

# Power play : impacts of flexibility in future residential electricity demand on distribution network utilisation

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# Power Play

Impacts of flexibility in future residential electricity  
demand on distribution network utilisation

Else Veldman

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# Power Play

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PROEFSCHRIFT

ter verkrijging van de graad van doctor aan de  
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Else Veldman

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Else Veldman  
Utrecht, October 2013

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## Summary

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The planning and design standards that have been developed in the past century, have led to well-functioning, reliable electric power systems. The electricity distribution networks that are part of these systems, have little embedded automation and a relatively low ratio of used capacity to available capacity. This presents a great potential for transferring extra energy within the existing capacity of these networks. Furthermore, developments towards a more sustainable energy supply system require support for distributed generation, integration of more flexible demand and a more efficient use of the grids. In addition, due to the liberalisation of the energy sector and the connection of generators at the distribution level of the power system, there is no longer a strict separation between suppliers and consumers. As a consequence of these developments, it is increasingly difficult to balance supply and demand, and the electricity distribution networks need to support and integrate distributed generation and facilitate a potential growth in electricity demand.

There exist various ways for the electricity distribution networks to accommodate future electricity demand and supply. The capacity of traditional power systems is dimensioned to meet peak demand. Because in these traditional power systems the electricity demand is inflexible and time-critical, the traditional approach is to control generators that supply electricity to follow the electricity demand to keep a continuous balance between generation and load. However, flexibility in electricity demand as well as new developments in storage of electricity, make it possible to delay or advance the electricity demand. In so-called *smart grids*, the demand for electricity may, for example, be adjusted to the (local) availability of renewable, intermittent generation. Or, following another smart grid strategy, demand may be increased when electricity prices are low. This, amplified with the uncertain developments in the electricity demand and supply at residential areas, makes it more complex to determine the required capacity of future distribution networks.

Though it is recognised that functionalities in smart grids can contribute to reducing peak loads and required network capacity, it is still unclear to what extent peak loads can be reduced and what the resulting effect is on the required investments in distribution networks. This is mainly caused by the fact that it is highly uncertain how future electricity demand and supply will develop. Also, smart grids

can develop in various directions and in these smart grids, various functionalities and strategies can be applied. Therefore, the goal of this thesis is to investigate the consequences of future residential electricity demand and supply on electricity distribution networks and to explore measures to optimise the utilisation of the distribution networks.

The research gives more insight in what applying various smart grid strategies means for the required capacity of the medium voltage distribution networks by using a scenario-based methodology to model future residential loads. This novel approach to model the aggregated load profiles of residential areas, takes into account the uncertainties in future residential electricity demand by separately modelling the load (and generation) profiles of different future residential technologies, like heat pumps, solar panels and electric vehicles. With the proposed modelling method it is also possible to compose profiles that include demand that may be flexible and shifted in time, for example in the case of smart charging of electric vehicles or in the case of applying demand-side management. With this method, future aggregated residential net load profiles can be modelled and used as input for load-flow calculations to assess the effect of the changes in future residential electricity demand and supply and of various smart grid strategies on the utilisation of the distribution networks. In this thesis, the case of the Netherlands has been used as a case study.

Firstly, net load profiles of residential areas for three different scenarios in 2040 have been constructed using the proposed method. The results show that for each of the scenarios, the peak demands for electricity in future residential areas will be higher compared to the case that corresponds to the conventional network planning method that takes into account a yearly growth of 1% for the residential peak demand. The future demands do, however, differ significantly per scenario. Furthermore, the impacts of two different smart grid strategies on the residential load profiles have been investigated. In the first strategy the smart grid functionalities are focused on the responsibilities of the network operator and the strategy aims at minimising network load. With this strategy the flexible load in residential areas is shifted from moments of high load to off-peak moments to optimise network utilisation and reduce network reinforcements; this will lead to more flattened load profiles. The results show that by managing flexible loads this way, the maximum loading of the networks can significantly be reduced. The second smart grid strategy aims at enabling residential customers to participate in the electricity market by introducing more advanced pricing schemes. With this strategy the flexible demand in residential areas is shifted towards moments with low electricity prices at the wholesale market to minimise electricity supply costs. In one of the scenarios, this strategy leads to an increase of the maximum loading compared to a situation without shifting of flexible load.

Secondly, the modelled net load profiles have been used as input for load-flow calculations to assess the impacts on the utilisation of distribution networks. The calculations yield the maximum loadings of the assets. With the results of the

maximum loadings and with the values of the maximum allowable loadings of the assets, the required reinforcements of the assets in a large set of medium voltage networks have been quantified. Because energy losses are partly dependent on the shape of the load profiles, the impact of changing load profiles on annual energy losses have been assessed as well. Though energy losses contribute significantly to the total impacts, the differences in the impacts between applying various smart grid strategies are mainly caused by differences in the required network capacities.

The results show that the flexibility in residential electricity demand that can be enabled by smart grids, has value for distribution network operators (DNOs) when it is used to reduce maximum loadings, and could contribute to a more efficient utilisation of the distribution networks. It is, however, yet unclear how this value relates to the value this flexibility has for the customer and the value that it creates on electricity markets. There are different ways to organise the market and build smart grids in which flexible demand is enabled in order to optimise distribution network utilisation. The role and possibilities of the DNO will change in such a smart grid environment. Further research needs to pay attention to regulatory barriers (in particular, the uncertainty among parties about roles and responsibilities and the uncertainty about sharing of costs and benefits among different stakeholders) in order to be able to adjust the regulatory framework in such way that the system as a whole is optimised. Besides that, the customer must be willing and able to make the flexibility in residential electricity demand available to other parties and therefore, customer involvement is becoming more important in a smart grid environment. Further research is needed to be able to quantify the value that flexible electricity demand has for the residential customers themselves as well as the amount of flexibility that may become available.



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## Samenvatting

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De planning- en ontwerpmethoden die de afgelopen eeuw zijn ontwikkeld, hebben geleid tot goed functionerende, betrouwbare elektriciteitsvoorzieningssystemen. De elektriciteitsdistributienetten die onderdeel uitmaken van deze systemen, zijn slechts in beperkte mate geautomatiseerd en de verhouding tussen de gebruikte en de beschikbare capaciteit van deze netten is laag. Dit maakt het mogelijk om binnen de bestaande capaciteitsgrenzen een extra hoeveelheid energie te transporteren. Daarnaast zorgen ontwikkelingen naar een duurzamere energievoorziening ervoor dat zowel decentrale opwekking van elektriciteit als een grotere vraag naar elektriciteit op een efficiënte manier in de netten moet worden ingepast. Bovendien is er door de liberalisering van de energiesector en het feit dat op decentraal niveau elektriciteitsproductie plaatsvindt niet langer een duidelijke scheiding tussen leveranciers en gebruikers van elektriciteit: klanten kunnen zowel elektriciteit afnemen als invoeden. Als gevolg van deze ontwikkelingen wordt het steeds uitdagender om de balans tussen vraag en aanbod van elektriciteit te handhaven en zullen de netten moeten worden aangepast om aan de groeiende vraag naar en aanbod van elektriciteit te kunnen blijven voldoen.

Er zijn verschillende manieren waarop de distributienetten kunnen inspelen op de veranderende vraag naar en aanbod van elektriciteit. Traditioneel worden elektriciteitssystemen gedimensioneerd op basis van de piekvraag en worden generatoren die elektriciteit leveren aan het net, bijgeschakeld op het moment dat de elektriciteitsvraag toeneemt. Deze traditionele benadering waarbij het aanbod, ofwel de productie van elektriciteit, de vraag volgt om het systeem in balans te houden, heeft te maken met het feit dat de huidige vraag naar elektriciteit grotendeels inflexibel en tijdkritisch is en er geen tot weinig passende oplossingen zijn om elektriciteit op te slaan. De flexibiliteit in de toekomstige elektriciteitsvraag en ontwikkelingen in opslag van elektriciteit maken het echter mogelijk om de vraag naar elektriciteit in de tijd te verschuiven. Zo kan in zogenaamde *smart grids* de vraag naar elektriciteit worden afgestemd op de (lokaal) beschikbare duurzame elektriciteitsproductie. Of de flexibele vraag naar elektriciteit kan worden verschoven naar momenten waarop de elektriciteitsprijzen laag zijn. Omdat er verschillende manieren bestaan om smart grids in te richten en omdat het met name in woonwijken onzeker is hoe de vraag

naar en het aanbod van elektriciteit zich ontwikkelt, wordt het ingewikkelder om de benodigde capaciteit van toekomstige distributienetten te bepalen.

Ondanks dat wordt ingezien dat smart grids kunnen bijdragen aan het verminderen van piekbelastingen en van de benodigde netwerkcapaciteit, is het nog altijd onduidelijk in hoeverre piekbelastingen kunnen worden verminderd en wat het effect hiervan is op de benodigde netwerkinvesteringen. Dit wordt hoofdzakelijk veroorzaakt door het feit dat het nogal onzeker is hoe de toekomstige vraag naar en aanbod van elektriciteit zich zal ontwikkelen. Bovendien kunnen smart grids zich in verschillende richtingen ontwikkelen en kunnen verschillende smart grid strategieën worden toegepast om de flexibele elektriciteitsvraag naar andere momenten te verschuiven. Het doel van dit proefschrift is daarom om de gevolgen van de toekomstige huishoudelijke elektriciteitsvraag en -aanbod op de distributienetten te onderzoeken en om te verkennen hoe met name de bestaande capaciteit van distributienetten optimaal benut kan worden.

Door het toepassen van een op scenario's gebaseerde methodologie om toekomstige huishoudelijke belastingen te modelleren, geeft het onderzoek meer inzicht in wat het toepassen van verschillende smart grid strategieën betekent voor de benodigde capaciteit van (middenspannings)distributienetten. Deze nieuwe aanpak om geaggregeerde belastingsprofielen te modelleren houdt rekening met de onzekerheden in de toekomstige huishoudelijke elektriciteitsvraag in woonwijken door de verschillende profielen van toekomstige technologieën, zoals warmtepompen, zonnepanelen en elektrische auto's, afzonderlijk van elkaar te modelleren. De voorgestelde methode maakt het bovendien mogelijk om profielen samen te stellen waar flexibele belastingen onderdeel van uitmaken die verschoven kunnen worden in de tijd, bijvoorbeeld door het opladen van elektrische auto's slim aan te sturen. Met deze methode kunnen toekomstige geaggregeerde huishoudelijke belastingsprofielen worden gemodelleerd die vervolgens gebruikt kunnen worden in load-flow berekeningen. Met de uitkomsten van deze berekeningen kunnen de effecten van zowel veranderingen in de toekomstige huishoudelijke elektriciteitsvraag als van verschillende smart grid strategieën op het gebruik van de distributienetten worden bepaald. In dit proefschrift wordt de situatie in Nederland gebruikt als casestudy.

Allereerst zijn met de voorgestelde methode belastingsprofielen voor verschillende woonwijken samengesteld voor drie verschillende scenario's die een situatie in 2040 beschrijven. De resultaten laten zien dat de piekvraag naar elektriciteit in de woonwijken voor elk van deze scenario's toeneemt in vergelijking met de traditionele netwerkplanningsmethode die uitgaat van een jaarlijkse groei van 1% van de huishoudelijke piekvraag. De grootte van de toekomstige vraag hangt wel sterk af van het scenario dat aangenomen wordt. Daarnaast zijn de effecten van het toepassen van twee verschillende smart grid strategieën op de huishoudelijke belastingsprofielen onderzocht. In de eerste strategie richten de functionaliteiten in het smart grid zich op de verantwoordelijkheden van de netbeheerder en is het doel van de strategie het minimaliseren van de netwerkbelasting. Door het toepassen van deze strategie wordt het gebruik van flexibele belastingen in woonwijken verschoven van momen-

ten met een hoge netwerkbelasting naar dalmomenten zodat netwerkinvesteringen gereduceerd worden. Dit leidt tot vlakke belastingsprofielen. De resultaten laten zien dat door de elektriciteitsvraag van flexibele belastingen op deze manier in de tijd te verschuiven, de maximale belasting van de distributienetten significant kan worden verlaagd. De tweede smart grid strategie heeft als doel om kleinverbruikers intensiever te betrekken bij de elektriciteitsmarkt door meer gevarieerde prijzen of nieuwe diensten aan te bieden. Met deze strategie wordt het gebruik van flexibele belastingen in woonwijken verschoven naar momenten waarin de elektriciteitsprijs op de groothandelsmarkt laag is, zodat de elektriciteitskosten (exclusief de transportkosten voor elektriciteit) geminimaliseerd worden. In één van de scenario's leidt deze strategie tot een toename van de maximale belasting in vergelijking met de situatie waarin de flexibele vraag niet verschoven wordt.

Vervolgens worden de belastingsprofielen gebruikt voor load-flow berekeningen om de effecten op het gebruik van de distributiesnetten te bepalen. Uit de berekeningen volgen de maximale belastingen van de netwerkcomponenten (kabels en transformatoren) in een grote set van middenspanningsdistributienetten. Met deze resultaten plus de gegevens over de maximale belastbaarheid van de netwerkcomponenten wordt bepaald hoeveel netwerkuitbreidingen nodig zijn. Omdat energieverliezen (deels) afhankelijk zijn van de vorm van de belastingsprofielen, is ook het effect van veranderde belastingsprofielen op de jaarlijkse energieverliezen onderzocht. Hoewel de jaarlijkse kosten van energieverliezen groot zijn in vergelijking met de kosten van netwerkinvesteringen, worden de verschillen tussen de totale kosten voor verschillende smart grid strategieën met name bepaald door de verschillen in investeringskosten.

De resultaten laten zien dat de flexibiliteit in huishoudelijke elektriciteitsvraag die in smart grids beschikbaar komt, waarde heeft voor regionale netbeheerders wanneer deze wordt ingezet om de maximale belasting van het net te verlagen. Op deze manier kunnen smart grids bijdragen aan een efficiënter gebruik van de distributienetten. Het is echter nog onduidelijk hoe deze waarde zich verhoudt tot de waarde die deze flexibiliteit voor de kleinverbruiker heeft en tot de waarde die door deze flexibiliteit op elektriciteitsmarkten gecreëerd kan worden. Er zijn verschillende manieren waarop de markt ingericht kan worden en waarop smart grids gerealiseerd kunnen worden op een zodanige manier dat de flexibiliteit in de elektriciteitsvraag beschikbaar komt om het gebruik van de netten te optimaliseren. De rol en verantwoordelijkheden van de netbeheerder zullen veranderen in smart grids die dit mogelijk maken. Vervolgonderzoek zal aandacht moeten besteden aan de beperkingen die door de huidige wet- en regelgeving worden opgelegd (in het bijzonder gaat het hier om onzekerheden met betrekking tot de rol en verantwoordelijkheden van de betrokken partijen en met betrekking tot de verdeling van kosten en baten tussen deze partijen), zodat de regulering zodanig kan worden aangepast dat het systeem als geheel geoptimaliseerd wordt. Bovendien zal de kleinverbruiker bereid gevonden moeten worden en ook in de mogelijkheid moeten zijn om de flexibiliteit in zijn of haar elektriciteitsvraag beschikbaar te stellen aan andere partijen. De betrokken-

heid van de kleinverbruiker in smart grids is daarom cruciaal. Vervolgonderzoek is nodig om te bepalen welke waarde de flexibiliteit in de elektriciteitsvraag voor de kleinverbruiker zelf heeft alsmede om te bepalen hoeveel flexibiliteit beschikbaar kan komen.

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## List of acronyms

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( $\mu$ -)CHP	(Micro-)combined heat and power
COP	Coefficient of performance
DNO	Distribution network operator
DG	Distributed generation
DR	Demand response
DSM	Demand-side management
DSO	Distribution system operator
EU	European Union
EV	Electric vehicle
HV	High voltage
ICT	Information and communication technology
ISO	Independent system operator
LV	Low voltage
MV	Medium voltage
NPV	Net present value
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RES	Renewable energy sources
TNO	Transmission network operator
TSO	Transmission system operator



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## Introduction

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### 1.1 Transition towards a sustainable energy supply system

A sustainable, reliable and affordable electricity supply is of the utmost importance in satisfying the needs of individuals and enabling societies and economies to function. In present times, Europe faces the challenges of climate change, increasing import dependence and higher energy prices [107]. As a consequence of these challenges, the use of renewable energy sources increases fast and the energy supply system is changing [50]. The traditional power system that is developed over the years, is a vertically-operated system that consists of a transmission system, which transports large amounts of power from large-scale conventional electricity generation plants over long distances, and distribution networks, which distribute the electricity to the consumers (see Figure 1.1). This does not hold any longer due to the developments which are taking place at the moment and which might be expected in the next decades. The power system will become a system with bi-directional power flows that is supported by a sophisticated information and communication technology infrastructure. The environment in which distribution network operators (DNOs) operate is therefore changing rapidly. As a consequence, the DNOs need to facilitate the transition to a more sustainable energy supply, in addition to delivering affordable and reliable electricity with a high service level. In contradiction to large-scale, conventional power plants, renewable energy generation technologies are by nature quite suitable for small-scale, distributed implementation, and are connected to the electricity distribution networks [20]. In addition to changes in generation of electricity, the demand side also changes in response to the energy transition.

#### 1.1.1 Distributed generation

Because of the penetration of sustainable energy sources and more efficient use of primary energy, the implementation of distributed generation (DG) of electricity is accelerating. For instance, greenhouses which use cogeneration (also known as combined heat and power – CHP) and deliver electricity back to the grid, wind power and photovoltaic solar panels, are stimulated by energy policies and incentives of national governments and represent a growing share of the energy supply in the EU member states [27]. In general, DG can be defined as electric power generation

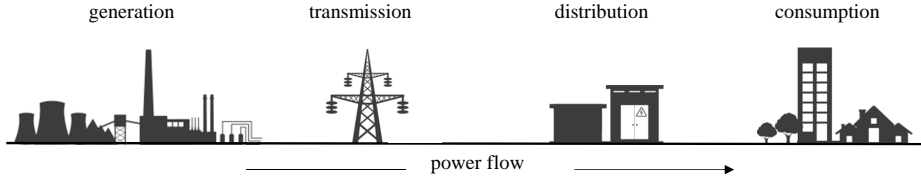


Figure 1.1: Structure of a traditional power system.

within the distribution systems or at the customer side of the grid [8]. Figure 1.2 depicts the growing share of CHP and renewable energy sources (RES) in various European countries.

Although each different type of DG has its own technical and commercial characteristics, all types of DG also share some similarities: they have independent producers and the location of production depends on the source. For wind power this means that electricity is usually generated in remote areas far from the more populated regions. CHP is usually located closer to the consumer, but is often primarily scaled to the local heat demand, rather than to the local electricity demand. Another aspect of DG is the intermittent and fluctuating nature of the resource. For instance, solar power is dependent on the abundance of sun and the absence of clouds. This makes the amount of solar power difficult to predict. Wind can be predicted more accurately, but can fluctuate drastically.

The connection of DG to the distribution networks can lead to technical challenges, such as voltage rise and increasing network fault levels. Operational issues, like the impact of DG on voltage stability and grid protection, and measures to manage these issues, are extensively studied in, amongst others, [12, 28, 87, 119]. The intermittent and fluctuating characteristics of these resources make optimal planning and operating of the power system fairly difficult. Without any changes to the operational structure of the power system, a high penetration of DG can only be achieved by major network reinforcements [25, 32].

### 1.1.2 Changes on the demand side

Using electricity produced by renewable energy sources for heating technologies, such as heat pumps, and for electric transport contributes to reducing the use of fossil fuels. The use of these technologies will lead to a substantial additional demand for electricity, though they can reduce the overall use of energy [24, 50].

Besides an expected increase in demand for electricity, residential consumers are starting to produce electrical energy themselves, and thus need less electricity from the grids. However, if they use e.g. photovoltaic panels and are temporarily not provided with solar energy, they may still need to be fully supplied by the grid at

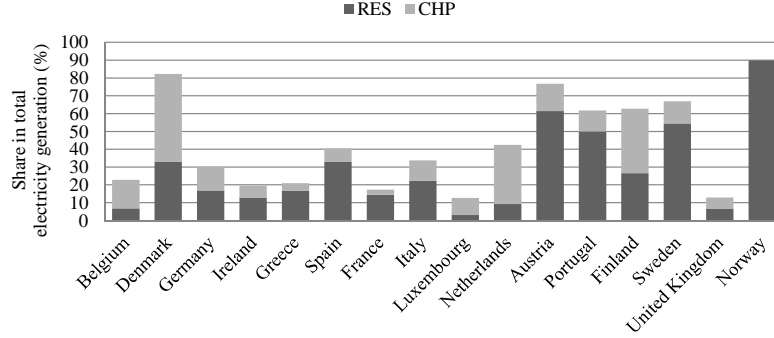


Figure 1.2: The amount of electrical energy generated by renewable energy sources and combined heat and power in various European countries [3].

moments the load peaks. This means that the net load profiles of the residential consumers will be less predictable and vary more.

The electricity distribution networks have to deal with these changing load profiles and the potential additional load with its specific characteristics. How the demand at the consumer side will develop is, therefore, surrounded with much uncertainty. The outlooks that have been developed are still very diverse on issues like the emerging new technologies that will be successful at local level, the timing and the penetration grades of these technologies. Another aspect of future residential demands is the degree in which the demand can be managed. Future electricity demand may be more flexible than it is currently. A large part of the future residential load might, for example, be the result of electricity demand of electric vehicles. Because cars do on average stand idle for at least 90% of the time, these loads are less time-critical than most other types of loads. This gives the electricity provider and/or DNO the opportunity to manage the charging of electric cars. The development towards so-called *smart grids*, that use information and communication technology to intelligently integrate the actions of the customers connected to the electricity distribution network, makes such demand response possible.

## 1.2 Preparing distribution networks for future demand and supply

Providing the electricity distribution networks with sufficient capacity for future electricity demand and supply involves large investments. The investment and replacement strategies which have been successfully deployed to the distribution networks so far no longer hold because they do not fulfil future requirements and cannot

handle uncertainties in the right way. Especially in a future power system, peak loads in electricity distribution networks can increase significantly and without any smart functionality to reduce these peaks, this can potentially lead to a considerable increase in network investments [19].

The consequences of the developments in the future demand and supply of electricity can be mitigated by enabling more flexible operation and more efficient use of the electricity distribution networks already in place, without compromising the quality of service. Due to the increasing flexibility in future demand and developments in electricity storage technologies, it becomes possible to shift the transport of electricity in time. This makes it possible to leverage local supply and demand or shift flexible demands to off-peak moments, allowing more energy to be transported without providing network capacity for high peak loads. A high penetration of DG and the integration of electricity storage and the use of flexible demands in the operation of the grids must be supported by the application of a more active approach to network management. Suitable concepts and advanced network technologies to realise active network management in distribution networks are studied in [70, 98].

The ability of functionalities in active distribution networks to reduce peak loads and use network capacity efficiently is recognised as one of the main benefits of smart grids (see e.g. [60, 90]). To realise the potential savings in network investments through smart grids, which eventually will flow back to the end customers, it is of utmost importance to make sound decisions related to the expected required capacity of the electricity networks. However, because of the long lifetime of the assets, planning of electricity networks is a challenge keeping in mind the uncertainty about future electricity demand.

### 1.3 Research objective and scope

The energy transition leads to a growth of decentralised production of electricity connected to the distribution networks and to an increase in electricity demand because of the use of new energy conversion technologies. The capacity of the electricity distribution networks is based on peak loads. On the one hand, these peak loads can increase significantly due to the changes in the future demand and supply of electricity. On the other hand, various developments lead to more active distribution networks. Functionalities in these smart grids can realise a more efficient use of network capacity and reduce required network investments. Though it is recognised that smart grids can contribute to reducing peak loads and required network capacity, it is still unclear to what extent peak loads can be reduced and what the resulting effect is on the required investments in distribution networks. This is mainly caused by the fact that it is highly uncertain how future electricity demand and supply will develop. Also, smart grids may develop in various directions and in these smart grids, various functionalities and strategies may be applied. This leads to the following research objective of this thesis:

*To investigate the consequences of future residential electricity demand and supply on electricity distribution networks and to explore measures to optimise the utilisation of distribution networks.*

The focus of this research is on the changes in the use of electricity in residential areas. In terms of amount of connections to the electricity distribution networks, the residential electricity users dominate. Besides that, these customers have an unpredictable behaviour and create much uncertainty in the expected electricity demand. It should also be noted that if the flexible residential demand is enabled and used to reduce peak loads, this will have implications on the organisation of the power system as a whole, including electricity market design. The time horizon for planning of electricity networks is at least 20 to 30 years because of the long lifetime of the assets, therefore, a time horizon of roughly 30 years is chosen (the final year in the investigation is 2040).

In order to achieve the research objective, several research questions are formulated which will be addressed in this thesis:

1. Which developments in the future electricity demand and supply in residential areas are foreseen?
2. How does future electricity demand and supply change residential loads?
3. What impacts do changing load profiles have on distribution networks?
4. How can residential demands be modelled taking into account uncertainties in future developments?
5. What are the impacts on the distribution networks, for various scenarios describing the future residential electricity demand and supply as well as for various smart grid strategies?
6. Which measures should be taken to optimise the utilisation of electricity distribution networks?

## 1.4 Definitions

For the sake of clarity, the explanation of some words that recur regularly in this thesis, are given here.

*(Electrical) energy* – In physics, the concise definition of energy is the property to perform work. Energy can take many forms. In this thesis, energy is defined by a physical quantity of power over time, expressed in kWh.

*Electrical load* – An electrical load connected to the network has a certain electricity demand and draws power from the network. The demand of an electrical

load is mostly expressed in terms of power ( $P(\text{kW})$ ), but sometimes it suits better to speak of the amount of power demand over a period in time and it is expressed in energy ( $E(\text{kWh})$ ).

*Generation* – Besides load, generation can also be connected to the network. Generation supplies power to the network. Electricity generation can be expressed in terms of power ( $P(\text{kW})$ ) as well as in terms of energy ( $E(\text{kWh})$ ).

*Loading* – The loading of an asset is the amount of power ( $P(\text{kW})$ ) to which the asset is subject to at a certain moment of time. The peak load is the maximum value of the loading over a certain period of time.

*Capacity* – The capacity of an asset, is the maximum loading that the asset is able to handle. Sometimes, the capacity is expressed in current ( $I(\text{A})$ ). Unless stated otherwise, the capacity will be expressed in power ( $P(\text{kW})$ ) in this thesis.

*Utilisation* – The utilisation of an asset is the share of the capacity that is used at the peak moment, expressed by the ratio between the maximum loading and the capacity of the asset.

## 1.5 Approach

To investigate the uncertainties in future electricity demand and supply, various scenarios will be regarded that have a very different impact on the distribution networks. Several scenario studies are reviewed to identify the main drivers and policy measures that may lead to variations in the local (residential) electricity demand and supply. After that, three specific scenarios are created based on these drivers. This approach leads to very different, yet realistic scenarios. The impact of these scenarios on the distribution networks can be explored after modelling the resulting residential loads for the scenarios.

This is done by applying a novel approach for a profile-driven determination of the peak load value and peak moments, which can differ per scenario. This method, unlike other methods, makes it possible to differentiate between residential areas by defining different shares of new technologies that contribute to the electricity demand. Also, using profiles makes it possible to assess the electricity consumption over time, rather than the peak load alone, and makes it possible to analyse the impact of the flexibility of electricity demand on the loading of the networks.

The resulting profiles are used for load-flow calculations of medium voltage (MV) distribution networks. This reveals differences in the impact of various scenarios on the loading of the distribution network and makes it possible to quantify the effect of flexible demands on the required capacity. Because the design of smart grids has implications on the entire electric power system, impacts of the change in residential

load profiles on the networks are to be considered. An approach could be to assess the impacts on a typical MV network and scale up the impacts. However, due to the differences between various MV networks, concentrating on a (or a few) typical MV network(s) is rather difficult. Therefore, the approach is to consider an extensive set of networks instead of investigating a few sample networks in detail.

The approach is applied to the case of the Netherlands. As in most countries in northwest Europe, the Dutch electric power system was introduced at the start of the 20th century and, after its initial introduction, increased in scale and developed into the extensive electricity supply system that we have today. Specific for the Netherlands is the fact that during its development nearly all connections in the distribution networks up to 20 kV have been replaced by cables; this resulted in a high reliability compared to other European countries. The uncertainties in future electricity demand and the opportunities provided by smart grids are nonetheless not different from other developed countries.

## 1.6 Thesis outline

The outline of the thesis is presented here. Every chapter in this thesis starts with a short introduction, introducing the most relevant topics to be treated and giving an overview of the chapter, and ends with a summary and conclusions on the main findings.

Chapter 2 – This chapter provides background on the existing electricity networks. It describes how the energy transition leads to changes in some fundamental principles of distribution networks and how these and other recent developments lead to new functionalities in future distribution networks. The various directions in which the networks can develop, are indicated by three smart grid concepts.

Chapter 3 – In this chapter, the first research question is addressed. The energy conversion technologies that are expected to change the electricity demand in residential areas substantially, are defined and described. A review of recent scenario studies identifies the main drivers that lead to various outcomes and subsequently, three scenarios are created for the case of the Netherlands.

Chapter 4 – This chapter describes how network planning traditionally has been done. An analysis on the utilisation of a large set of distribution networks gives some insight in the utilisation of distribution networks. The chapter explores present load models and addresses the second research question. Furthermore, it pays attention to the consequences of changing load profiles on distribution networks and with this, the third research question is answered.

Chapter 5 – With help of the insights gained in Chapter 4, a new modelling approach is developed to adequately model the aggregated load (and generation) of tens to hundreds of households. By describing this approach, this chapter addresses the fourth research question. Also, it elaborates on how profiles of flexible demands that can be shifted in time can be constructed for various smart grid strategies.

It describes how load profiles are derived for the three scenarios as well as for the applied smart grid strategies and presents the effect of these smart grid strategies on the net load profiles.

Chapter 6 – This chapter addresses the fifth research question; it describes the assessment of the impacts of future residential demands for the three scenarios and following two fundamentally different smart grid strategies. This assessment is done by executing load-flow analyses using the aggregated residential net load profiles that are modelled in Chapter 5. With the results, the required network capacities and the resulting reinforcements costs for installing sufficient capacity over the years, as well as the effects on the energy losses are assessed.

Chapter 7 – In this chapter, the sixth research question is addressed. First, the chapter describes how electricity distribution networks can benefit from smart grids, gives a reflection on current developments, and discusses in which direction the future power system should develop. Subsequently, it pays attention to the value that flexible electricity demand has for the customer. Finally, it pays attention to the implications that optimal use of flexible residential demand has on electricity market design by treating three examples in which flexible demand is enabled and used to reduce network peak loads.

Chapter 8 – This chapter presents the conclusions as well as the contributions of the research. Also, it gives recommendations for further research.

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## Developments in electricity distribution networks

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### 2.1 Introduction

Electric power systems are very complex. Since the introduction of electrical energy, the electric power systems have evolved to very extended systems that are linked over the borders of many countries and in which a continuous balance between demand and supply must be maintained to ensure reliable operation. In absence of large amounts of storage, this means that large amounts of electricity must be produced almost simultaneously with the demand. Also, the growing dependency of today's society on electricity make well functioning of these extended, physically complex systems important. The electricity distribution networks are an important part of these systems. Traditionally, the distribution networks bring the electricity from the transmission system to the consumers. The transition towards a liberalised and more sustainable energy supply system causes changes in the supply and demand of electricity and requires more flexible and efficient operation of the electricity distribution networks. This asks for a more active approach to distribution network management. Recent and ongoing developments in power electronics and information and communication technology (ICT) support this. This chapter addresses these issues to get a good overview of the developments that affect electricity distribution networks.

In Section 2.2, the development of traditional electricity networks will first be discussed. Then, it is treated in Section 2.3 how the energy transition changes some fundamental principles of distribution networks. In Section 2.4, it is described how these changes and other recent developments affect the functionalities in future distribution networks. The chapter is concluded in Section 2.5.

### 2.2 Traditional electricity networks

In this section, first, the historical development of the electric power systems that we know in Northwest Europe is addressed. Then, the characteristics of the existing electricity networks that resulted from these developments are treated.

### 2.2.1 Historical development of the power system of today

In most of the countries in Northwest Europe, the electric power system was introduced at the start of the 20th century. After its initial introduction, it increased in scale and the system developed into the extensive continent-wide, interconnected electricity supply system that we know today. Consequently, the electric power system consists of interconnected transmission systems, which transport large amounts of power from large-scale generation over large distances, and numerous distribution networks, which deliver the electricity from the transmission substations to the consumers. The transmission systems faced many challenges as power plants became larger and larger and the operation of interconnected networks became increasingly complex. Meanwhile, the distribution networks only focused on delivering reliable power from the transmission systems to the consumers with well-predictable demands, leading to limited uncertainty on these grids. In Figure 2.1 several significant developments since the introduction of electrical energy that led to the current electricity networks are depicted.

After the invention of the electric light bulb, Thomas Edison introduced in 1882 the first (private) electric power system in New York with the installation of a power station at Pearl Street that supplied a few dozens of customers in Manhattan and made electric lighting available for households and small businesses at a price that competed with gas lighting. After this first power system, many other small power systems were installed all over the world.

In the period after the initial introduction of electric power systems, authorities had the ambition to make electricity available for all citizens. Local, isolated systems were further expanded and interconnections to couple regional supply systems were established. A nationally integrated electricity supply system made electricity available everywhere in the country and brought the advantages of scale: it improved

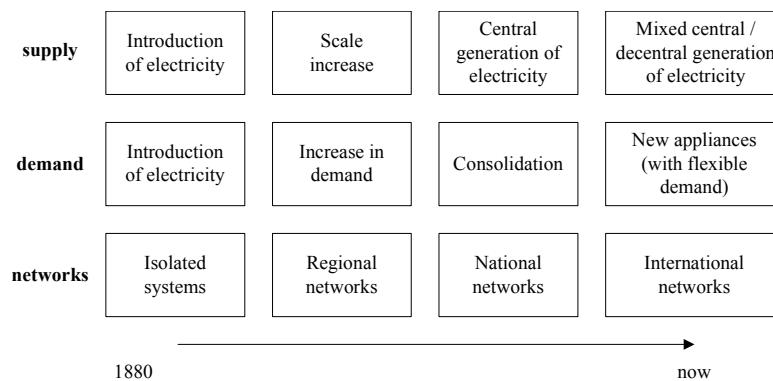


Figure 2.1: Developments in electricity supply systems.

reliability and large-scale, centralised production of electricity lowered costs. The continuous increase in scale of production and transmission was matched by the same pattern in the development of consumption of electricity. Consumption and installed capacity of electricity expanded rapidly, especially before and during the 1960s. In most West-European countries consumption doubled between 1960 and the early 1970s. Due to strong growth of electricity consumption and the centralisation of power generation, the electricity networks were further interconnected and the system was planned and coordinated on a national level. To transport electricity over longer distances, higher voltages were applied and more and more cross border interconnection lines were realised on European level, though the system was still coordinated at a national level.

In the 1970s the energy crises and a growing social opposition against centralisation and scale increase, gave rise to some new developments in the energy sector. A growing concern for the environment in the 1980s led to policies to increase diversification of energy sources to reduce the dependency on oil, energy savings and the stimulation of renewable energy sources. More decentralised, dispersed generation units were installed and a mixed system emerged, combining centralised and decentralised production of electricity. The technical changes were superimposed on the existing system which remained basically intact; large power units were expanded and adapted to environmental demands and new, small units were installed, while networks were only marginally adapted. Furthermore, liberalisation of the energy markets in the 1990s transformed the sector. The objective of market liberalisation was to grant consumers free choice and to enable more competition between companies in the European Union, which was intended to lead to lower prices and a better standard of service on energy-related issues. For DNOs, the liberalised energy market means that they have little to no influence on the location of consumers and suppliers connected to the distribution networks. These developments increase the complexity involved in predicting the transports of electricity and require changes in the operation of the grids.

### **2.2.2 Characteristics of electricity networks**

In short, the electric power system has evolved from small, isolated systems to a large and complex system over roughly the last 130 years. The historical development of the power system has characterised the existing electricity networks in several ways. One aspect is that, because electricity is mainly generated by large-scale power plants at central locations and transmitted from the high voltage (HV) transmission grid towards the end consumer connected to the medium voltage (MV) and low voltage (LV) grids, the direction in which the electricity flows was known. Another aspect is the features of the demand. Until now, the growth of the electricity demand has been quite predictable. Aggregated electricity demand profiles of consumers have not changed much over the years and the demand growth has been following the economic growth. Another characteristic of the demand is that

it fluctuates continuously due to consumer behaviour. Also, the demand is time dependent and inflexible; electricity must be available when people switch on the lights, their washing machine or their television.

This has led to the characteristic of the electric power system that supply follows demand; to ensure reliable operation of the electric power system, the consumption of electricity must always be balanced with the supply. Because the inflexibility of the demand, the fact that storage of large amounts of electricity is (often) not available, and the fact that the electricity generated at large-scale, fossil fueled power plants is predictable and can be controlled, this is done at central level by controlling the generators to follow the demand profile.

For the electricity networks, these issues meant that the networks have historically been dimensioned to meet peak demand, and the equipment has been designed for peak load conditions. The engineers made various assumptions to make the design and operations manageable rather than relying on highly detailed modelling and analysis. Protection and control were adjusted to ensure reliable service during worst-case situations. These efforts have been quite successful and have led to highly reliable systems. As a result of these design philosophies, complemented by a policy of generous investment to cover future demand, distribution networks were typically designed with abundant capacity. Much of this capacity is utilised these days, although grids in some regions are still profiting from it. These past developments led to the current electricity distribution networks, which rely on little online automation and a relatively low ratio of used capacity compared to available capacity.

## **2.3 Fundamental changes in electricity distribution networks**

The energy transition towards a sustainable electricity supply system leads to a growth of decentralised production of electricity connected to the distribution networks and to an increase in electricity usage for new appliances. These developments lead to two fundamental changes that affect the electricity distribution networks:

- due to the strong increase in DG, the electricity flows are no longer known;
- there is an increase in flexibility in the electricity demand that can be used.

This has consequences for the operation and design of electricity networks. How this affects the electricity distribution networks, is discussed in this section.

### **2.3.1 Distributed generation**

In the traditional power system the electricity flows top down from centralised generation units connected to the HV grid to the consumers connected to the MV and

LV grid. In this system the distribution networks play passive roles as they just receive the power from the transmission networks and deliver it to the loads (customers) and the power flow is mostly mono-directional. The infrastructure of the current distribution networks, their protection and monitoring devices, as well as their control systems are all designed to operate in this passive environment [36]. Integration of large-scale DG into the distribution networks changes the networks into active distribution networks with bi-directional power flows [22].

The capacities of the generators determine whether they are connected to the MV or LV grid. Current praxis shows that available technology for DG and the typical available size varies widely [8]. Also the location of the generators is arbitrary and not always close to the demand. This is especially true of wind power, which is usually generated in remote areas far from the more populated regions. Wind turbines are often concentrated in wind parks and connected to the MV grids. At the LV grids, in residential areas, electricity can be generated by photovoltaic panels which are placed at roof tops of houses and office buildings, by micro combined heat and power systems (small, domestic systems that generate heat for space and tap water heating and simultaneously deliver electricity back to the grid) that may replace conventional boilers, or even by small city wind mills.

The connection of DG to the distribution networks can lead to operating issues; for instance, DG can affect voltage control or distribution grid protection [9, 28, 119]. Besides this, especially the intermittent and fluctuating character of renewable distributed generation poses some additional difficulties to their integration into the distribution networks. For instance, solar power is dependent on the abundance of sun and the absence of clouds. This makes the amount of solar power difficult to predict. Wind can be predicted more accurately, but can fluctuate dramatically. This not controllable nature makes it fairly difficult to use these resources optimal and pose obstacles to their integration into the power system. It makes it difficult to match the available electricity to the local electricity demand, and can cause large variations in power flows in the distribution network. Without any changes to the networks and the way DG is operated, a high penetration of DG can only be achieved by major network reinforcements [32].

One way to support a higher level of penetration of DG is to invest in the capacity of the networks, but there are also other solutions which can be thought of. These assume continuously monitoring and controlling the grid and the generators. With active management, the penetration grade can be much higher [151]. Simultaneously, distributed electricity storage and controllable loads can be incorporated into the grids by applying more active network management. These technologies make it possible to shift demand for electricity in time or, more precisely, to shift the transport of electricity in time and use the intermittent distributed generation locally. Distributed electricity storage can store the energy produced by DG when the source is abundant and demand is low, and release the power during peak periods. Management of controllable loads would make it possible to shift the demand in time. In this way, the electricity grids can be used more efficiently, energy loss

due to the transportation of electricity is reduced and the integration of distributed renewable energy sources into the electric power system can be supported without requiring major network reinforcements in the first place.

