Final report 18 August 2017

Development options and impacts of distribution tariff structures

Samuli Honkapuro, Jouni Haapaniemi, Juha Haakana, Jukka Lassila, Jarmo Partanen

Lappeenranta University of Technology

Kimmo Lummi, Antti Rautiainen, Antti Supponen, Juha Koskela, Pertti Järventausta

Tampere University of Technology

LUT Scientific and Expertise Publications, No. 65

ISBN: 978-952-335-105-9

ISSN-L 2243-3376

ISSN 2243-3376

Preface

This report presents the results of the research project “Jakeluverkon tariffirakenteen kehitysmahdollisuudet ja vaikutukset” [Development options and impacts of distribution tariffs]. The research project was completed by research groups at Lappeenranta University of Technology (LUT) and Tampere University of Technology (TUT) between August 2016 and June 2017. The research was conducted by prof. Samuli Honkapuro, Jouni Haapaniemi, M.Sc., Juha Haakana, D.Sc., Jukka Lassila, D.Sc., prof. Jarmo Partanen, Kimmo Lummi, M.Sc., Antti Rautiainen, D.Sc., Antti Supponen, M.Sc., Juha Koskela, M.Sc., and prof. Pertti Järventausta. The research was funded by the Finnish Electricity Research Pool. The report has been translated into English by Hanna Niemelä, PhD.

The project steering group comprised the researchers and Pirjo Heine (Helen Electricity Distribution Network Ltd, chairwoman of the steering group), Sirpa Leino (the Finnish Electricity Research Pool), Kenneth Hänninen (the Finnish Energy Industries), Johannes Salo (Elenia Oy), Antti Latsa (Järvi-Suomen Energia Oy), Juha Kaariaho (Kymenlaakson Sähköverkko Oy), Arto Ahonen (Turku Energia Sähköverkot Oy), Jarmo Saarinen (Caruna Oy), Jari Nykänen (Paikallisvoima ry.), Heidi Uimonen (Fingrid Oyj), and Veli-Pekka Saajo/Mikko Friipyöli (Energy Authority). The steering group held six meetings and one Skype workshop during the research project. In addition, a workshop was held within the project for the stakeholders on 7 February 2017, where the distribution tariff structures and their impacts were discussed from the perspectives of different stakeholders involved. 44 persons participated in the workshop.

The researchers express their gratitude to the steering group and the participants in the workshop for their active supervision of the research and valuable ideas and comments during the project.

Lappeenranta and Tampere 18 August 2017

Authors

Abstract

The research project investigated development options of distribution tariffs from the perspective of small-scale customers, with a special reference to the steering effects of tariffs. The special focus of the studies is on tariff structures, and thus, a tariff reform is not assumed to have a significant impact on the revenues of the distribution system operators (DSO). In Finland, the DSOs are free to choose their tariff structures, but in order to prevent abuse of monopoly power, the Energy Authority regulates and monitors the total turnover and returns of the companies.

At present, the distribution tariff of small-scale customers consists of a charge based on transmitted energy and a fixed basic charge, which in some companies depends on the size of the main fuse. At present, the cost-reflectivity and steering effects of the tariff structure are deficient, in addition to which the growing proportion of basic charges has weakened the steering effects. Furthermore, the spread of new energy solutions, such as small-scale distributed generation, market-based demand response, electric vehicles, energy storages, new energy efficiency regulations for buildings, and general improvement in energy efficiency alter the ratio of transmitted energy and power. This generates challenges in a situation where the distribution pricing is based on energy transmitted on the network, but the costs remain unchanged in the short term and are significantly dependent on peak powers in the network in the long term.

This research analyses various alternatives for linking power to the small-scale customer’s electricity pricing. The features of different tariff options are considered from the perspectives of different stakeholders (customer, distribution system operator, retailer, society) both qualitatively and by techno-economic simulations. The studies show that incorporating a power-based cost component into the distribution tariff is justifiable especially from the viewpoint of cost-reflectivity and steering effects. The power-based cost component enhances the customer’s opportunities to affect her/his network service fee, incorporates features encouraging resource and energy efficiency, ensures a stable business for the DSO, implements the matching principle provided by the Electricity Market Act better than the present one, reduces cross-subsidies between customers, and establishes conditions for third parties to

develop their services or set up services that might play a key role in the development of the electricity markets.

There are a wide variety of alternatives to incorporate power in the distribution tariff, two of which are considered in this study: power limit tariff (also known as power band pricing) and power tariff for small-scale customers. Based on the analyses, the latter alternative, the small-scale customer's power tariff, seems to be the most feasible option in terms of practicality, intelligibility and cost-reflectivity. A tariff structure of this kind is already applied to larger customers connected to the medium- and low-voltage network. The automatic meter reading (AMR) equipment installed over the past few years to meter the customers' hourly energies enables implementation of the distribution tariff structure also on small-scale customers' premises. The proposed tariff structure can be introduced to small-scale customers by adding a power-based cost component to the present tariff structure and by gradually increasing the proportion of the power charge, at the same time reducing the basic and energy-based charges. With a reasonable transition period (e.g. five years), it is possible to avoid large annual changes in the network charges of the customer groups. A threshold power, for instance 3–5 kW, can be incorporated in the power tariff, below which the power consumption does not generate a separate power charge. Thus, the smallest customers will not get a tariff structure that would be more complicated than the present one.

Contents

1 Introduction

The energy systems are in transition from the perspectives of both technology and business. The future electric energy system will be more dynamic than today. Fluctuations in electricity production, consumption, and price will increase when a growing proportion of production will be fluctuating wind and solar power. In order to be able to maintain the power balance of the electric power system in the future, also the customer has to be an active participant in the system, which calls for demand response and energy storages, such as batteries of electric vehicles and households.

The role of a distribution system operator (DSO) is to provide the different stakeholders with an electricity network, which acts as a neutral marketplace for the use of various distributed and concentrated resources. At the same time, the pricing of network services has to be such that the costs of maintaining the distribution network can be gathered from the customers as well as possible according to the matching principle. This study addresses the pricing structure of the distribution network services; in particular, linking of the customer's peak power to the distribution fee paid by the customer. It is emphasized, however, that the price of distribution network services (distribution of electricity) is on average only one-third of the electricity bill paid by the domestic customer, the other components being electricity sales (electric energy) and taxes (electricity tax and value added tax).

The electricity distribution business is a regional monopoly business, whose reasonableness of pricing is regulated by the Energy Authority. The regulation governs the reasonableness of pricing (turnover) as a whole, but the tariff structure, in other words, how the costs are gathered from different kinds of customers, is up to the distribution system operators to decide. The focus of this study is on the structure of pricing rather than on the level of pricing.

At present, the distribution fees paid by small-scale customers depend essentially on the amount of electric energy transmitted (kWh). In addition to the charge based on energy use, the distribution fee typically contains a fixed basic charge, which in some network companies (DSOs) depends on the size of the main fuse. This energy dependence of the distribution fees is problematic as the costs of the DSO are largely based on the capacity reserved for electricity distribution, that is, power (kW). Hence, it is reasonable to better link the distribution fees paid by the customer to the actual costs of the DSO, as these costs depend on power (kW), especially in the long term. Even though the fuse-based basic charge has a power-based component, and is therefore more cost-reflective than a fixed basic charge, its steering effect is quite weak. There are relatively few fuse sizes (3 x 25 A, 3 x 35 A, 3 x 50 A, 3 x 63 A), and changing the size of the main fuse requires a visit by an electrician. Further, the main fuse acts as a fixed limit for power, and thus, does not allow any flexibility. In addition to the above, in the presence of significant volumes of wind and solar power generation, the competiveness of very inexpensive energy available for the production of various goods is reduced, if the network tariff and taxation are tied to the amount of transmitted energy.

The spread of new energy solutions, such as distributed generation, market-based demand response, electric vehicles, energy storages, new energy efficiency regulations of buildings, and general improvement in energy efficiency have an impact on the ratio of transmitted energy and power. This poses challenges in a situation where the distribution pricing is based on energy transmitted on the network, but the costs remain unchanged in the short term and are significantly dependent on peak powers in the network in the long term. The pricing of the DSO has to be developed to be more cost-reflective to ensure incentives for the customers to efficiently exploit the network capacity. This will reduce network costs in the long term and different stakeholders' risks associated with the transition, and further, enable a lower distribution price level for the end-customers in the future.

The technical facilities for the development of pricing have also improved. Previously, the customers' electricity use was measured by energy meters recording cumulative energy consumption. At present, as a result of the Government Decree (66/2009) on metering of electricity consumption, all places of electricity use in Finland are equipped with AMR devices that allow remote reading of hourly energies. Compared with the previous meters, the present meters provide better opportunities to develop the DSOs' pricing practices also for small-scale customers. Thus, the power-based tariffs already applied to larger customers can technically be extended to smaller-scale customers. At the time of writing this report, two Finnish DSOs, Lahti Energia and Helen Electricity Network, have launched the power tariff for their small-scale customers. However, the development of the tariff structure does not attract interest only in Finland, but is under study worldwide (see e.g. Schreiber et al., 2015; Saraiva et al., 2016; Eurelectric, 2013; Eurelectric, 2016; GEODE, 2013; ENA, 2014; The Brattle Group, 2016). Over the past few years, numerous reports and Master's theses have been published on the current state and development of the Finnish distribution pricing (see e.g. Kasari, 2003; Roivainen, 2003; Pantti, 2010; Niemelä, 2010; Perälä, 2011; Similä et al., 2011; Aho, 2012; Partanen et al., 2012; Lummi, 2013; Haapaniemi, 2014; Apponen, 2016; Suikkanen, 2016; Vuohelainen, 2017).

Further, it is important to note that the proportion of the fixed charge in the distribution fee, which the customers cannot affect, has increased in recent years, as can be seen in Figure 1.1. This trend is anticipated to continue unless the tariff structure is not reformed. When considering the steering effects, the present development trend is not desirable, and also in the light of the recent development of pricing structures, there is also a need for a tariff structure reform.

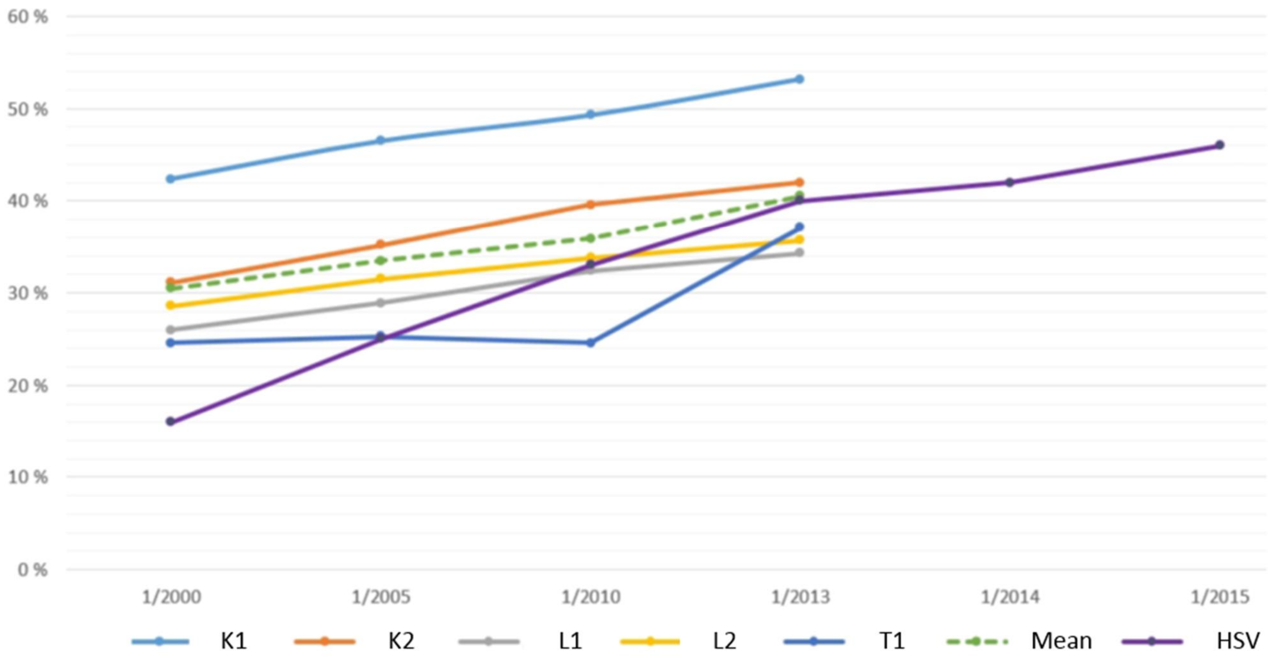

Figure 1.1. *Proportion of the fixed charge in the distribution tariff for different types of customers in different years. K1: Flat, no electric sauna heater, main fuse 1 x25 A, 2 000 kWh/v, K2: Detached house, direct electric space heating, main fuse, 3x25 A, 18 000 kWh/v, L2: Detached house, partly accumulating electric space heating, main fuse, 3x25 A, 20 000 kWh/v, T1: Small-scale industry, power demand 75 kW, electricity consumption 150 000 kWh/v, HSV: Helen Electricity Distribution Network tariff (Apponen 2016, the data in part from (EMA, 2013)).*

This report presents the key results of the research project ”Jakeluverkon tariffirakenteen kehitysmahdollisuudet ja vaikutukset” [Development options and impacts of distribution tariffs]. Chapter 2 of the report describes the formation of the customer’s electricity price. Chapter 3 elaborates on the cost structure of the DSO. Chapter 4 focuses on the general constraints, objectives, and fundamentals of distribution tariffs. Chapter 5 introduces the tariff structures considered in the study. Chapter 6 provides the key results, in other words, the effects of tariff structures on different stakeholders. Conclusions are drawn in Chapter 7.

2 Formation of the customer’s electricity price

The customer’s electricity bill comprises three components; electricity sales, distribution, and taxes. Each component accounts for approximately one-third of the electricity bill, as shown in Figure 2.1.

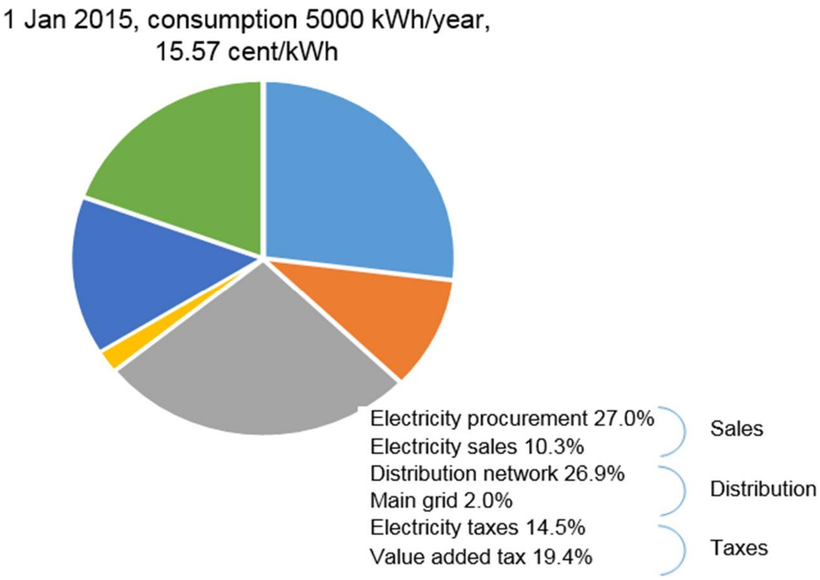

Figure 2.1. *Formation of a domestic customer’s electricity price (Energy Authority 2015a).*

In electricity sales, the pricing is mainly based on the amount energy consumed (cent/kWh), in addition to which the price may contain a basic charge, which covers operating overheads. In the present network pricing, the tariff for small-scale customers typically comprises a basic charge (€/month) and an energy charge based on consumption (cent/kWh). The taxes included in the price are value added tax and electricity tax, which is for small-scale customers based on Tax Class 1, 2.79372 cent/kWh (incl. VAT 24 %). The customers pay the electricity tax in conjunction with the distribution fee.

In the electricity sales price, the customer pays for the consumed electric energy, including energy production at the power plant and costs of electricity sales. The electricity distribution price, again, covers transmission of electricity on the national grid and local electricity distribution. The national grid and the electricity distribution network are local monopolies (”natural monopolies”), whose reasonableness of pricing is regulated by the Energy Authority.

When a customer is connected to the distribution network, she/he pays a *connection fee*, which covers the connection construction costs. In addition, the customer pays a *network service fee*, which covers the capital and operational costs of the whole distribution network development and maintenance, and other DSO’s costs, such as administration and customer services and acquisition costs of grid losses. Finally, the network service fee contains the national transmission system operator’s transmission fees from the end customers. This study focuses on the determination of the distribution network service fee.

Considering the above-described costs, only losses and transmission grid fees are directly dependent on the amount of transmitted energy. The other costs are generated even when no energy is transferred on the network. Thus, the customer's network service fee is, to a large extent, based on the fact that the customer is provided with an opportunity to consume electricity whenever she/he wishes; in other words, the fee covers the costs generated by keeping the network always at the ready. The DSO's cost structure is discussed in more detail in the next chapter.

3 Distribution system operator’s cost structure

This chapter addresses the DSO’s costs at a general level by providing a general description of example cost items included in different types of costs. These cost items, however, are not all-encompassing, but in reality, a DSO may have also other expenses not described in this chapter.

The purpose of this chapter is to demonstrate that the DSO incurs costs of various kinds, and the presence of these costs forms the basis for the different cost components of the distribution tariffs. Further, it is emphasized that even though the amount of transmitted electricity were small, the DSO would incur a variety of costs over the year from providing electricity distribution to the customer. In addition to the costs presented in this chapter, the distribution tariffs should produce return on capital invested in the distribution network. The amount of return obtained by distribution tariffs is highly dependent on the present value of the distribution network.

3.1 Capital costs

The DSO’s most significant cost item is comprised of the distribution network assets. In practice, such costs are for instance depreciation costs of network components and interest costs of external capital to fund network investments.

3.2 Other costs

The DSO’s operational costs comprise other costs such as network operation, planning, and maintenance costs and rental costs.

3.3 Load losses; transmission system fees and regional distribution network service fees

Some of the DSO’s costs are proportional to the amount of electricity transmitted to the customers. For instance, the DSO pays grid service fees for the national system operator (Fingrid) according to the listed prices. At the moment, Fingrid’s grid service prices mainly consist of energy-based grid service unit prices (MWh) as listed in Table 3.1.

Table 3.1. *Grid service unit prices (Fingrid, 2017)*

Unit prices	**€/MWh**
Consumption fee, winter weekday *)	9.0
Consumption fee, other times	2.70
Fee for output from the main grid	1.09
Dee for input into the main grid	0.72
Generation capacity fee for power plants	162.50 €/MW, month (1950 €/year)
Energy fee for short operating times	3.20
Reactive power fee	333.00 €/Mvar, month
Reactive energy fee, output	5.00 €/Mvar
Reactive energy fee, input	5.00 €/Mvarh

Prices excl. VAT
*) Winter weekday 900 hrs, December–February Mon–Fri at 7 am–9 pm

In addition to grid service fees, the DSO incurs costs from losses on the distribution network; these costs can be considered to be based mainly on the amount of energy transmitted to the customer.

3.4 Customer costs

The DSO incurs certain costs even though no electricity is transmitted to the customers over the year. The facilitation of electricity distribution alone causes significant costs to the DSO. There are also various costs not dependent on the electricity distribution, such as customer services, billing, metering, and administration.

4 Constraints, objectives, and characteristics of distribution tariffs

This chapter introduces the key constraints associated with distribution tariffs, the primary constraint being the legislation. Moreover, the chapter discusses the main objectives and characteristics of distribution tariffs.

4.1 Constraints and fundamentals of distribution tariffs

Electricity distribution is a monopoly business, legislation being the primary means to regulate the electricity distribution business and pricing (in Finland the Electricity Market Act). Compliance with the Act is monitored by national authorities (in Finland Energy Authority, former Energy Market Authority).

4.1.1 Legislation

The Electricity Market Act (588/2013)[1] sets the terms for pricing, providing that:

The distribution system operator must offer system services on equitable and non-discriminatory terms to the electricity market participants. The supply of services shall not include any unreasonable conditions or limitations that would obviously restrict competition within electricity trade. (18 §)

The distribution system operator shall sell electricity transmission and distribution services against reasonable compensation to those that need them within the limits of its system transmission capacity. (21 §)

The sale prices and terms of the system services and the criteria according to which they are determined shall be equitable and non-discriminatory to all system users. Exceptions to them may only be made on special grounds. The terms of sale intended for consumers have to be presented in a clear and understandable manner, and they shall not include any constraints outside the contracts on the exercise of the consumers' rights.

The pricing of system services shall be reasonable.

The pricing of system services must not present any unfounded terms or restrictions obviously limiting competition within the electricity trade. However, the pricing shall take account of any terms needed for reliable operation and efficiency of the electricity system as well as the costs and benefits arisen by the connection of an electricity generation installation to a system." (24 §)

The system operator shall, for its own part, create preconditions permitting the customer to conclude a contract on all system services with the system operator to whose system he is connected as subscriber.

The system operator shall, for its part, create preconditions permitting the customer to be granted the rights, in return for payment of the appropriate fees, to use from its connection point the electricity system of the entire country, foreign connections excluded. (25 §)

---

[1] Unofficial translation made for the purposes of this report, including sections adapted from the unofficial translation of the Electricity Market Act (386/1995).

Within a distribution system, the price of system services must not depend on where within the system operator's area of responsibility the customer is located geographically. However, in parts of the system operator’s area of responsibility that are geographically separated, the transmission prices of each area shall apply. In individual cases the electricity market authority may grant an exemption for application of separate prices for transmission services, if the cost levels and pricing criteria of the parts of the distribution system holder’s area of responsibility do not much differ from each other. (55 §)

In invoicing, the distribution system operator shall give its customer an itemised account of how the price of electricity distribution is formed. In the invoices sent to consumers, the distribution system operator shall provide information about making a complaint, and in invoicing of consumers, information about the dispute resolution procedures available for consumers. The Energy Authority may provide more detailed regulations on the information to be included in the invoice, and on the mode of providing this information.

The distribution system operator shall provide different methods of payment for consumers to pay the invoices of electricity distribution. The alternatives offered shall not include any unfounded terms or conditions or conditions that are discriminatory to different customer groups. In the terms and conditions of the methods of payment, it is possible to take account of reasonable differences in costs caused for the distribution system operator by the provision of alternative methods of payment. If the distribution system operator offers the consumers an advance payment system, the system shall adequately reflect the consumer’s estimated annual electricity consumption. (57 §)

Furthermore, section 1 of the Act provides that *The duties of companies operating in the field of electricity include the responsibility to ensure provision of services related to the electricity procurement of their customers and network users as well as promotion of efficient and economical use of electricity both in the company’s and the customers’ activities.*

To sum up, the Electricity Market Act specifies that the pricing shall be equitable and reasonable, and the price must not depend on where within the system operator's area of responsibility the customer is located geographically.

The reasonableness of pricing is monitored by the Energy Authority, which defines the regulation methods for four-year regulatory periods. At the moment, the regulation methods have been defined for two four-year periods (2016–2023). The regulation focuses on reasonable rate of return, in addition to which a reasonable level is defined for operational costs and depreciations. Thus, the regulation determines, in practice, the DSO’s reasonable turnover. However, the Authority does not take a stand on the pricing structure itself, but it is left for the DSOs to decide.

