113]

9.1.1 Renewable electricity generation

The share of renewable electricity generation in Spain has increased massively over the last decade and will continue to do so. In 2020, renewable electricity accounted for 44 per cent total national generation in 2020, a 12.8 per cent production increase from 2019. Wind and solar have been areas of particularly high growth with wind contributing 21.9 per cent in 2020, only second behind nuclear[114] and solar growing by 65 per cent against the previous year. At the same time, fossil fuels and nuclear are being phased out. In 2020, coal accounted for only 2 per cent of annual electricity generation in 2020, a reduction of 60 per cent from the previous year. Future targets mean a continuation of these trends: a phase out of coal and potentially of nuclear is expected by 2030, with a target of 100 per cent renewable electricity production by 2050.[115]

The shift to renewable electricity poses significant challenges for the electricity networks in Spain. Networks need to be able to connect growing numbers of generation plants, and there is a need to ensure security of supply, transmission and distribution is maintained with the new fuel mix. The early 2000s saw large investments in the networks to account for large increases in generation capacity and this will need to be intensified as renewable electricity contributions ramp up.

9.1.2 Connecting renewable electricity assets

The connection of renewable energy plants to the transmission and distribution networks has been a significant issue in Spain. There has been a sharp rise in grid access requirements reported by REE, particularly for solar and wind.[116] The problem is due to the large volume of access and connection requests – far above that anticipated – and current regulations which allow for applications to be submitted on a speculative basis. In 2019, REE reported they had only pre-authorised around a third of renewable electricity generation plants and that the requests for a total capacity of 147,300 MW far outweighed the anticipated volumes at this stage (i.e. it is triple the amount expected to be available by 2030 and half the installed capacity in 2018). Similarly,

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[112] Pylon Network (2018) "The actors of the Spanish energy system" [online]
[113] Jacques Delors Institute (2014) "Energy policy: European challenges, Spanish answers" [online] p.13
[114] Red Electrica de Espana (2021) "2020, the year with the 'greenest' energy thanks to record wind and solar photovoltaic generation" [online]
[115] Red Electrica de Espana (2020) "Spanish Electricity System - End of Year Forecasts 2020" [online]
[116] Simmons & Simmons (2019) "The saturation of the electricity grid access requests in the current regulation" [online]

in May 2020, figures from REE showed that only 29 per cent of combined capacity of the 527 nodes of the transmission grid were available for the connection of new generation facilities.[117]

9.1.3 Energy tariff deficit

One of the biggest issues facing the Spanish electricity system over previous years has been a tariff deficit, the difference between the system costs and the revenue generated from tariffs. The problem was caused by the majority of customers paying a regulated tariff, which did not meet the cost of generation – these tariffs continue to diverge from market electricity prices. The problem grew with increasing renewable electricity generation, which has surpassed renewable electricity targets.[118]

In 2013 Spain began reforming the electricity market to eliminate the 'tariff deficit' which was estimated to be around €30 billion at the time, and the highest among EU Member States. The tariff deficit has been building up since 2000 with the tariff revenues received by network companies not covering the regulated costs (also called the access costs). These costs included:

- transmission and distribution costs;
- "special regime" costs to support renewable energy and co-generation;
- "extra-peninsular costs" to compensate for higher electricity costs e.g. in the Balearic and Canary Islands;
- annuities to cover the tariff deficit in the previous years; and
- other costs.

The increased uptake of various distributed energy resources (DERs) such as PV solar panels also contributed to the tariff deficit problem.[119] The regulated costs increased considerably through the period from 2000 to 2013, with the costs associated with renewable energy growing from €1.2 billion in 2005 to €8.4 billion in 2012.[120]

Since the introduction of reforms and measures starting in 2013, Spain has made considerable progress in the tacking the 'tariff deficit' issue, with more balanced system costs during the 2014-2018 period.[121]

9.1.4 Self-consumption

Self-consumption[122] has significantly increased in Spain in recent years, especially through rooftop solar PV and co-generation. For example, in 2013 the installed rooftop solar PV capacity was 4.6 GW, of which approx. 0.6 GW was in the form of behind-the-meter rooftop solar PV. In general, "behind-the-meter" energy systems include on-site generation where energy is generated on the property, for example through solar panel systems or small wind turbines. Therefore, "behind-the-meter" systems can provide energy directly to the end-user without going through a meter or interacting with the electric grid.[123] Given the increase in self-consumption and behind-the-meter generation, Spain introduced changes to its regulatory framework to address the new issues arising from the increased uptake of solar PV (and DERs more in general), as described in section 9.1.3. This included the new Electricity Sector Law in 2013 (24/2013), which is described in further detail in section 9.4.1 below.

