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Proposed changes to the design of network tariffs for low voltage grid users in Norway

English summary

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Summary: The current regulation in Norway allows for different tariff designs in the low voltage distribution grid, i.e. tariffs for households, vacation homes, and smaller commercial customers. This report summarizes the changes NVE-RME has proposed from volumetric to capacity based tariff designs for these customer groups.

Subject terms: Network tariffs, tariff design, cost-reflective, capacity based tariffs, DSO

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1 Introduction

One of the Norwegian Energy Regulation Authority's (NVE-RME) main tasks, is to promote economically efficient production, transmission, conversion and use of electrical energy. A subgoal is to contribute to efficient operation, utilisation and development of the grid. The design of network tariffs is an important instrument to achieve this goal.

The consumption of electricity in Norway is increasing. Electricity is used for new purposes to a growing extent, and more of the consumption is happening at the same time. These developments challenge the current capacity of the network, and could, if it is not met by new policy instruments, lead to an increasing need for investments. 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 proposition implies that customers with a predominantly volumetric tariff today, will pay network tariffs based primarily on their demand for capacity in the future. Customers connected to higher voltage levels, and larger commercial customers in the low voltage distribution network, have received such price signals for decades. A few Norwegian DSOs have also already introduced capacity based tariffs for households and smaller commercial customers.

NVE-RME proposes changes to network tariff design to improve efficiency of utilization and development of the electrical network, as well as facilitate a reasonable cost distribution among network customers in the future. The changes are also intended to contribute to providing network services at least cost, thus limiting the customer's future bill Finally, a new network design will be better suited for further electrification, which is an important prerequisite to achieve Norwegian climate targets.

The public consultation document primarily concerns design of network tariffs for customers in the low voltage distribution network. In conjunction with these changes, we also propose changes to the general principles for design of network tariffs and rules regarding information to customers. These changes affect all customers connected to the grid but will not affect design of network tariffs specifically.

This document is a summary of the proposed changes to network tariffs and describes the reasoning behind the proposal, proposed tariff principles and expected consequences of the changes. For further information, please refer to the public consultation document[1] or contact us at rme@nve.no.

[1] RME Høringsdokument nr. 01/2020 (in Norwegian): http://publikasjoner.nve.no/rme_hoeringsdokument/2020/rme_hoeringsdokument2020_01.pdf

2 Current tariff regulation and network tariffs as a share of the total customer bill

2.1 Current network tariffs are predominantly volumetric

The current regulation allows for different tariff designs. However, only a few DSOs have introduced capacity based network tariffs for smaller customers. The average household pays around one third of the network costs through a fixed charge and the remaining two thirds through an energy charge. Thus, most households have a volumetric tariff design and lack incentives regarding reduced capacity utilization.

In addition, current regulation does not allow for subscribed capacity approaches or time-of-use principles. As such, there is a need to change and clarify how tariff design should be defined to be cost reflective. A concept hearing on the future design of network tariffs in the distribution grid was conducted in 2015-2016.[2] Already then, NVE-RME signaled a transition from a volumetric tariff structure to a capacity based approach.

Another public consultation document, proposing a subscribed capacity model for all customers in the distribution grid, was published in December 2017.[3] NVE-RME received many objections to the proposed model, and it was, therefore, not introduced. Several of the stakeholder responses did, however, point to the fact that more cost reflective tariffs should be introduced. In the new public consultation document, we have considered the feedbacks we received, both in the two previous public consultations and recent ones.

2.2 Network tariffs constitute one third of the electricity bill

Network tariffs constitute approximately one third of the total electricity bill and comprise payment for the transportation of electricity from production to end users. All customers receive price signals from DSOs, either directly from the DSO or as a separate part of a joint bill from the electricity supplier.

The electrical grid is a natural monopoly with high fixed costs and low variable costs. Therefore, each DSO has an exclusive right to distribute electricity within its concession area, where the DSO's income is strictly regulated.

The remaining two thirds of the electricity bill constitutes the market price for electricity, taxes and levies. Taxes and levies are set by the Norwegian parliament, and include a consumption tax, a fee to the Enova fund and VAT. The electricity price is determined by market conditions and reflects the relationship between supply and demand. Electricity

[2] NVE Høringsdokument 3:2015 and NVE Rapport 53:2016 (in Norwegian)
[3] NVE Høringsdokument 5:2017 (in Norwegian)

suppliers buy and sell electricity on behalf of household customers. Each customer can freely choose their preferred supplier.

The proposed changes to tariff design affect the division of cost elements in the network tariff. 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.