At the time of writing of this report (May 2017), a Government proposal (HE 50/2017 vp) has been published, proposing changes to the Electricity Market Act. On increasing the electricity transmission and distribution tariffs, Article 26 a § of the proposal provides:

The distribution system operator is allowed to raise its electricity transmission and distribution fees by 15 per cent at the maximum compared with the electricity transmission and distribution fees collected over a period of 12 months preceding the price increase. If the distribution system operator makes further increases in the electricity and distribution fees during the period of 12 months following the price increase, these increases shall not exceed 15 per cent of the amount of the electricity transmission and distribution fees collected during the period of 12 months preceding the first price increase either.

The maximum allowable price increase is calculated based on the average total fee of each customer group representing the distribution system operator's network users over a reference period of twelve months. The allowable maximum price increase is thus calculated from the taxable price of electricity transmission and distribution determined based on the highest tax rates for the network users in each customer group, not including the increase in taxes and levies that are based on the network users' use of electricity as well as increases in the value added tax exercised from the date of the price increase onwards. The customer groups have to be determined so that they describe the distribution system operator's network use and the characteristics of the network users in an equitable and non-discriminatory manner.

…

In an individual case, the Energy Authority can, based on application, grant permission for the distribution system operator to derogate from subsection 1, if it is necessary for meeting the preconditions for granting an electricity system licence or the obligations prescribed by law.

The Energy Authority may issue more detailed orders on the customer groups defined in subsection 2 and on determination of these customer groups.

Moreover, the rationale of the Proposal[2] provides:

Considerable changes may occur in the proportion of different tariff components in the customer groups' total fees as a result of reforms in the tariff structures applied by distribution system operators in their pricing. Thus, the changes in the distribution system operators' tariff structures should be implemented so that they do not cause unreasonably large one-time effects on the total fee paid by the customer group.

...

Under subsection 2 of the section, the maximum allowable price increase would be calculated primarily based on the average total fee of each customer group representing the distribution system operator's network users over a reference period of twelve months. Examples of such customer groups would be the established customer categories determined by the Energy Authority or trade associations, or electricity producers and network users of different sizes that are customers of the national grid operator and the high-voltage distribution system operator, as well as distribution system operators. In the customer group specific considerations, the percentage increases of individual customers belonging to the customer group could exceed 15 per cent without the price increase being considered to be in violation of the regulations for these customers. Conditions or rationale that may lead to a situation where an individual customer's price increase exceeds the limit set in the provision could be for instance the customer's exceptionally low or high electricity consumption compared with the average electricity consumption determined for the customer group, or an electricity transmission or distribution product or fuse size poorly compatible with the customer's consumption profile.

Based on the Government proposal, when reforming the distribution tariff structure, it is essential to take account of the customer group specific changes in tariffs, rather than changes in individual customer's tariffs, where the changes can be considerable for instance owing to issues stated in the rationale of the proposal.

[2] Unofficial translation made for the purposes of this report.

Directive 2012/27/EU on energy efficiency focuses mainly on the dynamics of tariffs; the topic is addressed in more detail in Section 4.2.7.

Further, Government Decree (66/2009)[3] on determination of electricity supply and metering provides that

The metering of electricity consumption and small-scale electricity production shall be based on hourly metering and remote meter reading (hourly metering obligation).

The distribution system operator may deviate from the hourly metering obligation in 20 per cent of the places of electricity use of the distribution network at the maximum, if the place of electricity use within the exception is

1) equipped with 3 x 25 A main fuses at the maximum;

2) equipped with larger than 3 x 25 A main fuses, the electricity consumption at the place of electricity use is 5 000 kW at the maximum, and the electricity is purchased at the place of electricity use in accordance to the conditions set in section 21 of the Electricity Market Act. (4 §)

Thus, based on the above, **we may assume that the places of electricity use are comprehensively equipped with AMR meters**, which allow the implementation of the distribution tariff structures discussed in this report.

4.2 Key characteristics and objectives of distribution tariffs

Nowadays, electricity can be considered a necessary basic commodity rather than a luxury. In practice, modern society is highly dependent on electricity and its reliable and high-quality supply. This imposes certain requirements also on distribution tariffs. This section introduces criteria for distribution tariffs (Table 4.1), and the most important characteristics and objectives of the tariffs.

Table 4.1. *Summary of the criteria for distribution tariffs.*

Criterion	**Description**
Cost-reflectivity	In this context, 'cost-reflectivity' means that the distribution tariff structure reflects the cost structure of the distribution system operator within the limits of spot pricing. This supports fairness and neutrality of the tariffs for different customers. Further, the distribution tariffs shall generate sufficient revenue to ensure the operating conditions of the distribution system operator.
Neutrality for third parties	This criterion indicates that the distribution tariff structure should not constrain or prevent the operation of third parties. Further, the primary objective of the distribution tariffs is not to generate new business options e.g. for demand response services but rather ensure that the distribution tariff does not constrain the future operation of these third parties within the technical limits of the distribution system.

[3] Unofficial translation made for the purposes of this report.

Steering effects/ Incentives for efficient use of electricity	The core idea of this criterion is that the distribution tariff is one of the components in incentivizing the customer for resource efficient use of electricity. In the long term, this will lead to a reduction in the total costs of the electric power system. The distribution tariff allows the customer to affect the amount of her/his distribution fee by her/his own actions and decisions.
Feasibility of practical implementation	‘Feasibility of practical implementation’ means that the tariff structure can be implemented at a reasonable cost. The practical implementation of the basic functions of the tariff should be cost-effective and, as far as possible, realizable with the present and foreseeable systems and infrastructure (e.g. next-generation metering and ICT systems) in order not to cause unreasonable costs to the distribution system operators and customers. In the new tariff structure, also customer communications and contacts with customer services have to be taken account of initially or annually, e.g. if the power threshold is changed.
Compliance	‘Compliance’ means that the tariff structure is not in conflict e.g. with the present but also potential new tariffs provided by the electricity retailer. This criterion shall also take account of third parties’ future development trends in pricing.
Intelligibility	’Intelligibility’ means that the tariff structure, in other words, the set of rules according to which the customer’s distribution fee is determined, is consistent and simple enough as a whole. Based on the price list, the customer has to be able to comprehend the rationale behind her/his distribution fee without unreasonable effort.

4.2.1 Non-discrimination and fairness

Under the Electricity Market Act, the distribution tariffs should be non-discriminatory. This means that the price of system services must not depend on where within the system operator's area of responsibility the customer is located geographically. In practice, the customers pay for their electricity on the same principles according to the distribution price list in force independent of their geographical location. Furthermore, the customers are not able to choose their distribution service provider but the service has to be subscribed from the local distribution system operator. Thus, unlike in the case of electric energy and multiple retailers, the customer cannot invite tenders for electricity distribution.

Furthermore, fairness and non-discrimination steer pricing towards minimum cross-subsidization between different customer groups. This means that different customer groups pay only for those costs that are considered to be generated by them; for instance the customers connected directly to the medium-voltage level (20 kV) do not have to pay for the costs of the low-voltage network (0.4 kV).

4.2.2 Reasonableness

Under the Electricity Market Act (Chapter 4, section 24),

When considered as a whole, the pricing of system services shall be reasonable.

The requirement of the reasonableness of distribution pricing is primarily related to the monopoly nature of the electricity distribution business. From the perspective of public economy, it is not reasonable to construct parallel distribution networks, because a single operator is able to provide the distribution services efficiently enough within its area of responsibility.

The lack of natural competition does not incentivize distribution system operators to keep their distribution tariffs low, and therefore, the level of pricing has to be regulated and monitored. At the practical level, the regulator (the Energy Authority) does not follow individual tariffs very closely, but the regulation focuses on the amount of returns obtained by distribution fees. The Energy Authority monitors the reasonableness of pricing according to the regulation methodology valid for the regulatory period in force (Energy Authority, 2015b).

4.2.3 Cost-reflectivity

Owing to the monopoly nature of the electricity distribution business, the distribution tariffs should correspond to the actual operational costs. Further, the distribution system operators must be able to justify the rationale behind the distribution tariffs.

4.2.4 Steering effects

Through price signals, distribution tariffs can be used as an instrument to affect the customer's electricity consumption habits. One of the key properties of tariffs is their incentive function, which means steering the electricity use by different price signals. For instance the present time-of-use tariffs (e.g. night tariff) encourage the customers to use electricity in the night-time instead of the daytime. Typically, there has been more distribution capacity available on the network in the night-time than in the daytime, when for instance the electricity use of the industry is lower.

4.2.5 Intelligibility

One of the core objectives of the distribution tariffs is that the customers understand the rationale behind their distribution fees. In particular when designing new distribution tariffs, it is important to pay special attention to the presentation of the operating principles of different tariff cost components so that the consumption habits of the customers will not be opposite to the intention of the tariffs.

4.2.6 Hearing other stakeholders' views

Even though distribution tariffs are directly linked to the DSO's income formation, the other electricity market participants (e.g. retailer) have to be taken into account in the development of the distribution tariffs. The distribution tariffs shall not pose obstacles to other stakeholders in the market.

The distribution tariffs shall not prevent for instance demand response, which, in this context, may refer to both reducing and increasing demand as needed.

4.2.7 Viewpoints related to the dynamics of distribution tariffs

The Directive 2012/27/EU on energy efficiency implemented in 2012 provides that

(45) Demand response can be based on final customers' responses to price signals or on building automation. Conditions for, and access to, demand response should be improved, including for small final consumers. Taking into account the continuing deployment of smart grids, Member States should therefore ensure that national energy regulatory authorities are able to ensure that network tariffs and regulations incentivise improvements in energy efficiency and support dynamic pricing for demand response measures by final customers. Market integration and equal market entry opportunities for demand-side resources (supply and consumer loads) alongside generation should be pursued. In addition, Member States should ensure that national energy regulatory authorities take an integrated approach encompassing potential savings in the energy supply and the end-use sectors.

3. Network or retail tariffs may support dynamic pricing for demand response measures by final customers, such as:

(a) time-of-use tariffs;

(b) critical peak pricing;

(c) real time pricing; and

(d) peak time rebates.

The tariff dynamics can be understood in different ways depending on how the tariff is addressed. For instance, at present, many electricity retailers offer their customers a tariff option where the price of electric energy is tied to the Nord Pool Elspot hourly prices. The customer is notified of the day-ahead hourly prices for electricity on the preceding day. The price of electricity may thus fluctuate considerably in time, and the customer has to ensure her/himself that she/he gets the best benefits from the fluctuations in electricity prices. 'Dynamics' in the case of distribution tariffs can be understood for instance as follows

1. The unit price of a commodity or a service varies in a dynamic way (e.g. similar to the market price of electricity on the power exchange, where a separate price is defined for electric energy for each hour).
2. The unit price of a commodity or a service is fixed for a longer period of time and the consumer is able to reach a target cost level by her/his own decisions.

In the case of distribution tariffs, dynamics does not necessarily mean the same as in the case of electricity sale tariffs. The DSOs have to notify their customers about the rationale behind their distribution tariffs in advance. Dynamic pricing based on the network state is also limited by the spot pricing principle written in the Electricity Market Act. In addition, owing to their cost structure, the DSOs have no grounds to offer similar dynamic tariff structures for their customers as the electricity retailers do. In the case of transmission tariffs, a dynamic pricing scheme could mean that the customer's distribution tariff structure allows the customer to actively affect her/his distribution fee; this is an example of the second alternative presented above. This assumption is taken as the starting point in this report.

4.3 Societal objectives of distribution tariffs

There are multiple objectives associated with distribution tariffs. In the context of this study, the most essential high-level societal objectives are the following:

- Reduction in the costs of the electric energy system and enhancing the resource efficiency in the long term.
- Providing incentives and activating customers to enhance their resource efficiency by their own choices and actions.
- Reduction of cross-subsidization between different customers ('free-rider problem').
- The distribution tariff allows the distribution network to act as a technology-neutral platform for electricity markets and integration of renewable energies.
- Securing sustainable and predictable electricity distribution business also in the future in the changing operating environment.
- Enabling generation of new business opportunities.

5 Tariff structures under study

This chapter presents alternative methods to incorporate power dependence in the customer's distribution tariff. The objective is to provide a general analysis on the operating mechanisms of different tariff alternatives. In the analyses, the target is not to fix energy or power to distribution tariffs so that they would represent final results, but the chapter approaches inclusion of power in the distribution tariff at a general level.

5.1 Cost components of the distribution tariff

Distribution tariffs have traditionally consisted of three main cost components:

1. Monthly basic charge.
2. Volumetric consumption charge (based on the amount of transmitted electricity).
3. Active power charge.

In addition to the above three components, large-scale customers have had a separate cost component for reactive power. Each of the three components is discussed at a general level in the following.

5.1.1 Basic charge

The simplest payment mechanism, which is applied to basic charges, is a monthly fixed sum of money (€/month). In recent years, the DSOs have increased the proportion of basic charges in the distribution fees of small-scale customers. According to cost-based thinking, this trend is right, as the majority of the DSO's annual costs presented in Chapter 3 do not depend on the amount of electric energy transmitted to the customer (kWh).

In an ideal situation, only those costs are allocated to the basic charge that depend on the mere presence of a customer (e.g. customer services, metering, billing, and some of the network costs). At present, also other costs are allocated to the basic charge in order to increase the weight of the basic charge in the distribution fee; thus, the DSOs are able to keep their tariff structures simple and ensure predictability of the revenue stream from distribution fees.

5.1.2 Consumption charge

Considering consumption charges, a simple practice of payment is applied especially to flat rate tariffs (i.e., general distribution tariffs), in which the customer's consumption is multiplied by the unit price of the consumption charge (cent/kWh). In flat rate tariffs the unit price is the same regardless of the time of day when the energy unit is transmitted. In two-rate tariffs (e.g. time-of-day and seasonal tariffs) there are two separate unit prices for the consumption charge. The unit price is typically lower either in the night-time (night tariff) or on the non-winter weekday (seasonal tariff). The cumulative amount of energy is multiplied by the unit price for that period.

In an ideal case, only costs that are dependent on the amount of transmitted electricity would be allocated to the consumption charge (e.g. load losses and grid service fees) As in the case of basic charge, based on the tariff structure, DSOs have allocated also other costs to the consumption charge according to their practices.

5.1.3 Power charge

Compared with the basic and consumption charges, power charges are determined on a slightly different basis. At simplest, a certain predefined power (contract power) or the highest measured power within a certain period (e.g. a year or a month) can serve as the basis for the determination of the power charge. In the present pricing model, the concept of power refers to the hourly mean power (hourly power).

The practices concerning the determination of the power charge vary considerably between DSOs. At present, the basis for determining the power charges in the low-voltage power tariffs for large customers connected to the low-voltage network varies from a twelve-month sliding highest measured hourly power to the highest measured hourly power of a month. Again, in some DSOs' tariffs, the power charge takes account of only the peak hourly powers in winter months, whereas in some companies there are also various year-level power charges, which are based on the average of the powers of several peak load hours. Thus, at the moment, there is significant variation in the approaches taken to the determination of power charges.

Costs associated with the required network distribution capacity (e.g. depreciation of network components) would be allocated to power charges. However, in the present distribution tariff structures for small-scale customers there is no separate cost component for power but the above-mentioned costs are usually allocated to either basic or consumption charges.

5.2 Possible effects of power on different cost components

There are a variety of alternative combinations to incorporate power in the cost components of distribution tariffs for small-scale customers. This section aims at illustrating these options. The characteristics of different tariff structures especially with respect to power are discussed in more detail in Section 5.3 in the context of different distribution tariff structures.

5.2.1 Impact of power on basic charge

The impact of the customer's power on the amount of the basic charge in the distribution tariff is already now in use in some network companies in tariffs where the basic charge is determined based on the size of the main fuse. In such cases, a larger main fuse will basically lead to a higher basic charge, and a higher basic charge will incentivize the customers to choose a smaller fuse.

5.2.2 Impact of power on consumption charge

The customer's demand for distribution capacity can, instead of the basic charge, be linked to the consumption charge in the distribution tariff. In practice, this would mean for instance that a higher demand for power would lead to a higher consumption charge either temporarily or for a longer period (e.g. for a month).

5.2.3 Separate power charge

Instead of the cases described above, it is possible to introduce a separate power charge in which the customer's power demand is directly linked to the amount of distribution fee paid by the customer without the power affecting any other cost components of the tariff.

As in the case of present low-voltage power tariffs, there are alternative ways in which the power charge is determined. In practice this means that the amount of the power-based proportion of the distribution fee can be determined for instance according to the customer's highest annual measured hourly power, monthly peak powers, different combinations of peak powers (e.g. average of hourly powers of several hours) or according to a predefined power. The selection of the determination principle may have a significant effect on the steering effects of the tariff, and thus, the selection should be thoroughly considered and justified.

5.3 Distribution tariff structures

The distribution tariff structures consist of different cost components, which have been introduced in the previous chapters. This section presents the basic structures of different alternative distribution tariffs. The tariffs discussed here offer an insight into different distribution tariff structures, yet the presented tariff structures do no not cover all the alternatives available. To clarify the distribution tariff alternatives, Table 5.1 presents the potential determination principles involved in each distribution tariff structure. The alternatives in the table do not represent final choices, but different tariff structures, and the choices related to their cost components will be addressed later in the report.

Table 5.1. Basis for determination of the distribution fee for different distribution tariff structures.

	Basis for determination of the distribution fee		
Distribution tariff	**€/month (or €/a)**	**cent/kWh**	**€/kW**
Fixed annual charge	x		
Fixed basic charge and consumption charge	x	x	
Fuse-based basic charge and consumption charge	x	x	
Power limit tariff			x
Power limit tariff with seasonal division			x
Two-tier tariff	x	(x)	(x)
Three-tier tariff	x	(x)	(x)
Small-scale customer's power tariff with threshold power	x	x	x
Small-scale customer's power tariff	x	x	x

x = Included in the distribution tariff structure
(x) = May be included in the distribution tariff structure

The mechanisms of the different cost components of the distribution tariffs determine the rules based on which the customers finally pay their distribution fees. The distribution tariff provides this set of rules, and therefore, it is highly important that the application of different tariff structures produces desired customer effects and the tariffs are intelligible to the customer.

The cases depicted in the figures of this chapter describe the basic operating mechanisms of tariffs with a special focus on power. The figures do not give exact values for example for monthly distribution fees, customer powers, or sizes of the cost components of the distribution tariffs, as the customers' electricity use is not homogeneous when considering the entire customer base. The price parameters and quantitative customer effects of the tariffs will be addressed later in the report.

5.3.1 Fixed annual charge

The distribution fees can be collected from the customers simply as fixed annual fees (€/a), billed as equal monthly charges (€/month). In practice, in this alternative, *the DSO would divide all the costs allocated to the small-scale customer evenly between all the small-scale customers.* Figure 5.1 depicts the development of the customer's distribution fee over a year, when the customer is assumed to have a fixed annual charge as the tariff. The present trend in tariffs leads to this direction, if the tariff structures are not reformed; the proportion of the fixed charge has increased considerably in the past 15 years, as was stated in the introduction of this report.

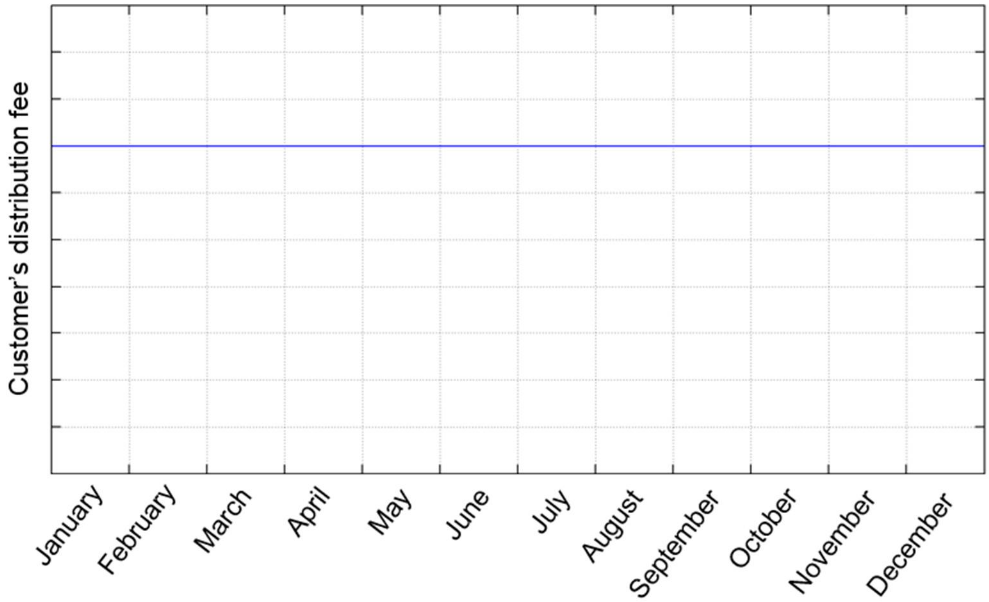

Figure 5.1. *Variation in the customer's distribution fee in a year in a fictitious example where a fixed annual charge is used as the customer's distribution tariff.*

5.3.2 Fixed basic charge and consumption charge

At present, some of the DSOs charge their small-scale customers based on a distribution tariff structure, which consists of two cost components: a monthly basic charge (€/month) and a volumetric consumption charge based on the amount of transmitted electricity ('energy charge', cent/kWh). In addition, the present time-of-day and seasonal tariffs have price steps for the energy charge for different times of the day. Distribution tariffs of this kind are typically applied by urban DSOs with a large number of customers, who are typically concentrated on smaller areas. Figure 5.2 illustrates the behaviour of a customer's *basic charge* over a year in an example where the customer's tariff is assumed to be of this type.

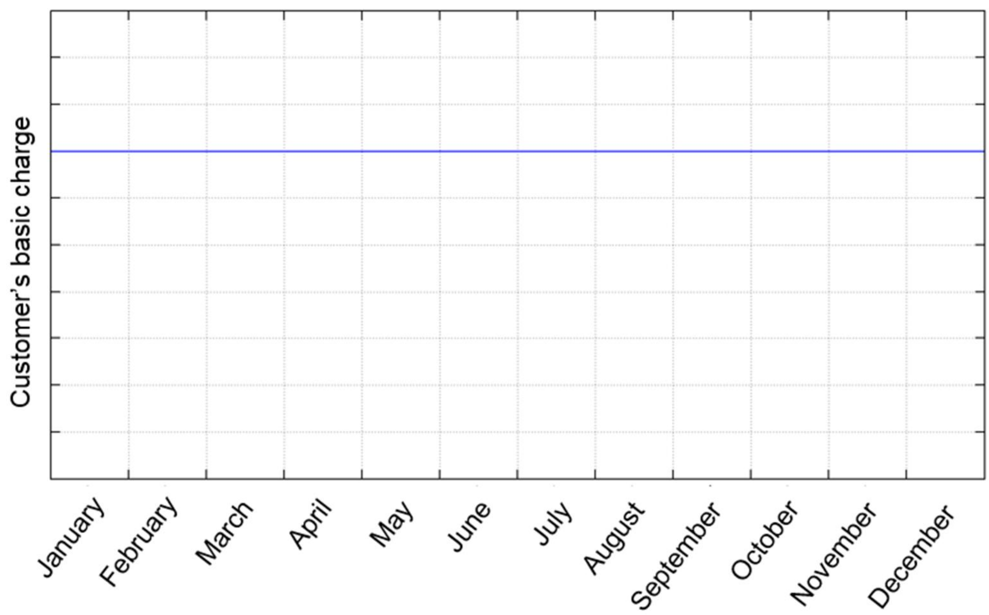

Figure 5.2. *Variation in the basic charge in a customer's distribution fee in a year in a fictitious example, where the customer's distribution tariff consists of a basic charge and a consumption charge.*

5.3.3 Fuse-based basic charge and consumption charge

At present, the basic charge of the distribution tariffs (€/month) depends on the DSO and is equal for all customers with that tariff, or the charge is based on the size of the main fuse, in which case a larger main fuse results in a higher basic charge. The payment mechanism is the same as in the previous alternative depicted in Figure 5.2. The tariff structure including a fuse-based basic charge makes it possible for the customer to utilize the power transmission capacity to the full without any sanctions. For instance for a customer with a 3 x 25 A main fuse, the highest available hourly power is about 17 kW. Distribution tariff structures of this kind are typically offered by DSOs located in sparsely populated or rural areas, where the customer density is lower than in the previous tariff option. As shown in the previous example, different time steps can be applied to the consumption charge also in this case, depending on the product.