In addition, a controversial tax was also introduced for microgenerators in 2015, the so-called 'sun tax' ("impuesto al sol"), which has been subsequently removed in 2018. The tax meant that homes fitted with

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117 Thomson Reuters Practical Law (2020) "Electricity regulation in Spain: overview" [online]
118 Jacques Delors Institute (2014) "Energy policy: European challenges, Spanish answers" [online] p.27
119 CEPA and TNEI Services Ltd (2017) "International Review of Cost Recovery Issues" [online].p.31
120 European Commission (2014) "Electricity Tariff Deficit: Temporary or Permanent Problem in the EU?" [online]. p.28
121 IEA (2021): "Spain 2021 Energy Policy Review" [online]. p.124
122 Defined as "consumers who generate electricity for their own consumption", IEA (2021): "Spain 2021 Energy Policy Review" [online]. p.124
123 Energysage (2019) "Behind-the-meter: what you need to know" [online].

solar panels were required to contribute to the costs of distribution and maintenance of the electricity networks. Additional taxes were paid for every kWh produced by the solar installation, which was almost half the kWh price paid by the consumer to the electricity company. In addition, the householder had to give surplus energy to the network for free. The new model and regulations allow for collective self-consumption for generation located in one building or in a local area.[124] It also means a simplified mechanism for the compensation of self-produced and unconsumed energy.[125]

A new network tariff will also be introduced for self-consumed energy if it uses a local distribution tariff for nearby generation assets. Energy exported into the grid by prosumers is currently charged the regular generation charge (G-charge) of 0.5 €/MWh as with other generators but this should be eliminated in new network tariff designs.[126] This provides an incentive and acts to facilitate the integration of generation assets onto the network.

9.1.5 Other key decarbonisation trends

In addition to the decarbonisation of electricity through expansion of renewable electricity generation, Spain has a focus on energy efficiency, electrification and renewable hydrogen to meet or decarbonisation targets.[127]

Many homes are already heated by electricity in Spain, and this is likely to grow. Cooling demands in buildings is also expected to grow due to increased temperatures from climate change, with Spain seeing one of the biggest impacts across Europe.[128] Peak demand for heating and cooling is therefore expected to grow on the electricity networks.

To date, the uptake of EVs and charging infrastructure has been slow in Spain. However, this is set to grow, leading to increased loads on the electricity networks.

Network impacts and increased flexibility

As with other countries, the need for flexibility and storage on the electricity system will grow as the electrification of sectors intensifies. Solutions to address this include storage, demand side management, digitalisation and international interconnectors. Uptake of residential storage is currently very low in Spain and demand side flexibility is still at trial stage – although most of the DSOs are actively involved in European demand side flexibility programmes. Spain has electricity transmission capacity with other European countries (notably France and Portugal) but is behind on targets set by the European Commission to ensure interconnections equivalent of their domestic generation capacity – 10 per cent by 2020 and 15 per cent by 2030.[129]

Relation between network tariffs and electrification

Royal decree RD15/2018 is an urgent measure put in place to enable the energy transition and support consumer protection. This replaces a previous regulation 'Gestor de Cargas' – a legal duty not to re-sell final electricity demand – which was a barrier to the rollout of EV charge points.

