Jouni Haapaniemi

POWER-BASED ELECTRICITY DISTRIBUTION TARIFFS PROVIDING AN INCENTIVE TO ENHANCE THE CAPACITY EFFECTIVENESS OF ELECTRICITY DISTRIBUTION GRIDS

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Abstract

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Energy transition is reshaping the electricity sector at a fast pace. As a consequence, electricity distribution systems are facing profound changes because also customer loads are undergoing a significant development. In particular, electrification of transportation, microgeneration, energy storage options, and smart control of loads are altering the electricity end users' load curve. These changes will most probably increase the peak demand in distribution systems and reduce the total transferred energy.

The major changes impact the distribution system operators (DSOs) in many ways. Electricity distribution systems are dimensioned for peak demand, and thus, increments in peak loads can cause a need for reinforcing the grid capacity. Hence, there is a risk of increasing the costs of electricity distribution systems. Electricity distribution tariffs are yet typically based on the total electricity consumption of the customers, and therefore, the distribution system operator's tariffs do not reflect the cost structure. The energy-consumption-based pricing has traditionally been dictated by limitations of the metering technology. The rollout of smart meters, however, has made it possible to develop the tariffs in a more cost-reflective way. In the development of the tariff structure, it is of high importance to understand how the tariffs will incentivize customers to adjust their load patterns and, in particular, how the tariffs will influence the incentives associated with new loads.

In this doctoral dissertation, a methodology is developed to estimate the short- and long-term effects of the tariff development on incentives for customers and the load control driven by power-based tariffs, as well as the impacts of new tariffs on the distribution grid load rates.

The results of this doctoral dissertation show that power-based tariffs provide incentives that can lead to improved capacity efficiency and a lower need for grid reinforcement investments if the customers react to the new tariff. However, there is uncertainty of how the customers will react to the price signal, and thus, whether the potential of the power-based tariff (PBT)-based load control can be taken into account in the dimensioning of the distribution grid. On the other hand, if the customers do not react to the tariff and the risks of overloading the network increase, the costs will be gathered more cost-reflectively from the customers who have a high peak demand.

Keywords: distribution tariffs, distribution networks, new customer loads, flexibility and future electricity demand

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Jouni Haapaniemi
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Lappeenranta, Finland

Contents

Nomenclature

Abbreviations

AMKA	bundle assembled aerial cable
AMR	automatic meter reading
BESS	battery energy storage system
CAPEX	capital expenditure
CO_2	carbon dioxide
COP	coefficient of performance
DER	distributed energy resource
DG	distributed generation
DSO	distribution system operator
EU	European Union
EV	electric vehicle
GHG	greenhouse gas
GSHP	ground source heat pump
IoT	Internet of Things
kWp	kilowatt peak
LV	low-voltage
MV	medium-voltage
OPEX	operating expense
PBT	power-based tariff
PHEV	plug-in hybrid electric vehicle
PV	photovoltaics
SOC	state of charge
TOU	time of use
TSO	transmission system operator
UG	uderground
VAT	value added tax
WACC	weighted average cost of capital

Latin alphabet

C	cost
d	day
E	energy
k	outdoor temperature dependence factor
k_1	customer-group-spesific factor
k_2	customer-group-spesific factor
n	number of customers
P	power
p	price

T	temperature
t	time, hour
W	annual consumption
z	Z-score corresponding to excess probability

Superscripts

ˆ	peak

Subscripts

0	no load
cap	capacity
Cust	customer
Distribution	distribution tariff
e	energy
EV	electric vehicle
fixed	fixed fee
i	customer
Inv	investment costs
k	on load
max	maximum
Opex	operating expense
Orig	original
ps	peak shaving
Retailer	retailer tariff
shave	peak shaving
SOC	state of charge
Target	target power level
Tax	electricity tax

1 Introduction

Electricity systems and electricity distribution systems in particular are facing significant changes now and in the near future. At the same time as expectations of the security of supply in distribution systems are rising, customers' electricity demand is evolving faster than ever. Novel loads like distributed microgeneration, electric vehicles (EVs), battery energy storage systems (BESSs), automation, Internet of Things (IoT), and changes in heating or cooling systems are altering customers' electricity demand profiles to a great degree. These changes are increasing the peak demand, yet at the same time, slightly decreasing the total electric energy transferred to the customers (Lassila et al., 2019b). Because the costs of the electricity distribution grid depend on peak demand, which has a significant effect on the dimensioning of the network components, it is necessary to consider ways to avoid an unnecessary increase in peak loads. On the other hand, distribution system operators' (DSOs) income from distribution bills is strongly dependent on consumed energy. As a result, the DSO pricing does not adequately reflect the costs that the customers cause, and the customers do not have incentives to pay attention to their peak load if it does not exceed their main fuse limit, which easily leads to the inefficient use of grid capacity. Increasing costs in the distribution infrastructure result in higher distribution bills, and thus, it is important to study whether customers' choices could be incentivized so that the grid costs would not increase unnecessarily. The energy-based tariff structure was logical in the past, because customers' loads were recorded only based on total electricity consumption and read on the spot typically once a year. The rollout of automatic meter reading (AMR) based on hourly recording of loads was carried out for all customers in Finland in the early 2010s. Now when there are load data available from multiple years it is possible to comprehensively analyze the tariff development. In this doctoral dissertation, the objective is to develop a methodology needed to analyze the development of electricity distribution tariffs from energy-based tariffs toward peak-power-based tariffs.

1.1 Objective and research questions of the work

The objective of this doctoral dissertation is to answer the following questions:

- Which kind of methodology and analyses are needed to estimate the effects of the introduction of a PBT?
- What are the main factors affecting the DSO's tariff structure development and what are their mutual effects?
- How will the introduction of the PBT affect the customers' distribution bills with the present loads?
- Which kinds of incentives will the PBT introduction provide for the customers?
- How will the customers' peak powers develop if the customers take into account the incentive from the PBT?

- How will the distribution grid load rates develop if the customers react to the PBT?
- How will the PBT introduction affect the distribution bills when customers have new distributed energy resources (DER)?
- Which development trends have to be considered in the tariff development?
- How will the PBT affect the customers' incentives to invest in DER elements, including for example
  - EV charging
  - Battery energy storage systems and automation
  - PV production
  - Heating systems
  - Grid defections with PV and BESS?

1.2 Outline of the work

Chapter 2 describes the development of the operating environments of distribution systems as a response to societal and customers' needs and presents the recognized challenges. The main targets, limitations, and alternatives for a DSO's tariff development are presented.

Chapter 3 focuses on changes in customers' loads. The chapter describes the megadrivers affecting the development of customer loads and the main features of the new loads.

Chapter 4 presents the methodology to estimate wide-scale effects of the distribution tariff development. The chapter also discusses the DSO's cost allocation.

Chapter 5 focuses on the effects of the PBT on customers' new loads and the load control potential. The chapter presents methods to estimate the effects of the PBT on new loads.

Chapter 6 demonstrates the effects of the PBT-based load control in a case area study. In the chapter, EVs, photovoltaic (PV) systems, ground source heat pumps (GSHPs), and peak shaving BESSs are simulated for customers in three scenarios where the DSO's tariffs and customer reactions are varied.

Chapter 7 discusses the results and the phenomena affecting the tariff development.

Chapter 8 concludes the results of this doctoral dissertation.

1.3 Research hypothesis

The research hypothesis was that introduction of a peak-power-based fee also to the residential and other small customers would provide customers an incentive that would lead to the more effective use of distribution network capacity and prevent overloading caused by new customer loads. When customers consider the PBT in their decisions, the increasing trend in distribution grid peak powers is restrained, which should lead to lower risks in the grid capacity dimensioning in the long term. Hence, the DSO's costs should develop in a more favorable way and lead to lower distribution bills on average for the customers.

1.4 Scientific contribution

The main scientific contribution of this doctoral dissertation is in developing the methodology needed to comprehensively estimate the short- and long-term effects of the distribution tariff development. The tariff development can have an impact on how the loads develop in the future, and thus, it is important to understand the related phenomena and their connections. There are previous studies focusing on effects of PBTs, but a comprehensive methodology to analyze the short- and long-term effects has been lacking. In this doctoral dissertation, the analyses and methods required for the DSO to analyze the effects of the tariff structure development are described. With the developed methodology, a DSO can estimate the effects of the tariff structure development on the customer payments, the customers' load optimization incentives, and the development of the distribution grid loads. The main focus is on developing a methodology that a DSO can use to estimate the incentives that the PBT provides for the customers, and how reactions to these incentives would affect the distribution grid loads. The dissertation also describes the principles of tariff formation, cost allocation, and the long-term development of the distribution grids; however, these aspects are not in the focus of this doctoral dissertation.

The analyses are performed with customers' hourly AMR load data and case area network data. New customer loads and PBT-based load control actions are modeled to the customers' load data, and then, the development of the distribution grid load rates and the customers' distribution bills are analyzed. The proposed methodology enables a DSO to analyze how distribution grid loads would develop if a PBT was introduced; however, it is outside the scope of this doctoral dissertation to study whether the DSO can take the PBT-based flexibility into account in the distribution grid dimensioning.

The author has also contributed to the following related publications as the first author:

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

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

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tions? In *Proceedings of the 15th International Conference on the European Energy Market (EEM)*. 27–29 June 2018. Lodz, Poland.

4. Haapaniemi, J., Haakana, J., Räisänen, O., Lassila, J., and Partanen, J., DSO tariff driven customer grid defections - Techno-economical risks for DSO? In *Proceedings of the 25th International Conference on Electricity Distribution (CIRED)*. 3–6 June 2019. Madrid, Spain.

5. Haapaniemi, J., Haakana, J., Räisänen, O., Lassila, J., and Partanen, J., Power-Based Distribution Tariffs for Residential Customers - a Risk for Overloading of Network in Areas With High Penetration of Time-of-Use Dso Tariffs?. In *Proceedings of the 25th International Conference on Electricity Distribution (CIRED)*. 3–6 June 2019. Madrid, Spain.

6. Haapaniemi, J, Räisänen, O., Haakana, J., Lassila, J., and Partanen, J., Estimating the effect of post-outage consumption peaks on customers' peak power-based tariff costs. In *Proceedings of the 26th International Conference and Exhibition on Electricity Distribution (CIRED)*. 20–23 September 2021. Online conference.

7. Haapaniemi, J., Räisänen, O., Haakana, J., Vilppo, J., and Lassila, J., *Joustava ja toimintavarma sähkönjakeluverkko – Pienasiakkaiden tehoperusteinen sähkönsiirron hinnoittelu haja-asutusalueilla toimivissa jakeluverkkoyhtiöissä (Flexible and reliable electricity distribution network – Power-based tariffs for small customers on DSOs operating in rural areas)*. LUT Scientific and Expertise Publications, No. 129. ISBN: 978-952-335-706-8. 2021. Only in Finnish.

The author has also been a coauthor in the following publications on closely related topics:

8. Honkapuro, S., Haapaniemi, J., Haakana, J., Lassila, J., Partanen, J., Lummi, K., Rautiainen, A., Supponen, A., Koskela, J., and Järventausta, P., *Development options and impacts of distribution tariff structures*. LUT Scientific and Expertise Publications, No. 65, ISBN: 978-952-335-105-9. 2017.

9. 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., Reforming distribution tariffs of small customers – targets, challenges and impacts of implementing novel tariff structures. In *Proceedings of the 24th International Conference and Exhibition on Electricity Distribution (CIRED)*. 12–15 June 2017. Glasgow, Scotland.

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

11. Haakana, J., Haapaniemi, J., Tikka, V., Lassila, J., and Partanen, J., Risk or benefit on the electricity grid: distributed energy storages in system services. In *Proceed-*

ings of the 24th International Conference and Exhibition on Electricity Distribution (CIRED). 12–15 June 2017. Glasgow, Scotland.

12. Haakana, J., Haapaniemi, J., Lassila, J., Partanen, J., Niska, H., and Rautiainen, A., Effects of Electric Vehicles and Heat Pumps on Long-Term Electricity Consumption Scenarios for Rural Areas in the Nordic Environment. In *Proceedings of the 15th International Conference on the European Energy Market (EEM)*. 27–29 June 2018. Lodz, Poland.

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14. Lassila, J., Haakana, J., Haapaniemi, J., Räisänen O., and Partanen, J., *Sähköasiakas ja sähköverkko 2030 (Electricity customer and electricity distribution network 2030)*. LUT Scientific and Expertise Publications, No. 94. ISBN:978-952-335-357-2. 2019. Only in Finnish.

15. Haakana, J., Haapaniemi, J., Lassila, J., Partanen, J., Härmä, R., and Ryhänen, M., Electricity demand profile for residential customer 2030. In *Proceedings of the 25th International Conference on Electricity Distribution (CIRED)*. 3–6 June 2019. Madrid, Spain.

16. Lassila, J., Haakana, J., Haapaniemi, J., Partanen, J., Gylén, A., and Pajunen, A., Effects of the future trends in distribution networks. In *Proceedings of the 25th International Conference on Electricity Distribution (CIRED)*. 3–6 June 2019. Madrid, Spain.

2 Business environment of the electricity sector

Global challenges concerning the mitigation of climate change, the reduction of pollution, and the conservation of biodiversity drive humankind to change the course of action. The energy sector plays a significant role in the process as the electricity and heat production sector covers approximately 30% of the total global greenhouse gas (GHG) emissions. To fight the climate change, most of the countries in the world have signed the Paris Agreement, the main aim of which is to limit the global temperature rise to well below 2 °C above preindustrial levels (United Nations Framework Convention on Climate Change, 2015). The goal is mainly pursued by reducing GHG emissions. To meet the requirements of CO_2 emission reductions, at least partial electrification of other sectors is also inevitable. In addition, technological development enables new solutions for cleaner energy production. Another significantly changing sector is transportation, where electrification has started to take over lately. The transition from a fossil fuel burning system toward a sustainable energy system is necessary to maintain the viability of Earth. This will require efforts at all levels of the energy system. Furthermore, it is very important to ensure that the transition is handled in a controlled manner so that the choices made do not lead to local optima at different levels of the system. This dissertation focuses on studying the development of the electricity system at the distribution level. To comprehend which kinds of changes are happening in the DSOs' operating environment, we have to understand the megatrends that are affecting the societal decision-making and thus, the choices that individuals make.

2.1 Social relevance of electricity distribution

The role of electricity as an enabler has grown over the past century, and this trend seems to continue in the future. From the societal perspective, the supply of electricity enables new technologies and solutions to become part of people's everyday life. Without electricity even the basic functions of modern society are out of use. For instance, our communication and transportation rely, to an increasing extent, on the availability of electricity. Thus, it is more and more reasonable for societies to be concerned about the security of supply, and thus, the electricity grid plays a very important role in modern society.

In the past, the electricity system was unidirectional from centralized large-scale power production units to end users, such as households. Electricity was transmitted from production plants to the electricity transmission system, then to local distribution grids, and finally to the customers. The nature of customers has started to evolve because of microgeneration, such as solar PV systems. Thus, electricity distribution systems need to transfer electric energy also from prosumers (customers who are both consumers and producers of electricity) to other customers. Hence, connection to the electricity system works as a channel for a customer to act in the electricity market.

From a societal perspective, the most important requirements for the electricity system are sufficient capacity, reliability, and cost-effectiveness. An electricity system should be built so that the present and future needs of customers can be fulfilled in a reliable manner with a reasonable cost level. Environmental aspects also have a huge impact on the electricity sector, because electricity is in many cases a viable alternative when considering replacement of old unsustainable or polluting technologies.

Curbing climate change has become a significant driver in the energy sector, and it has had several effects on the development of electricity production and consumption. The targets to reduce CO_2 emissions have an impact on how legislation, subsidies, and taxation of different solutions will develop. The aim of these signals of societal guidance is to affect customer decisions so that broader objectives are achieved.

2.2 Electricity end users' viewpoint

For the electricity end users, electricity supply makes life easier and opens many opportunities. The basic need for electricity covers many parts of people's everyday life, from necessities like home heating, cooling, and lighting to conveniences. One important expectation of people is that they can adopt novel technologies to improve their standard of living. When the customers' dependence of electricity is high, also the expectations of the security of supply are higher. On the other hand, electricity should not cost too much.

2.2.1 Electricity costs of a customer

The electricity bill of a customer consists of three main parts: the electricity retailer bill, the electricity tax, and the electricity distribution bill. The electricity retailer tariff reflects the electricity production cost and the commission of the retailer. The distribution bill includes the costs of the electricity distribution system and also typically the costs of the transmission system, in other words, in total, the costs of the channel from production to customers. If the distribution business is decoupled from the electricity production and markets, the customers can choose their electricity retailer, but the electricity distribution bill comes from the local DSO that provides the local grid.

Retailer tariffs are typically mostly dependent on the consumption of electric energy with only some minor fixed fee included. The electricity production cost varies over time because of different conditions in production and different load demand at the system level. Small customers' retail tariffs can be single rate tariffs, Time-of-Use (TOU) tariffs, or market-price-based tariffs. Thus, retailer tariffs reflect system-level aspects of the electricity system, but do not comprehensively take into account local conditions near the customer.

DSO tariffs typically include a fixed monthly fee, which can be dependent on the connection size of the customer, and an energy-consumption-based fee, which is typically single rate or TOU based. This dissertation focuses on studying how the development of these DSO tariffs would affect the incentives of a customer, and thus, the development of the grid loads.

The electricity tax and possible subsidies are dependent on societal decision-making. The electricity tax in Finland is approximately 2.79 cent/kWh for small customers like households. For a household with 5000 kWh of annual consumption, the electricity bill consists, on average, of approximately one-third of sales, one-third of distribution and transmission costs, and one-third of taxes. The proportions of the electricity bill components are presented in Figure 2.1.

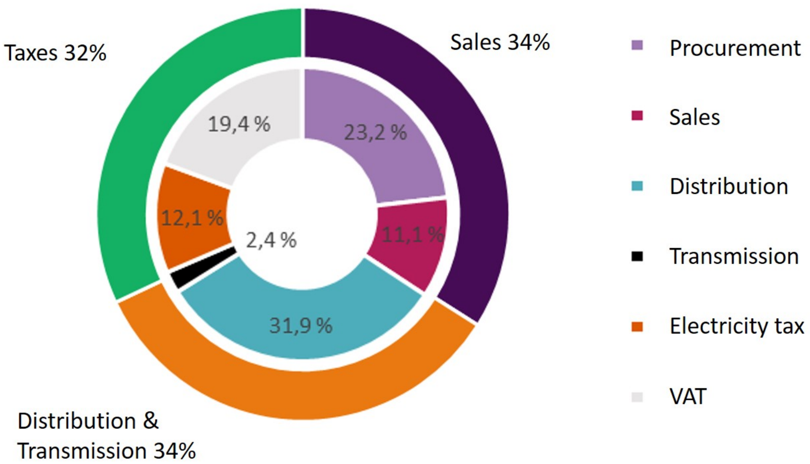

Figure 2.1: Average proportions of the electricity bill components for a Finnish 5000 kWh customer. Adapted from (Finnish Energy, 2021).

In practice, a customer's total electricity price and the proportions of the electricity bill components are dependent on the customer's location, retailer choice, tariff choice, and consumption patterns. The customer's location has an effect on the bill because a local DSO can have significantly different tariffs in different areas. In the case of a DSO that operates in rural areas, the distribution prices are higher and the proportion of fixed fees can also be higher.

At the European level, the average price of electricity for household customers with an annual consumption from 5 to 15 MWh varies between 5.7 and 28.3 cent/kWh (Eurostat, 2021). The electricity price for household end users is highest in Germany, whereas the lowest prices are found in Eastern European countries, such as Georgia and Kosovo. Finland is close to the average of the European Union, if taxes and levies are not considered. Figure 2.2 illustrates the average electricity prices in different European countries.

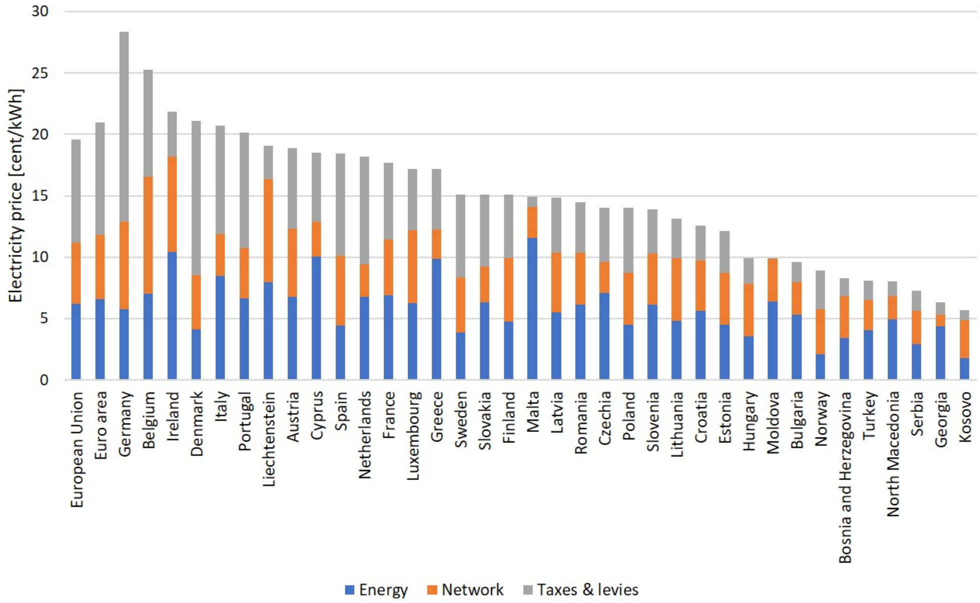

Figure 2.2: Household electricity price in European countries during the first half of 2020 (Eurostat, 2021)

It is clear that there are significant differences in the cost of electricity for households in the European countries. One major reason for this are differences in taxes and levies. Different electricity production portfolios also affect the energy cost. Cost differences in electricity networks are also visible. The main factors affecting electricity network costs are the operating environment, the number of customers, the volume of electricity consumption, and the general price level. If electricity consumption is low, the relative cost of network can seem high. If the customer density is high, less grid infrastructure is needed per customer, and thus, the costs per customer are probably lower. If the general price level in the country is high, wages are also typically higher, which leads to higher costs of grid planning, construction, and maintenance. In Finland, the electricity cost varies based on the customer's local DSO, which is illustrated in Figure 2.3.

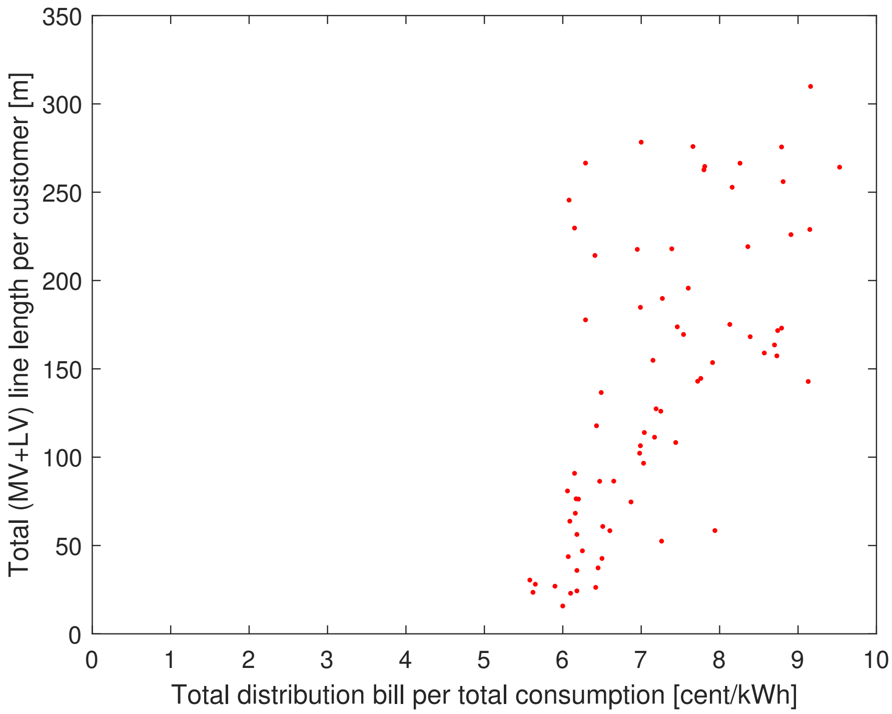

Figure 2.3: Line length of the distribution grid of a Finnish DSO per customer compared with the distribution bill per consumption. The distribution bill is for a detached house with electric heating and 18 MWh/a consumption (Energy Authority, 2020a,b)

As can be seen from Figure 2.3, the amount of grid infrastructure per customer affects the total distribution bill. These prices are only a sample to illustrate the present price levels; however, the prices can be affected by the DSO's pricing choices and regulative state; regulative surplus or deficit from previous years.

2.2.2 Decisions of customers

Customers' decisions are affected by many factors, of which financial profitability is only one. Customers' values affect for instance the customers' preferences for eco-friendly solutions. In reality, customers' appliance choices can also be highly affected by investment costs even though the life cycle costs of the appliances are higher. Finally, comfort of living is a significant driver in customers' decision-making.

Currently, customer loads are typically turned on or off manually, or temperature-dependent loads are controlled with a thermostat, and thus, the control of these resources would require effort from the customers and possibly cause discomfort. However, the technological development of IoT can have a significant effect on this.

2.3 Business environment, economic regulation, and legislation

Electricity distribution companies are operating as local natural monopolies, because it is not reasonable or cost-effective to build parallel competing electricity distribution networks in the same area. Because of the monopoly nature of the business that provides people an essential necessity such as electricity, society has to set limits on the business to guarantee that the market position cannot be abused. Furthermore, to ensure the reasonable development of distribution networks, the effectiveness of operation, and the fairness of cost to the customer, society has to set limits, guidelines, and targets for the electricity system development. This is carried out in practice by legislation, regulation, and standardization.

2.3.1 Legislation

There are different levels of legislative rules and regulations that limit and guide the business. In Europe, the European Union (EU) sets the general rules and guidelines that are applied in national legislation.

Regulation (EU) 2019/943, Section 2 *Network charges and congestion income*, states that connection charges, network charges, and network reinforcement-related payments should be cost-reflective, transparent, and nondiscriminatory (Council of European Energy Regulators, 2020):

"Distribution tariffs shall be cost-reflective taking into account the use of the distribution network by system users including active customers. Distribution tariffs may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles. Where Member States have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of (EU) 2019/944 and, where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer."

Thus, at the EU level, DSOs are encouraged to exploit the development opportunities of the tariff structures, enabled by smart metering, to improve the tariff design in a more cost-transparent and predictable way. Highlighting the role of active customers in the context of tariff development provides a good starting point for tariff structure development considering future load control incentives.

In Finland, most of the limitations on the electricity distribution business are stated in the Electricity Market Act (Finlex, 2013). The most important ones from the viewpoint of electricity distribution pricing are discussed next. The DSOs have to connect a customer to the distribution grid if the customer wants to buy a grid connection. The cost of connection depends on the location of the connection point and the capacity needed. The connection fee is a partly refundable payment, and it is paid only once when a new connection to the grid is built. Customers can receive a refund when the connection is deactivated. Connection fees are left outside of the scope of this dissertation even though they are part of the customers' total electricity costs paid to the DSO. The electricity distribution pricing has to be the same for all customers of the same kind independent of their location; a DSO cannot set prices locally for individual areas or customers. This limits the tariff structure development in a direction where bottlenecks would be handled with a higher local energy price during peak demand.

In Finland, DSOs are obliged to ensure the security of supply so that from 2028 onward customers will not experience interruptions longer than 6 h in urban areas and 36 h in rural areas (Finlex, 2013). Some rural area DSOs have received extension until year 2036. For many DSOs operating in rural areas, these security of supply requirements mean large investments to improve the security of supply. An exceptionally high amount of investments in the grid infrastructure while customers' loads are developing significantly increases the risks of considerable financial losses as a result of grid overloading. The importance of successful prediction of the future load demand increases when overhead lines are replaced with underground cables, as increasing the load capacity afterward is more expensive in the case of underground cabling.

For DSOs, a restriction has been imposed on the annual increase in pricing, which limits the maximum annual increments in the distribution bill that customers in a typical user group can experience. These user groups were updated in year 2019 to also include information of the customers' peak load demand (Mutanen, 2019). Until 2021, the limit for the annual increment of the distribution bill of a customer in a typical user group was 15%, but the limit was reduced to 8%. This kind of limit can affect the tariff structure development so that the required transition from the present tariffs to the target tariff will take a longer time.

2.3.2 Regulation

Regulation can be dissimilar in different countries when considering restrictions on the tariff development. In some countries the pricing parameters and unit prices can be strictly regulated, but in some European countries the DSOs can set their tariffs quite freely within the limits set by national regulators (European Union Agency for the Cooperation of Energy Regulators, 2021).

Because of the monopoly nature of the DSOs' business, regulation plays a significant role in ensuring reasonable pricing of electricity distribution. In Finland, pricing is regulated from the perspective of total distribution revenue. The allowed revenue is calculated from grid infrastructure depreciations, network losses, the transmission system operator's fees, operative costs, and reasonable return. The regulation system sets incentives for the DSO to reduce the Operating Expense (OPEX) and customer interruption costs. The regulatory model does not determine the tariff structure, and thus, it is possible for the DSOs to develop their pricing schemes. However, the Finnish regulator is about to introduce harmonized definitions of the pricing parameters for peak-power-based tariffs.

2.3.3 Standardization

Standardization sets limits on the electricity distribution business from the technical perspective. The purpose of standardization is to ensure that certain technical requirements, such as electrical safety and electricity quality, are met. Standardization sets limits for example on voltage quality, connection of devices to the distribution grid, customers' electrical safety requirements, and protection of the electricity distribution grid.

2.4 Technical and economic aspects of electricity distribution

As mentioned above, the electricity grid plays a significant role in modern society. It is important for the DSO to succeed in meeting the requirements of society within the limits set by legislation, regulation, standardization, and public opinion.

2.4.1 Targets

The basic target of a DSO is to build, maintain, and operate the grid connection from the customers to the electricity system, and importantly, to do it cost-effectively. Several limitations to the grid development come from electrical safety and the quality of supply. The DSO has to follow and predict the development of society and its customer base to understand which kinds of needs will arise now and in the future in order to be able to develop the grid in a reasonable way. To understand better how the electricity distribution tariffs are formulated, the operating environment, the cost structure of the DSO, and the electricity demand of the customers have to be examined.

2.4.2 Operating environment

The operating environment has a significant effect on the business of a DSO. In urban conditions, the distances are typically short, the customer density is high, the grid is more likely built with underground (UG) cables than with overhead lines, the population in the area is more likely to grow than decline, and there is other infrastructure, such as district heating and fiber-optic connections, available for the customers. Because of the short distances and the high customer density, the grid can be built so that the grid components supply a larger number of customers. For example a secondary substation can supply even dozens of customers in urban conditions, whereas in rural areas the customers can be scattered and a separate secondary substation transformer may be needed even for individual customers. Hence, less grid infrastructure per customer is needed in urban conditions, but the capacity of the components can be dimensioned for a larger number of customers.

Urban conditions also increase the costs of UG cabling, because excavation is more expensive. For example in Finland, the low-voltage (LV) and medium-voltage (MV) cable trench cost is 10 700 €/km in easy conditions, 24 200 €/km in normal conditions, 77 200 €/km in difficult conditions, and 151 200 €/km in extremely difficult conditions (Energy Authority, 2015). In Finnish rural areas, the excavation conditions are mainly in the easy category. In Finnish urban areas, the excavation conditions are typically normal, difficult, or extremely difficult in some city centers.

The operating environment of a Finnish DSO in rural conditions is typically characterized by long distances, a low customer density, possibly regressive overall development resulting from urbanization, a different customer base compared with urban areas, and a significant proportion of overhead lines. Long distances and the low customer density lead to the fact that in rural areas much more grid infrastructure is required per customer than in urban areas. Long distances in rural areas can also affect the future choices of DER and their effects, because for example the driving distances are longer and the need for a private car is more significant than in urban conditions.

The customer base in urban areas consists mainly of residential, commercial, institutional, and industrial customers. Residential customers include apartment houses, row houses, and detached houses. It is common that there are many customers behind one grid connection in urban areas. In rural areas there is typically only one customer per grid connection. Apartment buildings and office buildings are less common in rural areas, whereas agricultural customers and vacation homes are typical in these areas.

2.4.3 Cost structure

A DSO's business is in planning, building, maintaining, and operating the grid infrastructure. The life cycles of the electricity grid components range from 20 to 50 years and investments in the components are significant. Thus, the decisions made today will affect the costs long in the future. The total costs of the distribution business consist of investment costs, operative costs, transmission system operator (TSO) tariff payments, and network losses.

The investment costs are mainly dependent on the location of customers, the customer and load density, the load demand of the customers, the required level of the security of supply, the required supply quality, and the required dimensioning from the perspective of electrical safety. On the other hand, the choices that the DSO makes affect the maintenance costs, the customer interruption costs, and losses in the system, and thus, the investment decisions have to be made considering all life cycle costs. The operative costs include costs from the DSO's daily operation, such as grid planning, maintenance, and operation, which consist mainly of personnel and equipment costs as well as operative costs of the information and other systems. The nature of these costs is mainly fixed, meaning that the load patterns of a customer do not directly affect the costs. The TSO costs are dependent on the TSO's tariff structure, which is in Finland mainly dependent on the total transferred energy with TOU price variations. Part of the payments to the TSO are also dependent on the reactive power balance at the DSO level. The network losses are partly fixed and partly dependent on demand.

Higher peak demands can also affect the operative costs in the future. Traditionally, operating of the grid has been quite passive in normal conditions when there are no interruptions in supply or any maintenance work in progress. A changing load demand can also affect the requirements for operating a smart grid, and thus, the operative costs can be dependent on the development of customer loads. The grid maintenance can be preventive or corrective, but the costs of maintenance are more dependent on the grid technologies chosen and the aging of the network than the electricity demand itself. Thus, the nature of maintenance costs is mostly fixed.

One major issue that affects the costs is the customers' load demand and especially the demand when the grid load rates are high. The development of load demand, in particular, can significantly affect the costs of electricity distribution.

2.4.4 Electricity demand

Customer needs and thereby the electricity demand have evolved considerably over the past century, but changes happening now and in the near future are even more significant. In the past, the demand for electricity was based on customer needs at a certain time, but nowadays, opportunities to intelligently control various devices and to store energy in different forms are becoming more common.

In the past, the metering technology only allowed to record and read customers' total consumption on site typically once a year, which meant that an individual customer's consumption patterns were not known. Traditionally, peak power has been estimated from the customers' total energy consumption and the customer classification by using the Velander formula (Lakervi and Holmes, 1995). Grid loads have been estimated with an assumption that customer loads follow the normal distribution. With these assumptions, grid loads have been estimated with quite adequate precision. The rollout of smart meters allows DSOs to analyze the electricity demand more precisely.

In Finland, the AMR metering rollout was carried out mainly in 2012–2013, after which basically every customer's load has been recorded on an hourly basis and read on a daily basis. Nowadays, a DSO can analyze realized grid loads on an hourly basis at any point of the distribution grid. Knowledge of the customers' hourly consumption patterns also enables the development of the DSO's pricing scheme, whereas in the past the pricing had to be dependent on known parameters, connection size, and total consumption. Understanding of the consumption patterns more precisely plays an even more important role when demand response opportunities and incentives are estimated. Smart metering also makes it possible to communicate between a smart meter and the demand response controlling party. Furthermore, smart meter data enable more precise modeling of future loads (Tuunanen, 2015).

2.4.5 Distribution system planning and dimensioning

To understand how customer loads affect the costs of the DSO, grid dimensioning principles have to be studied. In network planning, it is necessary to understand the customer consumption patterns and peak loads to correctly dimension the grid infrastructure for the peak demand. In the past, the peak power of a customer was estimated with Velander's formula

$$P = k_1 * W + k_2 * \sqrt{W}, \tag{2.1}$$

where k_1 and k_2 are customer-group-based factors and W is a customer's annual consumption in MWh (Lakervi and Holmes, 1995). After this, load modeling has been developed by making load profiles for different typical user groups. In these load profiles, customer loads are typically described with relative weekly or two-week indices and different types of day (Sener, 1992; Seppälä, 1996). Customer load profiles are scaled to meet the customers' annual consumption, and outdoor temperature correction is applied to present different years. These probabilistic load profiles include average expected power and standard deviation values. Common for different load modeling practices is the assumption that the load behavior follows a probability distribution, typically normal distribution. Figure 2.4 demonstrates the 1% and 5% exceedance probabilities of normal distribution when the expected value is 0 and the standard deviation is 1.

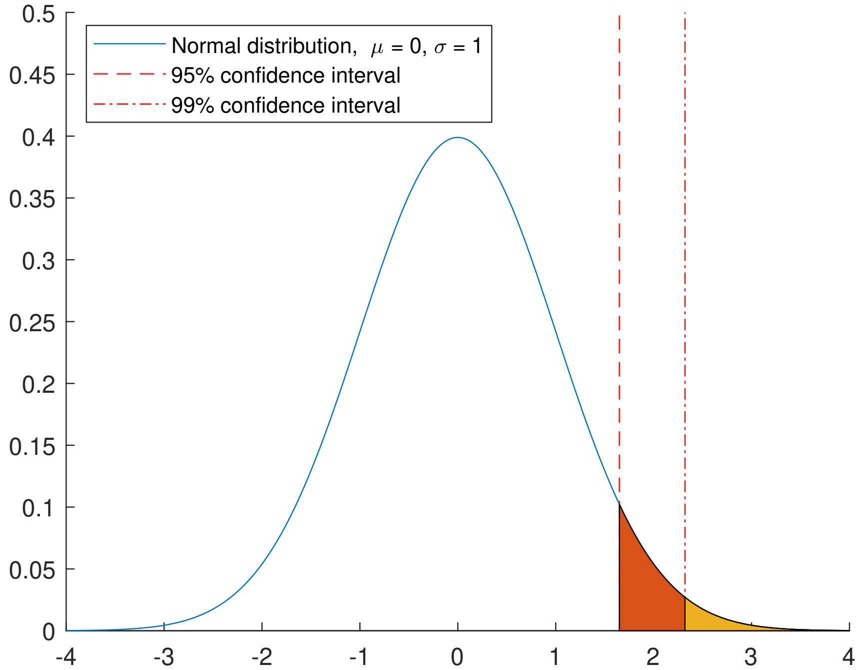

Figure 2.4: Normal distribution when the mean value is 0 and the standard deviation is 1.

With the 95% confidence interval for exceedance, power that is not exceeded with the 95% probability can be defined. In that case, the peak power is approximately 1.65 times the standard deviation away from the expected value, and correspondingly, with the 1% exceedance probability 2.32 times the standard deviation. For a group of multiple customers of the same kind, the total peak power can be estimated as (Lakervi and Partanen, 2008),

$$P_{max} = n * P + z_a * \sqrt{n} * \sigma, \tag{2.2}$$

where *n* is the number of customers, *P* is the average expected power of the customer group, z_a is the chosen exceedance probability, and σ is the standard deviation of the customer group's power. Figure 2.5 illustrates the estimated peak demand of a customer group with the exceedance probability of 1% and 5% compared with the expected power of the customer group by using Equation (2.2). It is assumed in the figure that the standard deviation is equal to half of the average expected power.

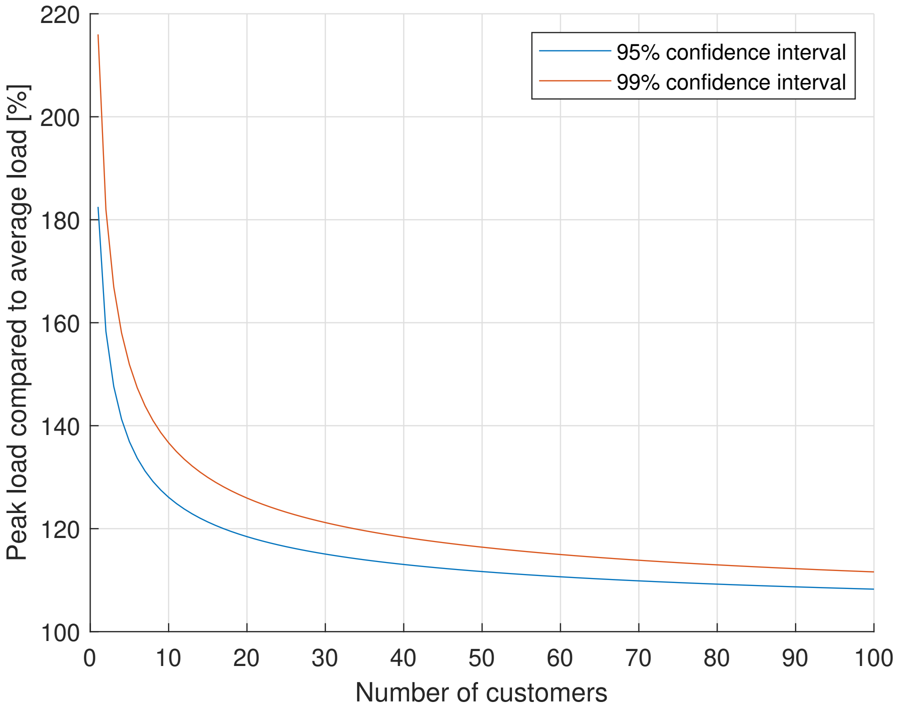

Figure 2.5: Effect of the standard deviation on the peak power of customer group with different numbers of customers.