### 2.3.2 Flexible electricity demand

The demand for electricity is expected to grow, especially due to an increase in demand for heat pumps and electric transport. This does not inherently mean that it is difficult for the grid to cope with this additional load. The reason for that is that an important characteristic of these loads is that the exact moment at which the demand is fulfilled is less important than for regular loads like electric lighting or microwaves. For example, a house has the capacity to hold the thermal energy within its walls for some time, and cars may be charged during night. The electricity demand for these loads is less time dependent than for most other types of loads. The flexibility in these demands brings with it the opportunity to shift demand in time and apply load management without any discomfort for the consumer. There can be various reasons to use this flexibility in residential electricity demands.

As mentioned in Section 2.2, the electricity networks are designed to meet peak demands. However, shifting a part of the electricity demand by for instance directing flexible loads to off-peak periods or by applying demand response programmes to stimulate the consumers to use domestic appliances at other moments of the day, makes it possible to shift the loads, allowing more electricity to be transported without increasing the network capacity to the level of high peak demands. As was already mentioned in the previous section, another advantage of shifting the use of electricity in time is that it can contribute to a better integration of DG.

From the broader perspective of the electricity supply system, a third advantage of shifting demand in time would be to match electricity demand with supply in order to optimise the electricity production capacity and maintain the power balance in the system. The fulfilment of this overall, system-wide requirement can be achieved by large-scale storage technologies, such as pumped hydro or compressed air energy storage, but also by distributed electricity storage or load management. An example of applying load management for this goal will be demonstrated at the island of Bornholm in Denmark where more than 50% of the electricity consumption is supplied by renewable energy sources. In this project a real-time market concept is developed to give end users of electricity and owners of small-scale DG units new options (and potential economic benefits) for offering additional balancing and ancillary services to the system operator. Of a total of 28,000 customers on Bornholm, approximately 2000 residential consumers will participate with flexible demand response to real-time price signals [6].

One should realise that, in a liberalised electricity sector, the aforementioned objectives for load management are in the interest of different parties. Maintaining the balance between demand and supply of electricity is primarily the responsibility of transmission system operators and commercial electricity suppliers. However, the

optimal use of electricity grids is the responsibility of network operators. These different objectives can be conflicting, which might result in sub-optimal shifting of electricity demands from the perspective of these different parties. Therefore, assessing the impact of various load management strategies on the grids and the market is regarded to be an important step towards smart grids.

## 2.4 Smart grids

As a consequence of the energy transition, the distribution networks need to support and integrate DG and facilitate a potential growth in electrical loads. On the other hand, controlling all or part of future flexible demand and developments in storage provide opportunities to manage the grids more flexibly and efficiently. This can increase the capacity usage of the system and result in more efficient use of our energy resources [64]. The current progress that has been achieved in power electronics and ICT can support these goals. Also, the developments in smart metering can support further integration of demand-side management (DSM) in the electricity supply system and hence increase customer awareness and improve the electricity market through customer participation. These developments lead from electricity distribution networks with little embedded automation, to networks that will intelligently control loads and integrate DG and energy storage devices in the operation of the networks. Active network management will ensure cost-effective development of an efficient and reliable electricity system that allows the integration of DG. These developments lead to a power system as presented in Figure 2.2, with a much more important role for the distribution networks than before.

The process of increasing the intelligence and flexibility of the distribution networks is often referred to as *smartening the grid*. There exist many definitions for a smart grid and an exact, generally accepted definition is not yet available. An overview of definitions concludes that the core of a smart grid is adding ICT to today's electricity distribution networks on a large scale [127]. In Figure 2.3 an artist impression of a smart distribution grid is given. Possible goals of smart grids are [125]:

- reducing costs; e.g., by efficient integration of renewable, distributed energy resources and optimal utilisation of the networks;
- involve residential customers by making them active participators at liberalised electricity markets, in such way that they can profit from price fluctuations at the electricity market and by providing services to network operators;
- increase the reliability and performance of the electricity supply system.

In this section, the organisation of and roles as well as possible functionalities in the future power system are first treated. Then, some attention is paid to the

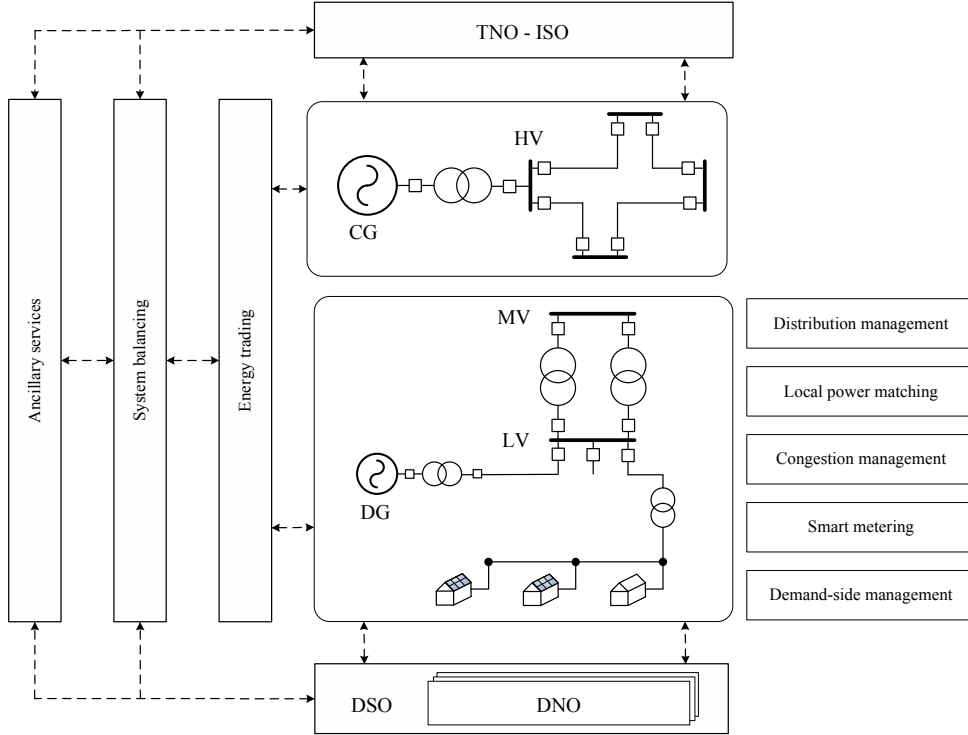


Figure 2.2: Organisation of the future power system (adapted from [98]).

various ways the future power system can develop by making a distinction between three smart grids concepts.

#### 2.4.1 Roles and functionalities in the future power system

In the future power system, see Figure 2.2, conventional and renewable energy generators, energy storage systems, DSM, and intelligent control are all embedded into the system. Centralised generators (CGs) as well as distributed generators (DGs) are involved in energy trading. The transmission network operator (TNO) is the owner and operator of the transmission network while the independent system operator (ISO) is responsible for system security and balancing. In many European countries the roles of the TNO and the ISO are unified in one transmission system operator (TSO). The distribution network is owned and operated by a distribution network operator (DNO). The responsibilities of a distribution system operator (DSO) reach further than those of a DNO. Based on transparent, non-discriminatory and market-

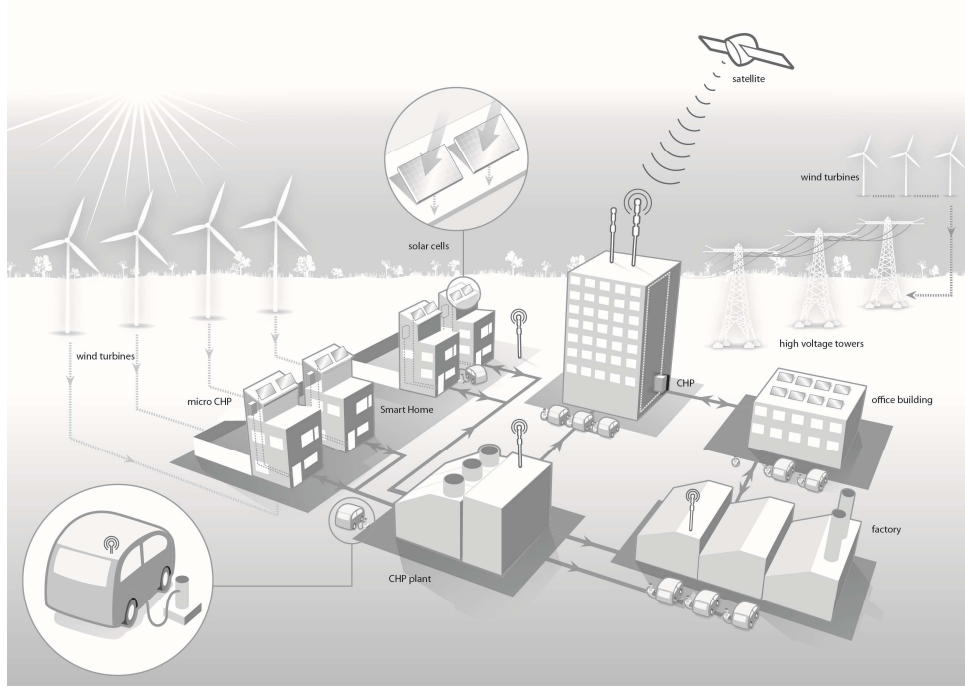


Figure 2.3: Artist impression of a smart distribution grid.

based procedures, the DSO may procure the energy to cover energy losses and might be responsible for handling emergency situations in its local area. Moreover, the DSO is responsible for regional grid access and grid stability, integration of renewables at the distribution level of the grid and regional matching of supply and demand. In addition, the DSO may be required to give priority to generating installations using renewable energy sources or waste or producing combined heat and power [114]. Though the future roles and responsibilities for all kinds of actors in the electricity supply chain are still under discussion, it is clear that in active distribution networks the DSOs should be able to take an active role and their responsibilities become more complex than those of a DNO nowadays [49].

The TSO and the DSO share certain responsibilities on balancing power and organising so-called ancillary services. These ancillary services are services provided by the market to the electricity supply systems which are necessary for the operation of an electric power system [41]. These services may include the participation in balancing, frequency regulation, reactive power regulation, voltage control, congestion management, etc. In the distribution system, new control functions such as local power matching and congestion management might arise besides available functions

of distribution management, smart metering, and DSM [98]. These functionalities will now be treated separately.

### **Distribution management**

To manage the distribution system and fulfill the functions of real-time monitoring and control, the DSO uses supervisory control and data acquisition (SCADA) systems, energy management systems (EMS) and distribution management systems (DMS). These systems developed in the course of time and more and more automation is applied in the distribution systems.

Especially the integration of DG can be done more efficiently by continuously monitoring and controlling the grid and the generators. With active management, the penetration grade of DGs can be increased without the need for additional investments in the capacity of the networks [151].

Also, the increasing use of automated monitoring and control of the electricity distribution system can counter the anticipated decrease in reliability caused by an increase in component failures due to the ageing infrastructure. The reliability can be improved by increasing the speed of restoration after an interruption. This can be realised by the large-scale deployment of remote control at certain points in the MV grids to detect and localise outages due to component failures [15]. As a result, this will eliminate the need to rely on phone calls from people whose light and televisions turn off to detect outages and make it possible to restore power much more quickly.

### **System balancing and (local) power matching**

In traditional power systems, the TSOs are responsible for maintaining the power balance between generation and load. In case of an unbalance, the TSO uses reserves to restore the balance within its area. These reserve capacities can be acquired beforehand; e.g., by capacity contracts or a day-ahead market, or in a real-time market for balancing power. Also, (large-scale) storage technologies, such as pumped hydro accumulation storage or compressed air energy storage, can support the fulfilment of this overall, system-wide requirement. Because of the characteristics and especially the intermittency of many of the more renewable resources, keeping the balance in a sustainable power system becomes more challenging. As a consequence, sufficient flexibility of the system is required and it is important to develop large-scale solutions as well as small-scale decentralised solutions [91].

At a decentralised level with a large amount of DGs connected to the distribution networks, these DGs, but also control of flexible, residential loads or distributed electricity storage (stationary or in electric vehicles) can contribute to matching supply and demand. This can be supported by decentralised actions triggered on price signals and markets [98]. Also, smart meters offer much more advanced metering than traditional meters, which are being read only few times a year, and enable appropriate control mechanisms for flexible, residential loads. This might enable residential

customers to take part in day-ahead spot markets to support matching of demand and supply or even into real-time balance markets to support real-time balancing of the system and in this way fundamentally changing balancing approaches [127].

Using the generators and loads at the various network levels to keep balance between demand and supply in a large, system-wide area is called system balancing. In the longer term, the availability of distributed electricity storage together with the expected increase of DG, and flexible, residential loads, may enable balancing in a smaller area. Real-time local balancing in the area designated to the DSO gives the possibility of distribution networks in this area to self support their demand by distributed energy sources. Real-time local balancing as well as local matching of supply and demand may decrease the need to transport electricity over long distances, can relief network loadings, and can reduce related energy losses.

### **Congestion management**

Physical and security limits on the maximum power flows in the transmission networks represent crucial system constraints, which must be satisfied to protect the integrity of the system. A TSO has the responsibility of keeping the line flows in a transmission system below certain, predefined security limits, i.e. it is responsible for congestion management. Efficient congestion control has to account for those limits by adequately transforming them into market signals, i.e. into electricity prices [68].

With an increase in DG in the distribution networks, congestions may also become an issue in distribution networks. To prevent network congestions and solve network constraints in the distribution networks, power routing is needed [98]. Power routing deals with the congestions related to the actual load and generation schedules of the market parties; to physically control the power flow in the distribution networks power electronic devices might be required.

### **Smart metering**

Nowadays, smart meters and sensor systems start appearing in the distribution networks. This is expected to provide large amounts of information for management and control purposes in future networks. Smart meters measure consumption with a high resolution (normally somewhere between 5 minutes and 1 hour) and in this way enable advanced tariff schemes. Theoretically, the number of tariff zones can be equal to the measuring frequency, which is a major step compared with the traditional flat or only slightly differentiated (e.g. day/night) tariff. With smart meters, however, tariffs are still static.

Dynamic tariffs, taking into account such factors as the local availability of renewable energy, day-ahead or real-time electricity market prices and actual network loading are generally not supported by smart meters. Reason for this is that smart meters in most cases do not enable bi-directional data transfer, but only mono-directional data transfer with the smart meter transmitting. Some smart meter

devices do not only transmit measurement data to the network operator and/or energy company, but are also capable of communicating data locally using wireless communication. This enables informing the customer about his energy consumption in real time and/or with a high resolution. It also supports the customer in actively shifting his demand to optimise his electricity consumption (and if available his generation as well) according to the tariff scheme. The customer can do this himself and buy smart services or use electronic devices to this end. The latter two cases, are examples of smart metering [127]. In this way, DSM can be implemented and supported by two-way smart meters and smart sensors on equipment communicating through ICT, managing the demand of customers according to the agreements reached with the customers [69].

Further, some types of smart meters are capable of detecting outages and signalling the network operator if one occurs. When the network operator combines the signals received from such devices with his network topology, it becomes possible to detect which customers no longer have electricity and which are not affected by the component failure. It can then be determined which network component has caused the outage [127].

### **Demand-side management**

DSM refers to a series of policies and measures which cover from long-term energy efficiency policies and incentive rates, to real-time control of distributed energy sources [83]. Historically, the prospect of increasing the efficiency of system operation and the existing investment in the generation and transport of electricity has been the key driver for introducing DSM programmes [130]. Though the terminology has changed – DSM is sometimes referred to as demand-side integration [13] and load management is increasingly being replaced by the term demand response (DR) – load shaping concepts originally devised in vertically-integrated utility environments are still applicable in restructured environments [23]. Figure 2.4 presents various load shape objectives grouped in three DSM categories.

If we look at the development of the grids, the relatively low utilisation of generation and network capacity means that there is significant scope for DSM to contribute to increasing the efficiency of system investments. Also, ageing assets, the growth in renewable and other low-carbon generation technologies and advances in information and communication technology (ICT) are identified as major drivers that could lead to wider applications of DSM in the medium term [130]. Some reasons for a slow uptake of DSM are lack of metering, information and communication infrastructure, an increase in the complexity of system operation and inappropriate market incentives [130].

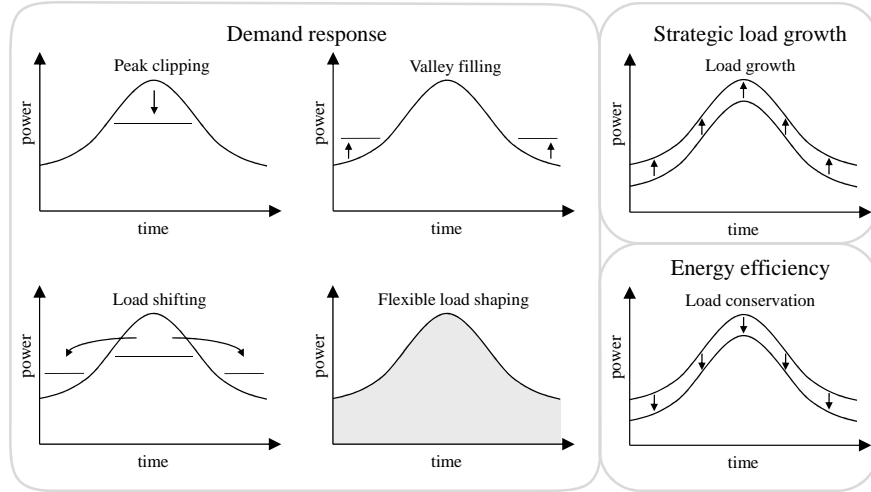


Figure 2.4: Load shape objectives grouped in three DSM categories [23].

### 2.4.2 Smart grid concepts

The various functionalities that have been treated in the previous section can be realised by technologies as well as by other market structures or tariffs. In which way smart grids will develop is not yet clear and depends on the focus on specific goals. Three smart grid concepts can be distinguished to indicate these different directions [125]:

- The *grid-oriented* smart grid concept; this concept aims at reducing reinforcements, supporting and accelerating outage restoration and determining condition, remaining lifetime and failure risk of grid components as well as semi-automated restoration of the network after outages. This concept focuses on the responsibilities of the network operator and there is no involvement of electricity suppliers and consumers.
- The *market-oriented* smart grid concept; this concept aims at enabling residential customers to participate in the electricity market by introducing more advanced pricing schemes. In this concept, only commercial market parties and customers are involved; the function and role of the network operator does not change.
- The *system-oriented* smart grid concept; this concept aims at optimising the system as a whole, both from the perspective of keeping the energy balance as well as from the perspective of grid operation. The combination of the actual, system balance on the one hand and the locally produced electricity

and network capacity on the other, results in a signal that incorporates both system and local quantities. This enables actions that take into account both the system and the local situation. These actions can be either taken by electricity companies and/or network operators directly, or the situation can be translated into tariffs, enabling the customer to act accordingly when desired.

In this thesis the impact of various smart grid concepts on distribution network utilisation will be investigated. It is important to be aware of the differences between these concepts and understand which goals are pursued by the smart grid concept that is applied. Analysing and comparing various smart grids concepts will gain insight in the potential benefits of these concepts and support the developments towards a fully deployed smart grid that supports the interest of different parties and combines various goals best.

## 2.5 Summary and conclusions

Over more than a century, electric power systems have evolved from small, isolated systems to a large and complex system. The planning and design standards that have been developed over this period, have led to well-functioning, reliable systems. The electricity distribution networks have little embedded automation and a relatively low ratio of used capacity to available capacity. This presents a great potential for transferring extra electrical energy with the existing capacity of the networks. Furthermore, new developments towards a more sustainable energy supply system require integration of DG, facilitation of more flexible demand and a more efficient use of the grids. In addition, due to the liberalisation of the energy sector and the connection of generators at the distribution level of the power system, there is no longer a strict separation between suppliers and consumers. As a consequence, it becomes more difficult to balance supply and demand and this requires changes in the operation of the grids.

These developments lead to two fundamental changes that affect the electricity distribution networks: due to DG electricity flows are no longer known, and there is an increase in flexibility in the electricity demand. Controlling all or part of future flexible demand and developments in storage provide opportunities to manage the grids more flexibly and efficiently. The current progress that has been achieved in power electronics and in ICT can support this. Also, the developments in smart metering can support further integration of DSM in the electricity supply system and hence increase customer awareness and improve the electricity market through customer participation. The grids will adapt from a passive to an active system. The process of increasing the intelligence and flexibility of the distribution networks is often referred to as *smartening the grid*. It is generally accepted that making the grids smarter is necessary in the light of future sustainable energy systems.

The organisation and roles in the electric power system change and besides available functions of distribution management, smart metering and DSM, additional

control functions such as local power matching and congestion management might arise in the distribution system. Which and how these functionalities will be realised in the future power system depends on specific goals of smart grids. Three smart grid concepts are introduced in this chapter to indicate different directions in which smart grids can develop: the *grid-oriented*, the *market-oriented*, and the *system-oriented* smart grid concept. The impacts of various smart grid concepts will be further analysed and compared to gain insight in the potential benefits of smart grids.



### 3.1 Introduction

In Chapter 2 we have seen that the energy transition leads to a growth of decentralised production of electricity connected to the distribution networks and to an increase in electricity demand because of the use of new technologies in residential areas. Although the need for a transition towards a more sustainable energy system is generally accepted, recent publications reveal that the transition at the moment not develops fast enough to achieve energy-related policy goals, e.g., to reduce greenhouse gas emissions and increase the share of renewable energy production. One of the examples is the World Energy Outlook that emphasises that without a bold change of policy direction, the world will lock itself into an insecure, inefficient and high-carbon energy system [60]. This is not different in the Netherlands, where the transition towards a low-emission energy supply is still in an early phase and can develop in many directions [121, 139].

Scenarios are used to investigate the impact of the different directions in which the transition can develop. Various scenarios are described in this chapter. First, it is discussed how the energy transition changes the electricity demand in residential areas in general. Then, the technologies that are expected in residential areas are described. In Section 3.4 recent scenario studies are reviewed to identify the main drivers that lead to various energy scenarios. In this thesis the case of the Netherlands is used as a case study. Therefore, subsequently, three scenarios for the Netherlands based on these drivers are described. It is indicated how each scenario affects the electricity system, in terms of the expected demand growth for electricity, the voltage level to which generators will be connected and developments of new technologies that are applied in residential areas. The chapter is concluded in Section 3.6.

### 3.2 Electricity demand in residential areas

The main function of the electricity distribution networks is to transport electricity from the transmission grid or the generators connected to the distribution networks

to the consumers connected to these networks. In terms of the amount of connections, the residential electricity users dominate in these networks; more than 90% of the connections are residential customers [38]. The electricity demand in residential areas contributes for around one third to the total electricity consumption; in 2011 the residential electricity demand accounted for 28.8% of the total electricity consumption in the EU member states [3].

Due to the energy transition new technologies will certainly influence the future demand in residential areas and households may also start to produce electrical energy themselves. More and more electricity in residential areas may be provided by photovoltaic (PV) panels, but also micro combined heat and power systems ( $\mu$ -CHPs) that produce electricity besides heat might replace conventional boilers and contribute to the residential electricity supply. When producing electrical energy themselves, residential customers may need less electricity from the grid. However, if they use for instance PV panels and are temporarily not provided with solar energy, they may still need to be fully supplied by the grid. On the demand side, new technologies like heat pumps, electric vehicles (EVs) and smarter domestic appliances are expected. These new, energy intensive loads may increase the residential electricity demand, but are also flexible demands that bring the opportunity to shift the electricity load in time.

Another consequence of these developments in the future electricity supply and demand of residential customers is that more differences may exist between individual customers connected to the grid; e.g., one household may choose for a  $\mu$ -CHP and the other for a heat pump in combination with solar panels. This means that the load profiles of individual households will differ more and will be less predictable than nowadays. Looking at a larger scale, the differences between residential areas may diverge. A newly developed residential area in a city, for example, may have a very different load profile than an existing group of houses in the countryside.

Besides the large contribution of the residential electricity demand to the total electricity demand, a motive to zoom in on the changes in residential areas, is the uncertainties related to future electricity use of residential customers. The outlooks that have been developed are still very diverse on issues like the emerging new technologies that will be successful at the residential level of the grids, and the timing and the penetration degrees of these technologies. Besides the technological development of the technologies, this depends on governmental stimulation measures as well as on customer acceptance of new technologies. Another aspect that will influence the electricity distribution in future residential areas is customer behaviour. Especially in future, smart grids customer involvement is expected to play an essential role. However, to what extent involvement of customers will be introduced in the consumption and distribution of electricity is surrounded with much uncertainty and their behaviour is very unpredictable. Also, residential customers are little involved and unwilling to change when the incentives to change are too low [147]. The large number of residential customers connected to the distribution networks and the unpredictable behaviour of these customers create much uncertainty in the expected

residential electricity demand.

### 3.3 Expected technologies in residential areas

At the household level of the electricity system several changes in the demand and supply of electrical energy are expected. Besides a possible change in the demand for regular domestic appliances, appliances with a flexible demand for electricity ('smart appliances') may be used and new technologies like heat pumps, EVs and PV panels will be more applied. The technologies that will substantially change the electricity load in residential areas, are [61, 94, 105]:

- appliances with a flexible demand for electricity ('smart appliances');
- application of new technologies for heating:  $\mu$ -CHPs and heat pumps;
- generation of electricity by PV panels;
- the adoption of EVs.

The development of each of these technologies will be briefly described in this section.

#### 3.3.1 Smart appliances

Residential customers use electricity for all kinds of electric appliances. The breakdown of the current European residential electricity consumption is depicted in Figure 3.1. The demand for electricity of some of these electric appliances, like lighting and televisions, depends on the moment that the residents want to use them. However, many other appliances are less time critical and can be used at other times of the day. With the use of an energy management system (EMS) the electricity consumption of these appliances can be shifted and used for demand response actions to reduce peak demands or to match the demand with local, available (sustainable) electricity.

An extensive European research investigated the potential of load shifting by suitable domestic appliances [103]. In this project several domestic appliances have been selected that can be used for demand response options. The average load curve of a generic European household which is using all of these domestic appliances is presented in Figure 3.2. In this study, a distinction has been made between five regions in Europe. Some results for these regions are presented in Table 3.1. The research concludes that for the region that represents Germany and Austria, the largest contributors to the evening peak are the tumble dryer, the dish washer, and the washing machine. It also concludes that by controlling the devices 10–30% of the power demand of these appliances may be shifted to other times of the day [129].

This potential for load shifting can be unlocked by using EMSs. For instance, with these systems consumers can be motivated to use electric appliances such as

a washing machine to match locally available, sustainable electricity produced by PV panels. To successfully apply energy management and maximise the likelihood that users of an EMS will shift their electricity consumption and will persist in this behaviour, it is important to be aware of the joint effect of the user's motivation, contextual factors and the design of the EMS [76].

### 3.3.2 Heating technologies

A large share of the residential energy demand is used for cooling and heating of houses. Currently, both space heating and cooling as well as hot water are estimated to account for roughly half of the global energy consumption in buildings [59]. In the residential sector the aim to save energy leads to better insulated houses to lower the heat demand and new technologies to efficiently use energy for cooling and heating without compromising on or even while improving the comfort of living. In many countries conventional heating systems are replaced with these new domestic heating technologies.

In areas where gas is applied for heating, more efficient technologies are introduced, such as  $\mu$ -CHPs, which generate electricity besides heat and improve overall energy efficiency. Another technology to efficiently use energy is the heat pump. A heat pump converts energy from the environment (which can be the outside air, soil or ground water) to energy that can be used for space or tap water heating or cooling.  $\mu$ -CHPs and heat pumps are often cited as promising technologies to reduce the overall use of energy and the large-scale deployment of these technologies is seen as a means of energy saving and reducing carbon emissions [24, 46, 59].

The electrification of heating through heat pumps and the large-scale application of  $\mu$ -CHPs which generate electricity in addition to heat will change the electricity demand at the household level substantially. They alter the aggregated residential electrical load size and profile, and the possibility of controlling them offers the opportunity to manage the aggregated residential demands and operate the electricity distribution network more efficiently [116].

The development of the share of  $\mu$ -CHPs and heat pumps can vary substantially per country, depending on issues like the average outside temperature as well as the availability of energy sources like gas. The likely primary fuel for  $\mu$ -CHPs is natural gas, therefore, this technology is envisaged as a promising next generation heating system for areas with extensive natural gas infrastructures [56]. In these areas,  $\mu$ -CHP is regarded as an element in the transition towards a renewable energy system [46, 117]. Unlike the market for  $\mu$ -CHPs which is still in the early stages of development, the market for heat pumps is more mature and they are already more widely applied in the residential sector. It is a proven, commercially available technology that has been available for decades and has become more efficient over the years, though room for improvement still remains. For instance, the coefficient

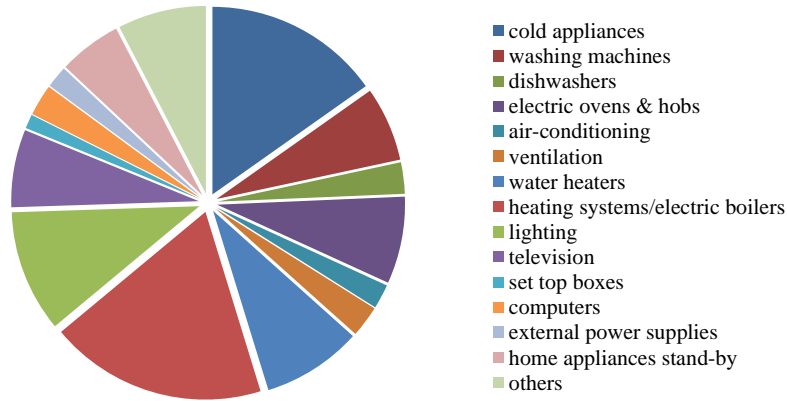


Figure 3.1: Breakdown of the residential electricity consumption of 27 EU member states [11].

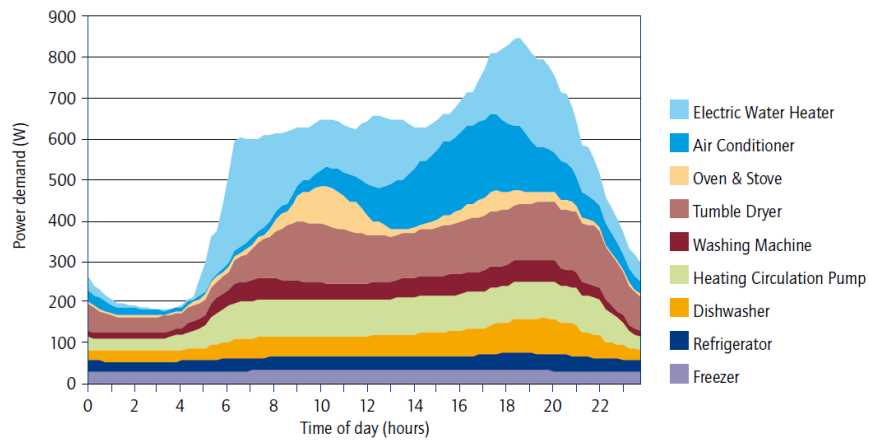


Figure 3.2: Average load curve with a market penetration of 100% of nine domestic appliances suitable for load shifting in a generic European household [124, 129].

of performance (COP)<sup>1</sup> of heat pump water heating systems in Japan has increased from around 3.5 in 2001 to 5.1 in 2008 [59].

<sup>1</sup>The coefficient of performance is the ratio between the heat delivered and the electrical energy used by the heat pump and describes the efficiency of the heat pump.

Table 3.1: Demand response potential of domestic appliances expected for 2025 in five generic EU regions (TD = tumble dryer; WM = washing machine; DW = dish washer; RF = refrigerator) [124, 129].

Region Represents	A Southern Europe	B Scandinavia	C New Member States	D Germany/ Austria	E UK
Expected ‘smart’ load per 1000 households	100 kW	150 kW	100 kW	150 kW	150 kW
Top three appliances contributing to the peak power	1. WM 2. RF 3. DW	1. TD 2. DW 3. WM	1. TD 2. WM 3. RF	1. TD 2. DW 3. WM	1. TD 2. WM 3. RF
Penetration TD	20%	55%	40%	50%	60%
Penetration WM	95%	90%	95%	95%	95%
Penetration DW	50%	65%	50%	70%	50%
Penetration RF	100%	100%	100%	100%	100%

### 3.3.3 Photovoltaic panels

Solar PV power is a widely available and reliable technology with a significant potential for long-term growth in nearly all regions in the world. The global cumulative installed PV power capacity has grown from 0.1 GWp<sup>2</sup> in 1992 to 14 GWp in 2008; in Europe the installed capacity has grown from 2.2 GWp in 2005 to 51 GWp in 2011 (see Figure 3.3). The International Energy Agency (IEA) estimates that by 2050, PV could provide for 11% of global electricity supply and avoid 2.3 gigatonnes of CO<sub>2</sub>-emissions per year [57]. A large part of the electricity produced by PV panels is generated by panels on roofs of houses. Figure 3.4 presents the share of the electricity produced by PV systems in the total amount of electricity produced and the share of residential PV systems in the total amount of all PV systems. Though the share of residential PV systems is expected to decrease over the years, this share is substantial.

The deployment of PV panels largely depends on the adoption of incentive schemes for PV systems; e.g., policy measures decrease overall costs of PV panels for the user and/or increase the relative costs of other technologies and advance the moment of grid parity (i.e. the moment that electricity generated by PV panels can compete with electricity supply prices). A European research project concludes that grid parity in many European countries is already in sight or even reached [16]. The exact moment of grid parity depends on several factors. Besides the solar irradiation level, this mainly depends on the development of the prices of the PV system and financing costs, the development of electricity supply prices, the possi-

<sup>2</sup>Wp = Watt peak; this is the maximum power output of solar panels under standardised test conditions.

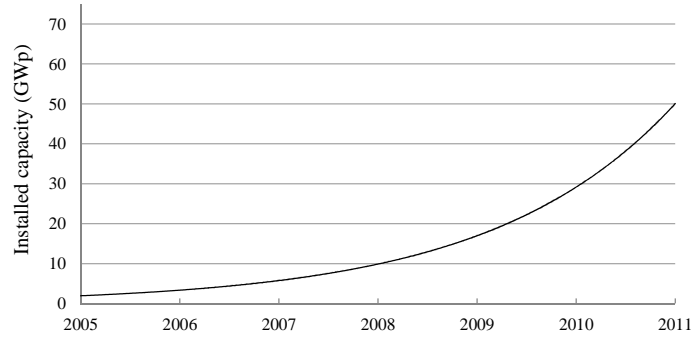


Figure 3.3: Cumulative installed PV capacity in Europe [2].

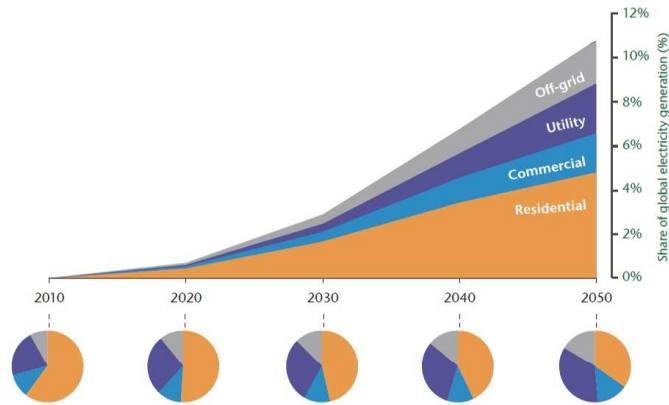


Figure 3.4: Possible development path for electricity generation of PV systems worldwide by end-use sector [57].

bilities to use the produced solar electricity directly by the producer, and the value of the electricity which is delivered back to the grid. Accelerated deployment will in turn bring about further cost reductions from economies of scale, significantly improving the relative competitiveness of PV panels and possibly spurring additional market growth. All these factors lead to large differences in the moment at which grid parity is reached for the customer.

### 3.3.4 Electric vehicles

Road transport, based on conventional combustion engines, is responsible for a significant share of the total of CO<sub>2</sub>-emissions and for polluting cities with fine dust.

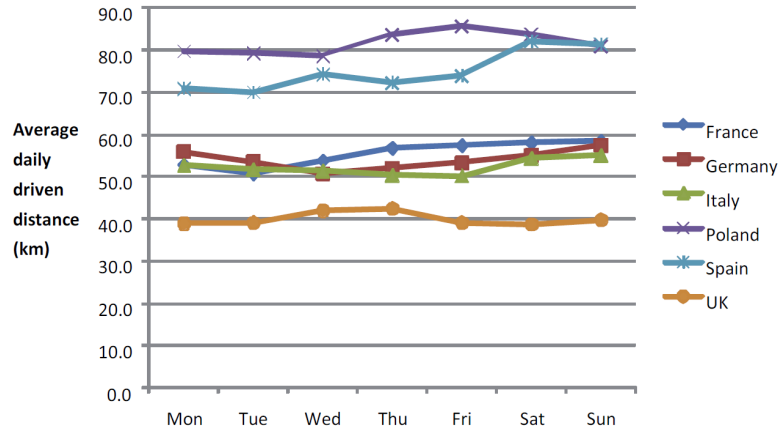


Figure 3.5: Average daily travel distance (km) by day of the week in 6 EU member states [115].

On the contrary, EVs are (at least locally) environmentally cleaner than conventional cars and also decrease CO<sub>2</sub>-emissions through the higher efficiency of power plants compared to combustion engines. Including all energy losses from resource to road, the efficiency of an electric car loaded with conventionally generated electricity is already significantly better than the efficiency of a conventional car. The use of renewable energy sources adds to this and EVs can therefore contribute substantially to the decarbonisation of road transport [92]. The intermittent output characteristics of, for example, wind power and solar energy, limit the optimal use of these resources and complicate their integration into the power system. Batteries of EVs can use the electricity produced when available, thereby supporting a high penetration of intermittent renewable energy generators. Furthermore, EVs need to be regularly recharged, offering storage capacity that makes it possible to shift the electricity demand in time, creating the opportunity to transfer more energy through the distribution network and better using the potential of the existing networks [137].

The largest barrier for the deployment of EVs is the battery technology. Batteries have a low energy density compared to diesel or petrol and the vehicles need a large and expensive battery pack to achieve a reasonable range [109]. But, in most cases the range of EVs will be sufficient: in Europe, 50% of trips are less than 10 km and 80% of trips are less than 25 km [58]. In Figure 3.5 the daily driving distance in 6 EU member states are depicted. These distances can comfortably be covered by the battery capacities of the EVs that are currently available on the market [115].

The electric and plug-in hybrid electric vehicle (PHEV) roadmap of the IEA states that the next decade is a key ‘make or break’ period for EVs and PHEVs [58]. This roadmap is based on an IEA scenario that targets a 50% reduction in CO<sub>2</sub>

Table 3.2: The number of EVs on 1 January 2012 [80].

Country	Number of EVs	Country	Number of EVs
Belgium	346	Portugal	250
Denmark	749	Spain	753
Germany	4.541	UK	1.219
France	>4000	China	2.631
The Netherlands	1.182	USA	18.076
Norway	5.326	South Korea	50
Austria	1.047		

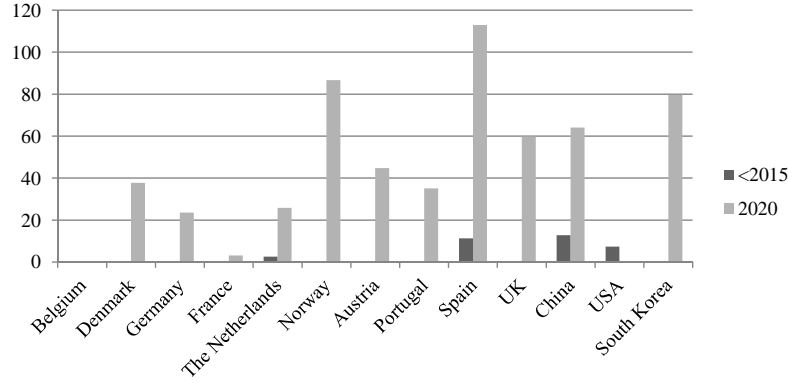


Figure 3.6: Ambition of various countries presented in the number of EVs per thousand cars [80].

worldwide by 2050. For transport, a 30% reduction is achieved via efficiency improvements, along with the introduction of new types of vehicles and fuels. In this scenario, sales of (PH)EVs begin to grow rapidly after 2015 and reach in total 7 million per year by 2020, and 100 million by 2050, over half of all cars sold around the world in that year. The current numbers and ambitions of several countries related to the amount of electric cars are presented in Table 3.2 and Figure 3.6.