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124 Aragones et al (2016) "The New Spanish Self-consumption Regulation" Energy Procedia, Vol.106 p.245-257 [online] p.251
125 Forbes (2019) "Renewable Energy In Spain: From The 'Sun Tax' To The Promotion Of Collective Self-Consumption" [online]
126 Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.86
127 Red Electrica de Espana (2020) "Spanish Electricity System - End of Year Forecasts 2020" [online]
128 EEA (2019) "Adaptation challenges and opportunities for the European energy system" [online] p.48
129 Jacques Delors Institute (2014) "Energy policy: European challenges, Spanish answers" [online] p.13

9.1.6 Smart tariffs

Spain was a front runner in Europe in the rollout of smart meters with all households being fitted with them by 2018. The rollout is ongoing for commercial and industrial customers. In theory, this provides an opportunity for the introduction of smarter network tariffs and time of use tariffs which could be used to reflect congestion of LV networks. However, suppliers get a lower profit margin from TOUs compared to static tariffs and so have not publicised them widely, with a lack of awareness amongst customers.[130] Tariffs with hourly discrimination are available to residential and commercial customers; there is a residential three period tariff which would be suitable for EV users to charge vehicles overnight but there has been limited uptake to date.

In addition, electricity prices in Spain are amongst the highest in Europe for residential customers – although below the EU's average for industrial customers. As with Portugal, the reasons for this are mainly due to high taxes that cover the majority of the bills e.g. around 50 per cent of the price paid by household consumers corresponds to taxes and levies. This limits the impact that network tariff design can have influencing consumer behaviour.

9.2 Reviews of network tariff structures

Since 2020 the National Commission of Markets and Competition (Comisión Nacional de los Mercados y la Competencia, CNMC) sets the network tariffs for transmission and distribution in Spain.[131] The tariff methodology is set for six years and allows mid-term amendments during the current regulatory period (2020-2025).[132] In 2019-20 the CNMC approved a series of regulations (*circulares*) introducing provisions for different activities in the electricity sector.

This included Regulation 3/2020,[133] which sets out the methodology applicable for calculating tariffs payable by users of the electricity transmission and distribution infrastructure. In reviewing and setting the applicable tariff structure methodology, the CNMC considered the following tariff principles:[134]

- Sufficiency – The transmission and distribution tariffs calculated using the new tariff methodology[135] guarantee the recovery of remuneration for the relevant activities, in line with the applicable forecasts.
- Efficiency – The transmission and distribution tariffs calculated using the new tariff methodology assign the remuneration of networks to each tariff group based on the principle of causality, avoiding cross-subsidies between tariff groups; and encourage the efficient use of the transmission and distribution network.
- Additivity – The transmission and distribution tariffs additively include the remuneration for transmission and distribution for each tariff group.
- Transparency and objectivity – The criteria for allocating the remuneration for transmission and distribution, as well as the inputs and parameters used in the methodology are defined explicitly in this regulation, and are publicly available.
- Non-discrimination in transmission and distribution tariffs between network users mean that those with the same characteristics belong to the same tariff group.

[130] Smart Energy Europe (2019) "The smartEn Map Network Tariffs and Taxes" [online] p.84
[131] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.5
[132] ACER (2021) "Report on Distribution Tariff Methodologies in Europe" [online] p.21
[133] Circular 3/2020, de 15 de enero, de la Comisión Nacional de los Mercados y la Competencia, por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad [online].
[134] Artículo 4. Principios generales, Circular 3/2020, de 15 de enero, de la Comisión Nacional de los Mercados y la Competencia, por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad [online].
[135] Basen on Regulation 3/2020.

- The transmission and distribution tariffs are the same throughout the national territory.

9.3 Potential methods to solve any issues identified

Until early 2013 electricity consumers in Spain faced both a contracted capacity and a volumetric energy component as part of their bills, with the volumetric component being greater in general. In practice, this meant that the volumetric component covered a part of the fixed network costs as well as policy costs (i.e. the "special regime" costs to support renewable energy and co-generation; the "extra-peninsular costs" and annuities to cover the tariff deficit in the previous years). The volumetric component could also be reduced through on-site generation (e.g. through the use of solar panels).[136]

To tackle the “tariff deficit” problem identified, one of the changes introduced by the new Electricity Sector Law in 2013[137] was to shift most of revenue recovery from volumetric charges to capacity charges for all consumers.[138]

9.4 Changes to network tariff structures to help solve the issues identified

9.4.1 Increased capacity charge and provisions for self-consumption

The new Electricity Sector Law introduced in 2013 shifted the focus on revenue recovery from volumetric to capacity charges. Consequently, following the shift capacity tariffs accounted for as much as 60 per cent of network charges for residential consumers[139] (compared with around 30 per cent previously), and 80 per cent for commercial and industrial consumers (compared with around 30 to 45 per cent previously).[140]