The effect of standard deviation on peak power decreases rapidly when the number of customers increases. If the number of customers is low, the effect of standard deviation is significant, because single customer loads can have a lot of variance. For example, in the case of five customers, the peak load differs from the average expected load by 51.9% if a confidence interval of 99 % for exceedance is considered. Correspondingly, if a customer group of ten customers is considered, the peak load differs only by 36.7%

from the expected load and by 25.9 if there are 20 customers. For multiple customer groups, the total peak power can be estimated as (Lakervi and Holmes, 1995),

$$P_{max} = n_1 * P_1 + n_2 * P_2 + z_a * \sqrt{n_1\sigma_1^2 + n_2\sigma_2^2} \tag{2.3}$$

As can be seen from Equations (2.1), (2.2), and (2.3), the grid dimensioning has typically been founded on an assumption that the customers' loads have temporal variation. If loads are controlled with a common signal, for example an electricity market price signal, these assumptions can lead to problems.

To analyze the development of peak loads in distribution grids, Monte Carlo simulations can be conducted. In Monte Carlo simulations, customer load patterns are modeled taking into account the sporadic nature of appliance use by repeating the simulation for a suitable number of times.

From the perspective of the distribution grid, new load trends can cause many challenges. EVs can affect customers' load curves so that high consumption peaks caused by EV charging become more common than expected based on the assumption of normal distribution. On the other hand, load control options are increasing rapidly because of IoT, which can cause new risks for traditional grid dimensioning principles if customer loads do not have expected randomness, as illustrated in Figure 2.5. In the figure, this would mean that the curves will not decline as rapidly as expected when the number of customers increases. Hence, there is a risk that the deviation in customer loads increases, and at the same time, a risk that customer loads do not have natural time variation in the future. It has been noted in scientific publications that customer loads do not follow the Gaussian distribution precisely, but have skewness to the right (Rouvali, 2000), and resemble more log-normal or Gamma distribution than normal distribution (Mutanen, 2018).

Against this background, it is reasonable to study the possibilities of a DSO to affect the load patterns of the customers. However, the possibilities of a DSO are limited, and the main tool for the purpose is the distribution pricing. In particular, pricing that is based on the customers' peak loads is an interesting option. With a peak-power-based tariff (PBT), the DSO could incentivize customers to reduce their peak demand, or at least not to increase the peak demand if not necessary. A PBT does not directly mitigate the risk of time-harmonizing load demand, but provides an incentive for the customers to consider their own peak demand and to shift loads more evenly to different times of day.

Grid planning and dimensioning principles can differ significantly in different operating environments. The average grid length per customer in urban areas can be tens of meters, whereas in rural areas it can be up to several hundred meters or even over a kilometer in some cases. The LV grid planning principles in urban areas differ from the ones that are typical in rural conditions. The main drivers in the LV grid dimensioning in rural areas are typically the voltage drop and 1-phase short-circuit currents required from the perspective of the customers' electrical safety. These factors are significantly dependent on distances and the chosen dimensioning. Owing to 1-phase short-circuit current requirements, DSOs may have to choose larger secondary substation transformers and higher-capacity LV lines. The voltage drop depends on transferred power. In the dimensioning of grid capacity, long-term costs should be considered. In the life cycle costs, costs of losses have a significant effect in addition to investment costs. Selection of a line of higher capacity typically reduces losses but increases investment costs. Figure 2.6 illustrates the life cycle costs of different line capacity alternatives.

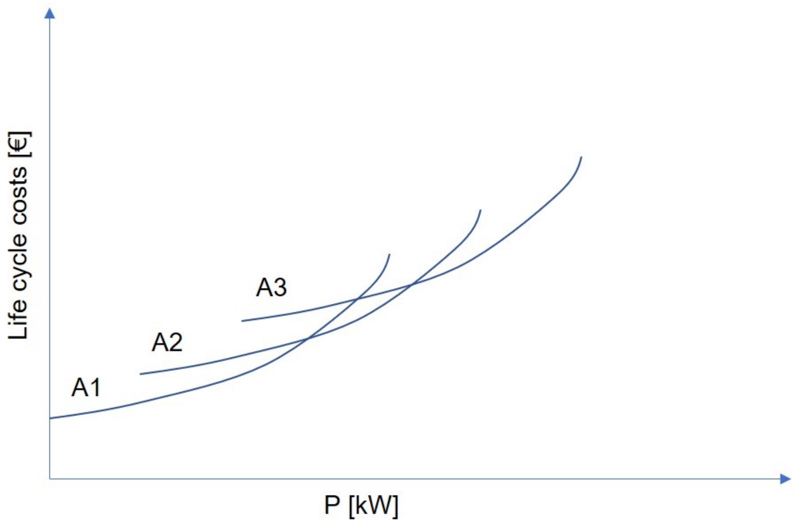

Figure 2.6: Optimization of distribution line dimensioning (Lakervi and Partanen, 2008).

The curves in Figure 2.6 form the optimal economic dimensioning, and the optimal limit for choosing a suitable line capacity in different cases can be found from the intersections of these curves. In LV grid dimensioning, technical limitations, such as 1-phase fault currents and voltage drop, limit the economic optimization (Lakervi and Partanen, 2008). The risks and opportunities arising from changes in the load demand are different when considering new distribution grids, existing old, or recently renovated grids. In recently renovated grids, an increase in the peak demand can cause an immediate need for premature strengthening investments, but a decrease in the peak demand will not reduce costs in the short run. In relatively old networks, an increase in the peak demand can also cause a premature investment need, but the drawback of a premature investment is not as significant as in the case of a recently renovated grid. In the old grid infrastructure, a decrease in the peak demand can allow to reconsider a lower-capacity option when the grid is renovated anyway because of aging, poor condition, or for the purposes of improving the security of supply. When planning new distribution grids, new load trends can be taken into account, but there are always sources of inaccuracy involved, which can cause a risk in the grid dimensioning. Figure 2.7 illustrates the effects of the development of the peak demand on the costs of an existing LV line.

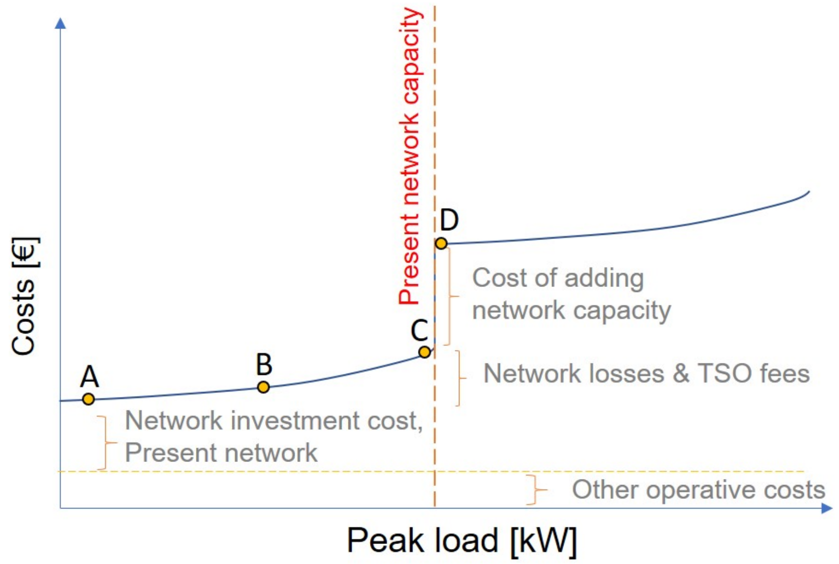

Figure 2.7: Effects of peak power on the electricity distribution costs of an already existing network in rural conditions.

In the left corner of Figure 2.7 it is shown that the presence of customers in the grid causes quite significant costs (A). The level of these costs depends significantly on the operating environment. The customers' load patterns and energy and power use (B) increase the costs slightly until the grid capacity is exceeded. The costs from losses increase faster when the load demand is higher because of the quadratic depedence between the load current and the losses (C). When the grid is overloaded (D), the DSO has to make strengthening investments in the grid. Especially in underground cable networks, adding the capacity afterward can be expensive, because the excavation work has to be carried out again. When the grid capacity has been increased by a strengthening investment, it takes a long time before dimensioning can be restored to the former level, even though the customers' load demand would no longer require a higher capacity. This is due to the long lifetimes of grid investments and the significant proportion of installation costs. Thus, an increase in load demand can cause a rapid increment in the costs, but decreasing the peak demand can affect grid dimensioning only in the future, when the grid is renovated again.

In the MV networks, factors that affect the dimensioning are the maximum short-circuit current, load capacity, voltage drop, losses, and capacity during exceptional events, such as a primary substation transformer replacement. In urban conditions, the MV grid is built with several ring connections so that the switching state of the system can be managed efficiently (Lakervi and Partanen, 2008). Thus, the load capacity is an important factor in grid dimensioning. In rural conditions, the feeder lengths can be several tens of kilometers, and the distances between primary substations can be long. The rural area MV feeders can also include long radial branches without a backup connection. Thus, the maximum short-circuit currents and the load capacity needed during a primary substation replacement can determine the dimensioning of the MV lines in the rural conditions (Lakervi and Partanen, 2008). However, the load profile and losses have a significant effect on the MV life cycle costs, and thereby the network dimensioning. It is typical of rural-area networks that the grid is radial and that there are at least a few backup connections and possibly also long branch lines.

2.4.6 Long-term development of the distribution infrastructure and electricity distribution

In the long-term development of the electricity distribution system, the DSO has to take into account many development trends and aim at optimizing the costs within limitations coming from technical, safety, and security of supply aspects. In the planning of investments, the DSO has to consider the present state of the network: age, condition, location, reliability, and power flows. These factors affect the pace at which the DSO has to make the decisions about investments to ensure the security of supply and capacity demand of the future grid.

In the long-term development of the electricity distribution system, risk management is of high importance. The DSO cannot fully predict all the developing aspects, but it has to handle risks coming from different sources. There is significant uncertainty in future loads with new DER elements. First of all, the DSO does not necessarily know which customers will adopt new appliances. This means that the DSO cannot define where the loads will develop with an increasing trend and where with a decreasing one. Based on different datasets available, prediction of various technology adopters has been studied for instance in (Priessner et al., 2018; Graziano and Gillingham, 2015). This raises the question of what kinds of devices these customers will select? For instance, will future EV owners choose a 3-phase or 1-phase charger, or will they choose high power charging even though this would require resizing the grid connection? What will their consumption patterns be like? Will they adopt smart control of devices and will they sell the control of these resources to some load aggregator? There are many sources of uncertainty even with one DER element. Yet, the DSO has to make decisions that affect the grid costs long in the future.

Investments made at different levels of the distribution grid can affect an individual customer only, or hundreds or thousands of customers. Here, the operating environment plays a significant role. In urban areas where customers are located close to each other, investments are more likely to affect more customers than in rural conditions, where the line length per customer can be multiple compared with urban areas. In rural conditions, the electricity distribution grid is typically radial including only a few medium voltage backup connections at most.

In rural areas, one major challenge can be depopulation or the possibility that customers might go off-grid when technological development makes it possible and feasible. In an off-grid solution, a customer sets up a local electricity system that produces electricity for their own demand. With an off-grid system, the customer does not have a connection to the network of a DSO. This can increase the risks in network investments in rural areas, because the grid lengths per customer are high.

2.4.7 Distribution pricing

The base function of electricity distribution tariffs is to collect reasonable revenue from the customers to the DSO, to cover the costs of the distribution business, and bring reasonable profit for the invested capital. Besides this, distribution pricing should also have other targets, especially to incentivize customers for efficient grid capacity use. Pricing should also reflect the costs of the DSO, be understandable, intelligible, and nondiscriminating. Next, the distribution tariffs are discussed.

2.5 Electricity distribution tariffs

Distribution pricing has been traditionally based on a customer's connection size and total consumption, with possibly some TOU variations. The present tariff structures do not incentivize customers to consider taking actions to affect their peak demand.

2.5.1 Present electricity distribution tariffs

Traditional distribution tariffs have included a fixed fee and an energy-consumption-based fee. The reason for this is that previously, the customers' load patterns were not known and their consumption was monitored only on an annual basis. With fixed fees, the DSO can ensure that all customers contribute to the costs at some level. With an energy-consumption-based fee, the DSO can allocate more costs to those customers who are more likely to use more grid capacity.

One challenge with the present energy-based tariff structures has been their low cost-reflectiveness and minor steering effects on the development of peak loads. The present tariff structure does not include any incentives for customers to consider their peak demand. From the DSO's viewpoint, the relatively low predictability of the income from distribution can be challenging in the short term. From the customers' viewpoint, the limited possibilities to affect their distribution bill can be considered problematic, and even more so if the proportion of fixed fees is set higher. In Finland, the proportion of fixed fees has been increasing. Figure 2.8 shows the development of the proportion of fixed fees in Finland.

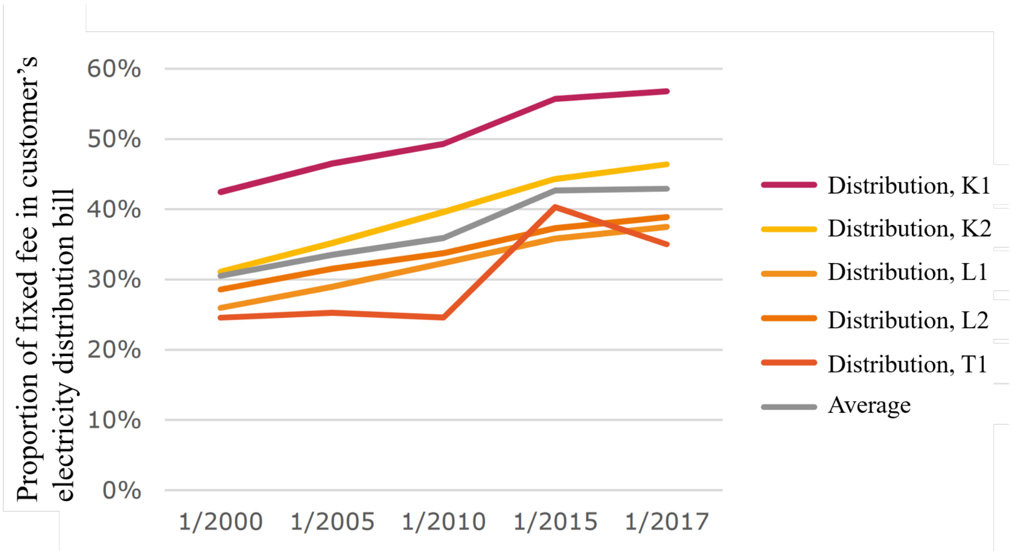

Figure 2.8: Development of the proportion of fixed fees in a customer's total distribution bill in 2000–2017. K1 = apartment, 1x25 A, 2 000 kWh/a; K2 = detached house, 3x25 A, no electric heating, 5 000 kWh/a; L1 = detached house, 3x25 A, electric heating, 18 000 kWh/a; L2 = detached house, 3x25 A, partial electric storage heating, 20 000 kWh/a; T1 = small-scale industrial customer, 150 000 kWh/a, power demand 75 kW. Adapted from (Energy Authority, 2017).

It can be seen from Figure 2.8 that on average, the proportion of fixed fees has increased from approximately 30% to 43% between the years 2000 and 2017. Increasing the proportion of fixed fees might not be in the interest of DSOs in the long run. When the proportion of fixed fees increases, the customers' incentives to consider their consumption patterns decrease. Thus, customers may not make decisions that would be favorable from the perspective of grid loads when choosing new appliances or making load control decisions. On the other hand, a high proportion of fixed fees can lead customers to consider other options to replace their grid connection.

2.5.2 Novel electricity distribution tariffs

In the case of peak-power-based tariffs (PBTs), the customers are charged for their peak loads. The customers' peak loads that are considered in pricing can vary. In this doctoral dissertation, power-based tariffs are considered almost only from the perspective of active power. Considering also reactive power loads in pricing might be reasonable from the DSO's viewpoint, especially when overhead lines are replaced with underground cables, which shifts the reactive power balance toward the capacitive side. In reality, however, charging of household customers based on reactive power would be even more complicated than charging based on active power, because customers' knowledge of reactive power is often limited.

Different PBTs have been in use for larger customers, typically for those with over 3x63 A or 3x100 A fuses, but for smaller customers the tariff structure has not included a peak-power-based tariff. In the Finnish case, the determination of a power-based fee has varied considerably between DSOs (Lummi et al., 2019). In Finland, three DSOs have recently introduced a PBT also for some of their smaller customers (Helen Sähköverkko Oy, 2019; Lahti Energia Sähköverkko Oy, 2018; Kuopion Sähköverkko Oy, 2021).

The AMR rollouts in the past decade enabled an analysis of tariff structures and studies of cost-reflective tariff systems in the early 2010s (Partanen et al., 2012; Apolinario et al., 2009; Mandatova et al., 2014). In the past few years, Finnish DSOs have also started to analyze how a change in the tariff structure toward a PBT would affect their customers' payments (Haapaniemi, 2014; Suikkanen, 2016; Apponen et al., 2017; Rossi, 2018; Sormunen, 2019; Koski et al., 2019; Vaniala, 2019; Tikka, 2020). Results of these studies show that in the Finnish operating environment, it is possible to change the tariff structure, but changes in customer payments can vary significantly. Thus, comprehensive analyses of different options are needed before wide-scale introduction of such tariffs.

During the years 2016–2017, the author of this dissertation participated in a research project (Honkapuro et al., 2017b) in which different PBT options were extensively analyzed from different perspectives and viewpoints taking especially into account their feasibility. The results of this tariff development project were published in (Honkapuro et al., 2017b,a; Haapaniemi et al., 2017b,a; Rautiainen et al., 2017). The most important result of this research project was that a PBT structure where a power-based component is introduced besides a traditional fixed fee and an energy-based fee is the most feasible option as the future tariff. The power limit tariff was found to be too complicated in practice from typical electricity customers' viewpoint, even though it could work in theory. Considering step tariffs, practical problems were identified, especially in control signals that the tariff can have. It was found in these studies, however, that the introduction of a PBT is possible, but it might require a transition path of several years to ensure that the customers do not experience too drastic changes on one occasion. In (Rautiainen et al., 2017), different PBTs are studied quantitatively from multiple actors' viewpoints on the feasibility of the introduction of the PBT tariff.

Also some DSOs operating in Sweden have a PBT in use (Sala Heby Energi, 2018; Sollentuna Energi & Miljö AB, 2018; Bjärke Energi AB, 2021; Karlstadt El & Stadsnät AB, 2021; Sandviken Energi AB, 2021; Nacka Energi AB, 2021). In the Swedish implementations, the principles of PBTs have varied, but they are mainly based on monthly peak loads. Typically, apartments have been excluded from the introduction of PBTs. In most of these companies, the monthly unit price of the PBTs varies. The unit price is usually higher during winter months.

PBTs have also recently been introduced by some companies in the USA, Australia, and Italy (Haapaniemi et al., 2021b). In most of these implementations, it can be seen that the PBT is intended to incentivize customers to shift their daily peak consumption from early evening on-peak hours to off-peak hours. The basis of the PBT varies considerably in different companies.

2.5.3 Variations of PBTs

There are many different possibilities for a power-based tariff structure. The main structures of different power-based tariffs are introduced next. A peak-power-based tariff, or a load demand tariff, includes the traditional pricing components; a fixed fee and an energy-consumption-based fee, and also a charge that is based on a customer's peak load. Part of the distribution fee can be shifted from fixed fees and electricity-consumption-based fees to be collected with a fee based on customers' recorded peak powers. In this pricing structure, customers are charged afterward based on their metered peak consumption (Honkapuro et al., 2017b).

In the power limit tariff, also known as the power band tariff, a customer orders a power limit in advance and can then use electricity without extra costs for the DSO if the customer does not exceed the chosen power limit (Partanen et al., 2012). The power limit tariff could be a very simple tariff structure, including only one tariff component, and it would reflect the costs quite well, but it includes challenges that might be too complicated for the implementation of the tariff. In practice, this tariff structure would probably be too complicated for customers. In particular, choosing a suitable power limit would be difficult for many customers with their present understanding of their consumption, because until now, customers have had to consider the volume of their consumption only (Honkapuro et al., 2017b; Haapaniemi et al., 2017b).

In step tariffs there is a power limit above which the load is more expensive (Honkapuro et al., 2017b). Step tariffs have several challenges that make their implementation unlikely in practice. First, setting a power limit above which the price of consumption will rise is very complicated from the perspective of cost-reflectiveness. Secondly, the tariff could lead to unwanted control actions when the customer's load demand is near the power limit.

For these reasons, including a power-based fee alongside the traditional energy-based fee and the fixed fee would probably be the feasible way of implementing the PBT. In peak-power-based tariffs, the peak power that defines a customer's electricity bill can also be set in various ways, for example based on weekly, monthly, seasonal, or annual peak power, the highest peak of a month, the average of five highest peak powers, and so on. The tariff structure can also include a certain minimum power limit to be charged. Peak demand can also be defined from hourly, 5 min, or 15 min load data depending on metering capabilities and incentives pursued. In this dissertation, different variations of PBTs are not comprehensively analyzed, but the author recognizes that these choices can have significant effects for example on the acceptability of the PBT or the incentives for customers from the PBT. In this dissertation, the basis for the PBT is varied between monthly and annual peak loads. Especially the effects of shorter than hour-long average peak loads should be analyzed in detail when there are data of customers' loads available.

2.6 Changes in demand—Need for the development of distribution pricing?

New customer loads are changing the DSOs' business environment in many ways. New loads pose a risk of overloading of the grid, unfair cost allocation between customers, customer grid defection, and thereby a risk of over- or underdimensioning of the distribution grid. To understand the challenges that DSOs might encounter in the near future and the need for tariff structure development, three development scenarios are discussed next.

If we first consider a case where customers will adopt new technologies but do not choose to control their loads, there lies a significant possibility that new loads will raise grid load rates and thus increase the risk of overloading. Especially uncontrolled EV charging can cause problems by overloading the grid capacity or causing violations of the limits of the voltage drop. New loads that reduce the customer's energy consumption but do not reduce the DSO's costs affect the cost-reflectiviness of the DSO tariffs, which might lead to unfair allocation of costs between customers.

The challenges can escalate when there are more smart control options but the viewpoint of the distribution grid is ignored. This can happen mainly because distribution grids are typically dimensioned under the assumption that customer loads have temporal variation, which might not be the case if a common signal is used to control customer loads simultaneously. With the present tariff schemes, the DSO cannot affect or control customers' load patterns, and the tariffs do not incentivize customers to take into account the limitations of the distribution grid. Thus, load control can cause problems in distribution grids, which will increase the costs of electricity distribution and the customers' total electricity bills in the long run.

By developing the tariff structure, the DSO could attempt to signal the distribution grid costs to the customers, and thus maybe affect the customers' decisions when making investments in appliances and also when controlling these new loads. Tariff development should not prevent the necessary demand response actions, but guide the choices also from the distribution network's perspective. On the other hand, tariff development should balance the cost-reflectiveness so that costs would be directed to those customers that are causing them. By steering customers' load patterns with a tariff signal, the DSO can give customers a choice to be flexible or to pay the costs.

To understand better how new customer loads are affecting the DSOs' business, the next chapter discusses customer load trends and their characteristics. Understanding of the present and past loads also plays an important role when aiming to estimate new load trends and their effects on the distribution grid infrastructure.

3 Demand for electricity

Electricity demand has evolved together with the development of societies mainly during the 20th century. Electricity grids in developed countries have been built to supply household demands also in rural areas after the Second World War. For example, the last rural villages in Finland were electrified in the 1970s. Electricity demand profiles have been highly dependent on people's daily routines and their property-based needs, i.e., electric heating. Thus, the electricity demand profiles have been based on predictable factors, such as working time, outdoor temperature, and weekday. Distribution systems have typically been dimensioned under the assumption that customer loads follow traditional load patterns with a slight increase in total demand over time and that customers' loads have a statistical temporal variation that limits the total peak load to a lower level than the sum of individual customers' peak loads. Because of the electrification of new sectors, distributed generation, and the IoT, these traditional assumptions may lead to new challenges. Electricity distribution grids are facing many changes in the customer loads. Some of the new loads, such as EVs, increase the total electric energy consumption, whereas some, for example solar PV and energy efficiency actions, reduce it. The effect of these DER elements on peak powers depends strongly on which customers adopt them and how and when they use them. In this chapter, drivers affecting the spread of these new loads are shown, and the characteristics of these novel loads are discussed mainly from the perspective of the grid load.

3.1 Drivers for changes in customer loads

The energy sector is facing significant changes. Especially climate change and air quality issues are forcing to consider cleaner solutions. Technological development brings novel solutions available for customers, and the IoT can revolutionize the control options of customer loads.

Climate change causes various challenges for humankind by increasing global temperatures and risks for extreme weather conditions. These worldwide problems call for efforts and investments to maintain the viability of the Earth. Mitigation of climate change has a huge effect on the energy sector, because power generation has traditionally been highly dependent on burning of fossil fuels. Targets to reduce GHG emissions affect both the electricity production and consumption. At the electricity distribution network level, two significant changes are distributed electricity production and electrification of transportation.

On the production side, cleaner eco-friendly technologies have been developed to replace old fossil-fuel-based power plants. Wind power is installed especially in offshore locations, on coasts, or in windy inland destinations. Hydro power is installed in suitable river locations. These production units are typically larger-scale units, which can also affect the DSO's grid, but the most radical change has happened in small-scale production units. Solar power units were much more expensive back at the beginning of the 21st century (IEA PVPS, 2021). However, mainly because of subsidy programs in many countries, such as Germany, the mass production of household-size PV units started to reduce the unit price of the systems and thus made the technology a feasible option (IEA PVPS, 2021). After that, the unit price of PV systems has continued to decrease, and PV systems have started to become increasingly popular everywhere in the world (IEA PVPS, 2021).

Air quality issues have been one megadriver toward cleaner transportation and energy production. Air pollution from burning fossil fuels has caused problems especially in heavily populated cities (Chan and Yao, 2008; Mayer, 1999). Breathing problems, diseases, and even deaths caused by air quality problems have accelerated the demand for cleaner solutions. These kinds of problems that affect peoples' everyday life can have an even more significant effect on decisions like investing in EV. Traditional combustion engine vehicles and power generation are major sources of air quality problems. Changing over to EVs can mitigate the problems of air quality and GHG emissions, but the sources of electricity production play an important role here (Tikka et al., 2016; Van Vliet et al., 2011).

Environment-friendliness, in general, is also affecting people's choices. Willingness to preserve the biodiversity and protect nature affects customers' choices so that polluting appliances are avoided and eco-friendly alternatives are preferred. These values can significantly affect customers' EV or PV investment decisions.

One major driver is technological development, which enables new solutions to be implemented on a large scale. When novel technologies are introduced, the technology is typically first adopted by a small group of early adopters that want to try new solutions. When a solution becomes more mainstream, the mass production reduces the unit price. This has happened for PV production unit prices.

Smart control solutions and the number of measurements in different appliances is growing fast. An increasing number of devices have an Internet or other connection and deliver different data to the owner. This development changes the basis of loads so that a customer does not need to control the loads manually. Previously, there have not been load data available and the need to understand power consumption has been minor, as a result of which customers' knowledge of the electricity consumption of their appliances and their own load curve has been relatively low. Customers' understanding can be increased when there is an incentive to consider also the power and the total load profile. This can benefit also other electricity system participants, even though the incentive for the customers comes from the DSO's tariffs.

Peoples' everyday life is nowadays increasingly dependent on the availability of electricity. Previously, heating systems of buildings have typically been based on other heat sources than electricity, but heat pumps and electric space heating are now becoming more common as the primary heating solution when old oil-, wood-, and gas-based systems are replaced. Electrification of transportation, in other words, EVs, also significantly increases the dependence on the secure supply of electricity.

3.2 Present customer loads

To predict the future development of electricity demand, it is necessity to understand the electricity demand profiles today. Customers' load profiles can vary according to the time of year, time of day, and weekday. A typical household's load profile can be largely dependent on outdoor temperature if the building is equipped with electric space heating or cooled. These thermal loads are significantly affected by the construction materials, area, and insulation of the building. A customer's heating solution and other building automation loads have a more significant effect on the annual profile, whereas the electricity consumption patterns of a customer can define the daily profile. In Figure 3.1, different electricity consumption profiles are illustrated.

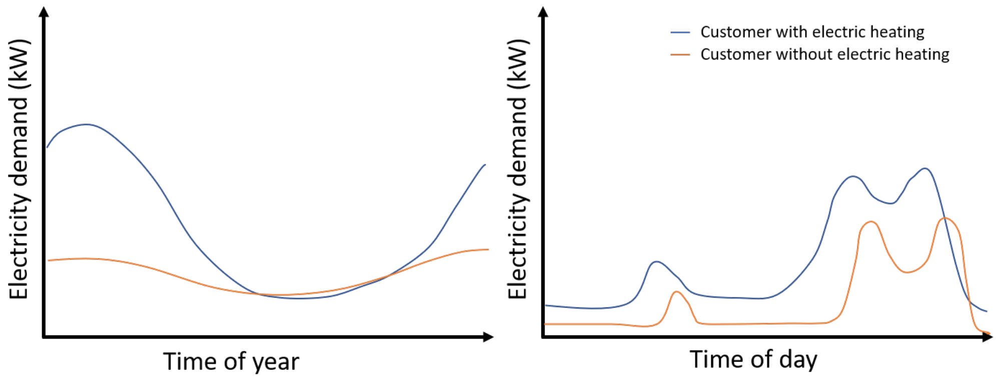

Figure 3.1: Illustration of the load curve of customers with and without electric space heating at the yearly and daily level.

In the Finnish case, the electricity consumption of a typical detached house with electric space heating varies between 10 and 25 MWh/a. This is highly dependent on the size of the house, the year of construction, and other secondary heating solutions like burning of wood. The number of different electric appliances has grown rapidly over the past decades, but simultaneously, the energy efficiency of the devices has improved. Thus, the total electricity consumption of household devices has not changed significantly. A household's daily electricity load profile is highly dependent on daily routines, such as the household members' working hours. On the other hand, the daily consumption profile of the customers can be highly dependent on house-related devices, such as heating of domestic water or ventilation. In Finland, air source heat pumps have become popular since the beginning of the 21st century (European Heat Pump Association, 2019).

3.3 Novel load trends in distribution grids

Electricity loads are going through significant changes. Traditional centralized electricity production units are, to some extent, replaced by distributed generation units. In the transportation sector, electric motors are superseding fossil-fuel-burning combustion engines.

Technologies in the electric energy storage options are developing and becoming feasible for an increasing number of solutions. Furthermore, different electrical appliances have more and more smart control capabilities, which has a significant impact on how future customer load patterns will evolve. In Figure 3.2, an estimation of the future demand is illustrated based on novel load trends affecting customers' load profile.

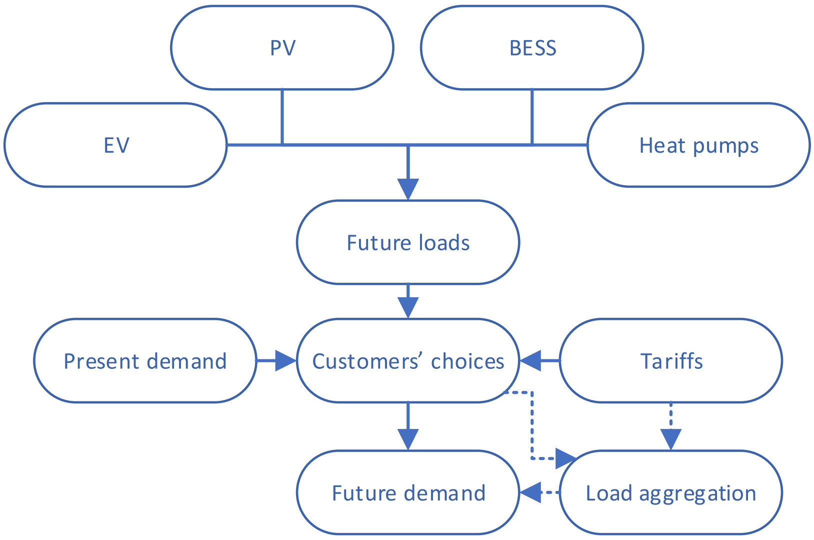

Figure 3.2: Estimation of the future electricity demand.

Future electricity demand is, to some extent, dependent on the present demand and the customers' buildings and appliances. Thus, it is important to understand the present demand of the customers, and especially the trends that are affecting the customers' future demand. A DSO can attempt to affect customers' choices with distribution tariffs. Otherwise, the DSO's options are very limited if the customer appliances do not violate the terms of electricity supply. Next, significant new loads are discussed. Load aggregation might also have a significant impact on future customer load profiles.

3.3.1 Distributed generation

Traditionally, electricity generation has concentrated in large production units, but lately, customer-side distributed generation has become increasingly common. Especially solar PV installations are popular in many countries. The amount of annual installed PV capacity has grown rapidly since the end of the 2000s, from 39 GWp in 2010 to 760 GWp in 2020 (REN21, 2021).

Globally, a large number of annual PV installations has reduced the PV panel unit prices (IEA PVPS, 2021). Historically, the PV panel price has decreased by 20% every time the global installed capacity has doubled (BloombergNEF, 2018). In Finland, the growth in PV installations has been lagging compared with the rest of Europe, but in the middle of the 2010s, customers' PV installations have become more common. The Nordic conditions are challenging from the perspective of PV production, because solar irradiance is at highest in the summertime when the load demand is relatively low. In contrast, when heating loads are turned on in the wintertime, the PV production is low or nonexistent because of short days and the snow cover on the panels. Figure 3.3 illustrates the PV production profile at the annual and daily level.

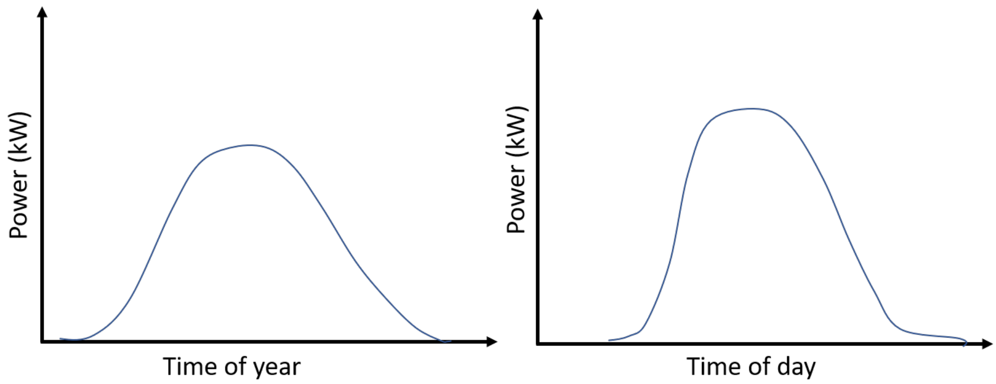

Figure 3.3: Illustration of PV production at the seasonal and daily level in Finnish conditions.

The load profile of a PV installation is affected by the location of the installation, the direction and tilt angle of the panels, possible shading, weather conditions, system size, and whether the system is a fixed or sun-tracking installation. In Finland, the seasonal variation is significant. In winter, the PV production is low because of the snow cover and short days. The conditions are challenging for PV also because customers' loads are typically high in winter when the PV production is low, and low in summer when the PV production is high.

From the perspective of the distribution grid, solar PV can cause challenges because of its simultaneous nature on a local scale. The simultaneous PV production can cause overloadings of secondary substation transformers, voltage rise problems for end users, and voltage fluctuation. From the viewpoint of distribution pricing, PV can cause challenges in the fairness of tariffs. With PV, customers can avoid paying energy-based tariffs, whereas the effects of PV on the DSO's costs can be either minor or the costs can even increase. Thus, PV owners pay less but may increase the costs of the DSO. To cover the costs, the DSO has to raise either the fixed fees or the unit price of the energy-based tariff. In other words, the costs will be collected from other customers.

3.3.2 Electrified mobility

Over the last decade, electrified mobility has started to become increasingly common. Electric cars, in particular, have a significant influence on end users' load profiles. Electrification of transportation has started to replace combustion engine vehicles with EVs. In the last few years, EVs have started to penetrate the market (EV-Volumes, 2021). The development has been dissimilar in different countries. It has a significant effect on customer choices if there are financial support for EV buyers, high taxes for combustion engine vehicles, and charging stations available.

However, the investment costs of EVs or plug-in hybrid electric vehicles (PHEV) have been high compared with combustion engine vehicles, and therefore, EVs have not yet become mainstream. Many countries are providing incentives for EV investments and, on the other hand, setting limitations on fossil fuels, and thus, the attractiveness of EVs is increasing. Figure 3.4 illustrates the EV charging load at the customer level.

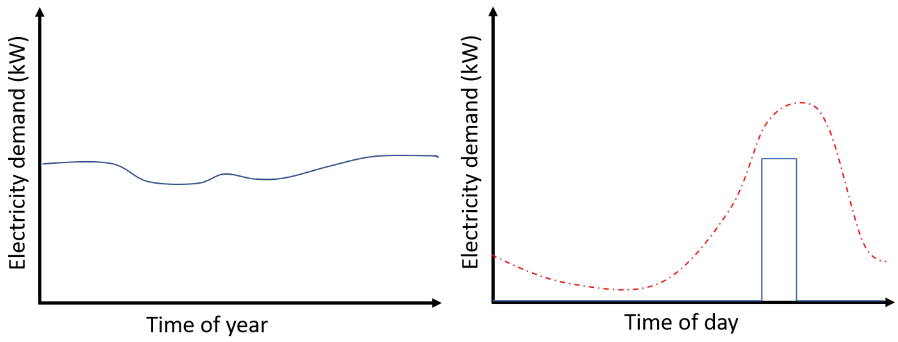

Figure 3.4: Illustration of EV charging at the yearly and daily level. At the daily level, a single customer's EV charging power (blue) and typical statistical behavior of larger customer groups (red) are illustrated.

From the electricity sector's point of view, the electrification of the transportation sector is a significant change. The new energy-demanding sector will be increasing the energy demand throughout the year. The challenges and opportunities of the EV charging for the electricity system can be different depending on how and where EVs are charged. From the DSO's viewpoint, EVs are a new significant load that can cause overloading of the network and thereby premature investments in the distribution grid capacity.

EVs increase customers' total electricity consumption and most likely also customer peak demands. With energy-based tariffs, a DSO's incomes increase slightly because of EV charging. The present tariffs do not incentivize customers to consider their peak demand and control the EV charging, which can lead to overloading of the grid capacity.

3.3.3 Heating and cooling systems of buildings

Heating of buildings is a significant part of the total electricity demand in the Nordic conditions. For the electricity distribution grid infrastructure, heating loads are a significant factor in dimensioning because of their simultaneous outdoor-temperature-dependent nature. There are different heating systems that consume electric energy. Indoor air can be heated directly with radiators or with a heat pump. Alternatively, thermal energy can be stored in a water storage, water-circulating radiators, or floor heating instead of directly heating the indoor air. Some customers have electric space heating with a storage, a water tank. With a storage boiler, the electricity demand of heating can be fulfilled in advance. Storage boilers have typically been installed to shift the heating loads to night hours when volume-based tariffs have been cheaper if the customer has chosen a TOU tariff. In many cases, this has caused a demand peak during the first hours of the cheaper electricity price.

Heat pumps are an energy-efficient solution for heating and cooling of buildings. In Finland, the number of installed heat pump systems has increased rapidly in the 21st century. There are different types of heat pumps that exploit the heat energy from outdoor air, ground, water, or exhaust air of the building. These have naturally different requirements for the building and its location. The investment costs of air source heat pumps and exhaust air heat pumps are lower than with ground and water source heat pumps. Ground source heat pumps can, however, cover the total heating demand, whereas air source heat pumps cannot typically provide the peak heating demand during the coldest outdoor temperatures in Finland.

From the distribution grid's perspective, it has a significant effect on the development of loads which heating system the customer had before investing in a heat pump. If the customer had a nonelectric heating system, a heat pump increases the total electricity consumption and most likely also the peak loads of the customer. When a heat pump is installed to a household where the heating demand has been fulfilled with electric heating, the total consumption decreases. Thus, in different areas, the effects of heat pumps on a DSO's income and network loads can differ.

Cooling of buildings is an important factor especially in countries where the outdoor temperatures are high. Heat pumps can be used for cooling purposes. In Finland, the cooling demand is low compared with the heating demand. For this reason, the cooling loads are not studied in depth in this dissertation. When considering the PBT, cooling loads occur typically at the same time with the solar PV production. Thus, the PBT might have a positive effect on grid loads also in conditions where cooling loads are a significant driver in the grid dimensioning.

3.3.4 Energy storage systems

With an energy storage, customers can adjust their consumption profile seen on the distribution grid side without changing their consumption patterns. An energy storage can be used to store electrical energy, for example in a battery energy storage system, or thermal energy, for instance in a boiler with a water tank. The storage of electrical energy becomes more interesting when customers have distributed generation of their own, because the option of storage increases the self-consumption rate of the produced electricity.