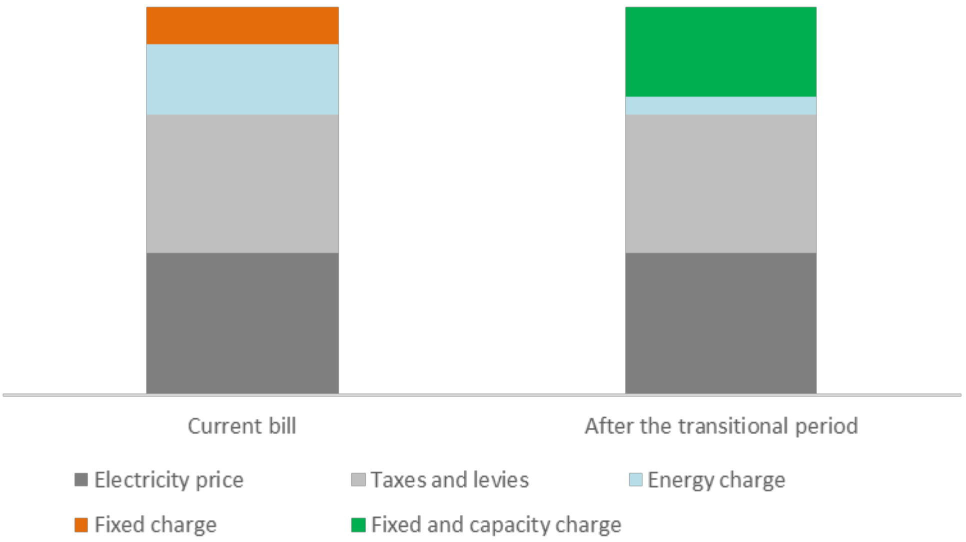

Figure 1: The figure shows how the total bill is split for a Norwegian household customer (consumption 20 000 kWh) before and after the transitional period. The bill constitutes approximately one third network tariffs, one third taxes and levies and one third the market price for electricity (an average Norwegian household customer pays around € 0.11 per kWh, including the fixed charge in the network tariff).

3 Why is a change from volumetric to capacity tariffs necessary?

3.1 Network tariffs should reflect the division of fixed and variable costs in the network

Network capacity must be dimensioned to handle transmission and distribution of electricity during hours where consumption peaks occur. If more consumption is concentrated to these peak hours, the demand for network capacity increases. Higher grid investments imply increased network costs and higher network tariffs. In addition, building new grid capacity often leads to negative environmental impacts. The electrical grid has available capacity during most hours, also during days with peak consumption. If we utilise existing capacity more efficiently, customers' network tariffs will decrease.

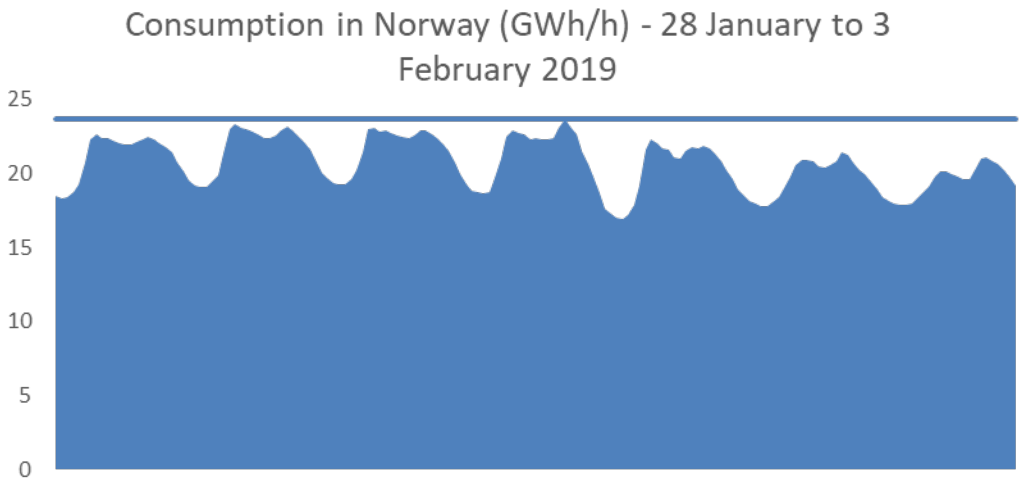

Figure 2: In 2019, peak consumption occurred between 17:00 and 18:00 on Thursday 31 January. The white area below peak consumption makes a simplified illustration of hours with available capacity in the grid. Source: [Nord Pool.](#)

The electrical grid is financed through network tariffs. Tariffs are meant to both ensure a reasonable distribution of network costs as well as function as a tool for achieving efficient utilization and development of the grid.

The cost of transporting electricity through the grid constitutes approximately 10% of total costs. The remaining 90% are to a large extent unrelated to the yearly transportation of electricity through the grid. The structure of network tariffs should reflect this, implying a large portion of network tariffs being allocated based on customer demand for capacity.