5.3.4 Power limit tariff

In this tariff structure, the payment mechanism of the tariff is, in its purest form, the same as in the case of fixed annual charge presented above. The key difference when compared with the previous tariff is that in this alternative the customer's power demand determines the amount of distribution fee for a period of a year.

Figure 5.3 shows the determination of the power-based cost component of the customer's distribution fee. Figure 5.4, again, illustrates the customer's distribution fee in different months of a year. In these example cases, it is assumed that the customer's distribution fee is determined completely based on the highest measured hourly power of the previous year ('predefined power limit').

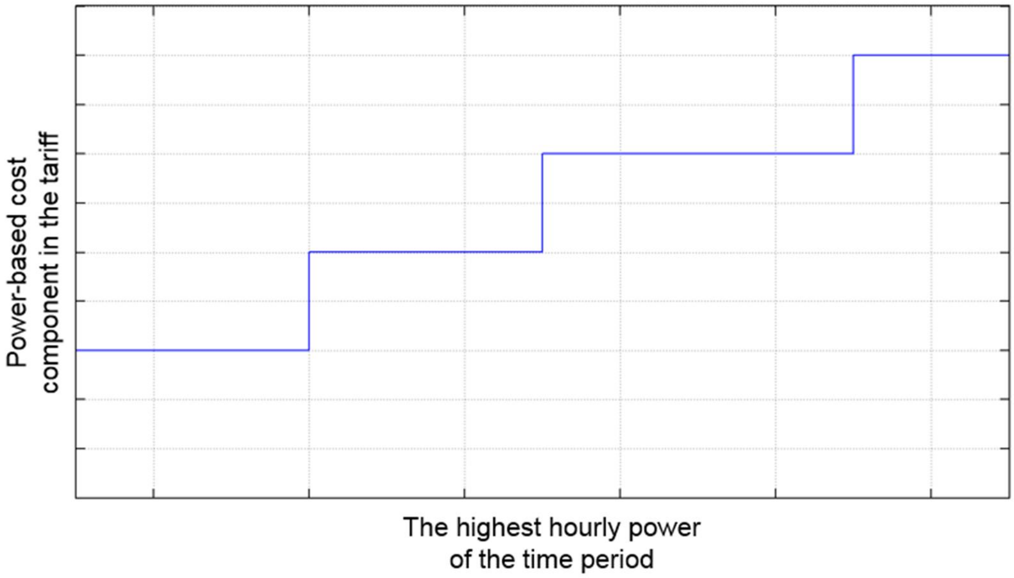

Figure 5.3. *Variation in the power-based cost component of the customer's distribution fee based on the highest measured hourly power of the previous year.*

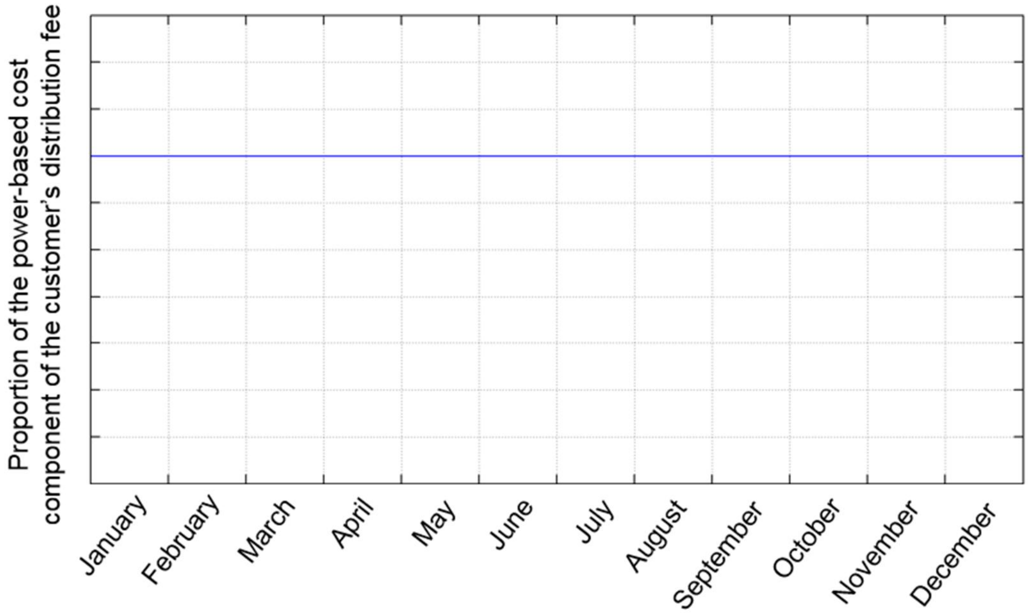

Figure 5.4. *Variation in the power-based cost component of the customer's distribution fee in a fictitious example, where the power limit tariff is applied as the customer's distribution tariff.*

When considering the practical implementation options of the power limit tariff, special attention should be paid to the aspects related to the basic structure of the tariff as well as to solutions to special cases. A brief summary of these aspects is provided in the following.

The extreme example of the power limit tariff discussed in this section consists entirely of a *power charge* (€/kW), the amount of which is based on a predefined set of limits. In the calculation, however, it is necessary to first determine which kinds of steps should be used for the power limits. The calculation examples presented in this report apply a fixed 5 kW step (power band) for the power limits. It is emphasized that the proposed fixed power band is not universal, and in practical cases, the limits do not have to be fixed, but some other alternatives can be considered that better correspond to the target networks and customer structures. The selected set of power limits is the same in each of the networks studied in this report.

When considering the implementation of the power limit tariff, the following challenges are recognized:

- Determination of the selection of power limits
- Determination of the procedures for exceeding of the power limit and the ensuing actions

In the case of the power limit tariff, in addition to setting the power limits, guidelines have to be determined for cases where the customer exceeds the power limit. Alternative measures in such cases are for instance:

- A separate penalty paid for exceeding of the power limit (e.g. €/kW or €/event)
- Transfer to the next power limit

The first approach is somewhat problematic to apply in analyses, as it is challenging to determine the amount of penalty without using any artificial methods. The second approach does not have this problem, but the consequences of exceeding the limit are further reaching for instance in a situation where the size of the customer's power limit is assessed based on the sliding twelve-month peak consumption.

The following example demonstrates application of the power limit tariff in practice. It is assumed that the second alternative is adopted when the power limit is exceeded.

Example: The power limit tariff comprises a pure power charge (€/kW), divided into the following selection of limits. The customer's lowest possible distribution fee in a year is a fee of xx €/month charged based on the lowest power limit. In the example, it is assumed that the power limit is determined according to the sliding twelve-month peak consumption.

Tables 5.2 and 5.3 present the monthly powers of two example customers for two years and the power limits selected for the customers based on these powers.

Table 5.2. Monthly peak powers and power limits of the example customer A for two years.

Customer A	Month	Highest monthly consumptions in the previous year (kW)	Power limit (kW)	Highest monthly consumptions in the year of analysis (kW)	Power limit (kW)
	January	4.8	5	4.8	5
	February	4.9	5	5.3	10
	March	4.2	5	4.7	10
	April	3.6	5	3.5	10
	May	3.5	5	3.3	10
	June	3.2	5	3.2	10
	July	3.2	5	3.3	10
	August	3.8	5	3.7	10
	September	4.1	5	4	10
	October	4.2	5	4	10
	November	4.7	5	4.4	10
	December	4.9	5	4.8	10

Table 5.3. Monthly peak powers and power limits of the example customer B for two years.

Customer B	Month	Highest monthly consumptions in the previous year (kW)	Power limit (kW)	Highest monthly consumptions in the year of analysis (kW)	Power limit (kW)
	January	11.2	15	8.8	10
	February	9.7	15	8.1	10
	March	9.4	15	8	10
	April	6.6	15	6.4	10
	May	5.1	15	5.8	10
	June	5	15	5.4	10
	July	5	15	5.2	10
	August	5.2	15	4.8	10
	September	6.4	15	6.5	10
	October	7.1	15	6.7	10
	November	8.8	15	8.2	10
	December	8.4	15	8.4	10

The case of Customer A shows that the peak consumption of one month has a significant impact on the customer's distribution fee. We can see that the power limit is exceeded in February, as a result of which the customer is shifted to the next power limit, and the distribution fee will be determined according to the 10 kW limit for the rest of the year.

The case of Customer B shows that the customer can also decrease her/his distribution fee. The effect of the previous January's peak consumption disappears in January in the year of analysis, and the distribution fee paid by the customer is essentially lower.

5.3.5 Power limit tariff with seasonal division

In this tariff option, the power charge is determined by the same mechanism as in Figure 5.3. This option, however, differs significantly by the fact that the customer's distribution fee varies between seasons (see Figure 5.5).

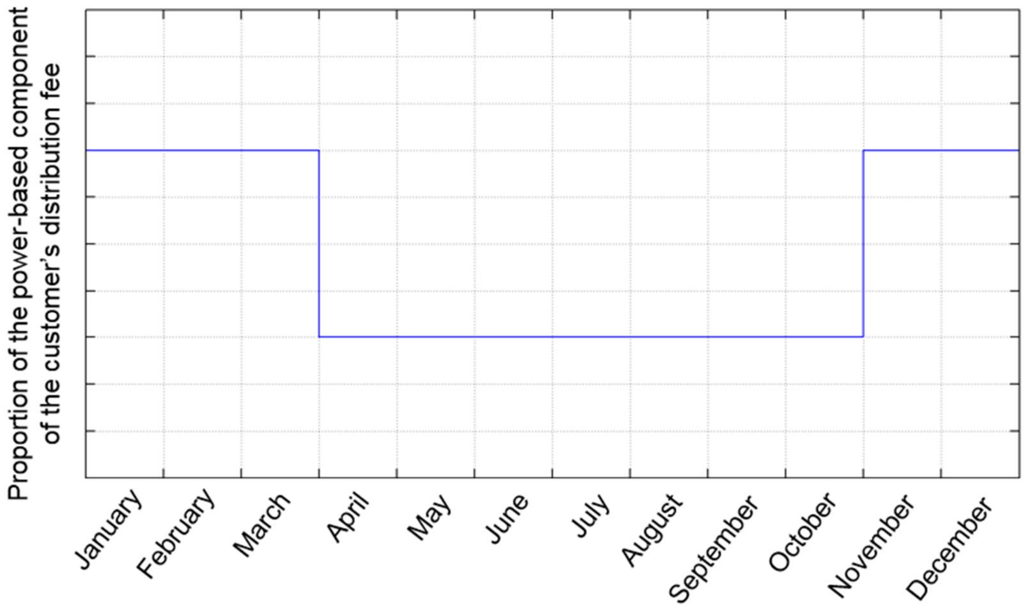

Figure 5.5. *Variation in the power-based cost component of the customer's distribution fee in the course of a year in a fictitious example where the power limit tariff with seasonal division is applied as the customer's distribution tariff.*

5.3.6 Two-tier tariff

The basic structure of this tariff option resembles the present two-rate tariffs, in which the prices (cent/kWh) of the consumption charge in the distribution fee are graded based on time of the day. In the DSOs' present night-time tariffs, the proportion of the consumption charge is smaller in the night-time (10 p.m.–7 a.m.) than in the daytime. In the proposed two-tier tariff, the amount of the charge (basic, consumption, power) is not determined based on temporal variation, but the amount of the cost component (€/kW, cent/kWh or €/month) is determined based on the customer's hourly power demand. In the following example, it is assumed that the customer's consumption charge is determined by power regardless of time.

Example: The amount of the consumption charge in the tariff is 5 cent/kWh when the power is less than 5 kW. When the power exceeds 5 kW, the consumption charge is twice as high as the charge at the lower power limit, in other words, 10 cent/kWh.

At hour 1, the customer consumes 4 kWh of electricity, and remains at the lower price level. Thus, the customer's cost for this hour is 4 kWh · 5 cent/kWh = 20 cent. At hour 2, the customer consumes 8 kWh, thereby exceeding the limit of 5 kW. Now, the customer's cost for the electricity distribution is 8 kWh · 10 cent/kWh = 80 cent.

Figure 5.6 illustrates how the power-based cost component in the tariff is determined based on the customer's hourly power.

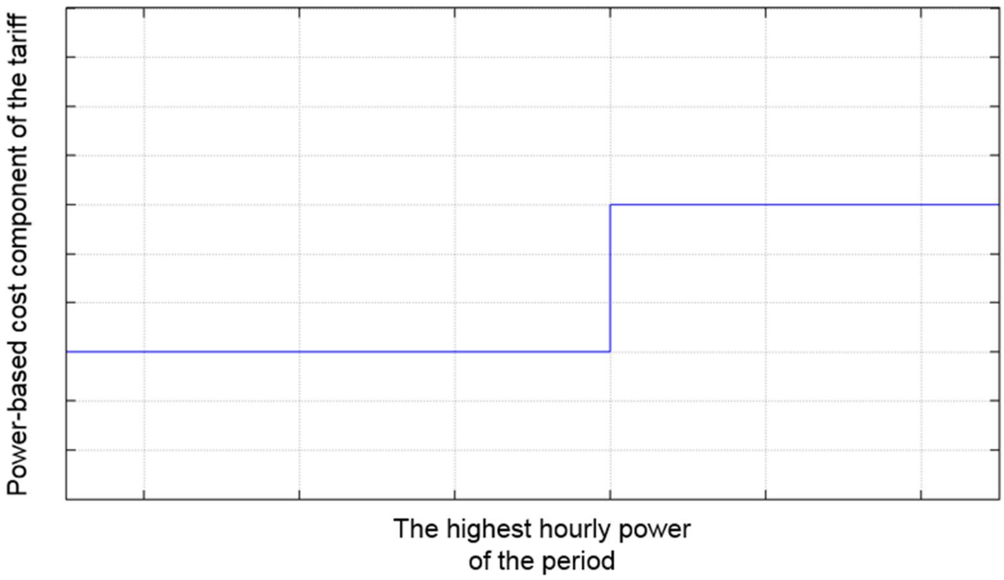

Figure 5.6. *Determination of the power-based cost component based on the customer's hourly power in the two-tier tariff.*

Figure 5.7 demonstrates how a customer's power-based cost component of the distribution fee varies over a period of a month. The figure shows that there is significant variation in the customer's distribution fee during a single month. The average monthly price is indicated by a red dashed line in the figure.

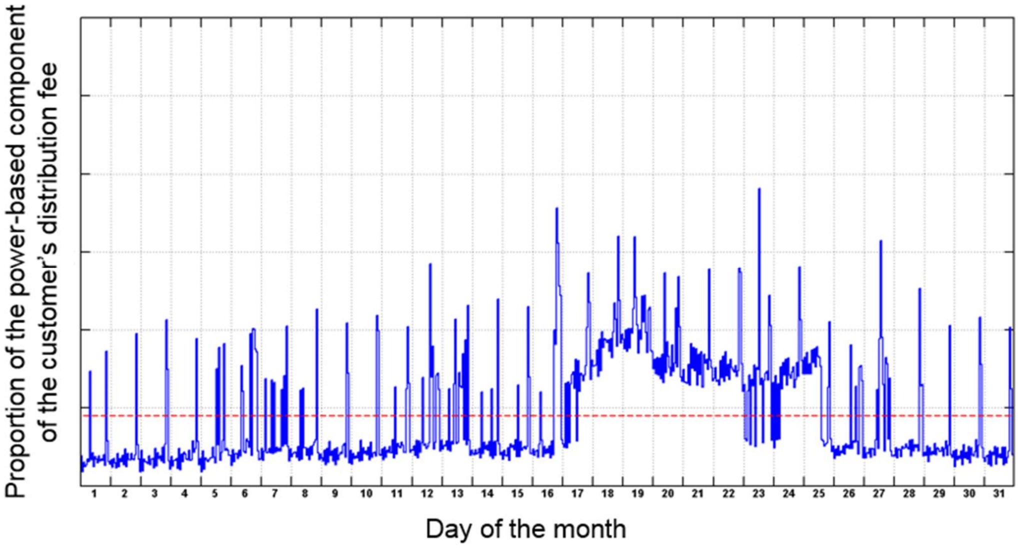

Figure 5.7. *Variation in the customer's power-based component during one month in a fictitious example where a two-tier tariff is applied as the customer's distribution tariff. The average monthly price is indicated by a red dashed line.*

5.3.7 Three-tier tariff

The three-tier tariff corresponds to the structure of the two-tier tariff, but there are three price levels instead of two for the cost component. Adding an extra level to the tariff may increase its steering effect, as a higher power demand raises the price level of the cost component of the distribution tariff even further.

In this distribution tariff, it is possible to adopt an approach where the pricing usually comprises two price levels. However, during some hours of the year, the DSO can, after a prior notice, introduce a third price level, for instance in cases where the network load is expected to be exceptionally high and congestion may occur in the distribution network. In the literature, this pricing system is referred to as Critical Peak Pricing. Figure 5.8 depicts determination of the power-based cost component in the three-tier tariff.

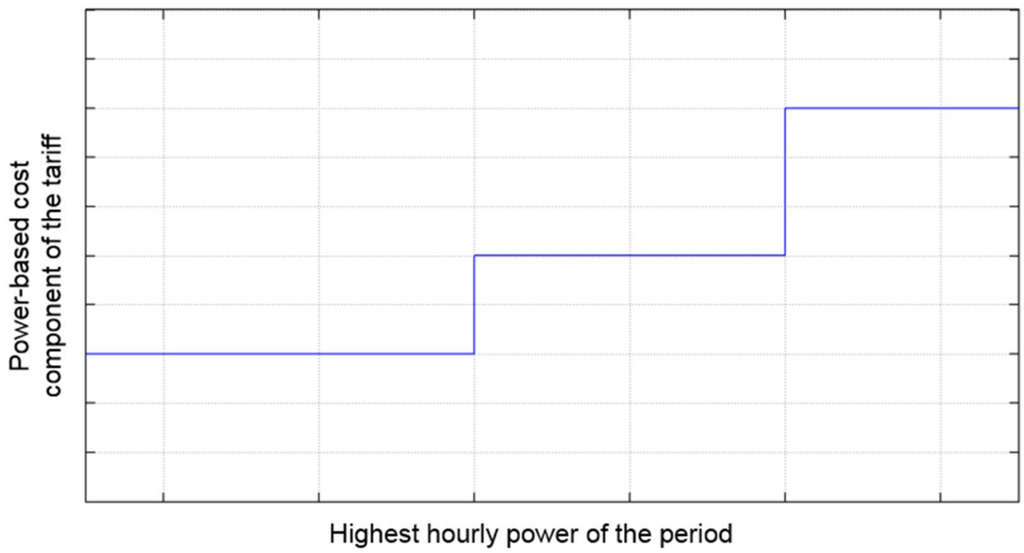

Figure 5.8. *Determination of the power-based cost component of the customer's distribution fee based on the customer's measured hourly power in the three-tier tariff.*

Figure 5.9 illustrates an example of the power-based cost component of the customer's distribution fee over the period of one month. Compared with the two-tier tariff, we can see higher peaks in the power-based cost component of the customer's distribution fee. These peaks are due to the exceeding of the third power limit during some hours of the month. The purpose of the figure is to illustrate the basic operating principle of the tariff, and therefore, the network state is not assumed to have an impact on the activation of the third price limit, but the activation is due to the customer's load. The red dashed line in the figure indicates the monthly average price for the power-based component of the distribution fee.

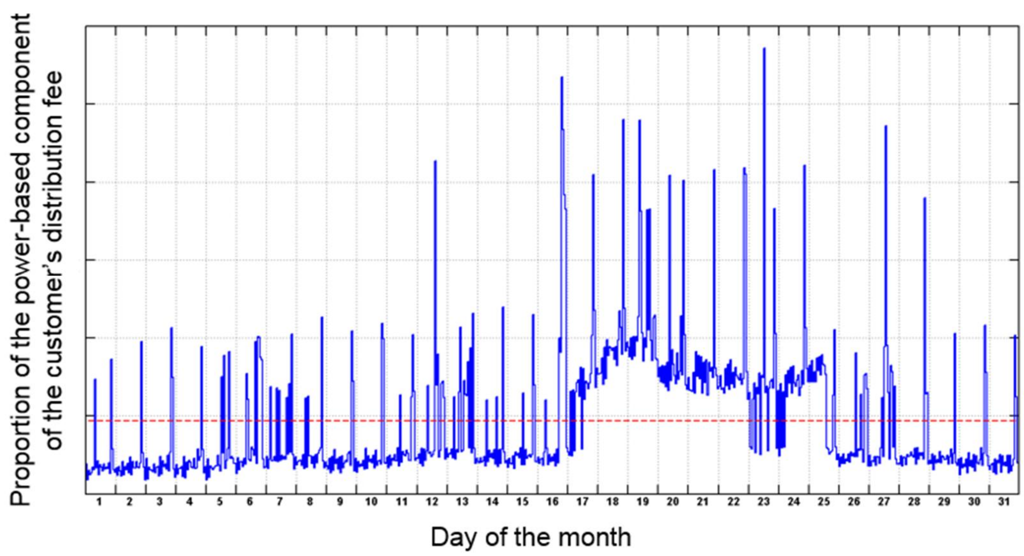

Figure 5.9. *Variation in the power-based cost component of the customer's distribution fee during one month in a fictitious example, where the three-tier tariff is applied as the customer' distribution tariff. The red dashed line indicates the monthly average price.*

5.3.8 Small-scale customer's power tariff

For small-scale customers, the structure of the power tariff is similar to the one that the DSO offers for its larger customers. The tariff comprises three main components: a monthly basic charge (€/month), a volumetric consumption charge (cent/kWh), and a power charge (€/kW). The power charge can be determined based on an array of power combinations from annual peak powers to monthly or even more frequently measured powers.

Figure 5.10 depicts the basic operating mechanism of the power-based cost component in the small-scale customer's distribution fee. Figure 5.11 shows the distribution fee paid by the customer in different months of the year. It is assumed that the customer's highest hourly power in a month is used as the basis for the determination of the power charge.