BESSs have not yet become popular for household customers, because the costs have been high and opportunities to benefit from energy storage have been slight. Recently, the price of BESSs has decreased rapidly, and this makes a BESS feasible in novel solutions.

BESSs differ from other new loads and devices because they are always executing some active task, such as electricity market price optimization. With BESSs, customers can modify especially their intra-day load profile. Seasonal variation in customer loads is typically significant, and because of the losses in energy storage over a long period of time, seasonal storage of electricity is challenging.

From the perspective of a DSO, BESSs can have either a negative or a positive impact on the distribution grid load rates. This is highly dependent on the objective of the BESS. BESSs can increase the flexibility in the customer loads, because a customer's load curve can be modified without affecting the customer's appliance use. If BESSs are used to optimize the electricity market price, or other common price signal, the temporal variance in customers' loads can decrease and cause problems to the distribution grid. Simultaneous control of BESSs can be challenging for the local distribution grid, even though it benefits the electricity system at the higher level.

3.3.5 IoT, smart control, and load aggregation

One major driver that should be taken into account when considering future load trends is the IoT. The IoT helps customers understand the consumption of their devices in a more precise manner and enables the control of loads intelligently. When the controllability of loads increases and measurement data are available, the flexibility potential of these resources increases. This can lead to load aggregation, where an aggregator controls customer loads to gain benefits from flexibility. The aggregators would probably try to optimize the timing of customer loads to gain benefits from the electricity market prices. If there is no incentive to take into account the constraints of the distribution grid, flexible loads can be controlled in a manner that causes local problems in distribution grids.

3.3.6 Energy communities

Energy communities have been studied recently in many scientific publications, such as (Narayanan, 2019; Jo et al., 2019) . The term energy community can have multiple meanings. The basic idea of an energy community is that a group of customers share the energy resources. At its simplest, an apartment house can form an energy community if there are common resources, such as a PV installation, that are used to reduce the residents' purchased electric energy. From the perspective of tariffs, the development of energy communities can have either a significant or only a minor effect. If the formation of energy communities does not affect the location of the connection point between the customers and the DSO, the effects on tariff development are minor. If customers' energy communities shift the responsibilities between the DSO and the customers, the effects on tariff schemes are more significant. In this doctoral dissertation it is assumed that energy communities do not change the main principles of electricity distribution. Thus, energy communities can have effects on pricing mainly if customers in an apartment house decide to form an energy community where electricity pricing is based on the connection point load instead of individual customer loads.

An energy community can also be a micro grid that is not connected to the public electricity system. Micro grids, where a customer group forms an energy community and operates their own electricity system without a connection to the DSO's distribution grid, have been studied recently (Liu et al., 2019; Laws et al., 2017). Individual customers can also choose to go off grid by investing in an own generation unit, energy storage system, and energy management system. The increasing price of the electricity taken from the electricity distribution grid, together with the decreasing price development of the PV systems and BESSs, are increasing the feasibility and attractiveness of the alternative solutions for a grid connection.

3.4 Conclusions of the load trends

While changes in customers loads are increasing momentary peak powers in the distribution grids, the energy transmitted to customers is decreasing. It is clear that the DSO's tariff structure should be developed to keep the distribution fees both cost-reflective and techno-economically effective.

4 Methodology to estimate impacts of peak-power-based tariffs

As the customer loads are developing, the load control options are increasing, and the data of appliance use and electricity consumption may be improving customers' understanding of their electricity use, there is a clear need for tariff development so that a DSO is able to carry out cost-effective long-term grid development. In this chapter, a methodology developed to analyze wide-scale effects of the distribution pricing development is presented. As described in Chapters 2 and 3, distribution tariffs are a possible means for DSOs to affect the development of the grid loads. Tariff development is always a multiobjective task, where the DSO tries to balance with different objectives. New customer loads and IoT advancements that enable smart control and metering devices significantly affect the need for tariff development.

When considering the traditional energy-based tariff structure, it is clear that it does not reflect the costs of electricity distribution. The trend of the increasing proportion of fixed fees does not seem optimal either from the perspectives of the customers or the load development on the distribution network. It would mean that the customers' opportunities to affect their electricity costs decrease, and thus, their interest in electricity-system-friendly solutions declines. Thus, the development of the tariff structure toward a PBT would be an interesting option. With the PBT, a DSO can attempt to affect the customers' future loads so that long-term grid asset management can be carried out in a techno-economically reasonable manner.

The tariff development is affected by various phenomena that impact the selection of the tariff structure and the weighting of the tariff components. When developing the tariff structure it is important to recognize the development trends both in society at large and locally in the DSO's operating area, which affect the customers' appliance choices and consumption patterns. These choices and patterns have a huge impact on the sufficiency of the grid capacity. With the tariff development, a DSO can attempt to impact the load development in a favorable way from the perspective of the grid capacity. In the long term, the tariff development should affect the grid dimensioning so that the capacity is used more efficiently and unnecessary cost increments can be avoided. On the other hand, if the customers consider that they need to use high power and the grid capacity has to be increased, distribution payments can be allocated more fairly. By using the methodology presented in this doctoral dissertation, a DSO can analyze which kinds of incentives tariffs would give to the customer loads, how the changes in customer loads would affect the distribution grid load rates, and how the distribution tariff payments would be distributed between the customers. In Figure 4.1, the factors related to the tariff development and their mutual effects are illustrated.

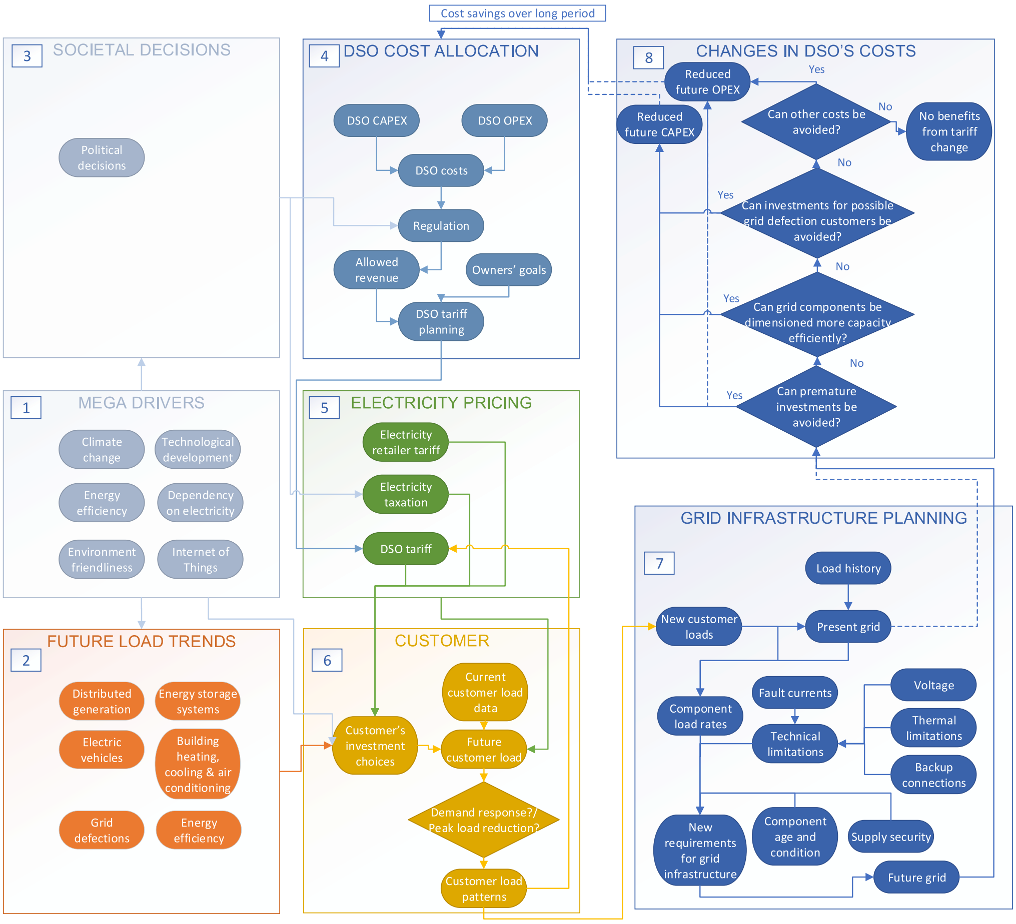

Figure 4.1: Principle of the proposed methodology.

In the left corner of Figure 4.1, the megadrivers and the new load trends that affect the customers' load demand in the future (boxes 1 & 2) are illustrated. The most significant ones are the global trends that affect both the societal decision-making and the load trends. New appliances affect the development of the customer loads. With the societal decision-making (box 3), the development of the load trends can be affected by subsidies and taxation. Societal decisions affect the DSO's tariffs also through regulation and legislation (box 4). The DSO can attempt to affect the development of customer loads with distribution tariffs (box 5). From a customer's viewpoint, distribution tariffs are only one part of the electricity costs, which are only one signal among the factors and price signals that affect the customer's decisions. The customers play the main role in the development of the loads (box 6). With a price signal, a DSO can attempt to affect a customer's decisions so that limitations of the distribution grid are taken into consideration. The DSO prepares a load forecast based on its knowledge of the future demand and makes decisions on the dimensioning of the future distribution grid (box 7). Multiple simultaneous changes in the customers' load demand cause uncertainty and risks that the dimensioning of the distribution grid fails, which increases the costs of the DSO. By developing the distribution tariffs toward the PBT, the DSO can attempt to affect the customers' decisions on appliance investments and their electricity consumption in such a way that the risks of grid overloading are reduced and unnecessary cost increments can be avoided. This can moderate the development of the distribution prices for the customers in the long run (box 8). With the PBT, customers can be treated more equitably, and distribution costs can be allocated more accurately to those customers who cause more costs. Thus, customers will have more power to affect their distribution bill and the development of the distribution bills in the future. In other words, the customers can increase the capacity demand, but the payments are more cost-reflective.

To understand how the changes in the tariff structure would affect the distribution asset management in the long run, the DSO has to understand the big picture all the way from the effects of megatrends on the incentives and interests of society and individual customers to the impacts of customers' new loads on the risks of the distribution network asset management in the future. There are many changes taking place that increase the risks in the distribution grid development. At the same time, the present tariff system does not properly reflect the costs of electricity distribution. Thus, in the future, the costs of electricity distribution may increase because of increasing peak loads, yet the present tariff structure shifts the costs more based on energy consumption.

Megadrivers, such as climate change and technological development, affect societal decisions. Customer choices are incentivized in the desired direction with pricing signals and subsidies. New load trends affect the customers' total load and distribution grid loads. With the tariff development, a DSO can attempt to affect the customers' load patterns by price incentives and thus encourage to the more effective use of the grid capacity. Customers' reactions have an effect on the distribution pricing if the DSO wants to maintain a certain revenue. In the long run, tariffs should significantly affect the customer loads, as the development of customer loads has an effect on the grid infrastructure planning and reduces the need for premature investments in grid reinforcement. If planning can be carried out more effectively in terms of grid capacity, the DSO's costs will decrease, which should reduce the costs of the customers.

In order to comprehensively analyze the tariff development, the DSO has to perform various analyses to increase the understanding of the customers' load data, the present and future grid costs, the nature of cost causation, and grid load rates. In addition, the DSO should understand the local development trends and changes taking place in society and in the customers' load demand.

4.1 Customer load data analysis

Traditionally, a DSO has only had information of the customers' total consumption, typically collected once a year. Knowledge of the customer types and the customer's typical consumption profiles has been used to estimate the distribution of the load demand within a year and a day (Seppälä, 1996; Sener, 1992), but the lack of precise data of customer load patterns has been limiting the development of tariffs. Installation of AMR meters to record hourly electricity consumption and remote reading of the metering data have provided opportunities to develop the distribution tariffs further.

Smart meter load data can typically be either hourly, 30 min, or 15 min data. This means that the AMR meter records a customer's total consumption for every hour, 30 min, or 15 min. In this dissertation, load data are considered mainly as hourly data, because the data available thus far have been with that resolution and the current generation of smart meters in Finland widely use this resolution. Hourly data are sufficient when considering thermal overloading of the grid components. Hourly resolution data do not, however, always reveal voltage problems in the distribution grid, especially if there are significant variations in the load demand. If the PBT was considered by a DSO who has shorter time resolution data from the load demand of the customers, it would be necessary to consider if the tariff should be based on that time resolution or somewhat longer, hourly average. However, the highest hourly consumption can be defined from 15 min data, and thus, pricing does not have to be based on the hour. From the perspective of the grid load, it does not matter that much whether the peak hourly load occurs at 16:00–17:00 or at 16:15–17:15. From the customers' perspective, a longer resolution is somewhat more tolerant, but this limits the effects that the PBT could have on the grid side. The question of the most suitable time resolution in the PBT is outside the scope of this doctoral dissertation.

From the customers' load data, a DSO can establish parameters of customer loads, such as monthly energy consumption, monthly peak loads with various definitions of peak load, and full-load hours. With these parameters, the DSO can analyze its distribution pricing with different tariff structures. From the load data, the DSO can also identify present load characteristics, such as outdoor temperature dependence and seasonal variation.

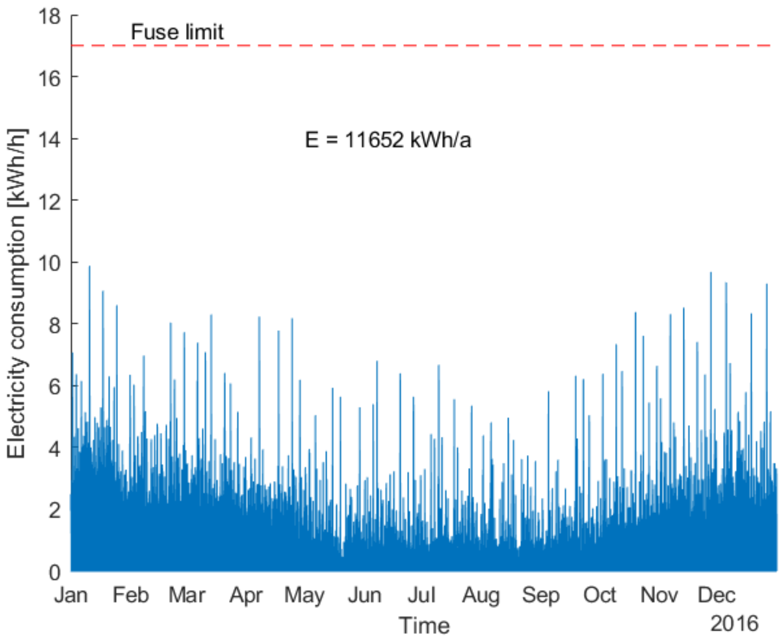

Figure 4.2: Example of hourly AMR load data of a customer. The fuse size limit is 3x25A.

It can be seen from the load data illustrated in Figure 4.2 that the customer's load demand is relatively low compared with the customer's main fuse size. Based on the annual load profile, the customer has outdoor-temperature-dependent loads, and thus, the load demand is higher during the winter months. The total consumption of the customer is approximately 11.7 MWh/a, which is quite typical annual consumption for a household customer with electric heating. In this customer's load curve there are load peaks of approximately 5 kW throughout the year, which are probably caused by an electric sauna or a domestic water heater.

4.1.1 Present tariff analysis

To develop the tariff structure, the DSO should first have comprehensive understanding of the present state, weaknesses, and strengths of its tariffs. This includes analysis of the present customer payments from the viewpoint of the total payments and how they are comprised. In addition, the DSO should understand in which kinds of actions the present tariffs incentivize the customers. With the present energy-consumption-based tariffs, the distribution bill collected from the customers can be estimated with the equation

$$C_{DSO,old,i} = p_e * \sum E_i + p_{i,fixed,DSO} * 12, \qquad (4.1)$$

where p_e is the unit price of the energy-based fee, E_i is the total electricity consumption of customer i, and $p_{i,fixed,DSO}$ is the fixed fee of customer i on a monthly basis. In Finland, the DSOs' tariffs also include statutory time-of-use-dependent tariffs. In these tariffs, the energy-consumption-based fee is lower in the nighttime or higher in winter weekdays. With these tariffs, the target is to shift the customer loads from system-level on-peak hours to off-peak hours. The effect of these tariffs on customers' loads has been such that appliances like storage heating systems or domestic water heaters have been controlled to turn on when the hours of lower price start, typically after 22:00. However, this control of loads can have led to a peak demand on local distribution grids because of a simultaneous drop in the electricity price.Furthermore, nighttime tariffs may have been selected by customers who do not actually shift the loads to night hours, but who benefit from selecting the tariff. As a strength of energy-consumption-based tariffs can be seen the incentive to improve the energy efficiency, which can, however, lead to unfair cost allocation and inefficient solutions from the perspective of the grid capacity. In addition to the network service fee, the customers also pay for the retailer, typically a basic charge and a fee according to their electricity consumption, and an electricity-consumption-based electricity tax.

4.1.2 Customers' peak powers

In the PBT, the customers' peak load is in the focus. Whereas in the energy-based tariffs the customers have not had incentives to consider variation in their loads and their peak demand, in the PBTs customers can benefit by considering their peak demand in the load curve and by distributing their loads more evenly. In the PBTs there can be many different definitions for the charged power, such as the highest hourly demand at a monthly level, the average of three highest hourly demands at a monthly level, or the highest demand at an annual level. If the billing was based on monthly peak loads, the example customer's monthly charged peak loads would be as shown in Figure 4.3.

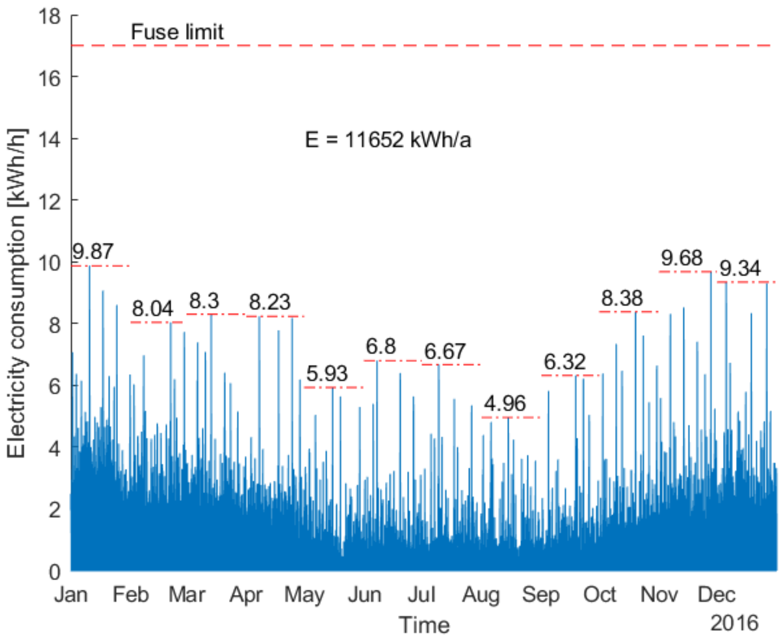

Figure 4.3: Monthly peak load of the example customer.

It can be seen in Figure 4.3 that the example customer's monthly peak power varies between 4.96 and 9.87 kW. Thus, the highest power at the annual level would be 9.87 kW, which has occurred in January. From the viewpoint of the customer's billing, this 9.87 kW peak load can be seen as a 12 x 9.87 kW = 118.44 kW total billing base over a year in the annual PBT. In practice, the charged peak power could more likely be defined as the peak value of the last 12 months instead of a calendar year. In total, the monthly peak powers for this example customer would be 92.52 kW. By comparing the monthly and annual peak powers of this customer, it can be seen that the customer would pay for 92.54 kW in the monthly PBT instead of 118.44 kW in the annual PBT. This does not necessarily mean that this customer would benefit from the monthly PBT because the unit price can differ significantly and must be calculated based on all customers' load data. The definition of the charged power can vary; the PBT can be based for example on the highest power, the third highest peak power, the average of three highest peak powers, or the highest peak power during the hours 7:00–20:00. This peak power computation process should be carried out for all the customers under the PBT. When the total sum of peak powers is calculated with different definitions of peak power, the DSO can begin to estimate the cost structure, revenue allocated to the PBT, and then finally the unit prices for the power component based on different definitions.

4.1.3 Effects of exceptional situations on tariff determination

In some circumstances, customers' peak demand can be due to reasons that are independent of the customers' choices. These kinds of exceptional consumption peaks can be caused by a fault in the distribution system. During a supply interruption, the customers' load demand is not fulfilled, and the demand can accumulate. Especially during the heating period, the indoor air in buildings with electrical heating cools down during a supply interruption, and thermostat-controlled heating loads turn on at high power when the supply is restored. This phenomenon can cause a demand peak to the customer's load curve regardless of the customer decisions. In the PBT, it may be problematic that in these situations customers have to pay more to the DSO because there was a fault in the DSO's distribution system (Haapaniemi et al., 2021a). It may be reasonable to consider and study this challenge especially in rural conditions, where the grid infrastructure can be more vulnerable to weather conditions.

On the other hand, part of these post-outage consumption peaks can be a result of a customer's own back-up BESS that is used during grid outages and charged after the outage. However, the DSO may consider whether there should be an incentive for these back-up BESSs to charge with a lower power after supply restoration.

4.1.4 Data proofing

Load data proofing and analysis is an important part of the tariff development process. If the pricing is to be dependent on the maximum value of single data points, the correctness of the hourly values is more important than with the energy-based tariffs. In AMR datasets, some customers' datapoints can be erroneous. For example in datasets, some customers' hourly consumption can be summed to one hour from multiple hours so that previous hours have zero consumption. This has not been a significant problem with energy-based tariffs because the total energy is recorded correctly, but in the case of the PBT this could cause significantly too high a distribution bill for a customer. Thus, the importance of proofing individual data values becomes higher.

4.1.5 Customer grouping and load data clustering

Customer grouping based on the DSO's information of the customers, such as the customer type and the customers' connection sizes and tariffs, can benefit the analysis. With customer load data clustering, the DSO can elaborate on customer grouping. Understanding of the customer load profiles enhances the estimations when aiming to anticipate the customers' future load choices and reactions. Moreover, it helps the DSO when analyzing changes in the customers' distribution bills with the PBT so that the DSO can identify which kinds of customers are experiencing different changes.

4.2 DSO's cost structure analysis

To analyze the tariff development, the DSO has to understand its cost structure, what is causing the costs, and how the costs will develop with the future loads. The cost structure of the DSO and allocation of the costs is studied next. When conducting the cost analysis, it is important to understand that the nature of cost causation can vary when the loads are developing. Hence, the nature of some costs may be currently fixed, but in the future based on peak demand. A DSO's costs can be divided into network investment costs, network operation costs, and financial expenses.

4.2.1 Cost allocation to the cost centers

The costs of the DSO can be first divided into cost centers, which are grid voltage levels and other component groups: 110 kV lines, primary substations, MV lines, secondary substations, LV lines, energy metering, information systems, and others. Network investment cost depreciations, operational costs, costs of network losses, the transmission system operator's fees, and reasonable return are then allocated to these cost centers by using suitable cost drivers. After this allocation, the DSO knows where each proportion of the costs is caused. To allocate the costs to the cost centers, suitable cost allocation drivers should be deployed. In the allocation of the network investment cost depreciations, a natural cost driver is the replacement value. Allocation of the DSO's OPEX can be done based on the grid length of a certain voltage level, the number of customers, or the total energy demand. If the DSO has collected statistics on its OPEX, for example the costs caused by the LV network repair, this information should be used in the process. Some operative costs are not directly caused by electricity distribution, for instance the costs of customer service and billing, and thereby a suitable cost driver can be the number of customers. The costs of losses and the TSO's fees are typically allocated based on the total electricity consumption. Losses can also be analyzed more comprehensively in the network information systems, where they can be allocated to the different voltage levels. Allocation of the allowed income can be based on the current replacement costs, because it is dependent on them in the present regulatory model. The allowed income is not, however, an actual cost, and thus, the allocation is not justifiable based on cost allocation, but more likely a choice that the DSO has to make. Figure 4.4 illustrates the allocation of the DSO costs to the cost centers.

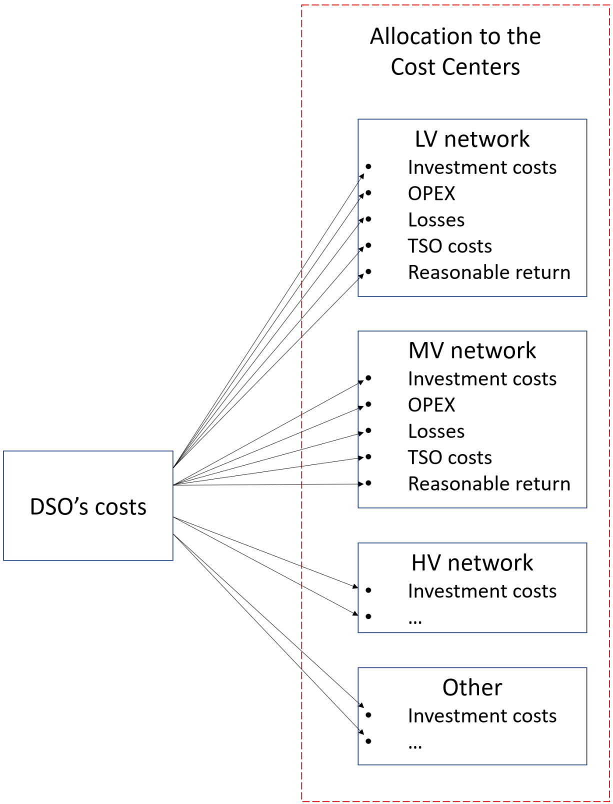

Figure 4.4: Cost allocation to the cost centers.

Figure 4.4 shows the allocation of the DSO costs to the cost centers.

4.2.2 Allocation of costs to the customer groups

Next, the costs have to be allocated from the cost centers to the customer groups. In this phase, the customer groups reflect the customers that would be assigned to each tariff option. For instance, customers living in apartment houses and row houses can form one group and customers with the present nighttime tariff another. From the cost centers, the costs can be allocated to the customer groups with responsibility factors, also known as participation factors (Honkapuro et al., 2017b; Lummi et al., 2014). In these factors, the proportion of the peak demand caused by each customer group is estimated. The responsibility factors should be defined separately for each voltage level to ensure that the cost allocation is fair. For some costs, for instance the losses, it can be reasonable to use other factors, such as the number of customers or the total energy consumption in the allocation. The target of this allocation process is to ensure that on average, the costs are collected in a cost-reflective way from the customer groups. Thus, with this analysis, the DSO gains understanding of how much distribution bill incomes should be allocated to each tariff. Figure 4.5 illustrates the allocation process from the cost centers to the customer groups in different tariffs.

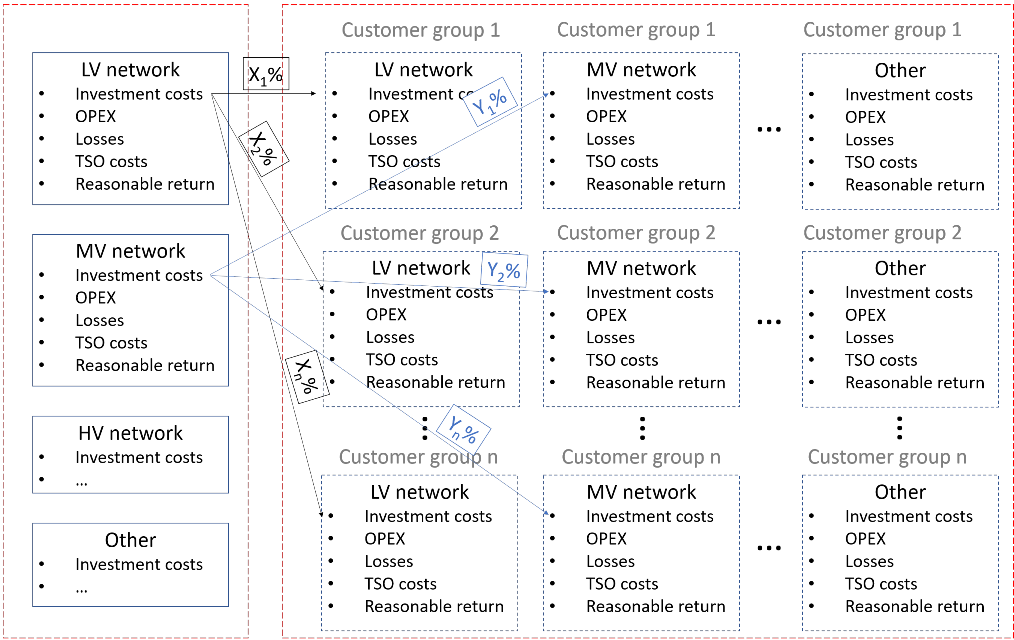

Figure 4.5: Allocation of costs to the customer groups. The allocation is demonstrated with LV network investment costs and MV network investment costs, but all costs from the cost centers have to be allocated to the customer groups.

Figure 4.5 shows the principle of allocation of costs from the cost centers to the customer groups. The main target of this phase is to define which proportion of each cost should be gathered by different customer groups, which are formed by tariffs.

4.2.3 Cost causation analysis

In the cost causation analysis, each cost is analyzed more comprehensively from the viewpoint of causation. With this analysis, the DSO can estimate which proportion of the costs should be allocated to each tariff component. Hence, it is necessary to study more precisely how different costs are caused, which proportion of the costs is fixed, and which is dependent on the customers' decisions.

It is characteristic for the network infrastructure costs that the investment lifetimes are long, even up to 60 years, and the investments are expensive. The drivers for investment decisions are typically the overloading of the grid capacity because of changes in the loads, security of supply improvements, and aging or poor condition of the present grid. The overloading of the grid infrastructure is significantly dependent on which kind of load development has been estimated in the past when the grid has been dimensioned and built.

Hence, the changes happening in the customer loads now and in the near future can cause uncertainty in how the costs will develop.

In practice, the existing distribution grid is developed by forming reasonable investment entities that are renewed to correspond today's and future requirements taking into account techno-economic limitations (Haakana et al., 2012). In particular, the LV lines are dimensioned for the investment lifetime needs, because typically the LV grid topology remains the same throughout the service life (Partanen, 1991). On the MV lines there may be a need to adjust the dimensioning prematurely because the MV grid topology can change or a higher capacity line might become feasible from the viewpoint of loss optimization (Partanen, 1991).

In the tariff development, the main principle has traditionally been that different voltage levels can be seen from the customers' viewpoint as a distribution channel or as a system, based on which costs are allocated to the fixed fees and the energy-consumption-based fees (Lummi et al., 2014). In the distribution channel model, the grid is assumed to be built for an individual customer's demand, and thereby, an individual customer's load patterns and appliance choices, mainly from the perspective of peak demand, have a significant effect on the grid dimensioning and development. In the system model, it is assumed that the distribution grid enables the supply of electricity to the customer, but the customer's own load patterns have only a minor or no impact on the grid dimensioning. In practice, dividing different grid components into the distribution channel and system models is not unambiguous, especially when a large customer base and a large amount of grid infrastructure are studied. Typically, the grid close to the customer is more dependent on the customer's choices. When MV lines or higher levels of the distribution grid are considered, an individual customer's choices have only a slight impact. Because the pricing has to be location independent, cost-reflectiveness has to be pursued by finding an averaged combination between the distribution channel and system models. Peak-power-based costs have typically been divided between energy-based fees and fixed fees (Blank and Gegax, 2016). This kind of cost allocation has worked well with the traditional energy-based tariffs, but because of the fast development in the customer loads, new features are required of the distribution tariffs in addition to the cost-reflectiveness with the present loads. In this doctoral dissertation, cost allocation is studied from the viewpoints of the present and future cost-reflectiveness and the pressure to raise distribution prices as a result of new loads and load control opportunities.

Grid dimensioning has only a slight effect on the grid infrastructure investment costs. This is highlighted in the LV grids, where the minimum short-circuit currents place restrictions on the grid dimensioning for electrical safety reasons. Table 4.1 shows a comparison of how the choice of the dimensions of LV bundle assembled aerial cables and UG cables affects the unit price of LV lines.

Table 4.1: Analysis of the LV bundle assembled aerial cable, AMKA, and LV underground cabling investment costs. Underground cabling costs include the cost of digging in easy conditions. The cost parameters are from (Energy Authority, 2015).

	Cost [€/km]	Cost compared with next higher capacity option [%]	Cost compared with next lower capacity option [%]	Cost compared with the lowest capacity option [%]	The lowest capacity option; proportion of costs [%]
AMKA 16 - 25 mm^2	16 600	96 %	-	100 %	100 %
AMKA 35 - 50 mm^2	17 300	88 %	104 %	104 %	96 %
AMKA 70 mm^2	19 600	91 %	113 %	118 %	85 %
AMKA 95 mm^2	21 500	92 %	110 %	130 %	77 %
AMKA 120 mm^2	23 300	-	108 %	140 %	71 %
UG cable ≤25 mm^2	19 200	97 %	-	100 %	100 %
UG cable 35 mm^2	19 800	96 %	103 %	103 %	97 %
UG cable 50 mm^2	20 700	96 %	105 %	108 %	93 %
UG cable 70 mm^2	21 600	95 %	104 %	113 %	89 %
UG cable 95 mm^2	22 800	91 %	106 %	119 %	84 %
UG cable 120 mm^2	25 000	92 %	110 %	130 %	77 %

It can be seen from Table 4.1 that the difference in the investment unit costs of adjacent dimensioning options is approximately 5–10%. If there was not the risk for reinforcement needs in the distribution grids, the LV grid investment costs would be at least 71% of the fixed costs, and the proportion of customer-load-dependent costs would be, at most, 29% of the total LV investment costs. Hence, less than 29% of the investment costs should be allocated to consumption-related fees, the energy-based fee and the power-based fee. It should also be recognized that the capacity difference between the highest and the lowest capacity option is significant, and thus, in practice, the effect of an individual customer's load patterns on the grid investment costs is less than the above-mentioned 29%. Overall, it can be pointed out that the LV grid investment costs are, to a high extent, fixed costs, if there is no risk of overloading the grid by increasing the load demand.

By studying the costs from the viewpoint of secondary substation transformers, it can be noticed that dimensioning has a similar effect on the investment costs as with the LV lines.

By comparing the unit prices of the smallest distribution transformers, 16 kVA, and the higher capacity options, it can be seen that that the 16 kVA unit price is 94.4% of the next larger option, 30 kVA (Energy Authority, 2015). Correspondingly, the unit price of the smallest, 16 kVA transformer is 76% of the highest capacity option typically used in rural conditions, 100 kVA. Moreover, when the cost of the secondary substation is taken into account in addition to the transformer cost, the proportion of the load-demand-dependent cost is even lower. Similar trends are also visible in the unit prices of MV lines. In the MV line dimensioning, the normal-state loads play a role from the perspective of losses, but capacity may be dimensioned for the primary substation replacement conditions or other backup connection during grid faults. Therefore, the peak demand during normal operation of the grid may not affect the dimensioning, and individual customer load patterns have only a slight effect on these peak loads, and thus, costs are more likely fixed or energy-consumption-related than dependent on an individual customer's peak demand.

The allocation of consumption-dependent variable costs between the energy-consumption-based fee and the peak-power-based fee requires a comprehensive analysis. Here, also the operating environment of the DSO has an effect. The fewer customers there are in the grid, the more significant is the role of an individual customer's load pattern in the peak demand. When the number of customers increases, the customers' powers have more temporal variation, and thus, it may be important to know how often the customers use high power, in other words, how much energy is consumed.

In rural conditions, where the distribution grid lengths required for the connection of a customer to the grid can be hundreds of meters or even over a kilometer, the fixed nature of costs is emphasized. On the other hand, from the viewpoints of the DSO and society there lies a risk of the grid defection of customers. This risk becomes more pronounced when the technical development of alternative solutions makes grid defection a feasible and attractive option for the customers. However, these potential customers considering grid defection may also be located in places where the effects of the grid defection on the grid infrastructure are low. Higher fixed fees increase the low-consumption customers' grid connection costs, and thus make alternative solutions more attractive. In the tariff structure it may be reasonable to allocate the MV grid costs to the fixed fees so that customers who have only a low load demand participate also in the system maintain costs. Hence, grid defections can have an increasing or a decreasing effect on other customers' distribution bills depending on the location of the customers disconnected from the distribution grid. If customers that are anticipated to possibly go for off-grid are located in such grid locations where cost savings are low, other customers' distribution bills may increase because the system costs are distributed to a smaller group of customers. Other customers' distribution bills can decrease if the customers going off-grid are located in such places where significant investments can be avoided. Thus, in rural conditions, the tariff development should be considered also from the perspective of the future of the customers' grid connection.

Cost increments caused by new customer loads and control of the loads are significantly dependent on the DSO's operating environment and strategic decisions. The DSO can prepare for the increasing capacity need by adding capacity proactively or by reacting to the overloading problems when they occur. Both strategies have challenges especially if the DSO has to develop the level of the security of supply at the same time with grid infrastructure investments. If the DSO decides to use the ex-ante method, the challenge arises from predicting which customers will adopt the new loads. This can lead to unnecessarily high capacity selections widely in the distribution system. If the DSO chooses the ex-post strategy, it may have to make reinforcement investments in the locations where the grid has recently been renovated to meet the requirements of the security of supply. With the tariff development, the DSO can attempt to affect the new customer loads and their control so that the risk of overloading is minor. If the risks are realized, the cost increments are significantly dependent on the construction of the grid and locations where the new loads cause problems. The additional costs can be high especially if the grid has been recently underground cabled.

Another significant cost for the DSO are operative costs. The operative costs cover, in particular, costs from network maintenance, repair, and operation, which include personnel costs, equipment costs, and costs from different systems. These can be purchased services or provided by the DSO's own staff and equipment. Traditionally, operative costs have more likely been dependent on the extent of the distribution grid and the selected technology than the customers' load demand. Thus, from the perspective of cost allocation, the operative costs are more likely fixed costs. When active network control becomes more common, there will be logical reasons to allocate part of these operative costs also to the power-based and energy-consumption-based fees. The costs from administration, metering, customer service, and billing can be separated from other operative costs, and allocated based on the number of customers (Honkapuro et al., 2017b).

The losses in the distribution grid also cause operative costs to the DSO. The DSO has to buy the energy that is lost in the distribution system from the electricity market. The losses can be divided into technical and nontechnical losses. In this doctoral dissertation, only the technical losses are considered, because nontechnical losses are insignificant in Finland. In the distribution system, some losses occur when grid components are connected to live voltage (no-load losses), and some are caused when electric current flows through the components (load losses). No-load losses are caused by secondary and primary transformers in the distribution grid. Load losses occur when the power is transferred in the distribution system. The load losses are quadratically dependent on the electric current. The losses can be affected by line and transformer dimensioning. Typically, if a higher-capacity option is selected, the load losses decrease, and in the case of transformers, the no-load losses increase. A significant proportion of distribution system losses occur in low-voltage grids and in secondary substation transformers. No-load losses are mainly independent of the customers' load patterns, but can be affected by dimensioning. Load losses are dependent on the customers' peak demands and energy consumption. Transmission of electric energy always causes losses, but a spiky load profile causes them more compared with transferring the same energy with a flat profile. Table 4.2 illustrates transformer losses.

Table 4.2: MV/LV distribution transformer losses. Parameters for the no-load loss optimized secondary substation transformers are from (ABB Oy, 2000).

Transformer nominal power [kVA]	P_0 [W]	P_k [W]	Total losses [W]	P_0 proportion of losses on nominal power [%]
30	103	585	688	15.0
50	140	885	1025	13.7
100	220	1485	1705	12.9
200	420	2295	2715	15.5
315	600	4500	5100	11.8
500	720	6600	7320	9.8
800	1200	8500	9700	12.4
1000	1450	10200	11650	12.4

It can be seen from Table 4.2 that even during the nominal capacity load, secondary transformer losses account for 10–15% of the no-load losses. Thus, in the best optimal case, the transformer losses are at least 10% fixed, and at most, 90% dependent on the customers' peak demand or energy consumption. In practice, the secondary transformer load rates are, most of the time, significantly lower than the nominal capacity. Hence, the proportion of the fixed losses is higher. To estimate how losses should be allocated between fixed and consumption-based fees, transformer-level load curves should be studied. In Figure 4.6, a secondary transformer's load is illustrated throughout a year and as a duration curve.

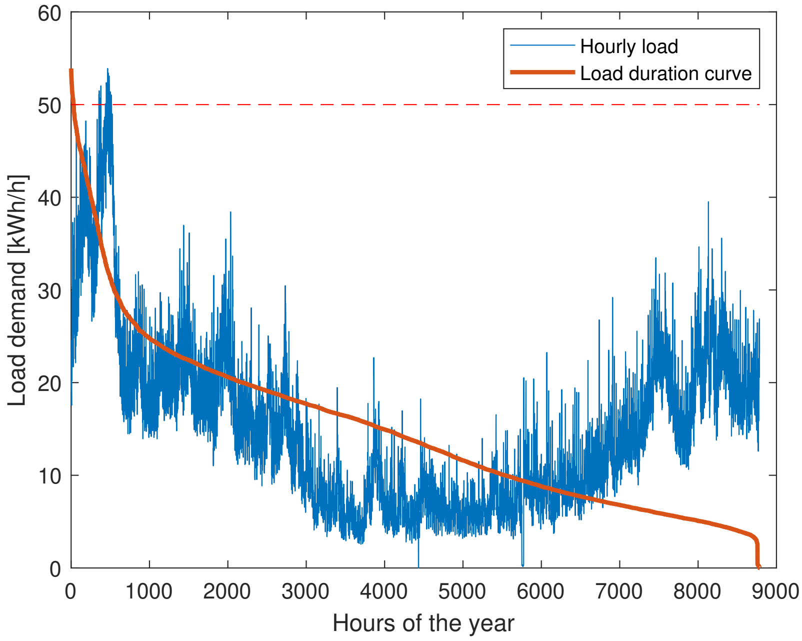

Figure 4.6: Example secondary transformer's load curve and load duration curve. The nominal power of the transformer is 50 kVA.