### 3.4 Scenario drivers

For the research conducted in this thesis, the required capacity of future distribution networks is investigated. Electricity needs to be transferred from the location where the electricity is produced to the location of demand. Therefore, not only the amount of electricity demand, but also the location of demand and supply deter-

mine the required capacity of future electricity distribution networks. There exist many scenarios that describe all kinds of developments and that are related to future energy production and demands. In this section, three scenario studies are briefly described to investigate what are the main drivers that lead to variations in future electricity supply and demand.

### 3.4.1 Exploration of energy scenarios

First, a European study is treated. This study is published by the European Commission and puts the development of the total energy production in a European context. Then, a closer look is taken at the situation in the Netherlands by treating two extensive scenario studies specific for the Netherlands.

#### EU energy trends to 2030

The European Commission has published several energy scenarios over the years. These are based on energy policies implemented on European level and in Member States, and updated every two years with the latest economic developments, energy prices, and new policies and measures [48]. A distinction is made between two scenarios: the baseline and the reference scenario. The baseline scenario includes macro-economic, price, technology and policy assumptions and based on this, the development of the European energy system is determined. Besides current trends and policies, the reference scenario also assumes that the two binding targets for 2020 on the 20% share of renewable energy production in the gross final energy consumption, and on 20% reduction of green house gasses will be achieved. More specific, this means that national targets under the Renewables directive 2009/28/EC [113] and the GHG Effort sharing decision 2009/406/EC [112] are achieved.

Compared to previous scenarios, the latest scenarios show that a change in economic development impacts the total energy consumption considerably. Also, the implementation of energy efficiency policies causes a decrease in energy consumption. The reference scenario shows higher investment in RES technologies and lower fossil fuel consumption than the baseline scenario. An increase in renewable energy production also increases the share of DG connected to the electricity distribution networks.

#### A scenario study for the Netherlands in 2040

A scenario study that is more specific for the Netherlands, is performed by a collaboration of three Dutch research institutes [118, 33]. In this very extensive scenario study the long-term effects of current policy on various themes are assessed for 2040; one of these themes is energy. The main uncertainties that are recognised and explored in these scenarios are uncertainties regarding the economic and demographic developments and uncertainties regarding international politics. These uncertainties

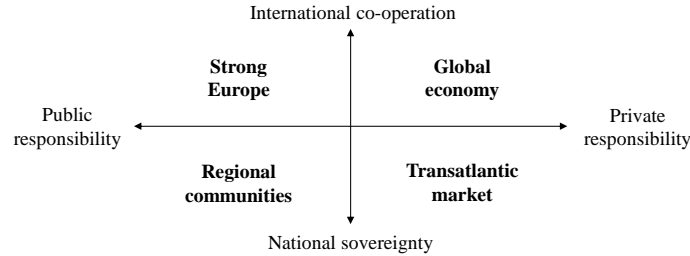


Figure 3.7: Four storylines based on two axes [118].

are analysed by investigating four storylines that were generated by the scenario-axis method [74], as shown in Figure 3.7. On these axes different directions in international politics (international co-operation or national sovereignty) and in international trade (with a focus on public or private responsibility) are defined. In all scenarios the effects of current policies till 2020 are investigated. After 2020 there is more variation in the scenarios following different story lines, because the political landscape can change over the longer term.

From this study it can be concluded that mainly the economic development and the climate policy in the various scenarios have large influence on the expected electricity demand. For instance, policies regarding climate goals can be effective through strong international co-operation with a focus on international climate goals (which is reflected in the *Strong Europe* scenario) or in a scenario where the overall electricity demand growth is limited through low economic growth (which is the case in the *Regional communities* scenario). In these two scenarios greenhouse gas emissions are reduced significantly and the share of distributed electricity generation is relatively high.

### Reference projection energy and emissions

Also relevant for the Netherlands is a study executed by the Netherlands Environmental Assessment Agency and the Energy Research Centre of the Netherlands [141]. It examines the future development of Dutch energy use, based on assumptions regarding economic, structural, technological and policy developments. Especially the effects of the current policy programme for energy and climate are assessed.

It concludes that if the climate policy measures to reduce greenhouse gas emissions and to increase the share of renewable energy production are continued, this will lead to a limited growth of electricity demand and to more decentralised (renewable) electricity generation in 2020 and 2030. Despite these effects, the goal set by the government regarding the total share of renewable energy sources is not reached.

### 3.4.2 Main drivers

After examining these scenario studies the main drivers behind the scenarios that lead to variations in the future electricity supply and demand, can be identified. These are:

- a more nationally or internationally focused policy;
- a more economically or environmentally oriented society;
- economic growth.

Variation in these drivers will lead to very different, yet realistic scenarios with different trends in types, location and size of generation and demand of electricity.

## 3.5 Three scenarios for the Netherlands

In this section, three scenarios for the Netherlands are defined. The time horizon of these scenarios is 2040. Three different combinations between the drivers that were identified in Section 3.4.2 are chosen which will lead to large differences in the impacts on electricity distribution networks. In this section these three scenarios are presented. It is indicated how each scenario affects the electricity system, in terms of the voltage level to which generators will be connected, the expected demand growth for electricity, and developments of new technologies in residential areas.

For each scenario various numbers on the technologies that are described in Section 3.3, are presented for ten typical residential areas as presented in Table 3.3. First, a distinction has been made between five types of residential areas based on population density, because, for example, the residential electricity demand and the car usage for residents in a small apartment in a densely populated area in a city can vary considerably compared to that of households in a low densely populated area at the countryside. Also, a distinction has been made between already existing and newly developed residential areas.

For each scenario the general development of the expected technologies in the residential areas are indicated and for each residential area numbers related to these technologies are presented<sup>3</sup>. Also, the heat demand is presented for each residential area, because the electricity generated by  $\mu$ -CHPs and the electricity demand of heat pumps are strongly related to the heat demand. The numbers presented in this section are derived from information that can be found in Appendix A.

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<sup>3</sup>A distinction has been made between air source heat pumps and ground source heat pumps; in the scenarios it is assumed that mainly air source heat pumps are applied in existing houses and ground source heat pumps in newly built houses (see Appendix A).

Table 3.3: Ten typical residential areas.

Area	Population density	New/existing residential area
1	>2500 households/km <sup>2</sup>	existing area
2	1500-2500 households/km <sup>2</sup>	existing area
3	1000-1500 households/km <sup>2</sup>	existing area
4	500-1000 households/km <sup>2</sup>	existing area
5	<500 households/km <sup>2</sup>	existing area
6	>2500 households/km <sup>2</sup>	newly developed area
7	1500-2500 households/km <sup>2</sup>	newly developed area
8	1000-1500 households/km <sup>2</sup>	newly developed area
9	500-1000 households/km <sup>2</sup>	newly developed area
10	<500 households/km <sup>2</sup>	newly developed area

### 3.5.1 Scenario A

*Low economic growth and an effective (national) climate policy* — In this scenario the number of households does not increase and the electricity demand growth is low. The investments in new technologies are low. A large growth of renewable energy production is not necessary to reach climate goals as a consequence of the low energy demand growth.

*Effect on the supply of electricity* — There is mainly centralised generation (connected to the HV level of the electricity networks). The share of medium-sized DG (such as CHP generators at greenhouses and onshore wind mills) stays on the same level as nowadays. The amount of PV panels grows slowly and the development of  $\mu$ -CHPs is not stimulated which leads to a low amount of  $\mu$ -CHPs.

*Effect on the demand of electricity* — The demand growth for the regular residential electricity use is 0%, the market share of EVs does not grow fast and heat pumps are mainly installed in newly developed areas. The electricity demand for industry grows with 0.5% per year. The total electricity demand in the Netherlands in 2040 is 141 TWh<sup>4</sup>.

The share of renewable electricity production and the share of DG are presented in Figure 3.8. The general development of the expected technologies in residential areas are presented in Table 3.4 and some numbers related to these technologies for each of the ten typical residential areas are presented in Table 3.5.

<sup>4</sup>For comparison: the total electricity demand in the Netherlands was 119 TWh in 2012.

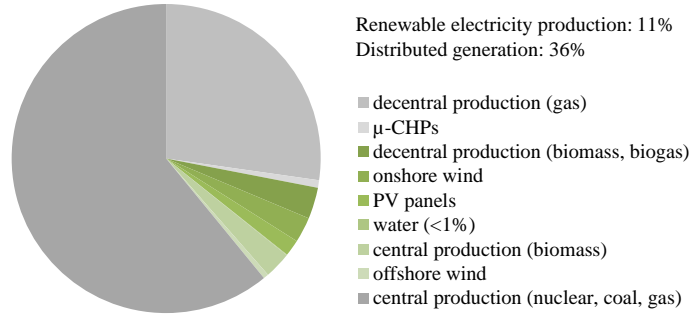


Figure 3.8: Electrical energy production in 2040 (Scenario A).

Table 3.4: Development of expected technologies in residential areas (Scenario A).

Growth regular electricity use	0%
$\mu$ -CHPs	low
Air source heat pumps (in existing areas)	low
Ground source heat pumps (in newly developed areas)	low
PV panels	low
EVs	low

Table 3.5: Numbers related to the technologies applied in ten typical residential areas (Scenario A).

Area	Annual demand for regular electricity use per household (kWh)	Annual heat demand per household (kWh)	Average PV panel area per house (m <sup>2</sup> )	Average daily driving distance with an EV per house (km)	Penetration degree $\mu$ -CHPs (%)	Penetration degree heat pumps (%)
1	2730	8840	0.9	8	5	4.5
2	3150	9510	1.3	12	6	4.5
3	3550	10460	1.7	14	8	4.5
4	3760	11560	2.1	16	12	4.5
5	3980	12840	2.5	18	17	4.5
6	2730	6130	1.1	8	—	40
7	3150	6940	1.5	12	—	40
8	3550	7800	2.0	14	—	40
9	3760	8340	2.5	16	—	40
10	3980	9040	3.1	18	—	40

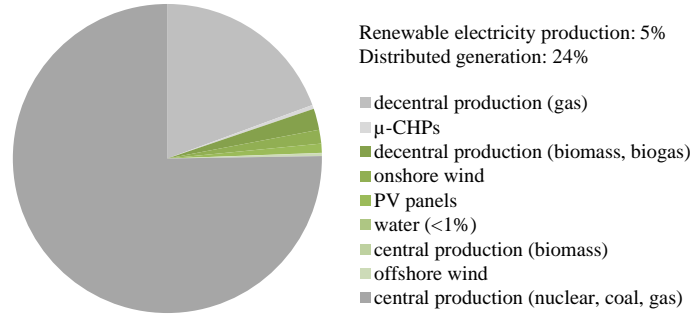


Figure 3.9: Electrical energy production in 2040 (Scenario B).

### 3.5.2 Scenario B

*High economic growth and not an effective climate policy* — Through strong international co-operation the economy flourishes, but climate goals are not reached. This scenario leads to high electricity demand and to generation on central locations. The number of households grows with 1.0% per year.

*Effect on the supply of electricity* — There is growth of generation on all levels of the electricity networks. Due to a high electricity price, the amount of gas-fired DG grows, but the share of centralised production connected to the HV level grows even more. The number of PV panels grows slowly and the development of  $\mu$ -CHPs is not stimulated which leads to a low amount of  $\mu$ -CHPs.

*Effect on the demand of electricity* — Because of an increase in the usage of electric appliances, the demand of regular residential electricity grows with 1.5% per year. Investments are done to insulate houses to reduce energy demand and many heat pumps are installed. In 2040 75% of the new bought vehicles is electric, which is consistent with the target set by the Dutch government. The electricity demand for industry grows with 2.0% per year. The total electricity demand in the Netherlands in 2040 is 258 TWh.

The share of renewable electricity production and the share of DG are presented in Figure 3.9. The general development of the expected technologies in residential areas are presented in Table 3.6 and some numbers related to these technologies for each of the ten typical residential areas are presented in Table 3.7.

Table 3.6: Development of expected technologies in residential areas (Scenario B).

Growth regular electricity use	1.5%
$\mu$ -CHPs	low
Air source heat pumps (in existing areas)	high
Ground source heat pumps (in newly developed areas)	high
PV panels	low
EVs	high

Table 3.7: Numbers related to the technologies applied in ten typical residential areas (Scenario B).

Area	Annual demand for regular electricity use per household (kWh)	Annual heat demand per household (kWh)	Average PV panel area per house (m <sup>2</sup> )	Average driving distance with an EV per house (km)	Penetration degree $\mu$ -CHPs (%)	Penetration degree heat pumps (%)
1	4270	8840	0.6	20	5	68
2	4920	9510	0.8	30	6	68
3	5550	10460	1.1	34	9	68
4	5870	11560	1.4	40	12	68
5	6220	12840	1.7	44	17	68
6	4270	5270	0.8	20	—	67
7	4920	5970	1.1	30	—	67
8	5550	6700	1.5	34	—	67
9	5870	7160	1.8	40	—	67
10	6220	7740	2.2	44	—	67

### 3.5.3 Scenario C

*Moderate to high economic growth and an effective international climate policy* — Due to a strong focus on the environment, much is invested in sustainable energy technologies and the share of distributed electricity generation grows. Through the focus on the environment, the economic growth is a bit restrained. That, in combination with measures leading to energy savings, limits energy demand growth. The number of households grows with 0.5% per year.

*Effect on the supply of electricity* — There is a large increase of DG connected to the MV and LV networks. The amount of PV panels and  $\mu$ -CHPs grows substantial.

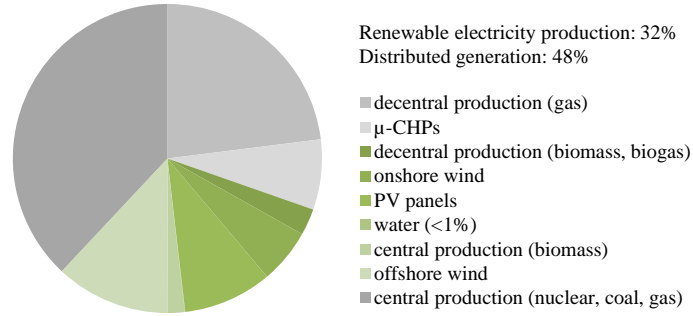


Figure 3.10: Electrical energy production in 2040 (Scenario C).

Table 3.8: Development of expected technologies in residential areas (Scenario C).

Growth regular electricity use	-1.0%
$\mu$ -CHPs	high
Air source heat pumps (in existing areas)	moderate
Ground source heat pumps (in newly developed areas)	high
PV panels	high
EVs	high

Table 3.9: Numbers related to the technologies applied in ten typical residential areas (Scenario C).

Area	Annual demand for regular electricity use per household (kWh)	Annual heat demand per household (kWh)	Average PV panel area per house (m <sup>2</sup> )	Average driving distance with an EV per house (km)	Penetration degree $\mu$ -CHPs (%)	Penetration degree heat pumps (%)
1	2020	8840	3.4	20	37	34
2	2330	9510	4.7	30	40	34
3	2630	10460	6.4	34	45	34
4	2780	11560	7.7	40	53	34
5	2940	12840	9.4	44	55	34
6	2020	5780	4.7	20	—	66
7	2330	6550	6.6	30	—	66
8	2630	7350	9.0	34	—	66
9	2780	7850	11.0	40	—	66
10	2940	8490	13.6	44	—	66

*Effect on the demand of electricity* — Due to energy saving measures, the demand for regular residential electricity decreases with 1.0% per year. Many heat pumps are installed, although the air source heat pumps have to compete with  $\mu$ -CHPs in existing houses. In 2040 75% of the new bought vehicles is electric, which is consistent with the target set by the Dutch government. The electricity demand for industry grows with 1.0% per year. The total electricity demand in the Netherlands in 2040 is 175 TWh.

The share of renewable electricity production and the share of DG are presented in Figure 3.10. The general development of the expected technologies in residential areas are presented in Table 3.8 and some numbers related to these technologies for each of the ten typical residential areas are presented in Table 3.9.

### 3.6 Summary and conclusions

In this chapter, first, the technologies that are expected in residential areas are described. The main developments that will substantially change the electricity demand in residential areas are the increase or decrease of load of regular domestic appliances, the use of appliances with a flexible demand for electricity ('smart appliances') and the application of new technologies like  $\mu$ -CHPs, heat pumps, EVs and PV panels. The development of these technologies have been treated.

To identify the main drivers and policy measures that may lead to variations in the residential electricity demand and supply, recent scenario studies have been analysed. It was concluded that depending on a more nationally or internationally focused policy, a more economically or environmentally oriented society and the degree of economic growth, the future power system can develop in different directions. Variation in these drivers will lead to very different, yet realistic scenarios with different trends in types, location and size of generation and demand of electricity.

In this thesis the Netherlands is used as a case study; therefore, three scenarios for the Netherlands based on divergent choices concerning the identified drivers are described. The time horizon of the scenarios is 2040. It is indicated how each scenario affects the electricity system, in terms of the expected demand growth for electricity, the voltage level to which generators will be connected and developments of new technologies that are applied in residential areas.

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## Utilisation of future distribution networks

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### 4.1 Introduction

As we have seen in Chapter 2, the capacity of traditional electricity distribution networks is dimensioned to meet peak demand. In contrast with the traditional approach in which supply ‘follows’ demand in order to keep a continuous balance between generation and load, flexibility in electricity demand as well as new developments in storage of electricity, make it possible to delay or advance the load demand, while the same energy content is provided. In smart grids, the demand for electricity may, for example, be adjusted to the (local) availability of renewable, intermittent generation. Or, following another smart grid strategy, demand may be increased when electricity prices are low. This, combined with the uncertain developments in the electricity demand in residential areas as described in Chapter 3, makes it more complex to determine the utilisation and required capacity of future distribution networks.

For distribution network planning purposes, future loading and resulting required capacities of distribution networks are estimated by executing load-flow analyses. Input for these analyses are future (peak) loads, which are often based on historical data in combination with an expected growth in electricity demand. In this chapter, it is shown that due to the changes in electricity demand the traditional methods that are used for network planning are no longer satisfactory and it is explored how future loading in distribution networks can be modelled for use in load-flow calculations to support the planning process of electricity distribution networks. In Section 4.2, it is described how network planning traditionally has been done. To gain some insight in the utilisation of distribution networks, an analysis on the utilisation of large set of distribution networks is given. Then, in Section 4.3, the focus is on how the loading in distribution networks may change due to changes in future residential electricity demand and supply, and especially, what this means for modelling loads for network capacity analysis. Changing load profiles do not only change the maximum loadings, but also have effect on distribution networks in other ways and affect energy losses. Therefore, in Section 4.4, attention is paid to what impacts changing load profiles have on electricity distribution networks. The chapter ends with summary and conclusions.

## 4.2 Distribution network planning

Distribution network planning is essential to assure that the growing demand for electricity can be satisfied by expansions that are both technically adequate and economically reasonable. Distribution planners must estimate the magnitude of the maximum loading, the demand profile, and the geographic location of the connections of loads and generation units. Then, distribution substations and feeders must be placed and sized in such a way as to serve a certain demand at minimum cost by minimising capital investments and operating costs, while considering the constraints of service quality, such as the voltage at substations and feeders, and capacity constraints [133].

The need for capacity at the distribution level of the electricity supply system is determined by the amount of electricity produced and consumed at a given moment in time as well as by the location where the loads and generators are connected to the grid. To investigate the required capacities of assets in distribution networks, such as cables and transformers, load-flow calculations using load forecasts are done to determine future electricity flows. In this section, present load models that are used to determine future loads that are used as input for the load-flow calculations are described. Then, attention is paid to load-flow analysis itself. Finally, an analysis of the current utilisation of a large set of Dutch MV distribution networks is given.

### 4.2.1 Present load models

Historically, utilities have dimensioned their grids to meet simultaneous peak demands. The common practice to estimate the peak demand for designing and planning distribution networks is still based on general formulas originating from the 1950s. In these formulas a coincidence factor  $c$  is defined to describe the relation between the peak demand of one consumer and the simultaneous peak demand of a group of  $n$  consumers:

$$c = \frac{P_{\max,\text{tot}}}{\sum_{i=1}^n P_{\max,i}} \leq 1 \quad (4.1)$$

Assuming the peak demand of these consumers to be identical, this can also be written as:

$$P_{\max,\text{tot}} = c(nP_{\max,\text{consumer}}) \quad (4.2)$$

In [122] statistics are applied to this formula, assuming that various loads of individual consumers during a peak period are normally distributed around a certain value. The paper demonstrates that this is a valid assumption by comparing formulas deduced from theory of statistics with actually recorded measurements, and is therefore also used in approaches developed later on. Another, empirical method is introduced by Velandar [136]. Velandar describes a relation between the peak power demand  $P$  and the average annual energy demand  $E$ :

$$P_{\max, \text{tot}} = k_1 E + k_2 \sqrt{E} \quad (4.3)$$

The relation is described by the constants  $k_1$  and  $k_2$  which are specific for a consumer group and can be determined by empirical data and subsequently used for general application to model the maximum simultaneous demand of this consumer group. This method is still widely applied for network planning [82].

Also, methods exist that model the electricity consumption over time rather than just the peak demand. In several papers load curves for specific user groups are determined, based on empirical data, and combined with statistical methods to model aggregated consumer demands [10, 67, 86]. Up till now, it has been sufficient to assume the shape of the daily load profile to be equal for all residential consumers, with (for the Netherlands and other industrialised areas) a peak in the evening when people get home after work, and to take into account a yearly growth rate to model future demands. However, since future demands are less predictable and cannot be based on historical measurement data, these models are not suitable.

A method that needs no empirical data is the bottom-up approach [111, 150]. In the models based on this approach the load profiles are constructed by adding up elementary load components which can be individual consumers or even individual appliances. These models are very suitable for modelling specific individual load profiles and can also be very suitable for investigating the application of DSM. However, for modelling large numbers of households for distribution network planning, this approach is very extensive and therefore not very easily applicable.

In summary, present methods for modelling residential loads that are most applied determine peak demands (or daily profiles) based on empirical data and under the assumption that certain consumer groups have identical profiles.

#### 4.2.2 Load-flow analysis

Load-flow calculations are used to calculate voltages, currents and power flows in electricity networks and to check design criteria during normal operation and emergency conditions. With the calculations it is checked if voltages and currents do not exceed certain limits during high loading conditions or short circuit situations. It is also possible to calculate energy losses.

A method to solve the load-flow equations is the Newton-Raphson method. This method applied to load-flow calculations, is first described in [97], and later on in [135]. It is an iterative technique for solving a set of nonlinear equations. The iterations start with an initial estimate for the unknown parameters and the process is repeated until the mismatches (in power) are lower than a specified tolerance. The Newton-Raphson method has a very good convergence rate and is widely used for network calculations. The computation time increases only linearly with the system size and is particularly suited for applications involving large systems requiring accurate calculations [81].

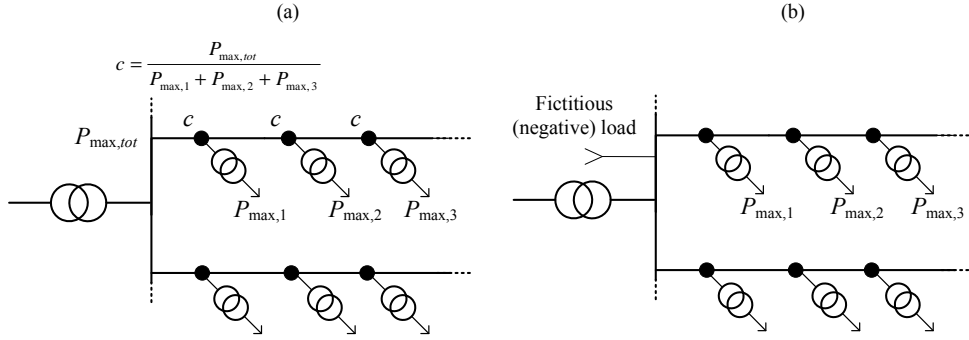


Figure 4.1: Compensation of diversity in loads (a) using coincidence factors and (b) using fictitious loads.

Furthermore, when applying load-flow calculations to transmission and distribution networks, it is often assumed that the three-phase networks are balanced. In this case, a single line representation of the network can be used for the load-flow analysis. This assumption is justified in most West-European MV distribution networks, but cannot always be applied to LV distribution networks [110].

Another issue related to load-flow calculations is that they should be able to handle simultaneity of loads. Distribution networks are dimensioned for the worst-case (loading) situation, therefore, peak demands are used as input for the load-flow calculations. Corrections are needed for the fact that maximum loading of the MV distribution cables is not equal to the sum of the individual peak demands of the connected loads, because these peaks occur at different moments in time. Ignoring this aspect results in overdimensioned networks and unnecessary investments. There are different methods to model the simultaneity of loads in MV distribution networks. One method is applying the same principle as when determining the simultaneous peak demand of a group consumers, by using coincidence factors (see Figure 4.1a). These factors are related to each node of the MV distribution cable. This results in proper values at the MV substation level, but the values in the MV cable become lower than in reality. Another method is to add a fictitious (negative) load to the MV substation [110]. This method is illustrated in Figure 4.1b. Due to the negative load connected to the substation, the load at the substation is compensated for the diversity of loads connected to the MV distribution cables. The MV cables are, however, not compensated for this and still overdimensioned. Other methods are, for example, stochastic load-flows, where the loads consist of a deterministic part (e.g. a daily load profile as function of time) and a stochastic part (e.g. a random variation of the load around its average) [119]. For stochastic calculations a large amount of data is needed (which is not always available) and more calculations need to be executed, which make the calculations more complex and time consuming.

### 4.2.3 Current utilisation of Dutch medium voltage networks

As described in Chapter 2, historical developments have led to the present approach regarding planning of distribution networks that resulted in distribution networks which rely on very little online automation and a relatively low utilisation of network assets. To illustrate this and gain some insight in the current utilisation of distribution networks, an analysis has been done on how the existing capacity in the network of Enexis, a Dutch DNO is used. The available capacity of a part of the distribution networks owned and operated by this DNO is estimated, based on measured data. Included in the analysis are the MV transmission and distribution cables that operate on a 10 kV voltage level, no transformers are included in this analysis. First, the topology and operation of the networks are shortly described and then it is explained how the utilisation of the MV cables are determined.

#### Topology and operation of distribution networks

In the distribution networks the electricity is transported from the transmission substations, or from small-scale generation which is directly connected to the distribution networks, to the loads. The motivation for an MV grid is based on the fact that material and construction costs are only a little higher than those for a LV grid, and are approximately one-tenth the costs of a typical HV line, while losses are substantially decreased by increasing the operating voltage from an LV to an MV level. The MV grid also provides a convenient voltage for connecting substantial industrial loads, larger buildings and office blocks. In rural areas the distance is the main criterion for the choice of voltage level. In urban areas the main factors are cost of substation equipment, limited availability of cable routes, and overall costs of energy losses. The length of new LV cable feeders is usually limited to around 500 m or less, depending on such factors as voltage drop, the number of phases used and the type of load, to reduce voltage problems and energy losses [82].

The typical topology of MV networks in the Netherlands is depicted in Figure 4.2. An MV network is fed by the transmission network through a HV/MV transformer. Typical primary voltages of HV/MV transformers in the Netherlands are 220 kV, 150 kV, 110 kV and 50 kV; typical secondary voltages are 25 kV, 20 kV and 10 kV. MV transmission can be carried out either at the same voltage as MV distribution, in which case no MV/MV transformer is necessary in the MV/MV station, or at a higher voltage (e.g., MV transmission at 20 kV or 10 kV and MV distribution at 10 kV or 3 kV, respectively). MV distribution feeders are generally constructed as two half rings which are disconnected from each other by a normally-open point [119]. These normally-open points make straightforward, radial operation of networks possible while still allowing for rerouting in case of an outage or maintenance along the feeder. The location of the normally-open point is optimal if the losses are minimised, though the resulting voltages and the physical location of the normally-open point are also issues that are taken into consideration [110].

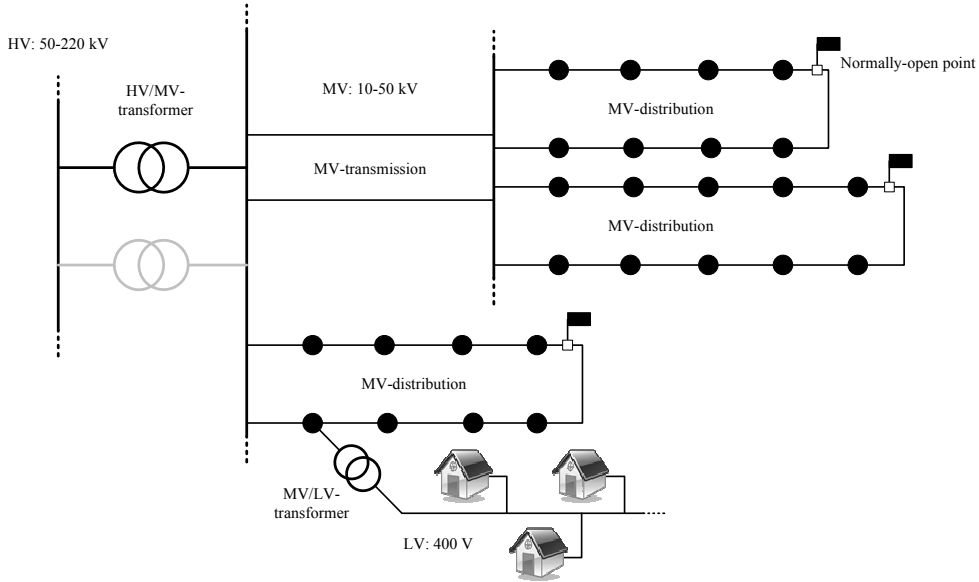


Figure 4.2: Typical topology of MV networks in the Netherlands, with and without MV transmission.

In Figure 4.2 MV networks with and without MV transmission are depicted schematically in their most straightforward form. More complex variations frequently occur, in which for instance an MV/MV substation is connected to several other MV/MV substations, or an MV network is fed by multiple HV/MV substations. Besides that, many MV installations at HV/MV substations feed both MV transmission cables and MV distribution cables and not all distribution cables feature the ring shape. MV transmission networks are typically designed to meet the (n-1) criterion, which means that when all (parallel) cable bundle circuits are in operation, any cable circuit in the bundle can be lost without causing an overload of any other cable and without any interruption of supply. Meeting the (n-1) criterion also facilitates maintenance, as one circuit can be taken out of service for carrying out maintenance while continuity of supply is guaranteed.

### Utilisation of MV cables

The utilisation of the MV transmission and distribution networks of the province Limburg in the Netherlands has been analysed. This region comprises one fifth of the total of distribution networks which are operated by Enexis. In this region Enexis owns and operates 29 HV/MV substations that supply 530,000 customers. No

MV/MV transformers are applied in the MV networks, while both the transmission and distribution cables in these networks are operated at a 10 kV voltage level.

The capacities of the cables are defined by the maximum allowable loading conform the guidelines of Enexis. These guidelines are based on the Dutch Practice Guidelines (Nederlandse Praktijk Richtlijn, NPR) 3107 and 3626 [95, 96] and the international standard IEC 60853 [62]. The capacities of the cables are expressed in current and determined with the following equation [126]:

$$I_{\max \text{ equal loading}} = F \cdot T \cdot D \cdot I_{\text{nom}} \quad (4.4)$$

in which  $I_{\max \text{ equal loading}}$  is the peak current that may occur in (n-1) situations assuming that parallel cables are equally loaded.  $I_{\text{nom}}$  is the rated current capacity under standard conditions given by the manufacturer assuming the cable is continuously loaded.  $F$  is a correction factor for the thermal influence of parallel cables and the thermal resistance of the soil type.  $T$  is a correction for the soil temperature.  $D$  is a factor to incorporate the thermal dynamics of the cable; this factor is determined by the loading of the cable in normal operation [126]. When the cables are continuously loaded  $D = 1$ .

The average load profile of 69 MV transmission cables in the province Limburg on the day with the highest demand and the average capacity of these cables are shown in Figure 4.3a. The average capacity is defined by the maximum allowable loading of the cables as expressed in Equation 4.4. Conform the guidelines of Enexis, the average values of  $F$ ,  $T$  and  $D$  are 0.7, 0.92 and 1.3, respectively. The area between the load profile and the average capacity shows that 57% of the total capacity of the MV transmission cables is not used in normal operation. This is mainly because of the (n-1) criterion applied in the design. The cables must be able to take over the load of a faulted parallel cable; this reduces the maximum allowable loading in emergency situations, depending on the number of parallel cables (e.g., in case of three parallel cables, the other two cables must be able to take over the load of the faulted cable). Also, a conservative estimation of the simultaneity of peak demands and the fact that the networks are laid out for a foreseeable future loading contribute to low utilisation of the transmission cables.

Just as for the transmission cables, the average load profile and the average capacity of MV distribution cables are determined and presented in Figure 4.3b. These results are based on data of 147 distribution cables. The factor  $F$  is used in case of parallel cables and not applied to distribution cables. The values for  $T$  are 0.92 and 0.93 for paper insulated lead covered (PILC) cables and cross linked polyethylene (XLPE) cables, respectively (in normal soil), and the value of  $D$  is 1.1. The area between the load profile and the average capacity shows that in comparison with transmission cables an even higher percentage of the capacity is not used in normal operation. This is because the networks are mostly designed to be operated in two half rings. When a fault occurs, one part of the ring can be fed through the other side of the ring by closing a normally-open point. Therefore, extra capacity is

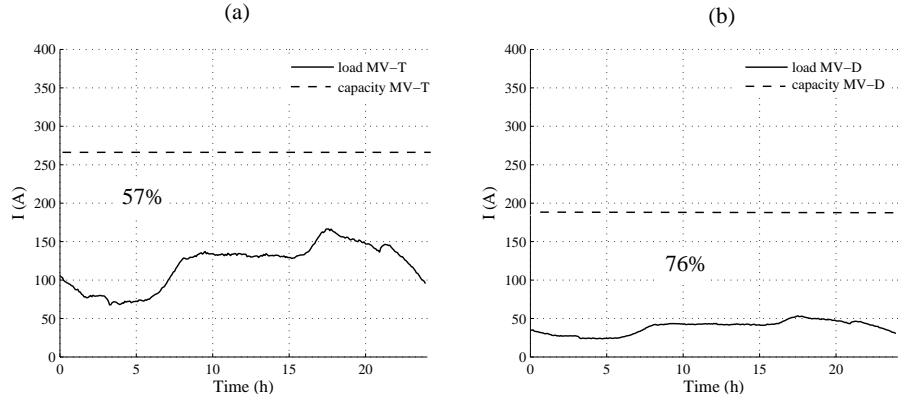


Figure 4.3: The average net load profile on the day with the highest loading and the average capacity of (a) an MV transmission cable and (b) an MV distribution cable in Limburg.

needed. It should be noted that it is ensured that failures of MV distribution cables are repaired within 72 hours and in these emergency situations, a higher loading is allowed: in this case,  $D = 1.3$ .

This analysis of a part of the distribution networks in the Netherlands shows that 57% of the capacity in MV transmission cables is available to transport extra energy and an even higher percentage is available in the MV distribution cables. It should be noted however, that there is some capacity planned for future loading and the capacity must be sufficient to meet the (n-1) criterion for regular, not flexible loads and meet the high reliability standards. Still, this analysis shows that a vast amount of spare network capacity is currently unused. As a result of this unused capacity in distribution networks, the networks offer great potential for transferring extra energy without increasing the capacity of the existing networks.

### 4.3 Loading of future distribution networks

As we have seen in Section 4.2, the planning and design standards that have been developed over the years, have led to well-functioning, reliable distribution networks with sufficient capacity margin. However, considerable changes are expected and the present approach will no longer be adequate in the future [47]. These changes include changing consumer load characteristics, higher marginal costs of losses, higher reliability standards and an increased penetration of distributed generation. A planning concern is the sensitivity of the expansion plan with respect to changes in long-term demand forecast [73]. Already for several years it has been recognised that the distribution networks will have to meet higher demand peaks due to the use of new technologies in residential areas [17]. Due to the ongoing developments related to

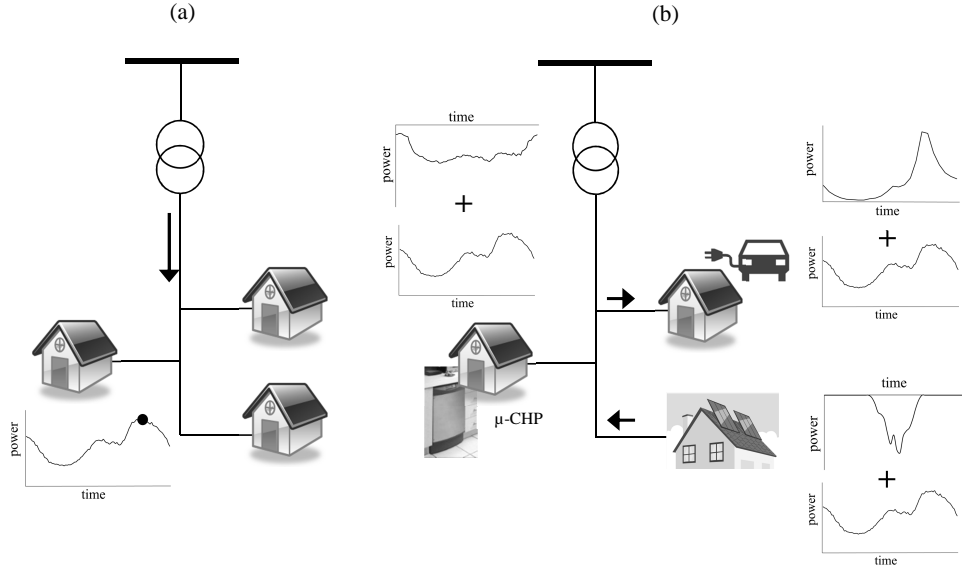


Figure 4.4: (a) Mono-directional power flow due to regular residential electricity daily profiles with a peak in the evening; (b) bi-directional power flow, due to new technologies with different profiles and peaks at different moments during the day.

the transition to a more sustainable energy system this is now becoming a more actual issue. Besides this, storage opportunities and developments towards smarter grids that may unlock the flexibility of electricity demands, influence the loading of the distribution networks.

#### 4.3.1 Changing demands

The introduction of local generation and new types of loads such as EVs and heat pumps will alter the current patterns of electricity demand. Technologies like  $\mu$ -CHP systems, heat pumps, PV panels and EVs all have different characteristics in terms of size and time when they produce or consume electricity. The variability and flexibility of their electricity production or consumption differ considerably over the day. This is illustrated in Figure 4.4.

Because of these new technologies that may be introduced at individual households, more differences between individual customers connected to the grid will exist; e.g., one household may choose for a  $\mu$ -CHP and the other for a heat pump in combination with solar panels. Also, because of the uncertainty with respect to the development and adoption of these technologies, load profiles of individual households will be less predictable than nowadays.

At the same time, to adapt the grids to integrate a growing share of distributed generation it may be advantageous to take into account flexible, not time-critical loads in order to limit network capacity and/or reduce network losses. Because the use of these flexible loads may be shifted in time, they will change the load profiles and hence the capacity requirements for the distribution networks.

### 4.3.2 Load modelling in future networks

Although the existing approaches to model residential loads have performed very well up till now, they will become increasingly unsuitable in the future. The variation between households cannot be modelled with traditional models that were presented in Section 4.2.1, because these need user measurement data which are not available for future loads. In addition, the time element must be taken into account, as is essential when new technologies are introduced. To analyse the impact of the flexibility of electricity demand on loading of the networks, modelling the electricity consumption over time, rather than the peak load alone, is becoming important.

This asks for an adaptation of present modelling of residential loads in such a way that the aggregated (peak) demand for several tens to hundreds of households can be estimated, taking into account the variation between consumers and the variation over time. This can be done by using a load model that constructs load profiles that take into account the variation between households that may use different new technologies, including decentralised generation of electricity, and that can handle shifting of flexible loads. Subsequently, these profiles can be used in load-flow calculations in order to assess the capacity need of the distribution networks for future demand and to investigate the benefits of DSM in relation to network capacity. A new modelling approach that takes these issues into account is elaborated in Chapter 5.

## 4.4 Consequences of changing load profiles

So far, it has been argued that for planning of distribution networks it is of importance to be aware of the shape of the load profiles, because peaks can occur at various moments during day. In smart grids it may become possible that demand, and with that the peak of the demand, is shifted in time. A less predictable load profile not only has implications for modelling the maximum loadings, but changing load profiles over time may also affect other issues in distribution networks. For example, energy losses are dependent on the shape of the load profiles. And an asset that is more continuously loaded will cool down less after maximum loading; this may affect the maximum allowable loading and the lifetime of the asset. These issues will be treated in this section.