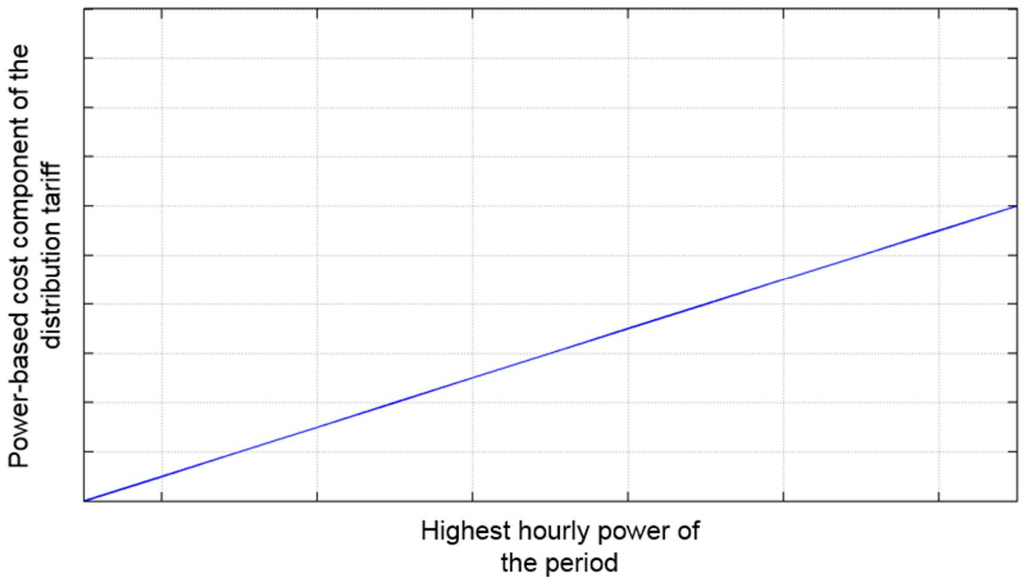

Figure 5.10. *Determination of the power-based component of the customer's distribution fee based on the customer's measured hourly power in the small-scale customer's power tariff.*

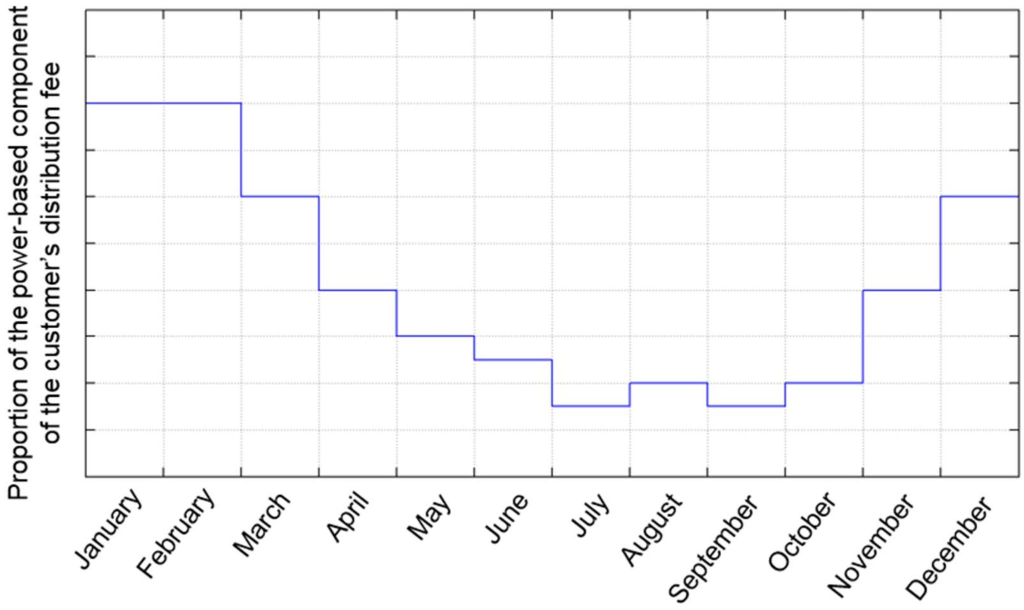

Figure 5.11. *Variation in the power-based cost component of the customer's distribution fee during one year in a fictitious example, where the small-scale customer's power tariff is applied as the customer' distribution tariff.*

The small-scale customer's power tariff applied in the analysis comprises three tariff components:

1. Monthly *basic charge* (€/month).
2. *Power charge* (€/kW) based on the highest consumption during a certain period, e.g. a month.
3. *Volumetric consumption charge* (cent/kWh) tied to energy consumption.

Certain assumptions, which have an impact on the operation of the tariff, have to be made also in this tariff option. The basic assumptions concerning the small-scale customer's power tariff are:

- Determination of the basis on which the power charge is determined (e.g. on a monthly, seasonal, or annual basis).
- Possible temporal thresholds in the consumption charge.

5.3.9 Small-scale customer's power tariff with threshold power

In this alternative, the power is linked to the customer's distribution fee only when a certain power limit is exceeded. The basic charge in the customer's distribution fee contains a certain amount of 'free power' up to a predefined power limit, and only when this limit is exceeded, the customer's distribution fee is determined directly by the amount of power exceeding the threshold power. When considering cost components, the most convenient approach is a separate power charge (€/kW). The following case aims to exemplify the payment practices related to the distribution tariff assuming that the power-based cost component of the customer's distribution fee is determined based on the highest measured hourly power of the month.

Example: The threshold power of the distribution tariff is 5 kW and the price for the power exceeding the threshold is 3 €/kW. Up to the threshold power, the monthly power tariff in the distribution fee is 10 €/month.

In January, the customer's highest measured hourly power is 3 kW, and thus, the threshold power is not exceeded. The customer pays a power charge of 10 € in the distribution fee.

In February, the customer's measured peak hourly power was 6 kW, and thus, the threshold power was exceeded by one kilowatt. In February, the customer pays a 10 € threshold power charge in the distribution fee, and an additional cost of 1 kW · 3 €/kW = 3 € for the one kilowatt exceeding the threshold. In February, the amount of power charge in the customer's distribution fee is 13 € (10 € + 3 € = 13 €).

Figure 5.12 illustrates the basic mechanism of the power-based cost component in the small-scale customer's power tariff with threshold power (threshold power tariff).

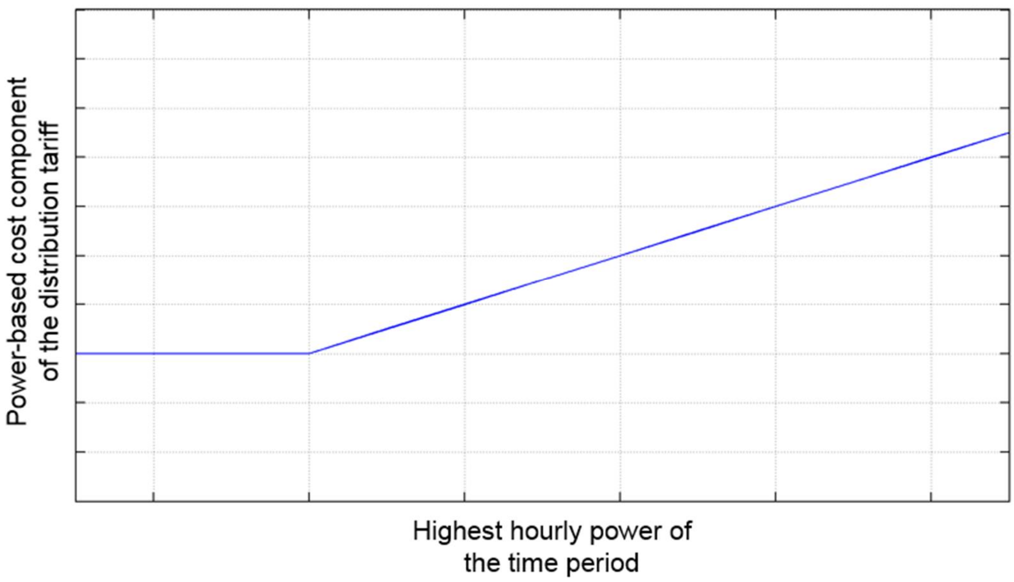

Figure 5.12. *Determination of the power-based cost component of the customer's distribution fee based on the customer's measured hourly power in the case where threshold power is included in the small-scale customer's power tariff.*

Figure 5.13 demonstrates the behaviour of the power-based cost component of the customer's distribution fee during one year. It is assumed in the example that the power invoiced to the customer is determined based on the highest measured hourly power.

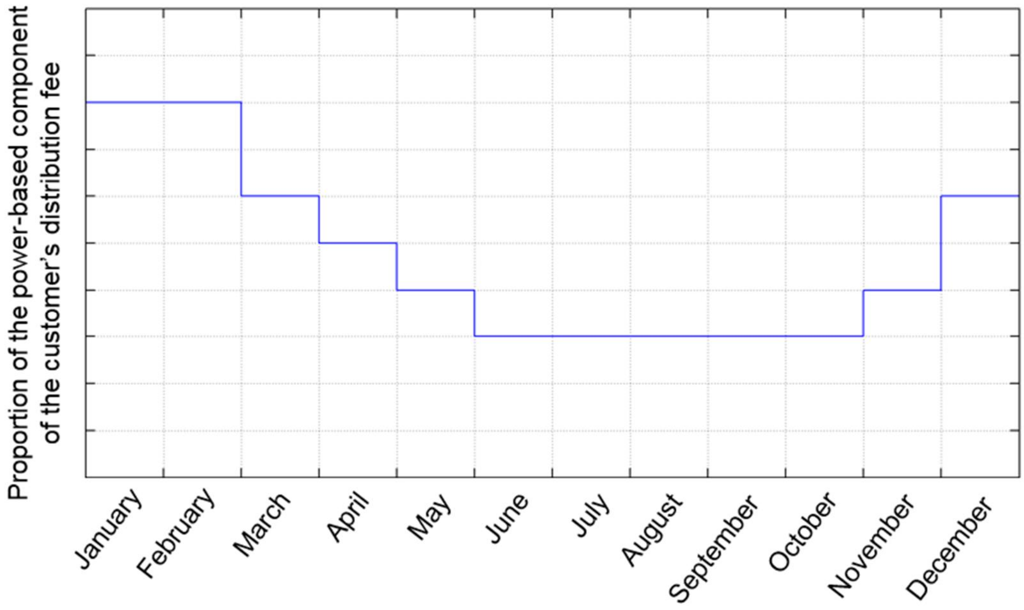

Figure 5.13. *Variation in the power-based cost component of the customer's distribution fee in a year in a fictitious example where the threshold power tariff is applied as the customer's distribution tariff.*

The power tariff including the threshold power comprises the following three tariff components:

1. Monthly *basic charge* (€/month).
2. Monthly *power charge* (€/kW, month).
3. *Consumption charge* based on volumetric energy consumption (cent/kWh).

Certain assumptions have to be made also in this case. The effects of the tariff depend essentially on the following issues:

- Determination of the threshold power.
- Determination of the *basic charge* below the threshold power.
- Determination of the unit charge (€/kW) for the power exceeding the threshold power.
- Possible temporal thresholds in the consumption charge.

The principles according to which the threshold power is determined for the customer group in question have to be consistent and unambiguous. It is emphasized that the principles and the threshold power presented here are by no means the only universal solution.

In the analyses, the threshold is set at 5 kW, which is considered to cover the basic load, for instance common household appliances, including kitchen appliances. The feasibility of the threshold has also been assessed with respect to the network consumption data available by studying the customers' peak hourly powers. The assessment shows that the threshold is quite realistic. The operating principle of the tariff is based on the idea that the customer's peak hourly power in the month determines whether the customer is invoiced separately for the power. If the customer's peak hourly power of the month exceeds the 5 kW limit, a separate power charge is invoiced to the customer for the amount of power exceeding the limit.

The assumptions listed below have to establish consistent principles for the determination of the amount of the *basic charge* below the threshold power and the unit price of the *power charge* for the amount of power exceeding the threshold power. In the calculations presented for the tariff formulation in this report, the following assumptions are made based on the calculated cost components:

In the threshold power tariff, the revenue component collected from the customers, which is allocated to the customers according to power, is charged based on the ratio of the sum of the powers exceeding the threshold power to the sum of the highest monthly powers. This assumption does not yield the same results with all the networks under analysis; nevertheless, the tariff calculation principles are consistent, and thus, it is easier to evaluate the effects of the tariff in different kinds of networks than in a case where the unit prices of the tariff are determined for each network individually.

5.4 Outline of the tariff calculation methods

Considering alternatives available for the determination of the distribution tariffs, the cost-based approach applies the matching principle. It means that when the tariffs are determined, the costs in different example cases (DSOs) are directed to the customers with different tariffs so that the costs are allocated to the different customer groups in a systematic way.

There is no single universal and unambiguous method for the calculation of distribution tariffs; therefore, the methods introduced in this section represent typical approaches taken to calculation. There are also other methods available, and the reader should not stick rigidly to the approach presented in this report only. Furthermore, it is emphasized that, for instance, exact cost data have not been applied in the analysis, as it is extremely challenging to acquire such detailed data from a specific, limited section of the network operated by a DSO. Nevertheless, the approach introduced for tariff calculation is accurate enough to offer an insight into the topic.

The determination of tariffs is based on the DSO’s cost structure, which in these analyses consists of straight-line depreciations of different types of costs (calculated based on network component data and unit prices published by the Energy Author), reasonable return on capital, other operational costs, national and regional grid service fees and load losses, and customer costs.

5.4.1 Allocation of costs to distribution tariffs

The above costs are allocated to distribution tariffs so that the costs of different cost types are distributed to different cost pools and from there further to different customer groups by applying cost pool specific cost drivers. The cost drivers used in this analysis are power, energy, and number of customers.

The costs are allocated to different customer groups according to the following principles:

- Customer-dependent costs are allocated to the customer groups according to the number of customers.
- Energy-dependent costs are allocated to the tariff groups under analysis in proportion to the groups' annual energy.
- Power-based costs are allocated to the customer groups based on participation and coincidence factors according to network levels (e.g. medium-voltage and low-voltage levels, if there are customers that are directly connected to the medium-voltage network).

The allocation of costs yields information on the amount of revenue that should be collected from different customer groups in order to meet the target total revenue with the planned tariffs. The load data of two consecutive years are applied in the calculation so that the hourly metering data or annual energy data of the first year and statistical load models are used to generate the distribution tariffs for the following year. The actual (realized) revenues generated by the tariffs are analysed by applying the hourly metering data of the latter year. If there are no metering data available of certain customers, the loads of these customers are modelled for instance by applying the SLY/Sener profile or other statistical load model and the customer's annual energy data.

Allocation of network costs to the power charge or the basic charge is not quite straightforward. Some of the network components, such as underground cables, distribution transformers, and main transformers are dimensioned based on power. In addition, there are plenty of network components, such as transformer substations, cable ditches, and primary substations, whose costs are not directly based on power, but are fixed ones. The peak power of an individual small-scale customer does not usually have an impact on the costs of the main transformer at the primary substation; however, in the future, for instance simultaneous heavy-duty charging of electric vehicles might do so. Even though a significant proportion of network costs are due to the customers and are not directly dependent on power, the customers' consumption can be steered by cost allocation so that it is possible to avoid network reinforcement investments. For instance in the case of underground cables, the cable ditch generates a significant fixed cost, which is not directly dependent on power, and in the case of a network reinforcement investment, a new cable ditch has to be excavated. In the tariff structures considered in this report, the network costs are, to a large extent, allocated according to a distribution-channel-based pricing model (see e.g. Lummi, 2013; Apponen, 2016) to the power charge to highlight the differences between the steering effects of the tariff alternatives under study.

In general, the DSO's other operational costs are not directly dependent on consumption. For instance, the DSO's personnel salaries are not directly dependent on the customers' electricity consumption.

By allocating other operational costs, similarly to network costs, to the power charge, it is possible to avoid network investments, and thereby an increase in the operational costs.

6 Impacts of tariff structures on different stakeholders

This chapter addresses the impacts of distribution tariff structures from different perspectives. First, the power management and effects of tariff structures on different stakeholders are considered. Finally, some quantitative results on the simulated effects on tariff structures are presented.

6.1 Opportunities for power management

The distribution tariff with a power component provides the customer with an economic incentive to control and manage the peak power of her/his connection point or place of electricity use (metering point). In this report, peak power refers to the hourly mean power, which means that even if the mean power of the hour is moderate, there may be very high instantaneous peaks within the hour. There are a variety of technologies and methods for peak shaving. For a customer, the most cost-effective way is to alternate between the use of some high-power appliances, such as electric sauna, drying cabinet, tumble dryer, washing machine, dishwasher, and electric vehicle battery charger. If the customer does not have an opportunity or willingness to take actions of this kind, she/he can purchase a power management system, which automatically switches the appliances on and off. Alternative methods of power management are load control, energy storages, or small-scale electricity production on the customer's premises. Sometimes it may be necessary to modernize certain electric equipment to cut the peak powers. An example is the use of full load capacity ground source heat pumps instead of undersized heat pumps; thus, no electric heating backup causing power peaks in the electricity use should be needed under normal conditions.

The profitability of the power management actions depends on the structure of the distribution tariff containing a power-based component. If the tariff has no price steps, each action to cut the peak power reduces the price paid for the electricity distribution. If the tariff has a price step or limit at which the price changes, as is the case with the power limit tariff, step tariffs, and threshold power tariffs, peak shaving is not profitable, if the action does result in a shift to a lower price step or the power consumption is already below the threshold power. The period applied to the determination of the peak power also has a significant influence on power management. If the period is one month, power management in every month of the year is profitable. On the other hand, if the peak power is determined on an annual basis and the customer has a large heating load, power management is profitable only in the coldest winter periods.

In most cases, load control is probably the most cost-effective alternative. From the viewpoint of practical implementation, however, it is obvious that the load control should primarily be automatic. The focus of load control is on high-power electric devices that can be controlled without major impacts on the users of these devices. When considering electrical equipment in common use today, various electric heating devices, boilers, and heat pumps are an obvious target for cutting the peak consumption. In the future, the electric vehicle charging devices can be significant and potential current-using equipment to be controlled. The well-established method of alternating between electric sauna heaters and electric heating groups can be extended to cover a larger range of electric devices, and for instance the charging power of an electric vehicle can be controlled in a fast and almost stepless manner. In any case, the basic strategy for load cutting can be considered to be based on the rationale that the non-controllable loads determine the minimum load level for different hours, and the controllable loads are used to minimize the actual peak demand. It is most likely that the majority of the peak shaving potential can be activated by relatively simple load control devices, and thus, the investments required from the customers can be kept at a reasonable level. If the electricity user has for instance a real-time pricing contract and a distribution tariff with a power component, and the customer wants to direct some of the consumption to cheap hours, the control system has to contain a load control algorithm combining these cost functions.

An electric energy storage, for instance a system based on batteries, provides new opportunities to cut the peak power drawn from the electric power network. A storage allows to cut the power from the network whenever desired, and moreover, the power cut is not limited by the controllability of the current-using devices applied or the critical role of the devices for the customer. The customer does not detect any changes in the operation of the devices, even though the network consumption caused by the customer will change. At present, the main challenge is the high investment costs of the energy storages, but if the weight of the power component is high enough, the benefit reaped over the lifetime of the storage may cover the investment costs. The electric energy storage can be employed also for other purposes than cutting the peak power, such as shifting the consumption to lower-cost hours in connection of the hour-based (time-of-day) electricity contract and as a backup supply during supply shortages. A further benefit of an energy storage is that the storage capacity and power can be dimensioned according to the customer’s typical consumption and the distribution tariff in use. In the future, the prices of electric energy storages are assumed to fall, and consequently, their role in the customers’ power management may increase.

Further, the load control and electric energy storages enable participation in the demand response markets, which may also mean that the load is increased. In that case, when determining the total price, the control system has to take into account the price signal from the demand response markets combined with the cost components of the distribution tariff. However, conflicting control targets weaken the profitability of different actions, and as a result, the load control as a whole may become unprofitable. On the other hand, if different control objectives happen to be simultaneously in line with each other, their total effect may significantly increase the benefit received by the customer.

The small-scale electricity production capacity on the customer's premises offers an opportunity to shave the peak powers, but for instance in the case of a solar power plant, the peak shaving potential is limited to very few premises. Cutting the customer's peak power by means of a solar power plant requires that the peak load is highly likely to occur at such instants when there is significant solar production available. A further factor affecting the peak shaving potential is the structure of the distribution tariff. If the period for determining the peak demand is one month, the production of the solar plant may have a significant impact on the peak power in summer months as the solar production and the demand for cooling power probably occur on the same hours at the places of use equipped with cooling equipment. Then again, if the period is one year, large-scale solar production is unlikely to occur during the hour that is used for the determination of the peak power. In the case of step tariffs, the small-scale production may enable the shift to a lower step at some individual hours, which may bring significant benefits; nevertheless, the customer's typical consumption has to be suitably above this step, and therefore, the benefit is limited to a very small proportion of the customers. In addition to this, the present practices concerning metering and netting the electricity produced on the customer's premises have an impact on the opportunities to cut the peak load. At present, the electricity production and consumption of a small-scale producer are not netted within the unit of trade (hour). Thus, within a certain hour, the small-scale producer can be both a purchaser and seller of electricity, and the effect of small-scale production on the power drawn from the network is probably smaller than the mean hourly power of the small-scale production.

6.2 Qualitative effects of tariffs on different stakeholders

In this study, the effects of tariffs are considered from different perspectives both at a general level and by simulating the economic and technical effects of the tariffs. This section introduces some qualitative effects, while numerical effects of the tariffs are presented in Section 6.3.

The effects of the tariffs are studied from the viewpoints of customers, network companies, electricity retailers, and society. The effects on various energy resources, such as small-scale production, energy storages, and demand response are also analysed. Moreover, the requirements set by tariffs on metering and information systems are addressed, and the strengths and weaknesses of each tariff are evaluated in the transition to the new tariff scheme; in other words, how easy it is to change over to each tariff structure alternative. Detailed tables on the strengths and weaknesses of each tariff are provided in a separate report, in which the effects of tariffs are exhaustively considered from different perspectives; this section presents a summary of the key observations.

6.2.1 Fixed basic charge

If the distribution tariff consists of a fixed annual charge, it is very simple from the customer's perspective, and it is not necessary to consider the effects of electricity use on the distribution fee. However, the customer's opportunities to affect her/his distribution fee are practically non-existent, and there is strong cross-subsidization between different (large and small) customers in the tariff structure.

From the DSO's perspective, the price list is simple and the revenue is fairly predictable in this tariff structure. The tariff does not present extra requirements for meters or information systems, either. Nevertheless, the customers have no incentives to enhance the efficiency of their electricity use, which may increase the powers and thereby create needs to reinforce the network.

From the electricity retailer's perspective, there are no significant weaknesses in the tariff structure, and it does not limit the retailers' operation.

This tariff structure allows participation of customers' flexible loads and energy storages in the demand response markets. The tariff itself does not contain elements that would incentivize to demand response or energy storage activities. This distribution tariff would also degrade the profitability of small-scale production.

The recent trend in the tariff development has been to increase the proportion of basic charge, which in extreme cases would lead to a tariff resembling the fixed annual charge described above. This tariff structure, however, does not encourage the customers to enhance the overall efficiency of their energy use or the resource efficiency in the electricity distribution system. Furthermore, the structure involves significant cross-subsidization between the customers. Even though the tariff structure is simple and predictable from the end-user's and DSO's viewpoints, it has considerable weaknesses from the societal perspective and in terms of energy and resource efficiency.

6.2.2 Fixed basic charge and consumption charge

In this tariff structure, in addition to the fixed basic charge, the customer pays a volumetric consumption charge for the transmitted energy. A tariff structure of this kind is in common use at present.

From the customer's perspective, the tariff structure is fairly simple, familiar, and similar to the pricing model for electricity retailers. The customers can affect their consumption charge, yet a negative aspect of the tariff is that the basic charge cannot be influenced. Furthermore, there is cross-subsidization between different customers in the tariff, and according to the matching principle, the tariff is not fully cost-reflective. If the customer's energy use decreases, but the power demand from the network remains unchanged for instance as a result of small-scale production, the customer's cost effect for the network remains the same, but the distribution fee paid by the customer decreases, and thus, the costs are allocated to other customers.