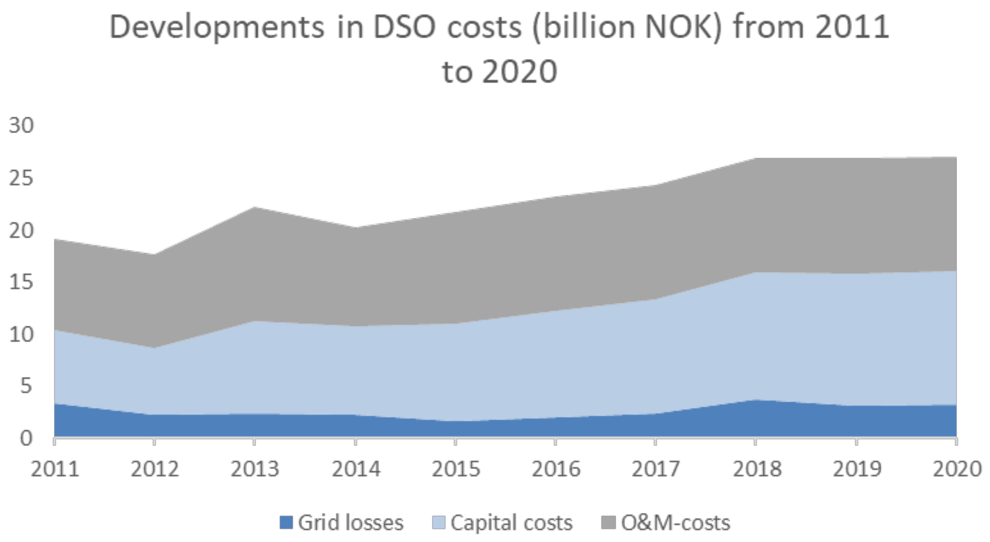

Figure 3: Developments in Norwegian DSO costs from 2011 to 2020, as illustrated by developments in the cost of grid losses, capital costs and operation and maintenance (O&M) costs. Source: NVE-RME

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. Therefore, the structure of the current network tariff is not sufficiently cost reflective.

DSOs' income from network tariffs covers costs related to the operation of and investments in the grid. We propose no changes to this principle. DSOs total income is strictly regulated through the yearly income cap set for each company by NVE-RME. The proposed new tariff design does not change the current regime for setting the income cap.[4] As such, DSOs' return on invested capital will not be affected.

3.2 Electricity consumption is changing

The power system is going through fundamental changes. Important drivers are climate policies and technological developments. These changes affect both how we produce and consume electricity.

Electricity is a perishable good. Production and consumption happen simultaneously and need to be balanced continuously. Normally, power production and consumption are at different locations, and the grid transports electricity between the two, i.e. to the end user. It is not possible at any given time to transport more electricity through the electrical grid than what it is dimensioned for. It is costly to build and maintain grid capacity and constructing new power lines also has a negative environmental impact.

The electrical grid is part of our shared infrastructure, that we all depend on. It is not publicly financed, but in its entirety through network tariffs to customers. Customers are all producers and consumers of electricity. More efficient utilization of the grid leads to lower network bills for Norwegian households and companies.

We are consuming more electricity than before. This trend will continue, as well as electricity being utilised for several new purposes in the future. The electrification of transportation is already well underway. Electricity consumption in the industry is also expected to increase, including new power consuming industry such as data centres, electrification of Norwegian oil production, battery factories and hydrogen production.

Equally important is the fact that consumption patterns are changing. Through electrification, more consumption happens simultaneously, e.g. charging of electrical vehicles (EVs). These developments challenge the current grid capacity. Combined with more weather dependent electricity production, the ongoing balancing of production and consumption will be more challenging in the future.

Transitioning from a volumetric to a capacity based tariff structure strengthens the relationship between network tariffs and grid costs. Thus, restructuring network tariffs contributes to keeping network costs reasonably distributed amongst network customers, while also contributing to lower overall network costs. The alternative to such a restructuring is a growing number of customers not paying for the capacity they demand, which implies a higher network tariff for the remaining customers.

3.3 Electrification of transportation in Norway

The ongoing, rapid electrification of transportation illustrates the main challenge with the current lack of price signals through network tariffs for smaller customers.

[4] The economic regulation is described in further detail on our webpage, NVE-RME

The current national transportation plan (2018-2029) includes goals for zero emission vehicles. New private cars and light utility vehicles will be produced as zero emission vehicles from 2025. New city buses are meant to be emission free or run on biogas from 2025. There are also longer-term goals on zero emission for heavy utility vehicles, new long distance buses and new trailers.[5]

At the end of 2019, the Norwegian EV fleet counted more than 250 000 cars.[6] This does not include hybrid cars. Given the goals in the national transportation plan, we expect a significant increase in the number of EVs going forward.

An EV with an average driving pattern amounts to around 15% of the electricity consumption in an average Norwegian household.[7] The energy needed from EVs is therefore not a major challenge for the Norwegian power system. However, the need for capacity might increase considerably if we do not utilise smart charging. A house charging an EV during existing peak hours, could potentially increase the demand for capacity by 50-100%.

Today, customers do not have incentives through network tariffs to utilise technology to steer power consumption in a smart manner. The Norwegian report *Kostnader i strømnettet – gevinster ved koordinert lading av elbiler*[8] illustrates possible challenges. In the report, an estimated new peak occurs during the afternoon on cold days if EVs are charged in an unsmart manner. In addition, the report estimates possible savings of around € 1.1 billion from smart charging.[9] These savings can be realised relatively easily, by moving charging from the afternoon to hours with available capacity in the grid.

In the report it is assumed that home charging is conducted at 7 kW. This is the typical standard today. If home charging is conducted at higher power levels, which we e.g. see for several new cars, the potential savings will be higher.[10] The same holds true for the trend where households have more than one EV.