In Figure 4.5 three examples are given of possible load profiles in future distribution networks. The profiles are divided in an inflexible part, which is the same

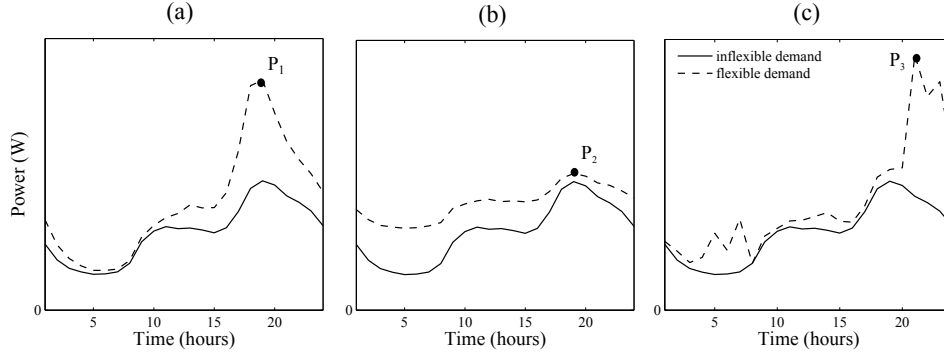


Figure 4.5: Load profiles with and without shifting the flexible part of the demand: (a) no shifting of demand; (b) shifting demand to reduce maximum loading; and (c) shifting flexible demand to balance wind production.

in all cases, and a flexible part that may be shifted in time. In Figure 4.5a no load management or DSM is applied. In Figure 4.5b demand is shifted to reduce maximum loadings. If flexible loads, as for example EVs, can be charged during off-peak periods when the demand is low, the capacity of the network can be used more efficiently and more energy can be transported without increasing the capacity of the network assets. In this way, growing electricity demand, e.g. due to electric cars, can be satisfied with only a limited need for investments to expand the networks ( $P_2 < P_1$ ). On the other hand, flexible demand can also be used to balance e.g. the production of intermittent wind energy. In this case, it can very well be possible that high loadings will occur in the network assets and more network capacity is required than in a situation without shifting flexible demands. Figure 4.5c depicts a load profile that might occur in a situation in which some of the demand is shifted to a period in which there is a surplus of wind energy in the late hours of the day ( $P_3 > P_1$ ). With help of these examples it will be illustrated how load profiles affect energy losses as well as the required capacities of assets.

#### 4.4.1 Energy losses

For efficient use of energy and reducing the costs related to energy losses, the energy losses in the networks should be minimised. Energy losses can be separated into so-called fixed losses and variable losses. The fixed losses are those due to the magnetisation currents of such items as transformers, which are often referred to as iron or core losses and are practically independent of the load. The variable losses are those caused by the flow of current through different networks assets, such as cables and transformers, and are also termed load losses [82].

Core losses include hysteresis loss and eddy-current loss in the iron core of transformers, which depend on the type of steel used to fabricate the core. The hysteresis loss is due to the power requirement of maintaining the continuous reversals of the elementary magnets (or individual molecules) of which the iron is composed as a result of the flux alternations in a transformer core. The eddy-current loss is the loss due to the circulating currents in the iron core, caused by the time-varying magnetic fluxes within the iron [53]. The fixed energy losses in transformers can be estimated by:

$$E_{\text{fixed loss}} = P_{\text{iron loss}} T_{\text{fixed loss}} \quad (4.5)$$

The value of  $P_{\text{iron loss}}$  is given by the supplier of the transformer and  $T_{\text{fixed loss}}$  equals the operation hours of the transformer which in general will be 8760 hours per year.

The load losses are due to the resistance of cables and of the primary and secondary windings in transformers, plus eddy-current losses in the windings and the core, tank and other metallic parts of the transformer caused by the leakage flux [82]. Power losses in a cable having resistance  $R$  are proportional to the square of the current flowing through it ( $P_{\text{loss}} = I^2 R$ ). The annual energy losses  $E_{\text{loss}}$  can be determined by integrating the power loss over time:

$$E_{\text{variable loss}} = \int_0^T P_{\text{loss}}(t) dt \quad (4.6)$$

In practice, the variable transformer losses are estimated by using the following formula:

$$E_{\text{variable loss}} = \alpha^2 P_{\text{load loss}} T_{\text{variable loss}} \quad (4.7)$$

In this formula  $P_{\text{load loss}}$  is the power loss at full load which is given by the manufacturer of the transformer and  $\alpha$  is the utilisation factor of the transformer.  $T_{\text{variable loss}}$  is the loss duration which is defined by the area under the energy loss profile. This profile is quadratically related to the load profile. A more continuous load as presented in Figure 4.5b will result in a larger value of the loss duration.

Because of the squared relationship between the load current and the loss, a more continuous load in a component will mean that the variable losses will decrease. It should be noted, however, that when replacing of the asset is delayed because the peak load is decreased due to shifting flexible demands (in a situation similar to the situation presented in Figure 4.5b where  $P_2 < P_1$ ), the energy losses may increase compared to a situation in which the asset would be replaced, because in the latter case the characteristics of the asset (i.e. the resistance) will alter. This makes it rather complex to determine if changing load profiles in combination with the resulting replacement strategy will have a positive or negative effect on the energy losses in the network infrastructure. When assessing the impacts of changing load profiles on the energy losses later on in this thesis, the losses are quantified assuming

a replacement strategy that replaces every overloaded asset with an asset with a higher capacity.

#### 4.4.2 Maximum allowable loading

As described in the previous section, a part of the energy will be lost during the transport of electric power through an electric component. This energy loss will be converted to heat which will increase the temperature of the associated electric component. High temperature can result in premature ageing of insulation and more excessive temperatures can even result in melting of conductors or insulation [82]. Therefore, the temperature of the components should be kept below a maximum allowable temperature to prevent faults and dangerous situations, and not to accelerate ageing.

The temperature in cables depends on the condition of the surrounding environment (the thermal resistance and humidity of the soil, the type of soil, the temperature of the soil, etc.). These issues are treated in the international standard IEC 60287 that describes how the allowable current rating of continuously loaded electric cables can be calculated [63]. In case of cyclic loading of cables, the current can temporarily be allowed to exceed the continuous rating without the cable temperature exceeding its maximum allowable value. This is treated in the standard IEC 60853 [62] and in [126] that describes the thermal dynamics in cables based on a fully dynamic thermal model. In this thesis, the maximum allowable loading for cables is defined by Equation 4.4 (see Section 4.2.3). If loading patterns change in future, and the cables will for example be more continuously loaded, as is the case in Figure 4.5b, the cyclic current ratings will have to be adjusted downwards compared to the present situation. This means that the value of  $D$  in Equation 4.4 needs to be adjusted.

Just as for cables, the loading of transformers is limited by heating. When subject to cyclic loading, the loading of transformers may also be allowed to temporarily exceed the rated capacity<sup>1</sup> of the transformers. And thus also in the case of transformers, a more continuous or a more dynamic loading pattern will affect the maximum allowable loading. In accordance with Equation 4.4, this can be expressed as:

$$P_{\max} = D \cdot P_{\text{nom}} \quad (4.8)$$

where  $P_{\max}$  is the maximum allowable loading,  $P_{\text{nom}}$  the rated capacity and  $D$  a factor to incorporate the thermal dynamics of the transformer.

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<sup>1</sup>The rated capacity of the transformers is the capacity given by the manufacturer under standard conditions assuming continuous loading.

## 4.5 Summary and conclusions

At the MV grids tens to hundreds of houses are connected behind MV/LV transformers. To assess the capacity need of these networks with respect to future demand, including decentralised generation of electricity in residential areas, the aggregated (peak) load of the households at these transformers needs to be estimated. Subsequently, these forecasted (peak) loads are used as input for load-flow calculations. Present methods for modelling residential loads that are most applied determine peak demands (or daily profiles) based on empirical data and the assumption that certain consumer groups have identical profiles. This in combination with extrapolating historical demand growth has been sufficient for demand estimates to be used for planning.

Although the existing approaches to model residential loads have performed very well up till now, they will become increasingly unsuitable in the future. The variation between households cannot be modelled by present models because these need user measurement data which are not available for future loads. In addition, the time element is mostly not taken into account, which is essential when new technologies and flexible, not time-critical loads are introduced. This asks for a method for modelling residential loads in such way that the aggregated (peak) load for tens to hundreds of households can be estimated, taking into account the variation between consumers and the variation over time to assess the capacity need of the distribution networks for future demand, including decentralised generation in residential areas. A method to model aggregated residential loads that takes into account these issues is introduced in the next chapter.

Subsequently, the effect of various developments in future demand on the required capacity of future distribution networks can be assessed and the benefits of DSM in relation to network capacity can be investigated. Besides the effect on the maximum loadings, changing load profiles may affect other issues in distribution networks. Energy losses are partly dependent on the shape of the load profiles. Energy losses can be separated into fixed and variable losses, dependent on the load and on the material characteristics of the network assets. When assessing the impacts of changing load profiles on the energy losses, both types of losses should be quantified, taking into account the fact that replacing assets influences the energy losses as well. Changing load profiles may also change the maximum allowable loading of an asset, because a more continuously loaded asset has a lower maximum allowable loading than a similar asset with a more dynamic loading. These issues should be taken into account when assessing the impacts of future demand on distribution networks.

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## Modelling residential demand profiles

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### 5.1 Introduction

In the previous chapter, it has been shown that the available methods for modelling residential electricity demands are not satisfactory for modelling future demands for use in load-flow calculations to support the planning process of electricity distribution networks. Therefore, to adequately model the aggregated load (and generation) of tens to hundreds of households to analyse the impacts on the distribution networks a new modelling approach is developed. This approach aims at estimating the aggregated (peak) load while taking into account the variation between consumers and the variation over time, in order to assess the capacity needs of the distribution networks to accommodate future demand and decentralised generation in residential areas. The approach takes into account the load (and generation) profiles of the different future residential technologies, like  $\mu$ -CHPs, heat pumps, PV panels, and EVs. In this approach the profiles of the different future residential technologies which consume or produce electricity are first considered separately. After careful modelling of the individual load and generation profiles, they are subsequently combined to construct the aggregated profile of a group of households.

Constructing demand profiles in this way makes it possible to differentiate between residential areas with various types and penetration degrees of emerging technologies. Also, to analyse the influence of controlling and storing electrical energy it becomes important to assess the electricity consumption and production over time. With the proposed modelling method it is possible to analyse management of flexible loads, for example smart charging of EVs or DSM. Besides the aggregated peak, the shape of the demand profile will change in these situations. The resulting aggregated (peak) demands can be used for load-flow calculations to assess the required capacity of electricity distribution networks. In addition, the benefits of smart grids can be assessed by comparing the impact of aggregated demands with and without management of flexible loads.

First, modelling the profiles of the individual load and generation technologies in future residential areas will be treated in Section 5.2. In Section 5.3, it is described how profiles can be modelled of flexible demands that can be shifted in time. The construction of load profiles of flexible demands that follow two different smart grid

strategies are further elaborated. In Section 5.4, examples are given of aggregated net load profiles of residential areas that are constructed by combining the individual load and generation profiles and the effect of the two different smart grid strategies on the net load profiles are presented. In the last section, the chapter is summarised and some conclusions are given.

## 5.2 Modelling individual load and generation profiles

In the approach proposed in this chapter, the profiles of the different future residential technologies that consume or produce electricity are first considered separately. Besides the regular residential electricity use for household appliances, the profiles of  $\mu$ -CHPs, heat pumps, PV panels, and EVs are separately modelled. These technologies were identified in Section 3.3 as technologies that change the electricity demand in residential areas substantially. In this section, it is described how the load and generation profiles of these individual elements of the aggregated residential electricity demand are modelled. No load management is applied to the profiles constructed in this section; modelling of flexible demands to which load management is applied is treated in Section 5.3.

### 5.2.1 Regular residential electricity use

Individual residential consumers use electricity in different ways and at different times. The demand for regular use of electricity in and around the house depends on house occupancy and individual activity, but also on the seasonal day cycle and ambient temperature. The profiles of individual consumers are unique, but for large numbers of customers, individual peak demands are levelled out in the combined demand through random customer behaviour. This means that the coincidence factor, the ratio between the maximum peak demand of the combined loads and the sum of the individual peak demands (see Section 4.2.1), remains constant. Examples based on historical data of residential consumers in [72] and [110] show that this is the case from 70 customers and more. This justifies working with aggregated profiles of residential loads representing 70 customers or more.

The aggregated load of the regular electricity use (for household appliances, computers, lighting, etc.) of a certain number of residential consumers, can therefore be modelled using normalised profiles. These normalised profiles present the average load profiles of a large number of households and are based on actual measurements. The normalised profiles are expressed as a time series of a dimensionless fraction of the electricity demand. To obtain the actual predicted load of a number of households expressed in kW, the time series are multiplied by the annual electrical energy demand of those households. For instance in the Netherlands, normalised profiles based on data of 400 households are available for all days of the year [35]. In Figure 5.1 current average load profiles for a residential customer with an annual

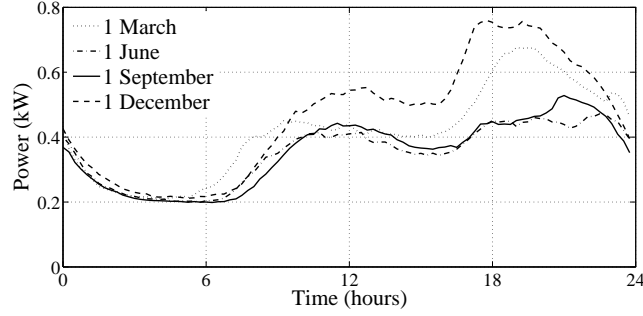


Figure 5.1: Four daily load profiles of the residential electricity use of a household in the Netherlands with an annual electricity demand of 3400 kWh.

electricity demand of 3400 kWh (this equals the average electricity demand per household in the Netherlands) are shown for four different days of the year. The shape of these profiles have not changed much over the years, although the total demand steadily increased in relation to the economic growth [110].

In future, the electricity demand of households may change due to for example energy efficiency or economic growth. To change the profiles accordingly, the average annual demand can be increased or decreased. Furthermore, the shape of the profiles can change due to developments in domestic appliances. The technologies that are expected to change these profiles substantially are modelled separately. Patterns can also change due to DSM by means of smart grids. Modelling the flexible demand of the regular residential use due to DSM in smart grids, is treated in Section 5.3.

### 5.2.2 Heating technologies: $\mu$ -CHPs and heat pumps

In this section, measurements of  $\mu$ -CHPs and heat pumps are analysed and models are presented to construct the (aggregated) peak production or consumption and daily profiles for one or more of these devices. At the moment only a limited amount of these devices have been deployed and a limited amount of data is available. Another issue related to modelling the electricity profiles of  $\mu$ -CHPs and heat pumps is that these profiles depend on the heat demand of a household which is related to the outside temperature and subject to change in the coming years when houses will be better insulated. The models must be able to handle these variable inputs. The following approach is applied to build the models:

1. First, measurement data are analysed to determine which parameters influence the generation and load profiles of  $\mu$ -CHPs and heat pumps.

2. Based on these findings, models are developed which can be generically applied to establish profiles of a large number of  $\mu$ -CHPs or heat pumps with specific characteristics and different heat demands.
3. These models are validated by applying the specifications of the measured  $\mu$ -CHPs and heat pumps and comparing the measurements with the model outputs.

### Modelling generation profiles of $\mu$ -CHPs

#### *Analysis of measurement data*

Measurement data of 8  $\mu$ -CHPs (i.e. gas consumption and power production recorded on a 15-minute time base) have been analysed. The  $\mu$ -CHPs are installed in 8 houses in the Netherlands. The houses are located in the same area, but characteristics, like size and age of the house, type of insulation and number of residents, differ. The primary goal of the application of the  $\mu$ -CHP installations is space heating. Therefore, the  $\mu$ -CHPs will follow the heat demand of the households (heat-driven control) and only generate electricity as a secondary product. As a consequence, the  $\mu$ -CHPs generate most electricity during cold days when heat demand is large; in the summer, if there is no heat demand, the  $\mu$ -CHPs do not generate power at all. To meet demand for tap water heating, and to meet peak heat demand on very cold days, an auxiliary burner is used. This allows a lower rated power of the  $\mu$ -CHPs and in this way, the operation hours of the  $\mu$ -CHPs are maximised.

The heat demand of the individual houses depends on different factors, like the individual behaviour and needs of the residents, the type of house, the amount of insulation, and the outside temperature. The gas consumption of the individual household (that reflects the heat demand) is directly correlated to the power production of the  $\mu$ -CHP. Analysis of the measurements shows that differences between the profiles (of the gas consumption and of the power production) and the total generated electricity by the  $\mu$ -CHPs between various households are large. The variation in the profiles is illustrated in Figure 5.2. It can be seen that in one house more electricity is generated in the morning, while in another electricity is mainly generated in the evening. These variations are caused by the differences in the lifestyles and personal preferences of the individual residents. In the figure it can also be seen that when the profiles of the individual houses are summed up to an aggregated profile, the individual variations vanish. Irrespective of the shape of the profile, a strong relationship between the total generated electrical energy on a day ( $E_e$ ) and the average outside temperature on that day can be found. In Figure 5.3 this relationship is shown by plotting the combined electrical energy generated by the 8  $\mu$ -CHPs on 61 individual days (the two coldest months of the year).

The above observations lead to the following conclusions regarding the issues that should be taken into account when modelling generation profiles of  $\mu$ -CHPs:

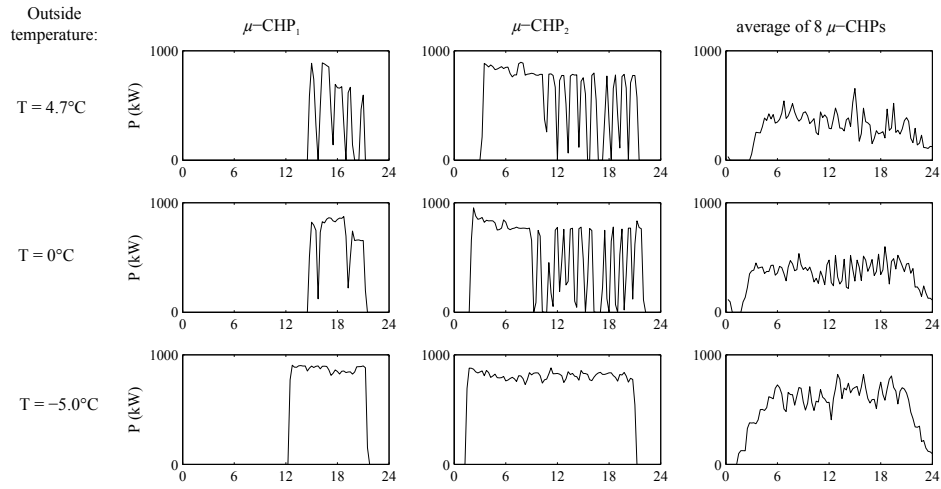


Figure 5.2: Measured profiles of the generated electricity by two individual  $\mu\text{-CHPs}$  and the average generated electricity of 8  $\mu\text{-CHPs}$  (the rated electrical power of the  $\mu\text{-CHPs}$  is  $P_{e\ max} = 1.0\text{ kW}$ ).

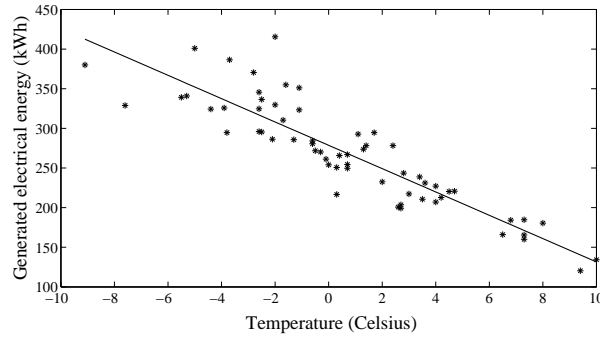


Figure 5.3: Relationship between the outside daily average temperature and the combined electrical energy generated by 8  $\mu\text{-CHPs}$  on 61 individual days.

- The shape of the generation profile of a  $\mu$ -CHP follows the heat demand profile and is subject to the behaviour of individual residents. As a consequence, the output of an individual  $\mu$ -CHP can be very unpredictable. However, for several  $\mu$ -CHPs a more uniform aggregated profile emerges.
- The total generated electrical energy of the  $\mu$ -CHP ( $E_e$ ) relates to the total heat demand on a day ( $E_{th}$ ), which is strongly dependent on the outside temperature.
- The output of the  $\mu$ -CHP depends on the rated electrical and thermal power,  $P_{e\ max}$  and  $P_{th\ max}$ , and the ratio between the electrical and thermal output indicated by  $\varepsilon_{\mu\text{-CHP}}$ .

#### Developed model

To determine the required capacities of MV/LV transformers it is important to be able to model the profiles for a group of  $\mu$ -CHPs. Therefore, the simultaneous power output that these devices will deliver at a certain moment must be captured by the model. These model requirements lead to the flow chart for modelling the daily profiles as presented in Figure 5.4.

In Step 1 and 2 the input is defined and the heat demand is converted to the generated electrical energy of a  $\mu$ -CHP delivered on a day ( $E_e$ ). In the example shown in the figure, the average heat demand of a Dutch household with an annual gas demand of 12.500 kWh on a day with an average temperature of  $-4.5^\circ\text{C}$  is used<sup>1</sup>. In Step 3 a profile for a single  $\mu$ -CHP is constructed in which only a distinction is made between the minimum (0) and maximum ( $P_{e\ max}$ ) output of the  $\mu$ -CHP. To model the profiles, it is determined for every 15 minutes if the  $\mu$ -CHP is delivering power or not. The number of times the  $\mu$ -CHP is delivering power ( $k$ ) follows from:

$$k = \frac{E_e}{P_{e\ max} \cdot \Delta t} \quad (5.1)$$

in which  $\Delta t = 0.25$  hour. The profiles follow the heat demand of the household but are also partly random because they are subject to random customer behaviour (the thermostat settings can be adjusted by the residents on a daily basis). Therefore a chance  $p$  is introduced that is defined by the heat demand profile and includes a random component  $a$ ; the values of  $a$  are drawn from the standard uniform distribution on the open interval (0,1):

$$p(t) = a \cdot \frac{P_{th}(t) \cdot \Delta t}{E_{th}} \quad a \in \mathbb{R}(0, 1) \quad (5.2)$$

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<sup>1</sup>For the Netherlands normalised daily profiles for the gas demand for space heating of residential consumers are available based on data of 400 households [35]. With the annual gas demand per residential consumer and a given outside temperature, the heat demand profiles can be determined for every day of the year.

In Equation 5.2,  $P_{th}(t)$  is the thermal power demand at time  $t$  and  $E_{th}$  the total heat demand over the day. Now, an individual profile can be constructed by determining for every 15 minutes (96 quarters) if the  $\mu$ -CHP is generating electricity:

$$P_e(t) = \begin{cases} 1 & \text{if } p(t) > \frac{96-k}{96} \\ 0 & \text{else} \end{cases} \quad (5.3)$$

The final step in the modelling is to create the aggregated profile of  $n$   $\mu$ -CHPs by summing up  $n$  individual profiles. In Figure 5.4 the aggregated profiles are shown for various values of  $n$ .

#### *Validation*

For the 8  $\mu$ -CHPs which were analysed, the gas demand in  $m^3$  has been measured for 15-minute intervals. These data are converted with the lower heating value of natural gas (31.65 MJ/ $m^3$ ) to the average heat demand  $P_{th}(t)$  in kW. With the known rated thermal and electrical powers of the  $\mu$ -CHPs, an aggregated profile can be created by the model. In Figure 5.5a the measured as well as the modelled profile of the generated power by 8  $\mu$ -CHPs on a certain day are shown.

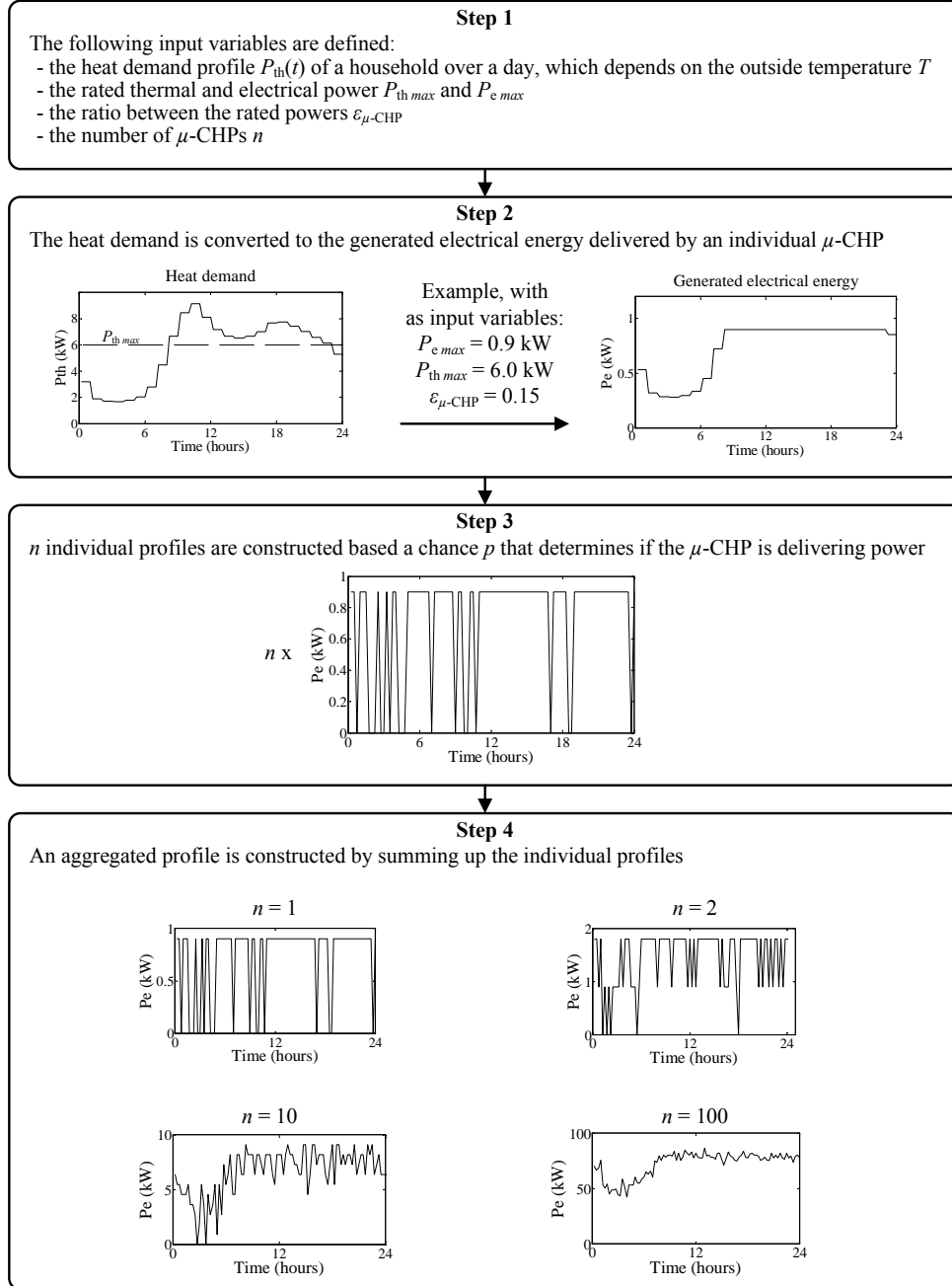
Only measurements of 8  $\mu$ -CHPs are available. Therefore, to compare an aggregated profile for a larger number of  $\mu$ -CHPs as constructed by the model, 61 daily profiles of each of the 8  $\mu$ -CHPs (measured during the two coldest months) are treated as daily profiles of 488 individual  $\mu$ -CHPs. The daily profile of the sum of the generated power of these 488 measured profiles is compared to the aggregated profile of 488  $\mu$ -CHPs constructed by the model. In this case the heat demand over a day for one household  $P_{th}(t)$  which is used as input, is derived from the average measured gas demand profile (on a 15-minute time base) over these 61 days. Both the measured and the modelled profile are depicted in Figure 5.5b.

The profiles show a good resemblance with the measurements, especially for a larger  $n$ . Table 5.1 gives the peak values found in the measurements and the model. It can be noticed that for  $n = 8$  the output of the model is based on the possibility that the maximum capacity at a certain time is 8 times the maximum output ( $8P_{e\ max} = 8$ ). Although this value was not reached during the measurement period, this value can be approximated on extreme cold days. The difference for  $n = 488$  between the measured and the modelled peak is smaller (7%) than for  $n = 8$ , because the chance of simultaneous maximum output by the  $\mu$ -CHPs is smaller for larger  $n$  (this is also represented by the difference in smoothness between the measured profiles in Figure 5.5).

### **Modelling load profiles of heat pumps**

#### *Analysis of measurement data*

Measurements of daily load profiles of 7 different types of heat pumps at 6 different locations are analysed and compared; the measurements concern several individual heat pumps as well as groups of heat pumps in new neighbourhoods. The heat

Figure 5.4: Flow chart of profile modelling for  $n$   $\mu\text{-CHPs}$ .

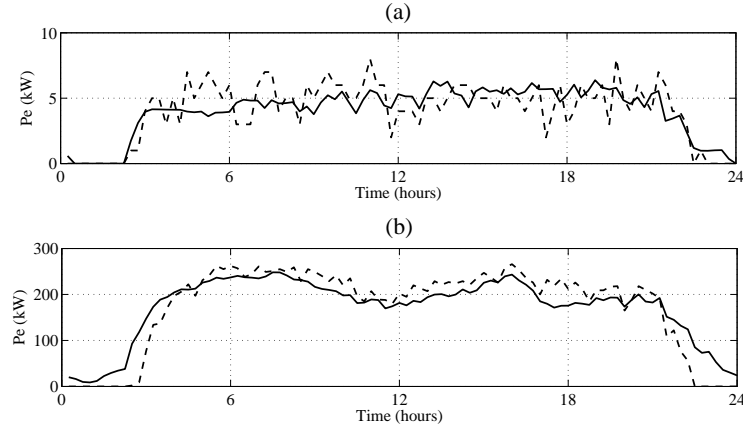


Figure 5.5: The solid lines present the measured profiles and the dashed lines the modelled, aggregated profiles of (a) 8 and (b) 488 individual  $\mu$ -CHP profiles.

Table 5.1: Peak values of the measured and modelled profiles.

	Maximum measured power (kW)	Maximum power simulated by model (kW)	Deviation
$n = 8$	6.4	8	25%
$n = 488$	284	266	7%

pumps have one or two compressor steps and in most cases possess an additional resistive heating element. One type of heat pump is only used for space heating (or cooling) as this heat pump is additional to a gas boiler which is used for heating tap water and extra heating on cold days. This heat pump has only one compressor step and no resistive heating element. In the other cases the heat pumps are applied for both space and tap water heating; these heat pumps have two compressor steps and a resistive heating element which can be used for additional heating on cold days.

The measurements show that the first compressor step is used for space heating and can have long durations. Just as described by the modelling of  $\mu$ -CHP profiles, there exists a strong relationship between the total heat demand on a day (in kWh) and the average outside temperature on that day. This can be translated into a relation between the duration of the first compressor step and the outside temperature, which is demonstrated in [88]. For different households the total heat demand can differ substantially, depending on the type of house, insulation and individual preferences and number of the residents. However, the load profile of the heat pump is not susceptible to customer behaviour on a daily basis as is the case

for  $\mu$ -CHPs, because the settings of the heat pump are fixed (after being set once by the customer). The second compressor step is used for tap water heating. The durations of the compressor steps for tap water heating are short and subject to random customer behaviour. If a resistive heating element is present, it is sometimes used for additional heating on very cold days. The application of this element not only depends on the total heat demand over a day, but it is also influenced by the possibility to store heat. Some houses are well insulated and/or many liters of hot water can be buffered; in these cases the resistive heating element is less or not at all used, unlike in houses with smaller buffer capacity to store heat.

Based on these findings, the following conclusions can be drawn concerning modelling the load profiles of heat pumps:

- The shape of the load profile of a heat pump is determined by the size (and presence) of the compressor steps  $P_1$  and  $P_2$  and the resistive heating element  $P_{\text{booster}}$ ; these values depend mostly on the type of heat pump.  $P_1$  is used for space heating (or cooling) and, if the heat pump is used for tap water heating as well,  $P_2$  is used for tap water heating.  $P_{\text{booster}}$  is sometimes used for additional heating on cold days.
- If the compressor step is used for space heating ( $P_1$ ), the duration can be long. The total time the compressor is operating depends on the total heat demand on the day (in kWh). The timing of the steps does not follow the heat demand profile and is not subject to customer behaviour; the measurements show that these compressor steps are randomly spread throughout the day.
- If the compressor is used for hot water ( $P_2$ ) the durations of operating are short and random.
- The use of the resistive heating element  $P_{\text{booster}}$  depends on the amount of the heat demand and the available buffer capacity of the house to store heat.
- The total load of the heat pump depends on the total heat demand for space and tap water heating of a household (in kWh) and on the efficiency of the heat pump described by the coefficient of performance (COP), which is the ratio between the heat delivered and the electrical energy used by the heat pump.

#### *Developed model*

For heat pumps a similar model is developed as for the  $\mu$ -CHPs that includes the different characteristics of heat pumps. Just as for  $\mu$ -CHPs, the model must capture the aggregated (peak) load of a group of heat pumps. The model is presented in Figure 5.6.

In Step 1 and 2 the input variables are defined and the heat demand is converted to the electrical energy demand of the heat pump for the compressor steps and the resistive heating element. The heat demand given in the example in the flow chart is

the average heat demand for a household of the Netherlands, with both a component for space heating (dependent on the outside temperature) and a component for tap water heating (independent on the outside temperature)<sup>2</sup>. Since the heat buffer capacity of a house influences the application of the booster element, a variable  $\alpha$  is used to describe the buffer capacity of a house. The buffer capacity is maximal if  $\alpha = 1$ ; in this case the resistive heating element, if present, will only be used if the first compressor step is not delivering enough heat for space heating while functioning 24 hours a day. If the buffer capacity of the houses to store heat is less, a different value for  $\alpha$  ( $< 1$ ) is used; in this case the booster element will be used more. In Step 3 the profiles are constructed; two example profiles are given in the flow chart. These profiles are for the same type of heat pump applied at houses with equal heat demand, but with different values for  $\alpha$ . In the first case, the resistive element is not applied and the compressor is delivering enough heat for the house; in the second case the booster element is applied although the compressor is not operating 24 hours a day. By applying various values for  $\alpha$ , the model is able to resemble the variability that was observed in the measurements between the number of times the booster element was used at different houses. The modelled profiles reproduce the power peaks of the heat pump ( $P_1$ ,  $P_2$  and  $P_{\text{booster}}$ ) and the total load of the heat pump. The time steps are defined in 15-minute intervals. The number of 15-minute time steps for the compressor steps  $P_1$  and  $P_2$  and the booster element  $P_{\text{booster}}$  are given by:

$$k_{P_1} = \frac{E_{P_1}}{P_1 \cdot \Delta t} \quad (5.4)$$

$$k_{P_2} = \frac{E_{P_2}}{P_2 \cdot \Delta t} \quad (5.5)$$

$$k_{P_{\text{booster}}} = \frac{E_{P_1}}{P_{\text{booster}} \cdot \Delta t} \quad (5.6)$$

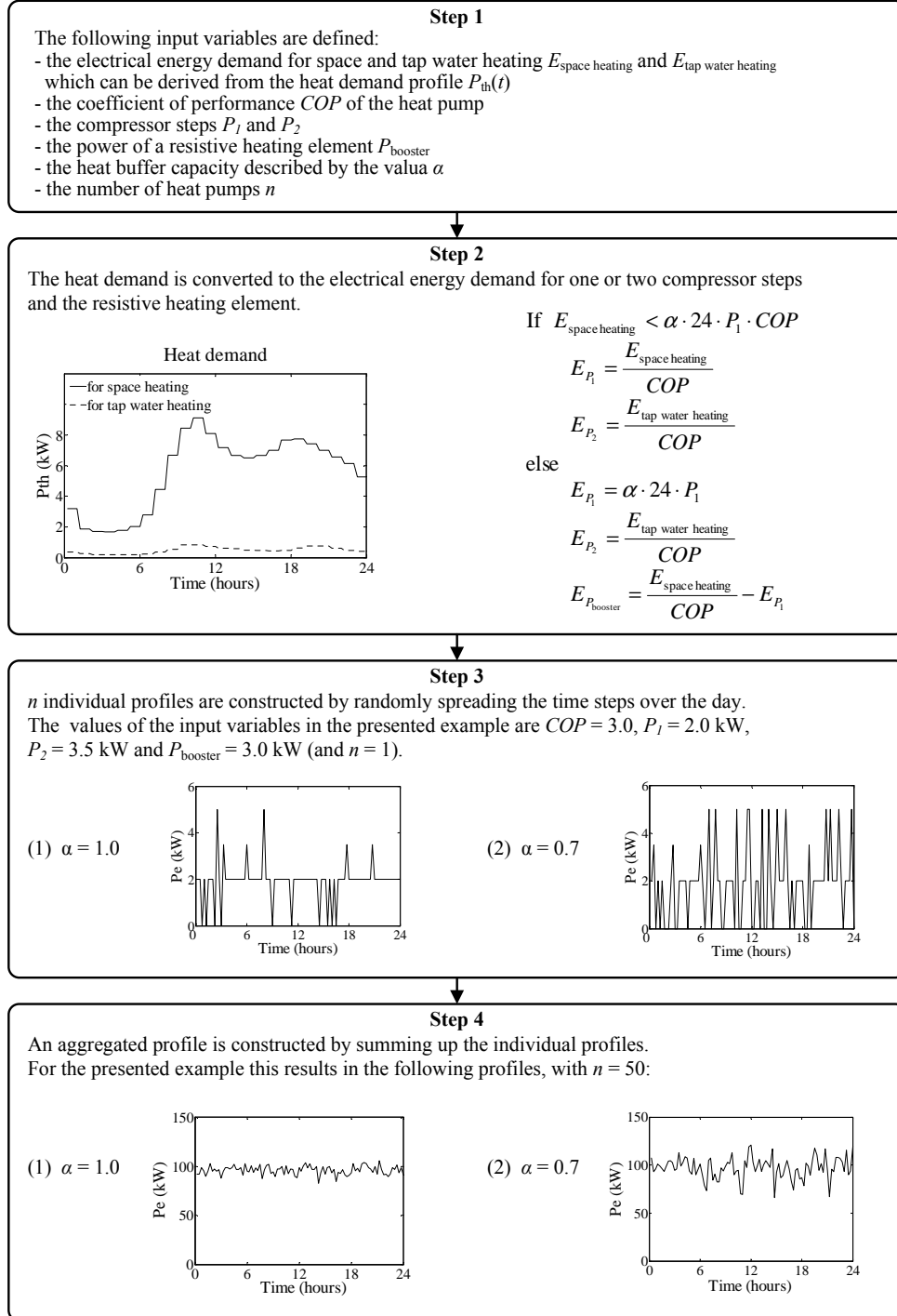
in which  $\Delta t = 0.25$  hour. An individual heat pump profile is constructed by randomly spreading these time steps throughout the day, resulting in  $n$  different profiles. The final step in the modelling is again to create the aggregated profile of  $n$  heat pumps by summing the individual profiles. In the flow chart, this is presented for  $n = 50$  for the same two examples as were shown in Step 3.

#### Validation

Figure 5.7 shows the graphs of measurements for three different heat pumps on a cold winter day. Besides the measured profiles, profiles that are constructed with the model are presented. The graphs show how the model reproduces the peaks, although they may occur at other moments. In reality the peak demand of the heat

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<sup>2</sup>Just as for space heating, normalised daily profiles for the average gas demand for tap water heating are available for the Netherlands at [35]. With the lower heating value of natural gas (31.65 MJ/m<sup>3</sup>) this can be converted to the heat demand in kW.

Figure 5.6: Flow chart of profile modelling for  $n$  heat pumps.