The law also introduced provisions for self-consumption units that did not have a specific legal and regulatory framework to date.[141] The law requires most self-consumption units to pay for the system costs in line with other network users. The tariffs depend on the contracted capacity, as well as the use/ consumption of the grid. Further, self-consumers pay for the “charges associated with the electricity system cost” and the back-up provided on all electricity consumed.[142] Nonetheless, the proportion of the costs paid may be lower when self-consumption leads to a reduction in system costs. In addition, installations smaller than 10 kW, as well as those located in the Canary Islands, and Ceuta and Melilla are exempt from the charge.

In addition, in 2015 Spain introduced a new self-consumption law[143] (also titled as the “sun tax”) taxing self-consumption PV system even if the electricity produced did not feed into the grid.[144] The tax was removed in 2018 as part of the measures introduced to reduce electricity prices in Spain, which were among the highest in Europe.[145]

Together with the “sun tax”, the introduction of access tariffs reduced the incentives to invest in self-generation facilities and reduce the share of the fixed costs paid.

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136 CEPA and TNEI Services Ltd (2017) “International Review of Cost Recovery Issues” [online] p.32
137 Ley 24/2013, de 26 de diciembre, del Sector Eléctrico, [online].
138 CEPA and TNEI Services Ltd (2017) “International Review of Cost Recovery Issues” [online] p.33
139 The costs covered by the electricity bill include (i) grid costs for transmission and distribution networks; (ii) other system costs; and (iii) energy costs including the cost of generation, losses, system reserves and back-up. CEPA and TNEI Services Ltd (2017) “International Review of Cost Recovery Issues” [online] p.32
140 CEPA and TNEI Services Ltd (2017) “International Review of Cost Recovery Issues” [online] p.33
141 Ley 24/2013, de 26 de diciembre, del Sector Eléctrico, [online].
142 CEPA and TNEI Services Ltd (2017) “International Review of Cost Recovery Issues” [online] p.35
143 Real Decreto 900/2015, de 9 de octubre, por el que se regulan las condiciones administrativas, técnicas y económicas de las modalidades de suministro de energía eléctrica con autoconsumo y de producción con autoconsumo [online].
144 Tsagas (2015) “Spain Approves ‘Sun Tax,’ Discriminates Against Solar PV [online].
145 Binnie and Elías Rodríguez (2018) “Spain scraps 'sun tax' in measures to cool electricity prices” [online].

9.4.2 Tariff methodology published by CNMC

Voltage levels used to define transmission and distribution tariffs

Article 6 of the Regulation 3/2020 defines the structure of transmission and distribution costs. The structure means that transmission and distribution tariffs are differentiated by voltage levels and time periods. Further, tariffs consist of contracted power and active energy consumed. Where appropriate, a charge for the power demanded will also be applied (when this exceeds the power contracted) as well as for reactive energy.

The transmission and distribution tariffs applicable to consumers, self-consumption for energy demanded from the network, and generators for their own consumption are the following:

- for consumers connected in voltage networks not exceeding 1 kV, with contracted power less than or equal to 15 kW in all periods, the tariff consists of two terms of contracted power and three terms of consumed energy.
- for consumers connected in voltage networks not exceeding 1 kV with contracted power greater than 15 kW in any of the six time periods, the tariff consists of six terms of contracted power and six terms of consumed energy.
- for consumers connected in voltages higher than 1 kV and lower than 30 kV (tariff voltage level NT1) the tariff consists of six terms of contracted power and six terms of consumed energy.
- For consumers connected at voltages equal to or greater than 30 kV and less than 72.5 kV (tariff voltage level NT2) the tariff consists of six terms of contracted power and six terms of consumed energy.
- for consumers connected in voltages equal to or greater than 72.5 kV and less than 145 kV (tariff voltage level NT3) the tariff consists of six terms of contracted power and six terms of consumed energy.
- for consumers connected at voltages equal to or greater than 145 kV (tariff voltage level NT4)the tariff consists of six terms of contracted power and six terms of consumed energy.