From the DSO's perspective, a strength of this tariff is that there is decades-long experience of this tariff type, and the present meters and information systems are adequate for the purposes of the tariff. Nonetheless, a weakness of the tariff is that it does not steer the customers to control their power use, which may cause a need for network reinforcements. Moreover, changes in the energy use may introduce uncertainty to the DSO's revenues.

From the retailer's perspective, the tariff is compatible with the retailer's similar distribution tariff. However, the tariff may contain different time steps (time-of-day tariffs) compared with the retailers' tariffs.

The energy component of the distribution tariffs incentivizes the customers to save energy and acquire electricity production of their own, but this incentive is weakened if the proportion of the basic charge increases. The tariff enables the use of demand response and energy storages in the demand response markets, but the incentives of the tariff are limited to price differences between possible time steps (time-of-day tariffs). All in all, this tariff structure does not provide incentives to enhance the overall efficiency of electricity use, as the incentives for power control are deficient.

6.2.3 Fuse-based basic charge and consumption charge

This tariff is presently in common use, and largely corresponds to the tariff with the fixed basic charge and the consumption charge described above. The basic difference is that the basic charge is based on the fuse size, which incentivizes the customers to optimize the size of the main fuse, and may also have an effect on the dimensioning of some of the larger current-using equipment (e.g. heating). In practice, the incentive effect of the tariff is fairly low, as the amount of the basic charge can only be affected by changing the main fuse size, which is typically quite expensive (requires electrical installations). The power can be consumed freely within the limits of the main fuse, and thus, the steering effect on power use is very limited. The cost-reflectiveness according to the matching principle is achieved somewhat better than in the previous alternative, because the amount of the basic charge depends on the fuse size of the connection point.

6.2.4 Power limit tariff

In the power limit tariff, also known as the power band tariff, the customer subscribes to a certain power, which serves as the basis for invoicing. Exceeding of the power limit generates an excess fee or the customer is shifted to the next power limit. In practice, the width of the power band could be for instance 3 or 5 kW, or the limits could be determined by each DSO individually. In this report, the power limits are set at 5 kW intervals (e.g. 5 kW, 10 kW, 15 kW).

From the customer's viewpoint, the power limit tariff is fairly simple as the customer will pay a fixed monthly fee according to the principles of the power limit tariff after the power limit has been set. The tariff also encourages to optimize the power use to achieve the lowest and most inexpensive power limit. Furthermore, it is possible to use electricity freely without any extra charges based on the distribution network tariff, which allows the utilization of cheap market-based electricity up to the power limit. However, there are no incentives to control the powers below the limit, and the power limit that is determined according to possible individual peak hours removes the incentive to power control at other times. In the year-based pricing, the customer pays the same distribution fee both in summer and winter, even though the electricity use is significantly lower in summer. Large power bands (e.g. 5 kW) also restrict the opportunities to benefit from the reduction of power. The selection of the power limit and power control require more activity and knowledge on the customer's part, because the customer has to familiarize her/himself with the concept of power, follow her/his electricity use, or acquire an automatic power control system. The selection of the power limit, in particular, is challenging for the customer. The customer should be aware of the specifics of her/his power use. Thus, issues related to the selection of the power limit would significantly increase the demand for customer services.

From the DSO's perspective, this tariff structure generates predictable and stable revenue, and the tariff better reflects the DSO's cost structure and incentivizes the customers to decrease their peak loads, which may also cut the peak powers on the network and thereby reduce costs and the need for network reinforcements. On the other hand, intersecting of load curves may also decrease, which may even increase the peak powers on the network in certain locations. The present meters measure and register hourly powers, thereby enabling the application of the power limit tariff. The meters, however, do not control the power limit or alarm the customer if the limit is exceeded. Finally, the tariff may require changes in the information systems for billing processes.

From the retailer's perspective, the power limit tariff allows free use of electricity within the power limit (band) without the energy charge of the distribution tariff, which may have an influence on the use of inexpensive market-based electricity. Then again, the power limit may also restrict the retailer's opportunities to control flexible loads especially in situations where loads should actually be increased. Determining a customer specific power limit can also require extra work, yet the customer specific optimization of the power limit may also become a new service product for the retailers.

The power limit tariff encourages to optimize the power use, thereby enhancing the profitability of both demand response and batteries, and may create new demand response services. In some cases, the power limit may also restrict the full-scale deployment of these resources in the demand response markets. The profitability of small-scale electricity production is basically lower than in the present tariff, because there is no separate energy charge in the power limit tariff. Therefore, small-scale production will reduce the distribution network charge only in a situation where it can be used to lower the power limit.

The power limit tariff provides incentives for demand response and procurement of energy storages and steers to cut the power drawn from the network. When implemented well, the tariff structure will bring cost savings in the long term, if for instance investment in network reinforcements can be delayed. The new demand response opportunities also enhance the overall efficiency of the energy system operation.

The challenges of this tariff structure are determination of the power limit and practices for exceeding the limit as well as issues related to the transition to the new tariff structure. Transition from the present distribution tariffs to the power limit tariff can be problematic, because some power-based cost component may be required for the transition period. Furthermore, the DSOs currently have a low-voltage power tariff for their larger electricity users. Therefore, it may be difficult to comprehend the use of different power tariffs, which poses extra challenges for customer communications.

6.2.5 Power limit tariff with a seasonal division

This tariff is similar to the power limit tariff, but in this case, the power limit is dissimilar in different seasons of the year. The characteristics and effects are largely similar to the basic case presented above. In the case of the seasonal tariff, however, the customers' fees and thereby the DSOs revenues are concentrated on the winter period, when the power use is at highest. Small-scale electricity production on the customer's premises may lower the customer's power limit in the summertime, which is positive in terms of profitability of the customer's own generation.

6.2.6 Two-tier tariff

In the case of the two-tier tariff, the amount of the customer's consumption charge is determined based on power so that a higher price is charged for the energy consumption exceeding the predefined power limit.

In this tariff, the customer is able to affect her/his distribution fee through both power and energy. Even though there is a power limit incorporated in the tariff, above which the consumption charge will increase, the cost of a single event of exceeding the limit is relatively low. The customers' distribution fees are also more cost-reflective than the present ones, but the practical steering effects of the tariff are difficult to estimate. If the customer's consumption is mainly below the power limit, but exceeds the power limit during certain hours, it is advisable for the customer to aim at reducing her/his consumption below the power limit. A single power limit, after which the energy charge increases for the consumption of the whole hour, may also guide the customers to shift their consumption to single hours in the proximity of the power limit. (*Example: If the customer's consumption for five hours were 6 kW for each hour, the customer would pay a higher price for the delivered energy for each hour, i.e., 5 h * 6 kW * 10 cent/kWh = 300 cent. By shifting the proportion of consumption that exceeds the power limit to one hour, the customer would pay 4 h * 5 kW * 5 cent/kWh + 1 h * 10 kW * 10 cent/kWh = 200 cent.*)

For all customers whose consumption in the proximity of the limit does not behave like this, this tariff option would basically be seen as an energy charge only (e.g. it does not matter whether the customer consumes 13 kW in the present hour and 7 kW in the next hour, or 10 kW in both hours.)

On the customer's part, following the power limits requires greater awareness and understanding of her/his electricity use as well as active monitoring of power and automation equipment on the customer's premises.

From the DSO's perspective, the tariff may encourage the customers to cut their peak powers, which may produce cost savings in the network in the long term. Maintaining the energy-based unit of invoicing (cent/kWh) may facilitate customer communications compared with power-based tariffs, but linking power and energy to each other may also degrade the intelligibility of the tariff. On the other hand, the tariff structure does not generate significant needs for changes in the metering and information systems; however, the meters do not indicate the real-time power or exceeding of the power limit.

Determination and communication of the power limits and explaining the rationale behind them is not a simple task. In practice, the power limit should be the same for all customers as a customer specific power limit can be seen as unequal treatment of customers, and it is also challenging to justify to the customers. A common power limit for all customers means that there is only one power limit in the tariff, and the tariff steers the customers to stay below this limit. Therefore, the steering effects of the tariff are relatively limited. Furthermore, there is no previous experience of a tariff structure of this kind, which may represent extra challenges in practice. In addition, the DSOs already have a low-voltage tariff for their larger customers, and thus, communicating two different power tariffs to the customers may be challenging.

From the electricity retailer’s perspective, the tariffs do not impose any constraints; nevertheless, finding out the power limits for each customer or DSO in question may cause extra work.

Because there is still an energy-based cost component in the tariff structure, it also has an incentive for customers’ small-scale production. Further, the effect of power on the price incentivizes to the use of flexible resources (demand response and energy storages). However, charging energy storages at a high power is expensive, which may weaken the opportunities to use them.

From society’s viewpoint, the two-tier tariff may promote the customer’s overall efficient use of electricity; energy efficiency is incentivized by the energy-based pricing, whereas control of power use is encouraged by the power steps of the energy price. The tariff also boosts the use of demand response, energy storages, and small-scale electricity production. Transition to this tariff structure would be technically relatively easy to implement by changing from the present time-of-use prices to power-based price steps.

6.2.7 Three-tier tariff

The basic difference between the three-tier tariff and the two-tier tariff is the third price step, which can be applied for instance a few times a year when the peak loads are at the highest (Critical Peak Pricing).

The effects of this tariff structure on the different stakeholders are very similar to the ones described in the two-tier tariff. The third step, however, boosts the steering effects of the tariff, yet it poses further challenges for the customer communications and determination of the tariff.

6.2.8 Small-scale customer’s power tariff

The small-scale customer’s power tariff consists of three components: a monthly basic charge (€/month), an energy-based volumetric consumption charge (cent/kWh), and a power charge, which is based on the highest measured power during a year or a month, depending on the basis of determination. Compared with the present distribution tariff, the proportions of basic and consumption charges in the small-scale customer’s power tariff are smaller, as more weight is placed on the power charge.

For the customer, the opportunities to affect the distribution fee are good, as both the power and energy components can be influenced by the customer’s own electricity use. The tariff encourages to use electricity so that the costs of electricity distribution are reduced in the long term. Because of the three components in the tariff structure, it is more complicated but also brings more versatility than the small-scale customer's present tariffs. Furthermore, management of power use requires activity and understanding or investments in home automation by the customer.

From the DSO's perspective, the steering effects of the tariff are positive, and the revenues are more predictable than in the present tariffs. The power tariff is already in use for larger customers, and thus, there is previous experience of its effects and implementation. No significant changes are required to the present metering and information systems when changing over to the power tariff. However, the present meters do not provide real-time power data for the customer. At the time of writing this report, two Finnish DSOs have launched the power tariff to their small-scale customers. From 2017 onwards the customers of Lahti Energy, whose main fuse size is larger than 3x50 A, are within a power tariff, in which there is a power component in addition to the basic and energy charges. It has also been notified that from 2018 onwards also the customers with 3x50 A and 3x35 A main fuses will be included in the power-based pricing scheme. The company's objective is that by the end of the decade most of the customers will have a tariff with a power component (Lahti Energy 2016). Besides Lahti Energy, also Helen Electricity Network operating in the Helsinki region is reforming its distribution products especially with respect to its time-of-day product ('aikasiirto') intended for larger small-scale customers. From July 2017 onwards, the company's time-of-day distribution tariff has a separate power charge, which is applied to all customers of this product (Helen Electricity Network, 2017).

From the retailer's perspective the tariff does not contain elements that would have adverse effects on the retailer's operation. The customer's power management, again, may bring new service business opportunities for instance for the electricity retailer.

Power-based pricing incentivizes the customer to reduce the peak power drawn from the network for instance by demand response and energy storages. The tariff also makes it possible to use demand response and energy storages so that the power taken from the network will increase, if the benefit of such operations in the demand response markets is higher than the price of power in the distribution tariff. Thus, the combined effect of the demand response market and the distribution tariff steers the customers towards more overall efficient choices, if the pricing is cost-reflective. The profitability of customers' small-scale generation is lower compared with the present tariffs, because the energy-based consumption charge is lower than the present one. Challenges may also arise in situations where the profitability of previous investments has been based on the energy component of the distribution charge. However, the profitability of small-scale production will be better if it can also be used to reduce the power charge. This is possible especially in the seasonal and monthly power tariffs.

From society's viewpoint, the tariff structure encourages customers to overall efficient use of electricity, which leads to more efficient use of the electric power system. Well-implemented matching principle also reduces cross-subsidization between the customers. Transition to this tariff structure is relatively easy to achieve by gradually increasing the proportion of the power charge in pricing and simultaneously considering the effects of the new pricing scheme; thus, the optimal tariff structure may be reached already during the transition.

6.2.9 Small-scale customer's power tariff with threshold power

The small-scale customer's power tariff with threshold power (threshold power tariff) is similar to the above-described small-scale customer's power tariff with the exception that in this case the power charge component (€/kW) will be in effect only above a certain predefined threshold power, below which the power charge is included in the basic charge.

In this tariff, the customers exceeding the power limit have good opportunities to affect their distribution fee, whereas for the customers remaining below the power limit the options are limited to the energy-based volumetric consumption component.

From the DSO's perspective, the strength of the tariff is the cost-reflectivity of the tariff with threshold power also for customers consuming very small volumes of power. Naturally, the questions related to the determination of the power limit have to be dealt with when the tariff structure is taken into use.

From the retailer's perspective, finding out the power limits used by different DSOs may cause extra work.

6.3 Economic effects of the distribution tariffs under analysis

In order to analyse the proposed distribution tariffs in more detail, distribution tariffs have been generated for three case networks based on cost data. The networks taken under analysis do not fully cover the operating environment of DSOs that operate in a large geographical area; nevertheless, these different example networks provide information about possible differences in the effects of tariffs for instance on urban and rural networks.

The following sections introduce and describe the case networks and the tariffs calculated based on costs for each network. In the calculations, the tariffs are determined by applying the principles presented in Chapter 5. Moreover, the effects of the distribution tariffs on the customers and the DSO's revenues are discussed, assuming that the tariff does not have an impact on the customers' load behaviour.

When interpreting the results, it is important to note that the results aim at representing the extremes of the tariffs, especially with respect to the power charge. In reality, however, the proportions and amounts of different tariff components are probably essentially different.

6.3.1 Urban area

The network under analysis is located in an urban area and covers areas supplied by two primary substations. There are 32 000 places of electricity use (metering points) on the network, most of which are small-scale customers, and which are, according to the type user group identifiers indicated in the customer data, mainly customers living in terraced houses and apartment houses. There are also customers dwelling in detached houses and larger customers (commerce, industry, services), whose effect has been taken into account when formulating the distribution tariffs. The focus of the analysis is yet on the distribution tariffs of small-scale customers. In this network, the network length per customer is 12 m.

Based on the cost analysis and cost allocation, the objective for the revenue collected from small-scale customers is approximately 65 % of the targeted total revenue. At present, for a network area of this kind, a pricing scheme is applied where the basic charge in the small-scale customers' distribution tariffs is the same for different customers within a distribution product. However, there are several different distribution products offered to the small-scale customers, and the basic charges vary between different products. For comparison, distribution tariffs are given according to the present distribution tariffs for small-scale customers but also with the aim of achieving the above-mentioned target revenue.

Tables 6.1–6.5 provide data of the distribution tariffs based on the costs and revenue targets for each network area. Table 6.1 presents the current tariff structures, whose unit prices are obtained by cost-based calculation and which meet the targets set for the revenue described in this section for the small-scale customers in each network.

Table 6.1. Calculated distribution tariffs according to the present tariff structure in the urban network area

			Consumption charge (cent/kWh)	
Tariff	**Contract power charge (€/kW, a)**	**Basic charge (€/month)**	**Daytime / Other time**	**Night-time / Winter weekday**
General distribution	-	3.63	2.83	-
Time-of-day distribution	-	14.43	2.77	4.00
Controlled night-time distribution	6.19	10.55	0.67	1.70

Table 6.2. Power limit tariff in the urban network area

Power limit (kW)	Price (€/year)	Price (€/month)
5	116.69	9.72
10	233.39	19.45
15	350.08	29.17
20	466.77	38.90
25	583.46	48.62
30	700.16	58.35
35	816.85	68.07
40	933.54	77.80
45	1 050.23	87.52

In the step tariff, each customer's hourly consumption is priced based on hourly mean power so that when the customer's hourly power exceeds 5 kW, a higher price is paid for the consumption of the whole hour. Correspondingly, when the consumption remains below the limit, the customer pays a lower price for the consumption of that hour.

Table 6.3. Step tariff in the urban network area

Tariff	Basic charge (€/month)	Consumption charge, if below the limit (cent/kWh)	Consumption charge, if above the limit (cent/kWh)
Step tariff	4.03	2.13	6.35

In the small-scale customer's power tariff, the customer's power charge is determined based on the highest hourly power in a month.

Table 6.4. Small-scale customer's power tariff in an urban network area

Tariff	Basic charge (€/month)	Power charge (€/kW, month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff	4.03	3.00	0.53

In the threshold power tariff, no extra power charge is collected from the customer if the highest hourly power of the month does not exceed 5 kW. If the customer's highest load is above the predefined limit, a power charge is collected according to the price list for the power exceeding the limit.

Table 6.5. Small-scale customer's power tariff with threshold power (5 kW) in an urban network area

Tariff	Basic charge (€/month)	Unit price for the power exceeding the power limit (€/kW, month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff with 5kW threshold power	9.30	2.95	0.53

The effects of calculated distribution tariffs on individual customers' distribution fees are presented in Figure 6.1. The figure compares distribution fees that are calculated according to the present distribution tariffs and distribution fees that are based on different power-based distribution tariff structures.

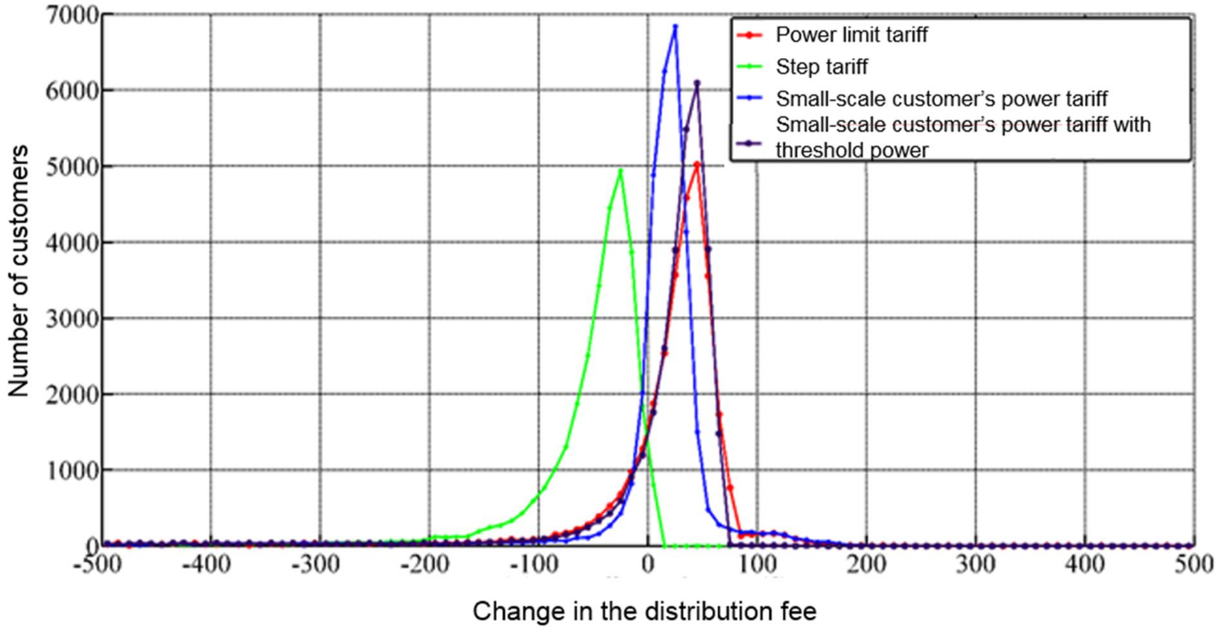

Figure 6.1. *Distribution of changes in the customers' distribution fees. Each power-based distribution tariff option is compared with distribution tariffs calculated following the present tariff structure. The range of analysis covers more than 97 % of the small-scale customers in all cases.*

The figure shows that with the different distribution tariff options, most of the customers would see changes in their distribution tariffs. Nevertheless, the absolute size of changes would not be dramatic, which, however, does not guarantee that the relative change in the customer's distribution fee would not be substantial. Outside the range of analysis there are also customers who would have experienced a change of more than 500 euros. Most of the changes are due to the fact that there are customers in the present tariff groups who should actually belong to another tariff group or whose electricity use is exceptional in some way (e.g. the customer has occasionally a very high power demand, yet the annual energy use is small). The different power-based distribution tariffs lead to a situation where significant changes would take place in the exceptional customers' distribution fees, if the new tariff structure were introduced overnight.

Table 6.6 presents the effect of each distribution tariff option on the DSO's revenue, when the load behaviour is assumed not to change as a result of the tariff. The positive values in the tariff refer to a situation where the anticipated target revenue is exceeded, while negative values indicate revenue deficit.

Table 6.6. *Effect of different distribution tariff options on the DSO's revenue when no changes are assumed to occur in the customers' load behaviour as a result of the tariff.*

Tariff	Difference compared with the target revenue (%)
Present distribution tariff structures	0.21 %
Power limit tariff	-1.36 %
Step tariff	-0.34 %
Small-scale customer's power tariff with threshold power	-0.09 %
Small-scale customer's power tariff	1.19 %

From the DSO's perspective, the values in Table 6.6 show that if the customers had not reacted to changes in the tariff structure, the changes in the DSO's revenue would have been moderate. Considering a successful tariff reform, this is positive as the DSOs have to secure both their short- and long-term operating conditions, and therefore, changes in revenues have to remain at a reasonable level.

6.3.2 Population centre within a rural area

The network under analysis is located in a small town and covers an area supplied by one primary substation. There are 8 000 places of electricity use (metering points) on the network, most of which are small-scale customers living in detached houses and terraced houses (according to the type user group identifiers indicated in the customer data). There are also larger customers on the network (e.g. commerce and services), whose effect has been taken into account when formulating the distribution tariffs; however, the focus of the analyses is on the small-scale customers' distribution tariffs. There is approximately 170 m of network per customer in this distribution network.

Based on the cost analysis and allocation of costs, the target revenue of the small-scale customers' distribution tariffs in this network is about 90 % of the total target turnover. At present, the pricing method applied in a network of this kind contains a fuse-based basic charge in the small-scale customers' distribution tariff. In addition, there are several distribution products offered to small-scale customers, and the basic charges vary between the products. For comparison, the distribution products are generated according to the present small-scale customers' distribution tariffs so that the above-mentioned target revenue is achieved. Tables 6.7–6.11 summarize data on the distribution tariffs based on the costs of each network area under analysis. Table 6.7 lists the present tariff structures, whose unit prices are based on cost-based calculation and which meet the target revenues described in this section for the small-scale customers on each network in question.

Table 6.7. Calculated distribution tariffs according to the present tariff structure for a network located in a population centre in a rural area.