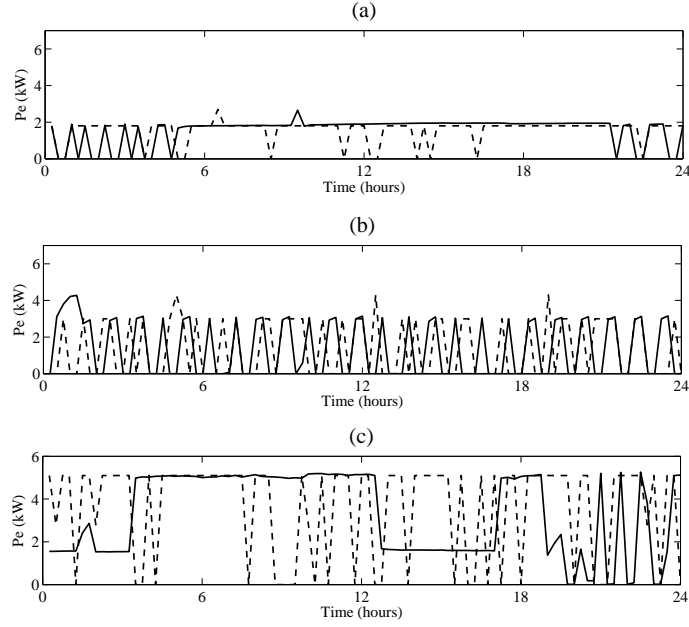


Figure 5.7: The measured (solid lines) and modelled (dashed lines) profiles of three individual heat pumps with (a)  $P_1 = 1.9$  kW;  $P_2 = 2.7$  kW (b)  $P_1 = 3.0$  kW;  $P_2 = 4.3$  kW (c)  $P_1 = 1.5$  kW;  $P_2 = 2.8$  kW;  $P_{\text{booster}} = 5.1$  kW;  $\alpha = 0.9$ .

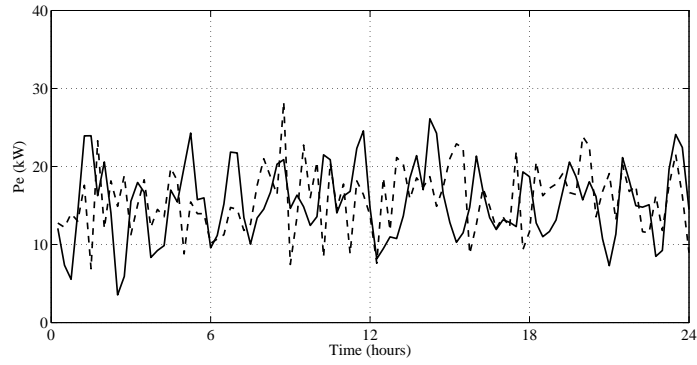


Figure 5.8: The aggregated profiles of 183 individual heat pump profiles; the solid line presents the sum of 183 measurements and the dashed line presents the profile constructed by the model ( $P_1 = 0.95$  kW and  $P_2 = 1.35$  kW).

pumps is also randomly spread over the day, so the model does not have to match the peaks of the measurements at the moments they occur on that certain day. The graphs also show that according to the modelled profiles the heat pump is switched on and off more often than in reality. However, for network planning, the peaks and possible moments of the peaks are of importance, not the duration of continuous operation of the compressors or booster element.

For three households that have the same type of heat pump, the heat demands are measured and the average daily heat demand for space and tap water heating,  $E_{\text{th space heating}}$  and  $E_{\text{th tap water}}$ , of 61 individual days (2 months) are used to model an aggregated daily profile of 183 heat pumps ( $n = 183$ ). This modelled profile is compared to the sum of the individual measured profiles of the electrical load for the three measured heat pumps on these 61 days. Both profiles are presented in Figure 5.8. The difference between the minimum and maximum load of the measured profile is 22.6 kW. Being aware of the fact that the aggregated profile is the sum of 183 individual profiles, this is relatively large compared to the measured peak (which is 28.3 kW). This is caused by the fact that the compressor steps  $P_1$  and  $P_2$  are large compared to the small average daily heat demand. The modelled profile also reproduces this: the difference between the minimum and maximum load of the modelled profile is of the same order of magnitude (21.4 kW).

For  $n = 1$  the peaks in the modelled profile will always be similar to the peaks of the measured profile, because these will be  $P_1$ ,  $P_2$  and  $P_{\text{booster}}$  (which are input variables for the model). For  $n > 1$ , the simultaneous, aggregated peak will be less than the sum of the peak power of  $n$  individual heat pumps. The simultaneity the measurements show is comparable to the simultaneity the model reproduces: the difference between the measured and the modelled peak in the case shown in Figure 5.8 (28.3 and 26.1 kW, respectively) is 8.3%.

### 5.2.3 Solar panels

The power output of solar panels depends on the sunlight availability which has strong daily and seasonal patterns. Every day the irradiance of the sun reaches its peak around noon and is zero overnight and every year the four seasons with their longer and shorter days return. Besides that, the solar radiation also depends on actual weather conditions (e.g. the presence of clouds) although there is always an amount of diffuse sunlight in daytime independent of the weather conditions. The irradiance at the PV panel also depends on the inclination angle; this is the orientation and the angle of the panel in relation to the horizontal plane (for maximal irradiance in the Netherlands the PV panels should be oriented 36 degrees south and 5 degrees west [101]). For every half hour, the maximum and minimum irradiance of the sun in the Netherlands that have been measured in the months July, having the longest days, and December, having the shortest days, are presented in Figure 5.9. It can be noticed that in the Netherlands the peak of the irradiance lies around 12 p.m. in winter and, because of advancing clocks during the summer months, in

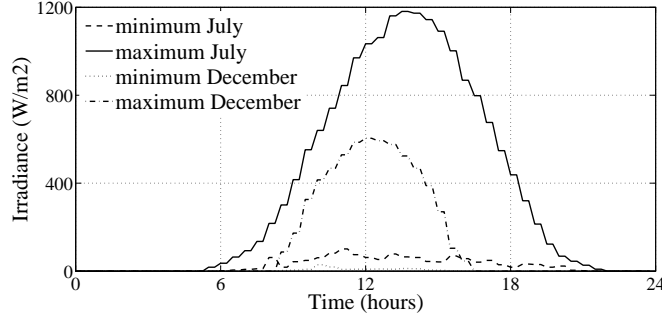


Figure 5.9: The irradiance  $I_\beta$  in the Netherlands under an angle of 36 degrees south and 5 degrees west.

summer closer to 2 p.m. The used data are obtained from [4] and contains half-hour values that are measured during one whole year. The power output of a PV panel furthermore depends on the efficiency and the area of the panel:

$$P_{PV}(t) = A \cdot \eta \cdot I_\beta(t) \quad (5.7)$$

In Equation 5.7,  $A$  is the area of the panel,  $\eta$  the efficiency of the panel and  $I_\beta$  the irradiance given an inclination angle  $\beta$  to the horizontal plane. To create an aggregated generation profile for solar panels in a residential area, the total area of the panels can be summed up and the efficiencies of the solar cells can be averaged.

The electricity generated by PV panels has a stochastic character due to the unpredictable local weather conditions, but for network planning the minimum or maximum output of the panels are of most interest. In contrast with, for example,  $\mu$ -CHPs which are mostly operating in the winter, the maximum power output of solar panels is generated in the summer around noon, if it is sunny. Besides that, the simultaneous output of PV panels in a residential area should be taken into account. Assuming simultaneous production of all PV panels connected to MV networks that cover wider areas might be a slightly conservative assumption, because simultaneous production of the maximum output of all PV panels will occur less often. Still, a cloudless day for an area that covers the Netherlands is not unrealistic.

#### 5.2.4 Electric vehicles

For the load profiles of EVs the same method is used as for the regular residential electricity use. Based on transportation data, an aggregated normalised load profile of a large number of EVs is constructed. This aggregated profile can then be scaled to represent the average load profile of a single EV or a group of EVs by multiplying

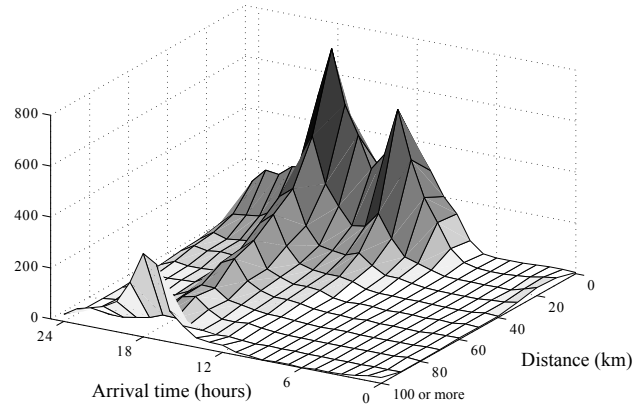


Figure 5.10: Distribution of the last home arrival times of the cars in the Netherlands (data from [106]).

it with the energy demand of the EV(s). In this section it is described how load profiles for uncontrolled charging of EVs are constructed.

### Data on driving behaviour

An extensive research on mobility (the journeys that people make from one place to another) in Netherlands compiled a large data set of individual trips by various transportation means [106]. The data are collected by means of a survey of roughly 40,000 people in the Netherlands. The data set consists of over 130,000 individual displacements (one way trips), from which approximately 40,000 are trips by car made by roughly 18,000 individual cars. The most important variables that have been used to construct the charging profiles are (for each of the 18,000 individual cars): daily driving distance, home arrival time and home departure time.

To get some initial insight into the driving patterns, Figure 5.10 shows the distribution of car trips based on daily driving distance and the time at which the *last* home arrival takes place; these are two important parameters in the construction of the charging profiles. From Figure 5.10 it can be concluded that on average, the majority of car drivers covers only modest distances. Furthermore, it can be noted that the distribution of the shorter trips shows two peaks, one around noon and one around 6 p.m. Apparently, a significant fraction of the people tend to use their car only in the morning. For most trips and especially the longer distances, the time of the last home arrival is mostly in the early evening or late afternoon. This corresponds with the expectation that most trips start from home in the morning

when driving to work and end when people return home at the end of the working day.

### Composing the charging profiles

The simplest possible charging scheme is where people plug in their EV after their last home arrival and start charging with a fixed rate until the battery is full. The energy need of a single car and thus the duration of charging depends on the daily driving distance; an EV efficiency of 5 km/kWh is assumed (see Appendix A). The profile of the power drawn by one individual EV has a block form, where the height is given by the charge rate and the beginning and endpoints are determined by the home arrival time and daily driving distance. The aggregated load of EVs with different driving distances and arrival times will be the sum of all profiles. Figure 5.11 schematically depicts this method for a fixed charge rate of 3 kW (for this rate a one-phase connection to the LV grid with a maximum current capacity of 25 A is sufficient; one of the standard connection types in the Netherlands). The aggregated profile of a large number of EVs, shown in the bottom graph of Figure 5.11, clearly correlates with the driving patterns of Figure 5.10.

For an increased charge rate of 10 kW (for this rate a three-phase connection with a maximum current capacity of 25 A per phase is sufficient), the method is identical, but a different aggregated profile will emerge, see Figure 5.12. The individual profiles of which the aggregated profile is composed have block forms that are shorter, but greater in magnitude. The aggregated profile correlates with the distribution of the arrival times even closer, because it is more smoothed out.

Similar to the normalised profiles for the regular residential electricity use, the EV charging profiles are normalised and can subsequently be multiplied with a specific energy need demand for the EV in kWh to obtain an electricity demand profile in kW. The charging profiles for charging with 3 kW as well as with 10 kW are plotted in Figure 5.13 for a daily energy need of 6 kWh, which is equivalent to 30 km, approximately the average Dutch daily driving distance. It can be observed that a charge rate of 10 kW (which more than 3 times larger than 3 kW), only results in peak that is 1.5 times larger than with charging with a 3 kW rate. This can be understood by realising that although the charge rate is much higher in case of charging with a 10 kW charge rate, there is much less overlap in the time of charging the different EVs. The profiles are in good agreement with the results of [132], where a mean peak of approximately 0.7 kW is found for the power demand per vehicle.

As it has been discussed in Section 5.2.1, aggregated demand profiles can be used for large numbers of loads, because the variability in the individual load profiles is smoothed out. This can be formulated mathematically with the use of a coincidence factor (see Section 4.2.1). By definition, the coincidence factor of an individual load is one. For large numbers of customers, the value of the coincidence factor of residential loads typically lies in the range 0.2–0.3, see e.g. [72] and [110]. These values are based on historical measurements of the regular residential electricity use.

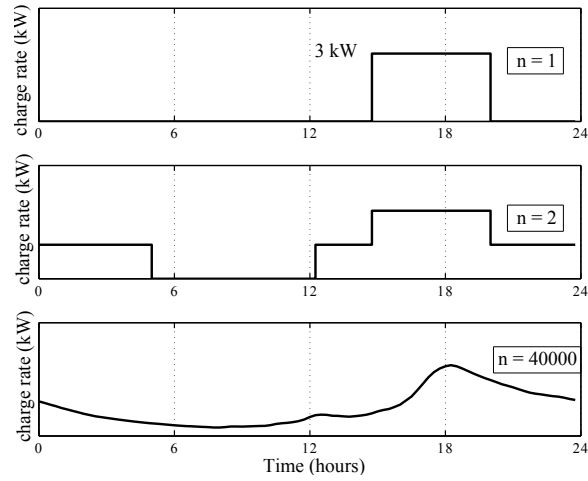


Figure 5.11: Schematic representation of composing the aggregated charging profiles from individual EV energy needs when charging with a fixed charge rate of 3 kW (uncontrolled charging).

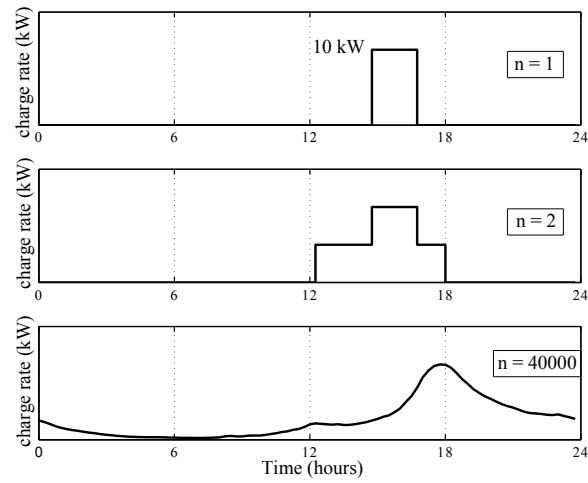


Figure 5.12: Schematic representation of composing the aggregated charging profiles from individual EV energy needs when charging with a fixed charge rate of 10 kW (uncontrolled charging).

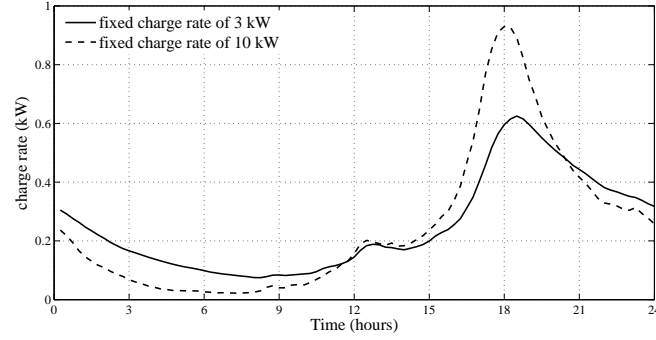


Figure 5.13: Aggregated load profiles of EVs with an average daily driving distance of 30 km charging at home with a fixed charge rate (the profiles are scaled back to the load of a single EV).

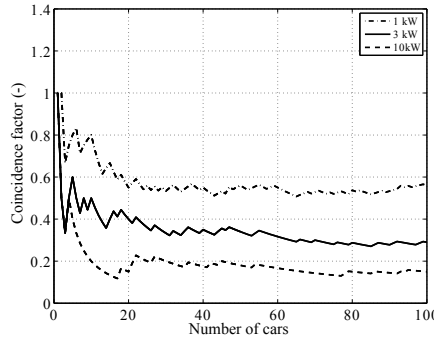


Figure 5.14: Coincidence factor as a function of the number of EVs.

Being a different load by nature, it is interesting to evaluate how the coincidence factor of EVs will depend on the number of vehicles. From this analysis it is also possible to determine for what numbers of EVs it is justified to work with the aggregated profiles. Figure 5.14 shows the coincidence factor as a function of the number of cars for three charging profiles based on various fixed charge rates. It can be concluded that after approximately 20 cars, the coincidence factor goes towards a constant value. This means that the aggregated profiles can be used for the combined load of 20 or more EVs. To consider the joint effect of a smaller number of cars, one cannot directly use the aggregated profiles. This can be solved by either relying on stochastic methods or by multiplying the aggregated profile with an appropriate factor that can in principle be determined from Figure 5.14. It is also observed that the coincidence factor shows a strong dependence on the charge rate of the

individual EVs. This is caused by the fact that the probability that multiple EVs charge at the same time is small when charging times are short.

### 5.3 Modelling flexible demands

A part of the residential demand for electricity may be flexible and shifted in time for various reasons in smart grids. The flexible part of the residential demand is defined in this section. Subsequently, two smart grid strategies that can be applied to utilise the flexibility in residential demands are described and profiles of flexible demands that follow these strategies are constructed.

#### 5.3.1 Flexible demands

To create profiles that include the flexible parts of the demand that follow certain load management strategies, first, the flexible components of the individual generation and load profiles that were treated in Section 5.2 are described.

The electricity generation of solar panels, that is dependent on sun availability, cannot be shifted in the absence of storage. Also, shifting the generation of electricity produced by  $\mu$ -CHPs is left out of consideration, because when assessing the impacts of maximum loading on the electricity networks, days with maximum generation or maximum demand are considered. And on cold winter days, when the demand is maximum, the electricity produced by  $\mu$ -CHPs cannot be shifted because the  $\mu$ -CHPs (if well-dimensioned) are continuously producing their maximum power. On a summer day, when demand is low and electricity generation by PV panels peaks, they are producing no power at all.

#### Regular residential electricity use

It is expected that in the future smart grid 10% of the regular residential electricity use for household appliances can be shifted to other times in the day through load management. This percentage is based on an extensive European research on the potential of load shifting by domestic appliances [129]. It concludes that in a region that represents Germany and Austria (comparable to the situation in the Netherlands in terms of climate and living standards), the evening peak is for almost 50% caused by dish washing, and laundry washing and drying. The study also concludes that 10–30% of the power demand of these appliances may be shifted to other times of the day by DSM.

#### Heating technologies: heat pumps

The electricity demand for the compressor of well-dimensioned heat pumps cannot be shifted on (very) cold days, because the compressors that are used to provide basic heat demand are continuously functioning during these days. Especially on a

very cold winter day with maximum demand (for which the grid must be dimensioned), this will be the case. In case of ground source heat pumps that are expected to be mainly applied in newly developed areas, where no gas networks are present, a resistive heating element is present for additional heating on very cold days. Measurements show that this element is only used for short periods and that its use depends on the capability of the house to store heat [138]. In [148] the thermal capacities of various house types are determined. It is shown that under extreme Dutch winter conditions it takes more than an hour (90–130 minutes, depending on the type of house) for the indoor temperature to decrease with 1 degree Celsius in existing houses that are not well-insulated and that under normal Dutch winter conditions in well-insulated newly built houses this takes at least 7 hours (450–760 minutes, depending on the type of house). In the case of well-insulated newly built houses under extreme winter conditions, the temperature loss in the houses will be somewhere in between these two values. This makes it a valid assumption to state that all types of newly built houses in the scenarios described in Section 3.5 have enough capacity to store heat for at least a few hours and that it is possible to shift the additional heating and thus the electrical demand of the resistive heating element to another point in time.

### Electric vehicles

The greater part of the demand for charging EVs is flexible, because generally speaking the time the cars need to be charged is less than the EVs are at home and connected to the grid. In this thesis, the total demand of EVs is considered as flexible demand. This type of demand is subject to some constraints though. The assumption is made that EVs are connected to the grid when people are at home and a condition for the applied control strategies is that the EVs must be fully charged before the next departure moment.

#### 5.3.2 Smart grid strategies

In this thesis, the impacts of two different smart grid strategies on the utilisation of distribution networks are investigated. The first smart grid strategy is based on a grid-oriented smart grid concept, as introduced in Section 2.4, in which the smart grid functionalities are related to the responsibilities of the network operator. With this strategy the flexibility in residential demands is enabled to reduce peak loads such that network utilisation is improved and necessary network reinforcements are reduced. From the perspective of the network operator, this will be the optimal strategy. It may, however, lead to suboptimally functioning of the electricity market and thus to higher electricity supply prices for the user. The second smart grid strategy is based on a market-oriented smart grid concept which aims at enabling residential customers to participate in the electricity market by introducing more advanced pricing schemes. This strategy will be facilitated by an electricity provider

or another commercial party to minimise the electricity supply costs and comes down to offering cheap electricity to flexible demands at moments with low prices at the wholesale market. Commercial parties benefit from this strategy, but it may lead to additional costs for the network operator. How these two strategies, referred to as *minimising network load* and *minimising electricity supply costs*, change residential profiles will be investigated in this section. In Section 5.4 examples are given of the resulting profiles following these strategies.

### Minimising network load

With this strategy the flexible demand in residential areas is shifted from moments of high loading to off-peak moments; this will lead to more flattened load profiles. To construct daily profiles the function  $f(t)$  is used to spread the flexible demand from the peak to other times in the day:

$$f(t) = C - \frac{P_{\text{total}}(t)}{P_{\text{total max}}} \quad (5.8)$$

In Equation 5.8,  $P_{\text{total}}(t)$  is the total inflexible load at time  $t$  (the total load minus the load of the flexible demand which is shifted) and  $P_{\text{total max}}$  is the maximum value of the total inflexible load on that day.  $C$  is a constant that determines how much of the flexible demand can be served during the peak moment. Under the condition that all flexible load can be served during off-peak hours, the peak of the new total load is never higher than the peak of the total inflexible load if  $C = 1$ . To study the effect of e.g. a group of EVs connected to a distribution cable, it seems closer to reality to assume that not all connected vehicles can be controlled perfectly. Therefore, a value of  $C = 1.1$  is chosen here. This means that 10% of the peak can be used by the flexible demand at the peak moment.

This function is first applied to the flexible demand of EVs. The charge rate is in this case no longer fixed. To fulfil the energy needs of an individual car, the integral of the charge rate  $P_{\text{EV}}(t)$  has to equal the energy need corresponding to the driven distance. In the case of uncontrolled charging with a fixed charge rate that was presented in Section 5.2.4, this condition was automatically fulfilled because the duration of charging was explicitly based on that energy need. Here,  $P_{\text{EV}}(t)$  is obtained by multiplying the car's energy need  $E_{\text{EV}}$  by the function  $f(t)$ , after normalising it with its integral:

$$P_{\text{EV}}(t) = E_{\text{EV}} \frac{f(t)}{\int_{T_{\text{charge}}} f(t) dt} \quad (5.9)$$

where  $T_{\text{charge}}$  is the available charge time between home arrival and departure.

To illustrate the construction of the profiles, an example is given for a winter day in which  $f(t)$  is determined by using the normalised daily profiles for the regular electricity use in the Netherlands on December 1 as depicted in Figure 5.1. For an

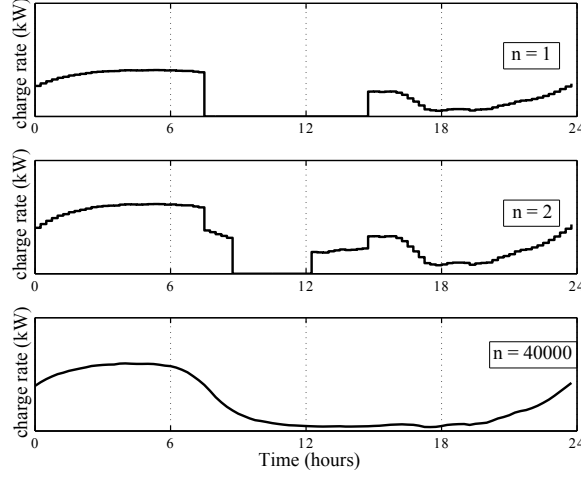


Figure 5.15: Schematic representation of composing an aggregated charging profile from individual car energy needs when applying controlled charging to reduce peak loads.

individual EV, this leads to a variable charge rate as depicted in the top graph of Figure 5.15. Analogous to the uncontrolled cases, the aggregated profile is the sum of all individual car profiles. Compared to the aggregated profiles in Figures 5.11 and 5.12, the aggregated profile in the bottom graph of Figure 5.15 clearly shows that the bulk of electricity load is now shifted in the night when loading due to the regular electricity use is low.

After constructing the load profiles of controlled charging of EVs, the profiles of the heat pumps with flexible demand for the resistive heating elements are constructed. In contrast to the charge rate of the EVs, the power ratings of the resistive heating elements of the heat pumps are fixed. The function  $f(t)$  is in these cases only used to shift the times when these demands are fulfilled. As discussed in the previous section, it is possible to shift the load of the resistive heating elements at least a few hours, and measurements showed that resistive heating elements are only used for short periods that are spread throughout the day [138]. Still, it may not always be possible to shift the load of the resistive heating elements to the preferred hours. Therefore, also in this case the value of  $C$  is chosen to be 1.1. The load profiles for  $n$  heat pumps with flexible demand for the resistive heat elements can be constructed with the model as introduced in Section 5.2.2 with the difference that the timing of the  $P_{\text{booster}}$  steps are not randomly spread, but determined by the function  $f(t)$ . For  $i = 1 : k_{P_{\text{booster}}}$ , with  $k_{P_{\text{booster}}}$  the number of 15-minute time steps for the booster element, the timing of the  $i$ -th time step is fixed at  $t_{\text{max}_i}$ , which is the moment the  $i$ -th maximum value of  $f(t)$  occurs. After constructing the individual heat pump profile with the flexible demand of the resistive heating element,  $P_{\text{total}}$

in Equation 5.8 is supplemented with the load of the heat pump. This process is repeated for all  $n$  heat pumps.

Finally, the flexible part of the regular residential electricity use that is subject to demand response, is used to shift load to off-peak moments. For the construction of the load profiles, it is assumed that the flexible demand has no further constraints. In reality, there may be moments that a part of the flexible demand will be served during the peak hours. This is again incorporated by choosing 1.1 for the value of  $C$  in Equation 5.8. The aggregated load profile of the flexible demand of  $n$  households is now obtained by:

$$P_{\text{flex demand}_n}(t) = n \cdot E_{\text{flex demand}} \frac{f(t)}{\int_T f(t) dt} \quad (5.10)$$

In Equation 5.10,  $E_{\text{flex demand}}$  is the average energy demand of the flexible part of the regular residential electricity use of one household in kWh and  $T$  the chosen interval (for a daily profile this is 24 hours).

### Minimising electricity supply costs

With this strategy the flexible residential demand is shifted towards moments with the lowest electricity prices at the wholesale market. The objective of this control strategy is to minimise the electricity supply costs for the flexible demand for a time-varying electricity price. The strategy is applied to the flexible demand for the EVs and is described by an optimisation problem. The optimisation problem that is used here, is formulated in [143] and [146].

#### *Electricity price*

For constructing the profiles, first, a future electricity price is created. This is done by taking into account the future demand and installed generation capacity that depend on the scenario that is regarded. The price signal reflects the net system load (i.e. load minus electricity generated by PV panels and wind turbines) that has to be met by the thermal plants. In this manner the important property that electricity prices tend to be low when wind power generation is high – a phenomenon already observed in countries with high penetrations of wind power such as Denmark and Germany [100] – is conserved. The formulation also takes into account that the additional future flexible loads themselves alter the electricity prices. The exact formulation of the modelled future electricity supply price used here, is adopted from [146] and briefly described in Appendix B.

#### *Optimisation problem*

To charge the flexible demand of EVs, aggregators that represent a number of EV owners have the task to charge the EVs while taking into account the driving patterns of the EV owners. The aggregators buy power against a time-varying price based on the day-ahead price (see [146]). The market prices are modelled to depend linearly

on the total electricity demand, that includes the inflexible electricity demand as well as that of the flexible demand of EVs. The demand for electricity over a time interval  $t$  is given by:

$$P_t = P_{\text{inflexible},t} + P_{\text{EV},t} \quad (5.11)$$

where  $P_{\text{inflexible},t}$  is the inflexible demand and  $P_{\text{EV},t}$  the additional demand for charging EVs.

If the market price of electricity is assumed to be some function of the demand,  $\lambda_t = f(P_t)$ , then a first order Taylor approximation of the electricity price at a certain time interval is given by:

$$\lambda(P_t) \approx \lambda(\bar{P}) + \frac{d\lambda}{dP}(\bar{P})(P_t - \bar{P}) \quad (5.12)$$

where the overbar denotes averaging over the time interval under consideration. After substitution of Equation 5.11, Equation 5.12 can be written as:

$$\lambda_t = \alpha_t + \beta P_{\text{EV},t} \quad (5.13)$$

with

$$\alpha_t = \lambda(\bar{P}) + \frac{d\lambda}{dP}(\bar{P})(P_{\text{inflexible},t} - \bar{P}) \quad (5.14)$$

$$\beta = \frac{d\lambda}{dP}(\bar{P}) \quad (5.15)$$

The coefficient  $\beta$  represents the sensitivity of the electricity price to the demand and is estimated by using the exponential fit of the merit order that includes future installed generation capacity (see Appendix B). With these assumptions, the optimisation problem takes the following form:

$$\min_{P_{\text{EV},t}} \sum_t \lambda_t P_{\text{EV},t} = \min_{P_{\text{EV},t}} \sum_t (\alpha_t P_{\text{EV},t} + \beta P_{\text{EV},t}^2) \quad (5.16)$$

This is a quadratic programming problem. Solving this optimisation problem yields the load profiles of the flexible demand to which the strategy is applied.

#### Constraints

When solving this optimisation problem, some constraints must be taken into account for charging of the EVs. The same constraints are applied as described in [146]. The (power) demand for EVs over a period  $t$  in Equation 5.16 can be written as:

$$P_{\text{EV},t} = \sum_i P_{\text{EV}_i,t} \quad (5.17)$$

with  $P_{\text{EV}_i,t}$  the charge rate of the  $i$ -th vehicle during time  $t$ . Now, the optimisation problem defined by Equation 5.16 can be solved subject to the following constraints:

$$E_{\min_i} \leq E_{\text{EV}_i,t} \leq E_{\max_i} \quad (5.18)$$

$$P_{\min_i} \leq P_{\text{EV}_i,t} \leq P_{\max_i} \quad (5.19)$$

with  $E_{\text{EV}_i,t}$  the battery state of charge of the  $i$ -th vehicle at time interval  $t$ . The battery parameters  $E_{\min_i}$ ,  $E_{\max_i}$ ,  $P_{\min_i}$ ,  $P_{\max_i}$  are given for each EV. The battery state of charge is given by:

$$E_{\text{EV}_i,t} = E_{\text{EV}_i,t-1} + \eta_i P_{\text{EV}_i,t} \Delta t - d_{i,t} \quad (5.20)$$

in which  $\eta_i$  the battery efficiency,  $\Delta t$  the duration of the time interval, and  $d_{i,t}$  the reduction in the battery state of charge due to driving. This equation can be used to express the constraint defined in Equation 5.18 in terms of the optimisation variables  $P_{\text{EV}_i,t}$ . The values of  $d_{i,t}$  are given by the travel distance and the efficiency of the EV.

A last constraint that has been added is an inequality constraint to make sure the battery state of charge at the end of the optimisation horizon, denoted with time  $T$ , is at least as full as at the beginning:

$$x_{i,T} \geq x_{i,0} \quad (5.21)$$

Load profiles that result from solving the optimisation problem are presented in Section 5.4. The optimisation period that is chosen for the optimisation is one year. Note the difference with the strategy to minimise network load: this latter strategy has as goal to reduce peak loads on certain *days* with maximum generation or maximum demand. For optimisation, a so-called rolling horizon optimisation scheme is used. This means that the optimisation problem is solved for a period of 5 days, then the control actions for the first day are implemented, then the horizon is moved one day, etc.

## 5.4 Aggregated residential net load profiles

In the previous sections it has been described how the profiles of individual load and generation elements and the flexible demand components are constructed. These individual profiles are combined to construct the aggregated net load profiles for the residential areas in the three scenarios that were presented in Section 3.5. In these scenarios ten typical residential areas are distinguished that have different penetration degrees of various technologies. For each of these areas the aggregated net load profile is constructed by summing up the individual profiles of the technologies. In this section, some examples are given of the resulting aggregated profiles of these residential areas for the situation without management of flexible demand, and for applying the minimising network load and minimising electricity supply costs smart

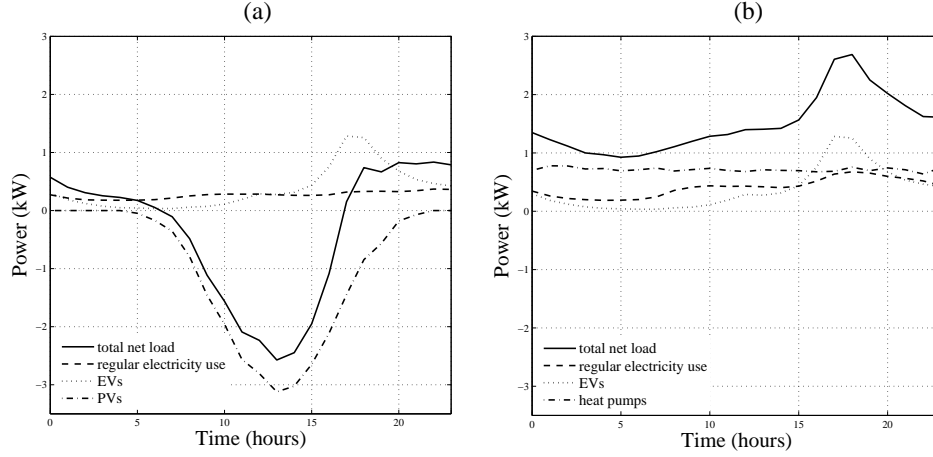


Figure 5.16: The aggregated demand and individual load and generation profiles of a newly developed, very high densely populated neighbourhood in Scenario C during (a) summer time with maximum generation and minimum load and (b) winter time with minimum generation and maximum load (the profiles are scaled back to one household).

grid strategies. The profiles of all ten typical areas in the three scenarios can be found in Appendix C.

#### 5.4.1 No smart grid strategy

For capacity planning of electricity networks the worst case situations are of most interest; these are the situations when there is either maximum generation or maximum demand. This can be a situation in the summer when there is much generation by solar panels and very low demand or a situation in the winter on a cold, cloudy day when heat demand is large and there is no generation by solar panels. In Scenario C, the share of PV generation in residential areas is the largest. In Figure 5.16a the profile of the residential area with the largest share of solar panels in summer time is presented (negative demand means that surplus power is fed back into the grid). The EVs are charged with a fixed 10 kW charge rate. In Figure 5.16b, the profile of the same area in winter time is presented. The individual profiles of the new technologies as they are expected in this area as well as the aggregated net load of the residential area are depicted. It can be seen that the absolute value of the peak load in the winter is larger than the absolute value of the maximum generation when generation peaks in the summer and that even with this large share of PV generation the highest peak will occur in the winter. This applies to all residential areas studied in this thesis.

Table 5.2: Properties of two typical residential areas in Scenario C.

	Existing area	Newly developed area
Population density (households/km <sup>2</sup> )	> 2500	1500-2500
Annual demand for the regular electricity use per household (kWh)	2020	2330
Penetration degree heat pumps (%)	34	66
Heat pumps – $P_1$ (kW)	0.5	1.0
Heat pumps – $P_{\text{booster}}$ (kW)	–	4.9
Penetration degree $\mu$ -CHPs (%)	37	–
$\mu$ -CHPs – $P_e$ (kW)	1.0	–
Average area PV panel per house (m <sup>2</sup> )	3.4	6.6
Average efficiency PV panels – $\eta$ (%)	17	20
Penetration degree EVs (%)	78	78
Average daily driven distance per household (km)	36	39

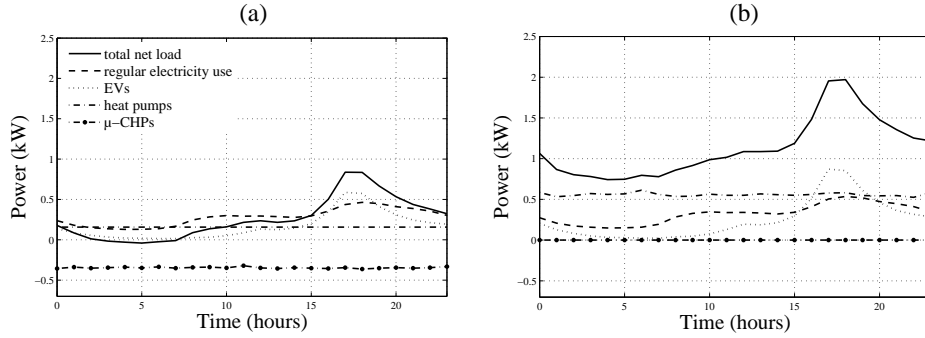


Figure 5.17: The aggregated net load profiles and the individual load and generation profiles of (a) an existing neighbourhood and (b) a newly developed area in Scenario C on a winter day (scaled back to one household).

Besides differences between profiles in summer time and winter time, the profiles of various residential areas can be different due to differences in the penetration degrees of new technologies. For instance, the parameters of two of the ten typical residential areas in Scenario C are listed in Table 5.2. In the Netherlands many houses have a connection to the gas network. However, newly developed areas are often built without gas networks and with heat pumps for heating. On the other hand, in an existing neighbourhood, gas networks may still exist and  $\mu$ -CHPs may be the heating technology of choice. In the existing area presented in Table 5.2, also

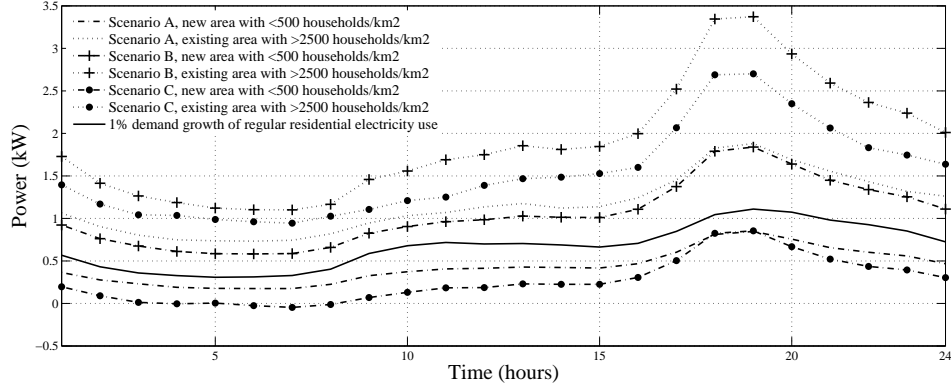


Figure 5.18: Aggregated residential net load profiles in 2040 for the three scenarios and various residential areas on a winter day (scaled back to one household).

some heat pumps are expected. These are air source heat pumps that are combined with an auxiliary burner that works on natural gas and is used for extra heating on cold days. Also, the existing area as presented in Table 5.2 is more densely populated than the newly developed area presented here and has a lower annual electricity demand per household (smaller houses) and a shorter daily distance driven per car. Using these parameters and applying the proposed modelling approach presented in this chapter results in the two aggregated net load profiles depicted in Figure 5.17.

The variation in the electricity demand in the ten typical residential areas in the three scenarios is presented in Figure 5.18. For each scenario the winter profiles of two residential areas, the area with the lowest and the area with the highest demand, are presented. Also, for reference, the profile of an average household with a current annual electricity demand of 3400 kWh, and assuming a demand growth of 1% per year, is presented. The figure shows that the average peak demand of one household can vary between 0.84–1.87 kW in Scenario A, between 1.83–3.32 kW in Scenario B and between 0.84–2.69 kW in Scenario C, depending on the type of residential area.

#### 5.4.2 Minimising network load

To illustrate how the load profiles change after modelling the flexible parts of the demand that follow the smart grid strategy to minimise network load as introduced in Section 5.3.2, the modified load profiles are again presented for the two residential areas in Scenario C with the parameters presented in Table 5.2. In Figure 5.19, the profiles are depicted in case of using the flexibility of the demand for the EVs, the additional heating elements of the heat pumps and 10% of the regular residential

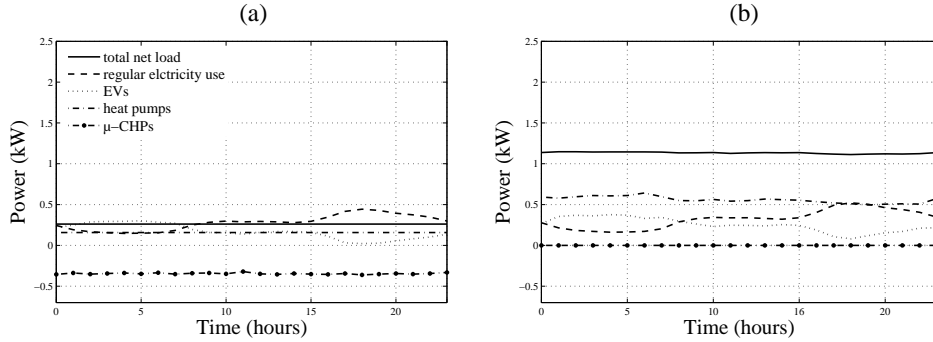


Figure 5.19: The aggregated net load profiles and individual load and generation profiles of (a) an existing neighbourhood and (b) a newly developed area in Scenario C in case of mobilising flexible load of EVs, heat pumps and a part of the regular residential regular electricity use to minimise network load on a winter day (scaled back to one household).

electricity use of households to shift load to off-peak periods.