[5] How electrification of transportation affects the electrical grid is discussed in detail in part A chapter 13 of *Klimakur 2030* (in Norwegian).
[6] Numbers from the Norwegian EV Association. Of new cars sold, fully electrical EV cars had a market share of 43,9 % per 30 October 2019
[7] EVs need around 50 kWh per week. The average Norwegian household consumes around 17 000 kWh electricity per year.
[8] NVE ekstern rapport 51/2019, *Kostnader i Strømnettet – gevinster ved koordinert lading av elbiler* (in Norwegian). Written by DNV GL and Pöyry Management Consulting as an external report for NVE-RME. See English summary on pages 5-8.
[9] The estimate is made for integrating EVs into the Norwegian grid. In countries where consumption of electricity per capita is lower, and the distribution grid thus has a lower capacity, potential savings could be higher.
[10] The first EVs on the market were capable of home charging around 3 kW. For many newer models, home charging is conducted at 11 kW, for some at 7 kW, and certain larger models are delivered with home charging at 16-22 kW.

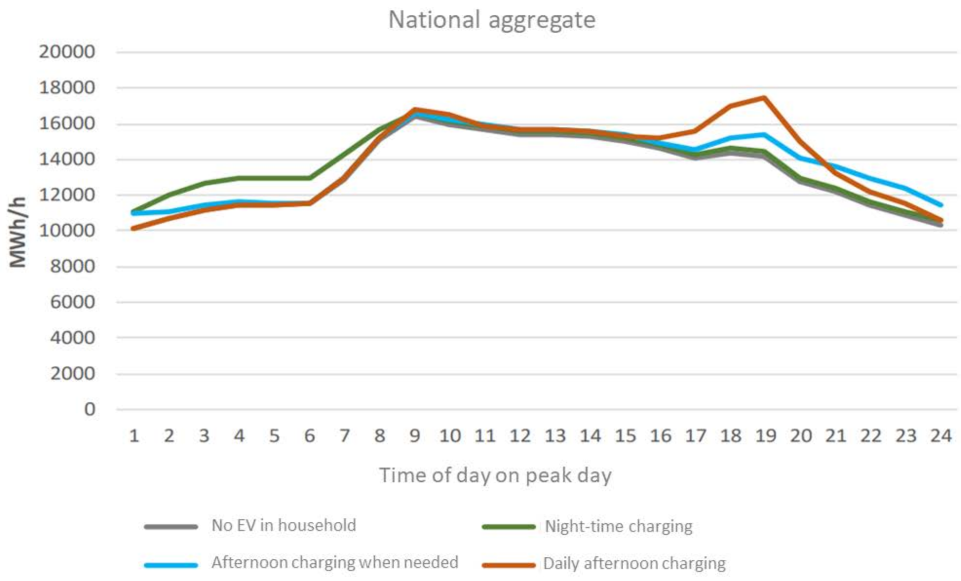

Figure 4: Consumption changes as we use electricity in new ways. The figure shows how peak consumption (from households) in Norway could change from morning to afternoon due to unsmart EV charging. Source: NVE ekstern rapport 51/2019 (in Norwegian), page 7.

3.4 Reduced consumption from the grid through energy efficient measures

Figure 5 shows the electricity consumption in a typical household, with a yearly consumption of around 22 000 kWh. Most household customers have a high electricity consumption during the winter, when temperatures are low and the demand for electricity for heating and lighting is high. During the summer, consumption is lower due to a low demand for electricity for heating and lighting.

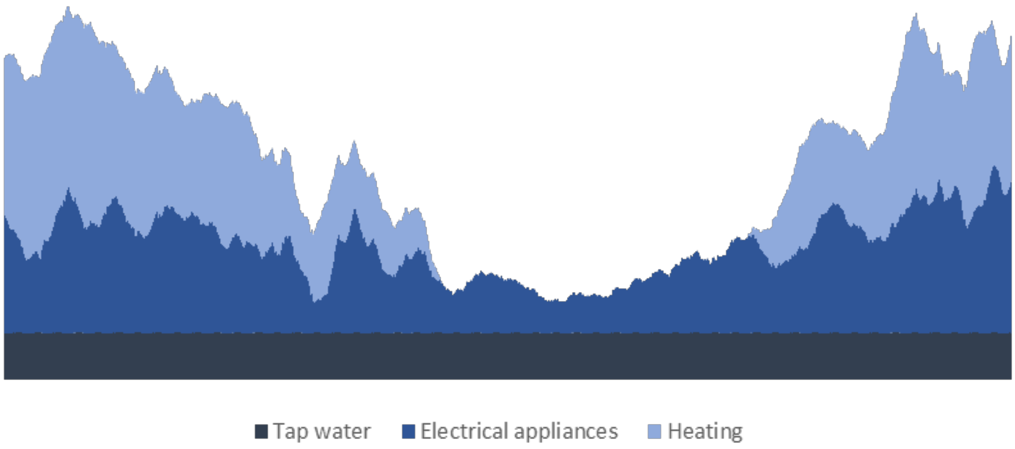

Figure 5: Electrical consumption in a household during a year (ca. 22 000 kWh), i.e. January-December. From *Impact of Zero Energy Buildings on the Power System (2017)*, Karen Lindberg. Electrical appliances refers to all other electrical consumption, such as lights, washing machines, etc. The series illustrates a gliding average to ease the representation of consumption.