		Consumption charge (cent/kWh)	
Tariff	**Basic charge (€/month)**	**Day / other times**	**Night / winter weekday**
General distribution 1x25, 1x35 A	3.11	2.66	-
General distribution 3x25 A	11.02	2.66	-
General distribution 3x35 A	15.43	2.66	-
General distribution 3x50 A	22.04	2.66	-
General distribution 3x63 A	27.77	2.66	-
General distribution 3x80 A	35.26	2.66	-
General distribution 3x100 A	44.08	2.66	-
Night-time distribution 3x25 A	20.91	3.42	2.09
Night-time distribution 3x35 A	29.27	3.42	2.09
Night-time distribution 3x50 A	41.82	3.42	2.09
Night-time distribution 3x63 A	52.69	3.42	2.09
Night-time distribution 3x80 A	66.91	3.42	2.09
Night-time distribution 3x100 A	83.64	3.42	2.09
Seasonal distribution 3x25 A	29.39	1.26	2.53
Seasonal distribution 3x35 A	41.15	1.26	2.53
Seasonal distribution 3x50 A	58.78	1.26	2.53
Seasonal distribution 3x63 A	74.06	1.26	2.53
Seasonal distribution 3x80 A	94.05	1.26	2.53
Seasonal distribution 3x100 A	117.56	1.26	2.53

Table 6.8. Power limit tariff in a network located in a population centre in a rural area

Power limit (kW)	Price (€/year)	Price (€/month)
5	208.74	17.40
10	417.49	34.79
15	626.23	52.19
20	834.98	69.58
25	1 043.72	86.98
30	1 252.46	104.37
35	1 461.21	121.77
40	1 669.95	139.16
45	1 878.70	156.56

In the step tariff, the customer's consumption of each hour is priced based on the hourly mean power so that if the customer's hourly power exceeds 5 kW, a higher price is paid for the consumption of the whole hour. Correspondingly, if the consumption remains below the limit, the customer pays a lower price for the consumption of that hour.

Table 6.9. Step tariff in a network located in a population centre in a rural area

		Consumption charge (cent/kWh)	
Tariff	**Basic charge (€/month)**	**Consumption charge, if below the limit (cent/kWh)**	**Consumption charge, if above the limit (cent/kWh)**
Step tariff (5kW steps)	3.82	3.30	6.80

In the small-scale customer's power tariff, the power charge is determined based on the highest hourly power of the month.

Table 6.10. Small-scale customer's power tariff in a network located in a population centre in a rural area

Tariff	Basic charge (€/month)	Power charge (€/month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff	3.82	5.83	058

In the threshold power tariff, no separate power charge is collected from the customer if the highest hourly power of the month does not exceed 5 kW. If the highest load of the customer exceeds the predefined limit, an extra power charge according to the price list is assigned to the power exceeding this limit.

Table 6.11. Small-scale customer's power tariff with threshold power (5 kW) in a network located in a population centre in a rural area

Tariff	Basic charge (€/month)	Unit price for the power exceeding the power limit (€/kW, month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff with 5 kW threshold power	19.04	5.3	0.58

The effects of calculated distribution tariffs on individual customers' distribution fees are illustrated in Figure 6.2. The figure compares distribution fees that are calculated according to the present distribution tariffs and distribution fees that are based on different power-based distribution tariff structures.

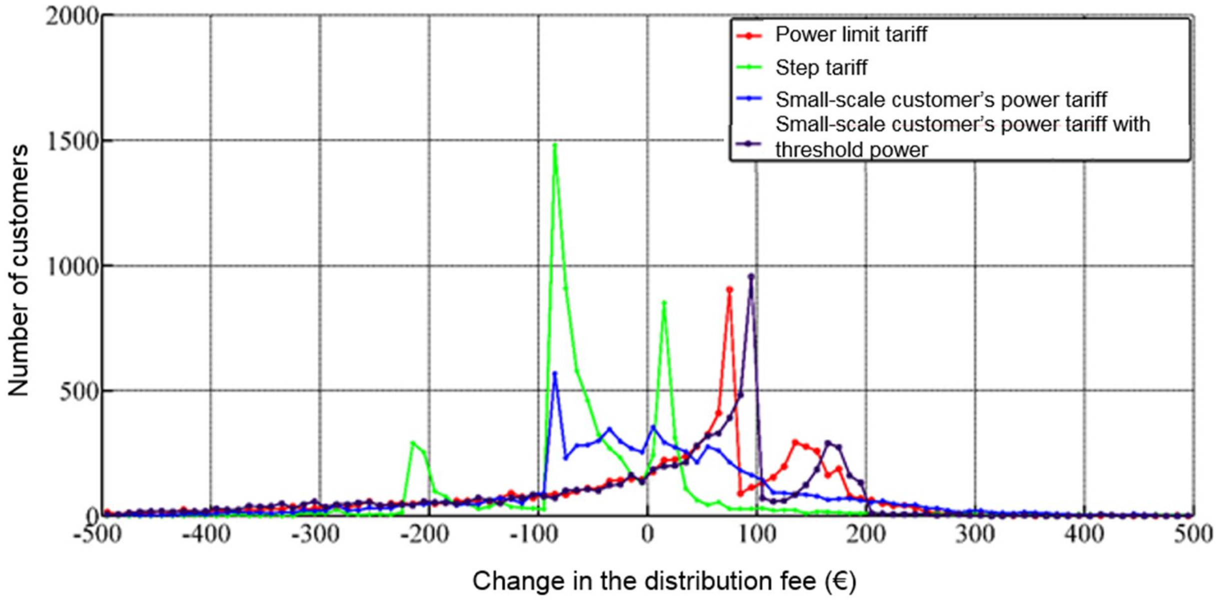

Figure 6.2. *Distribution of changes in the customers' distribution fees. Each power-based distribution tariff option is compared with distribution tariffs calculated following the present tariff structure. The range of analysis covers more than 96 % of the small-scale customers in all cases.*

Compared with the network in an urban area discussed above, the changes in the customers' distribution fees seem to be scattered over a slightly wider range. The peaks in the figure are partly due to the fact that the basic charges in the small-scale customers' distribution tariffs are based on the main fuse size, and thus, customers consuming less electricity are shown as peaks in the graph. The electricity use in the network under analysis is also different from the electricity use in the urban network, where the majority of the customers live in apartment houses. Hence, there are not as clear differences in the electricity consumption of the customer base as in the population centre located in the rural area.

Table 6.12 presents the effect of each distribution tariff option on the DSO's revenues assuming that the tariffs do not cause any changes to the load behaviour. The positive values in the tariff refer to a situation where the anticipated target revenue is exceeded, while negative values indicate a revenue deficit.

Table 6.12. *Effect of different distribution tariff options on the DSO's revenue when no tariff-based changes are assumed to occur in the customers' load behaviour.*

Tariff	**Difference compared with the target revenue (%)**
Present distribution tariff structures	3.49 %
Power limit tariff	-2.74 %
Step tariff	-1.73 %
Small-scale customer's power tariff with threshold power	-0.66 %
Small-scale customer's power tariff	0.68 %

The values in the table show that differences compared with the target revenue are relatively small also in this network, especially in the two latter alternatives (small-scale customer's threshold power tariff and power tariff). The difference from the target revenue is highest with the present distribution tariffs, where consumption charges play a significant role. Thus, various factors, such as temperature, have a major effect on the difference from the target revenue.

6.3.3 Network including population centres and rural areas

The network area under analysis contains both population centres and rural areas. There are over 14 000 inhabitants in the area, 13 800 of which are customers of fuse-based products. There are around 10 000 inhabitants in the largest population centre in the area. There are also industrial, service, and agricultural customers in the customer base. There is district heating network in the population centres in the area, but the specific heating systems of the customers are not known. The population in the area is growing. There is about 154 m of electricity network per customer in the area.

The basic charges in the present price list are based on fuse sizes. At present, the energy-based distribution fees collected from customers of fuse-size-based products cover about 58 % of the revenues. Below, the price list is calculated based on the present tariff structure for customers with a 3x35 A main fuse at the maximum. Tables 6.13–6.17 provide the distribution tariffs calculated based on the data of the network under analysis.

Table 6.13. *Distribution tariffs according to the present tariff structure for customers with a max. 3x35 A main fuse in networks including population centres and rural areas.*

Tariff	Basic charge (€/month)	Consumption charge (cent/kWh)	
General distribution 1x25A	6.06	4.09	
General distribution 1x35A	6.27	4.09	
General distribution 3x25A	15.86	4.09	
General distribution 3x35A	30.81	4.09	
		Day	**Night**
Night-time distribution 3x25A	27.60	4.09	2.68
Night-time distribution 3x35A	40.85	4.09	2.68
		Winter weekday	**Other times**
Seasonal distribution 3x25A	31.11	5.15	2.57
Seasonal distribution 3x35A	43.73	5.15	2.57

In the power limit tariff, the customer can choose a power limit. In the calculation it is assumed that if the power limit is exceeded, the customer is automatically shifted to a product at a higher power limit, and correspondingly, to a lower limit if the customer's sliding twelve-month consumption has not exceeded the present lower power limit.

Table 6.14. *Power limit tariff in a network including population centres and rural areas.*

Power limit (€/month)	Price (€/year)	Price (€/month)
5	339.30	28.27
10	678.60	56.55
15	1 017.89	84.82
20	1 357.19	113.10
25	1 696.49	141.37
30	2 035.79	169.65
35	2 375.09	197.92
40	2 714.39	226.20
45	3 053.68	254.47

In the step tariff, the customer's hourly consumption is priced based on the hourly mean power so that if the customer's hourly power exceeds 5 kW, a higher price is paid for the consumption of the whole hour. Correspondingly, if the consumption remains below the limit, the customer pays a lower price for the consumption of that hour.

Table 6.15. *Step tariff in the network including population centres and rural areas.*

Tariff	Basic charge (€/month)	Consumption charge, if below the limit (cent/kWh)	Consumption charge, if above the limit (cent/kWh)
Step tariff (5 kW step)	4.34	4.82	9.64

In the small-scale customer's power tariff, the customer's power tariff is determined based on the customer's highest hourly power of the month.

Table 6.16. *Small-scale customer's power tariff in the network including population centres and rural areas.*

Tariff	Basic charge (€/month)	Power charge (€/kW, month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff	4.34	9.54	0.54

In the threshold power tariff, no separate power charge is collected from the customer if the highest hourly power of the month does not exceed 5 kW. If the customer's highest load exceeds the predefined limit, a power charge is collected according to the price list for the power exceeding the limit.

Table 6.17. *Small-scale customer's power tariff with threshold power (5 kW) in the network including population centres and rural areas.*

Tariff	Basic charge (€/month)	Unit price for the power exceeding the power limit (€/kW, month)	Consumption charge (cent/kWh)
Small-scale customer's power tariff with threshold power	35.37	10.39	0.54

Figure 6.3 illustrates changes in the customers' distribution fees when the distribution fees resulting from different distribution tariff options are compared with the present distribution tariffs.

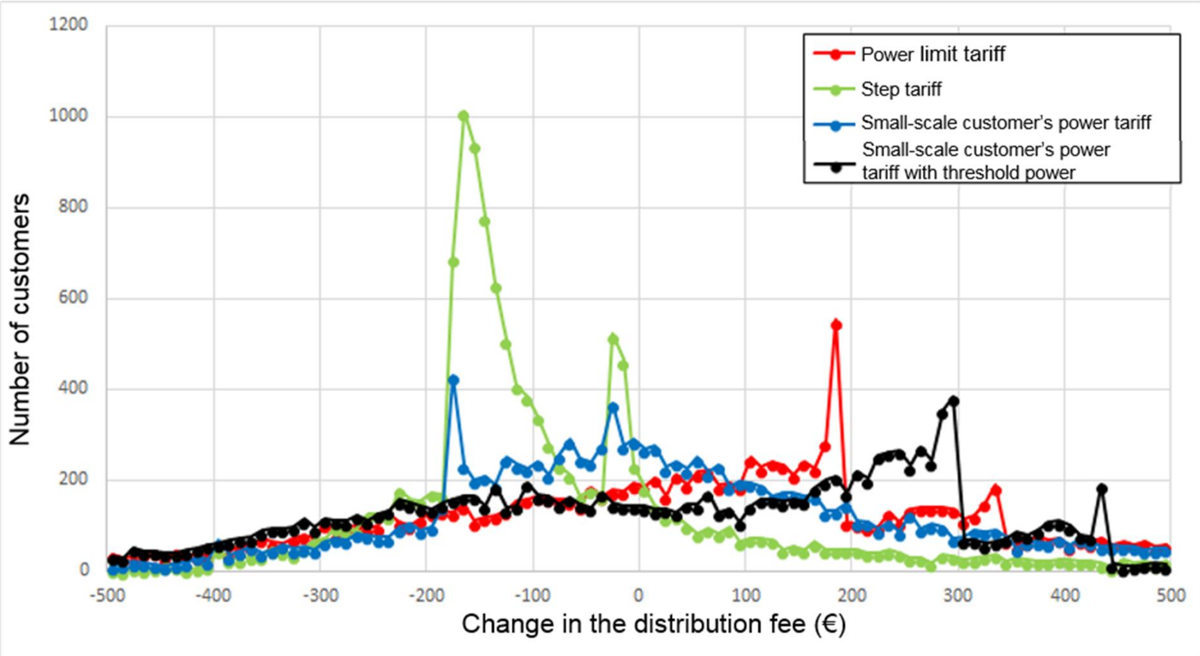

Figure 6.3. *Distribution of changes in the customers' distribution fees. Each power-based distribution tariff option is compared with distribution tariffs calculated following the present tariff structure. The range of analysis covers more than 90 % of the small-scale customers in all cases.*

The figure shows that in the case of step tariff, the distribution fees would decrease for a significant proportion of the customers. Considering step tariffs, it is noteworthy that for the customers with large electricity consumption, there will be substantial changes in the distribution fees. This is due to the fact that only one power limit is applied in the determination of the step tariff. Compared with the previously discussed networks, the changes experienced by the customers in their distribution fees seem to be scattered over a wider range in this network example. Also in this network, peaks can be seen in the changes in the distribution fees; the peaks are due to the present fuse-based charges. Table 6.18 shows the difference from the target revenue resulting from the different distribution tariff options.

Table 6.18. *Effect of the different distribution tariff options on the DSO's revenue when no tariff-based changes are assumed to take place in the load behaviour.*

Tariff	**Difference compared with the target revenue (%)**
Present distribution tariff structures	0.99
Power limit tariff	0.95
Step tariff	5.22
Small-scale customer's power tariff with threshold power	1.04
Small-scale customer's power tariff	3.16

In the area under analysis, the DSO’s revenue would have been 0.95–5.22 % higher than the target revenue with all tariff options. The revenue obtained with the power limit tariff would have been closest to the target revenue, but in this network example, the differences between the cases of the present tariff structure, power limit tariff, and the threshold power tariff are relatively small compared with the target revenue.

6.4 Effects of power pricing on loads

This section discusses different views to changes in the customer’s load behaviour. First, the peak shaving potential of the customers’ loads and its network effects are considered. Next, the section addresses the economic feasibility of solar power systems in a power-based pricing scheme. The third subsection considers the application of energy storages in cutting the peak powers of the customer.

6.4.1 Cutting the customers’ peak power by electric energy storages and the effects on loads on the distribution network

Electric energy storages, in practice usually batteries, provide the customers with opportunities to control their power drawn from the network and simultaneously affect the amount of their power-based distribution fee. In the example network, an analysis was calculated for the energy storage with the unit price of 500 €/kWh, 10-year lifetime, and 10 €/kW, month unit price for the power charge in the tariff option where the customer’s distribution fee is determined based on the monthly peak power. The profitability of cutting the customers’ peak power is highly dependent on the characteristics of the energy storage and its unit price. The unit price of 500 €/kWh would allow cutting of the customer’s peak power profitably even at the power charge of 4.5 €/kW, month with the assumed 10-year lifetime. For the customer, the most profitable option is to cut the highest peak powers, which is usually possible with energy storages of moderate energy content (typically 1 or 2 kWh), which are capable of supplying a power of a few kilowatts.

The analysis shows that the cumulative decrease in the peak power in the network is on average 1.6–10 % of the present peak power of the different network components depending on the network section where the component is located. The peak power decreases most (10 %) close to the customer, but also the distribution of peak powers is high. In the analysis, the peak power of transformers decreases by 4 % on average, and the peak powers of the medium-voltage lines decrease by 1.6 %. Figure 6.4 depicts changes in the peak powers of the transformers in the distribution network when comparing a situation where the peak powers have been cut and the present load of the network applying the customer load data of the example network. A more detailed description of the analysis is found in (Haakana et al., 2017).

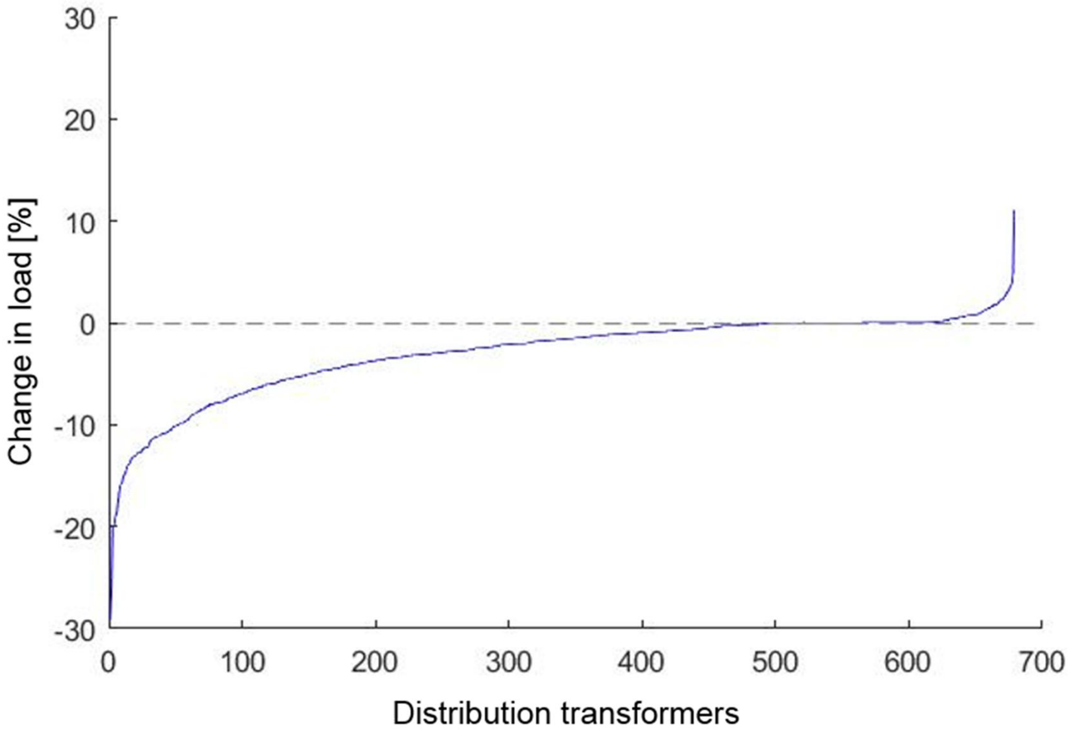

Figure 6.4. *Changes in the peak powers of the distribution transformers in the example analysis.*

6.4.2 Changes in the profitability of solar power systems

When considering the economic feasibility of solar power systems, the DSO's consumption charge that is based on transmitted energy is usually taken into account in the calculations. However, the energy produced by the solar power systems does not reduce the costs of the DSO almost at all, as a result of which the costs have to be transferred either to basic charges, or the unit price of the energy-based charge has to be increased. Consequently, the DSO's costs are concentrated on customers who do not have small-scale generation of their own. The effects of power pricing on the customer with solar power production were considered by comparing the customer's savings potential obtained by solar power production in the case of the DSO's power pricing and in the present situation. In the analysis, the benefits delivered by the solar power system compared with a situation where the customer acquires electric energy from the distribution network were taken into account. The production curve for the solar power was modelled by applying the solar radiation data provided by the Finnish Meteorological Institute (Finnish Meteorological Institute, 2017), and the production curve was applied to calculate the hourly energies produced by the solar panels facing south. The simulated production curve was combined with the actual electricity consumption data of the customers, and the effects of different pricing models were compared. It was assumed in the analysis that the production can be used to cut the consumption within an hour. In reality, some of the production must be supplied to the network, and thus, within an hour under consideration, there may be both consumption from the network and production supplied to the network. The analysis revealed that for about 80–90 % of the customers the savings brought by the solar power system would have decreased as a result of the customer's actual electricity consumption, if the pricing had based on power instead of energy. A more detailed description of the analysis can be found in (Haapaniemi et al., 2017). It is pointed out, however, that even though a change in the pricing system may reduce the benefits of a solar power system, it may also create an incentive to acquire an energy storage, which may increase the benefits reaped from a solar energy system.

6.4.3 Customers' energy storages in the network of a population centre in a rural area

In this study, the opportunities of using energy storages for the customer's load management were analysed. In the analysis and modelling, battery systems of different sizes were used to minimize the customer's electricity costs. A sample of 1525 customers with electric space heating (according to customer data) were taken from the example network in the urban area. The simulation was designed to resemble an actual situation by optimizing the use of the energy storage for each hour based on the customer's previous electricity use and by applying a consumption forecast compiled based on an air temperature (weather) forecast. The simulation model is discussed in more detail in a Master's thesis (Koskela, 2016) and in (Koskela et al., 2016). It is important to use a simulation model of this kind, because an error in the customer's consumption forecast may lead to a situation where the benefit gained from the battery is considerably lower than in an ideal case, or no benefit is obtained at all.

The study showed that the suitable size of a battery varies considerably between the customers, but on average, a battery with the capacity of 6 kWh and the C-rate of 0.7C yields the best results. The C-rate of the battery is the ratio of the discharge power to the capacity, in other words, the power of a 6 kWh and 0.7C battery is approximately 4 kW. In order to ensure comparability, this battery size was used for all customers in the analysis. Increasing the battery capacity enables a greater reduction in the peak power, yet only a few customers will actually benefit from this alternative. Only about 3 % of the customers reach more than a 1 kW cut in their peak power by increasing the battery capacity by 3 kWh. The highest peaks of these customers are very short and high, and occur very rarely.

By applying the battery used in this analysis, it would be theoretically possible to reduce a single customer's peak power by 4 kW at the maximum (6 kWh · 0.7 kW/kWh). In the simulations, only about 5 % of the customers reached this peak cut, and on average, a customer could reduce her/his peak power by 1.5 kW. When the powers of all the customers in the sample were added up, the change in the peak power was only about 8.5 kW. This is due to the fact that the customers' peak powers are distributed among different hours of the day and year. For comparison, a situation was considered where the customers would use their batteries to shift their consumption to inexpensive hours. In that case, the customer's peak power would increase by 0.5 kW on average. As all the customers would schedule their consumption for the same hours, this would be seen in the peak of the sum power of this customer group, which would increase approximately by 3 250 kW, that is, about 2 kW per customer.

A battery is very rarely needed to cut the peak power; only a few times a year at the very least, and even at the opposite extreme so seldom that in all the simulated cases the end of the battery's calendar life is reached before the cycle life. For this reason, the customer could use the same battery also to shift the consumption to inexpensive hours in hour-based electricity contracts or to increase the self-consumption ratio in connection with solar power production. These actions, however, increase the risk that the benefit gained from the power cut is lost and only a very few customers benefit from combination of different control objectives.