It can be seen from the figure that the transformer load rate exceeds the nominal capacity during the winter. However, 90% of the time, the load rate is under 50% of the nominal capacity. From the dimensioning perspective, this kind of load profile is challenging because the transformer capacity must be selected based on peak demand in the winter, but the load rate is typically low, as a result of which the proportion of no-load losses is high. By studying the hourly load data at the secondary transformer level, the proportions of no-load and load losses can be estimated. With this example transformer, the proportion of load losses of the total losses is quite high, 44%, when on average, the proportion of transformers with the same capacity is only approximately 17%. Figure 4.7 shows the proportion of load losses in a larger group of 50 kVA transformers in rural areas.

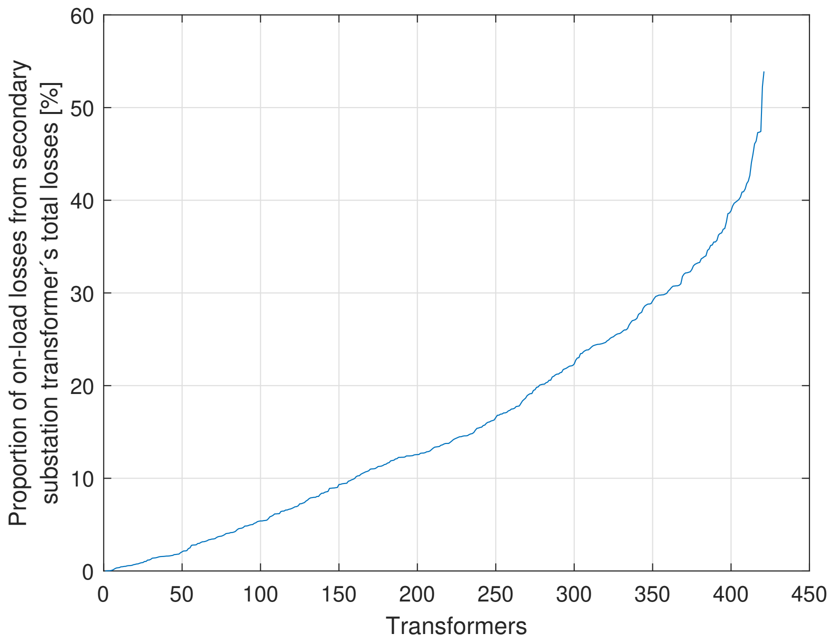

Figure 4.7: Proportion of on-load losses of a 50 kVA transformer's total losses.

Correspondingly, the proportion of load losses in the case of 30 kVA secondary substation transformers is approximately 12%, and 20% for 100 kVA transformers. Thus, in Finnish rural areas, the losses are also, to a large extent, fixed costs. Here, the quadratic dependence of the current on losses and the high seasonal variation of the electric loads have a significant effect. By studying a case where the transformer load is flat throughout the year, it is possible to estimate the effect of load variation on the losses. With a completely flat load, for the same transformers, the proportion of load losses would be approximately 9% in the case of 30 kVA transformers. For 50 kVA transformers, in turn, it would be 14% and 17% in the case of 100 kVA transformers. This means that with present loads, approximately 3% of the losses are caused by power variation and 9–17% by energy consumption, and 80–88% of the secondary transformer losses are fixed. It is noteworthy that these proportions can vary especially in operating environments that are different from Finnish rural areas. In Finland, the losses equal approximately 2% of the total transferred energy. However, the losses are, in total, only a minor component in the total cost structure of a DSO, accounting for 4–5% in Finland (Sormunen, 2019; Mustonen, 2020; Rossi, 2018). The proportion of the secondary substations' losses of the total distribution system losses is approximately 40% (Honkapuro et al., 2015). The distribution transformers installed today have also stricter limitations on losses, and thus, losses decrease when old transformers are replaced (EU Commission, 2019). Hence, the importance of losses in the cost allocation will decrease even further. On the other hand, the increments in peak power can lead to a situation where the DSO has to select higher-capacity transformers, which increases the no-load losses. Thus, the development of the customers' peak demand affects also the fixed part of the costs of losses.

In the case of LV and MV lines, the losses are dependent on load. In this doctoral dissertation, it is not estimated which proportion of the line losses depends on energy consumption and which on power. This could be estimated in a similar way as with distribution transformers, in other words, by comparing losses that are based on real load data with losses that have a flat profile. Overall, the losses are highly dependent on energy consumption, with a slight dependence on power variation. Approximately one-third of the distribution system losses is still fixed costs because of the no-load losses in the transformers. These losses can depend on the operating environment, in particular, the seasonal variation of the loads. If the seasonal variation is low, secondary transformers may operate closer to the nominal capacity, and thus, the importance of no-load losses is lower.

Transmission system fees depend on the TSO's tariffs. In Finland, the TSO Fingrid's tariffs for active power are based on total energy consumption, and in the tariffs, the unit price is higher when the system-level load is high during the heating season (Fingrid Oyj, 2021). Fingrid has also tariffs for reactive power, which have to be taken into account in the tariffs. In this doctoral dissertation, allocation of reactive power costs to the DSO's tariffs is not studied in detail. Including a reactive-power fee in the tariffs would improve the cost-reflectiveness of the tariffs, but it would require metering of the customers' reactive power, which the present metering is not typically capable of, and it would also require significantly greater knowledge from the customers. The costs caused by reactive power can be allocated to the small-scale customers' other tariff components.

4.2.4 Allocation of costs to the tariff components

To analyze the tariff components, it is of high importance to allocate the costs comprehensively. When the DSO has allocated the costs to the cost centers and to the customer groups and analyzed the cost causation, it can estimate how each cost should be allocated to the tariff components in order to define the cost-reflective tariffs. For example, the LV grid investment costs can be distributed between the fixed fee and the peak-power-based fee, as mentioned above. Here, the DSO can make decisions to support the tariff targets, avoid challenges, and exploit opportunities. The allocation process is illustrated in Figure 4.8.

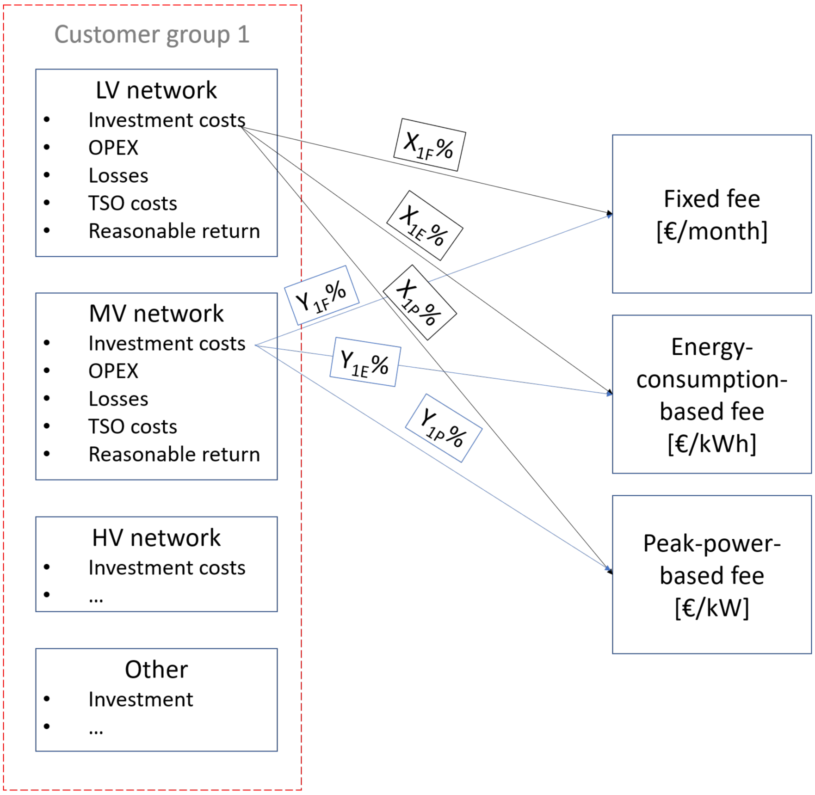

Figure 4.8: Allocation of the customer group's costs to the tariff components.

Figure 4.8 shows the tariff allocation process when the costs have been allocated to the cost centers and to the customer groups.

4.3 Tariff targets, opportunities, and challenges

With the allocation methodology described above, a DSO can aim for cost-reflectiveness of the tariffs. Cost-reflectiveness is an important target for the tariffs to ensure fair allocation of costs to the customers. When the tariffs are cost-reflective, unneccessary cross-subsidies between customers can be avoided (Council of European Energy Regulators, 2020; Honkapuro et al., 2017b). Fully cost-reflective tariffs would have to be location dependent, and there would have to be own temporal and grid-state-dependent rates for each customer. In practice, the cost-reflectiveness has to be pursued by averaging the cost allocation.

Traditionally, there have been limited opportunities for the control of customer loads, and the customer's load curve has been based on the customer's appliance use. Therefore, distribution tariffs have had only minor incentives to control the loads. The effect of these incentives has mainly been such that customers have shifted their domestic water heating and storage heating to nighttime. In the future, when new loads, such as EVs, will be more common and the load control opportunities will improve, the signals that the tariffs give to customers may be of higher importance.

Tariffs should be fair and nondiscriminating. This means that the DSO has to offer the grid service with the same prices for all all customers of the same kind. The rates should also be easily accessible. Further, the prices should be uncomplicated and easily understandable. This is important because the customers should be able to understand how their distribution bill is formed and to which kinds of actions the tariffs incentivize. If the tariff structure becomes complicated, the customers can be confused by different options, and the preferred load pattern changes may not achieved. The simplicity of the tariffs can be of high importance for third-party aggregators, particularly if the tariff structures are not harmonized and DSOs choose different tariff structures. In practice, the principle of simplicity is in contradiction to the principle of cost-reflectiveness, and thus, a compromise is needed.

One important feature for the tariffs is acceptability. This means how easy it is for the customers to accept the pricing components and principles. Acceptability of a tariff can be highly dependent on the customer type. For example, a high proportion of fixed fees can be hard to accept by customers with low consumption. Moreover, acceptability is partly related to whether customers can affect their distribution bills with load pattern choices.

Tariffs should be estimated also from the viewpoint of manageability. If a tariff structure causes the billing basis to be volatile, the DSO has to adjust the unit prices to meet the revenue target. This would reduce the predictability, which is also an important target for the tariff design. Predictability of the tariffs can affect the customers' interest to change their load patterns, if the principles and unit prices are adjusted often. If the customers do not know what the tariffs will look like in the near future, they cannot make decisions based on the tariffs.

4.3.1 Contradictions of tariff objectives

In the formation of the tariffs, the DSO has to make compromises to achieve the objectives set for the tariffs. A strictly cost-reflective tariff structure would be very complicated, which is in contradiction at least to the simplicity and predictability principles. A complicated tariff structure would be challenging to present as an understandable price list, especially if the tariff unit prices had temporal variation. Cost-reflective tariffs may also be challenging to estimate because the nature of the cost structure can be significantly fixed if there is no risk of load demand development. However, if the grid capacity is overloaded, the costs increase rapidly. The cost-reflectiveness can vary in different areas within the DSO's operating area, but the tariffs have to be the same for similar customers in different areas. Thus, the DSO has to recognize how the changes in the tariff structure affect in different areas with dissimilar development trends and customer bases.

The tariff component weighting has a significant impact on how the tariff incentivizes customers for energy efficiency or capacity efficiency, or how cost-reflective the tariff is. If the DSO emphasizes energy efficiency, a higher proportion of cost is allocated to the energy-consumption-based fee. This reduces the incentives for capacity efficiency if the revenue is taken from peak-power-based fees, or may reduce the cost-reflectiveness if revenue is shifted from the fixed fees. Correspondingly, if the DSO emphasizes the peak-power-based fee, it can also reduce the cost-reflectiveness and incentives for energy efficiency. Thus, the decisions on tariff weighting should be made considering the DSO's operating environment.

4.3.2 Challenges concerning different customer groups

Development of the tariff structure can also pose challenges in the treatment of different customer groups if the tariffs have not been studied comprehensively and from a long-term perspective. The DSO should pay attention to how the tariff development affects the distribution bills of different customer groups, and how these changes incentivize customers to change their load patterns, invest in new devices, and acquire automation to control their loads. Because the tariffs have to be available for different customers, the effects on customer decisions can be dissimilar. Challenges can develop from the perspective of cost-reflectiveness when tariffs are developed. One special group of customers can be found in rural conditions among low-consumption customers, who rarely use electricity. If the tariff weighting is shifted from fixed fees to consumption-based fees, a free-rider problem may arise.

In the free-rider problem, a customer group pays much less than what their cost-reflective proportion of the costs would indicate. This can happen more easily in rural networks, where the presence of customers causes a significant proportion of the total costs. If the proportion of costs allocated to the fixed fees is low, these customers' costs are covered from other customers. These customers, however, may be potential ones for grid defection.

New loads, such as EVs and PVs, have an effect on the tariff development, and customer payments have to be estimated and taken into account. These new loads change both the incomes and costs of the DSO as mentioned in Chapter 3. New loads change the customers' total energy demand and peak powers. The tariff development affects the attractiveness of new loads, such as investing in a GSHP or a smart EV charger. The DSO should not develop the tariffs so that they hamper or prevent new eco-friendly loads from becoming popular, but to give customers an incentive to consider also the capacity effectiveness.

Location-independent pricing functions always from the perspective of average costs caused by a customer. In practice, this means that cost-reflectiveness is realized only approximately within a group of similar customers.

The cost-reflectiveness of the monthly PBT has been challenged. In (Passey et al., 2017) it is studied how well the customers' peak demand correlates with the distribution grid peak loads. The publication challenges the cost-reflectivity of a monthly PBT, because during some months of the year, grid peak loads are unlikely to occur. The study was made in an Australian environment. The criticism may be valid with present loads, but the tariff development should be considered from the viewpoints of novel loads and smart load control. Nevertheless, a monthly PBT might be reasonable because it can be more easily acceptable for customers than an annual PBT. Thus, a DSO should analyze the effects of the PBT in its operating environment. It is clear that every peak load of the customers may not be relevant from the perspective of grid costs, but for the sake of simplicity, it can be a reasonable basis of a fee.

4.4 PBT analyses with present customer loads

The distribution tariffs can be set when the DSO has made comprehensive analyses about customers' present loads and the cost allocation analysis. From the present load data, changes in the customers' distribution bills can be estimated by assuming that the customers' loads do not change. To analyze the changes in distribution bills, the tariff component unit prices have to be defined.

4.4.1 Definition of power-based tariff unit prices

The PBT component unit prices can be estimated when the allocated revenues are defined with the cost allocation. The unit price for the peak-power-based fee can be calculated by the equation

$$p_{P,PBT} = \frac{R_P}{\sum\limits_{i=1}^{N_{cust}} (\sum\limits_{n=1}^{N_p} (P_{i,n}))}, \tag{4.2}$$

where R_P is the revenue allocated to the power-based fee, i is customer, N_{cust} is the total number of customers, n is the peak power under consideration, and N_{p} is the total number of peak powers considered. Estimation of a suitable price by applying load data of previous years also involves certain risks. It has to be taken into account that the consumption patterns and appliance choices of customers have so far been based on the pricing of that period. When a new tariff structure is introduced, customers' payments and incentives may change, and thus, the consumption patterns may not be the same as before.

In the PBT, the fixed fee and the energy-consumption-based fee play an important role. The unit prices for these tariff components can be estimated by

$$p_{fixed,PBT} = \frac{R_{fixedfees}}{N_{cust}} \tag{4.3}$$

$$p_{e,PBT} = \frac{R_E}{\sum E_i}, \tag{4.4}$$

where $R_{\text{fixed fees}}$ is the revenue allocated to the customer group's fixed fees, R_E is the revenue allocated to the energy-based fees, and ΣE_i is the total energy consumption of the customer group.

Tariff development should be carried out considering how the combination of tariff components appear from the customers' viewpoint, not only in respect of the peak-power-based fee. In particular, the DSO should determine the main targets pursued with the tariffs, as mentioned above in Section 4.3. If the revenues covered with tariff components have been allocated with a hasty decision, challenges can arise from poor cost-reflectiveness, unwanted control signals, degrading energy efficiency, or reduced capacity efficiency. The tariff change probably reduces the predictability of the tariffs, because customer reactions are not totally known in advance. Thus, the DSO should comprehensively estimate how the change affects customer payments and incentives now and in the near future.

4.4.2 Effects of the tariff development on the customer payments

When the tariff structure has been established by analyzing the load data and cost structure, the changes in customers' payments can be assessed. The changes in the payments can be examined from an individual customer's viewpoint and from the perspective of customer groups provided by the DSO's own information systems or the typical user groups defined by the Energy Authority. The changes in a customer's distribution bill can be estimated by

$$\Delta C_{Tariff,i} = C_{DSO,old,i} - p_{p,PBT} * \sum \hat{P}_i - p_{e,PBT} * \sum E_i - p_{fixed,PBT} * 12, \quad (4.5)$$

where $C_{DSO,old,i}$ is the distribution bill of customer i before the tariff change, determined by equation (4.1), $p_{P,PBT}$ is the unit price of the power-based fee defined by equation (4.2), $\Sigma\hat{P}$ is the sum of customer i's charged peak powers, $p_{e,PBT}$ is the unit price of the energy-consumption-based fee in the new tariff, and $p_{fixed,PBT}$ is the unit price of the fixed fee in the new tariff.

In theory, the development of a tariff structure does not change in the short term the total amount of charges covered with distribution bills, if the DSO does not simultaneously adjust the target revenue. In practice, the consumption varies between different years, and thereby, the total amount of distribution incomes can vary slightly. From an individual customer's viewpoint, the tariff structure development can have a significant effect on the distribution bill. In theory, a change in the tariff structure could affect only the control signals that the tariff gives to customers, but in practice, the customer load patterns are individual, and thus, the distribution bills change at an individual customer level. Further, these changes in the customers' distribution bills imply that the present tariffs have not been cost-reflective. In Finland, DSOs can estimate the effects on the typical user groups' distribution bills, and these typical user groups are used to regulate the annual increments in distribution bills (Energy Authority, 2019). These new typical user groups were updated in the year 2019 to include the peak-power-based fee in the observation of pricing (Mutanen et al., 2019). In addition to the typical user groups, the DSO can analyze changes in individual customers' distribution bills. Some customers who have deviant load patterns may experience excess increments, and thus, it is important to analyze in advance what kinds of customers will lose the most in the change, and what are their opportunities to affect their peak demand in the future. Even though the changes would be appropriate for most of the customers, challenges may arise from exceptional cases.

The changes in distribution bills when developing the tariff structure toward the PBT have been analyzed in numerous scientific publications, such as (Honkapuro et al., 2017b; Lummi et al., 2016a; Sæle et al., 2016; Sæle, 2017; Lummi et al., 2016c; Hledik and Greenstein, 2016; Brown et al., 2015).

Three different PBT effects on the electricity bills of five customer groups were studied in (Sæle et al., 2016). The studied PBTs were based on annual, seasonal, and daily peak loads. The main conclusion of this study was that customers with exceptionally high or low full load hours would experience significant changes in their electricity bills if a PBT was introduced. The study was carried out with one-year AMR data of Norwegian residential customers. In (Sæle, 2017), the authors analyzed the effects of the PBT for type customers. They concluded that the PBT should have time-of-use-based price variation if the effects on grid loads are desired to occur at a specific time of the day. The study reported in (Brown et al., 2015) investigated how costs would be divided between different customers in different tariff scenarios. The study was made for six type customers whose annual consumption and peak power were different. One tariff development option was to install smart metering and introduce a PBT. The study was made under Australian conditions.

The study of (Hledik and Greenstein, 2016) analyzed whether a PBT affects customers' payments differently if the customer has a low income level. 15 min AMR data from 1 000 customers were used in this study. The outcome of this study was that changes in low-income customers' payments did not differ from those of the other customers. It was also studied how a BESS could be used to reduce a customer's peak load. It was found that those customers who would pay more with the PBT would benefit more from the BESS.

In (Lummi et al., 2016b), the effects of different tariff structures on different electricity system actors were discussed. Three future scenarios of a DSO's pricing and penetration of microgeneration were studied in the paper. In the first scenario, energy-based tariffs are in use, but the PV penetration rate is high. In the second scenario, a PBT is introduced and the PV penetration rate is high, and in the third one, the PV rate is low. It was found that energy-based tariffs increase cross-subsidies between customers, and the DSO might face challenges in distribution grids.

4.4.3 Customer reactions to tariff development

Tariff structure development can have effects on the customers' present loads use, new appliance investments, and the smart control of loads in the future. A DSO can estimate the actions from the viewpoint of customers' financial benefits in different alternatives, but it can be challenging to predict how customers will react in reality.

From the present loads, the loads that have already been controlled to nighttime can be shifted in another way if the PBT is introduced. There is already flexibility in these loads, and thus, only the control devices and logic have to be updated. For example, domestic water heater and storage heating loads can be distributed more evenly to reduce the customer's peak powers. So far, the nighttime tariffs can have caused a consumption peak in the distribution grid during the first hours of a lower price, if customers with a similar load pattern are located close to each other.

The tariff development will probably also affect the customer appliance investment decisions. When the customers' knowledge of their electricity load curve and the PBT increases, the customers may take into account the peak demand when choosing new appliances. In practice, this requires understandable communication from the manufacturers and sellers.

The development in the smart control of loads can have a considerable effect on the future load curves of the customers. Hence, the incentives that the distribution bills signal to the customers are of higher importance. Automation and energy storage solutions provide opportunities to affect the customers' load curve to minimize the customers' electricity costs. The DSO can attempt to signal the grid capacity limitations to the customers with the PBT so that unnecessary peak load increments can be avoided and increments in the costs can be limited. The load control incentives are studied in more detail in Chapter 5.

4.4.4 Short-term feedback effects of the customer reactions to the tariffs

In the short term, customers' reactions to the pricing affect the revenue covered with the tariff. If a large proportion of the customers change their load patterns in the same way, the revenue collected with distribution bills can be either lower or higher than the targeted one. To reach the target revenue, the DSO may have to adjust the unit prices of tariff components. Figure 4.9 depicts the short-term need for the unit price adjustments after customer load curve reactions.

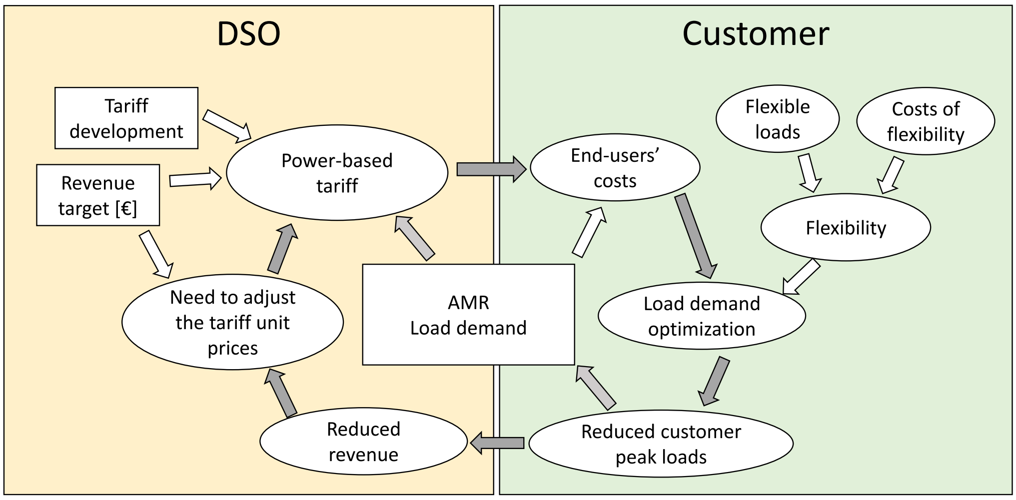

Figure 4.9: Short-term feedback effects of the customer reactions.

As can be seen from Figure 4.9, tariffs can have an effect on customer decisions, and the decisions that the customers make affect the DSO's incomes. Thus, the DSO should understand that customers make decisions from their own viewpoint, and distribution tariffs are only one pricing signal of all the signals that affect the customer decisions. Changes in the customer load patterns can cause fluctuation of distribution incomes and unit prices after the introduction of a new PBT. This can cause challenges for the DSO from the perspective of the price increment limitations.

4.4.5 Long-term feedback effects of the customer reactions on the grid infrastructure planning

In the development of the grid infrastructure, the time spans are long, and thus, it can take a long time to achieve the benefits in grid dimensioning that can be obtained by investments in tariff development. In contrast, in conditions where the grid will be renovated in any case in the near future to improve the security of supply, the benefits in dimensioning can realize fast. The long-term benefits involve a significant source of uncertainty, because the effects on customers' actual decision-making are not well known. This raises a question of whether the benefits in reducing the grid peak loads gained with the PBT can be taken into account in the actual grid dimensioning.

4.5 Transition to the new tariff structure

The transition from present tariffs to the PBT can pose practical challenges to the DSO. The implementation of the transition can have a significant effect on how the customers accept the new tariffs. Analysis of the transition is important to understand which kinds of annual changes the tariff development causes to customers' distribution bills, and how the transition can be carried out so that customers do not experience unfair situations.

The analysis of the transition can be divided into the following parts: 1) analysis of the transition of the customer base to the PBT and 2) analysis of the transition of the tariff weighting toward the target tariffs.

4.5.1 Transition of the customer base to the PBT

The transition of the customer base to the PBTs can be carried out in various ways; in other words, which kind of procedure is needed to move the customers from the present tariffs to the target tariffs. There are a few options of how to handle this transition. Options identified are direct transition, optional transition, main-fuse-size-based transition, and the present tariff-based transition (Haapaniemi et al., 2021b). In the direct transition, the new tariff structure is implemented simultaneously for all the customers. This can cause practical challenges for the DSO because a change in the billing basis of large customer groups can confuse the customers and cause congestion in the customer service. Thus, effective communication is a high priority when implementing a change in the tariff structure. In the optional transition, a peak-power-based fee is introduced as a new tariff alongside the present ones. This option is contrary to the direct transition. In this option, customers can choose the tariff, but the traditional energy-based tariffs will remain. If the transition to the PBT is optional, then most likely only the customers whose load profile is such that the customer would benefit from the selection of the tariff would choose the tariff. Hence, it could be challenging for the DSO to set the tariff unit prices so that customers would choose the tariff but the tariff would not lead to the free-rider problem. In the main-fuse-size-based transition, a power-based fee is introduced first for the larger customers, and then gradually extended to smaller customers. This kind of approach would limit the number of customers that would be moved to the PBT in the first stage. The DSO can improve the customer service and communication in terms of the PBT before widely introducing the tariff. Further, this allows the DSO to communicate the coming change to other customers and attempt to enhance the customer knowledge before the change. In the present tariff-based transition, the peak-power-based fee is introduced as part of a present tariff. This can be beneficial especially in cases where the flexible customers are already within a particular present tariff. The challenge in this option might be that customers who would not benefit from the introduction of the peak-power-based fee might change to other tariff options.

4.5.2 Transition of the tariff weighting toward the target tariff

In the transition of the tariff weighting, the unit prices of the tariff components are adjusted from the present tariffs toward the target tariff. The adjustment of the unit prices of the tariff components can cause significant changes in the customers' distribution bill, and thus, it is important to analyze how long a transition is required to ensure that the customers do not experience too drastic changes in the short term so that they can adjust themselves to the new situation and modify their load profile if necessary. In (Lummi et al., 2017), the transition of the tariff weighting was analyzed, and it was found that a period of several years is required for the transition.

The customer's viewpoint is a high priority when considering the transition of the tariff structure. The outcome of the tariff development can be significantly influenced by how the customers understand and accept the tariff structure development. The customers' opinions on the introduction of PBTs have been studied in some publications.

According to (Hobman et al., 2016), when designing a new electricity tariff structure, it is very important to understand psychological factors that affect how the tariff will be seen from the customers' perspective. This can have a significant effect on customers' willingness to optimize their electricity usage.

A customer survey was also conducted in a master's thesis (Tikka, 2020), where 544 of the DSO's customers answered an Internet survey about the PBT. Over two-thirds of the respondents found the PBT interesting or very interesting and only 4% of the respondents were of the opinion that they did not have any possibility to affect their peak demand. Most of the respondents were living in a detached house or in a row house in Finland.

4.6 Conclusions of the proposed methodology to analyze the short- and long-term effects of the tariff development

The tariff structure development has to be analyzed comprehensively from various viewpoints to ensure that from the perspective of long-term development of the grid infrastructure, the tariffs give the right kind of signals to the customers. In the short term, the tariff development can aim at improving the present cost-reflectiveness of the tariffs, but in the long term, the tariff structure should take account of the changes taking place in society and in the local customer loads. If the future development of the customer loads is not taken into account in the tariff development, the customer choices may end up being optimized only from one viewpoint. The analysis path developed in this study is demonstrated in Figure 4.10.

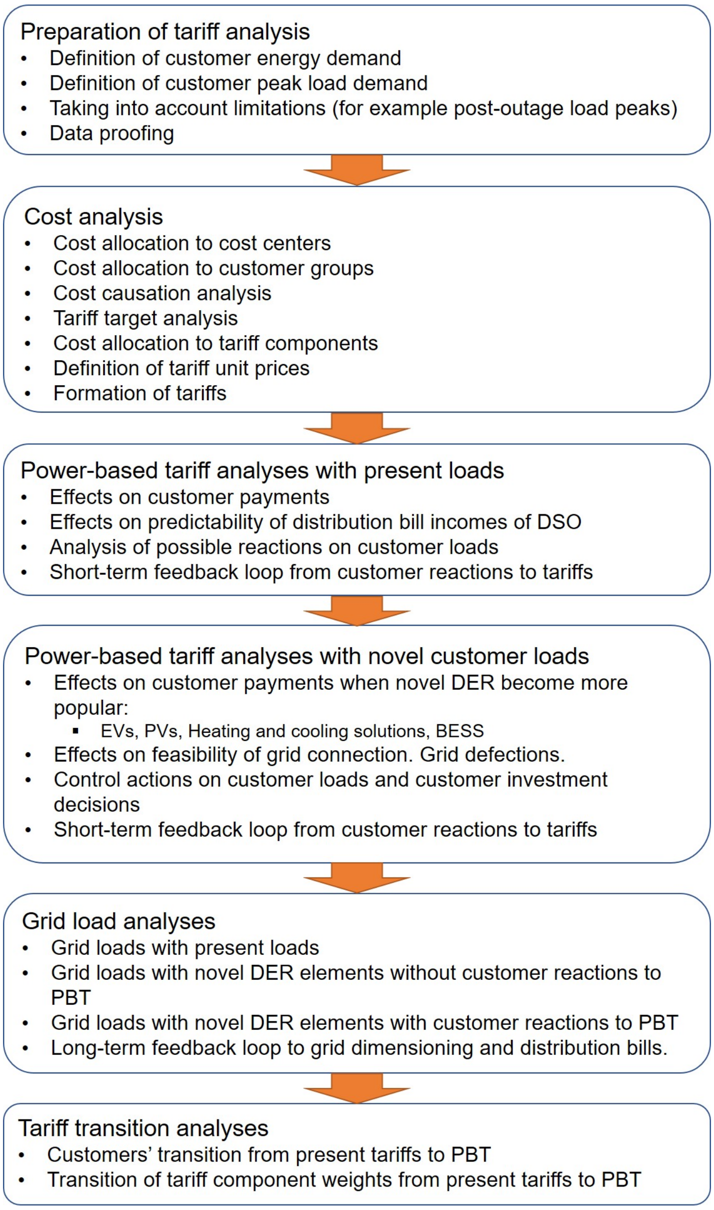

Figure 4.10: Illustration of the proposed tariff development analysis path

From the analyses shown in Figure 4.10, the preparation of the tariff analysis, the cost analysis, and the power-based tariff analyses with present loads should consider the whole customer base and cost structure of a DSO to ensure that the tariffs can be implemented in practice. The power-based analyses with new customer loads and the grid load analyses can be carried out with case area data to study the effects of future changes in different areas. Even though the analysis of all customers' data from the perspective of tariff development may require a lot of resources, the requirements for the modeling of new loads, their control actions, and effects on the grid loads are significantly higher. When the present state of the tariffs is analyzed and the preferred target tariffs are chosen, the DSO can analyze the transition path from the present tariffs to the target tariffs. The transition analyses are more likely to focus on the management of practical challenges, whereas other analyses concentrate on the risk management of the long-term development of the distribution infrastructure.

5 Customer-side PBT-based peak power optimization

Introduction of the PBT affects the customers' incentives to invest in appliances and to change their load patterns to modify the load curve in a way that takes into account the capacity effectiveness. Because the target of the PBT is to incentivize the customers to affect their distribution bills by peak demand management, the DSO should determine the types of load changes in which the target tariff will incentivize customers, and how these customer choices will affect the grid load rates. Introduction of a new power-based tariff structure changes customers' incentives to control their flexible loads. A tariff based on a customer's peak power incentivizes customers to shift loads from their peak load hours so that the loads are distributed more evenly throughout the day.

From the customers' perspective, the objective is to minimize the customers' overall costs without causing discomfort. Customers may also consider alternative costs in addition to the total electricity costs. These alternative costs can include, for example, the costs of heating with wood or the costs of another heating source instead of electric heating, or the total costs of a vehicle instead of the EV charging costs. Thus, the DSO has to be aware of many aspects that affect the customer's cost optimization. On the other hand, the electricity costs, and the distribution bills in particular, are the only means that the DSO can attempt to use to steer the customers' decisions in a favorable direction. The total costs of electricity can be formulated as

$$\min\left(\int_{t_0}^{t_n} (C_{\text{Retailer}}(t) + C_{\text{Distribution}}(t) + C_{\text{Tax}}(t))dt + \int_{t_0}^{t_n} (C_{\text{Inv}}(t) + C_{\text{Opex}}(t))dt\right) \tag{5.1}$$

where C_{Retailer} is the retailer tariff, $C_{\text{Distribution}}$ is the distribution tariff, C_{Tax} is the electricity tax, C_{Capex} are the investment costs of a peak load management system, and C_{Opex} are the operative costs of the peak load management system. Here, the peak load management system can refer to a smart EV charger, a home automation unit, BESS, or other appliance that is used to control the loads.

Customers have different loads that cause their peak loads. Hence, the customers' opportunities to affect their peak loads are dissimilar. Customer appliances and building characteristics have a major effect on the flexibility of customer loads. In some cases, shifting of certain loads to achieve flexibility in electricity consumption can cause discomfort, whereas in other cases where flexibility is pursued with some other loads, the customers will hardly notice any effects. For example, in the case of a customer with electric heating, factors such as the heat distribution system, the building insulation, the size of the building, and air conditioning can have a significant effect on the time delay when the customer will notice the control of the electric heating.

5.1 PBT vs. other price signals

The DSO should consider how the PBT will be seen as part of the total electricity costs of a customer. Which price signal will affect the customers' flexibility the most? Does the PBT suffice to restrain market-signal-based load control when it would be harmful for the distribution grid?

In Finland, the electricity-consumption-based part of the retailer tariffs is typically either a constant price or based on the Nord Pool Spot price. The Elspot price signal could affect customers' load patterns especially if there were more controllable loads. In this case, a load is shifted from expensive hours to cheaper ones. Because the Elspot price signal represents the balance between electricity system-level production and electricity demand, it can be in conflict with the load state of the local distribution grid. An electricity-market-based price signal can cause problems in distribution grids specially if flexibility actions are taken by a third-party aggregator, when locally loads can be shifted from multiple customers to the same time slot.

The Nord Pool Elspot price is defined by a day-ahead auction. In the auction, retailers set their buying offers including hourly price and power, and correspondingly, electricity producers set their selling offers. The market price is determined in the point where the supply and the demand meet. The system-level market price reflects the balance of electricity production and load demand, and the states of the electricity production sources. Hence, the market price reflects the costs at the electricity system level. The Nordic market is divided into bidding areas to take into account the constraints of the transmission system. Figure 5.1 shows the average Finnish area prices at different times of day in the years 2014–19.

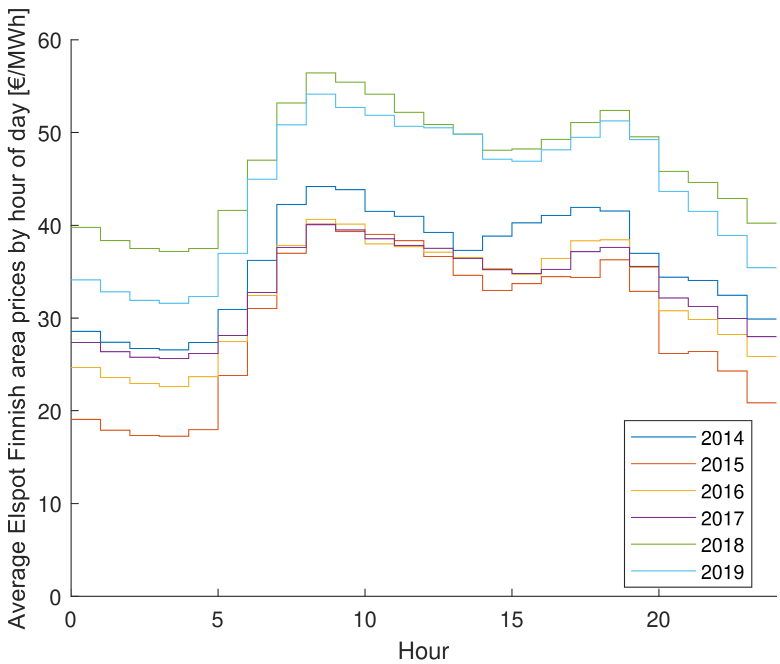

Figure 5.1: Average Elspot Finnish area price during different times of day in the years 2014–19 (Nord pool AS, 2021)

It can be seen from the figure that there have been differences in the Spot prices between different years. These differences can be due to the availability of hydro power, the heating demand, and the import or export of electricity. It can be noticed that the daily profile is similar in different years. The electricity market price typically increases after people wake up in the morning and go to their workplaces. The prices are mainly high until early evening. In the evening, prices start to decrease and are at the lowest at night.

Figure 5.1 shows that the electricity Spot price is lower in the nighttime, and on average, the prices are at the highest between 8:00 and 18:00. The average price difference between 17:00 and 22:00 varies from 0.72 to 1.05 cent/kWh in different years, at an average of 0.93 cent/kWh. If the annual PBT were 1.00 €/kW/month, exceeding a customer's present peak load by 1 kW would mean a 12 € increase in the annual electricity bill for the DSO. This would mean that the customer would have to use the exceeded power on average for 1200 cent/kWh/h/a/ (365d/a * 0.93cent/kWh) = 3.5 h/d. For customers that have already high peak loads compared with their total electricity consumption, exceeding the present peak load for 3.5 h/d on average would require lots of controllable loads, which does not seem realistic. The PBT would limit the customer's load demand only during the hours when the customer's load is already at the highest. At other times when there is capacity available, the flexibility would not cause costs to the customer if the peak demand was not exceeded.

A PBT would most likely prevent customers' consumption peaks from increasing, if only 1 €/kW/month PBT is enough to exceed savings from the Spot-price-based control. On the other hand, the PBT does not have an effect on how customers' loads are controlled if their peak powers do not increase. From the DSO's viewpoint, the target of the tariff development should not be to prevent flexibility actions, but to direct the flexibility to such places where customer loads are not already at the highest, in other words, to allocate the flexibility in the grid so that the risks of overloading the grid are lower. The DSO can also analyze which kind of impact it would have on the grid load rates if the peak demand of customer loads was harmonized. In reality, the flexibility of customer loads is individual.

(Supponen et al., 2016) have studied the effects of retailer-tariff-based customer load optimization and how the introduction of a power band tariff would affect customers' load optimization and thereby the MV network load flow. The study showed that distribution network load rates could increase significantly if customers optimized their loads based on the retailer tariff. If a PBT was introduced, the adverse effects for the grid infrastructure would be limited.

Similar results have been found in publications (Steen et al., 2016; Batista Abikarram et al., 2019), in which operating schedules of customer appliances were optimized based on energy-based tariffs or power-based tariffs. In (Steen et al., 2016), the authors studied how a PBT would affect customers' incentives to control their household appliances, for example, a dish washer, a laundry machine, a cloth dryer, and a plug-in electric vehicle, and how these load control actions would affect the grid load. The PBT was assumed to be based on daily or monthly peak powers. In this study, most of the customer loads were simulated to match the load curve of the total area. The optimization of customer loads was carried out with a customer scheduling model proposed in (Steen and Carlson, 2013). The analyses were made in a Swedish urban network with 1932 customers in the 10 kV system and 62 customers in the LV network. This kind of approach where customer data are simulated at the appliance level is very interesting but involves a lot of uncertainty.