Measures contributing to a more energy efficient consumption in general also contribute to reduced demand for capacity during winter, when peak demand occurs. By freeing up capacity e.g. for new and less flexible consumption, these measures can contribute to delayed and even avoiding unnecessary investments.

Energy efficiency measures affect the need for capacity to various degrees. Investments that reduce energy consumption during peak hours, when capacity is constrained, are of most value to the network. Insulation and switching energy carriers (e.g. district heating) are examples of such investments.

Measures that reduce consumer demand from the grid, but that do not reduce demand for capacity, will save less on the network bill as an effect of the proposal. However, our analyses show that this has a limited effect on the total profitability of such measures. These investments still reduce the overall electricity bill through reduced consumption of electricity.

3.5 Self-generated electricity

The market for rooftop PV is rapidly developing. The Norwegian legislative framework for consumers that generate their own electricity, « Plusskundeordningen[11]», makes it relatively easy for households, vacation homes and smaller commercial customers to produce their own electricity. NVE-RME is working on further developments to this framework.

A growing number of customers choose to install solar panels on the house roof. In the Norwegian context, solar power produces the maximum amount of electricity during the summer, when consumption is low and grid capacity is not constrained. This is illustrated below, by the production profile of a typical rooftop PV installation.

[11] A «Plusskunde» is a customer that both consumes and produces electricity, as so-called prosumer. The power fed into the grid from such a customer can, however, never exceed 100 kWh/h.

The solar production profile leads customers with volumetric tariffs to install solar panelling, reducing their network bill more than the reduced network costs.[12]

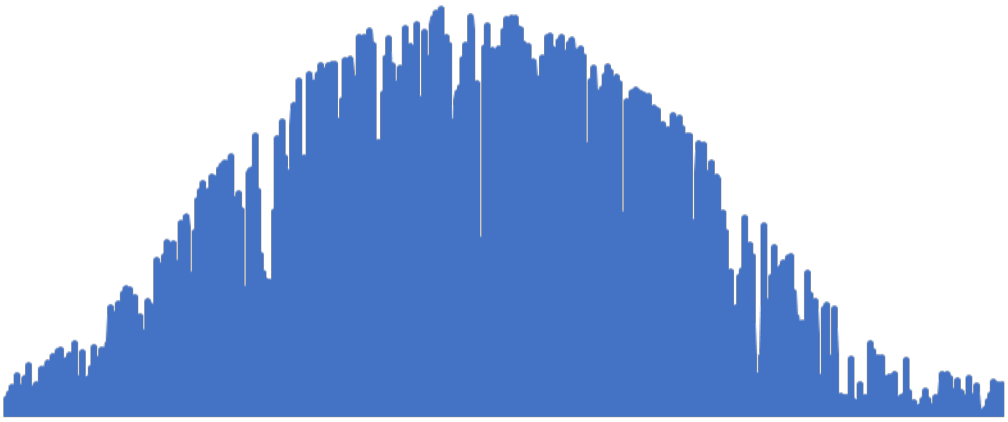

Figure 6: An illustration of the production profile of electricity from rooftop solar panelling on a house during a year. The home produces significantly more during summer than winter.

The implicit subsidy for self-generated electricity in the current tariff design, is financed by a redistribution of network costs to the remaining grid customers.[13] Through changes to tariff design, this will gradually be phased out from 2022 to 2027. Self-generated production will continue to reduce the costs of buying electricity from the market and be compensated for contributing to reduced losses in the grid. In addition, the consumption tax, a fee to the Enova Fund and VAT all give incentives to reduced demand from the grid.

The « Plusskundeordning» framework applies to all types of self-generated electricity. For technologies correlating better with variations in grid capacity, savings on the network bill may increase if the customers' demand for capacity is reduced.

4 Proposed changes to the design of network tariffs

4.1 Introduction to the proposed changes

We propose a principle-based approach, where each network company (DSO) sets its own network tariff within the limits of the regulation. This is also the approach in the current regulation, but the new proposition contains a revision of the relevant principles. The proposal suggest that the network tariff shall constitute of an energy- and a fixed

[12] This effect is also described in Simshauser, Paul (2015), *Demand tariffs: resolving instability and hidden subsidies.*

[13] The energy charge is on average around € 0.02 per kWh, while the marginal cost of grid losses (the short-term variable operational cost) is around € 0.005 per kWh. This implies an implicit subsidy for self-generation (and all other reductions in hours with available capacity) of € 0.015 per kWh of reduced demand from the grid.

charge.[14] In addition, the network tariff may include a capacity charge. In practice, this allows for three possible tariff designs: subscribed capacity, measured capacity and a fuse size approach. Time-of-use principles may be utilised in combination with the suggested models. We are asking for feedback from stakeholders on whether the proposed number of tariff structures within the proposed principles should be reduced.

To increase the cost-reflectiveness of network tariffs, we propose a change to the current design of the energy charge share of the tariff. This change entails that the energy charge can no longer include a share of the fixed network costs. Therefore, in hours with available capacity in the grid, the energy charge should reflect the cost of marginal losses in the network. Furthermore, we propose that the energy charge be set higher than the short-term marginal cost of utilizing the network in certain hours, to incentivize reduction in peak demand. We also propose changes to the current design of the fixed charge, giving it a reasonable distribution of fixed network costs, and a differentiation based on the customer's demand for capacity.