Similarly, Article 6 also sets out the payment provisions applicable for the use of the transmission and distribution network for self-consumption.

Time periods used to define transmission and distribution tariffs

In addition to defining the tariffs based on voltage levels, Article 7 of the Regulation defines the time periods used to determine the transmission and distribution tariffs. Time discrimination using the six periods explained below apply to the power and energy terms of all tariffs, with the exception of the tariffs for the lowest voltage users. This divides the hours of the year into six time periods (from P1 to P6) depending on the season, the day of the week and the time of day.

In terms of defining the electricity seasons, the following seasons apply for the Peninsula:[146]

- High season: January, February, July and December.
- Mid-high season: March and November.
- Medium season: June, August and September.
- Low season: April, May and October.

The types of days are defined as follows:

- Type A: Monday to Friday in high season, excluding holidays.[147]
- Type B: Monday to Friday in mid-high season, excluding holidays.
- Type B1: Monday to Friday in medium season, excluding holidays.
- Type C: Monday to Friday in low season, excluding holidays.

[146] The definition of the seasons is different for the Balearic and Canary Islands, as well as for Ceuta and Melilla.

[147] Holidays refer to national holidays, as defined in the official calendar, and exclude holidays where a substitute day exists as well as those that do not have a fixed date.

- Type D: Saturdays, Sundays, holidays and 6th January.

The different types of day are used in conjunction with six time-of-day definitions to determine the power and energy tariff components at any given moment. The tariff is highest for Level 1 and lowest for Level 6. For example, on a type A day (a high season weekday), tariffs are charged at one of three possible levels; Level 1, Level 2 or Level 6 for consumption at peak time, flat time or valley time, respectively. Conversely, on a type C day (a low season weekday), peak, flat and valley times are charged at Levels 4, 5 and 6.[148]

In addition, a three-period time discrimination applies to the energy (consumption) component of the tariff for low voltage consumers. The three-period time discrimination differentiates the hours of the day into three time periods: period 1 (peak), period 2 (flat) and period 3 (valley). All hours on Saturdays, Sundays, 6th of January and national holidays[149] are considered as hours of period 3 (valley).

Finally, a two-period time discrimination applies to the contracted power and excess power components of the tariff for low voltage network customers. This divides the hours of the year into two time periods: peak and valley. The peak period of the two-period hourly discrimination groups periods P1 and P2 of the three-period time discrimination, while the valley period of the two-period time discrimination corresponds to P3 of the three-period time discrimination regime.

Formulae used to calculate transmission and distribution tariffs

Taken together, transmission and distribution tariffs consist of charges for contracted power, energy consumed and, where appropriate, charges for power demanded and reactive energy. Article 9 of the Regulation sets out the formulae applicable to calculate these tariffs, taking into account the differentiation based on voltage levels and time periods set out above.[150]

9.5 Key findings

The energy tariff deficit, and the significant increase in self-consumption and the uptake of PV solar panels led to important changes in the regulatory framework in Spain. This included the introduction of the new Electricity Sector Law in 2013, which shifted the focus on revenue recovery from volumetric to capacity charges. It also required most self-consumption units to pay for the system costs in line with other network users, with the tariffs depending on the contracted capacity, as well as the use/ consumption of the grid.

In 2015, a controversial "sun tax" was also introduced, taxing self-consumption PV systems even if the electricity produced did not feed into the grid. The tax was subsequently removed in 2018.

Most recently, the CNMC published its latest methodology applicable for calculating tariffs payable by users of the electricity transmission and distribution infrastructure in early 2020.

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148 A full breakdown of the varying time-of-use charges and the specific hours they apply to is available at: Circular 3/2020, de 15 de enero [online] Section 7. As in the case of seasons, the definition is different for the Balearic and Canary Islands, as well as for Ceuta and Melilla.

149 As above, holidays refer to national holidays, as defined in the official calendar, and exclude holidays where a substitute day exists as well as those that do not have a fixed date.

150 For further details, please refer to "Artículo 9 Aplicación de los peajes de transporte y distribución de electricidad" of Circular 3/2020, de 15 de enero, de la Comisión Nacional de los Mercados y la Competencia, por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad [online].