5.2 Energy storage systems and automation

Energy storages and automation provide an opportunity to modify the load curve seen in the distribution grid so that the customers do not need to change their load patterns or reduce their comfort. Currently, energy storages other than electric storage heating or domestic water heating are uncommon. The development of BESSs and automation systems is opening opportunities for load demand flexibility, modifying the load curve of a customer without the customer even noticing the change. The unit prices of battery systems have been declining in the 2010s (BloombergNEF, 2020). BESSs can also be employed to operate many different tasks depending of the owner and location in the grid, but in this doctoral dissertation, the focus is on the end users' BESSs. BESSs can also be used in the distribution grids for congestion management or as a backup during grid outages. From the viewpoint of the PBT, the main interest lies in using the BESSs to reduce a customer's peak demand by peak shaving.

5.2.1 Customer-side peak shaving

The main principle of peak shaving is that the customer acquires flexibility by investing in the BESS. This flexibility is used to shift part of the customer's demand during the customer's peak demand to a later time so that the customer's load seen in the distribution grid will be more evenly distributed. The customer's peak demand decreases, and thus, the customer pays a lower power-based fee. Energy-storage-based modeling can be used to estimate the customers' potential for decreasing their peak power (peak shaving potential) taking into account that in reality, the reaction can take place without an actual BESS. By studying the peak shaving potential with a BESS model, it can be estimated which kind of energy flexibility is required from the customers to reduce their peak demand. To estimate the peak load shaving potential with different BESS capacities, an optimization algorithm was developed. The algorithm is described in Figure 5.2.

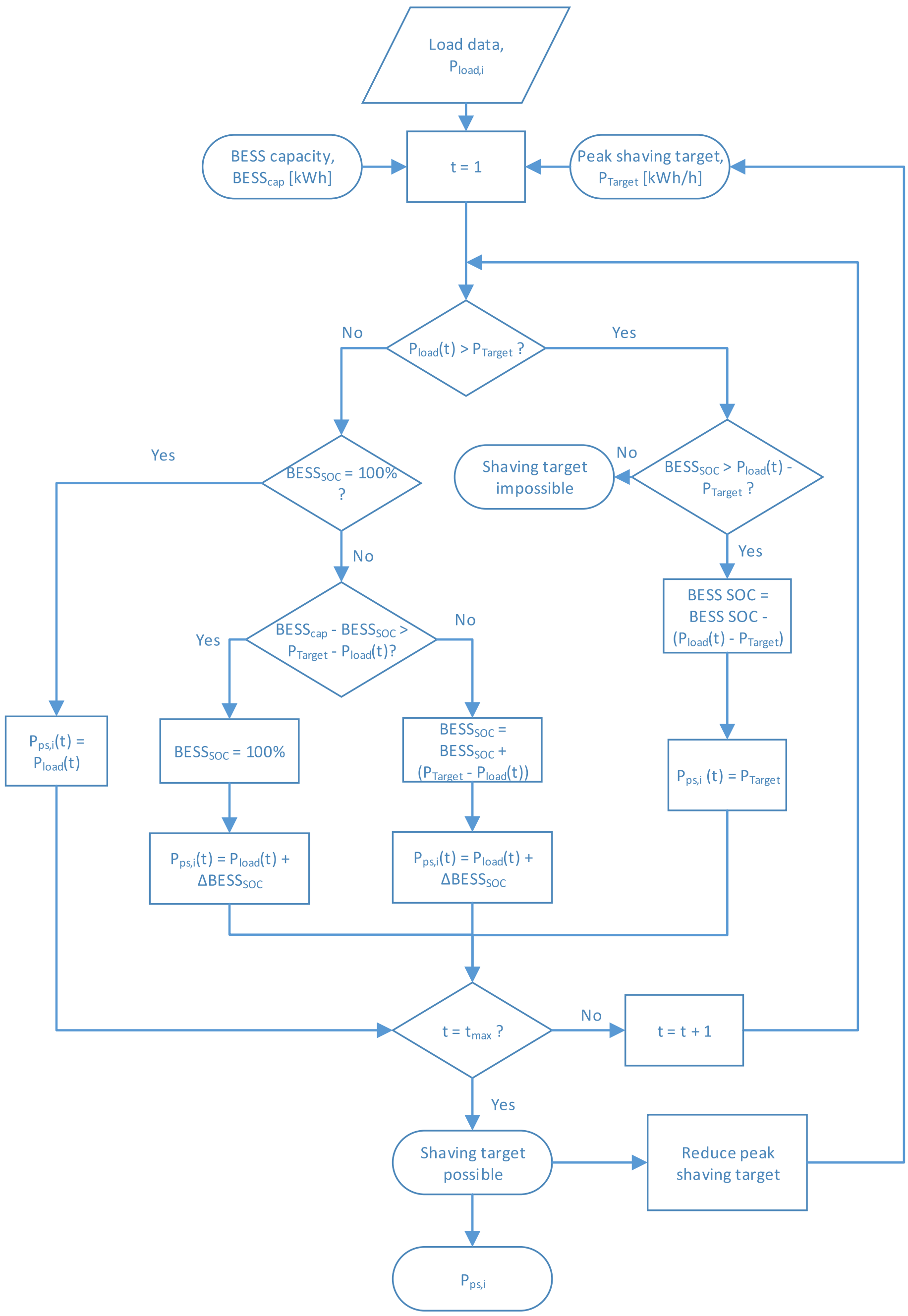

Figure 5.2: Flowchart of the peak shaving algorithm.

The algorithm aims to estimate the lowest achievable peak power level with the BESS used for peak shaving. As the input, the algorithm takes the customer's load data, the

BESS capacity, and the peak shaving target. In this doctoral dissertation, the peak shaving target was set to cut the customer's peak load with 0.1 kW steps starting from the present peak load and continuing as long as it was possible with the chosen BESS size. In the model, the customer's load data are simulated hour by hour. If the customer's hourly consumption exceeds the chosen target power, the consumption exceeding this power is provided from the BESS if possible. The BESS is charged after the customer's load does not exceed the target power anymore.

Figure 5.3 illustrates the effect of peak shaving for an example customer during three winter days. In this example, the losses were assumed to be 0%. The nominal capacity was assumed to be available for use. These assumptions can be altered in the optimization algorithm; here, the assumptions were made to represent the peak shaving potential in a case where the peak shaving is not necessarily made with a BESS. The horizontal lines represent the maximum power after peak shaving with different BESS capacities.

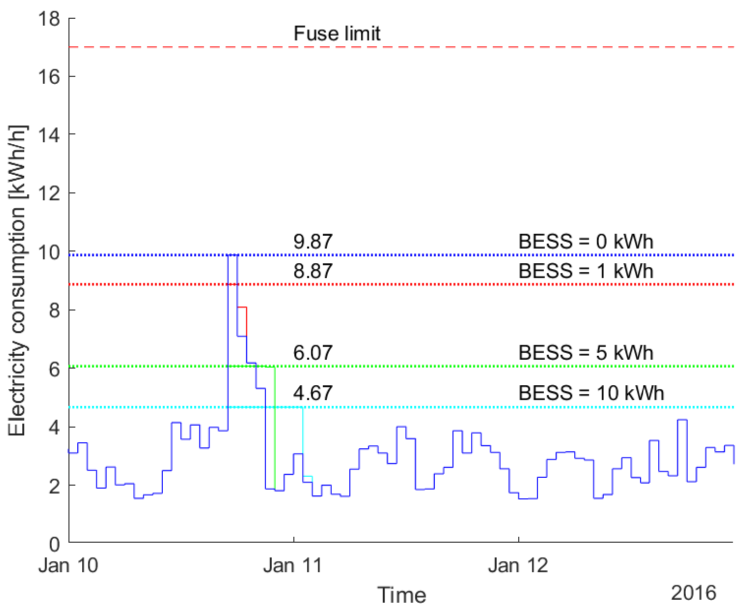

Figure 5.3: Peak shaving estimated on customer load data.

It can be seen from Figure 5.3 that the peak shaving shifts the customer's load from the peak load hour to the next hours. Figure 5.4 shows the effects of peak shaving at an annual level.

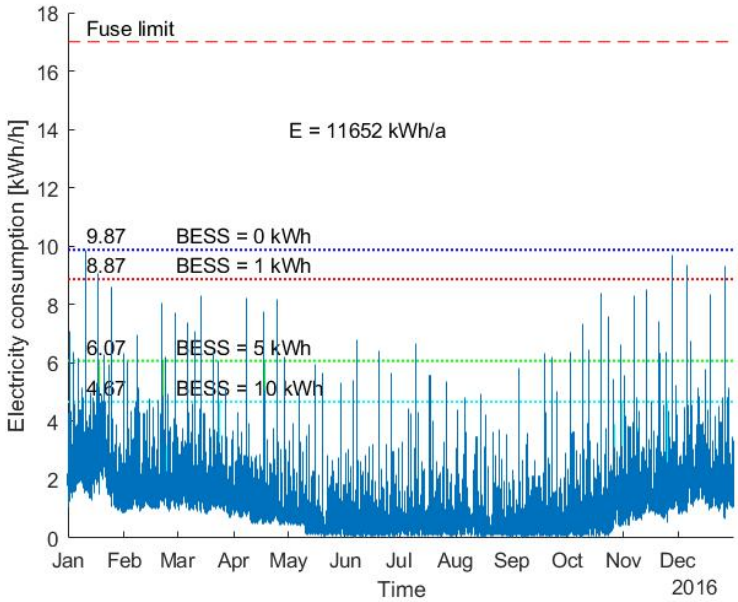

Figure 5.4: Peak shaving estimated on customer AMR data, the year 2016.

It can be seen in Figures 5.3 and 5.4 that the energy storage capacity needed for peak shaving increases rapidly when the target peak power level is set lower. For example, in this customer's case, a 1 kWh storage could reduce the peak power by 1 kW, but a 5 kWh storage by 3.8 kW, and a 10 kWh one by 5.2 kW. The reason for this is that more consecutive hours of peak load have to be cut if the target peak power is set lower. When the peak shaving potential of all customers is estimated with the algorithm, the DSO will have combinations of BESS sizes and peak power reduction potentials. The customers' potential to shave their peaks with different BESS sizes is illustrated in Figure 5.5.

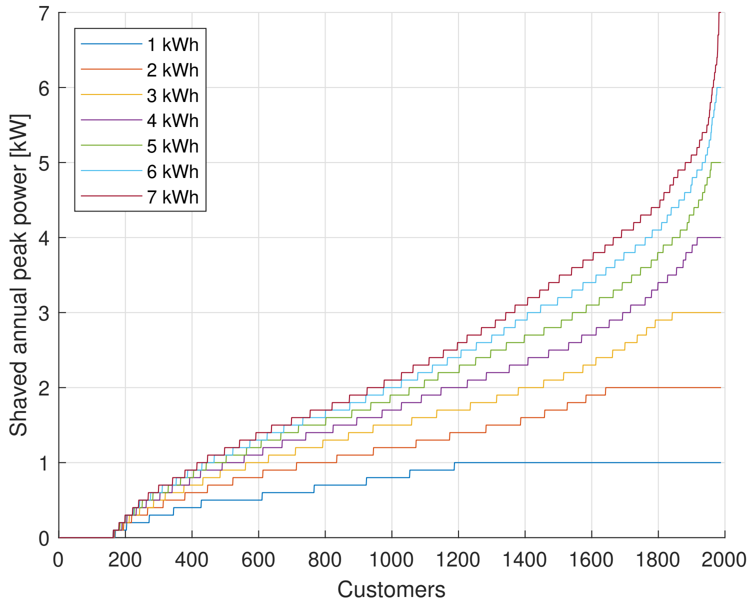

Figure 5.5: Estimated annual peak shaving potential with BESS sizes of 1–7 kWh, assuming 0% of losses. The order of customers can vary with different BESS sizes.

Figure 5.5 shows that the peak reduction potential with peak shaving decreases relatively in most of the cases when the BESS size is increased. This implies that it would be easier to shave the highest peak, but after the first kW the shaving requires more energy capacity. The full benefit, the 1 kW peak recuction with the 1 kWh capacity BESS, can be achieved by approximately 40% of the case area customers, whereas with the 3 kWh BESS, the proportion of customers who get the full benefit is approximately 7%. When the peak shaving potentials with different BESS capacities are estimated, the DSO can vary the unit price of the PBT and the costs of the BESS to estimate the optimized BESS capacities. From the customer's perspective, the optimization problem can be formulated as

$$\max((\Sigma(\hat{P}_{\mathrm{orig}}) - \Sigma(\hat{P}_{\mathrm{cut},c})) * p_{\mathrm{PBT}} - C_{\mathrm{BESS},c}), \tag{5.2}$$

where $\Sigma(\hat{P}_{\mathrm{orig}})$ is the sum of the customer's original peak powers, $\Sigma(\hat{P}_{\mathrm{cut},c})$ is the sum of the customer's peak-shaved peak powers with the BESS capacity c, p_{PBT} is the unit price of the power-based tariff, and $C_{\mathrm{BESS,c}}$ is the annual costs from the BESS with the capacity c. Figure 5.6 illustrates the optimized peak shaving BESS capacities.

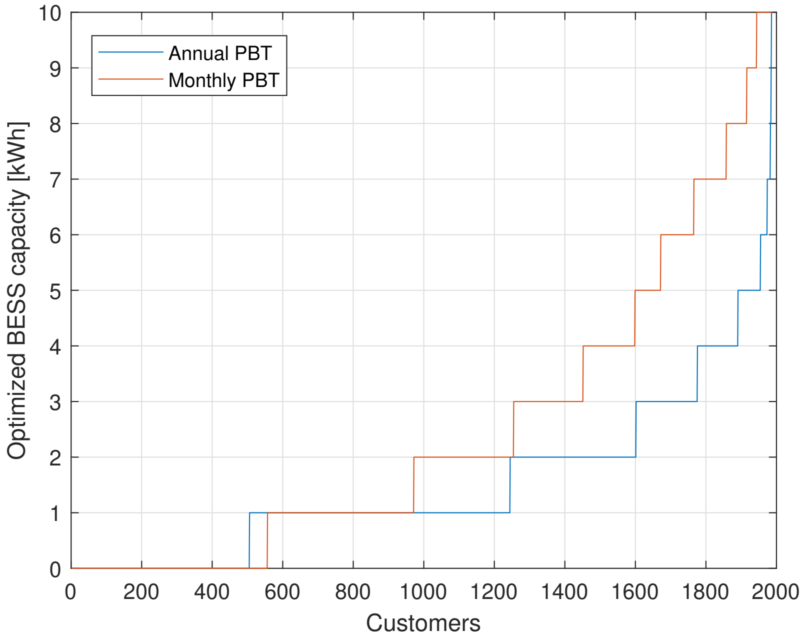

Figure 5.6: Optimized peak shaving BESS capacity. The BESS cost is 400 €/kWh, the BESS expected lifetime is 15 years, and the interest rate is 1%.

It can be seen from Figure 5.6 that in the monthly PBT it is more feasible to the customers to invest in higher capacity BESSs than in the case of an annual PBT. A customer can use the BESS capacity in the monthly PBT to reduce the monthly peak loads, but the customer has to use the capacity in the annual PBT only rarely. In the annual PBT, a BESS is feasible for more customers than in the monthly PBT, but the optimized capacities are smaller. This can be due to the seasonal variation in the customer loads. Hence, in the annual PBT, the wintertime base load of the customers can be relatively high, and there is no need to shave the peaks outside the heating season. It may be possible to reduce the highest peak with a small BESS capacity during the heating season, which can benefit the customer the most in the case of an annual PBT. In the case of a monthly PBT, the number of feasible peak shaving BESSs can be lower, because there can be customers, such as leisure homes, who do not consume electricity throughout the year, and thus, there is no peak shaving potential.

In practice, the most challenging part in the optimization is the prediction of the customer's hourly consumption. There is uncertainty about when the peak load will occur, how significant it is, and whether there are also consumption peaks on the following hours. If the BESS capacity is optimized too accurately to shave the customer's consumption peaks, the BESS's state of charge can run low too early, and the peak shaving can be unsuccessful. For this reason, the peak shaving BESS capacity should be slightly overdimensioned.

5.2.2 Benefits of peak-shaving-driven BESS investments for solar PV production

Customers can buy an energy storage to reduce their peak power demand, and the storage can be exploited to increase the customers' PV self-consumption rate. Especially if the PBT was based on the annual peak load, the BESS would be used for peak shaving very seldom in summertime. Hence, the BESS capacity would be available for other uses. It is necessary, however, to consider how this would affect the battery cycle life.

5.2.3 Benefits of peak-shaving-driven BESS investments in other markets

In (Haakana et al., 2017), BESS-based peak shaving and frequency containment were studied. The author of this dissertation performed most of the simulations in this publication. The case area included approximately 10 800 customers. In the paper, the BESS was first optimized for the peak shaving purpose, and then, the available BESS capacity was used to participate in the frequency containment market. The customers' original AMR load data were modified with a peak shaving algorithm described in Section 5.2.1 and with a frequency containment algorithm, and then, the grid load changes were studied at different levels of distribution grids. The study showed that the PBT-based BESS peak shaving could be profitable for many customers if the PBT unit price was high and the grid load rates mainly decreased, but participation in the frequency containment market could cause an increment in the grid loads. Customers' willingness to take the risk of increasing the peak power by participating in other markets was, however, not studied. The benefits of a BESS can be maximized by multiobjective operation (Belonogova, 2018).

5.2.4 Effects of BESS peak shaving on the distribution grid

The BESSs acquired to minimize the customer's PBT shift the loads from the highest peaks to be more evenly distributed on the customer's load curve. From the grid management perspective, it is important to know how the customer's peak shaving affects the load rates in the distribution grid. Next, the effects of the peak shaving BESSs on the secondary substation transformer's load rates is studied. Figures 5.7 and 5.8 depict the effects of customer-side peak shaving on the peak load of secondary substation transformers.

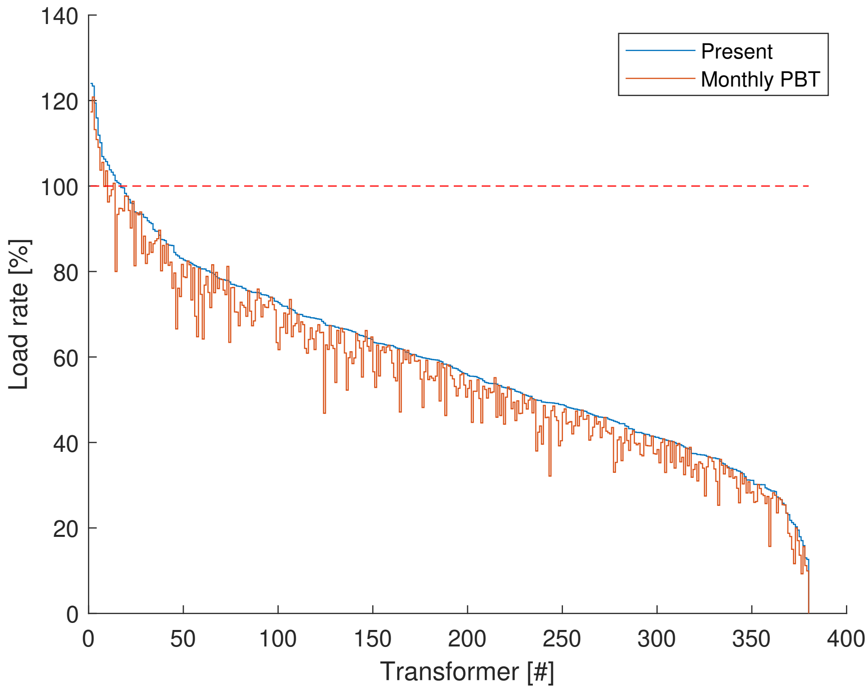

Figure 5.7: Impacts of monthly PBT-based peak shaving on the peak load of secondary substation transformers.

It can be seen from Figure 5.7 that the peak load would be reduced in most of the secondary substation transformers if the customers shaved their peak loads with BESSs. There are also eight transformers where reducing the customers' peak loads would slightly increase the total peak load at the secondary transformer level. This is due to the fact that the present peak loads of the customers can have temporal variation, but by peak shaving, a customer's consumption can be shifted to the times when other customers' load demands are high, thus causing a consumption peak at the secondary substation level.

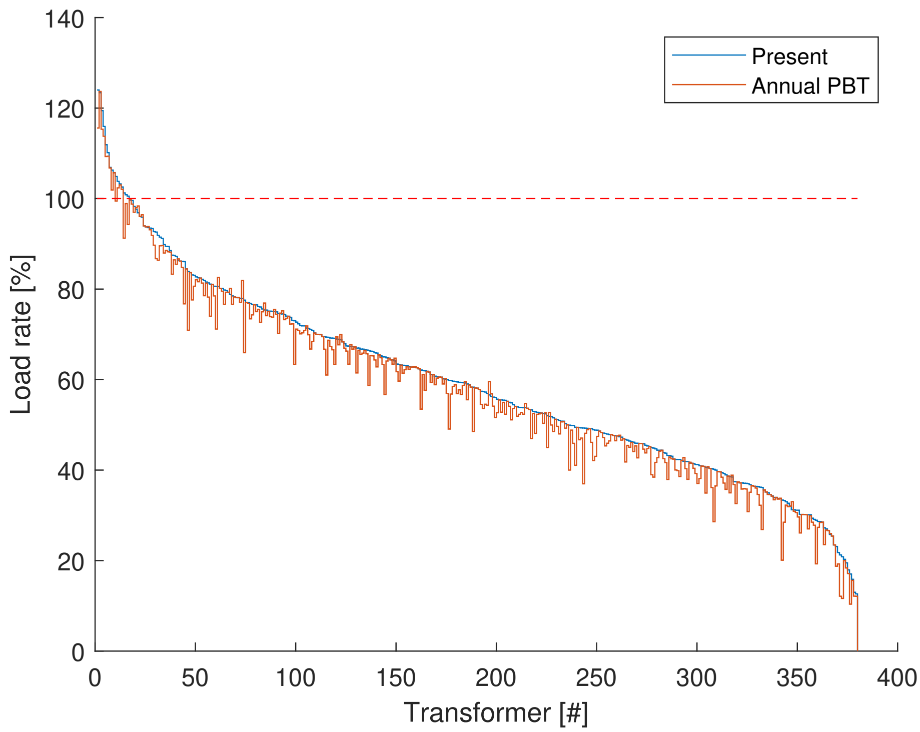

Figure 5.8: Impacts of annual PBT-based peak shaving on the peak load of secondary substation transformers.

By comparing Figures 5.7 and 5.8 it can be seen that the peak-load-reducing effects are higher in the monthly PBT case. The reason for this is that customers can benefit every month from the BESS. Thus, the customers have a greater incentive to acquire a larger BESS than in the case of an annual PBT. In practice, this means that the BESS would be used more often in the case of a monthly PBT than in the case of an annual one, and thus, the cycle life of the BESS can be consumed faster.

5.2.5 Challenges of the PBT-based peak shaving

The PBT-based peak shaving can also lead to a local optimum if the weighting of the peak-power-based fee is set too high. The PBT can provide a great incentive for the customers to invest in automation or in a BESS to reduce their own consumption peaks, and thereby minimize their distribution bill. The reductions in the customers' peak powers can still have only slight effects on the grid dimensioning. This can lead to a situation where customers' investments in their peak load control exceed the benefits gained from the lower grid load rates. In other words, this could lead to a need for the DSO to increase the proportion of fixed fees or raise the unit prices, like the reduction of energy consumption does in the case of present energy-consumption-based tariffs.

An investment in peak shaving with a BESS can also be risky for the customer if the peak shaving target is set too optimistic and the profits from the peak reduction fall while the costs remain. In the monthly PBT, the risk is lower because the consequences of failing in setting of the target power have an effect on that month only, and thus, the consequences of the materialization of the risk are lower. In the annual PBT, the load peak causes higher costs for the whole year. Hence, taking into account the typical lifetimes of BESSs, approximately ten years, failure in peak shaving in one year can totally ruin the profitability of the investment. However, a BESS or an automation unit can be acquired for some other reason than peak shaving, and peak shaving can be run as a secondary task that supports the grid load rates. If the customer can cover the BESS costs with some other task, the benefits from peak shaving are a bonus. Nevertheless, peak shaving BESSs can have an impact on the cost-reflectiveness of the tariffs and the cross-subsidies between the customers.

5.3 EV charging

Charging of EVs is probably the most significant element for the DSOs in the development of future loads (Lassila et al., 2019a). EV charging is a new load that increases a customer's total electricity consumption by a few MWh, which is approximately 10–20% of the annual consumption of a typical Finnish detached house. The increase in the total consumption depends on how much the customer drives the EV and how much the vehicle is charged elsewhere than at home. The increment in the peak load demand of a customer depends on the load profile of the customer, the choice of a charger, and EV charging patterns.

Over the past decade, EV charging has been a popular topic of scientific publications on electricity power systems. It has been recognized that uncoordinated charging of EVs can cause problems for the electricity distribution infrastructure. Many different algorithms for coordinating EV charging have been developed to manage the risks. To this end, different coordinated charging solutions have been studied for instance in (Deilami et al., 2011; Huang et al., 2019; Jin et al., 2013). Typically, coordinated charging would require communication between different EV chargers to optimize the total load. This kind of solution would probably be efficient in public charging stations or other places where many EVs are charged simultaneously close to each other, like at workplaces. Outside population concentrations, in rural areas, this kind of approach could be challenging. Furthermore, coordinated control of chargers would also require a wide approval of customers to be successful.

With a PBT, the DSO can attempt to affect the customers' EV charging with a price signal. In the PBT, the customers' incentive would be to avoid increasing their peak demand with a new load. Thus, a communication system between customers' EV chargers is not needed. Moreover, the PBT is an incentive in which customers can make decisions on whether they want to charge their vehicles fast and pay more or use grid capacity more efficiently and pay less.

With the current tariffs, the main reason for the need to control EV charging is that charging may lead to exceeding of the load limit of the customer's main fuse. Exceeding the limit set by the main fuse size would require increasing of the connection size, which can cost from hundreds to thousands of euros depending on the location of the connection. Otherwise, customers have only minor incentives to control the charging. With the PBT, customers have an incentive to avoid increasing their peak power. To be able to control their EV charging, customers would have to invest in a smart charger. An investment in a smart charger is profitable if savings in the distribution tariff are higher than the cost of the smart charger.

5.3.1 Methodology for modeling EV charging without a PBT

Modeling of EV home charging in the case of customers who do not currently have EVs is a complicated task. There are multiple variables that cause uncertainty from the perspective of grid load analysis. The first question is which customers will adopt an EV in the future. Next, it is important to know when the EV owners start to charge their vehicles. Further, the charger characteristics, such as the maximum charge rate and number of phases, are important factors when estimating whether charging of EVs causes challenges for the distribution grid infrastructure. Yet another aspect to be considered is charging elsewhere than at home, like at work or at public charging stations.

Because there is not enough information on how future EV owners will charge their vehicles, the EV charging events can be simulated based on surveys made on driving habits (Rautiainen, 2015). It can be assumed that customers' need for transportation does not change significantly when they change their old combustion engine vehicles to EVs. Thus, the present driving patterns can be used in the modeling of EV charging.

In this doctoral dissertation, EV charging is first modeled as dumb charging, meaning that charging is carried out with the full power that the charger allows, assuming that the customer's main fuse limit is not exceeded, starting right when the customer has arrived home. Full-power charging continues until the EV battery is fully charged or the customer unplugs the EV. Figure 5.9 illustrates the algorithm of uncontrolled dumb charging.

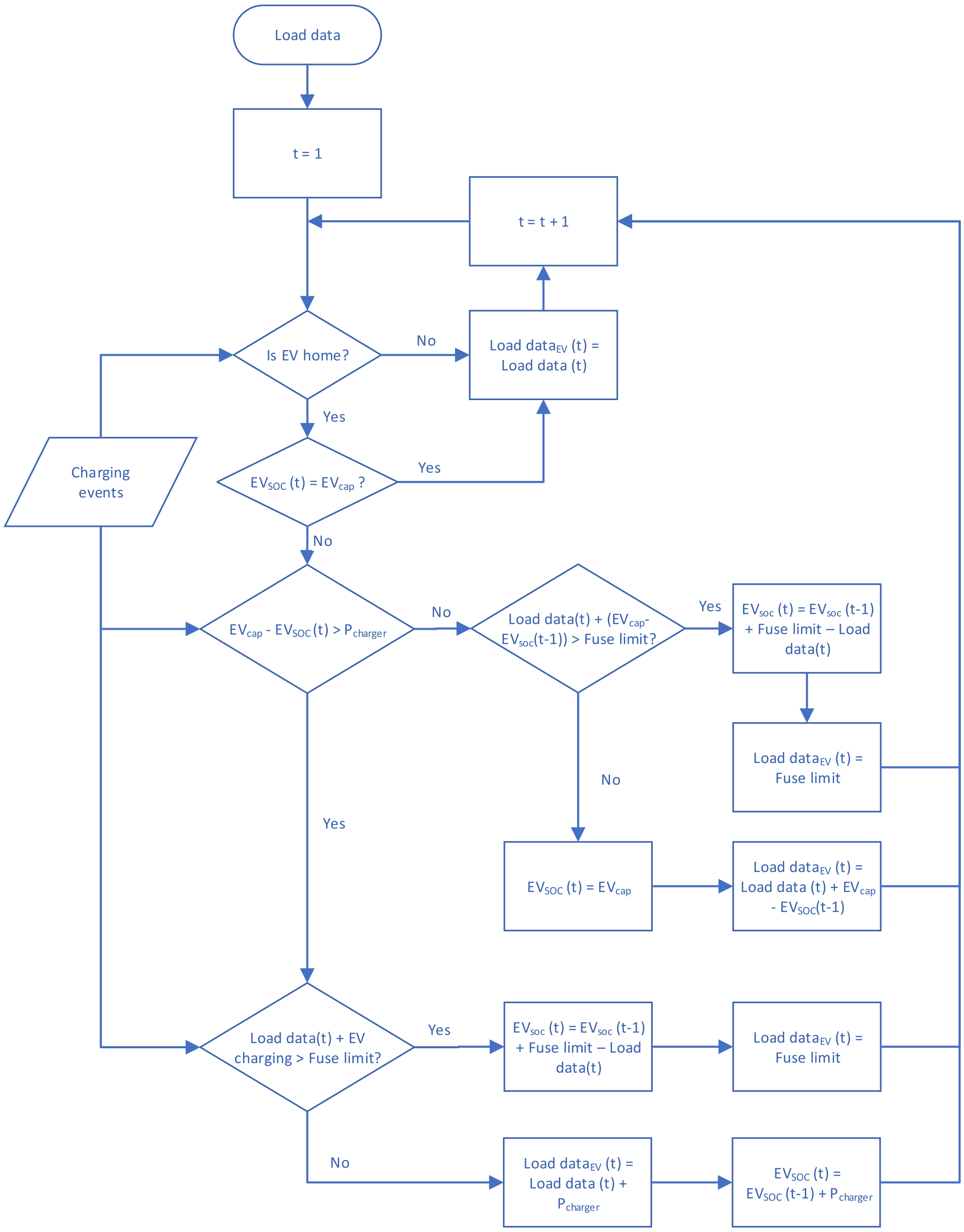

Figure 5.9: Flowchart of the EV dumb charging algorithm.

The simulation algorithm was made on an hourly basis. Charging events were simulated for each day and for every customer, including the home arrival time, the charging demand of the EV, and the home departure time. The target of the algorithm is to simulate customers' hourly load data with EV charging. In Figure 5.9, $\text{EV}_{\text{SOC}}(t)$ is the EV state-of-charge (SOC) at hour t, EV_{cap} is the EV battery capacity, Load data(t) is the customer's present load at hour t, Load $\text{data}_{\text{EV}}(t)$ is the simulated load curve with EV charging, and P_{charger} is the nominal power of the customer's EV charger. The algorithm begins from the first hour of the analysis time period. If the simulated EV charging event data show that the EV is not at home, the simulation moves to the next hour. If the EV is at home, the EV SOC is studied. If the EV battery is full, the simulation moves to the next hour. When the EV is at home and the battery is not fully charged, it is studied whether the charger could charge the battery during that hour. After that, it is studied whether the present load and the charger demand exceed the fuse size limit of the customer's connection. If charging cannot be carried out without exceeding the fuse size limit, charging is limited to the fuse size limit. Otherwise, charging is carried out at the full charger capacity, and the simulation moves to the next hour. As an outcome of the simulation, customer-specific customer-consumption-matched EV charging load time series can be formed.

5.3.2 Methodology for modeling EV charging with a PBT

When charging is controlled, it is more important to know when the customer will leave home, which limits the possible duration of charging. The PBT-optimized EV charging algorithm uses the same charging events that were simulated in the dumb charging scenario. The target of the algorithm is to shift the EV charging based on the customers' load data and present peak powers so that increments in customers' peak powers are minimized and the EVs are fully charged every day.

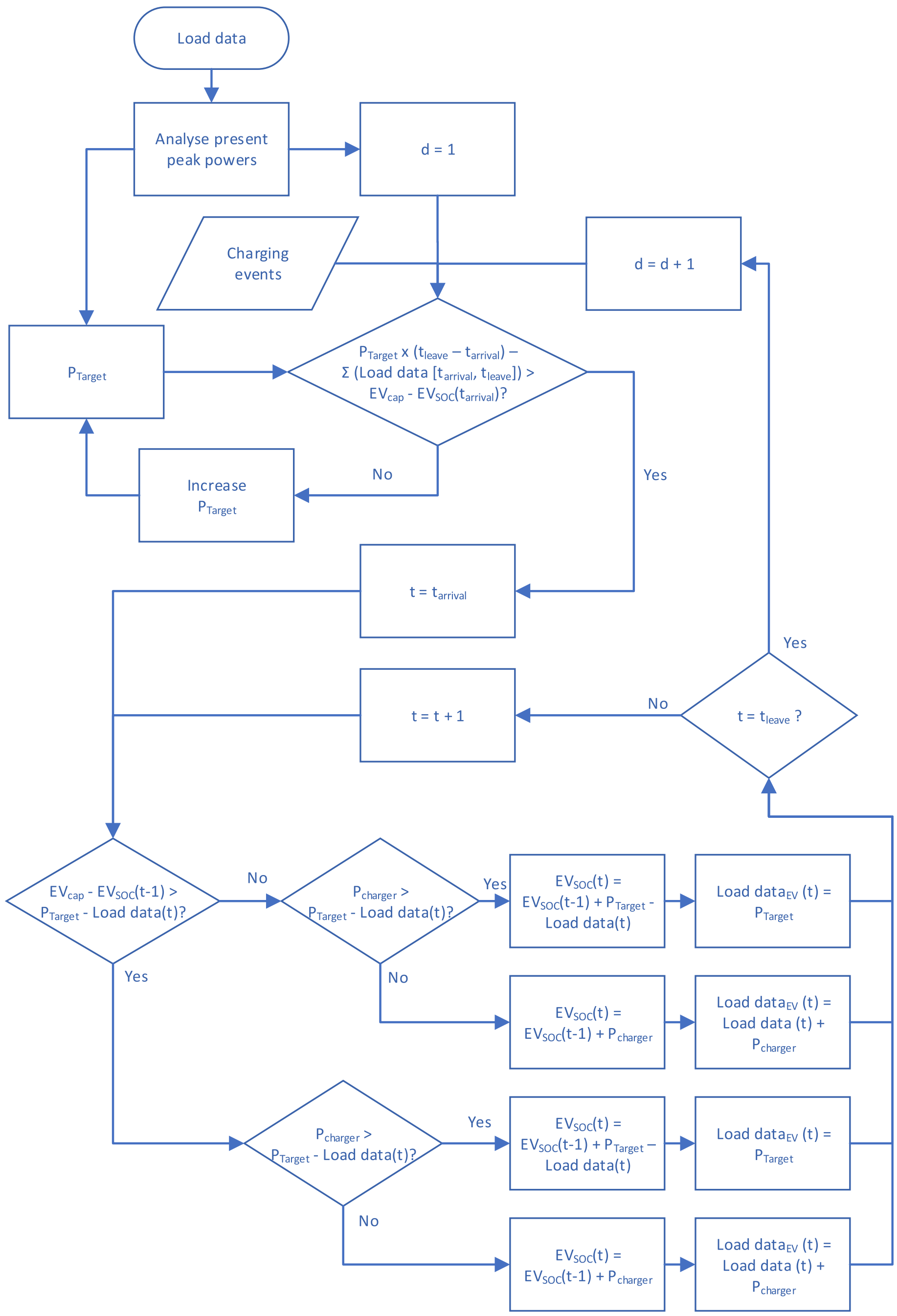

Figure 5.10: Flowchart of the PBT-optimized EV charging algorithm.

In Figure 5.10, d is the day index, $t_{arrival}$ is the hour when the EV arrives home, t_{leave} is the hour when the EV is expected to leave home, and P_{Target} is the target peak power. Peak-power-optimized charging was modeled so that the customer's present peak power was first defined from the load data. In the simulation, for each day, the capacity available for charging between the home arrival and departure of the EV, without exceeding the target power, was estimated and compared with the energy demand of the charging event. If EV charging can be carried out without increasing the target power, the hourly charging curve should be studied next. From the time of arrival onward, the charging will be carried out with the full charger capacity or the capacity between the target power level and other loads of the customer, whichever is lower at the time. The use of the capacity between the chosen target power level and the other load continues until the EV battery is fully charged. Figure 5.11 illustrates 3.6 kW charging without a control and with a control that aims not to increase the total monthly peak load of the customer.

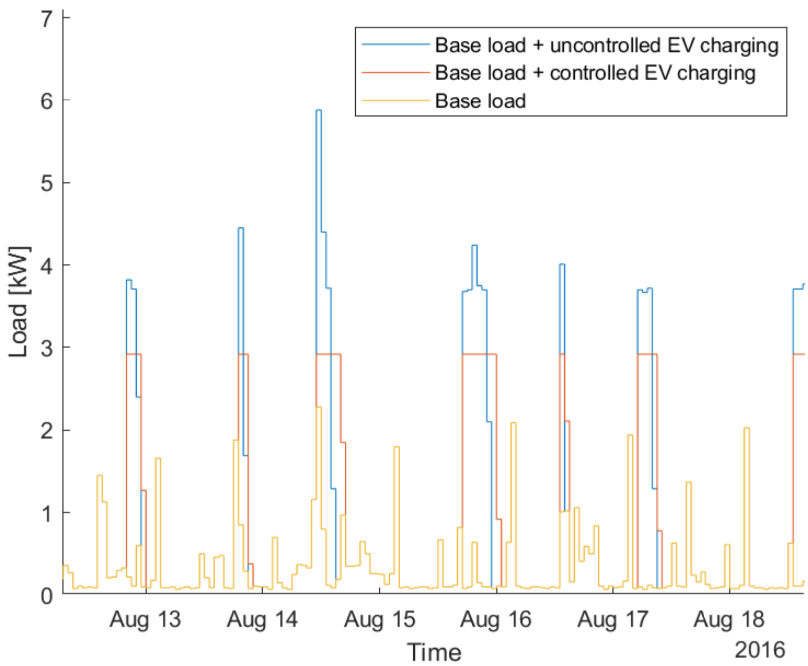

Figure 5.11: Example of a customer's load with uncontrolled EV charging and EV charging that aims not to exceed the present monthly peak power.

It can be seen that the uncontrolled EV charging can cause consumption peaks in the customer's load demand. By controlling the EV charging to avoid an increase in the peak loads, the effects on the customer's load curve can be managed. The control of the EV charging naturally extends the time required for the charging to complete. The challenges in combining EV charging and the PBT come mainly from predicting future loads. When considering modeling of the EV charging at the customer and local distribution grid level, there are many sources of uncertainty. Because EVs have only started to penetrate the market over the past few years, there is still limited knowledge of who is going to buy them in the coming years, when and where they will be charging their vehicles, where these customers will be located in the distribution grid, and how flexible they will be for the control of EV charging. EV charging can cause a high power peak if there is no incentive for the customers to control their EV charging. There have been studies attempting to identify potential EV owners (Priessner et al., 2018).

5.3.3 Benefits of power-based-tariff-driven EV charging for customers

Compared with energy-based tariffs, PBTs can either increase or decrease a customer's cost of charging the EV. Here, the cost allocation of the tariff structure plays a significant role. If customers can optimize their charging patterns so that the peak power does not increase and if part of revenue collected with the present volumetric charge is collected with the PBT, EV charging can be even cheaper than it is today. The effect of EV charging on an individual customer's electricity distribution bill is complicated to estimate in the case of the PBT. The effect is significantly dependent on how charging is managed. If the EV charging is carried out simultaneously with the other demand, the customer's peak demand will increase, and thus, distribution bills will increase.

The customers can attempt to optimize their EV charging also based on other price signals in addition to the PBT without causing an increase in the peak-power-based fee. In this case, the customer takes a risk of an increment in the peak load or stopping of the charging before the battery is fully charged. In practice, the PBT would steer the charging loads to the nighttime when there is typically more capacity available in the electricity system and in the distribution grids. Thus, the benefits of the PBT-based charging control can be seen also at the higher level of electricity system and in the production, even though the load control is mainly carried out to limit the problems of overloading in the LV grids.