When DSOs charge customers connected to the low voltage grid according to capacity, it is suggested that it is based on the customer's daily peak. For larger customers, the common practice today is to utilise the customer's monthly peak to define the network tariff. The change will make it easier for customers to understand the capacity charge and avoid an unreasonably high marginal cost of consumption on an hourly basis.

We propose that most changes enter into force from 2022, but with several transitional periods. 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. This will ensure that customers have enough time to adjust to the new tariff design, and that customers do not experience sudden changes to their network bill. For larger commercial customers with the current capacity-based tariff design, we suggest a transitional period for the capacity charge lasting until 2025. This will provide time for customers to adapt and give DSOs time to design a new tariff suited for all larger commercial customers. We also suggest that larger commercial customers are provided with a capacity charge based on the daily peak consumption from 2021. This entitlement is particularly important for customers with high peaks when consumption in general is low, giving them too high marginal cost on capacity consumption.[15]

The public consultation document describes several possible approaches, which we would like input on. In addition to asking for input on whether the possible designs should be limited, we are asking stakeholders to comment on whether the monthly peak should still be utilised in settlement for certain customers. We would also like input on the length of the transitional period for the energy charge.

[14] It is, however, important to note that this is not a fixed charge as it is typically referred to, but a charge differentiated based on the customer's demand for capacity. As such, the link between the fixed and capacity charge in the proposal is strong.

[15] This could e.g. be fast charging stations in suburbs.

4.2 Three overall principles for the future design of network tariffs

Network tariffs may constitute three type of charges: an energy charge, a fixed charge and a capacity charge. These charges can be mixed to allow for the construction of different types of tariff design.

The proposal states that DSOs shall include an energy- and a fixed charge when designing network tariffs. DSOs may also utilise a capacity charge. Due to the requirement that fixed costs in the network should be differentiated based on the customer's demand for capacity (see the third principle below), the difference between the fixed and capacity charge is in practice limited. Limits on how each of the charges can be defined, are laid out in the three overall principles for the future design of network tariffs:

1) *The energy charge shall be equal to the cost of marginal losses when there is excess capacity in the grid.*

Cost-reflective tariff design should distinguish between fixed and variable network costs. Network losses represent short-term variable costs in the grid. Therefore, the variable energy component in the tariff (the energy charge) should reflect the cost of marginal losses when there is excess capacity in the grid.

For households, the average energy charge is € 0.02 today, while the cost of marginal losses in the network is approximately € 0.005.[16] Thus, the principle implies a reduction in the energy charge of € 0.015. This reduction will reduce the cost of utilizing the network in hours with available capacity, incentivize e.g. home charging in these hours and remove the implicit subsidy to customers reducing their demand for electricity in hours where the network has available capacity.

2) *The price of utilizing the network should be higher than the cost of the marginal losses when capacity is constrained.*

When capacity is constrained, the estimated marginal cost, calculated through the energy charge, does not reflect the cost of utilizing the network. Therefore, the price of utilizing the network should be higher than the estimated cost of the marginal losses when capacity is constrained.[17]

[16] Network losses are calculated with the function $f(x) = x^2$, where x equals the amount of electricity transported through the network. Marginal losses are, therefore, two times x, and the cost of marginal losses is that figure multiplied with the market price of electricity. In Norway, losses amount to just below ten percent of DSO costs, implying that the energy charge should cover ca 1/6 of network costs. Optimally, this should be per hour per node, but this would lead to very high administrative and transactional costs. Thus, it is sufficient that the energy charge for households is estimated as an average per concession area. In practice, this means utilizing the average cost as a proxy for the marginal cost. Given the small share of costs covered through the energy charge, this simplification should not be too critical.

[17] This is a simplified way of constructing a marginal price per hour, without having to continuously re-estimate the basic energy charge. The share of costs recovered through this higher price should in theory be deducted from the estimated (average) energy charge, but the proposal does not define such a requirement.

DSOs can solve this through time-of-use differentiation of the cost of the energy charge[18], or overspending charges in a subscribed capacity model. Importantly, such a charge should mainly be a price signal, not a cost recovery mechanism. In theory, the price should never be higher than the long-term marginal cost of expanding the network. This cost could, however, be difficult to calculate in practice, and we consider it fair to define that the charge cannot be set too «high» or be applied to «too many» hours.

Other than this, our proposal does not strictly regulate how and even if such a price signal should be included. Firstly, the available capacity amongst Norwegian DSOs differs considerably. Some DSOs experience capacity constraints, others do not. Thus, whether a price on constraints is included in the tariff design should be decided by each DSO. Secondly, short-term capacity constraints might be better solved through other flexibility mechanisms – e.g. a market based system, where the market sets the price rather than the DSO. Finally, the inclusion of such price signals increases the complexity of the tariff. This added complexity should be weighed against expected gains.

3) *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.*

When the energy charge is reduced, more of the DSOs income cap must be recovered through fixed or capacity charges. This increases the cost reflectivity of the tariff, as network costs are mainly fixed in the short to medium term.