When comparing the individual profiles with the profiles in Figure 5.17, it can be seen that in the case of the minimising network load strategy a large part of the EVs is now charged during the night instead of during the evening peak. Furthermore, it can be noted that in the existing neighbourhood no change is found in the profile for the heat pumps in spite of the applied strategy. This is caused by the fact that the heat pumps are operating on their maximum power all day long which leaves no space for shifting demand; however, in the newly developed areas some control of the heat pumps can be applied by switching on the resistive heating elements earlier in the day and not during the evening peak. The profiles of the regular electricity use changed a little, because 10% of this demand is shifted.

### 5.4.3 Minimising electricity supply costs

With this strategy flexible EV demands are supplied at moments with low electricity prices. These are typically moments when electricity production by intermittent sources is high and/or electricity demand is low. The resulting load profiles of the flexible EV demand on five random days are presented in Figure 5.20. It can be seen that in Scenarios A and B, the load for the EV is mainly supplied during night hours. This can be explained by the fact that in Scenarios A and B the shares of electricity produced by intermittent wind and solar energy are relatively low and do not influence prices that much, resulting in flexible demand being supplied during night hours when the demand is low. In Scenario C substantial more wind and PV capacity is installed in 2040 and prices tend to be low at moments when electricity production by intermittent sources is high and the flexible demand is shifted to these

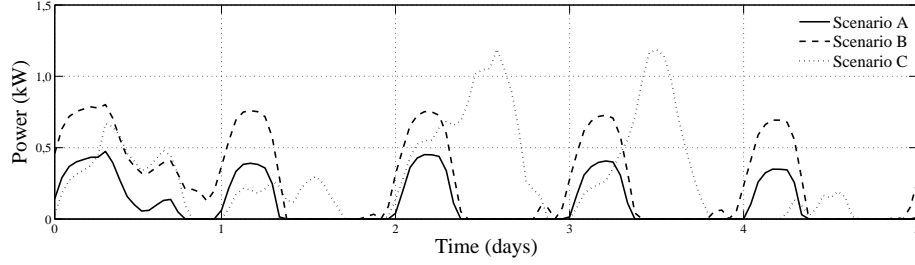


Figure 5.20: The load profiles of the flexible EV demand in the case of a minimising electricity supply cost strategy in the three scenarios for five (random) days (scaled back to one household).

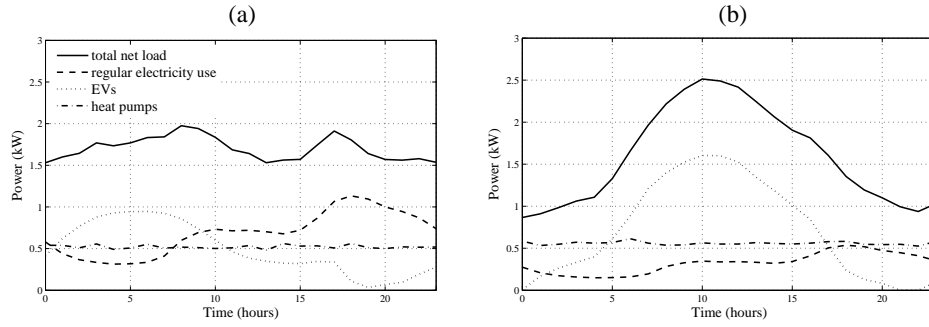


Figure 5.21: The aggregated net load profiles and individual load and generation profiles of a newly developed residential area with 1000-1500 households/km<sup>2</sup> (a) in Scenario B and (b) in Scenario C in case of mobilising flexible load of EVs to minimise electricity supply costs (scaled back to one household).

moments. Also, the fact that the average annual electricity demand for the EVs per household in Scenario A is only 944 kWh compared to 2335 kWh and 2340 kWh in respectively Scenarios B and C, is reflected in the load profiles.

The profiles of the flexible EV demand are combined with the profiles of the inflexible demand to construct load profiles of residential areas. In Figure 5.21, the aggregated net load profiles are depicted for the newly developed residential in Scenario C with the parameters that were presented in Table 5.2 and for a similar residential area in Scenario B. In both cases the days are presented when the aggregated net load peaks. Due to shifting of flexible demands to moments with low prices, peak loads do not necessarily occur on winter days with high inflexible demand and low generation, in contrast with the profiles presented earlier.

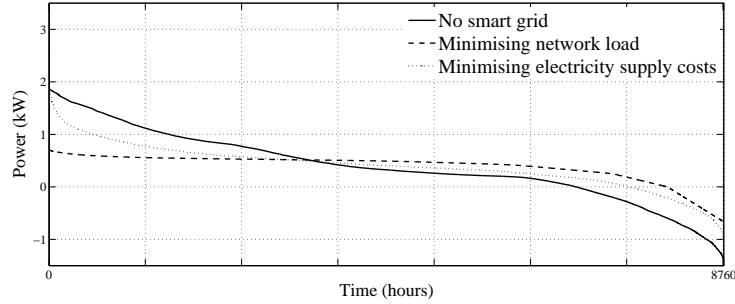


Figure 5.22: The load duration curve for an average household in Scenario C.

#### 5.4.4 Change in peak loads

The values of the peak load and of the contributions of the individual elements during the peak moment are summarised in Table 5.3. Only the values of the residential areas with the minimum and maximum demand are given; in Appendix C the profiles of all ten typical residential areas in the three scenarios can be found. The current average annual electricity demand of one household in the Netherlands is about 3400 kWh. The conventional network planning method assumes unchanged shape of the load profiles and a yearly growth of 1% for the residential electricity demand. This results in an expected average electricity demand of about 4500 kWh in 2040 and average peak values between 0.89–1.30 kW per household (for the ten typical residential areas). The average electricity use (with additional demand for new technologies and decentralised generation of electricity) is about 4400 kWh, 9200 kWh and 3500 kWh in Scenarios A, B and C, respectively. Comparing the values of the (aggregated) peak of the total net load, shows that even though the average electrical energy demand per household decreases in Scenarios A and C compared to the expected demand in the reference case, the peak loads increase.

Also, the load duration curve of an average household in Scenario C is presented for a whole year in Figure 5.22 (the load duration curves of all three scenarios can be found in Appendix D). The load duration curve equals the load profile, but the data are ordered in descending order of magnitude, rather than chronologically. The negative values present the moments load is delivered back to the grid. In Table 5.4 the percentages are presented of the number of hours that the load is higher compared to the load when the minimising network load strategy is applied. For Scenario C, it can be noted that even though the peak in the case of applying the minimising electricity supply costs strategy is higher than in the case of applying no smart grid strategy, the number of hours that the peak is higher than the load when the minimising network load strategy is applied is lower.

These results show that only in a limited number of hours the network loading

Table 5.3: Values of the (aggregated) peak of the total net load and the individual load and generation elements per scenario. Only the minimum and maximum values of the ten typical residential areas are presented.

	No smart grid (kW)	Minimising network load (kW)	Minimising electricity supply costs (kW)
Scenario A			
Total load	0.84–1.87	0.57–1.20	0.69–1.72
Regular residential electricity use	0.63–0.92	0.58–0.89	0.33–0.42
$\mu$ -CHPs	-0.10–0	-0.10–0	-0.10–0
Heat pumps	0.02–0.49	0.03–0.27	0.02–0.42
EVs	0.24–0.52	0.01–0.04	0.38–0.82
Scenario B			
Total load	1.83–3.32	1.22–1.95	1.43–2.68
Regular residential electricity use	0.98–1.43	0.90–1.36	0.52–1.35
$\mu$ -CHPs	-0.11–0	-0.11–0	-0.11–0
Heat pumps	0.32–0.71	0.32–0.45	0.32–0.66
EVs	0.59–1.28	0.04–0.10	0.23–1.26
Scenario C			
Total load	0.84–2.69	0.26–1.52	1.21–3.53
Regular residential electricity use	0.46–0.68	0.44–0.66	0.30–0.44
$\mu$ -CHPs	-0.54–0	-0.54–0	-0.54–0
Heat pumps	0.16–0.78	0.16–0.69	0.16–0.74
EVs	0.59–1.28	0.02–0.12	1.08–2.36

Table 5.4: Percentage of the number of hours that the load is higher compared to the load when the minimising network load strategy is applied.

	No smart grid (%)	Minimising electricity supply costs (%)
Scenario A	19.4	7.7
Scenario B	11.7	0.3
Scenario C	31.2	17.7

is higher than when using the flexible residential demand to minimise the network loading. In other words, the minimising network load strategy does not have to be applied during all hours of the year to reach the advantages of decreased peak loads in reduced network investments. In the off-peak hours, another smart grid strategy (such as the minimising electricity supply costs strategy) may then be applied. In this thesis, the impacts of applying either a grid-oriented or a market-oriented smart grid strategy are investigated. Developing the grid towards one of these directions or possibly a combination of these directions will further be discussed in Chapter 7.

## 5.5 Summary and conclusions

The modelling approach that is introduced in this chapter, combines individual load and generation profiles to construct aggregated net load profiles of a group of households. First, the load and generation profiles of the regular electricity use,  $\mu$ -CHPs, heat pumps, PV panels and EVs are separately modelled. This makes it possible to assess the impact of various future scenarios on the electricity distribution networks by applying different penetration degrees of each technology. Besides this, the method makes it possible to take into account demand for electricity that may be flexible and shifted in time for multiple goals in smart grids. The flexible part of the demand can be modelled separately according to the applied smart grid strategy and combined with the inflexible part to estimate the new aggregated load. This new aggregated load will have a different pattern and peak than the aggregated load profile of an area with the same technologies but without e.g. smart charging of EVs or DSM of household appliances.

The impacts of two different smart grid strategies, referred to as *minimising network load* and *minimising electricity supply costs*, on the residential load profiles are investigated in this chapter. The first smart grid strategy reflects a grid-oriented smart grid concept in which the smart grid functionalities are focused on the responsibilities of the network operator. With this strategy the flexible load in residential areas is shifted from moments of high load to off-peak moments to optimise network utilisation and reduce network reinforcements; this will lead to more flattened load profiles. The second smart grid strategy reflects a market-oriented smart grid concept that aims at enabling residential customers to participate in the electricity market by introducing more advanced pricing schemes. With this strategy the flexible demand in residential areas is shifted towards moments with low electricity prices at the wholesale market.

With the modelling approach, the net load profiles are constructed for ten typical residential areas in three scenarios that are defined in Section 3.5. Also, load profiles are constructed in case flexibility in demands is utilised according to the minimising network load or minimising electricity supply costs strategies. The resulting peak loads can be used for load-flow calculations and the impacts of various smart grid strategies can be assessed by comparing the impacts of aggregated loads with and

without shifting flexible demands in time.

Several examples of aggregated net load profiles elaborated in this way show that this method gives insight into the possible variation of future load profiles for different scenarios and for different residential areas. The examples also illustrate the effect of the two smart grid strategies on residential net load profiles. When applying no smart grid strategy or the minimising electricity supply costs strategy the peak loads are significantly higher than when applying the minimising network load strategy. The number of hours that the network loading is higher than when using flexible residential demand to minimise the network loading is, however, limited; this is especially the case for the minimising electricity supply costs strategy. This means that the minimising network load strategy does not have to be applied during all hours of the year to reach the advantages of decreased peak loads in reduced network investments. In the off-peak hours, another smart grid strategy (such as the minimising electricity supply costs strategy) may then be applied. In this thesis, the impacts of applying either a grid-oriented or a market-oriented smart grid strategy are investigated. Developing the grid towards one of these directions or possibly a combination of these directions will further be discussed in Chapter 7.



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## Impacts on medium voltage distribution networks

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### 6.1 Introduction

Smart grids can develop in various directions. In this thesis, these directions are indicated by the grid-oriented, the market-oriented and the system-oriented smart grid concept. In Chapter 5, future residential demands have been estimated so as to follow two fundamentally different smart grid strategies that match the first two smart grid concepts. The minimising network load strategy enables a higher network utilisation, thereby deferring or eliminating the need for asset reinforcements and corresponding capital expenditures, but it may lead to suboptimally functioning of the electricity market and thus to higher electricity supply costs for the user. The minimising electricity supply costs strategy aims at minimising the electricity supply costs and comes down to offering cheap electricity to flexible demands at moments with low prices at the wholesale market, but this strategy does not optimise with regard to network capacity and may lead to higher electricity distribution costs than in the case of applying the minimising network load strategy. The implications of both strategies on the distribution network will be investigated in this chapter. The impacts of the third smart grid concept, the system-oriented smart grid concept that aims at optimising the system as a whole, will lie in between the other cases.

As concluded in Section 4.4, changing load profiles not only affects the maximum loadings of the assets, but also the maximum allowable loading of the assets and energy losses. The expected maximum loadings in combination with the maximum allowable loadings, lead to the required capacities of the assets in the various cases. It can subsequently be determined which reinforcements are needed. The costs of the reinforcements and the costs of the energy losses in future grids can be combined, and conclusions can be drawn on the impacts of various smart grid strategies on the distribution network. These outcomes are relevant input for further assessment of the (societal) benefits of smart grids.

The chapter is organised as follows. First, the future loading of distribution networks is analysed by executing load-flow analyses using the aggregated residential net load profiles that are modelled in Chapter 5. In Section 6.2, the selected MV networks that are used for these analyses are presented. It is also described in this section how the loadings of the MV distribution networks that follow from the load-flow calculations are translated into the network capacities that are required for

future scenarios and the resulting reinforcement costs. Besides that, it is described how the energy losses are assessed. The results of the calculations for the three scenarios that were described in Section 3.5 are presented in Section 6.3. For each scenario three cases are compared: the case of no time-shifting of flexible loads, the case of applying the minimising network load strategy and the case of applying the minimising electricity supply costs strategy. A discussion on the results is presented in Section 6.4. In the last section, the chapter is summarised.

## 6.2 Method

In this chapter, the effects of changing load profiles on distribution networks will be assessed for future residential demands in the case of the three scenarios described in Section 3.5 and for the smart grid strategies described in Section 5.3.2. This is done by quantifying the net present value (NPV) of the cash flow of the required reinforcements and of the energy losses costs for a large set of MV networks in the Netherlands. Note that no change in loads other than residential loads is included in the analysis. In Figure 6.1 the relationships between the change in load profiles and these impacts are depicted. In this section, the set of MV networks that are used for this analysis and the procedures to calculate the various impacts are presented.

### 6.2.1 Loading of medium voltage distribution networks

The selected grids for the analysis cover networks from the 150 kV till 0.4 kV voltage level. The assets included in these networks are HV/MV transformers, 10 kV transmission and distribution cables and MV/LV transformers. The number of assets under consideration in this research can be found in Table 6.1. These numbers correspond with 48 MV networks that serve in total 920,000 residential customers. The current share of the residential load in the total peak load of these networks is 21%. In order to identify the impacts of future residential demands for various scenarios on the MV networks, the loadings of these four types of assets are estimated with load-flow calculations.

The values of voltages and currents of networks in normal steady-state operation are calculated using daily profiles of the residential loads as input with a hourly

Table 6.1: Overview of network data of 48 MV networks that are analysed.

Asset type	Number of assets
HV/MV transformers	122
MV transmission cables (10 kV)	2,664 km
MV distribution cables (10 kV)	14,002 km
MV/LV transformers	12,602

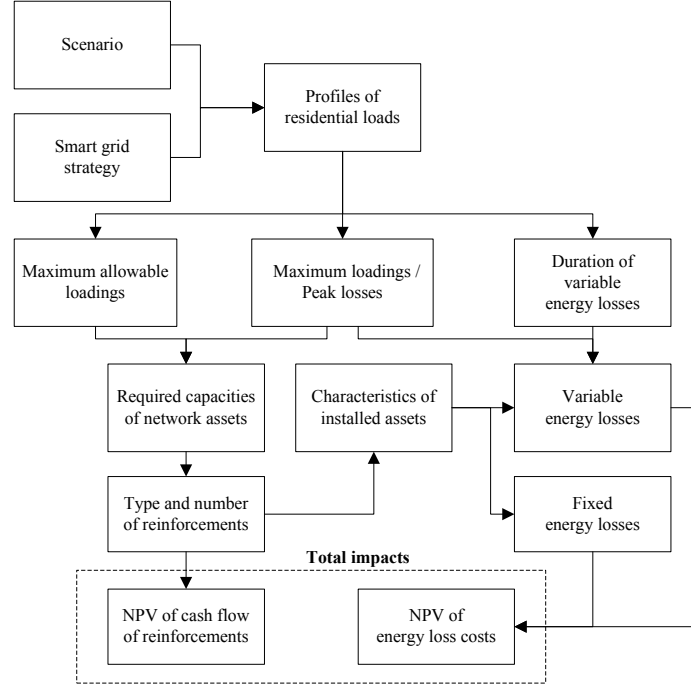


Figure 6.1: Block diagram presenting the relationship and consequences of various scenarios and smart grid strategies and their impacts on the distribution network.

resolution. For this research, the load-flow calculations are performed with the commercial package Vision [5], which uses the Newton-Raphson method to solve the load-flow equations. It is assumed that the HV side of the HV/MV transformer functions as a slack node. Loads are modelled as constant impedances to have better convergence of the load-flow algorithm (see Appendix E for more information on modelling of the aggregated residential loads for the load-flow calculations). The Vision network files are fine-tuned with recent measurements of cable and transformer loadings and coincidence factors based on these measurements. The coincidence factors are connected to each node of the MV distribution cable with a load to compensate for the fact that maximum power at the beginning of the MV distribution cables is not equal to the sum of the individual peak powers of the connected loads. Also, fictitious loads are applied to compensate for the difference in peak load at the HV/MV substation and the peak loads at the MV transmission and MV distribution cables connected to this substation. In future scenarios, the coincidence of peak demands of individual households may change due to for example a simultaneous demand for heat pumps on a cold day. This is taken into account in the way the

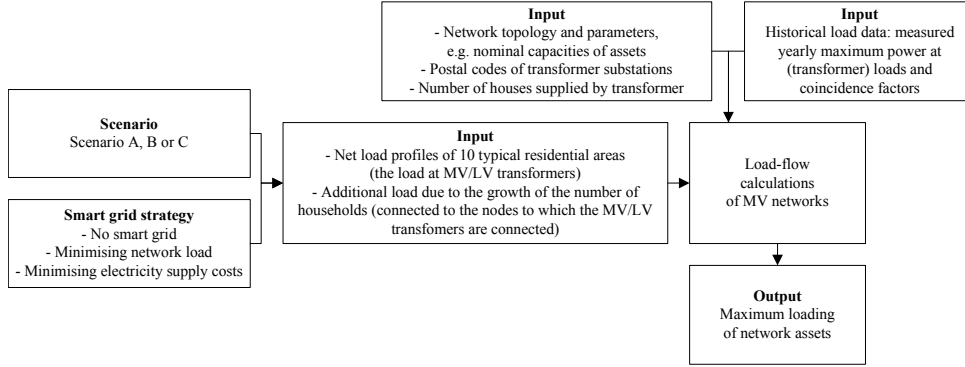


Figure 6.2: Block diagram presenting the procedure to calculate the maximum loading of network assets for various scenarios and smart grid strategies.

aggregated load profiles at the MV/LV substations are modelled. The diversity of the loads directly connected to the MV cables has not been altered for the load flows with future residential loads.

For the three future scenarios load-flow calculations are performed to calculate the maximum loading of the network assets in 2040 by altering the existing residential loads in the networks to future conditions. This procedure is presented by the block diagram in Figure 6.2. The loads at the transformer substations that supply residential areas are modified by connecting the aggregated daily profiles of the future residential loads that were modelled in Chapter 5. More precisely, the used profiles for the load-flow calculations are the profiles of the day in the year with the highest peak. The transformer substations in these networks supply on average 72 households. For the scenarios a distinction has been made between already existing and newly developed areas. The residential areas were classified by five degrees of population density, resulting in ten typical residential areas (see Section 3.5). With the postal code of the transformer substation the population density of the residential area that the transformer supplies is known; this can be used to connect the corresponding net load profile to this transformer. The distribution between already existing and newly developed areas in the various future scenarios is presented in Table 6.2. In all scenarios 0.3% of the existing areas are demolished and rebuilt per year (this corresponds to current figures [1]). As a consequence, in 2040 9% of the current MV/LV substations are supplying newly developed areas. Therefore, load profiles of newly developed areas are randomly connected to 9% of the MV/LV transformers. Also, completely new areas are arising due to the growth in the number of households (see Table 6.2); this will lead to the installation of new MV/LV transformers. The impact of the additional load due to these new areas on the required capacities of the MV distribution and transmission cables and the

Table 6.2: Number of households in the three scenarios.

	Existing/newly developed areas (%)	Number of households (million)
Current numbers	100/0	7.4
Scenario A	91/9	7.4
Scenario B	66/34	10.0
Scenario C	77/23	8.6

HV/MV transformers is included in the analysis; the installation of new MV/LV transformers is out of scope of this thesis and not included.

### 6.2.2 Required network capacity

The load-flow calculations yield the maximum loadings in 2040 of the four types of assets presented in Table 6.1. These loadings are used as input to evaluate the impact of the change in load profiles on the required capacities of the network assets and the resulting cash flow of the reinforcements. This procedure is depicted for one asset in Figure 6.3.

The maximum loadings are combined with a load development curve to determine the maximum loading of a certain asset in year  $t$ , to be able to quantify the required reinforcements in every year until 2040. This load development curve is a combination of the adoption curves of the various technologies that are presented in Appendix A taking into account the shares of these technologies in the total load for each scenario. For the growth (or decline) in regular electricity use a linear development curve is assumed.

The values of the maximum allowable loadings of the assets are conform the guidelines of the DNO that operates the networks that are assessed in this research. The capacities of the cables are expressed by Equation 4.4 as presented in Section 4.2.3. In the guidelines,  $D = 1.1$  for MV distribution cables. The chosen value of  $D$  for the transmission cables depends on the type of load fed by the transmission cable, but on average the value is 1.3. For the simulations, the same values are applied in all scenarios in the case of no shifting of flexible demands and in the case of applying the minimising electricity supply costs strategy. In the case the minimising network load strategy is applied, the value of  $D$  is set to 1.0 due to more uniform load profiles of the residential demands. The values of  $P$  and  $T$  in Equation 4.4 do not change due to changing load profiles and are not altered.

Also, for transformers a temporary higher loading than the rated capacity is allowed due to cyclic loading as has been expressed by Equation 4.8 in Section 4.4.2; conform the guidelines, the MV/LV transformers that supply residential areas are allowed to be loaded 1.2 times their nominal capacity ( $D = 1.2$ ). For the scenarios in which the minimising network load strategy is applied the maximum allowable

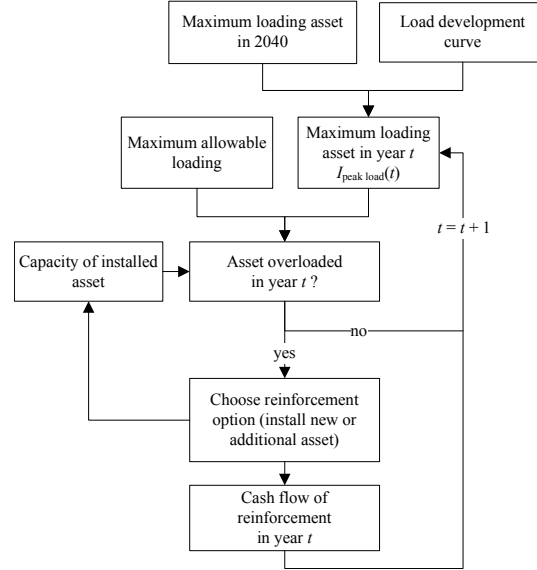


Figure 6.3: Block diagram presenting the procedure to evaluate the required capacity of a network asset resulting in the cash flow of the proposed reinforcements.

loading of the transformers are adjusted to 100% the nominal capacity ( $D = 1$ ). The maximum allowable loadings of HV/MV transformers is also 10% lower for the cases when minimising network load strategy is applied compared to the other cases.

Another issue related to the maximum allowable loading of MV transmission cables is the fact that because of the (n-1) criterion, the cables must be able to take over the load of a faulted parallel cable; this reduces the maximum allowable loading in emergency situations, depending on the number of parallel cables (e.g., in case of three parallel cables, the other two cables must be able to take over the load of the faulted cable). To fulfil the (n-1) criterion in case of HV/MV transformers additional transformers that are not in operation are present in the HV/MV substations to provide secure capacity; this does not affect the maximum allowable loading of the individual transformers. Note that when the transformers need to be upgraded the required spare capacity to fulfil the (n-1) criterion is taken into consideration.

When both the maximum loading and the maximum allowable loading of the asset are known, it can be determined whether the asset is overloaded in a certain year  $t$ . If so, the asset must be upgraded. The various reinforcement options that are possible can be found in Appendix F. Summing up the costs of all reinforcements for a certain year yield the annual cash flow of the reinforcements for the 48 MV networks including all assets presented in Table 6.1. Note that the total cash flow of the investments that are required for upgrading the capacities of the existing assets are

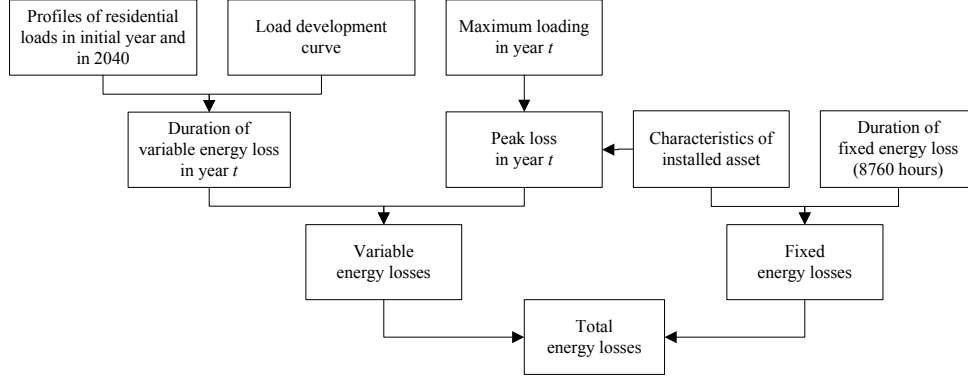


Figure 6.4: Block diagram presenting the procedure to estimate the energy losses in the network assets.

based on *current* investment costs, taking no price rises of material and labour costs into account.

### 6.2.3 Energy losses

In Figure 6.4 the procedure to estimate the energy losses for the network assets is depicted.

As described in Section 4.4, the fixed energy loss is given by the duration of the fixed energy loss which equals the annual operation hours of the transformer (8760 hours) and  $P_{\text{iron loss}}$ .  $P_{\text{iron loss}}$  is asset specific and given by the supplier of the transformer. The values of the asset specific characteristics of new installed assets can be found in Appendix F.

The variable energy loss is defined by the peak loss (the loss at the moment of peak load) and the duration of the loss. The peak loss in case of cables is given by  $P_{\text{peak loss}} = I_{\text{peak load}}^2 R$  and in case of transformers by  $P_{\text{peak loss}} = \alpha^2 P_{\text{load loss}}$ , in which  $P_{\text{load loss}}$  is the power loss at full load given by the manufacturer and  $\alpha$  is the utilisation factor of the transformer.  $I_{\text{peak load}}(t)$  or  $\alpha(t)$  equal the maximum loadings in each year  $t$ . These maximum loadings and the characteristics of the installed assets ( $R$  and  $P_{\text{load loss}}$ ; these values are given for new installed assets in Appendix F) determine the variable energy losses, together with the loss duration.

The duration of the variable energy loss is defined by the energy loss profile that can be derived from the load profiles. For the networks analysed, the loss duration at the MV/LV transformers in the initial year is estimated based on measurements (this is the average loss duration of all MV/LV transformers connected to the MV networks; both MV/LV transformers that supply residential areas and MV/LV transformers that supply industrial or commercial electricity consumption).

Table 6.3: Duration of the variable energy losses in relation to the residential load, in the initial year and in 2040 for various scenarios (No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

	Share of residential load in total load of MV/LV transformers (%)	Average annual electricity demand of one household (kWh)	Annual loss duration derived from residential load profiles (hours)	Annual loss duration at MV/LV transformers (hours)
Initial year	72	3400	2355	1172
Reference case (2040)	77	4582	2355	1238
A – No SG	75	4393	1604	813
A – MNL	75	4393	4173	2114
A – MESC	75	4393	1852	938
B – No SG	86	9171	1314	768
B – MNL	86	9171	3509	2050
B – MESC	86	9171	2405	1404
C – No SG	70	3462	1446	686
C – MNL	70	3462	3160	1498
C – MESC	70	3462	725	344

The change in loss duration at the MV/LV transformers is determined by the difference between the known residential load profiles in the initial year and the residential load profiles in 2040 constructed for the three smart grid strategies in three scenarios. Also, the change in the share of the residential load in the total load of the MV/LV transformers is taken into account for all scenarios. The results of the loss duration at the MV/LV transformers in the initial year and in 2040 are presented in Table 6.3. The results are also presented for a reference case that follows the conventional network planning method that takes into account a yearly growth of 1% for the residential peak demand. Load development curves of the various technologies are used to estimate the loss duration in the years between now and 2040. In summary, the duration of the variable energy loss at the MV/LV transformers in the initial year is known and is adjusted in the years after based on the changing load profiles at the MV/LV transformers as dictated by the change in residential demands.

The actual duration of the variable losses at the MV cables and HV/MV transformers are not known. These are estimated with help from the load-flow calculations in which also other (industrial/commercial) loads than MV/LV transformer loads are included. With these calculations the load profiles of the network assets are known on the day with the maximum loading. The differences between the load profiles of these assets compared to the average load profile of the MV/LV trans-

Table 6.4: Energy losses for the various network assets in the initial year.

	Estimated annual losses (GWh/year)	Measured annual losses (GWh/year)
HV/MV transformers (fixed)	19.5	19.2
HV/MV transformers (variable)	17.3	16.4
MV transmission cables	45.3	–
MV distribution cables	61.5	–
MV/LV transformers (fixed)	43.1	43.6
MV/LV transformers (variable)	14.5	14.0

formers are used to estimate the differences in loss duration at the various network levels.

The energy losses for the 48 MV networks in the initial year that are estimated with the procedure presented here are presented in Table 6.4. Also, measured values are presented of the annual energy losses of the HV/MV and MV/LV transformers for these networks (these values are not based on the loss duration which is not known for the HV/MV transformers); the estimated and measured values are of the same magnitude. The values of the energy losses in the cables of this part of the MV distribution network are not known. Unfortunately only limited measurements are available to validate the procedure presented here and the assumptions that have been made. Nevertheless, applying this approach is supported by the estimated and measured values of the energy losses presented in Table 6.4. The outcomes are used to compare the differences in energy losses in the various scenarios and in the various smart grid cases.

#### 6.2.4 Total impacts

To be able to combine the impacts and compare the different scenarios and smart grid strategies, the NPV of the required reinforcements and the energy losses are calculated based on the annual cash flow of the investment costs and energy losses.

The NPV associated with the reinforcements is calculated based on the annuity costs of the investments. The annuity costs of the reinforcement of an asset with a lifetime  $T_{\text{life}}$  is given by:

$$C_{\text{annuity}}(t) = \begin{cases} C_{\text{reinf}} \cdot \frac{r}{1-(1+r)^{-T_{\text{life}}}} & \text{if } t_{\text{reinf}} \leq t < t_{\text{reinf}} + T_{\text{life}} \\ 0 & \text{else} \end{cases} \quad (6.1)$$

in which  $C_{\text{reinf}}$  is the reinforcement costs,  $t_{\text{reinf}}$  is the year the reinforcement takes place and  $r$  the interest rate. In this analysis, an interest rate of 3% is assumed. Furthermore, a 50 year lifetime for MV/LV transformers and MV cables, and a 40 year lifetime for HV/MV transformers are used. By using this method, the reinforcement

costs are spread out over the lifetime of the new assets. This means that, since these lifetimes are longer than the 2040 horizon of the scenarios, a significant part of the investment costs falls outside the analysis.

The annual costs due to energy losses are based on the current electricity price  $p_e$ , which at moment lies around €0.08 per kWh for a DNO (energy taxes do not apply on this price). Now the NPV of the total costs are calculated by:

$$NPV = \sum_{t=t_0}^{t_{\text{end}}} \frac{C_{\text{annuity}}(t) + E_{\text{loss}}(t) \cdot p_e}{(1+r)^{t-t_0}} \quad (6.2)$$

in which  $t_{\text{end}}$  is the last year of the time horizon, in this case 2040.

### 6.3 Results

The results of the analysis are presented in this section for the three scenarios introduced in Section 3.5. For comparison, the results for the reference case that follows the conventional network planning method of the DNO that takes into account a yearly growth of 1% for the residential peak demand is presented as well. For each scenario the required network capacity and the energy losses are presented. The total impacts are given by the NPVs of the cash flow of the investment costs and the annual energy losses. The results are discussed in Section 6.4.

#### 6.3.1 Scenario A

Scenario A represents a situation with low economic growth in combination with an effective (national) climate policy.

##### Required network capacity

The distributions of the maximum loadings of the assets are depicted via the box plots in Figure 6.5 and the average values are presented in Table 6.5. The number of reinforcements and the corresponding cumulative cash flow for the 48 networks under consideration can be found in Table 6.6 and Figure 6.6.

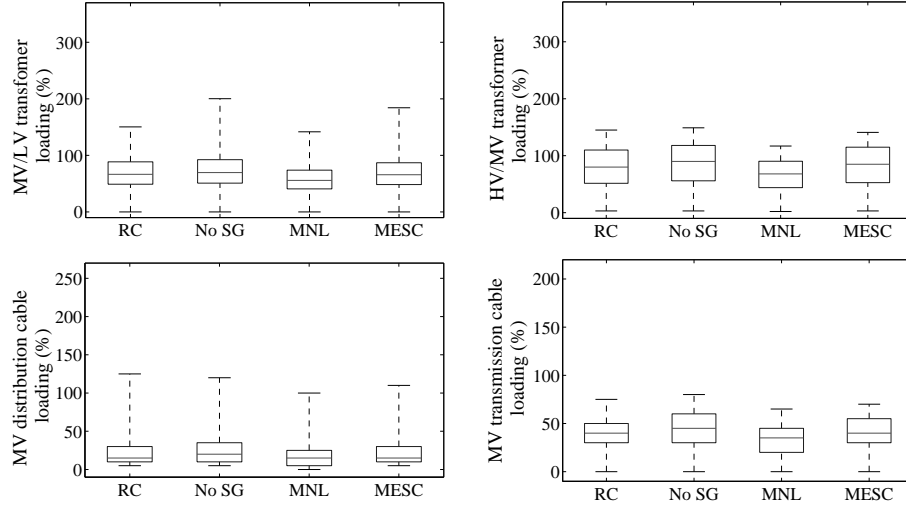


Figure 6.5: Distribution of the maximum loadings of the assets presented in Table 6.1 in Scenario A; the boxplots present the minimum and maximum values together with the 25<sup>th</sup>, 50<sup>th</sup> (median) and 75<sup>th</sup> percentiles (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

Table 6.5: Average value of the maximum loadings of the four types of assets in 2040 in Scenario A.

	Reference case (%)	No smart grid (%)	Minimising network load (%)	Minimising electricity supply costs (%)
HV/MV transformers	79	86	68	81
MV transmission cables	38	42	32	39
MV distribution cables	23	24	19	23
MV/LV transformers	68	72	57	68

Table 6.6: Number of reinforcements till 2040 in Scenario A.

	Reference case	No smart grid	Minimising network load	Minimising electricity supply costs
HV/MV transformers (#)	5	18	6	9
MV transmission cables (km)	427	661	130	490
MV distribution cables (km)	16	62	26	20
MV/LV transformers (#)	597	950	741	537

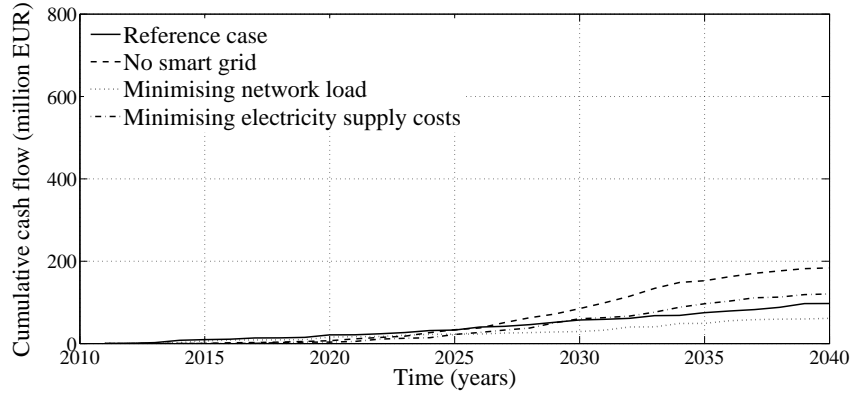


Figure 6.6: Cumulative cash flow of the total reinforcements (MV/LV transformers, the MV transmission and distribution cables and the MV/LV transformers) in Scenario A.

### Energy losses

The resulting annual variable and fixed energy losses in the investigated assets are presented in Figures 6.7 and 6.8, respectively.

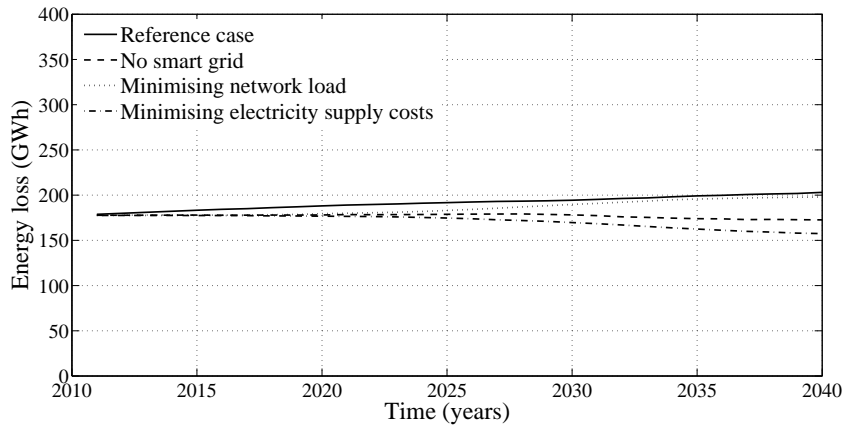


Figure 6.7: Variable annual energy losses in Scenario A.

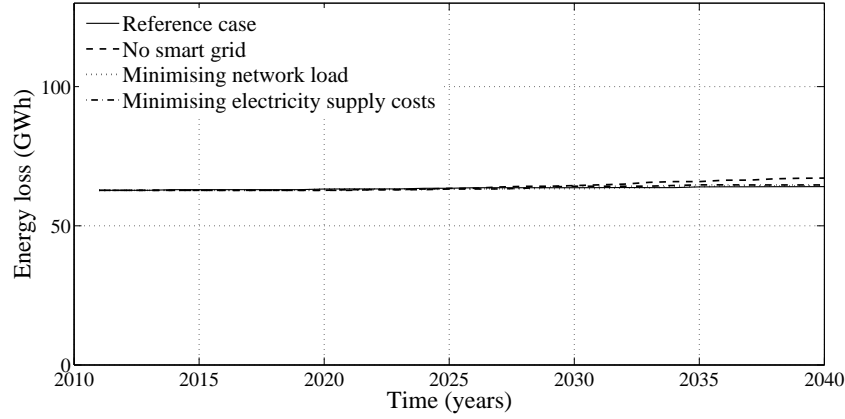


Figure 6.8: Fixed annual energy losses in Scenario A.

### Total impacts

Figure 6.9a shows the NPV for the different cases and its breakdown in the NPV of the reinforcement costs and the costs for the fixed and variable energy losses. The NPV is presented in relation to the reference case (yearly load growth of 1%); in this case the NPV is set to be 100%. Figure 6.9b presents the differences in the various cost components compared to the NPV of the reference case.