5.3.4 Estimation of effects on the grid load

Without power-based tariffs, customers would probably charge their vehicles immediately after arriving home. Average EV charging models give adequate estimations of how EV charging will affect grid loads at a higher level, but if an individual customer's load patterns are studied with a power-based tariff, a more sophisticated approach for modeling is required.

In this doctoral dissertation, these variables are taken into account by simulating daily charging profiles for all customers. Then, a 30% EV adoption rate is randomized 1000 times to customers, and the effects on distribution grid loads are analyzed. After that, individual customers' EV charging curves are sampled again, and the analyses are repeated. Modeling results of EV charging with the presented methodology are illustrated in Figures 5.12–5.16. The changes in the distribution transformer load rates are analyzed with a 30% EV penetration scenario and 10 kW 3-phase chargers. These simulation results are from one simulation round to demonstrate how the load rates of some transformers can develop. Figure 5.12 depicts the present load rates of the distribution transformers and with simulated 10 kW EV dumb charging.

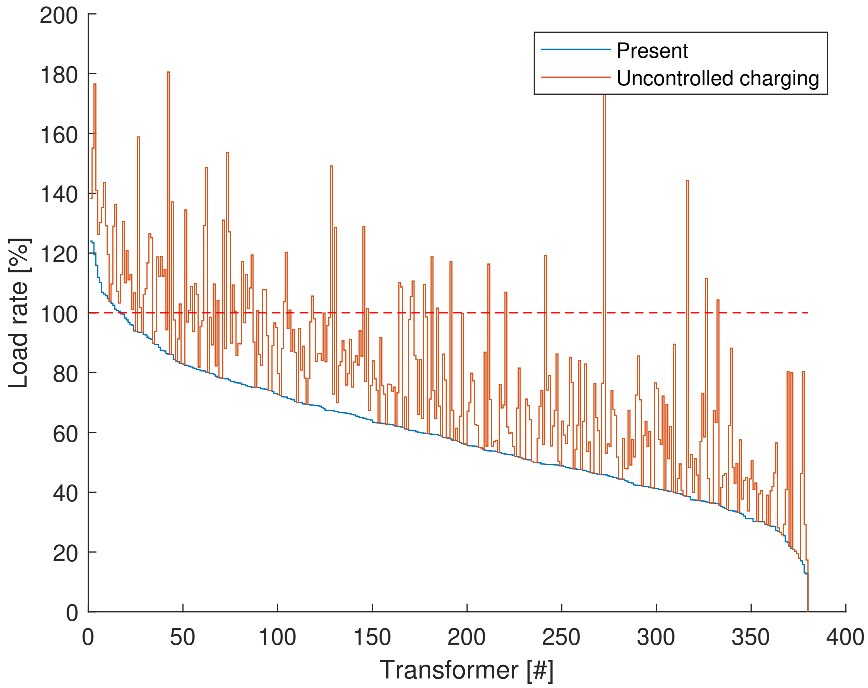

Figure 5.12: Impacts of dumb EV charging on the peak load of secondary substation transformers.

Figure 5.12 shows that 10 kW EV charging can cause significant load increments. There are approximately 20% of transformers that would be overloaded if EVs were dumb charged. Overloading occurs mainly at distribution transformers that are already experiencing a high load. There are also transformers that are currently lightly loaded, but which would now be overloaded. It can be seen from Figure 5.12 that there are already multiple transformers that have a higher maximum hourly load than their nominal power. Slight, no more than 10–15%, overloading can be acceptable, if overloading occurs in cold weather and the secondary substation is a pole transformer, because then the external cooling takes care of the warming effects of overloading. Exceeding the nominal capacity speeds up the aging of distribution transformers if it does not cause a failure; however, it is possible to curb the aging by demand response (Jargstorf et al., 2012). Figure 5.13 demonstrates the effects of the monthly PBT-based control of EV charging on the secondary substation load rates.

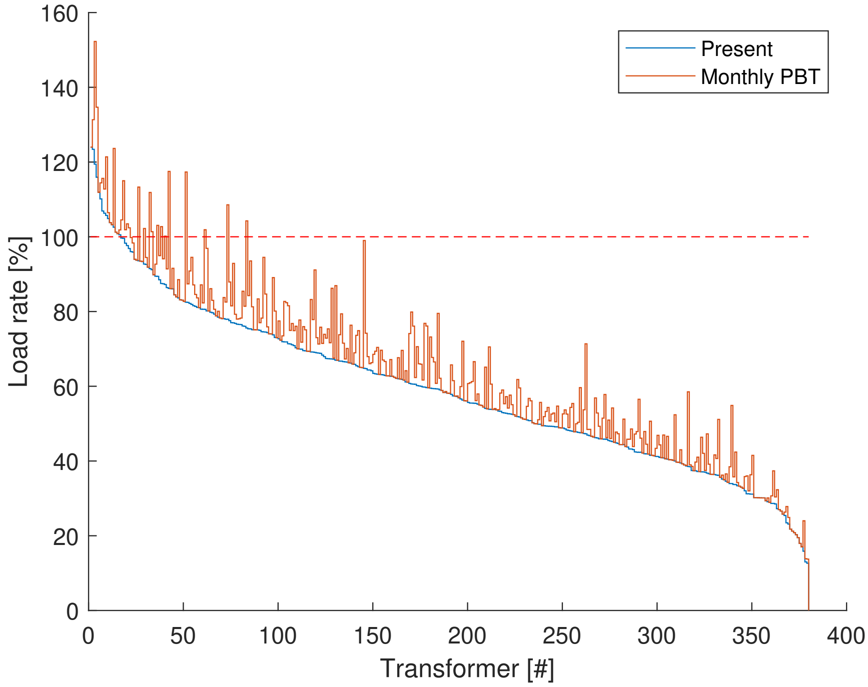

Figure 5.13: Impacts of EV charging on the peak load of secondary substation transformers in the case of a monthly PBT.

In the case of a monthly PBT, the target power level depends on the monthly peak load demand of the customers. Thus, customers have an incentive to control their EV charging every month. By comparing Figures 5.12 and 5.13, it can be seen that the PBT could have a significant effect from the perspective of distribution grid loading. Figure 5.14 shows how the peak power of distribution transformers can develop if customers control their EV charging with the aim of not exceeding their annual peak power.

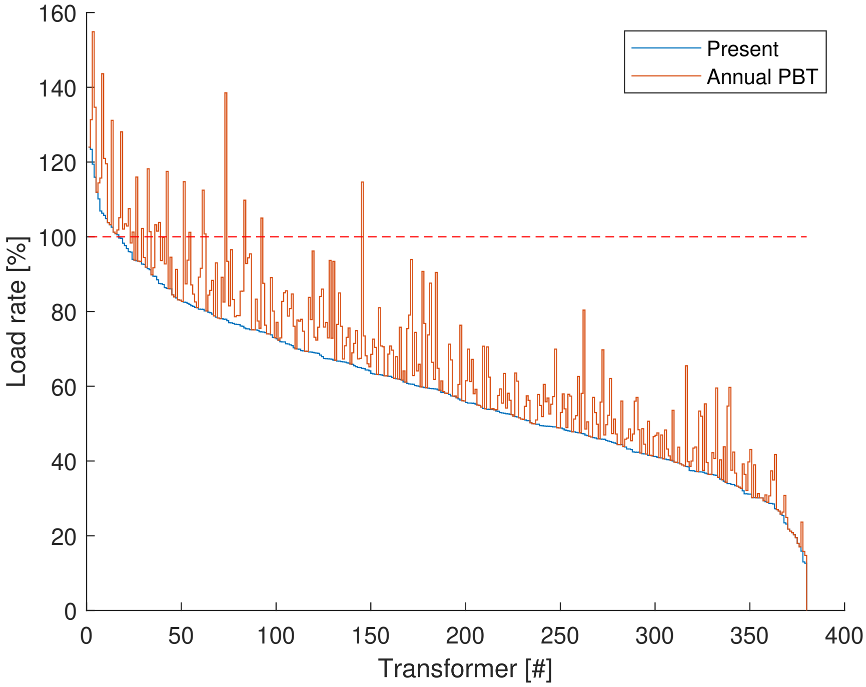

Figure 5.14: Impacts of EV charging on the peak load of secondary substation transformers in the case of an annual PBT.

It can be seen that the peak powers on some distribution transformers are much higher than in the monthly PBT. Even though the customers have a higher incentive to control their loads in winter when heating loads are on, the peak loads are higher on some distribution transformers. This is because the wintertime loads set high annual target loads for individual customers, which leads to the fact that these customers do not have an incentive to control their EV charging against the peak load limitation in the summertime. Thus, EV charging can be carried out without control in many cases, which in summer leads to a similar charging behavior as in dumb charging. In Figure 5.15, a comparison of the impacts of an annual and a monthly PBT-based charging on distribution transformers is demonstrated.

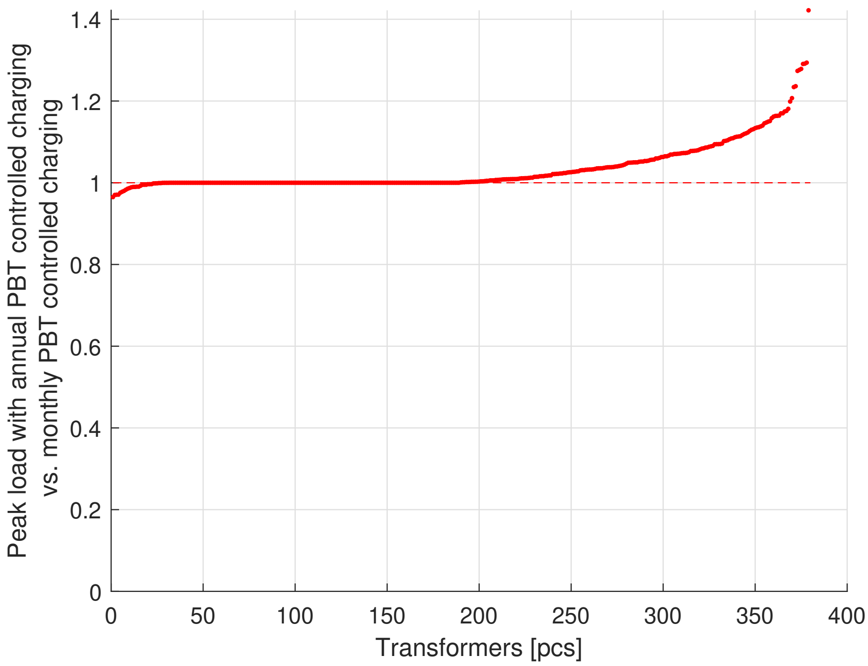

Figure 5.15: Impacts of EV charging on the peak load of secondary substation transformers.

Figure 5.15 shows that on this simulation round, for approximately half of the secondary substation transformers, the monthly PBT optimization would lead to lower peak powers than in the case of the annual PBT. Approximately 5% of the secondary substations would benefit more from an annual PBT.

Similar to the case of automation and BESSs, the risks of the customer are higher in the annual PBT if the EV charging optimization fails. In the case of the PBT-based EV charging optimization, the consequences of the risks are different compared with the peak shaving. If the optimization fails, the peak power does not necessarily increase, but the battery might not be fully loaded. The criticality of the full charge depends on the customer's following days' driving need and the opportunities to charge the EV elsewhere, either at the working place or at public charging stations.

From the DSO's viewpoint, the risks of EV charging are manifold. With the PBT, a DSO can attempt to avoid the realization of the risks, or at least allocate the grid reinforcement costs to the customers that cause the need for capacity increments. On the other hand, the peak powers have an effect on the customer's distribution bill only from a few months to a year, depending on whether the PBT is dependent on monthly or annual peak loads. Thus, the customers can choose to charge their EVs occasionally with a higher power and sometimes control the charging in an optimized way. However, even rare high powers can still lead to the overloading of the network capacity, and therefore, the reinforcement investments can increase the network costs for the next 40–50 years. Thus, the customers can cause a grid reinforcement need with their high-power EV charging before starting to optimize their loads. Hence, the estimations of the effects of the PBT on grid dimensioning include significant uncertainty. Figure 5.16 illustrates the simulated effects of different EV charging scenarios on the secondary substation load rates.

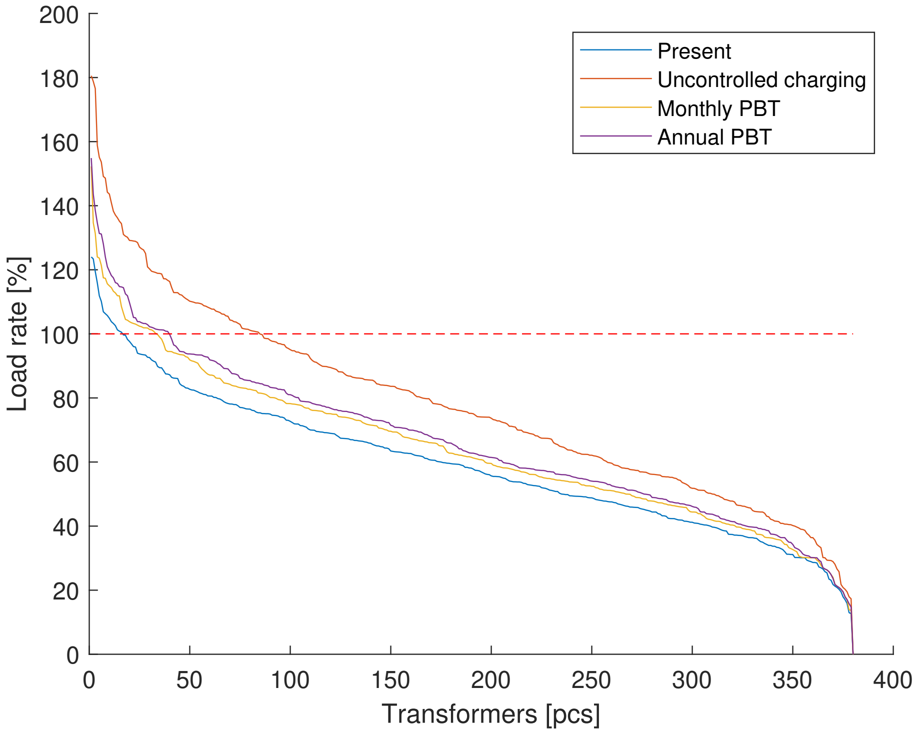

Figure 5.16: Impacts of monthly vs. annual PBT-driven EV smart control on the peak load of distribution transformers.

Figure 5.16 shows that with uncontrolled charging, approximately 20% of the transformers will be overloaded. With PBT smart controls, the number of overloaded transformers increases from the present 5% to 8–10%. The PBT can have a significant effect especially on charging multiple EVs simultaneously at home. Without a PBT, customers have no incentive to limit simultaneous charging of multiple EVs. In the future, when EVs will be common, families with EVs may gather at someone's home and without a PBT, all vehicles will be charged simultaneously after arrival.

To take into account uncertainty in modeling, the simulation must be repeated for a sufficient number of times. Because it is uncertain which customers will buy an EV, it is important to vary the expected location of the EV fleet. Another important variable in the simulation is the EV charging profile, including home arrival time, energy demand, and departure time, of individual customers.

In this doctoral dissertation, these variables are taken into account by first simulating daily charging profiles for all customers. A 30% EV adoption rate is randomized 1000 times to customers, and the effects on the distribution grid are analyzed. To achieve comprehensive understanding of the effects of the EV population in different locations, simulations should be performed many times. 1000 simulation rounds provides an adequate estimation of the PBT effects. Individual customer EV charging curves are varied. The simulation results are shown in Figures 5.17 and 5.18. Figure 5.17 illustrates the effects of EV charging on the peak load rate of the transformers.

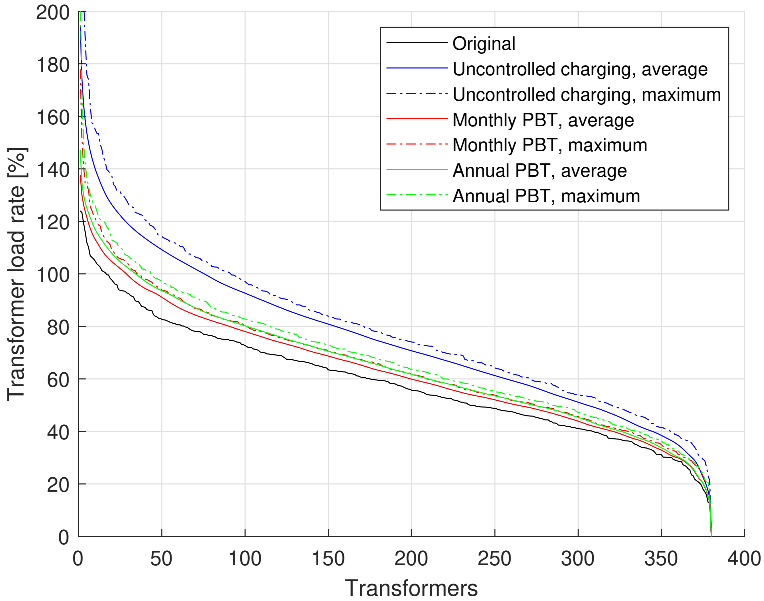

Figure 5.17: Impacts of EV charging on distribution transformer load rates, 1000 simulation rounds.

By comparing Figure 5.17 with Figure 5.16, it can be seen that the effects of uncontrolled charging and smart PBT charging on transformer load rates do not change significantly if the simulation is repeated with different EV adopters. On different simulation rounds, however, changes in the load rates of individual transformers vary. Figure 5.18 shows the number of simulations in which individual transformers were overloaded.

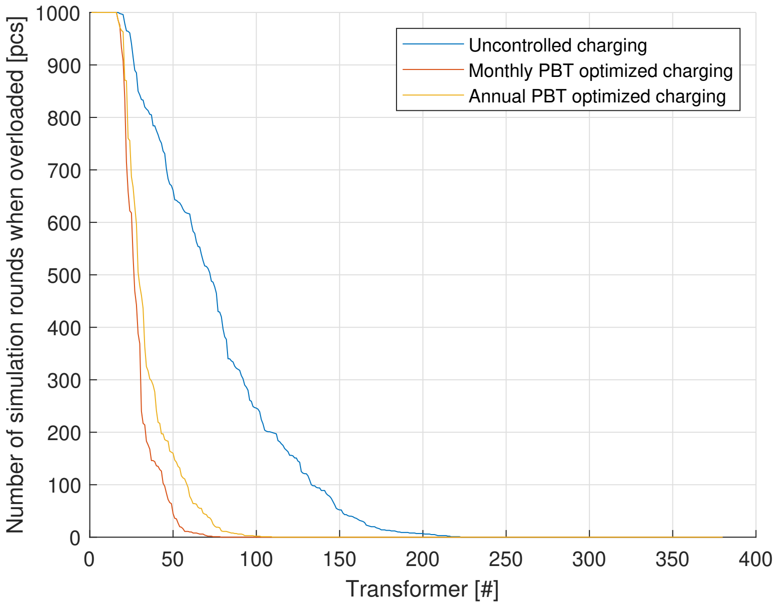

Figure 5.18: Number of simulation rounds when the distribution transformer is overloaded during 1000 simulations.

There are 72 transformers whose nominal capacity was exceeded with uncontrolled EV charging at least in half of the executed simulation rounds. Correspondingly, there are 133 transformers that would have been overloaded at least in 10% of the simulations. PBT-based optimization of EV charging seems to limit the number of overloaded distribution transformers and also the probability of overloading. Thus, the PBT mitigates the DSO's risks in predicting EV adopters. If the risk of overloading seems to concern only a limited proportion of the distribution grid, it can be reasonable to study these grid sections more precisely and estimate whether or not these customers would invest in an EV.

In practice, the customers would probably choose the target peak load above the present peak load at least in some months. This would allow faster charging times than the fully PBT-optimized charging but the customer would have to pay a higher peak-power-based fee. The selection of the target power would most likely depend on the customer's load curve. If the customer's peak loads are already high compared with the customer's base load, there is already capacity that can be utilized for the EV charging without increasing the peak powers. Setting the target power level over the present peak load can be reasonable also because the EV charging requires battery heating in the coldest outdoor temperatures.

5.4 PV production

The solar PV installations affect the customers' load curves by reducing the electric energy demand from the grid and also causing power injection to the grid. A PV load has low controllability and is highly dependent on weather. PV production can be modeled as

$$P_{Prosumer} = P_{Orig} - P_{PV}, \tag{5.3}$$

where P_{Orig} is the customer's hourly demand, and P_{PV} is the hourly production. Reductions in the customers' electric energy consumption reduce the DSO's income gathered with energy-based tariffs. Thus, the development of the tariff structure mainly affects the PV profitability.

With the present tariffs, customers that have installed PV have no incentive to control their production. Thus, data from previous PV installations can be used to estimate the effects on the grid infrastructure by taking into account limitations. Direction, tilt angle, location, and shading of the installation can have an effect on the production curve, and therefore, it is necessary to know that the data are valid to be used for the purpose under consideration.

In Finland, the snow cover during winter months poses a challenge for PV production. Some customers may clean their panels, but probably this is not commonly done. Figure 5.19 illustrates the production profile of 5 kWp solar PV installations in Finland.

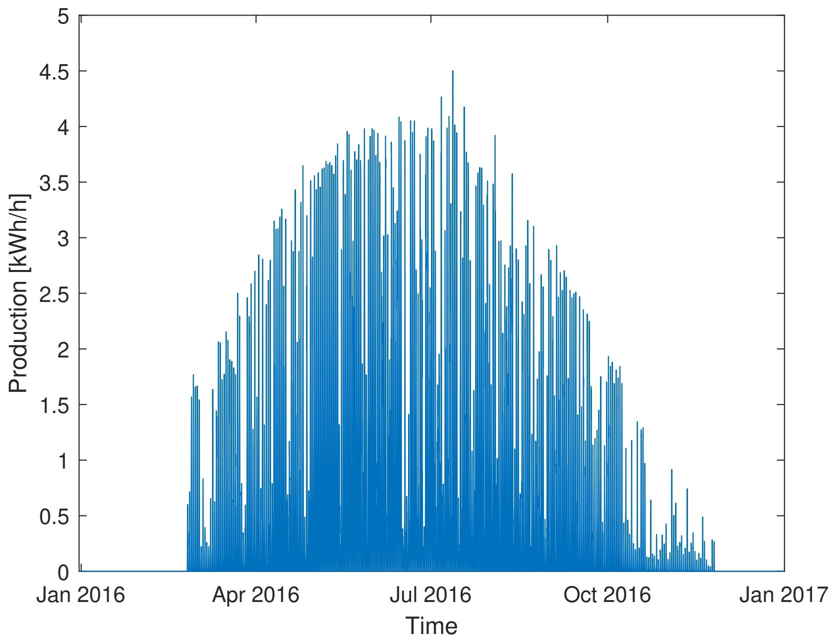

Figure 5.19: Hourly solar PV production curve.

The figure shows that the load profile of the production is highly dependent on the season and weather conditions. In the winter, the production is low because of short daylight hours and snow cover. The development of tariff structure can affect the energy-consumption-based fee and the peak-power-based fee, and thus, it is important to study how customers' benefits from the PV system change if the self-consumption rate affects less and the peak-powers have higher importance.

One major driver that can affect customers' PV investment decisions is the customers' load demand. If the customers can use the electricity produced with PV, the profitability of the installation is higher. Self-consumption rates were estimated with over 85000 customers' hourly data and production data. The production data were scaled to reflect different installed production capacities. Simulated self-consumption rates are illustrated in Figure 5.20.

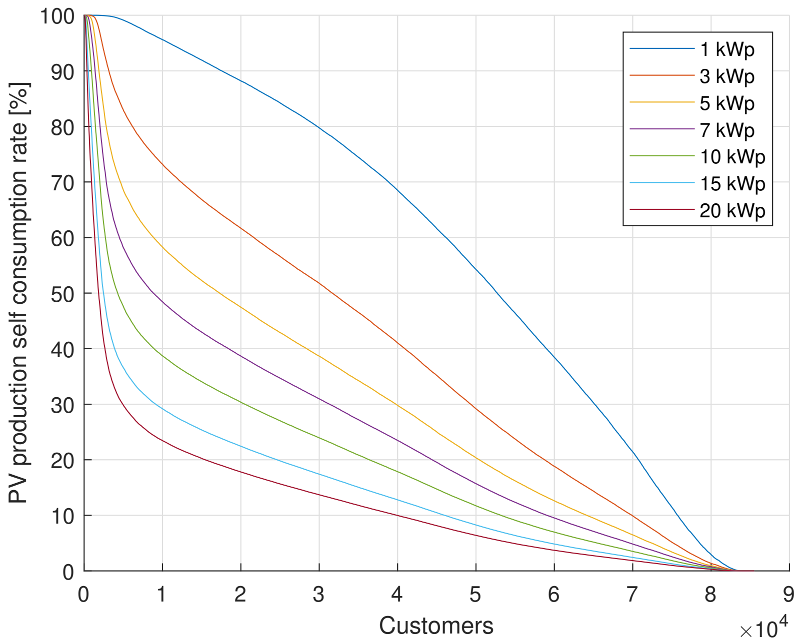

Figure 5.20: Self-consumption rates of PV production for different customers.

It can be seen from Figure 5.20 that the self-consumption rates decrease rapidly for most of the customers when the PV capacity is increased. One-quarter of customers could use half of their PV production themselves with the popular 5 kWp installation capacity. This estimate was made with hourly data, whereas in reality, the self-consumption rates would be lower because of intrahour variations in solar PV production and consumption, and the phase unbalance of loads.

With the PBT, customers can, in some cases, have an incentive to limit the injection of peak production into the grid. This is dependent on whether the injection is considered in the PBT or not, and on the customer's consumption profile. With the annual peak power PBT, the wintertime peak load of a customer living in a detached house with electric heating is higher than the summertime production peak if the PV system is reasonably dimensioned. If the PBT payment is defined by the customer's monthly peak powers, in the summertime also the peak production of a detached house would probably be higher than the peak consumption. In Finland, electric saunas may still cause a high peak demand in summer. For summer cottages and other seasonal customers, the peak production is probably higher than the peak consumption. This, of course, depends on the dimensioning of the PV installation.

The PV production curve is dependent on weather. Future PV prosumers are not well known yet, but there are some variables that the DSO can study to understand who are more likely to invest in PV. The variables of interest include, for instance, rooftop orientation, shading, and present energy demand. If we consider how PV will affect the energy demand from the distribution grid, there is some variation between different years, but when we consider how the PV will affect customers' peak powers, the uncertainty increases. Furthermore, PV can also affect the customers' peak power. Figure 5.21 illustrates the effect of simulated 5 kWp PV on customers' maximum annual power taken from the distribution grid.

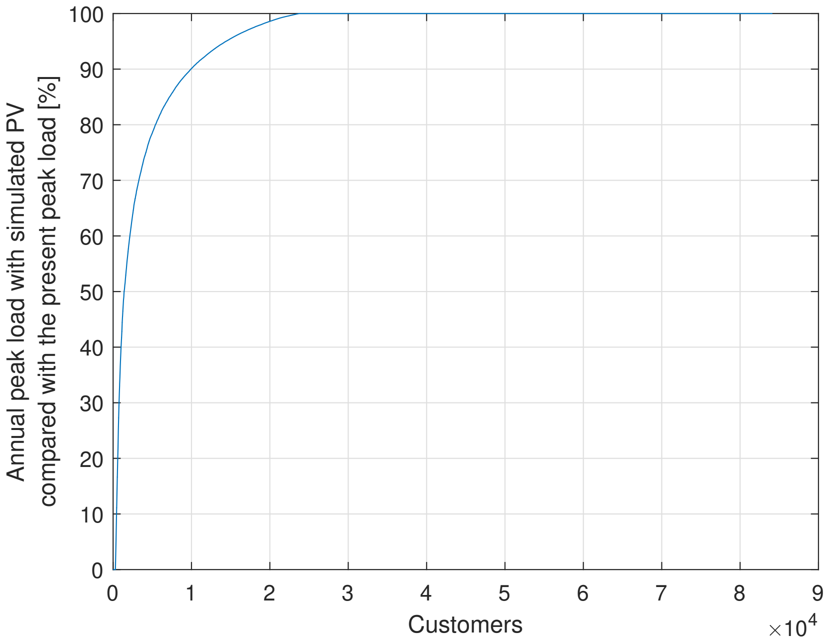

Figure 5.21: Effect of the modeled PV production on the customers' peak load taken from the distribution grid.

Figure 5.21 shows that PV does not reduce the customers' peak power in most of the cases. This is because the customers' peak consumption occurs in the wintertime when heating loads are on and the PV production is close to zero. It can be seen that there are approximately 5 000–10 000 customers whose peak power would decrease significantly. This happens because these customers have already a low consumption that mainly occurs in summer when solar radiation is available. Hence, for these customers, a 5 kWp system could be too large. If the peak power injection into the distribution grid is also considered as the customers' peak power, the simulated changes are shown in Figure 5.22.

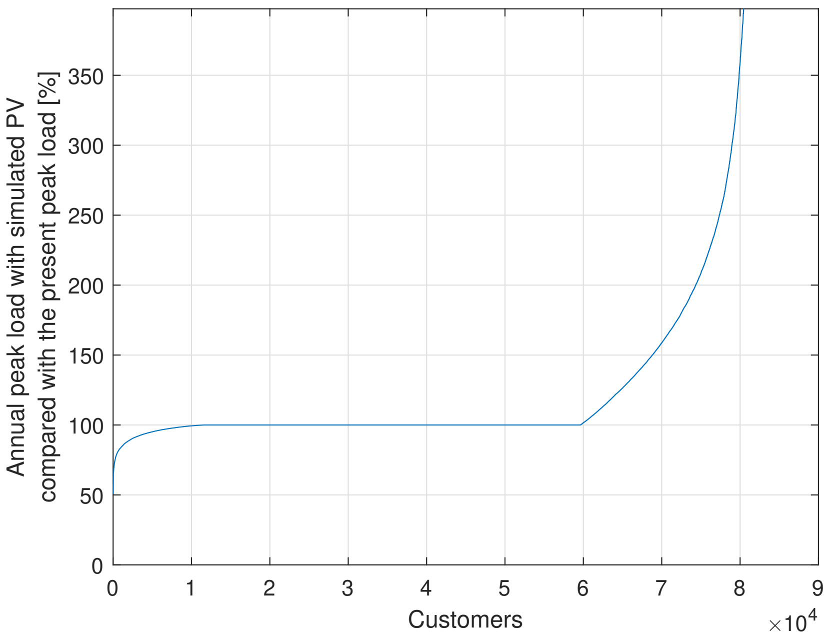

Figure 5.22: Effect of the modeled PV production on the customers' peak load when also the production peak is considered.

Figure 5.22 shows that the PV production would reduce the prosumers' annual peak load in approximately 10 000 cases (12%), increase it in 25 000 cases (29%), and not have an effect on annual peak powers at all in approximately 50 000 cases (59%). The relative increase in peak power would be significant for many customers, but this is due to the fact that these customers' original peak power was low. The tariff structure can be based on a customer's monthly peak load. In this case, the consumption-side peak load effects are demonstrated in Figure 5.23.

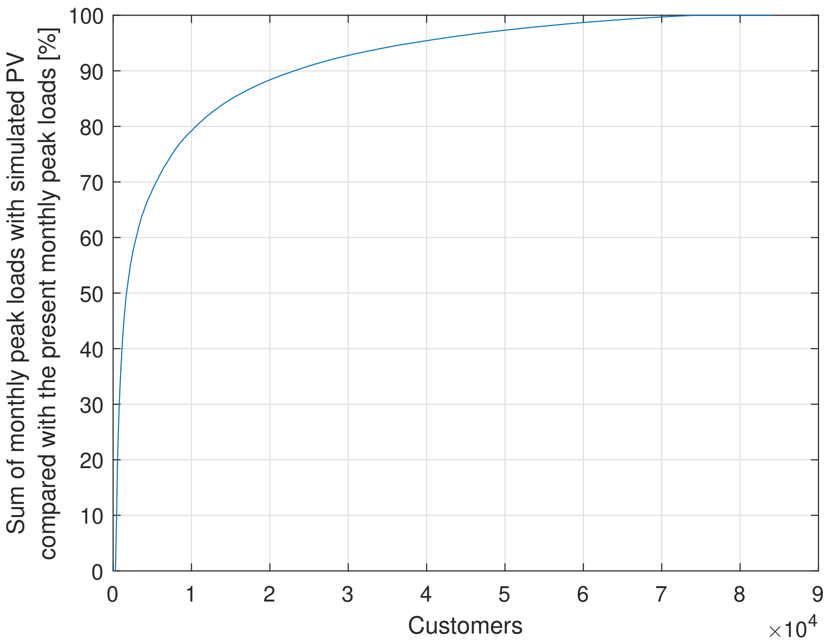

Figure 5.23: Effect of the modeled PV production on the customers' monthly peak loads.

From Figure 5.23 it can be seen that the PV would reduce the customers' total sum of monthly peak loads for most of the customers. The majority of changes does not exceed 10%. This means that most of the customers could slightly reduce the peak power taken from the grid in some months with a PV installation. When compared with Figure 5.21, it can be noted that there are significantly more customers, which would reduce the total sum of monthly peak powers with the PV, but there are still approximately 10 000 customers whose peak powers would decrease considerably. When also the power injected back to the distribution grid is considered, the changes are as shown in Figure 5.24.

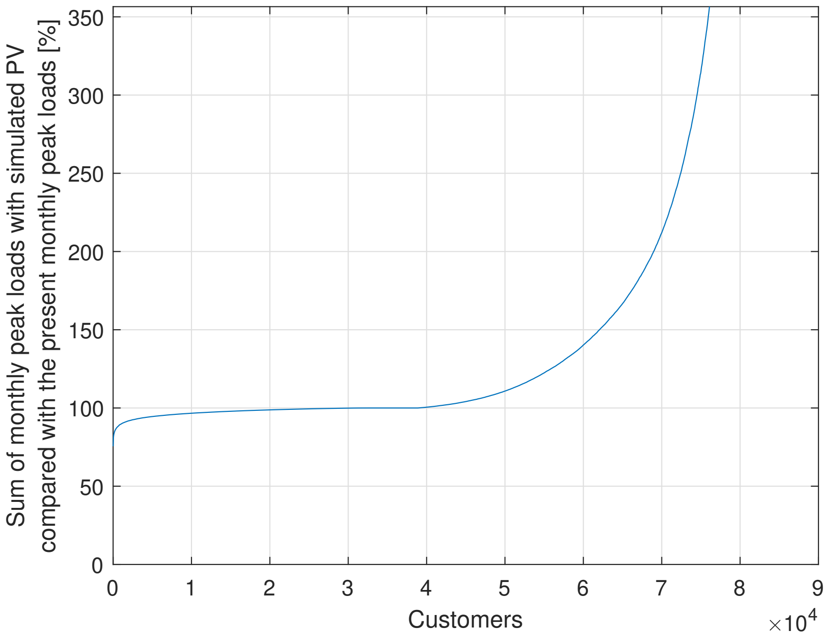

Figure 5.24: Effect of the modeled PV production on customers' monthly peak loads when also the production peak is considered.

It can be seen from Figure 5.24 that in many cases the monthly peak powers would be caused by injection of PV production into the distribution grid. By comparing Figures 5.21, 5.22, 5.23, and 5.24, it can be seen that the definition of peak power in the PBT has an impact on the benefits of PV for the customers. In Figure 5.25, the information of Figures 5.21 and 5.20 is combined.

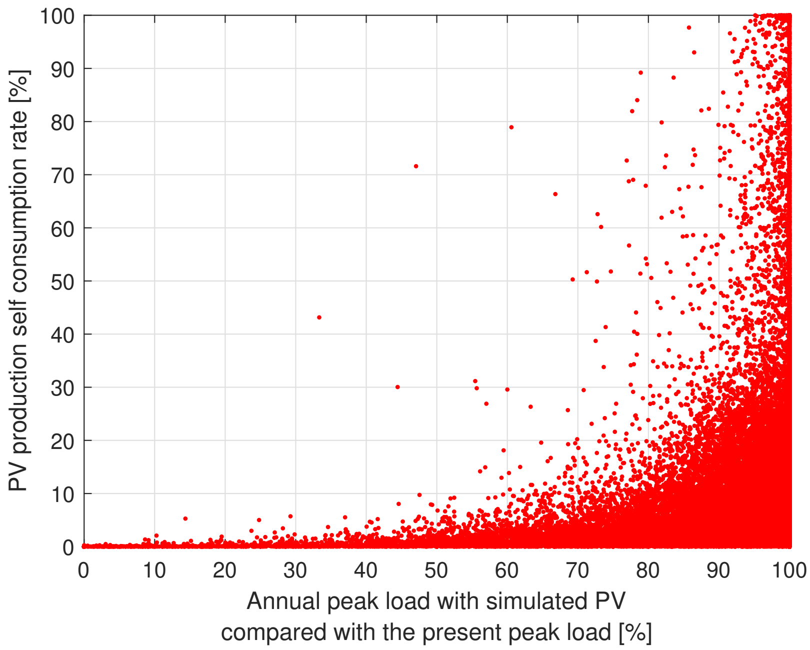

Figure 5.25: Simulated PV production rates and the effect on the customers' consumption peak.

It can be seen from Figure 5.25 that most of those customers whose annual peak consumption would significantly decrease with the PV are customers that would have low self-consumption rates. This means that the PV production would cover their consumption quite well, but also a lot of produced energy would be injected into the distribution grid. There also seems to be some customers that could have PV production over the 60% self-consumption rate and that could also reduce their annual peak load demand by 20–30%. The customers who have a high self-consumption rate would have only slight benefits from a lower annual peak power in the case of the annual PBT.

5.4.1 Effects on the profitability of solar PV systems

The changing distribution tariff system impacts the profitability of the distributed generation. Already in the present tariff system, customers have considered savings from distribution fees when making decisions to invest in solar PV systems. If the DSO changes the distribution tariff structure, customers' benefits from own production will change. There are approximately 80–90% of customers who would lose benefits from the simulated PV system if the power-based tariff was introduced (Haapaniemi et al., 2017a). The changes are highly dependent on the DSO's present tariff system, and especially the unit price of the energy-based fee. Customers will still gain the same benefit from electricity taxation and retailer fees. In Finland, the energy-consumption-based fee of the distribution tariff is typically approximately 4–5 cent/kWh, whereas the retailer's tariffs are approximately 4–7 cent/kWh and the electricity tax approximately 2.8 cent/kWh. Hence, the DSO's energy-based fee is one-third of the total energy-based electricity costs.

For the profitability of PV systems, it is relevant whether the power-based tariff is charged on the customer's monthly or annual peak power. In the Nordic conditions, customers' loads are typically high in the wintertime and relatively low in the summertime. Thus, the annual PBT is in most cases defined by the wintertime peak load rather than by the summertime production (Haapaniemi et al., 2017a). The PBT reduces the customers' profits from the PV, but the benefits of selling produced energy exceed the losses in the distribution fee with reasonable PV sizes (Narayanan et al., 2018).

In (Jargstorf et al., 2013), the cost recovery of three different tariffs was studied. The considered tariffs were: only a fixed fee, only an annual peak-power-based fee or a fixed fee, an energy consumption fee, and an annual peak power fee. According to the study, adding a peak load component to the distribution tariff could lead to the most reasonable outcome from the perspective of the DSO's cost recovery, if there were PVs and BESSs on the customer side. The analysis was made in Belgian conditions. These results are very logical when considering a DSO's short-term incomes. It was found that the PV production reduces the cost-reflectivity in distribution pricing with the present energy-based tariffs. A consequence of the energy-based tariffs is that customers that do not have production of their own will subsidize those with production (Jargstorf et al., 2015). The need for tariff development in the case of increasing household solar PV penetration was noticed also in (Young et al., 2016). (Jargstorf and Belmans, 2015) showed that electricity tariff design is a multiobjective task where high-level objectives should be taken into account especially when the PV penetration level is high. In this publication, grid tariffs were considered as part of the retail market offer design, which naturally affects the objectives of tariff development. Cross-subsidies between consumers and prosumers have been studied in (Picciariello et al., 2014, 2015; Picciariello, 2015; Simshauser, 2016). In these publications, it was found that PV systems increase network costs and cause cross-subsidies between customers if the DSO tariffs are based on a volumetric fee. In (Sæle and Bremdal, 2017), it was concluded that the introduction of power-based tariffs reduces the benefits of the PV for a prosumer; nevertheless, optimization of the self-consumption rate is important. The results of these publications support the findings made in this dissertation with the hourly AMR data.

In (Azuatalam et al., 2017), the authors studied how different tariffs would affect the profitability of PV–BESS installation and grid loads. The analysis was made for an Australian environment for a secondary substation circuit with 39 customers. The PV–BESS penetration was simulated from 10% to 90%. The PBT was considered to be defined from the four highest daily peak demands of a month. The main result of this study was that transition to the PBT would benefit the PV–BESS system owners.

5.5 Heating and cooling loads

Heating and cooling loads are, similar to solar PV, highly dependent on weather. These loads are controlled based on indoor temperature. Changes in outdoor temperature affect the indoor temperature with a time delay. The time delay is dependent on the building properties, such as insulation, air ventilation, and material choices.