In principle, reduced income from the energy charge could be recovered by increasing the rate of the current fixed charge. Most household customers have a flat fixed charge today. Therefore, such an approach has two drawbacks. Firstly, distributional effects, ranging from customers with a high energy consumption (typically single family households and smaller commercial customers) to customers with a low energy consumption (typically apartments) would be large. Secondly, a flat charge does not reflect the fact that even the total residual costs could be reduced over time if network users reduce their demand for capacity.

Both drawbacks can be accounted for, by requiring DSOs to differentiate the fixed and/or capacity charge based on the customer's demand for capacity. The correlation between energy and capacity utilization is still relatively high (though it is expected to weaken going forward, highlighting the importance of changing tariff design now). Making such a differentiation therefore ensures that the distributional effects from changing tariffs are small.

Requiring the fixed and capacity charge to be differentiated in such a way, also creates a forward-looking price signal for customers planning to make investments. This is fundamental, because it is the sum of the decisions of all network users that determines the future need for capacity in the network. Therefore, customers should internalize how decisions made today affect network investments in the future.[19] It is important to

[18] In principle, this could also include dynamic prices, although such prices raise several other issues that are not yet answered in the regulation, e.g. how should the price be set and communicated to customers?

[19] With the proposed new tariff design, this is carried out in two ways. First, customers on all network levels already pay a fully cost-reflective connection charge when connecting to the

consider that this cost internalization not first and foremost changes consumer behavior on an hourly basis – most smaller consumers are relatively price insensitive to short-term changes in the total price of electricity – but rather through its effects on investments customers make.

Implicitly, this principle is also a way of discovering customers' price sensitivity, as more price sensitive customers will make efforts to reduce their share of fixed network costs. Such an approach therefore shares similarities with Ramsey pricing principles, while at the same contributes to matching future demand for capacity with customers' willingness to pay.

4.3 Possible tariff designs in the proposed new regulation

The new principles require a switch from volumetric to capacity based tariff designs. Other than this, DSOs have the freedom to design a tariff reflecting the challenges in the local distribution grid. This is particularly important given the fact that most electrification is happening at lower grid levels.

Even though it is up to each DSO to design a tariff that complies with the regulation, there are in practice three approaches DSOs can choose from. Models can also be combined. In all models, the energy charge is set equal to the marginal cost of network losses. Charges may be differentiated based on time-of-use principles.

1) *Measured capacity*

In the measured capacity approach, network costs are mainly differentiated based on customers' daily peak. The daily peak is priced through a capacity charge, where the price each consumer pays is the sum of the daily peaks over the period in question. This gives customers a short-term price signal, incentivizing customers to reduce their daily peak. More importantly, it incentivizes investments reducing the daily peak over time, freeing up capacity for new consumption. The capacity charge must at least differentiate between winter and summer, to reflect the fact that capacity utilisation during winter is more expensive, as capacity is more constrained during those months. The remaining costs are divided into two types of charges (energy and fixed).

For larger customers, the common practice today is to utilise the customer's monthly peak to define the network tariff. The change in a daily peak is important for two reasons. First, when utilised for smaller customers, a monthly peak is difficult to understand. Therefore, using the daily peak will make it easier for customers to understand the capacity charge. Second, the monthly peak could give a marginal cost of utilizing the network that does not reflect actual network costs. This is especially true when the monthly peak occurs during hours with available capacity. A switch to the daily peak

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network or asking for increased capacity through an increased fuse size (assuming the capacity required is not available in the existing network). Second, the forward-looking price signal in the tariff signals to customers, that the sum of increased capacity from current users (not increasing their fuse size individually but increasing their simultaneous consumption), might lead to new investments. This is a way of internalizing the fact that the marginal cost of expanding the network is zero until the last kW of increased demand is used up, whilst after that point, the marginal cost becomes very high.

avoids an unreasonably high marginal cost of consumption in single hours. The fixed charge may still be differentiated based on capacity demand, to ensure that all customers pay their share of fixed costs even in the future.

2) *Subscribed capacity*

In the subscribed capacity approach, the fixed charge is divided into several subscription levels. The customer can either choose his or her subscription, or the subscription can be set automatically based on e.g. the customer's historical consumption. If the first approach is chosen, DSOs are required to provide a recommendation to each customer.

The fixed charge is thus fixed in the meaning that it is known at the beginning of the period but varies both over time and between different types of customers. A longer period allows for more consistency in the level of the charge. On the other hand, this implies that it takes longer before customers receive the benefit of investments reducing the demand for capacity.

When customers stay within the subscription (during an hour), the price of the demand for electricity equals the marginal cost of losses in the grid. When consumption is above subscription level, excess consumption entails a higher price. This price signal serves both as an incentive to reduce consumption within the hour, and calculates the optimal level of subscription. A higher price for «overspending» implies a lower optimal subscription level, and vice versa. Time-differentiating the overspending charge basically creates weights in the optimization, making consumption in certain hours more important when determining the subscription level.

3) *Fuse size*

In the fuse size approach, the fixed charge is also part of the subscription. However, the level of the subscription is determined by the customer's fuse size. This covers both physical and virtual fuse sizes in smart meters. The second approach allows for several subscription levels, thus making it easier to create a forward-looking price signal within the tariff.