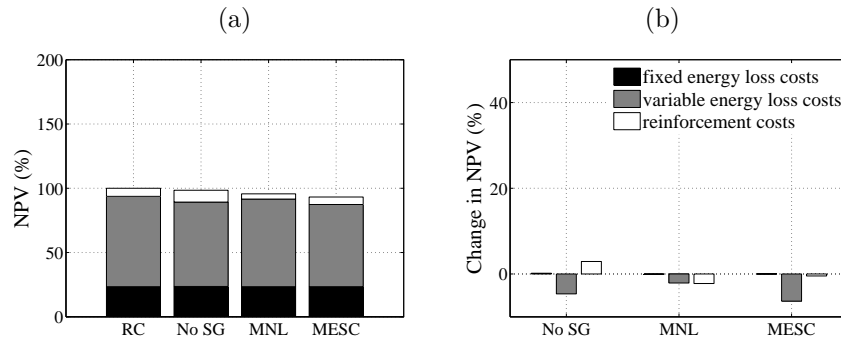


Figure 6.9: (a) NPV components of the reinforcement costs and the costs for the fixed and variable energy losses in Scenario A. The values are normalised with respect to the NPV in the reference case. (b) Differences of the cost components compared to the expected costs in the reference case. (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs.)

### 6.3.2 Scenario B

Scenario B represents a situation with high economic growth in combination with a less effective climate policy compared to Scenarios A and C.

#### Required network capacity

The distributions of the maximum loadings of the assets are depicted via de box plots in Figure 6.10 and the average values are presented in Table 6.7. The number of reinforcements and the corresponding cumulative cash flow for the 48 networks under consideration can be found in Table 6.8 and Figure 6.11.

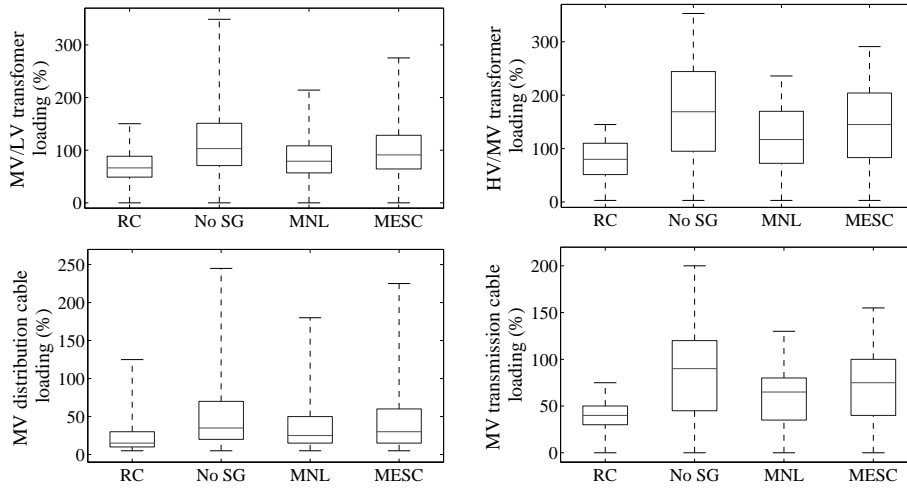


Figure 6.10: Distribution of the maximum loadings of the assets presented in Table 6.1 in Scenario B; the boxplots present the minimum and maximum values together with the 25<sup>th</sup>, 50<sup>th</sup> (median) and 75<sup>th</sup> percentiles (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

Table 6.7: Average value of the maximum loadings of the four types of assets in 2040 in Scenario B.

	Reference case (%)	No smart grid (%)	Minimising network load (%)	Minimising electricity supply costs (%)
HV/MV transformers	79	171	116	143
MV transmission cables	38	86	58	72
MV distribution cables	23	51	36	44
MV/LV transformers	68	117	84	100

Table 6.8: Number of reinforcements till 2040 in Scenario B.

	Reference case	No smart grid	Minimising network load	Minimising electricity supply costs
HV/MV transformers (#)	5	77	45	60
MV transmission cables (km)	427	2698	1863	2191
MV distribution cables (km)	16	3883	1442	1847
MV/LV transformers (#)	597	7468	5086	5096

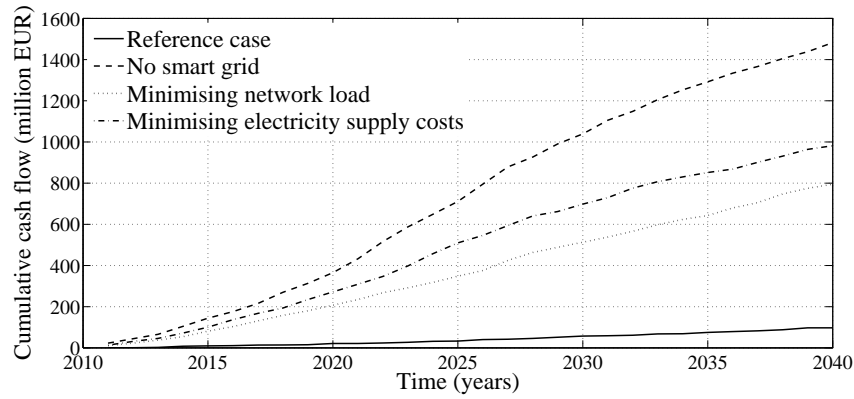


Figure 6.11: Cumulative cash flow of the total reinforcements (MV/LV transformers, the MV transmission and distribution cables and the MV/LV transformers) in Scenario B.

### Energy losses

The resulting annual variable and fixed energy losses in the investigated assets are presented in Figures 6.12 and 6.13, respectively.

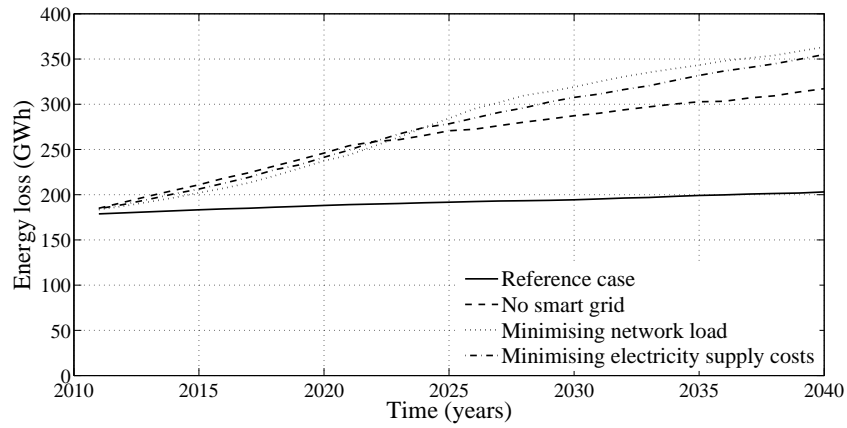


Figure 6.12: Variable annual energy losses in Scenario B.

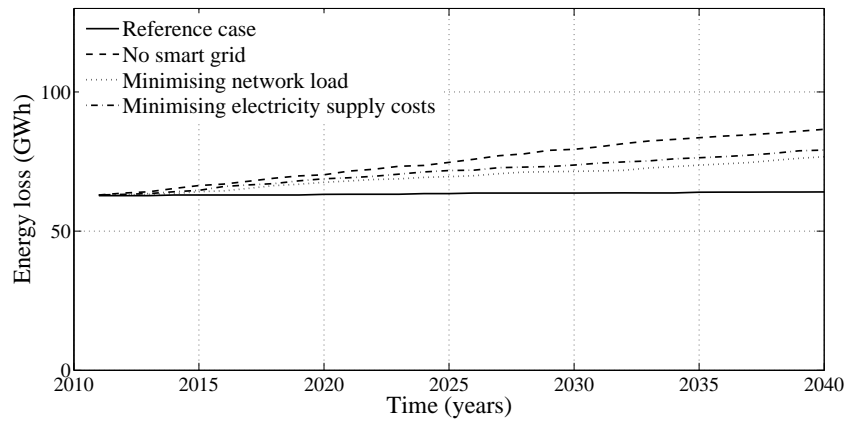


Figure 6.13: Fixed annual energy losses in Scenario B.

### Total impacts

Figure 6.14a shows the NPV for the different cases and its breakdown in the NPV of the reinforcement costs and the costs for the fixed and variable energy losses. The NPV is presented in relation to the reference case (yearly load growth of 1%); in this case the NPV is set to be 100%. Figure 6.14b presents the differences in the various cost components compared to the NPV of the reference case.

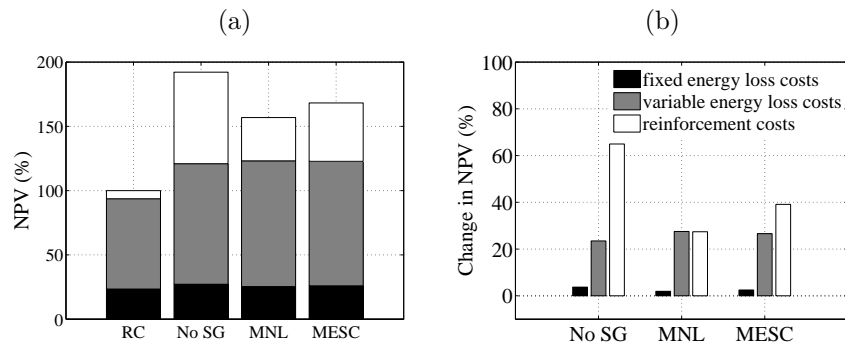


Figure 6.14: (a) NPV components of the reinforcement costs and the costs for the fixed and variable energy losses in Scenario B. The values are normalised with respect to the NPV in the reference case. (b) Differences of the cost components compared to the expected costs in the reference case. (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs.)

### 6.3.3 Scenario C

Scenario C represents a situation with moderate to high economic growth in combination with an effective international climate policy.

#### Required network capacity

The distributions of the maximum loadings of the assets are depicted via the box plots in Figure 6.15 and the average values are presented in Table 6.9. The number of reinforcements and the corresponding cumulative cash flow for the 48 networks under consideration can be found in Table 6.10 and Figure 6.16.

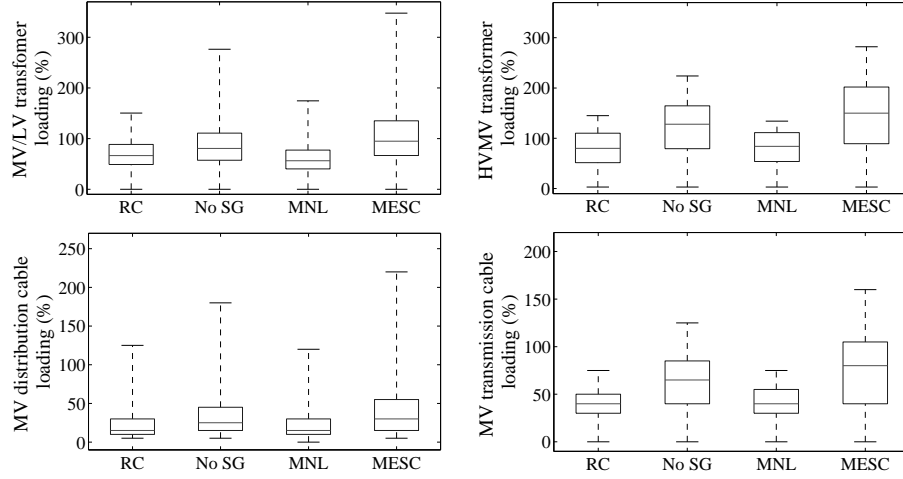


Figure 6.15: Distribution of the maximum loadings of the assets presented in Table 6.1 in Scenario C; the boxplots present the minimum and maximum values together with the 25<sup>th</sup>, 50<sup>th</sup> (median) and 75<sup>th</sup> percentiles (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

Table 6.9: Average value of the maximum loadings of the four types of assets in 2040 in Scenario C.

	Reference case (%)	No smart grid (%)	Minimising network load (%)	Minimising electricity supply costs (%)
HV/MV transformers	79	119	79	144
MV transmission cables	38	60	39	74
MV distribution cables	23	34	22	42
MV/LV transformers	68	87	60	106

Table 6.10: Number of reinforcements till 2040 in Scenario C.

	Reference case	No smart grid	Minimising network load	Minimising electricity supply costs
HV/MV transformers (#)	5	44	21	59
MV transmission cables (km)	427	1629	756	2313
MV distribution cables (km)	16	992	89	1687
MV/LV transformers (#)	597	3670	1459	6472

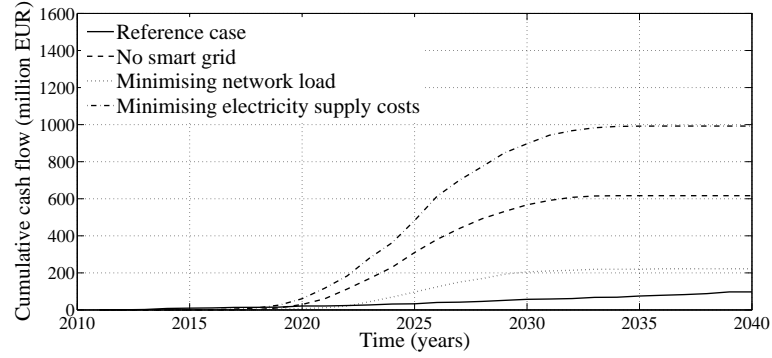


Figure 6.16: Cumulative cash flow of the total reinforcements (MV/LV transformers, the MV transmission and distribution cables and the MV/LV transformers) in Scenario C.

### Energy losses

The resulting annual variable and fixed energy losses in the investigated assets are presented in Figures 6.17 and 6.18, respectively.

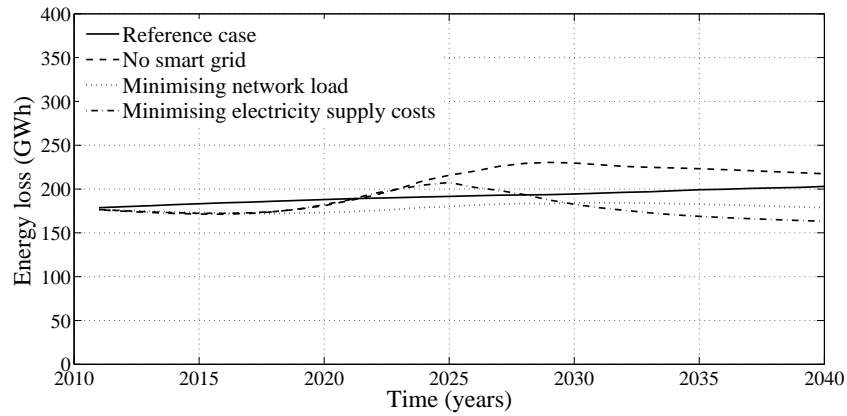


Figure 6.17: Variable annual energy losses in Scenario C.

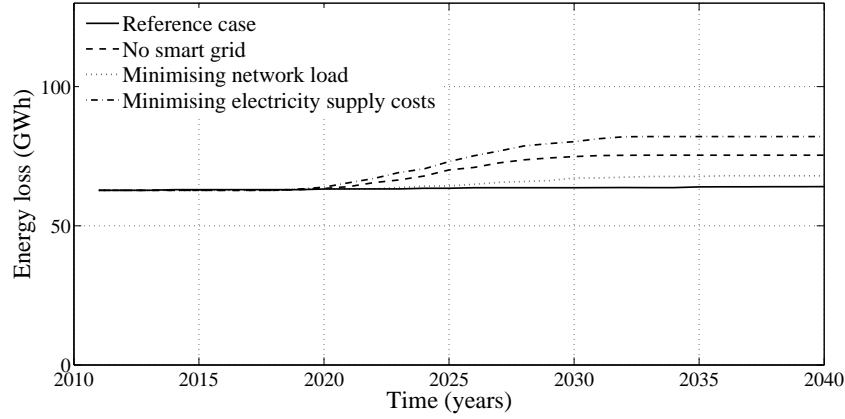


Figure 6.18: Fixed annual energy losses in Scenario C.

### Total impacts

Figure 6.19a shows the NPV for the different cases and its breakdown in the NPV of the reinforcement costs and the costs for the fixed and variable energy losses. The NPV is presented in relation to the reference case (yearly load growth of 1%); in this case the NPV is set to be 100%. Figure 6.19b presents the differences in the various cost components compared to the NPV of the reference case.

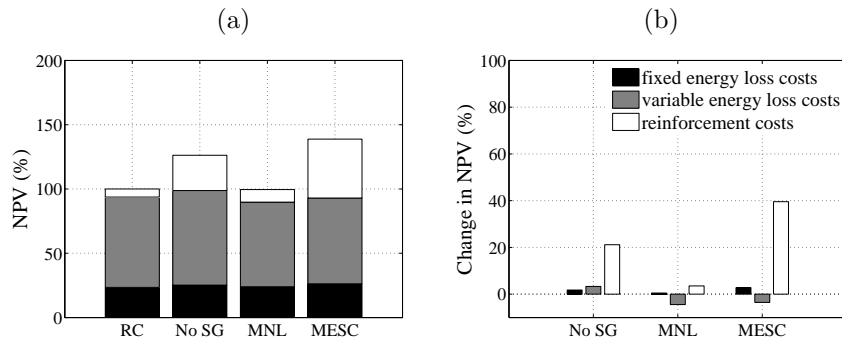


Figure 6.19: (a) NPV components of the reinforcement costs and the costs for the fixed and variable energy losses in Scenario C. The values are normalised with respect to the NPV in the reference case. (b) Differences of the cost components compared to the expected costs in the reference case. (RC = reference case; No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs.)

## 6.4 Discussion on the results

The results of the required network capacities, the energy losses and the combined impacts given by the NPVs of the cash flow of the required investments and the annual energy losses, are separately discussed in this section.

### 6.4.1 Required network capacity

A closer look at the average value of the maximum loadings of the four types of assets in Figures 6.5, 6.10 and 6.15, shows that the assets at a higher voltage level in the network are higher loaded than the assets close to the end users. This is caused by the fact that assets operating at a higher voltage level are more expensive and therefore HV/MV transformers with relatively less redundant capacity are chosen compared to MV/LV transformers. The fact that MV distribution cables have more redundant capacity available for future growth than MV transmission cables was also demonstrated in Section 4.2.3.

In Table 6.11 the differences in the maximum loadings of the four types of assets are presented compared to the expected maximum loadings in the reference case that assumes a yearly growth of 1% for the residential peak demand and no additional load due to new technologies. When comparing the results, large differences can be observed between the three scenarios. The expected maximum loadings can significantly increase compared to the reference case; this is especially the case for Scenarios B and C, except when applying the minimising network load strategy in Scenario C.

In Figures 6.6, 6.11 and 6.16, it can be seen that the cash flows of the rein-

Table 6.11: Change in the average value of the maximum loadings of four type of assets compared to this value in the reference case (No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

	HV/MV transformers (%)	MV transmission cables (%)	MV distribution cables (%)	MV/LV transformers (%)
A – No SG	+9	+11	+6	+5
A – MNL	–14	–17	–20	–17
A – MESC	+2	+4	–1	–1
B – No SG	+117	+125	+122	+71
B – MNL	+48	+53	+57	+23
B – MESC	+82	+90	+92	+46
C – No SG	+50	+57	+49	+27
C – MNL	+1	+2	–4	–13
C – MESC	+82	+94	+82	+55

Table 6.12: Difference between the cumulative cash flows due to the reinforcement costs (by 2040) of the two smart grid strategies compared to the cumulative cash flow in the case no smart grid strategy is applied in each of the three scenarios.

	Scenario A	Scenario B	Scenario C
	(%)	(%)	(%)
Minimising network load	-67	-48	-64
Minimising electricity supply costs	-36	-35	+59

forcement costs develop differently in the three scenarios. This is caused by the development of the load. For example, the cash flow clearly increases following an s-curve in Scenario C. This is the result of the load growth which is determined by the demand for new technologies that are introduced following technology adoption s-curves while the demand for the regular residential electricity decreases with  $-1.0\%$  per year in this scenario. In Scenario B, the regular residential use linearly grows with  $1.5\%$  per year and this demand growth has a large influence on the maximum loadings and the resulting required reinforcements and the NPVs associated with them.

To compare the impacts of the various smart grid strategies, the differences in the cumulative cash flow due to the reinforcement costs in the final year (2040) are presented in Table 6.12 compared to the case no smart grid strategy is applied to shift the demand of flexible loads. Applying the minimising network load strategy reduces the cumulative cash flow with 48–67%. The relative cost savings that can be realised by applying load management to reduce peak demands, are the highest in Scenarios A and C. Due to the fact that in Scenario B the growth of the electrical energy demand is much higher, the number of required investments will be higher, regardless of any load management. Therefore, the cost savings that can be obtained by applying any smart grid strategy relative to the investment costs if no smart grid strategy is applied, will be less compared with Scenarios A and C. But, because the total investments costs will be much higher in Scenario B, the absolute cost savings are still the highest in this scenario.

On the other hand, the minimising electricity supply costs strategy leads to higher loadings and results in higher investment costs in Scenario C compared to the case no smart grid strategy is applied. In Scenarios A and B this is not the case. With this strategy flexible demands will be supplied during moments when prices are low. These are typically moments when electricity production by intermittent sources is high and electricity demand is low. In Scenarios A and B the shares of electricity produced by intermittent wind and solar energy are relatively low and do not influence prices that much, resulting in flexible demand being supplied during night hours when system demand is low. On the other hand, in Scenario C, the electricity produced by intermittent wind and solar energy is that high, that prices are low at certain moments when these sources produce much electricity. At these

Table 6.13: Ratio between fixed and variable energy losses and the change in the annual energy losses (in 2040) compared to the reference case (No SG = No smart grid; MNL = minimising network load; MESC = minimising electricity supply costs).

	Fixed/variable energy losses	Fixed losses (%)	Variable losses (%)
A – No SG	28/72	+5	–15
A – MNL	25/75	+1	–3
A – MESC	29/71	+1	–22
B – No SG	21/79	+35	+56
B – MNL	17/83	+20	+79
B – MESC	18/82	+24	+75
C – No SG	26/74	+18	+7
C – MNL	28/72	+6	–12
C – MESC	33/67	+28	–20

moments large demand peaks will occur. As an effect, the residential load profiles have much higher peaks in this scenario (see also Section 5.4.4), leading to higher investment costs in the distribution networks. As expected, for Scenarios A and B the cost savings are more modest than when applying the minimising network load strategy.

#### 6.4.2 Energy losses

The energy losses are dominated by the variable losses. For the reference case that assumes a yearly growth of 1% for the residential peak demand and no additional load due to new technologies, 24% of the energy losses are fixed losses and 76% are variable losses. For Scenarios A, B and C, the shares of the fixed and variable energy losses in the total losses are presented in Table 6.13. Relative to the reference case, the share of the fixed energy losses slightly increases in Scenarios A and C with 1–9%, in Scenario B the share of the fixed losses decreases with 3–7%.

Also, the differences in the fixed as well as the variable annual energy losses in 2040 compared to the energy losses in the reference case are presented in Table 6.13. In general, it can be said that an increase in the required network capacity leads to higher fixed losses; the increase in fixed annual energy losses lies in line with the increase in maximum loadings (see Table 6.11). The fact that reduced loadings in Scenario A in the case of the minimising network load strategy does not lead to a reduction in fixed losses, is caused by a lower maximum allowable loading which leads to more reinforcements of MV/LV transformers (see Table 6.6) and thus higher network capacity.

The changes in variable losses are a combination of the changes in duration of the

energy losses and changes in the value of the peak losses. In some cases this leads to an increase and in other cases to a decrease in variable energy losses. In Scenario B, regardless of the applied smart grid strategy, the increase in maximum loadings (and thus peak losses) causes an increase in variable energy losses. The decrease in loss duration in the minimising electricity supply costs strategy (see Table 6.3) leads to a decrease in variable energy losses in Scenarios A and C, though peak losses increase. As expected, the minimising network load strategy leads to reduction in the peak losses in both Scenarios A and C and hence in a decrease in variable losses.

### 6.4.3 Total impacts

Looking at Figures 6.9, 6.14 and 6.19, it can be noticed that the costs for variable energy losses dominate the total NPV.

In Scenario A, the total NPV decreases slightly compared to the reference case in which the conventional network planning method is applied (with 1.6–6.8%), the difference between various smart grid strategies results in a maximum difference in the NPV of 5.2%.

In Scenario B the NPV increases significantly, regardless of the applied smart grid strategy. The increase in the NPV of 57–92% consists in all cases of 27–29% energy loss costs. The difference in the total NPV when applying different smart grid strategies is thus mainly caused by the required investments.

In Scenario C the NPV increases with respectively 26% and 39% for the case of no use of flexible demand and the case of applying the minimising electricity supply costs strategy. Applying the minimising network load strategy results in an increase of 3.5% of the NPV of the reinforcement costs compared to the reference case. Again, the energy losses only determine a few percent of the change in NPV (maximal 5.0%).

In general it can be said that, although the energy loss costs are a large component in the total costs, applying different smart grid strategies does not result in large differences in energy losses. The differences in the total costs can, however, be significant for different smart grid strategies. These changes are caused by the differences in the costs for the required investments. In Scenario A, the changes in the NPVs are small compared to the NPV in the reference case. In the case of Scenarios B and C, applying various smart grid strategies results in differences of 11–39% in the total NPV.

## 6.5 Summary and conclusions

In this chapter, the implications of various scenarios and smart grid strategies on the required distribution network reinforcements are investigated. This is done by quantifying the required capacities of the assets in a large set of MV networks. Also, the annual energy losses are assessed. The impacts are combined by calculating the

NPV of annual cash flows for the reinforcements that are required to upgrade the assets and the NPV of the annual energy loss costs. The results are presented for the three scenarios that are described in Section 3.5. For each scenario three cases are compared: the case of no shifting of flexible, residential demands in time, the case of applying the minimising network load strategy and the case of applying the minimising electricity supply costs strategy.

Load-flow calculations of the MV networks yield the maximum loadings of the assets (HV/MV transformers, MV transmission and distribution cables and MV/LV transformers). The aggregated residential net load profiles that are constructed in Chapter 5 are used as input for these load-flow calculations. With the results of the maximum loadings and the maximum allowable loadings of the assets, the required reinforcements can be determined. The load-flow calculations also yield the peak losses. The peak losses and the loss duration (that are derived from the annual load profiles) are used to estimate the energy losses.

The results show large differences between the three scenarios. The expected maximum loadings can significantly increase compared to the reference case (with a yearly growth of 1% for the residential peak demand); this is especially the case for Scenarios B and C. Applying the minimising network load strategy reduces the cumulative cash flow for the reinforcement costs by 48–67%. By contrast, in Scenario C the minimising electricity supply costs strategy leads to larger maximum loadings and results in larger investment costs compared to the case no smart grid strategy is applied. This is caused by high demand from the flexible loads at moments when prices are low. Because of the high share of electricity production by intermittent energy sources in Scenario C, these moments occur at moments when production by these sources is high.

Though the energy losses dominate the NPV of the total costs, applying different smart grid strategies does not result in large differences in energy loss costs. The differences in the total NPVs for the different smart grid strategies (which can be significant) are mainly caused by differences in investments costs. In Scenarios B and C the differences between the NPVs applying various smart grid strategies compared to the NPV in the case no smart grid strategy is applied amount to 11–39%. In Scenario A the differences in the NPV are less than 7%, because the share of the investment costs in the total NPV is much smaller than in Scenarios B and C.



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## Realisation of smart grids

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### 7.1 Introduction

In a country like the Netherlands the present annual investment costs in distribution networks are about €300 million [94]. Without any smart grid effects, it is expected that in the period towards 2050 €5–19 billion needs to be invested in the MV networks [94], which is substantial. The results presented in Chapter 6 show that network reinforcements costs differ per scenario, and that possible cost savings can be large, especially when applying a smart grid strategy that is based on the grid-oriented smart grid concept. To realise the potential cost savings, smart grids must be implemented and this requires some investments as well.

This chapter will discuss the implementation of smart grids and the related costs to enable flexible residential demand in order to optimise distribution network utilisation. First, the benefits of smart grids will be discussed. Not only the benefits for the DNO, but also the benefits for other parties and how the benefits for various parties can be balanced in the context of the electric power system as a whole, are discussed. Flexible electricity demand has value for various parties, but before it can create value to these parties, it must be made available by the residential customers. In Section 7.3 attention is paid to the value that flexible electricity demand has for the customer. The last section reflects on how smart grids can be put into practice and what implications smart grids have on electricity market design. Various examples are given of smart grid pilots and it is discussed which issues need attention to realise smart grids in which distribution network utilisation is optimised.

### 7.2 Smart grid benefits

In this section, a reflection will be given on current developments in smart grid functionalities and the investments that are already (being) made for various smart grid components are indicated. Specific attention is paid to identifying what is needed to develop the electric power system in the direction of a market- or grid-oriented smart grid. Finally, it is discussed how these strategies impact system costs.

### 7.2.1 Smart grid developments

In this thesis, two situations in which a smart grid strategy is applied to shift residential electricity demand in time, are compared to the situation in which no smart grid strategy is applied. In this latter case, the assumption is made that the operation of the power system will remain similar to the current situation. No costs will be made to realise any of the possible functionalities in smart grids, the electricity market will keep functioning as it does now, and there will be no change in the management of the grids. However, investments in network reinforcements will be made to cover the anticipated peak load. Looking at the results presented in Chapter 6, this will not be the optimal situation for the utilisation of the distribution networks in none of the scenarios.

It can, however, be argued if it is realistic to assume the current situation will hold. For example, the roll-out of smart meters is already well underway in many countries to realise various kinds of operational benefits, like elimination of meter reading costs and minimising power theft [45]. The goal set by the EU is that 80% of electricity consumers shall be equipped with smart meters by 2020 [114]. Though smart meters are an important component of smart grids, installing smart meters alone will not automatically lead to mobilising the flexibility in residential electricity demand. If energy providers could successfully use the flexibility in the residential electricity demand of their customers, and translate the financial gains they get on electricity markets into products and services from which the customers can profit, the flexibility can be unlocked. In [45], it is stated that to realise these gains, dynamic electricity tariffs should be introduced. From this perspective, smart meters support the market-oriented smart grid concept. The smart meters could also support a dynamic tariff that is a combination of a dynamic electricity tariff (to cover the electricity supply costs) and a dynamic network tariff (to cover the costs of the electricity network infrastructure). A dynamic network tariff means that various tariffs are introduced that depend on the available network capacity on a certain moment; in this way, a dynamic network tariff supports capacity management of the network.

Another example of developments that lead to mobilising flexible demands is charging of EVs. Load management of EVs using time-of-use tariffs with real-time adjustment strategies to be able to fully exploit the grid capacity has already been field-tested [37]. In these field tests, the electricity demand for charging an EV is shifted in time. If the car owner is offered various electricity prices at various moments (i.e. applying a dynamic tariff), commercial parties can offer their customers various types of contracts. The flexible demand for EVs can then be enabled and used on e.g. electricity markets or (in principle) to reduce network peak loads. However, the main EV applications so far fit in the market-oriented smart grid concept and not yet in the grid-oriented smart grid concept that, among other things, focuses on reducing network investments.

In the field of grid management there are also all kinds of developments leading

to smarter grids. For example, DNOs start to roll out distribution automation on a large scale to facilitate bi-directional power flows due to an increase of DG, and to improve reliability by increasing the speed of restoration after an interruption [93]. This can be realised by the deployment of remote control at certain points in the MV networks to detect and localise outages due to component failures. The increasing use of automated monitoring and control of the electricity distribution networks will result in a significant reduction of customer minutes lost [15] and can compensate the anticipated drop in reliability caused by an increase in component failures due to the ageing infrastructure and in this way delay replacement programmes that would be required to keep reliability at an acceptable level [149]. These developments fit in the grid-oriented smart grid concept, though the focus of the implementation of distribution automation is at present on accelerating outage restoration and not (yet) on optimising network utilisation.

### 7.2.2 The market-oriented smart grid

Electricity is a commodity that can be traded in different ways, e.g. via long-term contracts (bilateral agreements), on day-ahead spot markets, intraday spot markets or real-time balancing markets. If commercial parties (e.g., electricity providers or aggregators representing groups of residential customers or operating a so-called virtual power plant (VPP)<sup>1</sup>) enable residential customers to participate in the market, this will lead to a market-oriented smart grid. The flexibility of residential demand creates value on e.g. day-ahead spot markets when the demand can be supplied at moments with low prices [34, 131]. If fast price response of the flexible residential demand can be realised with smart grids (i.e. closer to real time), demand can also be used for power balancing and value can be created on balancing markets [7]. However, it should be noted that the reward from control of power consumption and the purchase of power at real-time prices varies significantly between various deregulated power systems at the moment [85]. In future power systems, the need for balancing resources, which is strongly influenced by fluctuations in power generation, are expected to increase due to the increased penetration of renewable generation and efficient real-time power balancing schemes will become crucial [68]. To apply residential demands for power balancing, they must be fast enough to respond to unexpected fluctuations in aggregated generation and load. To this end, a dynamic electricity tariff should be introduced that could be enabled by smart meters [51].

In Chapter 6, the impacts of the realisation of this smart grid concept on distribution network utilisation have been assessed by the strategy that minimises electricity supply costs. It has been shown that it depends on the scenario if the realisation of this smart grid concept has a positive or negative influence on network investments.

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<sup>1</sup>A VPP is a flexible representation of a portfolio of distributed generation, demand response and electricity storage. One of the key activities of a VPP is the delivery of (close to) real-time balancing services [78].

If low electricity prices coincide with low-demand moments, shifting of flexible demand to moments with low prices may reduce required network capacity (this was the case in Scenarios A and B). However, if the share of electricity production by intermittent energy sources in the total electricity production increases, prices may be low when the electricity production by intermittent sources is high. In this scenario flexible demand will shift to moments of low prices that coincide with moments of high intermittent electricity production (which do not necessarily correspond to low-demand moments). This leads to high demand peaks and requires high network capacity (Scenario C corresponds to this situation). The effect of intermittent energy sources on the fluctuations in electricity supply prices is a complex issue and has not been intensively investigated in this thesis; see for more information on this topic e.g. [14, 31, 84, 85]. The possibility that prices will fluctuate more in future and will lead to low prices when intermittent generation is high is, however, to be expected and already some moments of very low or even negative prices occur [79]. If this is the way prices develop, the market-oriented smart grid will lead to high demand peaks and require additional network investments.

### 7.2.3 The grid-oriented smart grid

The focus of a DNO will be to develop the power system in the direction of the grid-oriented smart grid. In Chapter 6, it has been concluded that if large reinforcements are needed to accommodate future residential electricity demands, significant reductions can be realised by applying a smart grid strategy that focuses on minimising network peak load. To realise the costs savings, investments in sensing, monitoring and control equipment in the distribution networks as well as in electronic devices, software and marketing to get the customer involved are required. Measurement on the LV side of the MV/LV substations can be done relatively easily and with low investments. The MV side is more complicated, but feasible [128]. Though the market for equipment for sensing, monitoring and control in LV and MV networks is relatively new and prices are still high, DNOs start to roll out distribution automation on a large scale [93]. To get the customer involved, the installation of smart meters is required, complemented with marketing and adequate products and services [127]. As mentioned in Section 7.2.1, the roll-out of these smart meters is already well underway. Taking into account the investments that are already (being) made, it can be concluded that the potential costs savings in investments by reducing maximum loadings through smart grids are very likely to offset additional costs that are needed to realise them.

If the available flexibility in the residential electricity demand is fully used by network operators to optimise network utilisation in a grid-oriented smart grid, this flexibility can neither be used on electricity markets nor for power balancing. In Section 5.4.4, it was presented that shifting flexible residential demand to moments of low electricity supply prices leads to a limited number of hours in which the network loading is higher than when using the flexible residential demand to minimise

network loading (see Table 5.4). To obtain the benefits in reduced investment costs, it is thus only required to use the flexible residential electricity demand to reduce network loading for those hours and these benefits should offset the benefits that can be reached by using this flexible demand on the electricity markets during these relatively small number of hours. In [144], it is investigated how the electricity supply costs for uncontrolled charging of EVs relates to the electricity supply costs if charging is controlled taking network constraints into account. The charging costs when applying an efficient congestion management method are found to be only slightly higher than the charging costs without consideration for grid constraints, and it is concluded that it seems cost efficient to apply congestion management that shifts the flexible load at moments of peak demand to other, off-peak moments. This would suggest to use at least part of the available flexibility in residential electricity demand for reducing the maximum loading during critical hours, and in this way, minimise overall system costs.

#### 7.2.4 Towards the optimal future power system

Summarising, investments towards various types of smart grids are already being made. The market-oriented smart grid may become reality under the current market structure, if a dynamic electricity tariff (supported by smart meters) is realised. This situation may not be optimal in terms of required network investments. On the other hand, various investments are also (being) made in the direction of the grid-oriented smart grid, though the focus is not (yet) on optimising network utilisation. These developments are hampered by the fact that DNOs are currently not allowed to offer their customers dynamic network tariffs (network costs are fixed, set between certain limits by the regulator). Furthermore, DNOs are required to give electricity consumers and producers unrestricted access to the grid and may not influence the timing of the demand. Nevertheless, the potential savings are very likely to offset the additional costs that are needed to benefit from using flexible demand to reduce peak load. Besides the additional costs, the benefits in reduced network investments should outweigh the possible (negative) influence on electricity markets if distribution network constraints are taken into account when shifting flexible demands.

The total electricity costs of a residential customer consists of electricity supply costs and network costs. The qualitative change in these costs in various smart grid concepts is visualised in Figure 7.1. In a market-oriented smart grid, residential customers participate in the electricity market (enabled by commercial market parties), the flexibility of the residential demand has value on the electricity markets, and the market functionality will increase, lowering electricity supply costs compared to a power system without a smart grid. Though supply costs will decrease in a market-oriented smart grid, it has been shown in this thesis that the network costs may increase, depending on the scenario. The variation in network costs is depicted by the hatched areas in Figure 7.1. In a grid-oriented smart grid, the network invest-

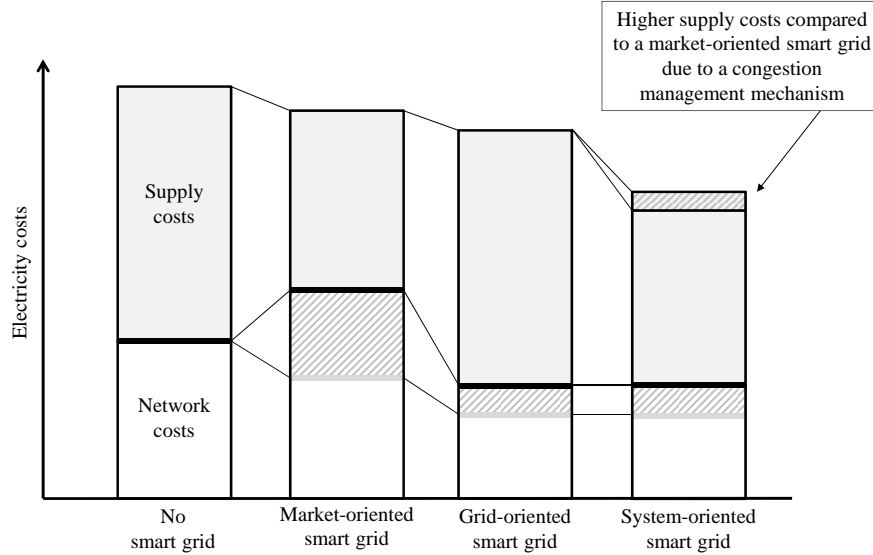


Figure 7.1: Total electricity costs of a residential customer in the future power system.

ments can significantly be reduced. To realise this, grid constraints need to be taken into account. If an efficient congestion management mechanism can be applied to do this only in those hours that the network load is high, network costs can be reduced and supply costs will only be slightly higher. This last situation is presented in Figure 7.1 as a system-oriented smart grid. The additional ICT infrastructure that is needed to realise a smart grid will be part of the network costs.

In this thesis, the focus has been on network impacts. It has been shown that flexibility in residential electricity demand has value for the DNO. In this section, it is argued that the flexibility also has value for market parties and the benefits for these parties as well as the benefits for the DNO are reflected in the electricity costs of the residential customer. Realisation of a power system in which the flexibility in residential electricity demand is made available for these various parties, raises two important questions:

- What is the value of flexible residential demand for various parties that are part of the electric power system?
- What implications does using flexible residential demand, while optimising distribution network utilisation, have on the organisation of the power system as a whole, including electricity market design?

These questions will be addressed in the following two sections.