According to this study, the threshold power tariff produces, on average, the best incentive for cutting the peak power by applying an energy storage. Energy storage is profitable for those customers whose consumption includes peaks and the highest peaks are clearly above the threshold power. The step tariff would be the most profitable option for one customer, but this customer was sorted out from the sample customer group because of the very exceptional consumption pattern, which varied on both sides of the threshold. The small-scale customer's power tariff without threshold power would give the most stable incentive for storing energy, yet the profitability of energy storages for a large number of customers would require lower battery prices in the future. The power limit tariff, again, would divide the customers into those who would not benefit from energy storages and those who would benefit from storages should the battery prices decrease. There is also a risk that in some years within the battery lifetime, the customer's power could not be brought below the limit by using the battery, and the benefit gained from the investment would be lost.

6.4.4 Changes in the customer's consumption behaviour as a result of demand response

This section analyses how customers' demand response actions as a means to react to the power tariff would affect the customers' peak powers and their annual energy and distribution costs as well as the loads and voltage levels on the medium-voltage network. The sample of customers and the network were the same as in the energy storage case discussed in Section 6.4.3.

The section introduces the modelling method and the assumptions made in the modelling. A calculation example is given to analyse the effects of optimization of one year on the above-mentioned parameters.

Modelling demand response and objectives of consumption optimization

The effects of demand response are studied by applying a heuristic model, which aims to demonstrate how a customer with direct electric space heating can affect her/his consumption by optimally scheduling the heating load. The customer is assumed to have an automation system capable of controlling the load throughout the day, and an adequate consumption forecast for the day ahead. Figure 6.5 illustrates the basic principle of demand response: part of the customer's measured load is selected to be flexible so that it can be shifted arbitrarily within the optimization window yet keeping the amount of energy consumed constant and not exceeding the power limit. The model is applied for instance in (Rautiainen, 2015) and (Supponen et al., 2016).

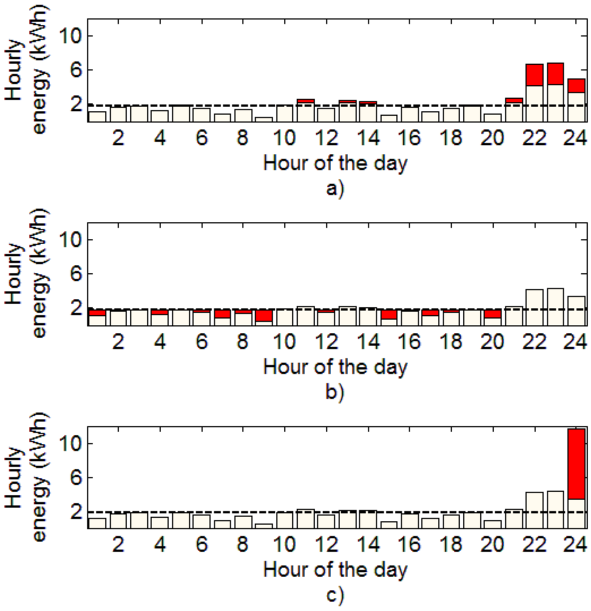

Figure 6.5. *Principle of load modelling; subfigures b) and c) represent two extreme cases in optimization. In case b), the load is evenly distributed over the day, and in case c) all the flexible load is scheduled to one cheap hour. In practice, the optimized load distribution of each customer lies between these two extremes.*

Optimization of the customer's electricity use is analysed from three angles. First, a situation is studied where all the customers chosen to be flexible aim at optimizing their use of electricity according to the hourly price for energy. This is a "worst-case" scenario, where natural intersecting of customers' load curves is at the minimum as a result of efficient load control and a strongly synchronizing control signal (hourly price of electric energy).

The second case is a situation where all customers aim at minimizing their peak power within the billing period regardless of fluctuations in the energy prices. From the network's perspective, this is a more desirable situation, in which all the customers aim at spreading their use of electricity as evenly as possible.

In the third case, the customer optimizes her/his energy use both according to the distribution tariff for the peak power and the price of the sales tariff for electricity.

In the calculations, the calculated distribution tariffs given in Section 6.3.2 for the small-scale customer's power tariff (Table 6.10) are used as the cost of the power tariff, and the Elspot hourly price including taxes for year 2015 is used as the price of energy.

Effects of demand response on the customer's distribution and energy costs and the peak demand of the year

Figures 6.6 and 6.7 show the change in the customers' peak demand and the change in the annual distribution and energy costs in a case where the customer primarily aims to optimize her/his use of electricity according to the spot price regardless of the price of power. The average change in the energy costs is -27 €/a and the corresponding change in distribution costs +104 €/a. The average change in the peak demand of the year was 2 kW.

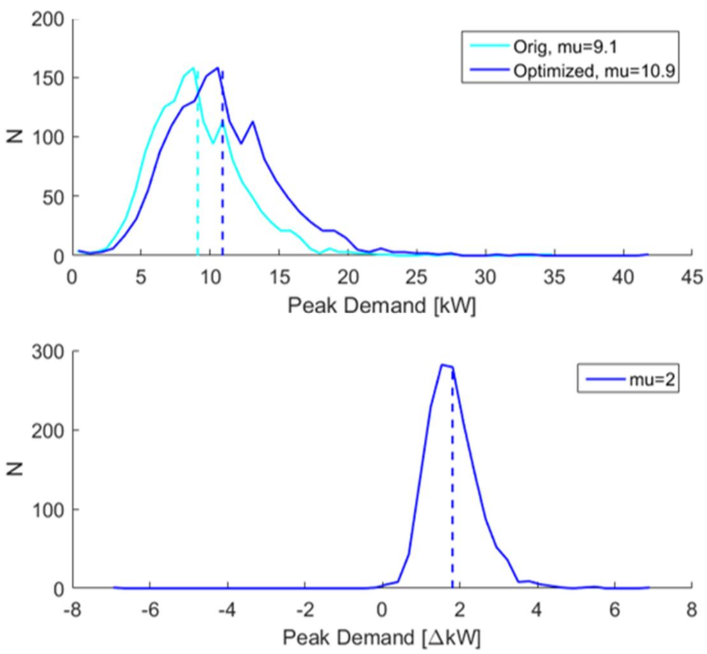

Figure 6.6. *Change in the peak demand, optimization based on spot price. N = number of customers, mu = mean.*

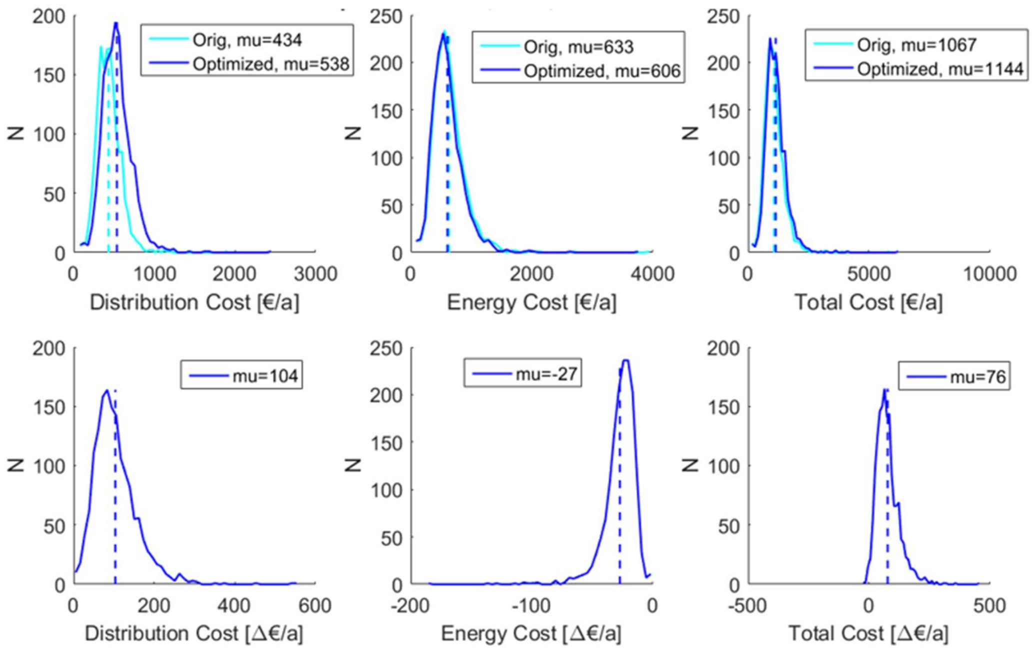

Figure 6.7. *Change in the customer's cost components, spot-price optimization. "Distribution Cost" refers to the network service fee and "Energy Cost" to the proportion paid for the electricity retailer. N = number of customers, mu = mean.*

The results show that the average savings obtained from the spot market are small, at least at the present price level. Thus, optimization of this kind is probably not the customer's most obvious choice. It is pointed out, however, that even though the benefit gained from the hourly price of energy is not significant, the setting of this optimization task is an illustrative example of other similar customer reactions (e.g. peak load management by reserve control).

Figures 6.8 and 6.9 depict changes in the peak demand in power tariff optimization and changes in the customer's costs. As a result of the power tariff optimization, the customers' average peak demand decreased by 4 kW and the distribution cost by 107 €/a while the energy cost remained almost unchanged.

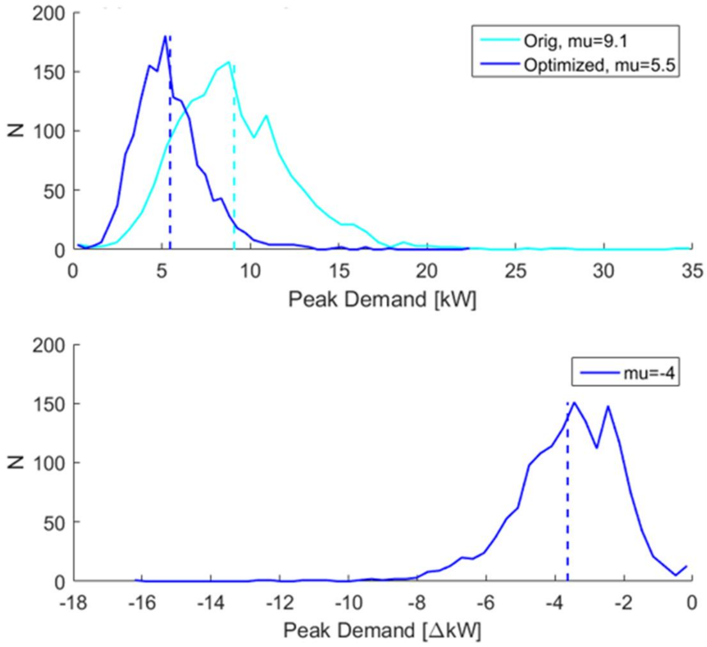

Figure 6.8. *Change in the peak demand, power tariff optimization. N = number of customers, mu = mean.*

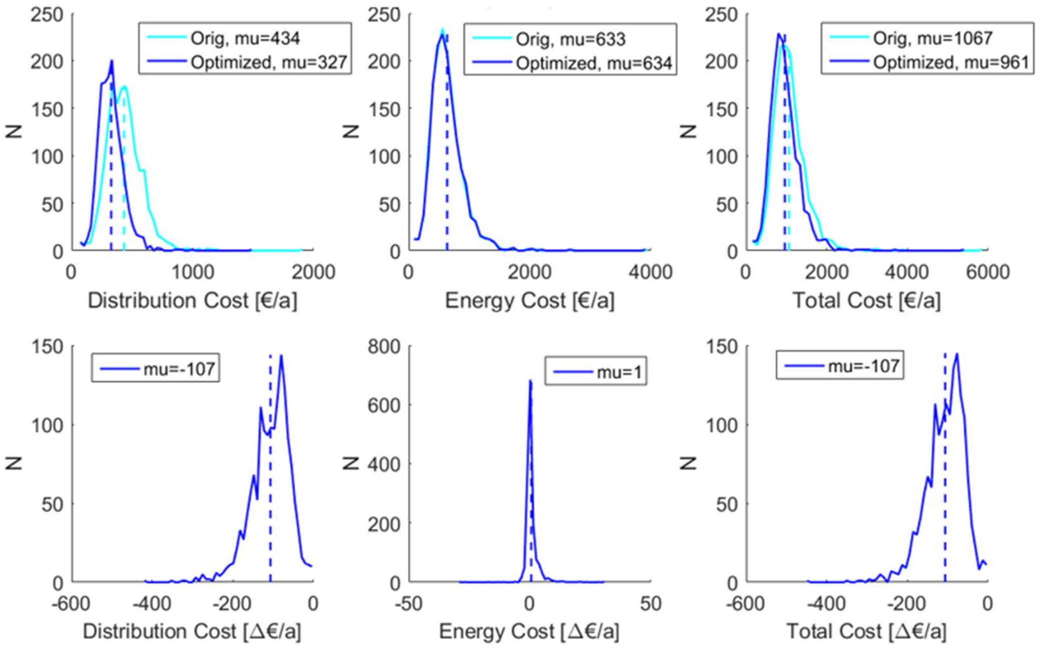

Figure 6.9. *Change in the customer's cost components, power tariff optimization. N = number of customers, mu = mean.*

With the pricing scheme applied in this analysis, optimization of peak demand is clearly more profitable than optimization based on energy price. However, annual savings of this scale for a large number of customers have an adverse effect on reaching the DSO's revenue target, and are thus not realistic in the long term. Figures 6.10 and 6.11 illustrate changes in the peak demands in the combined optimization and changes in the customer's costs.

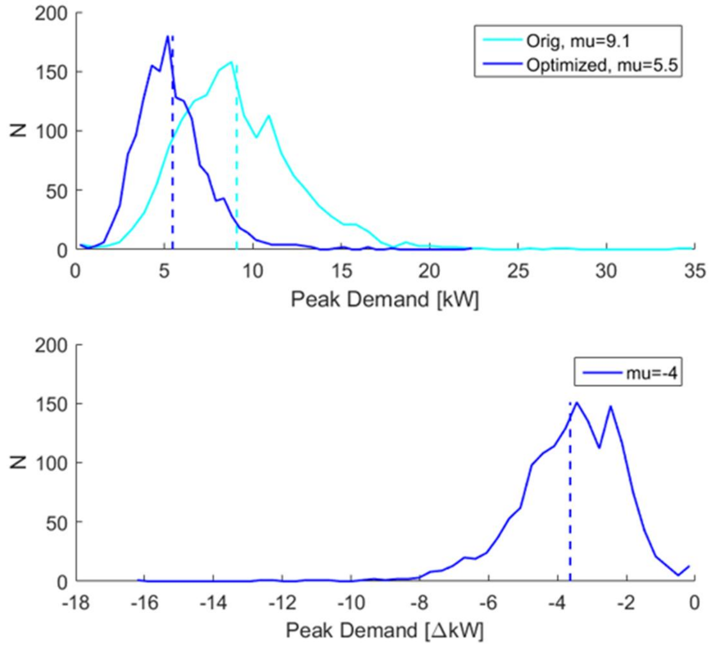

Figure 6.10. *Change in peak demand, combined optimization. N = number of customers, mu = mean.*

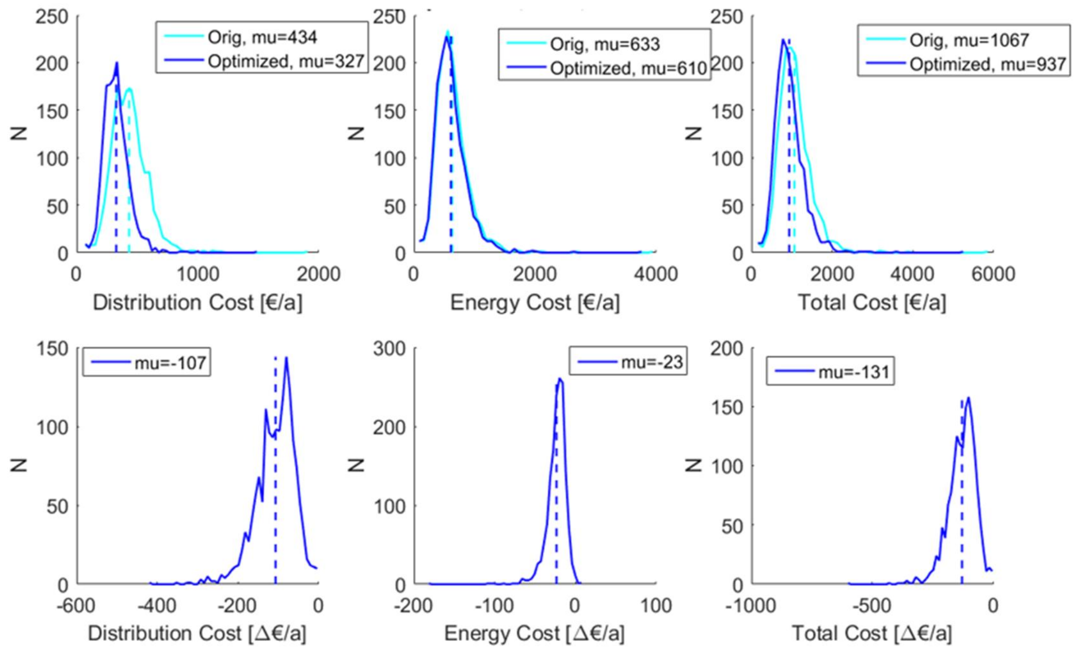

Figure 6.11. *Change in the customer's cost components, combined optimization. N = number of customers, mu = mean.*

The results show that the spot-price-based optimization is profitable as a whole for only a fraction of customers even in a case where power-based pricing is not used.

Effect of demand response on loads and voltage profile of the medium-voltage network

Finally, the effects of the above-described optimization on the loads and voltage level in the distribution network are considered. The measure of load used here is the change in the load factor of the distribution transformers, and the lowest annual hourly averages of voltage at network nodes are used as the measure of voltage change. The change in the load factor of the distribution transformers is illustrated in Figure 6.12 and the change in voltage in Figure 6.13.

The figures show that in this example case, the power tariff can be used at least at the distribution transformer level to reduce the increase in peak load caused by a reduction in the intersection of load curves. Furthermore, the voltage level of the network can be improved to the initial level. In the context of this analysis, the effect of power tariff would be minor on the currently prevailing state of load.

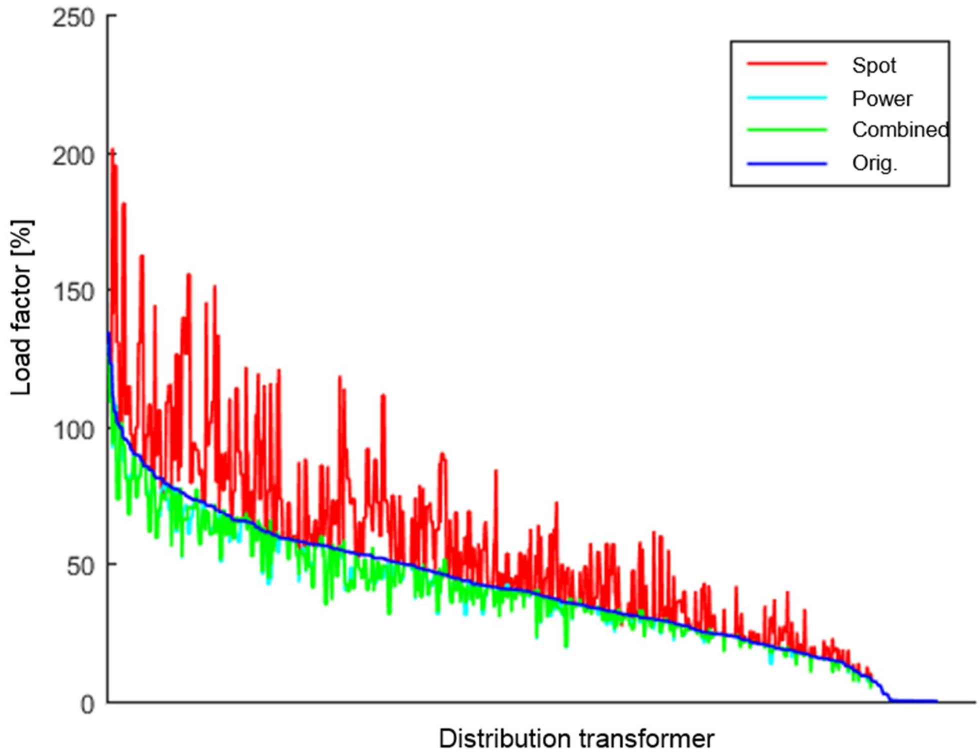

Figure 6.12. *Highest load factors of the distribution transformers, the number of transformers indicated on the horizontal axis.*

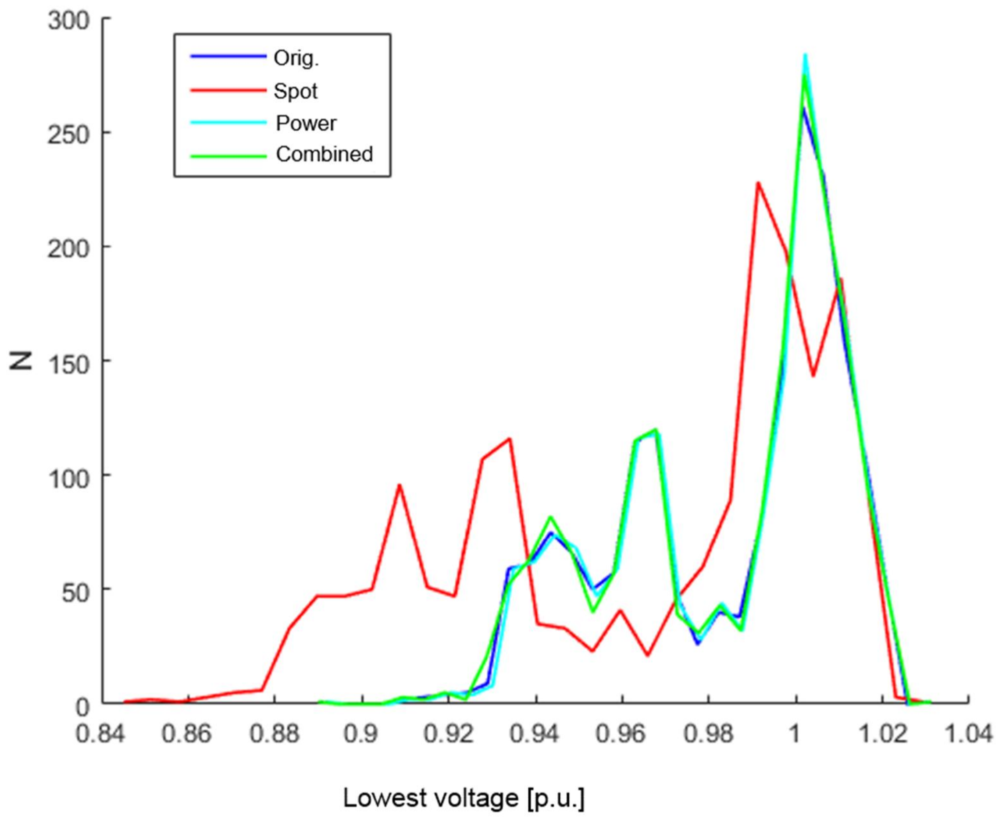

Figure 6.13. *Lowest annual voltages on the network*

Based on the analyses presented above, the power tariff gives far more incentives for the customer for demand response than spot pricing. However, in addition to the power-tariff-based load control, the customer can gain extra benefit also from the spot-price-based control.

From the network perspective, the analyses indicate that in the present situation, power-based pricing does not reduce loads on the network; nevertheless, it may be an efficient tool to limit an increase in loads in periods of transition, when a significant amount of new market-based demand response is introduced. This, in turn, reduces the need for investments in network reinforcement, which will produce cost savings in the long term.