Since consumption never can exceed the fuse size, the fuse size approach does not contain an overspending charge. The energy charge may however be time-differentiated to give a price signal to customers, signaling variations in the cost of utilizing the network.

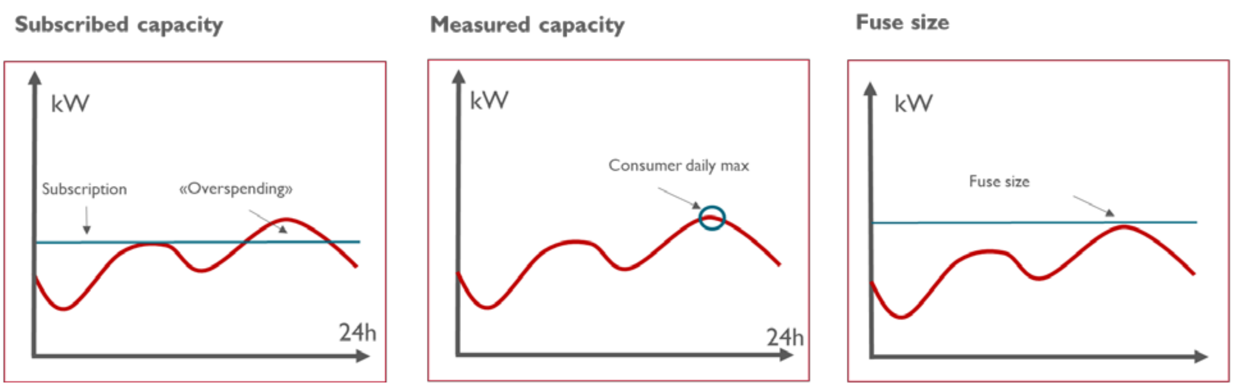

Figure 7: An illustration of the three main models in the public consultation document.

5 Consequences of restructuring tariffs

Consequences of the proposal are analysed thoroughly in chapter 4 of the public consultation document.[20] In particular, the analyses draw attention to the consequences regarding distribution of costs amongst network users and profitability of various electricity measures. The text below highlights some of the most important findings.

5.1 Distribution of costs

Due to the strong correlation between energy and capacity, a tariff design with an adequate differentiation of the fixed or capacity charge, will per definition give small distributional effects. This is illustrated in figure 8, showing the estimated changes in the electricity bill with a shift from the current volumetric tariff to one with subscribed capacity. Changes are similar in the other models, although a physical fuse size approach would lead to larger distributional effects due to fewer levels of differentiation in the fixed charge.

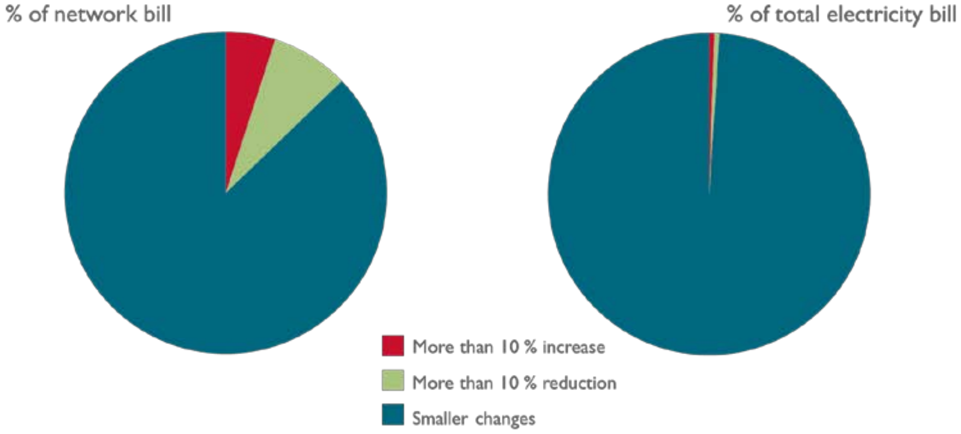

Figure 8: Estimated changes in the electricity bill with a shift from the current volumetric tariff to subscribed capacity.

5.2 Profitability of electricity measures

The network tariff constitutes approximately one third of the total electricity bill. Thus, changes to the network tariff will always have a limited impact on the profitability of various electricity measures. However, measures contributing to reducing the consumer's demand for capacity will in general become somewhat more profitable due to the new proposal. Insulation is an example of such a measure, illustrating the link between energy and capacity efficiency measures.

Perhaps most importantly, the proposal introduces an incentive to use new technology to steer consumption of electricity. An EV owner able to charge in a smart manner already, will receive a tariff reduction of around € 50 annually (or around 10 % of tariff costs for an average household customer). EV owners switching from unsmart to smart charging,

[20] While all assumptions and prices are described in "Vedlegg A" of the public consultation document.

can save up to € 200 annually depending on how often they charge and which model the DSO chooses.

Finally, the profitability of production of electricity from solar panels is reduced by approximately € 30 to € 70 annually. The reason for this change in profitability is the removal of the implicit subsidy through the high energy charge during the summer months.

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