In northern conditions, heating loads play an important role in the total electricity demand of the housing sector, whereas closer to the equator, cooling loads are more significant. Heating loads already have mainly a common signal, the outdoor temperature, and thus, the temporal variation of heating loads is low. The heating loads have naturally a temporal variation in the intraday loads, because different customers have different buildings and heating systems, and thus, different time delays and thermal storage capacities.

Changes in heating systems can affect the electricity demand in both ways, either by increasing or decreasing the demand, depending on for which customers the changes are made. If present oil heating, wood heating, or district heating systems are replaced by GSHPs, the electric energy consumption and peak power of the customers will increase. In contrast, when direct electric heating is replaced by a ground source heat pump, the total electricity consumption decreases and the peak load decreases or remains unchanged depending on the dimensioning of the heat pump system. Thus, the buildings and present heating systems have a significant effect.

5.5.1 Estimating the temperature-dependent heating load

To accurately estimate the outdoor-temperature-dependent load, more precise information of the customer's buildings and heating solutions would be required. Thus, the lack of accurate information causes uncertainty in the estimation. Especially from the hourly or higher resolution data it is challenging to separate the heating load from other loads without the knowledge of the factors affecting the customer's loads, such as the heating system, the heat distribution system, the size of the building, the air ventilation solution, and the secondary heating systems. Hourly electricity consumption of a customer with electric heating in different outdoor temperatures is illustrated in Figure 5.26.

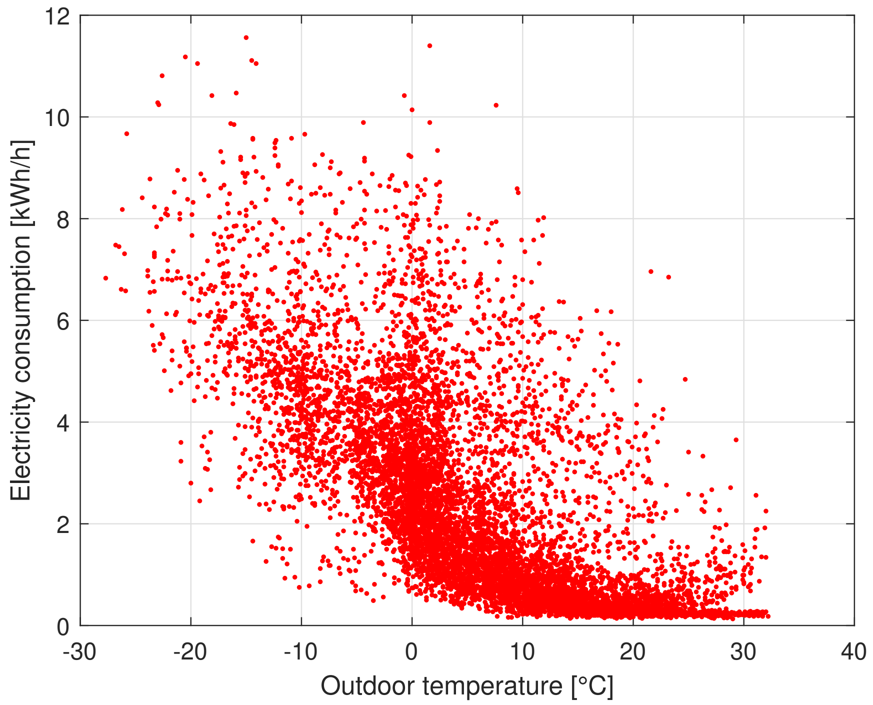

Figure 5.26: Example of the hourly electricity consumption of an electric heating customer in a detached house in different outdoor temperatures.

Figure 5.26 shows that on average, the electricity demand increases when the outdoor temperature decreases. There are consumption peaks in the example customer's load data, which are probably caused by an electric sauna stove or a domestic water heater. These consumption peaks occur also in warmer outdoor temperatures. It can be noticed that the heating demand begins when the outdoor temperature is below 10 °C. The outdoor-temperature-dependent part of the customers' load is estimated in this doctoral dissertation by fitting a linear curve to each customer's load curve in below 10 °C outdoor temperatures with the equation

$$P_{heating,T} = (T - 10) * k, \tag{5.4}$$

where T is the hourly outdoor temperature, and k is the customer-specific linear fit correlation factor. Thus, the average heating demand can be estimated for every hour and separate the electricity demand of heating from the customer's other electricity consumption. This method can lead to clearly erroneous estimations at some hours, and the heating demand can be estimated to be higher than what the actual total consumption of the customer has been. This can happen for instance if the customer has heated the building with a secondary heating system.

5.5.2 GSHP for an electric heating customer

When simulating a shift to a GSHP for a present electric heating customer, it is necessary to estimate the outdoor-temperature-dependent load from the customer's load data. When the hourly electricity heating load has been separated from the total load, the electricity demand of the GSHP system can be estimated with the temperature-dependent coefficient of performance (COP) factor

$$P_{HP} = P_{Orig} - P_{heating} * (1 - \frac{1}{COP}), \tag{5.5}$$

where P_{Orig} is the electric heating customer's original load, $P_{heating}$ is the estimated electric heating load, and COP is the coefficient of performance factor, which is outdoor temperature dependent. The COP is a variable that is dependent on the outdoor temperature and the heat pump system chosen. Figure 5.27 illustrates the COP of GSHPs in different outdoor temperatures.

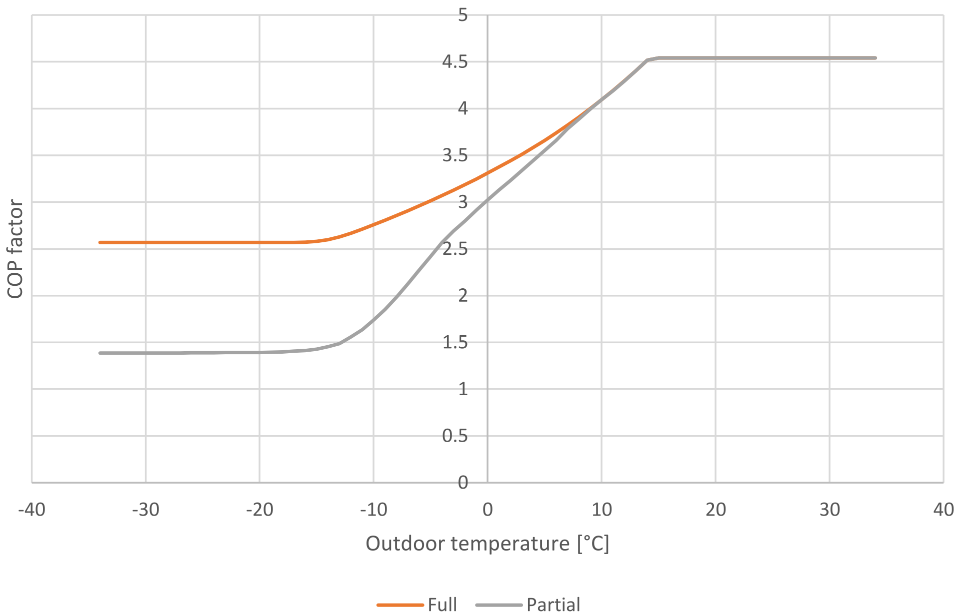

Figure 5.27: COP factor of a full and partial load capacity GSHP in detached houses.

The COP factors used in this doctoral dissertation were obtained from (Laitinen et al., 2011). By comparing the curves of full and partial load capacity GSHPs in Figure 5.27, we can see that a difference arises when the outdoor temperature is low. During coldest periods, a partial load capacity GSHP uses also resistors to cover the heating demand. Currently, customers often choose partial load capacity GSHPs. This means that most of the energy demand of heating is covered by GSHP, but during peak heating demand, resistors are used to produce heat. In Figure 5.28, the effect of GSHPs on present electric heating customers' load curve is demonstrated.

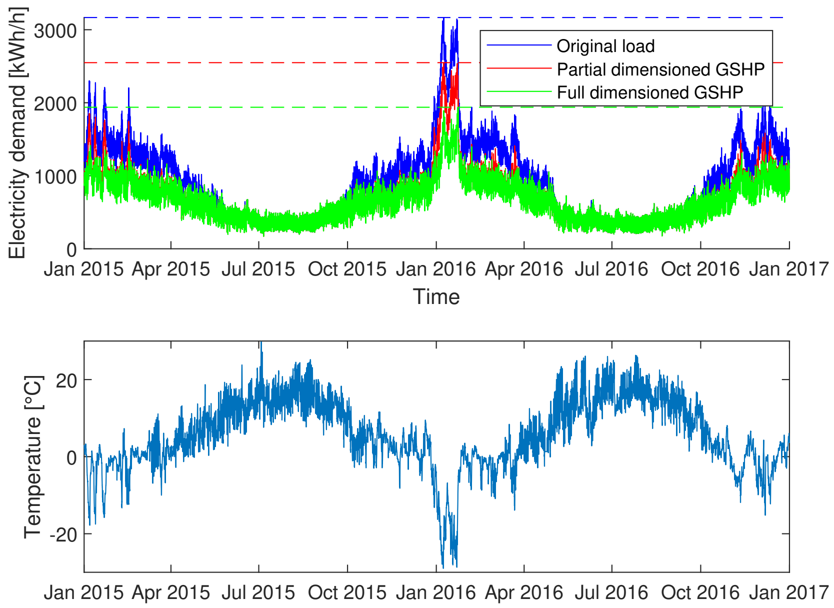

Figure 5.28: Effect of GSHPs on the electric heating customers' load. The outdoor temperature data were obtained from (Finnish Meteorological Institute, 2019).

Figure 5.28 shows that there can be a significant difference in the total load of a customer group in winter cold periods if the dimensioning of heat pumps is not considered from the perspective of peak demand. Figure 5.29 illustrates how the customers' peak power and annual consumption developed with the simulated GSHPs.

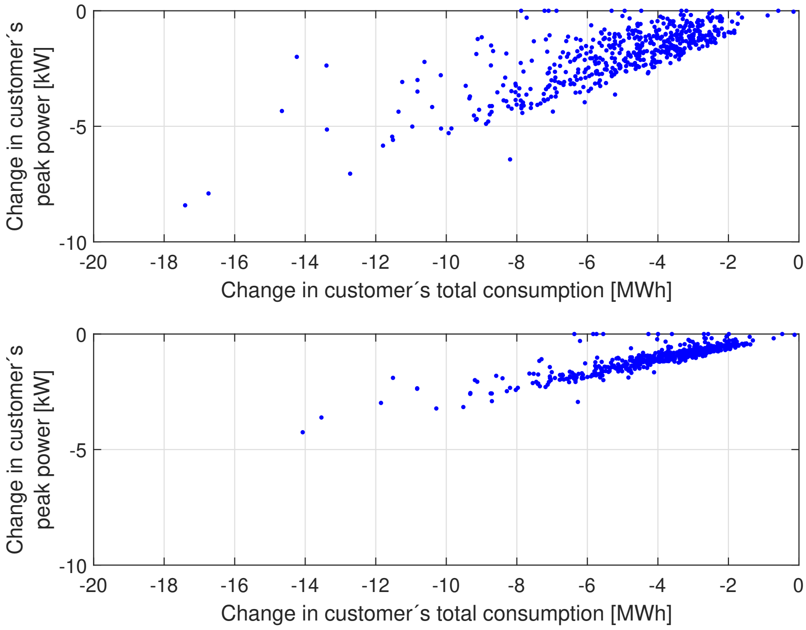

Figure 5.29: Effect of GSHPs on the customers' peak power and annual energy consumption. The upper figure presents the changes in the case of dimensioning based on full load capacity and the lower one in the case of partial load capacity.

It is noteworthy that there are also customers whose peak power does not change with the GSHP. The reason for this is that these customers have consumption peaks outside the heating period. These consumption peaks may be caused, for example, by electric sauna stoves. The effect of the introduction of the PBT on the profitability of a GSHP investment depends significantly on the parameterization of the PBT. When the revenue collected with the energy-based component of tariff is shifted to be collected with the PBT, the customers in the left upper corner in Figure 5.29 will benefit less than those in the lower right corner. If the revenue collected with fixed fees is shifted to be collected with the PBT, the customers that are lower in the figure will benefit more from the tariff change. Figure 5.30 illustrates the load curve of one of those customers whose peak power decreased only slightly, with and without a GSHP.

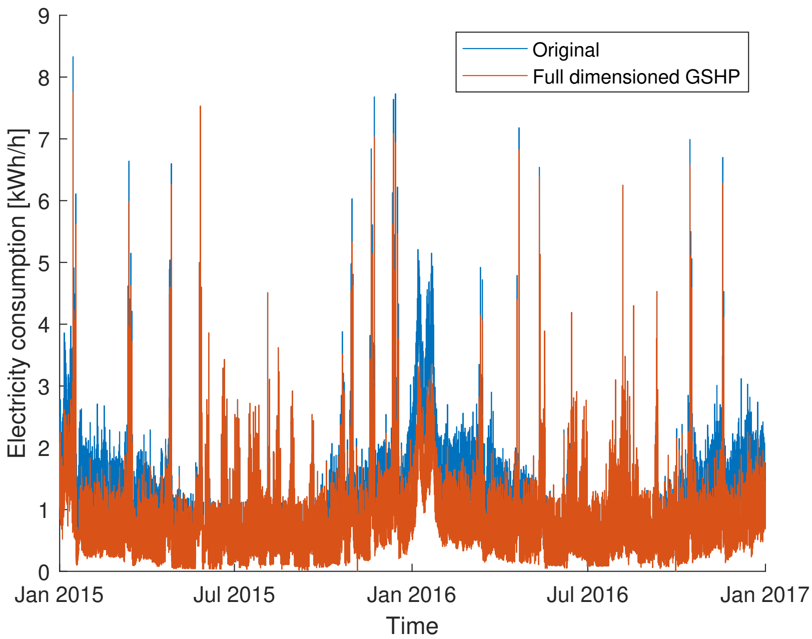

Figure 5.30: Example customer's original load and load after the modeled GSHP.

By studying Figure 5.30 it can be seen that the example customer's electricity demand decreases in winter, but there are also several consumption peaks that are not caused by electric heating. Figure 5.31 shows the difference in the customers' peak powers with differently dimensioned GSHPs.

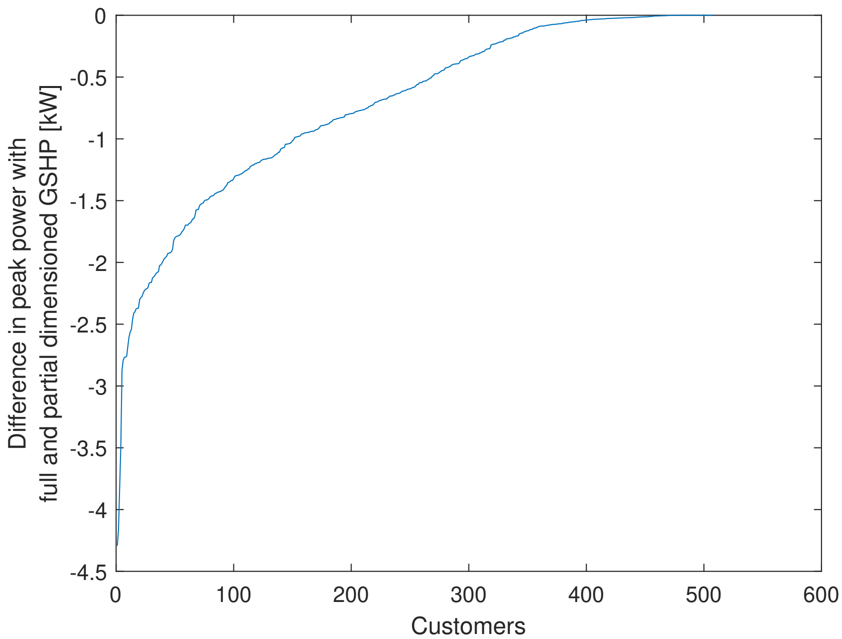

Figure 5.31: Difference in the customers' peak powers with differently dimensioned GSHPs.

By comparing the peak loads of the customers in the case of differently dimensioned GSHPs, Figure 5.31, it can be seen that differences in annual peak loads are relatively low. Thus, it is not completely clear whether the PBT will affect customers' choices when choosing GSHP dimensioning for a present electric heating customer, because customers' peak loads may not occur simultaneously with the heating need. With full load capacity GSHPs, the customers' peak load seems to be lower at the annual level than with partial load capacity dimensioning, but the difference can be, after all, too low to cover the difference in investment costs.

From the perspective of the distribution grid load, the difference is essentially dependent on how these customers are located in the grid. Because different customers' heating demands have a common factor, outdoor temperature, the benefits of full load capacity dimensioning can have a more significant effect on MV lines and the secondary substation load than on the customers' own peak demand. Thus, the PBT as an incentive for deciding upon dimensioning of the GSHP probably affects those customers whose peak demand occurs in the coolest winter periods. This would mean that the PBT has an effect on customers' decisions, where the selection of the GSHP dimensioning impacts the LV network peak load. However, a lot of potential may not be exploited when considering higher grid levels.

The design of the PBT will have an impact on how significant incentives customers will have in the selection of the heating system. If the PBT is defined by the customers' monthly peak demand, the customers have a lower incentive to invest in a full load capacity GSHP than in the annual peak power case.

The customers who currently have other heating system than electric heating, such as district heating, oil heating, or gas heating, can also invest in a GSHP. In these cases, the electricity consumption naturally increases from the perspectives of energy demand and peak power. It can be challenging for the DSO to estimate how these customers' load curves will change if they invest in a GSHP, because the DSO typically has no information of customers' buildings. These customers' electricity consumption with the GSHP can modeled by developing a load profile from the present known GSHP customers. The customer-spesific modeling can be improved if the information of the customer's building and appliances is available. In this doctoral dissertation, the GSHPs have not been modeled for the nonelectric heating customers. From the viewpoint of the PBT, the phenomena would most probably be similar to the electric heating customers.

5.5.3 Electric heating with a storage water boiler

In the present loads of the customer, a storage water boiler or a domestic water heater can cause the customer's peak demand that defines the peak-power-based fee. In these appliances, the electric power can be typically controlled to turn on based on the time of the day or on demand. In Finland, DSOs have traditionally had nighttime tariffs available for customers. Customers that have chosen this distribution tariff have had a cheaper volumetric price for nighttime hours, typically 22:00–07:00. Thus, controllable loads have been turned on at the first cheaper hour, 22:00–23:00. This can have caused local peak demands (Haapaniemi et al., 2019b). A PBT can affect the consumption patterns of these customers so that controllable loads are shifted more evenly to hours when the electricity consumption of the customer is low. Figure 5.32 illustrates the nighttime demand peak at the customer level caused by a stepwise decrease in the energy price and its possible effect if this load is consumed more evenly in the nighttime.

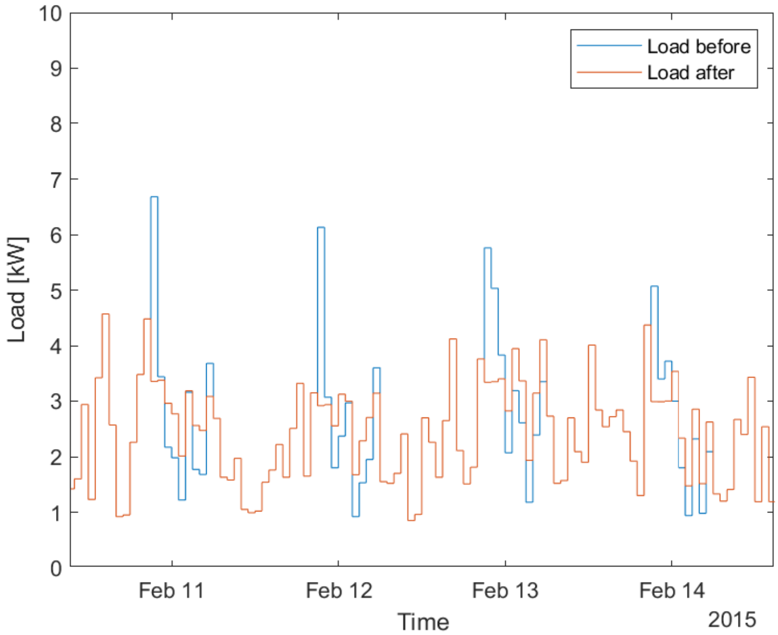

Figure 5.32: Customer's load before and after the nighttime load control.

To analyze the demand peaks caused by the present TOU tariffs, it is of high importance to identify the customers who are currently controlling their loads to the nighttime. Information on customer classification obtained by clustering in previous studies (Lassila et al., 2019b), was used in the identification of the nighttime load customers. The load patterns of the customers who were identified to have controlled their load were then analyzed. The nighttime-controlled load can be estimated by comparing the hourly load after 22:00 and before 07:00 with the day's average load. These loads already include some control opportunities, and thus, the load patterns can change if a PBT is introduced to the customers. The importance of the nighttime-controlled loads in the introduction of the PBT depends on the adoption rate of the TOU tariffs and how the customers are located. If the adoption rate of the tariff is locally high, the peak demand may be caused by the TOU control, and if the day-time-consumption customers constitute a majority, the TOU control reduces the local peak demand. In practice, a challenge with these controllable loads is that the present generation of AMR meters does not allow customers to change their control logic. When the smart control opportunities become more popular, these kinds of storage loads have a high potential from the viewpoint of PBT-based optimization. If the load is shifted more evenly through the night, this can also benefit the electricity system on a wider scale. On the other hand, when the PV adoption rate is high, it may be reasonable to fulfill the heating storage capacity with solar power in the daytime.

5.5.4 Other heating solutions during peak demand

The heating solution decisions can also be affected by other price signals than the electricity pricing. The pricing development can also have such an effect that the customers decide to use secondary heating solutions to cover their peak heating demand. Hence, the PBT can also have a slight negative effect on the development of the GHG emissions. However, it should be studied further if it is preferable to cover the peak heating demand with the grid capacity or by customer-side solutions. In Finland, electric saunas can cause a customer's peak power, and thus, in the future, the decision to invest in a sauna stove can be made considering its effect on the customer's distribution bill. In detached houses, in particular, customers can consider the selection of an electric or a wood-burning sauna stove, if an electric one causes a several kW peak to the customer's load profile.

5.6 Customer grid defection

As stated above, PV and BESS prices are decreasing, which can make customers connected to the grid consider going off-grid. Changing the tariff structure can also have an impact on customers' willingness to go off-grid by installing PV and BESS systems. In this dissertation, customers' future grid connections are studied only from the perspective of techno-economic grid defection. Migration from rural areas to cities or mortality rates (negative population change) are not considered further here as drivers for grid defection. To analyze how introduction of the PBT would affect the attractiveness of grid defection, a DSO has to estimate which customers are the most probable ones to weigh up other solutions. To assess the possible customers going off-grid (grid defectors), the DSO can analyze customers' AMR data if the customers can cover their electricity consumption with PV and electricity storage solutions of realistic size. When potential customers going off-grid are identified, the DSO can study how their electricity bill would develop in the case of introducing a PBT. From the viewpoint of the DSO, grid defection can reduce the incomes and pose a risk of grid investments that turn out to be useless in the near future.

5.6.1 Grid defection with a PV and BESS system

Solar PV production with an energy storage can enable some customers to be self-sufficient in electric energy. To be self-sufficient, the PV system would have to produce the energy needed, and the BESS has to cover the storage need because of variations in load demand and production.

In the Nordic conditions, the number of potential customers to disconnect from the grid (grid defection) is very limited with the present price levels of PV and BESS systems, but it might increase rapidly if the price level continues to decrease. The main limiting factor for grid defection in the Nordic conditions is the fact that PV production is low in the wintertime because of the snow cover on PV panels and also because of the short daylight hours. Another factor significantly affecting these customers' profitability of going off-grid is the DSO's tariff. From the DSO's viewpoint, grid defection can be a significant risk, or alternatively, an opportunity to reduce costs if these possible grid defectors can be identified in advance (Haapaniemi et al., 2018).

Identification of potential customers going off-grid is important especially in rural areas, where the line length per customer is high. While DSOs are making significant investments in the grid infrastructure to ensure that the requirements of supply security are met, it is very important to identify those customers that might not be on-grid in the near future and where a lot of the grid infrastructure is supplying only customers potentially going off-grid (Haapaniemi et al., 2019a). Therefore, DSOs have to carefully estimate how the tariff development should be carried out especially in areas where the grid length is high and where there are potential grid defection customers. The PBT can have such an effect that the customers with a possibility of grid defection will pay even less than they are paying at present. The algorithm developed to identify customers potentially going off-grid is presented in Figure 5.33.

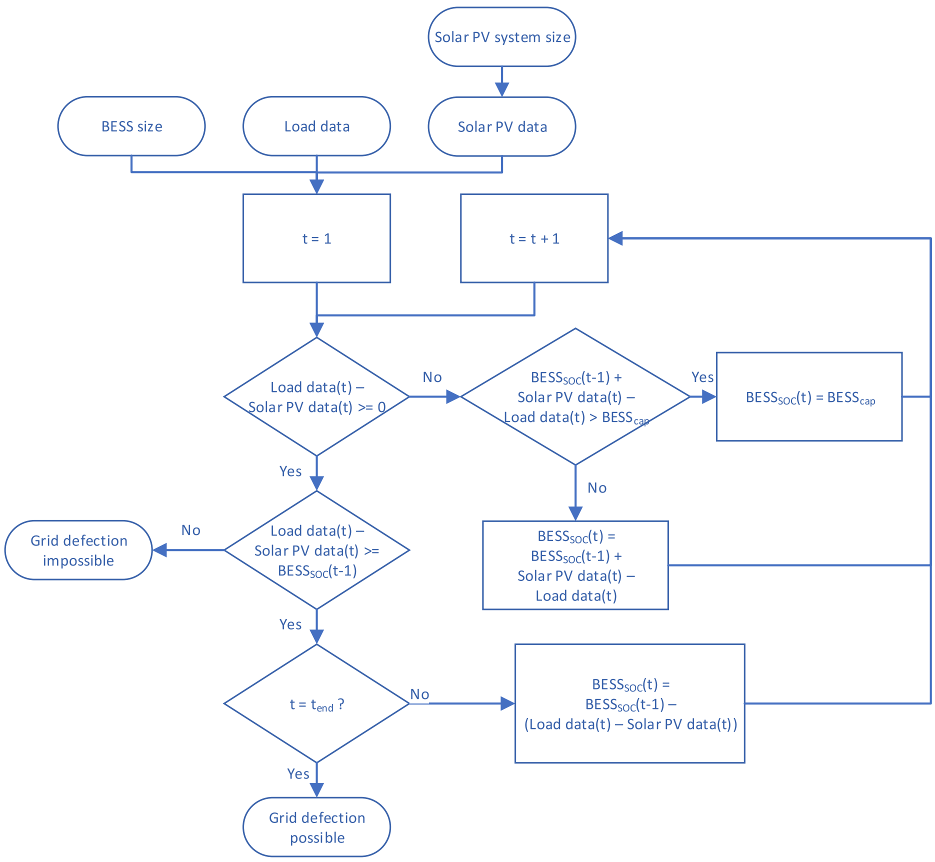

Figure 5.33: Flowchart of the algorithm for potential grid defection.

The simulation model takes as inputs the customer's load data, solar PV data, and the BESS capacity under consideration. The simulation model targets to study if the solar PV production can completely cover the customer's hourly consumption. If the PV production exceeds the customer's hourly consumption, the BESS is charged. If the consumption is higher than the production, the BESS is discharged. Different BESS and PV system capacities are varied to find out which combinations could be possible for grid defection. Then, the most feasible PV and BESS combination can be estimated with different cost development scenarios. The off-grid system costs should then be compared with the costs of electricity purchased from the distribution system.

When alternative solutions for electricity supply become cheaper, customers might start considering going off-grid. It is important to notice, however, that customers' present electricity demand does not necessarily reflect the future demand. For instance, the load demand can be currently low in leisure homes but the need to charge an EV in the future will change the load demand. Thus, the customer may need the grid connection even though the present demand seems suitable for grid defection.

Because in the Nordic conditions PV production is limited mainly to summertime, the number of possible defections with PV and BESS systems is limited. By adding a backup generator to the customer's system, also occasional wintertime consumption could be covered. The backup generator reduces the risk that occasionally a PV and BESS system cannot provide the power needed to cover the demand. It has to be borne in mind that the backup generator can disturb the customer and cause discomfort because of noise, exhaust emissions, and need for maintenance. The limited lifetime of backup generators also limits their long-term use.

5.6.2 Effects of grid defections on electricity distribution pricing and grid infrastructure

The effects of grid defection on distribution pricing depend highly on the DSO's tariffs. The potential grid defectors have a low consumption, and thus, they pay a low amount of consumption-dependent fees. The grid defection potential can be challenging particularly from the viewpoint of rural area DSOs, because the presence of customers causes significant costs, but gathering the costs with fixed fees increases the feasibility of grid defection. Thus, the DSO has to consider how to balance with cost-reflectivity and the risk of grid defection.

A grid defection can have a different effect on the distribution grid depending on where the customer is located in the distribution grid and what kind of grid infrastructure is supplying the customer. In rural areas, grid defections can have an effect on the pricing development. Even though a large amount of LV grid can be in a risk of potential customers going off-grid, the distribution bills gathered from the customers can be higher than the benefits of lower risks in the network planning. It has to be considered that the customers should pay their share of the system costs in addition to the LV grid costs. Hence, a result of grid defection can be that other customers have to pay a higher proportion of the system costs when there are fewer customers after some of the customers have disconnected from the grid. Thus, for instance the costs of primary substations, the MV grid, and the DSO administration are gathered from a smaller number of customers. If the

DSO estimates that the risks of grid defection risks will be realized anyway in the near future, the tariff development can be used to manage the timing in a more controllable manner when the risks will materialize.

With the developed methodology, a DSO can estimate the number of potential customers going off-grid, their location in the distribution grid, and how the pricing development can affect these customers' incentives. The number of potential grid defectors can vary in different areas (Haapaniemi et al., 2018), and also the effects on the grid infrastructure can be dissimilar in different cases (Haapaniemi et al., 2019a).

5.7 Conclusions

The PBT can affect several development trends in the customer loads. The local conditions have an effect on the intensity of the trends, and thus, the tariff development should be estimated considering the characteristics of different areas of the DSO. In different areas, the population, buildings, their heating systems, locations, and customer density have an effect on the load development trends. In rural sparsely populated areas, the development of distribution tariffs can affect the risk of grid defection. In urban conditions, the potential grid defections cause lower risks for the DSO because the presence of individual customers affects only a low amount of the distribution grid infrastructure. The EV home charging can pose a risk of grid overloading, particularly if the customers choose high-power chargers, and if the EVs are adopted in the same LV grids. The EV charging load is a significant load compared with the typical nominal capacities of secondary substation transformers. In particular, rural area transformers can be dimensioned for low powers, and thus, the simultaneous EV charging can cause problems. The PBT-based smart control of EV chargers can reduce the risks of overloading, and thus postpone the reinforcement investments.

The PBT reduces the customers' benefits from PV installations if the revenue presently gathered with the energy-consumption-based fee is shifted to the peak-power-based fee. However, this reduces the cross-subsidies between customers. In the long term, critical infrastructure monopoly company's charges may not be the most reasonable way to support technology choices. On the other hand, the PBT incentivizes customers for peak shaving, and the BESS acquired for peak shaving purposes can benefit the PV by increasing the self-consumption rate. This can be emphasized if the PBT includes a minimum charged power.

The benefits from PBT-based load optimization come mainly from the grid close to the customer; LV lines and secondary substation transformers. At the higher levels of the electricity system, the individual customers' peak powers have a lower impact on the total peak demand. However, the PBT can affect the customers' heating system choices, which can also have an effect on higher level loads because of the simultaneous nature of heating loads.

In general, the PBT can have positive impacts on the development of the distribution grid loads by steering the customer choices with an incentive to consider also the peak demand.

However, the weight of tariff components should be analyzed comprehensively to ensure that the tariff development does not cause unwanted local optima. In the next chapter, the effects of the PBT on the customer payments and distribution grid loads in the case area are analyzed.

6 Effects of tariff structure reform on customer payments and grid loads

In the tariff structure development, the DSO can have several potential future tariff alternatives. The short- and long-term effects of the tariff development alternatives should be analyzed before deciding upon the target tariff. Because the tariff structure cannot be changed often, the target tariff to be chosen should function with the load development trends. Figure 6.1 illustrates the target tariff selection problem from the viewpoint of the DSO.

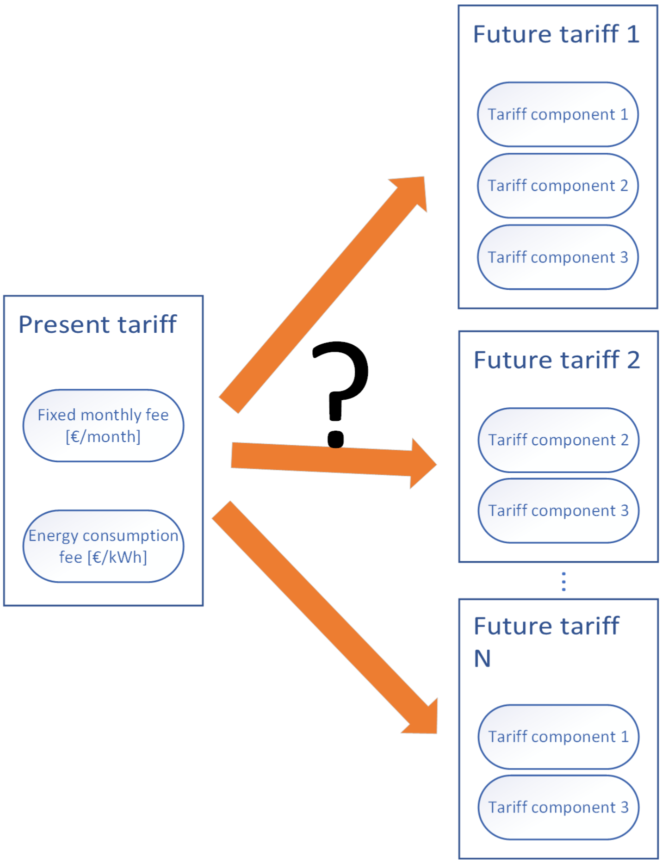

Figure 6.1: Target tariff selection problem.

The effects of the introduction of the PBT on the customer payment, the development of grid loads, and load control incentives can be analyzed in a smaller case area, such as a primary substation area. In this chapter, the changes in the grid loads and in the customer payments with new loads are analyzed in cases where the customer either does not react or reacts to the price signal. The methodologies presented above in Chapters 4 and 5 are applied to this study. The study does not pursue to define whether the customers would react to the PBT pricing signal but rather to understand what kinds of incentives the PBT introduction would present to the customers to control their loads, and what kinds of impacts these decisions would have on the grid loads. The impacts are analyzed with different scenarios, A, B, and C, which are presented next.

6.1 Scenarios

In scenario A, the DSO's pricing remains unchanged, that is, comprising a fuse-size-dependent fixed fee and an energy-consumption-based fee. Customers adopt new loads; EVs and PVs, and change their heating systems to the GSHP. The customers do not optimize their peak loads because there is no incentive from the distribution tariffs. The type of EV charging is 10 kW three-phase home charging without control of the charging event. The customers who adopt the GSHP choose the partial load capacity dimensioning, because there is no incentive to consider the peak demand.

In scenario B, the DSO's pricing is developed as a PBT, which includes a fixed fee, an energy-consumption-based fee, and a peak-power-based fee. The weights of the tariff components are varied. Customers adopt new loads; EVs and PVs, and change their heating systems to the GSHP. The customers do not optimize their loads, even though the pricing incentivizes them to consider also the peak demand. The customers choose uncontrolled 10 kW EV charging. The GSHP are dimensioned based on partial load capacity.

In scenario C, the DSO's pricing is developed as a PBT. The weights of the tariff components are varied. Customers adopt new loads; EVs, PVs, and peak shaving BESSs, and change their heating systems to the GSHP. The customers optimize their load demand based on the PBT incentive. The EVs are charged with a 10 kW smart charger that aims to limit the increase in the customer's peak power. The customers choose full load capacity GSHPs. Some customers adopt a BESS that is optimized for peak shaving, considering their present load curve and the PBT incentive.

In general, scenarios A and B are identical from the load perspective, but the DSO tariffs are different. With these scenarios, it can be analyzed how the profitability of different new loads will be affected if the DSO's tariff structure is developed. Scenario C shows which kind of incentive there would be for the customers to control their loads based on the PBT price signal, and what kind of benefit for the grid load rates the customer reactions would have. In the scenarios it is not analyzed further how the PBT would affect the new DER element adoption rates, but the scenarios are made with the assumption that new loads will be adopted.

6.2 Limitations and assumptions

New loads are modeled for the customers with the following assumptions. The new loads are modeled for the customers with a 3x63 A fuse or a lower main fuse size. 30% of the customers will adopt EVs, which are mainly charged at home. 10% of the customers are expected to replace their electric heating with a GSHP. A 5 kWp PV installation is modeled for 10% of the customers. In scenario C, 10% of the customers will adopt a BESS for peak shaving. In practice, the development trends can vary between different areas, but with these assumptions, the phenomena can be studied. The new loads are not modeled for customers that consume less than 1000 kWh/a, because there is significant uncertainty of how these customers' load demand will develop.

Customers' electricity price is assumed to include the electricity tax, 2.793 cent/kWh, the retailer's tariff, consisting of a 10 € fixed fee and a 5 cent/kWh energy-consumption-based fee, and the DSO's tariff. The DSO tariff is assumed to include a main-fuse-size-dependent fixed fee; 25 €/month for a 3x25 A customer, 35 €/month for a 3x35 A customer, 50 €/month for a 3x50 A customer, and 63 €/month for a 3x63 A customer. The energy-consumption-based fee is assumed to be 4 cent/kWh. These prices represent typical prices in rural areas of Finland, but are not real prices of any certain DSO.

At the beginning, 54% of the DSO's revenue is gathered with fixed fees and 46% with energy-consumption-based fees. The PBT is studied with four different weights, where the revenues shifted from the energy-consumption-based fees and the fixed fees are varied. In the first alternative, a 30% proportion of both revenues is shifted to the peak-power-based fee. In the second alternative, the DSO sets a lower weight to the energy-based fee, and shifts 60% of the revenue collected currently with the energy-consumption-based fee to the peak-power-based fee. In the third alternative, a higher proportion, 60%, of the fixed fee is shifted to the peak-power-based fee. In the last alternative, 60% of the revenues of both the energy-consumption-based fee and the fixed fees are shifted to be gathered with the peak-power-based fee. The PBT is analyzed separately in the cases of a monthly and an annual PBTs.

The case area includes a total of approximately 4030 customers on seven rural area MV feeders. The new loads and the PBT are modeled only for the customers with a 3x63 A or a lower main fuse size, which excludes approximately 680 customers from the study. A majority of these customers are agricultural customers. These customers' electricity consumption is assumed to remain unchanged to focus the PBT study on household-size customers. The same load control logic may not be suitable for larger-scale customers, and it would require a better understanding of the customer appliances and processes behind the load curve.

6.3 Effects of the PBT on customer payments

The PBT has an effect on how the distribution payments are distributed between the customers, and which kind of incentives are set for the customers to modify their load curve. In this study, the focus is on defining which kind of incentives different PBTs would set to the customers adopting new DER elements. This kind of approach gives the DSO an understanding how different PBT selections, monthly or annual, and tariff component weightings affect the customers' incentives to choose capacity-friendly alternatives, and how these factors will affect the development of grid load rates.

6.3.1 Effects of the monthly PBT on customer payments

Customers' electricity bills were estimated with the load data and present prices. The adoption of the new loads was randomized between the suitable customer groups, for instance, there are GSHPs only for the identified electric heating customers. The distribution bills with the load changes were analyzed, and the payments of the customer groups were compared with the present payments. Figure 6.2 illustrates the changes in the customer groups' distribution bills in scenarios A, B, and C, and with different tariff weightings.

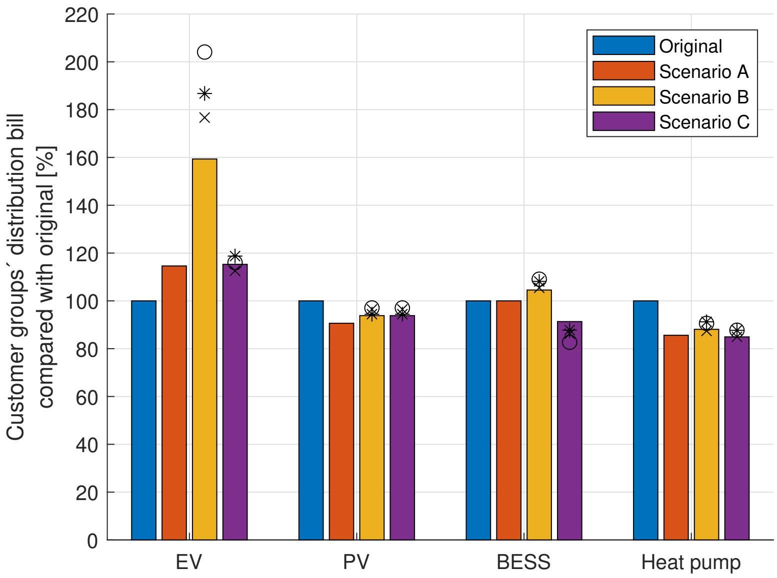

Figure 6.2: Changes in the customers' distribution bills with simulated DER elements in different scenarios with a monthly PBT. The bars show the changes in the 30%/30% pricing scenario, * indicates the estimated changes in the second pricing scenario, x denotes the changes in the third pricing scenario, and o represents the effects in the most significant power component weight scenario.