7 Conclusions

This research project analysed development options of distribution tariffs for small-scale customers, with a special reference to steering effects of the tariffs. The focus of the analysis was set on tariff structures, and the changes in the DSO’s revenues were assumed to be reasonable and their level to remain unchanged. Further, the changes were assumed to have an impact only on the allocation of costs to different types of customers, and on the actions encouraged by the tariff changes. It is emphasized that the distribution network tariff is only one part (one-third on average) of the total price paid by the customer for electricity; the other components being electricity sales and electricity tax. The customer can freely select her/his electricity retailer, whereas the DSO operates in a regional monopoly position. In Finland, the reasonableness of pricing of electricity distribution network operations is regulated by the Energy Authority.

From society’s perspective, the objective is to achieve a resource-efficient and climate-neutral energy system, in other words, minimization of the total costs of the system in accordance with the climate targets and other boundary conditions. Thus, the use of flexible resources in the system, such as controllable loads and energy storages, has to be optimized so that the benefits of local electricity distribution and a larger energy system are kept in balance. Key targets from the viewpoint of the distribution network are avoidance of peak loads that would require network reinforcements and an optimal capacity utilization rate. From the viewpoint of the electric power system, the most important challenge is the increasing amount of solar and wind power on the network, as a result of which also distributed flexible resources, such as load control and energy storages, have to participate more strongly in the maintenance of power balance within different time spans, including day-ahead, intraday, and very short (even second-level) periods typical in the reserve markets. For the power balance management, cost-reflective pricing is essential both in the network and in the market. The requirement of spot pricing, according to which the price of electricity may not depend on the geographical location of the customer, is also taken as a precondition in the determination of tariffs. Therefore, for instance pricing based on the loads in a certain network section is not a possible option in this scheme.

At present, the small-scale customer’s distribution tariff consists of an energy component based on the amount of transmitted energy and a basic charge, which, in some companies, depends on the size of the main fuse. The proportion of basic charges in the tariffs has increased considerably in the past few years, which has weakened the customers’ opportunities to affect their electricity bills. The problems of a tariff structure that has a basic charge independent of the fuse size and an energy-based component are the weak cost-reflectiveness and insufficient steering effects. These problems are somewhat smaller if the basic charge depends on the size of the main fuse. However, also in that case the steering effects are limited, because there is only a limited selection of fuse sizes, and changing the fuse size requires electrical installation. In the short term the costs of the distribution network are mainly fixed ones, and in the long term they primarily depend on the rated power of the network. Thus, from the viewpoint of the distribution network, it is essential that the use of electricity is controlled so that the capacity utilization rate is good and power peaks do not cause a need for network reinforcement. Moreover, it is important to recognize the role of the distribution network in the electricity market; distribution network is a neutral marketplace, which, on its part, makes it possible for the end-users and different distributed resources (small-scale production, demand response, energy storages) to participate in the market, yet so that the costs of the distribution network are transferred transparently to the operation of both the customer and the energy system. Key objectives in the determination of the tariff structure are intelligibility, acceptability, cost-reflectiveness, and the steering effects produced by the tariff. These objectives are partly in conflict with each other, and therefore, the final decision is always a compromise between different objectives.

Based on the analyses made in this study, including a power component in the distribution tariff is justifiable especially when considering the cost-reflectiveness and steering effects produced by the tariff structure. A power-based cost component enhances the customer's opportunities to have an impact on her/his network service fee, the component involves features that encourage to improve resource and energy efficiency, it secures stable revenue for the DSO, better implements the matching principle provided by the Electricity Market Act, reduces cross-subsidization between customers, and creates conditions for other stakeholders to develop the present services or establish new businesses and services, which may play a key role in the development of electricity markets. Thus, we may state that the power tariff has positive effects for the national economy, yet it is very difficult to estimate these effects in monetary terms. In the distribution network companies, including a power tariff in the distribution tariff requires extra effort in communications, while the customers have to adopt a new attitude to the control of their use of electricity. It is also noteworthy that the control of some individual customer's peak powers may in some cases even increase the peak power of the network, for example if customers with electric space heating cut their peak powers by shifting some of their consumption to an earlier time than at present. Therefore, the tariffs have to be designed carefully and their steering effects have to be considered for each case individually to achieve the desired steering effects.

In this study, the power used as the basis for the power-based cost component refers to mean hourly power determined from the measured hourly energy, and thus, the metering data produced by the present remotely read AMR systems provide the conditions required for the implementation of the tariff structures under analysis.

There are a wide variety of alternatives for including power in the tariff, two of which have been analysed in more detail: power limit tariff (power band pricing) and small-scale customer’s power tariff. In the power limit pricing the customer subscribes to the network capacity within predefined power limits. In the alternatives under analysis, it has been assumed that the tariff in question consists only of a power charge. In the latter alternative, the small-scale customer’s power tariff, the pricing is based on actual peak power, in addition to which the tariff contains a basic charge and an energy charge as is the case in the low-voltage power tariff currently in use in many network companies. The power tariff may also include a threshold power, in which case the power charge would be paid only for a proportion exceeding the predefined threshold power. The steering effects of all alternatives are mainly similar, in other words, the tariff including power steers to control the peak power drawn from the network.

In principle, the power limit tariff is a viable option, yet there are some major challenges related to its implementation in practice. Determination of the power limit may be challenging for the customer, and furthermore, an unambiguous and clear practice has to be established for events of exceeding the power limit. Moreover, transition from the present pricing models to the power limit tariff may be difficult; during the transition period, there would be very different tariff structures available for the customers, or otherwise, the transition should be carried out “overnight”. The power limit tariff can also be considered to set a limit for the power, which may pose a challenge in the demand response markets. Even though it is possible to exceed the power limit, which generates an excess cost or shift to a higher power limit, the power limit restricts increasing the load, and therefore, does not allow full exploitation of cheap hours in the energy market and participation in down-regulation (increasing the load). Finally, there are fixed power bands (e.g. 3 or 5 kW) in the power limit tariff, and thus, the customer’s opportunities to reduce her/his distribution fee are limited.

The small-scale customer’s power tariff, in which pricing is based on peak power, basic charge, and energy charge, seems to be the most feasible alternative in terms of practical implementation, intelligibility, and cost-reflectiveness. A tariff structure of this kind is already currently in use at larger customers connected to the medium- and low-voltage network. Small-scale customers can be incorporated in the scheme by adding a power-based cost component to the present tariff structure and by gradually increasing the proportion of power charge, simultaneously reducing basic and energy charges. By a relatively long transition period (e.g. 5 years), large annual changes in the customers’ network fees can be avoided. The steering effects can be intensified by information steering, and the customers can be given information about the significance of power control and control methods already before actual transition to the power pricing. Even though the proportion of the energy charge is gradually reduced in the tariff, it is advisable to keep an energy-based cost component in the tariff also in the future. This guarantees that the end-user who uses high network capacity (i.e., power) more often, pays more than the end-user who uses the same capacity less often. Simultaneously, it is also possible to ensure cost-reflectiveness of pricing with respect to energy-based costs. A threshold power, for instance 3–5 kW, can be added to the power tariff structure; power use below this threshold does not cause a separate power charge or lead to a more complicated tariff structure. In that case, the tariff structure remains practically unchanged for very small customers, who have very limited or non-existent opportunities for power control. This enables collection of cost-reflective distribution fees also from very small customers, simultaneously reducing challenges related to communication about the tariff reform.

This report has presented the rationale and principles for the determination of power-based tariffs. It is emphasized that these are not recommendations or the only way to determine power-based tariffs, but only intended to assist DSOs when considering the principles for determining their tariffs. Further actions to promote the spread of the power-based tariff and the desired effects are discussed in the following section.

7.1 Further actions

The DSOs are presently free to choose their tariff structures, only the total turnover and returns are regulated by the authority. This freedom of choice has to be maintained also in the future. Nonetheless, considering the functioning of the markets, it is reasonable that **some of the practices related to the tariff structures are uniform**, as in the case of two-rate time-of-day tariffs at present. In that case, the retailers and flexibility service providers (technical flexibility operators) are better able to take into account the effects of network tariffs on the implementation and marketing of demand response products. In the case of power pricing, a possible target of harmonization would be the practice of determining the basis for the power used in billing. The most suitable stakeholder for establishing uniform practices could be some authority (e.g. the Smart Grid working group of the Ministry of Economic Affairs and Employment).

In order to ensure that the power pricing applied in the distribution tariff supports, rather than undermines, the demand response market, it is necessary to actively monitor and follow the effects of the tariff on the customers' powers and flexibility and the development of the demand response markets after the implementation of the tariffs.

To determine the general acceptability and steering effects of distribution tariffs, more **studies on customer experience** are required. In this context, it is essential to survey the customers' understanding and knowledge of new distribution tariffs, practical effects of the tariff structure on the customers, and requirements for customer communications. In addition, these surveys could include an analysis of the load control systems and products currently in the market as well as the customer's opportunities to affect her/his electricity consumption and peak power.

In this study, the peak power used as the basis for billing is the mean power of one hour; this is based on the features of the present metering infrastructure and the imbalance settlement period of the electricity markets. In the future, however, it is advisable to study what the **most appropriate period for the determination of power** would be, if the billing basis of the power charge were not the hourly mean power obtained from the energy of the imbalance settlement period. This question is essentially related to the **determination of the characteristics of the next-generation AMR equipment**.

To strengthen the steering effects of the power component in the tariff, the **customers have to be actively informed** of the benefits and opportunities of the load control. This information can be distributed for instance in conjunction with invoicing and in online services where the customers' consumption data are displayed. Here, cooperation with the information system suppliers is required in order to develop the online services to support power management and load control.

To incentivize the customers to demand response, it is essential that all the components in the electricity bill; the distribution tariff, pricing of electricity sales, and electricity tax, support this objective. To this end, the electricity tax should be reformed to be more dynamic. At present, the DSOs collect the electricity tax from the customers in connection with billing of electricity distribution; the tax is fixed (for households 2.79372 cent/kWh) and it depends on the energy consumption. **Converting the electricity tax into a more dynamic one, for instance a tax depending on the wholesale price of electricity, would support flexibility.** Thus, it would also be **more practical if the tax was levied by the retailer, and not by the DSO**, even more so as the tax is an excise tax related to the production of electrical energy.

The Government proposal for changes in the Electricity Market Act states that the maximum amount of pay increases is calculated as an average of the pay increases of the customer groups, not based on changes in an individual customer's pricing. Further, the customer groups have to be defined so that they describe the DSO's distribution network use and the end-user characteristics in an equitable and non-discriminatory manner. The present customer groups are often based on the load survey of the Association of Finnish Electric Utilities (SLY) from 1992, and therefore, **the above-described customer groups have to be defined** in the future. Here, it is possible to use the available AMR data.

References

Aho, L. 2012. ”Pori Energia Sähköverkot Oy:n tariffirakenteen määrittäminen ja hinnoittelumallin kehittäminen.” [Determination of the tariff structure and pricing model development in Pori Energy Electricity Corporation]. Master’s thesis Tampere 2012. Tampere University of Technology. 77 p. In Finnish.

Apponen, R. 2016. ”Pienasiakkaan tehotariffin kehitys ja käyttöönotto.” [Development of power-based tariff structure for small customers and pathway for this change]. Master’s thesis. Aalto University 2016. In Finnish.

Apponen, R., Heine, P., Lehtinen, J., Lehtonen, M., Lummi, K., and Järventausta, P. 2017. ”Development of Power-based Tariff Structure for Small Customers and Pathway for this Change.” In *24th International Conference & Exhibition on Electricity Distribution (CIRED 2017)*. Glasgow, Scotland. 12–15 June 2017.

The Brattle Group 2016. *The Tariff Transition – Considerations for Domestic Distribution Tariff Redesign in Great Britain.* Final report.

Energy Authority 2015a. Annual Report 2014. http://www.e-julkaisu.fi/energiavirasto/vuosikertomus_2014/ [Accessed 9 May 2017].

Energy Authority 2015b. ”Valvontamenetelmät neljännellä 1.1.2016–31.12.2019 ja viidennellä 1.1.2020–31.12.2023 valvontajaksolla – Sähkön jakeluverkkotoiminta.” [Regulation methods for the fourth regulatory period 1 January–31 December 2019 and the fifth regulatory period 1 January–31 December 2023 – Electricity distribution business].

http://www.energiavirasto.fi/valvontamenetelmat-2016-20231 In Finnish.

Energy Market Authority 2013. Sähkön siirtohintatariffien kehitys 2000–2013. [Development of electricity distribution tariffs 2000–2013]. Report 12 September 2013. In Finnish.

Energy Networks Association 2014. ”Towards a national approach to electricity network tariff reform.” ENA Position paper.

http://www.energynetworks.com.au/sites/default/files/position-paper_towards-a-national-approach-to-electricity-network-tariff-reform_december-2014_1.pdf

Fingrid 2017. ”Kantaverkkomaksut.” [National grid service fees].

http://www.fingrid.fi/fi/asiakkaat/Kantaverkkopalvelut/hinnat/Sivut/default.aspx [Accessed 20 June 2017]. In Finnish.

Eurelectric 2013. ”Network tariff structure for a smart energy system.” A Eurelectric paper.

http://www.eurelectric.org/media/80239/20130409_network-tariffs-paper_final_to_publish-2013-030-0409-01-e.pdf

Eurelectric 2016. ”Network Tariffs.” A Eurelectric position paper.

http://www.eurelectric.org/media/268408/network_tariffs__position_paper_final_as-2016-030-0149-01-e.pdf

Directive 2014/25/EU of the *European Parliament and of the Council*, ”Directive on energy efficiency.”

GEODE 2013. “GEODE Position Paper on the Development of the DSO’s Tariff Structure.” September 2013.

http://www.geode-eu.org/uploads/GEODE%20Position%20Paper%20Tariff%20Structure.pdf

Haakana J., Haapaniemi J., Tikka V., Lassila J., and Partanen J. 2017. “Risk or benefit on the electricity grid: distributed energy storages in system services.” In *24th International Conference and Exhibition on Electricity Distribution, CIRED*. Glasgow, Scotland. 12–15 June 2017.

Haapaniemi, J. 2014. ”Siirtohinnoittelun kehittäminen etäluettavilta mittareilta saatavan datan avulla sähkönjakeluyhtiö Mäntsälän Sähkö Oy:lle.” [Development of electricity transmission pricing with automatic meter reading data in electricity distribution company, Mäntsälän Sähkö Ltd]. Master’s thesis. Lappeenranta University of Technology. 142 p. In Finnish.

Haapaniemi, J., Haakana, J., Lassila, J., Honkapuro, S., and Partanen, J. 2017. ”Impacts of different power-based distribution tariffs for customers.” In *24th International Conference & Exhibition on Electricity Distribution (CIRED 2017)*. Glasgow, Scotland. 12–15 June 2017.

Haapaniemi J., Narayanan A., Tikka V., Haakana J., Honkapuro S., Lassila J., Kaipia T., and Partanen J. 2017. “Effects of major tariff changes by distribution system operators on profitability of photovoltaic systems.” In *14th International Conference on the European Energy Market, EEM (2017)*. Dresden, Germany. 6–9 June 2017.

HE 50/2017 vp Hallituksen esitys eduskunnalle maakaasumarkkinalaiksi ja eräiksi siihen liittyviksi laeiksi. [Government proposal (HE 50/2017 vp) for the new Natural Gas Market Act and some of the related acts.] In Finnish.

Helen Electricity Network Ltd. 2017. ”Products (from 1 July 2017 onwards).” https://www.helensahkoverkko.fi/palvelut/tuotteet/ [Accessed 20 June 2017].

Honkapuro, S., Haapaniemi, J., Haakana, J., Lassila, J., Belonogova, N., Partanen, J., Lummi, K., Rautiainen, A., Supponen, A., Repo, S., and Järventausta, P. 2017. ”Development options for distribution tariff structures in Finland.” In *14th International Conference on European Energy Market (EEM 2017)*. Dresden, Germany. 6–9 June 2017.

Finnish Meteorological Institute 2017. ”Open data of the Finnish Meteorological Institute.” https://ilmatieteenlaitos.fi/avoin-data [Accessed 6 February 2017]

Järventausta, P., Repo, S., Trygg, P., Rautiainen, A., Mutanen, A., Lummi, K., Supponen, A., Heljo, J., Sorri, J., Harsia, P., Honkiniemi, M., Kallioharju, K., Piikkilä, V., Luoma, J., Partanen, J., Honkapuro, S., Valtonen, P., Tuunanen, J., and Belonogova, N. 2015. ”Kysynnän jousto – Suomeen soveltuvat käytännön ratkaisut ja vaikutukset verkkoyhtiöille (DR pool).” [Demand response – Practical solutions applicable in Finland and their effects on distribution system operators]. Final report. In Finnish.

Kasari, T. 2003. ”Jakeluverkon kustannusten jako siirtohinnoille.” [Sharing the distribution network costs to distribution prices]. Master’s thesis. Tampere 2003. Tampere University of Technology. 96 p. In Finnish.

Koskela J. 2016. ”Sähköenergian varastoinnin hyödyntämismahdollisuudet kotitalouksien energian käytön hallinnassa Suomessa.” [Utilization possibilities of electrical energy storages in households’ energy management in Finland]. Master’s thesis. Tampere University of Technology, June 2016.

Koskela J., Rautiainen A., and Järventausta P. 2016. ”Utilization Possibilities of Electrical Energy Storages in Households’ Energy Management in Finland.” *International Review of Electrical Engineering (IREE)*, vol. 11 no. 6, pp. 607–617.

Lahti Energia 2016. *LahtiWatti asiakaslehti 2/16*. [LahtiWatti Customer bulletin 2/16].

Lummi, K. 2013. ”Sähkön siirtohinnoittelu ja kuormitusmallien käyttö tariffisuunnittelussa.” [Electricity distribution pricing and use of load models in tariff design]. Master’s thesis. Tampere University of Technology. 75 p. In Finnish.

Lummi, K., Rautiainen, A., and Järventausta, P. 2017. ”Analysis of Transition Steps Towards Power-based Distribution Tariff of Small Customers.” In *24th International Conference & Exhibition on Electricity Distribution (CIRED 2017)*. Glasgow, Scotland. 12–15 June 2017.

Lummi, K., Rautiainen, A., Järventausta, P., Heine, P., Lehtinen, J., Apponen, R., and Hyvärinen, M. 2016. ”Variations of Power Charge Basis of Power-based Distribution Tariff of Small

Customers.” In *The IEEE PES Innovative Smart Grid Technologies 2016 Asian Conference (ISGT Asia 2016)*. Melbourne, Australia. 28 November–1 December 2016.

Lummi, K., Rautiainen, A., Järventausta, P., Heine, P., Lehtinen, J., and Hyvärinen, M. 2016. ”Cost-causation based approach in forming power-based distribution network tariff for small customers.” In *13th International Conference on the European Energy Market (EEM 2016)*. Porto, Portugal. 6–9 June 2016.

Lummi, K., Rautiainen, A., Järventausta, P., Heine, P., Lehtinen, J., and Hyvärinen, M. 2016. ”Electricity Distribution Network Tariffs – Present Practices, Future Challenges and Development Possibilities.” In *The CIRED Workshop 2016*. Helsinki, Finland. 14–15 June 2016.

Lummi, K., Rautiainen, A., Järventausta, P., Huhta, K., Talus, K., and Kojo, M. 2017. ”Aspects of Advancement of Distribution Tariffs for Small Consumers in Finland.” In *14th International Conference on European Energy Market (EEM 2017)*. Dresden, Germany. 6–9 June 2017.

Lummi, K., Trygg, P., Rautiainen, A., and Järventausta, P. 2015. ”Implementation possibilities of power-based distribution tariff by using smarty metering technology.” In *23rd International Conference on Electricity Distribution (CIRED 2015)*. Lyon, France. 15–18 June 2015.

Niemelä, E. 2010. ”Kaupunkialueella toimivan sähkönjakeluverkkoyhtiön siirtohinnoittelun kehittäminen.” [Development of the Transmission Pricing in Urban Electricity Distribution Company]. Master’s thesis. Lappeenranta University of Technology. 100 p. In Finnish.

Pantti, J. 2010. ”Sähkön siirtotuotteiden hinnoittelusovelluksen kehittäminen.” [Development of distribution network’s transmission pricing software.] Master’s thesis. Tampere University of Technology. 92 p. In Finnish.

Partanen, J., Honkapuro, S., and Tuunanen, J. 2012. *Tariff scheme options for distribution system operators*. LUT Energy research report 21.

Perälä, S. 2011. ”New network tariffs: Economical effects and possibilities for demand response.” Master’s thesis. Tampere University of Technology. 83 p.

Rautiainen, A. 2015. *Aspects of Electric Vehicles and Demand Response in Electricity Grids*. Doctoral Dissertation. Publication 1327, Tampere University of Technology.

Rautiainen, A., Lummi, K., Supponen, A., Koskela, J., Repo, S., Järventausta, P., Honkapuro, S., Partanen, J., Haapaniemi, J., Lassila, J., Haakana, J., and Belonogova, N. 2017. ”Reforming Distribution Tariffs of Small Customers – Targets, Challenges and Impacts of Implementing

Novel Tariff Structures.” In the *24th International Conference & Exhibition on Electricity Distribution (CIRED 2017)*. Glasgow, Scotland. 12–15 June 2017.

Roivainen, P. 2003. ”Imatran Seudun Sähkö Oy:n sähkön siirto- ja myyntituotteiden kehittämissuunnitelma.” [Development plan for tariffs of Imatran Sähkö Oy]. Master’s thesis. Lappeenranta University of Technology. 82 p. In Finnish.

Saraiva, J. T., Fidalgo, J. N., Pinto, R. B., Soares, R., Santos Afonso, J., and Pires, G. 2016. “Implementation of Dynamic Tariffs in the Portuguese Electricity System – Preliminary Results of a Cost-Benefit Analysis. In *13th International Conference on the European Energy Market (EEM 2016)*.

Schreiber, M., Wainstein, M. E., Hochloff, P. and Dargaville, R. 2015. “Flexible electricity tariffs: Power and energy price signals designed for a smarter grid.” *Energy Policy*, 93, pp. 2568–2581.

Similä, L. Koreneff, G., and Kekkonen, V. 2011. *Network tariff structures in Smart Grid environment.* Research report. Helsinki: VTT Technical Research Centre of Finland Ltd.

Suikkanen, P. 2016. “Tehoon perustuvan pienjänniteasiakkaiden siirtotariffirakenteen kehittäminen Mäntsälän Sähkö Oy:lle.” [Development of small voltage customers’ power-based distribution pricing for distribution system operator Mäntsälän Sähkö Ltd]. Master’s thesis. Lappeenranta University of Technology. 122 p. In Finnish.

Supponen, A., Rautiainen, A., Lummi, K., Järventausta, P., and Repo, S. 2016. ”Network Impacts of Distribution Tariff Schemes With Active Customers.” In *13th International Conference on the European Energy Market (EEM 2016)*. Porto, Portugal. 6–9 June 2016.

Electricity Market Act (588/2013).

Valtioneuvoston asetus sähköntoimitusten selvityksestä ja mittauksesta (66/2009). [Government Decree on determination of electricity supply and metering]. In Finnish.

Vuohelainen, V. 2017. ”Kaupunkiverkkoyhtiön sähkönsiirtotuotteiden uudistaminen.” [Distribution tariff design in the urban distribution network company.] Master’s thesis. Tampere University of Technology. 82 p. In Finnish.