Charging of an EV increases the electricity consumption, and thus, customers' distribution bills rise also in the case of energy-consumption-based tariffs, scenario A. The monthly PBT can cause a significant increase in a customer's distribution bill if the customer charges an EV with a 10 kW charger without considering limiting of the peak power, scenario B. In particular, the payments increase if the weight of the peak-power-based fee is set high. Even with a moderate weighting of the peak-power-based fee, the EV charging customers may experience, on average, a 60% increase in their distribution bills. If the weighting is set high, the customers' distribution bills can double. Uncontrolled EV charging causes high consumption peaks to the customer's load curve every month throughout the year. By controlling the EV charging event, the customer can avoid an increase in the peak power, and thus, also in the peak-power-based fee, scenario C. By comparing scenarios A and B, it can be estimated what kind of effect the monthly PBT will have on the costs of uncontrolled EV charging. The benefits of the PBT-based smart control of EV charging can be observed by comparing scenarios B and C. It can be seen that introduction of a monthly PBT will provide a great incentive to control the EV charging to avoid increasing the customer's peak load.

The energy-based DSO tariffs benefit the 5 kWp PV adopters by 9% on average, which can be seen in scenario A. The simulation results show that the tariff component weighting has significant effects on the benefits that a customer can get with a PV installation. If a moderate, 30%, proportion of the revenue currently gathered with the energy-consumption-based fee is shifted to the peak-power-based fee, the benefits decrease to 6.6%. Scenarios B and C are the same in the case of PV, because the PV customers are not assumed to react to the introduction of the PBT. In the monthly PBT, it has only a slight effect if the revenue currently gathered with fixed fees is shifted to the peak-power-based fee.

Peak shaving with a BESS is not assumed to happen if the pricing is based on energy consumption, and thus, scenario A is the same as the original in the case of a BESS. The customers who currently have a spiky load curve will experience an increase in their distribution bills when the PBT is introduced. These customers have a potential for peak shaving. The benefits in the customers' distribution bill from peak shaving seem to be high; even with a moderate weighting of the peak-power-based fee, the potential customers can save 14% on average in their distribution bills. With a higher weighting of the peak-power-based fee, the benefits of the peak shaving BESS get higher. Without peak shaving, these customers could experience a 10% increase in their distribution bills, but with the peak shaving BESS, these customers can reduce their distribution bills by 10–19% compared with their present payments. This indicates that some customers have a high potential to reduce their peak load with the peak shaving BESS, and there is a great incentive to shift the loads to be more evenly distributed.

A customer can reduce energy consumption by replacing an old electric heating system with a GSHP. The introduction of the PBT will slightly reduce the benefits of a partial-load-dimensioned GSHP, as can be seen in scenario B. The simulation results indicate that customers can benefit more in their distribution bills from full-load-dimensioned GSHPs than from partial-load-dimensioned ones if the DSO pricing includes a PBT. Thus, there would be an incentive to choose a full-load-dimensioned GSHP instead of a partial-load-dimensioned GSHP. Shifting the tariff component weighting from the fixed fees to the peak-power-based fee seems to reduce the benefits of GSHPs. In practice, GSHPs are also installed to customers who do not have electric heating, but the conclusions drawn from this study concerning the incentives in GSHP dimensioning should be similar.

The weighting of tariff components is of high importance in setting desired incentives for the customers. If the peak-power-based tariff weighting is set high, it can have a significant impact on the costs of the 3-phase uncontrolled EV charging, particularly in the case of a monthly PBT. It can also lead to a high profitability of peak shaving. Unconsidered weighting of the tariff components can lead to excessive increases in distribution bills when new loads are adopted. On the other hand, the PBT can incentivize customers to make unreasonably high investments in peak load control, and the benefits from the reduced risks in the distribution grids can be of a less value than the costs of customer efforts.

From the customers' viewpoint, it can be more interesting to compare the changes in the total electricity bill, not only the changes in the distribution bill. The changes in the total electricity bills of customers are illustrated in Figure 6.3.

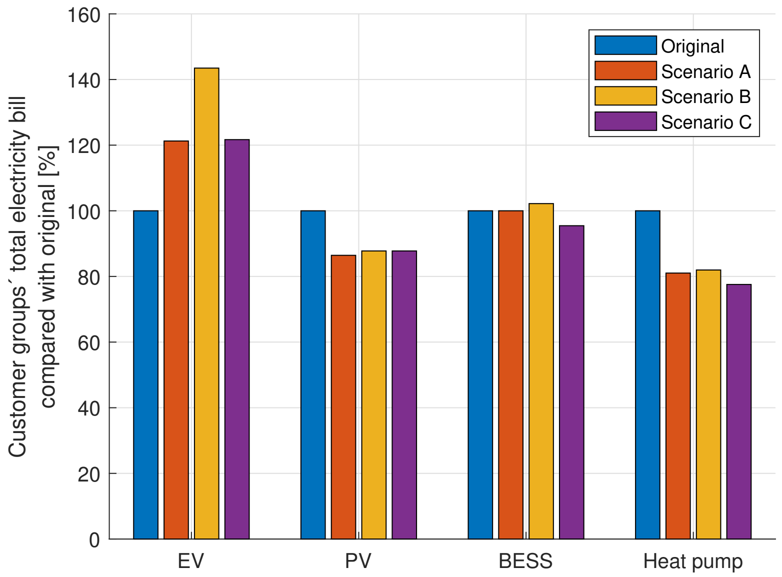

Figure 6.3: Customers' total electricity bills in different scenarios. Distribution tariffs in scenarios B and C include a monthly PBT.

Figure 6.3 shows that including the retailer tariff and the electricity tax in the comparison reduces the relative effects of the PBT and emphasizes the benefits gained from decreasing the customer's energy consumption. Figure 6.4 illustrates the changes in distribution bills from the viewpoint of individual customers in different scenarios.

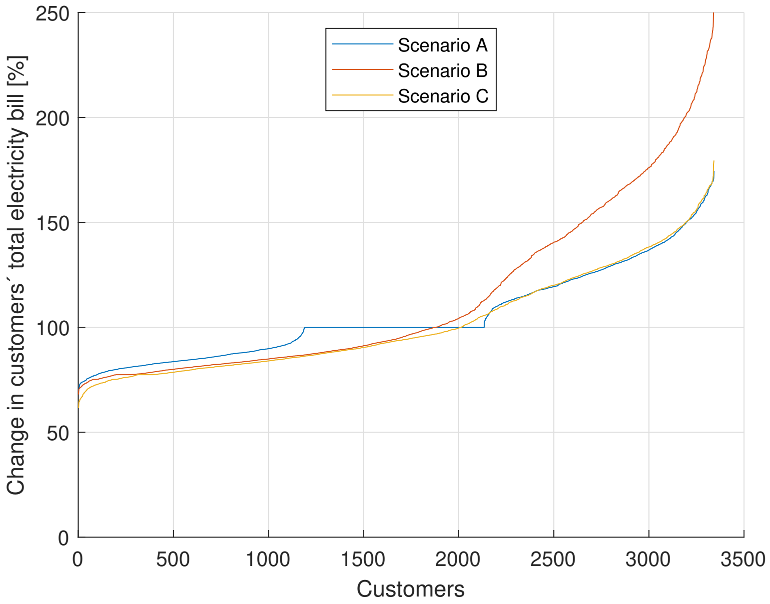

Figure 6.4: Changes in the distribution bills of all customers below 3x63A in different scenarios with a monthly PBT. The customer order may vary in different scenarios.

In the energy-consumption-based tariffs, scenario A, it can be seen that total electricity bills change only for those customers for whom the new loads were modeled. On the right side in the figure there are the EV adopters whose electricity consumption increases. The differences in the relative changes are caused by different present total consumption and load patterns. On the left side of the figure there are the customers who acquire PV systems or GSHPs. The figure shows that after the introduction of the PBT the payments are distributed differently than before, and all the customers experience changes in their total electricity bills. In scenario B, there are many customers who would experience a significant increase in their distribution bill. In this simulation, the unit prices were not iterated to meet the revenue target, but the changes were modeled with the PBT unit price estimated from present loads. In practice, the new loads would not be adopted simultaneously by the customers, and the transition of the tariff structure would probably not be carried out overnight. Hence, the simulation results show slightly higher effects than they would do in practice. In other words, the DSO will probably have a longer transition to set the weightings of tariff components and adjust the unit prices based on customer reactions. If the load changes and the tariff development happened overnight, the DSO's incomes would increase by 1.2% from this case area in scenario A. Correspondingly, in scenario B, the incomes would increase significantly, even by 18%. If the customers react to the tariff, scenario C, the DSO's incomes will decrease by 0.7%. In the short term, the DSO will have to adjust the unit prices to meet the target revenue. In the long term, the development of the grid loads can affect the tariffs. The effects of the annual PBT on the customer payments is estimated next. After that, the effects of different scenarios on the distribution grid load rates are studied.

6.3.2 Effects of the annual PBT on customer payments

The PBT can be dependent on the annual peak powers of customers instead of the monthly ones. Figure 6.5 shows the results of a similar analysis of the changes in customer distribution bills with new loads in different scenarios.

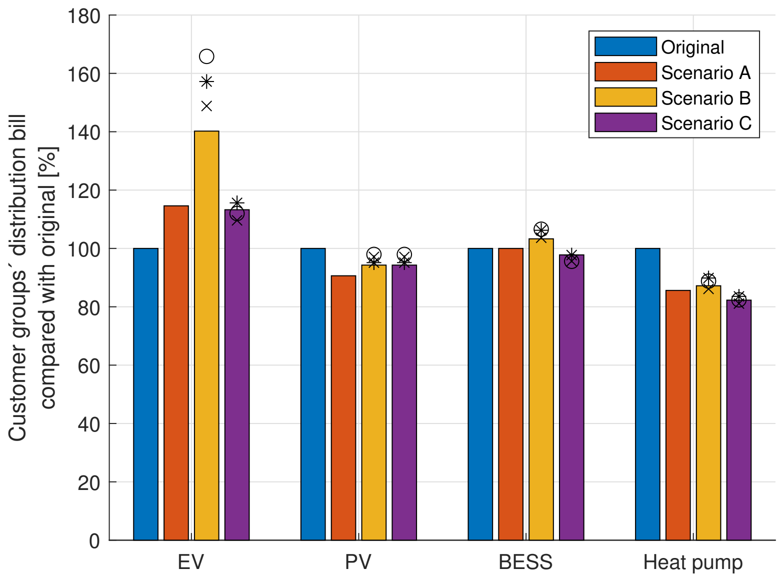

Figure 6.5: Changes in the customers' distribution bills with simulated DER elements in different scenarios with an annual PBT.

By comparing the results with Figure 6.2, it can be seen that the effects are mainly slighter. Still, the PBT has a significant impact on the costs of dumb EV charging, scenario B. However, the effect on the costs is lower, because in the annual PBT other customers pay for their annual peak power every month even though the seasonal variation in the demand can be higher. The annual PBT can have a greater impact on the selection of heating systems, because the selection can reduce the annual peak load, and thus cut the distribution bill every month of the year. In the annual PBT, optimized peak shaving BESS capacities are lower than in the case of the monthly PBT. Hence, the potential benefits in distribution bills obtained by peak shaving are lower. The simulations show that the DSO's need to adjust the tariff unit prices is lower in the case of the annual PBT. In practice, this is highly dependent on customer reactions. Figure 6.6 shows the changes in the total electricity bills of the customers.

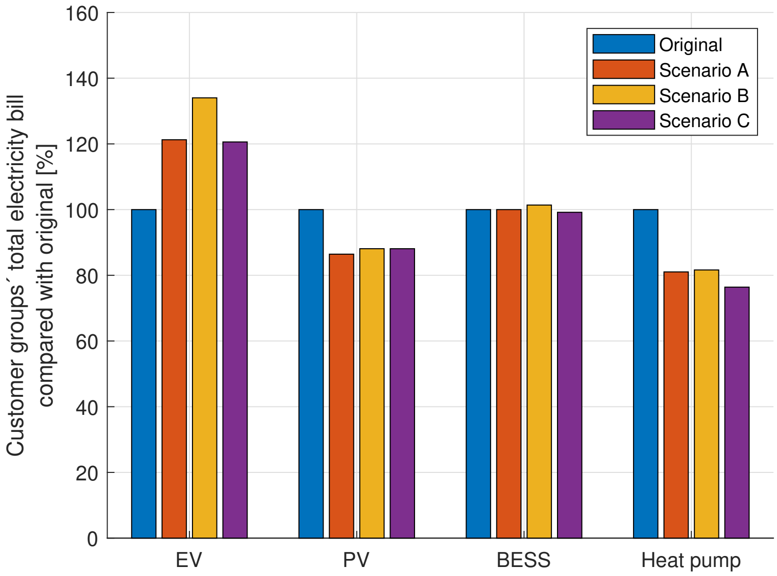

Figure 6.6: Customers' total electricity bills in different scenarios. Distribution tariffs in scenarios B and C include an annual PBT.

It can be noticed that considering also the electricity retailer tariff and the electricity tax affects the total electricity bill in the same way as in Figure 6.3, reducing the relative effects of the PBT and incentivizing more to reductions in energy consumption. Figure 6.7 illustrates the changes in the customers' total electricity bills in different scenarios.

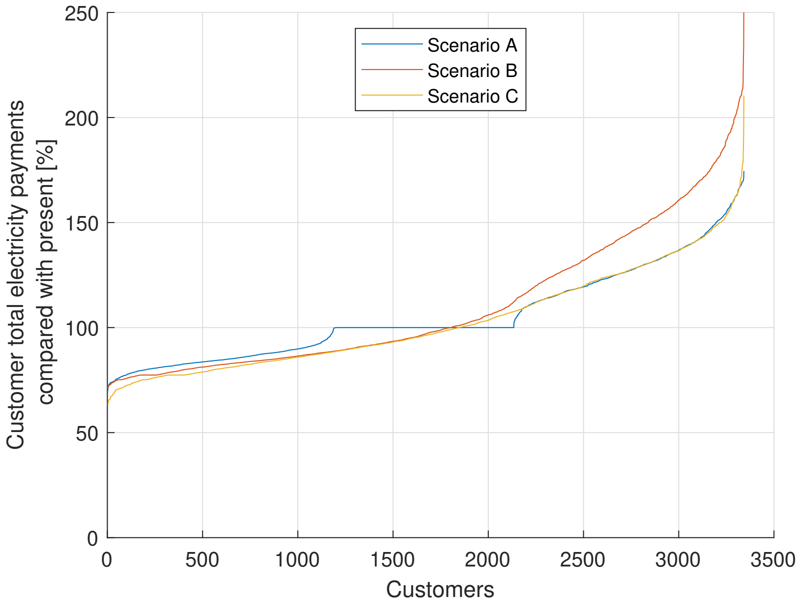

Figure 6.7: Changes in the distribution bills of all customers below 3x63A in different scenarios with an annual PBT. The customer order may vary in different scenarios.

By comparing Figures 6.4 and 6.7, it can be seen that the individual customers will experience significant changes in their distribution bills when a PBT is introduced to customers with DER elements.

6.4 Effects of the PBT on grid loads

The introduction of the PBT changes the customers' incentives to consider their peak demand in the load control and in the customer appliance decisions. The development of the distribution grid loads is considered in different scenarios at the secondary substation transformer level. Scenarios A and B are the same from the perspective of the distribution grid load, because in both scenarios customers adopt new DER elements and the customers do not react to the tariffs. As stated above, the distribution bills in scenario B provide a significant incentive for the customers to react like in scenario C. The differences in the distribution grid load rates in scenarios B and C are analyzed next. From the perspective of the distribution grid load, the load rates of the secondary substation transformers represent the loading of the distribution grid close to the customers. Secondary substation transformers can, however, be quite easily replaced with higher-capacity ones. At the LV network level, the amount of lines affected by new loads can differ depending on for which customers the new loads are modeled. The developed methodology gives an understanding of the LV and MV line loading, but in this doctoral dissertation, the results are presented at the secondary substation transformer level only.

6.4.1 Effects of the monthly PBT on grid loads

In the monthly PBT, the customers are provided with an incentive to control their controllable appliances to avoid increasing their peak loads. The peak load rates of the secondary substation transformers in different scenarios are illustrated in Figure 6.8.

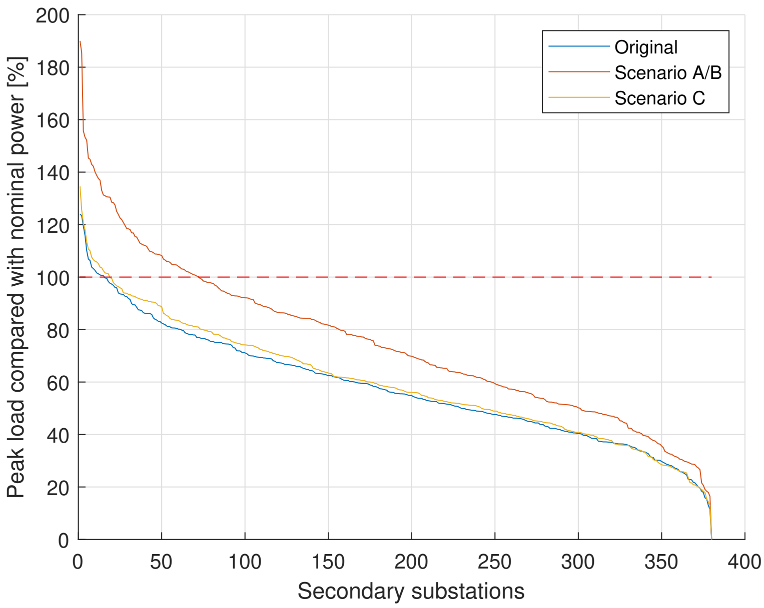

Figure 6.8: Peak load rates of the secondary substation transformers in different load scenarios with a monthly PBT.

Figure 6.8 shows that the secondary substation transformer peak loads increase after the adoption of DER elements. In scenario C, the peak load rates are close to the present ones, even though the customer loads are significantly changed because of the adoption of DER elements. Thus, an increase in the secondary substation peak loads can be avoided if the customers optimize their load patterns based on the PBT price signal. In scenarios A and B, one-fifth of the transformers are overloaded. In scenario C, only a couple of the secondary substation transformers are overloaded in addition to the ones that currently have experienced an overload. Figure 6.9 shows the changes in individual transformers' peak loads.

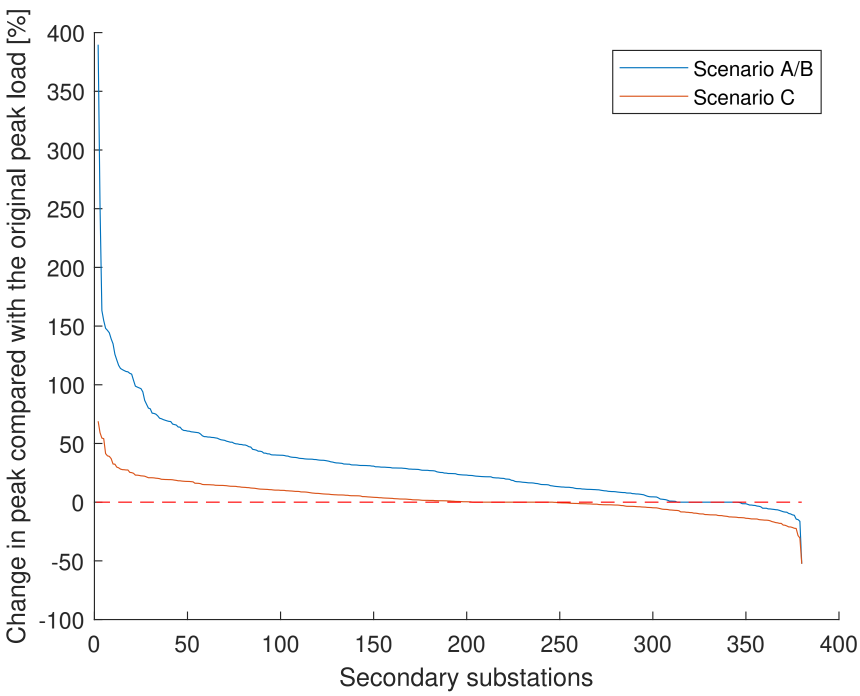

Figure 6.9: Peak loads of the secondary substation transformers in different scenarios with a monthly PBT.

Figure 6.9 shows that for most of the transformers the peak load increases, but there are also transformers where it decreases. For individual transformers, the relative change in the peak load can double, but this is caused by a low peak load with the present loads.

6.4.2 Effects of the annual PBT on grid loads

In the annual PBT, the customers' incentives to control their loads can be limited to only certain hours, because the peak load can be caused by a seasonal heating demand or other infrequent use of high-power appliances. Figure 6.10 illustrates the peak load rates of the secondary substation transformers in the different load scenarios.

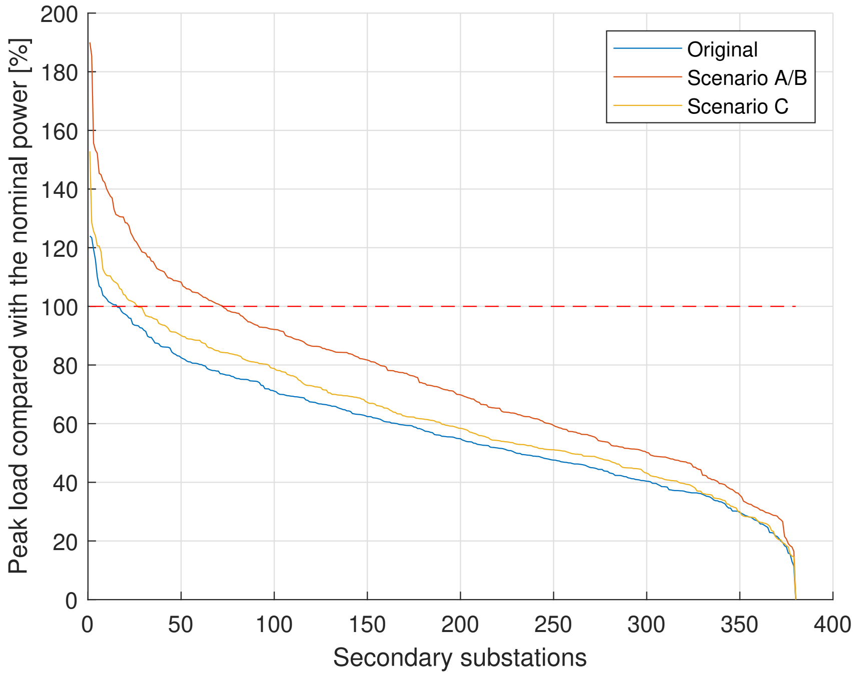

Figure 6.10: Peak load rates of the secondary substation transformers in different load scenarios with an annual PBT.

Scenarios A and B are the same as in the monthly PBT, but in scenario C the customers have a different incentive to control their loads. In the annual PBT, the peak load rates of the secondary substation transformers increase more than in the case of the monthly PBT, but the difference from the present load rates is still moderate. Figure 6.10 shows the changes in the transformer peak loads with the monthly and annual PBTs.

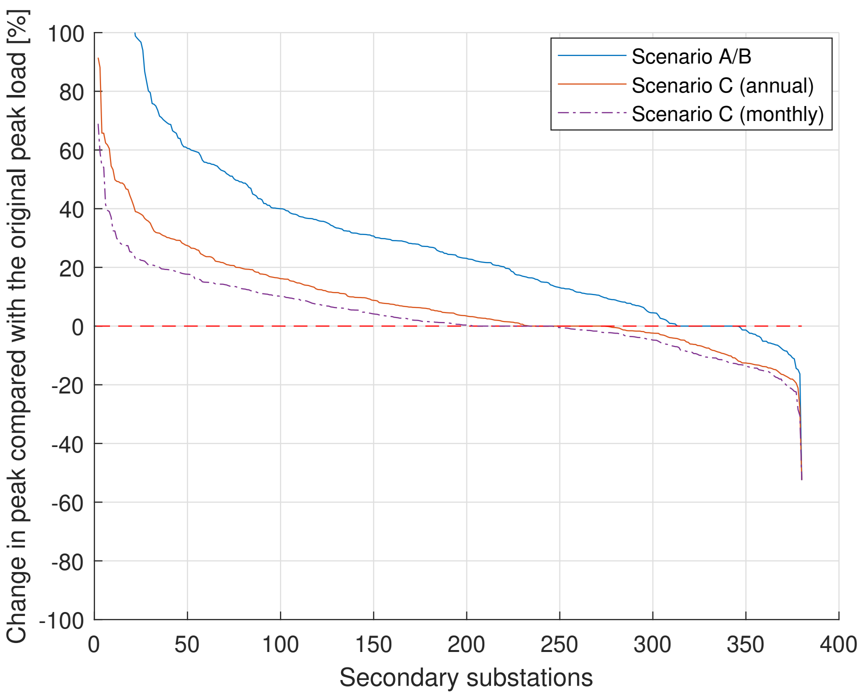

Figure 6.11: Peak loads of the secondary substation transformers in different scenarios with an annual or a monthly PBT.

In the annual PBT, the effects of the customers load control actions are similar to the monthly PBT, but with the monthly PBT, the peak loads of the transformers can increase slightly less with new customer loads. The increase in the peak loads of scenarios A and B is the same as in Figure 6.9. The results of this dissertation show that the monthly PBT can have a more positive impact on avoiding the overloading of the distribution grids than the annual PBT. This is mainly due to the fact that in the annual PBT, the wintertime heating loads can set the target power levels for the EV charging customers so high that the customers' charging patterns start to resemble dumb charging in the summertime. In the monthly PBT, the customers have an incentive to control the charging in all months. It is pointed out, however, that the lower the target power is set, the slower the EV is charged, and the risk that the charging optimization fails will increase. In the annual PBT, failure of the optimization can raise the distribution bill of a customer for the whole year.

6.5 Conclusions of the case area study

Introduction of the PBT can clearly have effects on customers' incentives to control their DER elements or choose more grid capacity-friendly options. The effects of the PBT can change if the tariff component weightings or the determination of the charged peak power are varied. The 3-phase EV charging load can be relatively high compared with other household customers' loads, thereby causing increments in the customers' peak demand every month, which can raise the customers' distribution bills in the case of the PBT. The monthly PBT incentivizes the customers to reduce their peak demands every month, and thus, the benefits of shifting their loads to be more evenly distributed can be higher for the customers than in the annual PBT. Moreover, the annual PBT can provide a higher incentive to consider the peak load of heating systems, in particular, the peak load during the coldest outdoor temperatures. Hence, the monthly PBT can lead to lower risks of overloading the LV networks and the secondary substation transformers. However, the annual PBT can provide a higher incentive to reduce the seasonal variation of the loads, and thereby support the grid load rates more at the higher levels of the electricity system.

It is noteworthy that the PBT can affect the electricity-market-based flexibility depending on whether the PBT is a monthly or an annual tariff. If there is a need to increase the customer loads, the PBT can affect the feasible capacity. If the PBT is based on the customers' monthly peak loads, the customers' capacity available between the peak load and the hourly demand is typically lower than it would be in the annual PBT. Particularly in summer, the customers' peak loads are lower than during the heating season. Thus, there is a lower potential for the customers to participate in flexibility if they are not willing to pay more for their increased peak loads. This means that the flexibility has to be gathered from a larger customer group.

However, it is pointed out that real customer reactions are not known. In the results, the customers are expected to act similarly, either to control or not to control their new loads. In practice, the customer reactions will probably be dissimilar. To achieve the full potential of the PBT, the load control actions have to be automated. If the peak load control requires customers' active decisions, the benefits of the PBT may be lower. The customers may still choose capacity-efficient appliances to reduce their PBT-based distribution bills. Because the customer reactions are not known in advance, there is uncertainty of how the effects of PBT can be taken into account in the distribution grid planning in the short term. If the customers do not react to the PBT, the tariff will distribute the payments in a more cost-reflective way.

7 Discussion

The development of the tariff structure can have dissimilar effects on different customers and their future load choices. With a PBT, the DSO can provide an incentive to customers to reduce their peak loads to cut their distribution bills. The PBT-based load control seems to shift the customer loads to grid-capacity-friendly times and prevent risks of overloading the distribution network. The results show that the PBT-based load control can, in rare cases, also increase the grid load rates because the temporal variation in the customers' loads decreases. The DSO can reduce the risks associated with the dimensioning of the distribution grid infrastructure. In practice, the steering effects of the PBT on customer decisions are not well known. The technological development can have a significant impact on the effectiveness of the peak-load-control actions. The automation of peak load control is of high importance because customers' knowledge, interest, and understanding of their peak demand may be low. Hence, to reach the peak load reduction potential of the PBT, the communication to the customers, electrical contractors, and appliance vendors is highly important. However, if the tariff does not affect the customers' choices, the distribution costs are still distributed in a more cost-reflective way, and the customers who cause a higher risk of overloading the distribution network will be paying higher distribution bills.

The operating environment of the DSO can have a significant impact on the benefits that can be achieved with the PBT. In this doctoral dissertation, the main focus has been on the DSOs operating in rural conditions, which emphasizes the high amount of grid infrastructure per customer, and a high ratio of customers to a connection point. When the number of customers is low, the PBT can have a higher impact on the secondary substation transformer load rates. This can also be dependent on the present load curves of the customers. On the other hand, the rural conditions emphasize long distances, which can set limitations to the grid dimensioning because of the electrical safety aspects. Thus, the reduction of the customers' present peaks loads may not necessarily enable lower-capacity options when the grid is renovated. The value of the increased capacity available can be dependent on the need of adjacent customers to increase their loads. If there is no need for the capacity and the minimum short-circuit currents limit the dimensioning, the benefits can be minor, for instance a better voltage quality. With the new loads, such as EV charging, the risk of the network overloading can rise, and the PBT price signal can reduce the risks. Hence, the main benefits of the well-implemented PBT can come from a higher capacity efficiency and lower risks of the grid capacity overloading, and thus, in the long term, a reduced need for distribution bill increments. In the urban conditions, the high customer density and high costs of the UG cable excavation are emphasized. In the urban residential areas of detached houses there are typically more customers per secondary substation, and thus, the increased grid capacity available may be more likely utilized by other customers in the secondary substation circuit. The urban area DSO can also play it safe and select higher-capacity options because the price difference of adjacent capacity options can be low compared with the cost of UG cable excavation. In other words, the costs of adding capacity afterward can be so high that the DSO does not want to take the risk of overloading. In that case, the benefits from the PBT can also be low, being mainly due to the lower costs of losses.

In the urban environment there are typically more connection points including several customers, such as apartment houses and row houses. For these customers, the peak load evens out naturally inside the connection point because of the temporal variation of different customers' loads. Thus, individual customers' peak loads cause a lower impact on the distribution grid load rates than in the case of detached houses. In the development of the PBT it should be considered and estimated whether it is reasonable to introduce the tariff also for these customers. For instance, the EV charging will not typically be connected to an individual apartment's metering, and it is not reasonable from the grid load perspective to optimize the charging events based on a single apartment's load patterns.

The technology of the distribution grid, overhead lines, or underground cabling, can also have a major impact on the benefits of the PBT. If the grid infrastructure is old or vulnerable to weather conditions, it may have to be renovated in the near future. The PBT-based load control can enable more cost-effective dimensioning of the grid. Furthermore, if the grid has recently been renovated with UG cabling to improve the security of supply, the PBT can provide the customers an incentive to manage their peak load, and thus secure the sufficiency of the capacity or postpone the reinforcement investment need.

The building-specific loads, particularly heating loads, have been the major factor affecting the customer's load profile in Nordic conditions. Hence, the connection point loads have not been significantly influenced if the customer at the connection point changes as a result of the customer moving from the premises. However, EVs and other controllable loads emphasize individual customers' choices. For example, a new customer at a connection point can have an EV. Moreover, the smart control of customer loads enables price signal optimization of customer loads, for instance heating loads. The traditional grid dimensioning principles do not take into account that customers' flexible loads can be shifted simultaneously to achieve benefits from different electricity market prices. With the introduction of the PBT, the DSO can attempt to reduce the risks with a price signal that takes into account the limitations of the distribution grid. This can reduce the disadvantages of flexibility in such grid locations where the grid loads are already high. These phenomena can have an impact on the future dimensioning principles of the distribution grids, but they are not further analyzed in this doctoral dissertation.

The weighting of the tariff components has to be considered comprehensively to reduce the risks of unwanted developments of customer optimization. For example, if the weight of the peak-power-based fee is set high, customers can optimize their distribution bill with a peak shaving BESS. The customers can invest more in their peak shaving solution than what the benefits from the decreased distribution system load rates would be. The high weighting of the peak-power-based fee can also cause a free rider problem particularly in rural conditions. Customers with a low consumption typically also have a low peak demand, and thus, the consumption-related fees do not reflect the costs caused by the presence of the customer. A high value of the peak-power-based fee can also set the EV charging costs high, which can disturb the development of the EV adoption rates. However, in urban conditions the distribution bills can be relatively low, and thus, reasonable weighting of the peak-power-based fee can be high to provide the customers with sufficient incentives. The risk of customer grid defection is typically insignificant in urban areas, and the presence of customers causes only minor costs. Thus, the fixed fee can have a low weight.

A major challenge in the tariff structure development is that the customers may lack knowledge of their electricity consumption, peak demand, and load curve. Hence, this knowledge has to be improved with suitable communication. If the tariff structure development is seen only as a new way to secure the DSO's income received from the customers, the positive impacts of the tariff development can be lost. In the long term, the tariff development aims to reduce the need for premature investments, which will benefit the customers. The DSO has a potential to improve the customers' understanding of energy consumption if the communication succeeds. Hence, it is of high importance to communicate the tariff development to the customers in an understandable and clear manner.

The success of the tariff development can also depend on the schedule of the tariff transition. Early adoption of the new tariff structure is likely to affect the customers' appliance investment decisions. The development of appliances and systems to take into account the PBT incentive can take time, and thus, the principles of PBT pricing should be known in advance. If the tariff structure is not actually implemented, service providers and appliance manufacturers may wait for the terms and conditions to clarify. On the other hand, if the customers invest in EVs, PVs, and heating systems before the tariff development, their decisions may be based on outdated assumptions. This will cause annoyance to the customers and create bad publicity for the DSO. Hence, the predictability of the tariff development is important.

Another question that can have a significant impact on the tariff development is the update of measurement resolution along with the AMR generation upgrade. In Finland, the AMR meters have so far recorded consumption at an hourly level, but the meters will be updated in the next few years to record customers' 15 min or 5 min loads. A higher resolution increases the understanding of the customer loads and allows more accurate analysis of grid load states and voltages. From the perspective of the PBT, the resolution can have a significant effect on how the distribution bills are distributed between the customers. 15 min peak loads can differ significantly from hourly loads, and thus, the benefits and drawbacks of considering shorter peak loads in the PBT should be comprehensively analyzed when suitable load data are available.

The PBT introduction can raise questions with respect to EV charging especially in row houses and apartment houses. If the EV charging load is allocated to the individual customers' load data, the PBT-optimized load will not be optimal at the connection point level. If the optimization is performed at the point of the property's shared electricity consumption, the allocation of the EV charging costs can be challenging, particularly if some customers want to optimize their charging based on the PBT while others do not.

In this doctoral dissertation, the charging of EVs was modeled based on average driving patterns. However, driving in the holidays can differ significantly from the average driving patterns. For instance in Finland, many people drive to their leisure homes at Midsummer, often over distances of hundreds of kilometers, and the traffic is mainly simultaneous. This raises questions of where the EVs will be charged and what kind of charging need will there be at home after the arrival. These rare events can potentially limit the PBT-based optimization in practice.Further, the PBT can guide the customers to choose lower-capacity chargers, which are typically 1-phase chargers. How can the DSO avoid situations where 1-phase chargers are connected to the same phase causing an asymmetrical load and thus problems to the distribution grid?

It has to be noted that the implementation of the PBT can also have a negative impact on the incentives for energy saving if the tariff component weighting is shifted from the energy-consumption-based fee to the peak-power-based fee. On the other hand, the DSO's tariffs should be cost-reflective, and thus, it may also be reasonable to shift the revenue from the energy-consumption-based fee. However, a lower energy consumption fee can increase the attractiveness of the electrification of loads, and the customers may be more willing to change their fossil-fuel-based heating systems over to electric heating. Hence, the weighting of the energy-consumption-based fee can affect the GHG emissions either positively or negatively depending of the customers in the DSO's operating area. The PBT introduction can also affect the feasibility of some loads so that customers may prefer nonelectric alternatives. In Finland, customers may consider wood-burning sauna stoves instead of electric ones, because an electric sauna stove can cause a several kW demand peak to the customer's load curve.

In general, many questions remain unanswered concerning the PBTs. The PBT seems to incentivize customers to make capacity-friendly decisions, but there is significant uncertainty about how the PBT-based load control can be taken into account in the distribution grid dimensioning. Further studies are needed to better understand the effects of the PBT on customers' decision-making. The reactions can, however, also depend on the success of the DSO's communication and the development of smart load control solutions.

8 Conclusion

In this doctoral dissertation, the objective was to develop methodologies that a DSO can use to analyze short- and long-term effects of the tariff structure development on the cost-reflectiviness of the tariffs, the development of the grid loads, and, in particular, the incentives provided by the PBT. Methodologies to estimate the effects of the PBTs were developed taking into account the new customer loads that will affect the future load demand. The developed methodology allows the industry to comprehensively estimate and understand the effects of the tariff structure development on the future distribution grid load rates and the cost-reflectiveness of distribution bills.

The results of this doctoral dissertation show that the PBT can allocate the costs of the distribution system to the customers more fairly than the present tariffs, which increase the peak loads in the distribution system and thus pose a risk of grid overloading and increments in the distribution system costs. The PBT-based load control seems to lead to lower peak demands at different levels of the distribution grid, but particularly in the LV networks close to the end users. In rare cases, the PBT-based flexibility can also increase the grid load rates as a result of the lower temporal variation of the customer loads. The PBT provides customers an incentive to consider also their peak demand in addition to the total energy consumption. Hence, the PBT can affect customers' heating system investments so that the peak heating demand is taken into account in the investment decisions. This can benefit the electricity system also at the higher levels.

The effects of the PBT on the long-term development of the distribution systems involve significant uncertainty. It has to be noted that introduction of the PBT provides an incentive to the customers to control their loads in a capacity-effective way, but it is unknown how customers will react to the tariff in reality. Hence, even though the PBT provides incentives, it is not clear whether the DSO can take the PBT-based benefits into account in the dimensioning of the distribution grid. However, if the customers do not react to the PBT price signal, the costs of the grid capacity reinforcements are allocated in a more fair way than with the present tariffs.

Introduction of the PBT can cause significant changes in the customers' distribution bills. This implies that the present tariff structure has not incentivized the customers to consider the effects of their decisions on their peak demand. In the short term, the PBT introduction will most probably affect the load patterns of already controlled loads, such as nighttime control of storage heating, and the simultaneous use of customers' high-power appliances. The PBT introduction reduces the benefits of the prosumers if the DSO shifts revenue also from the energy-consumption-based fee to the peak-power-based fee. This can be challenging when considering the target to increase renewable production, but the DSO's tariffs should reflect the costs of the distribution business, where energy consumption has only a minor effect. Hence, the subsidies for renewables may be reasonable to implement by other means than the pricing of a DSO operating in a monopoly position. Electrification of transportation can increase the peak load demand in the distribution system, particularly close to the customers. The PBT can have an impact on preventing the increments of distribution grid overloads caused by EV charging events. On the other hand, an EV can be an expensive investment for the customer, and thus, the customers may be willing to increase their peak power and pay a higher distribution bill to charge the EV faster. In this case, the costs are allocated in a more fair way to those customers who cause the increase in the distribution grid load rates. In the long term, the PBT can have an impact on customers' decisions on heating system so that the peak demand during extreme outdoor temperatures is considered in addition to the total energy demand. The tariff development can also have an impact on grid defection, which can be an important factor in the distribution grid development particularly in rural conditions. This is emphasized in sparsely populated areas where the ratio of distribution grid length to the number of customers can be high.

PBTs were analyzed in this doctoral dissertation with a special reference to Nordic conditions, but the same methods can be applied also in other parts of the world by taking into account local parameters. A special feature of the Nordic conditions is that the electric heating loads cause a significant difference in the load demand between seasons. Thus, customers' connections and distribution grids are already typically dimensioned for wintertime heating loads. Secondly, PV production is very limited in wintertime because of the snow cover and short daylight hours.

Now, when DERs have not yet become widely popular, it would be good time for DSOs to introduce a PBT. Customers can get used to a new DSO tariff structure, and they can take into account the PBT when making investment decisions. After customers have already installed a PV system or chosen a EV charger, the possibilities to affect customers' loads with the tariff will be more limited in practice.

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