### 7.3 The value of flexible residential demand for the customer

If flexibility in residential electricity demand is enabled, it can be used for multiple goals by different parties. In the first place, the customer must be willing and able to make the flexibility available to other parties. However, at present the possibilities of the user are often neglected [140]. It is expected that the adoption of a user centred perspective is necessary to reduce the chance that users will act as barriers. In the previous section, the value that flexibility of residential demand might have on electricity markets and for a DNO is discussed. In this section, attention is paid to the value of flexible demand perceived by the residential customers themselves.

A first question is, if residential customers are willing and able to shift their electricity demand in time, and if so how much? For this question it is important to be sensitive for the daily routines that cause electricity consumption. Daily routines that are shaped by the current context (e.g. technology and norms) need to be understood to change them. It is important to define the contextual factors that maintain the old habit, that can trigger and maintain a new and preferable habit and the chances of changing the habit [142]. For instance in the current context, it is possible to define which electric appliances have the largest chance in terms of the opportunity to shift times their electricity consumption in time. It is assumed that there are appliances (habits) that people are not likely to use at other moments (e.g. cooking). Still, there are appliances of which people are more likely to postpone the usage to later moments in time, like the washing machine. Last, some appliances are used almost continuously, such as heat pumps. Demand of these appliances can be shifted in time without the user noticing it, so no new habits are needed. For this type of shifting of electricity demand only an approval of the customer is needed to employ demand management [76].

Another question is, what are the perceived costs (e.g. in terms of investments, but also in terms of time, effort and comfort) and perceived risks (e.g. privacy and health hazards) of shifting electricity demand in time? It is important when developing smart grid concepts to be sensitive to these perceived costs and risks to foster the chance of success of the concept. For example, as a result of a new technology, some appliances could operate (semi-)autonomous, possibly reducing invested time and effort for the customer, but probably also increasing the investments.

At the same time it is important to answer the question whether residential customers value the possibility of shifting demand? What are the perceived advantages? By new tariff structures it might become financially interesting to shift demand. For example, an EV owner could be offered a higher tariff for fast charging of his EV, and a lower tariff if he is more flexible and gives his electricity provider and/or the DNO more time to charge his car. Another aspect is, that a smart grid can make it possible to match locally generated electricity with locally electricity demand and thus use locally produced, sustainable electricity. This might be interesting for local

sustainable energy initiatives, which have as main goal to locally produce energy by renewable sources and to be less dependent on conventional energy sources [152]. The number of these initiatives has grown exponentially the past years [120]. For instance, there are now more than 450 local sustainable energy initiatives in the Netherlands [55].

A last question in this context is, in what way do households (and even residents within households) differ? In this section, the word *perceived* (e.g. [66]) has been used intentionally, because the mentioned factors, such as costs, risks and advantages, can be influenced by the context (intended and unintended) and can be judged differently. Major differences exist between households if we look at demographics, but also if we look at other factors like habits, reactions to incentives or perceived risks. It is unlikely that one type of smart grid product or service fits all [29]. Therefore, different smart grid products and services are needed for different groups.

As a result of these uncertainties, the value that flexible electricity demand has for the residential customer and the amount of flexibility that may become available are not yet clear: this needs to be further investigated in pilots. These pilots will give insight in the amount of flexibility that can become available and will give answers to the questions who will be willing and able to make it available, and why or why not.

## 7.4 Implications on electricity market design

In liberalised electricity markets, consumers are free to choose their electricity provider. They have contracts with providers that offer them a certain tariff for their electricity consumption per kWh (sometimes simple variations to this, like day and night tariffs, exist). Furthermore, in most countries, the current market structure is such that residential customers pay the local DNO, that owns and operates the network to which they are connected, a fixed amount for the costs of the electricity network infrastructure, based on the capacity of their connection. Depending on the rules of the specific country, customers pay an additional network tariff per kWh. These network tariffs are fixed between certain limits, set by the regulator. An alternative could be to charge customers more directly for their capacity usage and apply a tariff per kW for the capacity they actually use. Furthermore, the electricity networks must be able to handle the electricity flows at all times. In general, DNOs have the responsibility to provide a reliable electricity distribution infrastructure that can satisfy the electricity demands of all customers connected to it and that can handle surplus of locally produced electricity after matching it with local demand. It is also their task to do this in an economically efficient way.

The results in Chapter 6 show that the flexibility in residential electricity demand that can be enabled by smart grids, has value for DNOs when it is used to reduce maximum loadings, and could contribute to a more efficient utilisation of the distribution networks. In the previous sections, it has been argued that it is unclear how

this value relates to the value this flexibility has for the customer and the value that it creates on electricity markets. Also, the amount of flexibility that will be made available by the customers needs further research. To investigate these issues in the real world pilot projects are being set up. Besides giving answers to specific research questions, pilot projects demonstrate the functionality of technologies which must be implemented to put smart grids into practice. Furthermore, the projects focus on the social and economic aspects of smart grids and pay attention to the regulatory framework, e.g. to allow DNOs, in contrast with current market rules, to shift the flexible electricity demand in time.

In this section, three examples will be presented of pilot projects that implement shifting of flexible residential demands for multiple goals. In Section 2.4.1, it has been explained that in the future power system, a distribution system operator (DSO) will exist of which the responsibilities reach further than those of a distribution network operator (DNO). Though the transmission system operator (TSO) will still be responsible for the system balance within a certain area, the DSO may be responsible for handling emergency situations in its local area, for regional grid access and grid stability, integration of renewables at the distribution level of the grid and regional matching of supply and demand. In addition, the DSO may be required to give priority to generating installations using renewable energy sources or waste or producing combined heat and power. Also, in the projects presented in this section the DNO plays a more active role and its tasks and responsibilities are broadened compared to the current situation. Therefore, in the remaining of this section, the DNO will be called a DSO.

#### 7.4.1 Smart charging

With smart charging of EVs, it is possible to adapt charging to the fluctuating in-feed of renewable electricity production taking into account the available network capacity and customer preferences [137]. A project was started to develop an open protocol and international standard to realise communication between market parties that will support smart charging. This follows up on a smart charging field test that has already been completed [39]. In general, the goal of smart charging is to support the integration of renewable energy sources and reduce network investments, leading to a reliable grid and lower costs for the customer.

In Figure 7.2, an overview of the smart charging project is depicted. There are various market models possible for the roll-out of a public charging infrastructure for EVs [42]. In [43] two of these market models are described in more detail. The smart charging project presented here assumes one of these models; i.e. an independent e-mobility operator model in which public charging stations are being deployed independently from the regulated DSO activities. The DSO has a direct contract with the owner of the network connection to which the charging station is connected. The role of the DSO allows him to send technical signals to the charging

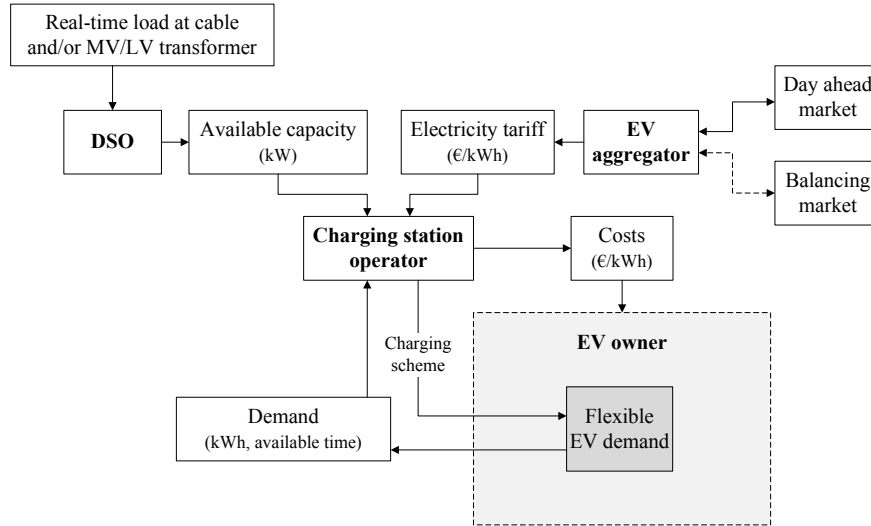


Figure 7.2: Overview of the smart charging pilot project.

station operator requesting power reduction, or power increase, according to the local situation of the network.

In this smart charging project, the DSO sends a forecast of the capacity that is available for flexible loads to the charging station operator. The protocol that is being developed in this project, will describe how the information is shared between the DSO and other parties. It should be noted that the protocol could be applied in a broader context; in this project EVs are used as flexible loads, but the same protocol could be used for management of other flexible loads.

In the project, the electricity tariff is fixed. Variations to this are also possible. For example, the EV aggregator can offer the EV owner a dynamic tariff that could be adjusted to the flexibility the EV owner gives the aggregator to charge his car (i.e. the time range that is available for charging). Furthermore, if dynamic tariffs are realised and flexible EV demand becomes available (close to) real time and in short intervals, the aggregator could trade the flexible EV demand with the DSO and/or TSO in order to provide ancillary services.

#### 7.4.2 Home energy management

The pilot project *Your Energy Moment* is a joint effort between electricity providers and a DSO. The objectives for the pilot are formulated as follows [75, 77]:

- The local capacity of the network will be used more efficiently by reducing the transport of electricity over the local MV/LV transformer.

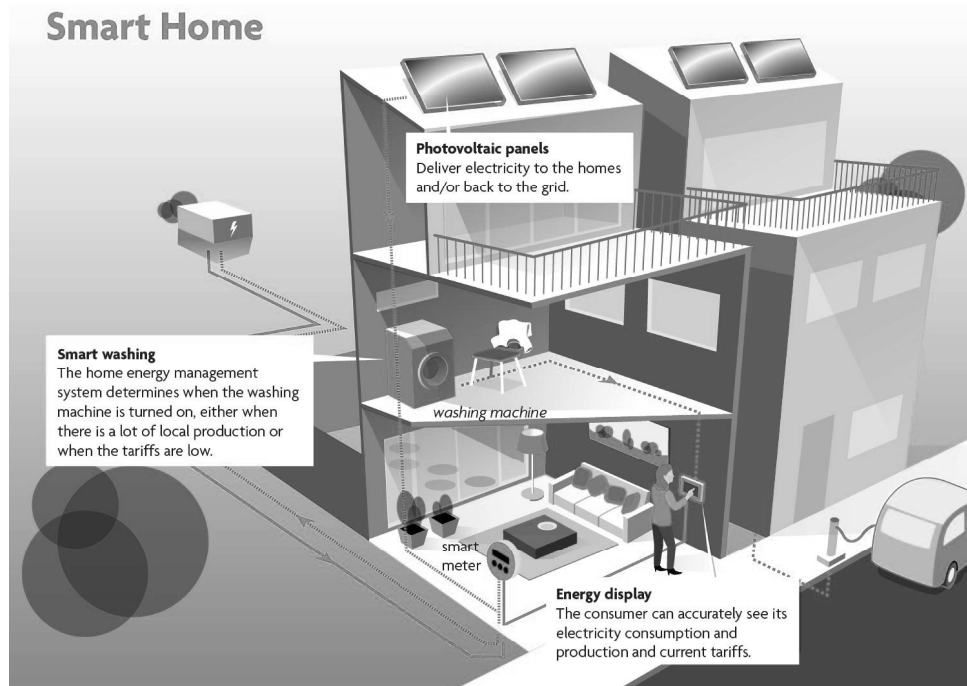
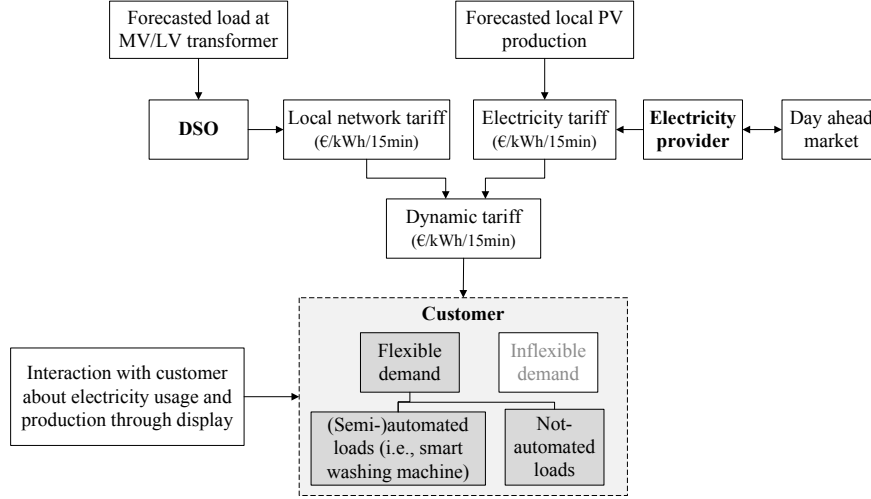


Figure 7.3: Illustration of the working principle of the home energy management system in the pilot *Your Energy Moment*.

- Fluctuating renewable distributed generation will be incorporated more efficiently into the local infrastructure by matching the local (flexible) demand to the use of locally produced electricity.
- Price variations on the day-ahead market will be transferred to the customer by translating the variations into dynamic electricity tariffs.

The goal of the pilot is to change customer behaviour in order to reach these objectives. Therefore not only technology, but also incentives, interaction and communication are considered key instruments in the pilot [77]. As for the technology, an illustration of the home energy management system that is applied in this pilot is provided in Figure 7.3 .

Next to a smart meter, customers have PV panels, an energy computer, a wall display, and a smart washing machine. The smart washing machine optimises its start time within the time frame set by the customer, taking into account the already scheduled washing machines in the same residential area, local production and/or dynamic tariffs for electricity. The interactive wall display is used for interaction and communication; the display informs the customers about electricity consumption and

Figure 7.4: Overview of the pilot project *Your Energy Moment*.

production, forecasts on local production and the height of the dynamic tariff. This dynamic tariff reflects all three pilot objectives and is a combination of a dynamic electricity tariff and a dynamic network tariff. An overview of the pilot is given in Figure 7.4.

The customers receive a tariff that is a combination of a dynamic electricity tariff from their electricity provider and a dynamic network tariff from their DSO. The electricity tariff is based on the day-ahead electricity market and also includes local electricity production by PV panels to stimulate the use of electricity at moments when locally generated electricity is available. The pricing scheme is constructed in such a way that if the customer would not change his expected consumption pattern the total annual electricity costs are equal to the situation in which the customer would not participate in the pilot and would pay a fixed electricity tariff.

In the Netherlands customers pay an annual fixed amount to their DSO, however, during the pilot the network tariff is made dynamic in order to stimulate DSM. For this network tariff a peak pricing scheme is applied, which depends on the daily peak hours. This tariff is again designed in such a way that if the customer does not change its consumption pattern the total annual network costs are equal to the situation in which the customer would have paid fixed network costs.

The pilot *Your Energy Moment* is realised at two locations in the Netherlands and there are in total about 250 participants. Next to interviews, observations and questionnaires, electricity consumption and interaction with the system of each participant is monitored, using a smart meter and the information on use of the display and smart washing machine. Furthermore, the load at the MV/LV transformers and the feeders to which the customers are connected is measured. These data will make

it possible to define the aggregated reduction of the peak load of the participants as well as the reduction of the peak loads at the MV/LV transformer level.

The pilot will show how participating households react to incentives, and answers the question if the customer is willing and able to adjust his electricity demand to the (local) available generation and network capacity in this context. Because the pilot duration is two years (2013–2015), the short- and long-term effect is studied. Do participating households form new habits and does the effect remain? Using the results, the contribution of the DSM possibilities to the objectives of the DSO can be defined.

The role of the DSO in this project is that of an independent market facilitator. The DSO provides other parties (the electricity provider and the customers) with data on energy usage, production and predictions. The electricity provider uses these data to offer its customers an energy service (that includes a DSM service of the DSO to relax the loading on the distribution networks on peak hours).

### 7.4.3 PowerMatching optimisation

The *PowerMatching City* pilot consists of two phases. In the first phase, launched in 2010, 25 households in Hoogkerk, the Netherlands, were involved [18]. A market model for intelligent network operation under current market conditions was developed. The coordination mechanism in this model is provided by the multi-agent based PowerMatcher technology, which allows simultaneous optimisation of the objectives of different stakeholders [18]. The PowerMatcher matches energy demand and supply, using the flexibility in residential electricity demand, such as the flexibility of  $\mu$ -CHPs, heat pumps, smart appliances (e.g., smart washing machines and smart dishwashers) and EVs. The group of households is treated as a VPP. The priority of devices to turn on or off is translated into a bid-price curve and consequently the market mechanism decides whether the devices are turned on or off by communicating back the market clearing price. In the first phase, it was shown that optimisation goals such as the reduction of imbalances are reached with this concept without compromising on customers' comfort [71].

In the second phase, which started in 2011, the focus is on integration of the market model into regular energy market processes like allocation, reconciliation and billing, and on evaluating the costs and benefits for the various parties [71]. The DSO is also involved in this phase and the goal of network capacity management is included in the multi-goal optimisation of the PowerMatcher technology [99]. The objectives of the different actors can be conflicting, e.g. the objective of the DSO can conflict with that of the party that runs the VPP if local congestion occurs while the balance responsible party has a long position in the system; in this case, the DSO will alter the local price signal by adding a network tariff and reduce power consumption in this part of the network. In this way, the DSO can enable a bid-price curve transformation in order to manage local congestion and limit the import or export of electricity of a part of the network [99]. To test this in real

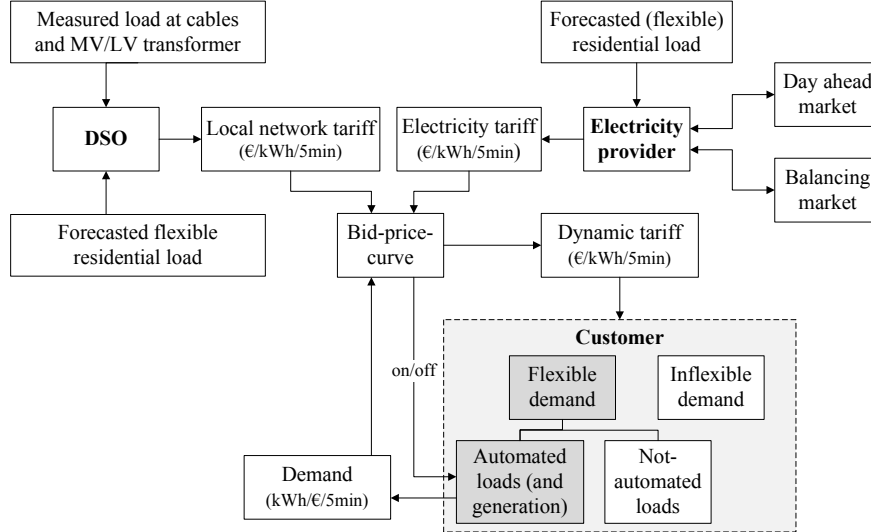


Figure 7.5: Overview of the PowerMatching City pilot project.

life, the pilot is scaled up with about 20 households that are connected to the same MV/LV transformer; this enables load management at the level of the distribution substation. The loading on the transformer and the cables to which the customers are connected will be actively monitored. Based on the measurements, incentives are given to the customers connected to the distribution substation if there is a need to reduce or increase the residential load. An overview of the project is presented in Figure 7.5.

In theory, incentives given by a DSO can be soft (price) incentives or hard (curtailment) incentives. In this project, the goal of the project is to integrate the objectives of various parties by using the PowerMatcher concept in regular energy market designs; therefore, the costs of the DSO associated with active capacity management need to be in line with the current market model and price incentives are considered (possibly in combination with a curtailment signal that overrules price incentives in emergency situations). The price incentives are translated into a local network tariff, with higher values for peak hours. As a starting point, the resulting average annual network costs based on this dynamic network tariff should equal the currently applied yearly fixed network costs. Furthermore, the cost and benefits of the ICT architecture for all the involved stakeholders will be evaluated in the pilot to be able to also integrate these costs in the cost-benefit analysis.

In this project, in contrast to the other projects that were mentioned in this section, the DSO is a party that participates in the market. Goal of the project is to demonstrate if the costs and benefits for the different parties can be valued and

allocated using a market environment. Answers are not yet given on e.g. which party will be responsible for well-functioning of this market mechanism.

#### **7.4.4 Discussion on pilots**

The pilots that have been presented in this chapter, give examples of smart grid architectures to realise shifting of flexible residential demand for multiple goals. These examples show that there are different ways to organise the market and build smart grids in which flexible demand is enabled. Also, attention is paid to the layout of the ICT infrastructure. The roles and responsibilities of the DSO are defined differently in the presented projects. Various options are possible, it is, however, clear that the role and possibilities of the DSO change in a smart grid environment and it is important to define these issues further in order to be able to adjust the regulatory framework accordingly.

There are many other projects that research these topics. The Joint Research Centre of the European Commission has made a comprehensive inventory of smart grid projects in Europe; an overview of these projects can be found in [21]. In 2012 this inventory included 281 smart grid projects and around 90 smart metering pilot and roll-outs projects from 30 European countries [52]. The most significant obstacle to the large-scale implementation of the applications tested in the smart grid projects surveyed in this report, are regulatory barriers. Particularly the uncertainty among parties about roles and responsibilities in new smart grid applications (e.g. in the ancillary service markets for network capacity) and the uncertainty about sharing of costs and benefits among different stakeholders (e.g. active demand market), create uncertainty about new business models and might be hindering implementation. The regulatory implications of changes in (local) electricity markets are discussed in [65] and several recommendations to adapt current regulatory practices to facilitate the efficient integration of smart grid technologies are presented in [26].

Besides that, it is noticed that customer involvement is becoming more important in the projects that are part of the survey [52]. Customers, their daily routines and the social context in which they operate, should be more central in the smart grid community, where the focus is still mainly on technological issues and economic incentives [140]. The survey indicates that the number of consumer involvement projects has grown since 2005, though these projects are still predominantly in the demonstration phase [52].

## **7.5 Summary and conclusions**

Investments towards various types of smart grids are being made. The market-oriented smart grid concept may become reality under the current market structure, if a dynamic tariff for the electricity supply costs (that can be supported by smart meters) is realised. This situation may, however, not be optimal in terms of required

network investments. On the other hand, various investments are also (being) made in the direction of the grid-oriented smart grid, though the focus is not (yet) on optimising network loading. If flexible demand is used to reduce peak loads, network investments can significantly be reduced and it is concluded that the potential savings are very likely to offset the additional costs that are needed to realise this. By applying an efficient congestion management mechanism when shifting flexible demands, the benefits in reduced network investments can be reached without a large increase in electricity supply costs.

Flexible electricity demand has value for various parties, but before it can create value to these parties, it must be made available by the residential customers. To be able to quantify the value that flexible electricity demand has for the residential customer as well as the amount of flexibility that may become available, various questions must be answered. Are residential customers willing and able to shift their electricity demand in time? What costs (e.g. in terms of investments, but also in terms of time, effort and comfort) and risks of shifting electricity demand in time do the customers perceive? Do residential customers value the possibility of shifting demand? What are the perceived advantages? And in what way do households (and even residents within households) differ? To answer these questions, they must be addressed in smart grid pilots.

Besides giving answers to these questions, pilot projects demonstrate the functionality of technologies which must be implemented to put smart grids into practice. Furthermore, the pilots focus on the social and economic aspects of smart grids and pay attention to the regulatory framework, e.g. to allow DNOs, in contrast with current market rules, to shift the flexible electricity demand in time and become DSOs. Three examples of pilot projects that implement shifting of flexible residential demands for multiple goals are presented. These examples show that there are different ways to organise the market and build smart grids in which flexible demand is enabled. The projects also show that various options are possible in defining the roles and responsibilities of the DNO. It is, however, clear that the role and possibilities of the DNO change in a smart grid environment and it is important to define these issues further in order to be able to adjust the regulatory framework accordingly. A review of other European smart grid pilots also confirms that, in order to implement smart grids, attention need to be paid to regulatory barriers (in particular, the uncertainty among parties about roles and responsibilities and the uncertainty about sharing of costs and benefits among different stakeholders).

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## Conclusions, contributions and recommendations

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### 8.1 Conclusions

The planning and design procedures and criteria that have been developed over the years, have led to well-functioning, reliable electricity distribution networks with sufficient capacity, based on peak situations. However, as a consequence of the developments due to the energy transition, the electricity distribution networks need to support and integrate DG and facilitate a potential growth in electric loads that use new, energy intensive technologies. On the one hand, loading of the networks can increase significantly due to these changes in the future demand and supply of electricity. On the other hand, the consequences of these developments can be mitigated by various developments that lead to more active (smart) operation of distribution networks.

The research objective in this thesis was to investigate the consequences of future residential electricity demand and supply on electricity distribution networks and to explore measures to optimise the utilisation of the distribution networks. This has been done by assessing the impacts of three future scenarios as well as the impacts of applying either a grid-oriented or a market-oriented smart grid strategy to shift flexible residential loads. The results show that to accommodate future residential electricity demand and supply network reinforcement costs can increase significantly, depending on the scenario. By applying a grid-oriented smart grid strategy that focuses on minimising network loading the possible cost savings can be large (compared to a situation without a smart grid as well as to a situation in which a market-oriented smart grid strategy is applied).

To realise these potential cost savings, smart grids must be implemented. The flexibility in residential electricity demand does, however, not just have value for the DNO, but also for market parties, such as suppliers, traders and providers of ancillary services. The benefits for these parties as well as the benefits for the DNO are reflected in the electricity costs of the residential customer. To minimise these costs, the benefits of the various parties should integrally be regarded in a system-oriented smart grid.

To unlock the flexibility in residential electricity demand and use it to optimise network utilisation, the DNO should be able to allocate the savings in network costs to the stakeholders in smart grids that enable flexible residential demand. This is not

possible in the current regulatory regime. Further research should focus on defining the role and responsibilities of the DNO in a smart grid environment. Customer involvement is a very important issue that needs full attention in order to successfully unlock the flexibility in smart grids and optimise utilisation of distribution networks.

These main conclusions are found by answering the research questions formulated in Chapter 1. The following sections elaborate on each of the research questions separately.

### 8.1.1 Future residential electricity demand and supply

To identify the main drivers and policy measures that may lead to variations in the (residential) electricity demand and supply, recent scenario studies have been reviewed. It can be concluded that depending on a more nationally or internationally focused policy, a more economically or environmentally oriented society and the degree of economic growth, the future electrical energy system can develop in different directions. Variation in these drivers will lead to very different, yet realistic scenarios with different trends in types, location and size of generation and loads.

Due to the energy transition new energy conversion technologies will certainly influence the future electricity demand in residential areas and households may also start to produce electrical energy themselves. The main developments that will substantially change the electricity demand in residential areas, are the increase or decrease of load due to regular domestic appliances and the application of new technologies like  $\mu$ -CHPs, heat pumps, EVs and PV panels. These new technologies change the net load profiles and it may increase or decrease the residential electricity peak demand; but it leads also to flexible demands that bring the opportunity to shift the electricity load in time.

Another consequence of the developments in the future electricity demand and supply of residential customers is that more differences may exist between individual customers connected to the grid; e.g., one household may choose for a  $\mu$ -CHP and the other for a heat pump in combination with solar panels. This means that the profiles of individual households will differ more and will be less predictable than nowadays. Looking at a larger scale, the differences between residential areas may diverge. A newly developed residential area in a city, for example, may have a very different load profile than an existing group of houses at the countryside.

### 8.1.2 Residential loads

Because of new energy conversion technologies that may be introduced at the individual household level, more differences between individual customers connected to the grid will exist. Furthermore, the electricity demand for some of these technologies is less time critical than for most other types of loads. The flexibility, that can be enabled by smart grids, brings with it the opportunity to shift load in time. This will change the load profiles. Also, because of the uncertainty with respect

to the development and adoption of the technologies (including the possibility to supply electricity to the grid), net load profiles of individual households will be less predictable than nowadays.

### 8.1.3 Impact of changing load profiles on distribution networks

When assessing the impacts of future electricity demand and supply on the distribution networks, the shape of the daily load profiles is of importance, because peaks can occur at various moments during the day. A less predictable load profile not only has implications for estimating the maximum loading, but changing load profiles over time may also affect other issues in distribution networks. Energy losses are partly dependent on the shape of the load profiles. Energy losses can be separated into fixed and variable losses, dependent on the loading and on the material characteristics of the network assets. When assessing the impacts of changing load profiles on the energy losses, both types of losses should be quantified, taking into account the fact that replacing assets influences the energy losses as well. Changing load profiles may also change the maximum allowable loading of an asset, because a more continuously loaded asset will cool down less after maximum loading and this may result in a reduction in the maximum allowable loading.

### 8.1.4 Modelling residential demands

When modelling residential demands, the variation between households must be taken into account. In addition, to analyse the impact of the flexibility of electricity demand on the loading of the networks, modelling the electricity demand over time, rather than the peak load alone, is necessary. Present methods for modelling large numbers of residential demands that are most applied determine peak loads (or daily load profiles) based on empirical data and under the assumption that certain consumer groups have identical profiles. However, since future demands are less predictable and cannot be based on historical measurement data, available models are not suitable. This asks for an adaptation of present modelling in such a way that the aggregated (peak) demand for several tens to hundreds of households can be estimated, taking into account the variation between customers and the variation over time.

This can be done by using a method that constructs load profiles taking into account the variation between households that may use different combinations of new technologies, including local generation of electricity, and that can handle shifting of flexible loads. The modelling approach that is proposed combines individual load and generation profiles to construct aggregated net load profiles of a group of households. This makes it possible to assess the impact of various scenarios on the electricity distribution networks by applying different penetration degrees of each technology and to take into account demand for electricity that may be flexible and shifted in time for various goals.

The modelling method is used to investigate the impacts of two different smart grid strategies, referred to as *minimising network load* and *minimising electricity supply costs* on the residential load profiles. The first smart grid strategy reflects a grid-oriented smart grid concept in which the smart grid functionalities are focused on the responsibilities of the network operator. With this strategy the flexible demand in residential areas is shifted from moments of high loading to off-peak moments to minimise network utilisation and reduce network reinforcements; this will lead to more flattened load profiles. The second smart grid strategy reflects a market-oriented smart grid concept that aims at enabling residential customers to participate in the electricity market by introducing more advanced pricing schemes. With this strategy the flexible demand in residential areas is shifted towards moments with low electricity prices in the wholesale market.

The resulting net load profiles show that applying no smart grid strategy or the minimising electricity supply costs strategy, results in significant higher peak loads than applying the minimising network load strategy. However, in not more than about 30% of the hours in the year, the network loading would be higher than in the case that the flexible residential demand is used to minimise the network loading; in case of applying the minimising electricity supply costs strategy this is even limited to 18% of the hours or less. This means that the minimising network load strategy does not have to be applied during all hours of the year to reach the advantages of decreased maximum loadings leading to reduced network investments.

### 8.1.5 Impacts on distribution networks

The impact of future residential electricity demand and supply on the distribution networks have been assessed by exploring three future scenarios and two smart grids strategies. The impacts on the required capacities as well as on energy losses in distribution networks have been quantified. Though energy losses contribute significantly to the total impacts, the differences in the impacts between applying various smart grid strategies are mainly caused by differences in the required network investments.

The three scenarios show large differences in the outcomes. The expected maximum loadings can significantly increase; this is especially the case for Scenarios B and C. Applying the minimising network load strategy reduces the cumulative cash flow for the reinforcement costs by 48–67%. By contrast, in Scenario C the minimising electricity supply costs strategy leads to larger maximum loadings and results in larger investment costs compared to the case no smart grid strategy is applied. This is caused by the extra demand from the flexible loads at moments when prices are low. Because of the high share of electricity production by renewable energy sources in Scenario C, these moments especially occur at moments when production by these sources is high.

### 8.1.6 Optimising distribution network utilisation

Already investments are (being) made for various smart grid functionalities. If flexible demand is used to reduce peak loads, network investments can significantly be reduced and it is concluded that the potential savings are very likely to offset the additional costs that are needed to realise this. By applying an efficient congestion management mechanism based on shifting flexible demands, the benefits in reduced network investments can be reached without a large influence on electricity supply costs. In this way, network utilisation can be optimised in smart grids and overall system costs can be minimised.

To realise such a smart grid, various issues need attention. Customer involvement is very important in order to successfully implement smart grids. Customer behaviour in this context is, however, not fully understood and should be given more attention. Various questions are to be answered to be able to quantify the value that flexible electricity demand has for the residential customers themselves as well as the amount of flexibility that may become available. These important questions must be addressed in smart grid pilot projects.

Another important issue is related to the organisation of the power system, including electricity market design. A review of pilot projects shows that various options are possible in defining the roles and responsibilities of the DNO. It is, however, clear that the role and possibilities of the DNO change in a smart grid environment and it is important to elaborate on these issues further in order to be able to adjust the regulatory framework accordingly and eliminate regulatory barriers.

## 8.2 Contributions

The main contributions of this thesis are summarised in this section.

- Future electricity demands differ for various scenarios and between individual customers, and include flexible demand that may be shifted in time. A novel approach for a profile-driven determination of the peak demand value and peak moments, is proposed to model residential demand profiles. The approach takes into regard the load (and generation) profiles of the different future residential technologies, like  $\mu$ -CHPs, heat pumps, PV panels and EVs. After careful modelling of the individual load and generation elements of the residential demand and supply, these individual profiles are subsequently combined to construct the total aggregated demand of a group of households. This modelling approach gives insight in differences between various residential areas and makes it possible to assess the impact of various scenarios on the electricity distribution networks by applying different penetration degrees of the technologies. Besides this, the method makes it possible to take into account control of flexible loads in smart grids.

- Using newly constructed residential net load profiles for ten typical residential areas, an elaborate assessment of the impacts of various scenarios as well as various smart grid strategies on distribution network utilisation is performed. To assess these impacts, the energy losses as well as the required network investments are quantified for all the cases.
- Being aware of the investments in smart grid functionalities that are already (being) made and the benefits that flexible demands can bring to other optimisations and services, it is demonstrated that distribution network utilisation can be optimised if flexible residential demand is enabled to reduce peak loads in future grids.
- A review of current smart grid developments is performed and it is shown that to reap the benefits of flexible electricity demand in smart grids, customer interests and customer involvement are very important issues that raise several questions that should be addressed in smart grid pilots.

### 8.3 Recommendations

Based on the findings in the thesis, a number of recommendations can be formulated. These are listed in this section.

- It is no longer sufficient to use historical load data in combination with an expected load growth to estimate future demand for the network planning process. By examining electricity networks in the Netherlands, the approach applied in this thesis has shown to give insight in the impacts of uncertainties in future electricity demands. The results illustrated that scenarios resulting from varied economic and demographic developments, but also driven by energy-related policy choices to e.g. reduce greenhouse gas emissions and increase the share of renewable energy production, can have considerable consequences on the loading and the resulting required network capacities of electricity distribution networks. To be able to respond to the developments on time, on the one hand, making use of the flexibility in future demands can be a way to reduce (rapidly growing) peak loads and optimise network utilisation. On the other hand, it is essential for DNOs to be flexible in network planning itself. This asks for additional research on how to include uncertainties in future demand in the network planning process. Also, clear visions on the future energy system of local as well as national governmental bodies and making clear choices regarding their energy policies can contribute to minimising this uncertainty.
- A modelling approach has been proposed that only needs limited information on new technologies that are applied in residential areas. One reason for this is that only limited amount of data is available on future technologies. To further

improve modelling of future residential demand and supply, further research on modelling approaches is required. In future networks, more and more measurements will become available and knowledge on differences between residential customers can be obtained that can be used for this research.

- Energy losses can increase significantly depending on the future scenario. In this research it was found that the actual energy losses (in specific parts of the network) were difficult to obtain. It is therefore recommended to investigate if actual energy losses can be quantified more specifically by measurements. Subsequently, the findings can be validated and it can be investigated whether energy losses can be reduced.
- As has been extensively discussed in this thesis, the amount of flexibility that may be made available by residential customers in smart grids are not yet clear. It is therefore important to apply a user-centric approach in smart grid pilots. Furthermore, clarifying the uncertainties related to customer behaviour should be a main research goal.
- From a societal point of view, a power system should be developed and operated that balances the benefits between the various parties that participate in this system and minimises overall system costs. To be able to do this, further research is required to quantify the value that flexibility of residential demand creates on the electricity market and the value it has for the customers themselves (not only in terms of money).
- To realise smart grids that enable flexible residential demand to optimise network utilisation, it is important to put smart grids into practice. On the one hand, this is done by testing technologies and smart grid designs in pilot projects. In these smart grid designs, several options are possible for the role and responsibilities of the DNO. To implement smart grids on a larger scale, it is important to clearly choose and define the role and responsibilities of the DNO in order to be able to adjust the regulatory framework accordingly and eliminate regulatory barriers.
- Another topic for further research is how to allocate the infrastructure costs to the customers in smart grids that enable flexible residential demand to optimise network utilisation. The costs the customers pay for the electricity infrastructure must reflect the actual use of the networks in such way that the DNO is able to deploy customers to use their (flexible) electricity demand with the goal of optimising network utilisation.



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## Background information on scenarios

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The numbers presented in Chapter 3 are based on information and data presented in this appendix. Some general numbers about the amount of houses, persons per household, the insulation of the houses and the amount of vehicles are defined for each scenario and presented in Table A.1. The numbers of households, the numbers of persons per household and the number of vehicles per household are determined with help of the scenarios in [118]. For Scenario A, the *Regional communities* scenario has been used and for Scenario C the *Global economy* scenario. For Scenario B, the average of the scenarios *Strong Europe* and *Transatlantic market* has been used. The specific numbers related to each of the technologies that are expected in the scenarios are treated per technology.

Table A.1: Specific numbers for each of the scenarios.

	Current numbers	Scenario A	Scenario B	Scenario C
Number of households (million)	7.4	7.4	10.0	8.6
Houses demolished and rebuilt per year (%)	0.3	0.3	0.3	0.3
Existing/newly developed areas	100/0	91/9	66/34	77/23
Decrease in heat demand per year due to insulation in existing houses (%)	–	1.0	1.0	1.0
Heat demand in newly built houses (kWh/m <sup>2</sup> )	53–66	42	35	39
Existing houses that are well-insulated (%)	0	10	50	30
Number of persons per household	2.31	2.26	1.95	2.20
Number of vehicles per household	1.03	1.10	1.17	1.13

### $\mu$ -CHPs

In a study that was assigned to various organisations by the Dutch government, two possible growth scenarios for  $\mu$ -CHPs have been elaborated [30]. The most positive scenario presumes that in a saturated market 350,000  $\mu$ -CHPs per year are sold; the other scenario presumes yearly sales of over 150,000  $\mu$ -CHPs. Both scenarios assume

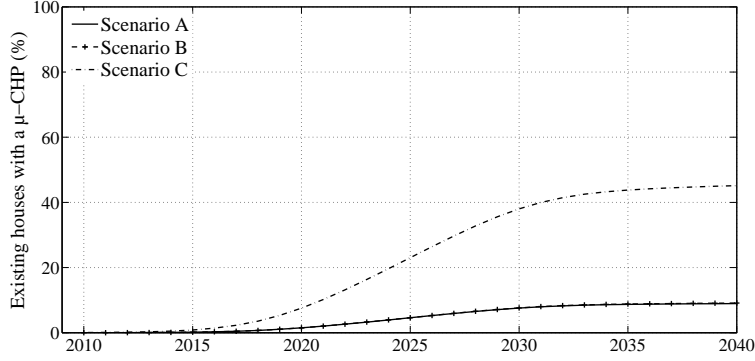


Figure A.1: Adoption curves of  $\mu$ -CHPs presented in the percentage of existing houses with a  $\mu$ -CHP.

that the commercialisation of the  $\mu$ -CHP takes off in 2008 and that in 2013 more than 70,000  $\mu$ -CHPs are sold per year. Though  $\mu$ -CHPs are already on the market, only a low amount of systems are currently sold and this number is by far not yet reached.

The scenarios applied in this thesis, consider a delayed development of  $\mu$ -CHPs with respect to the scenarios presented in [30]. In Scenarios A and B the development of the  $\mu$ -CHPs is not stimulated by the government and it is assumed that the sales of  $\mu$ -CHPs will stagnate at 50,000 pieces per year. In Scenario C policy measures are established to help the development of efficient technologies such as  $\mu$ -CHPs and a higher growth rate of  $\mu$ -CHPs is realised in this scenario. Taking into account the installation of air source heat pumps, which are a good alternative for  $\mu$ -CHPs, it is expected that in this more optimistic scenario around 250,000  $\mu$ -CHPs are sold per year in 2040. When these numbers are combined with the numbers of existing houses this leads to the adoption curves as presented in Figure A.1. In these numbers it is taken into account that  $\mu$ -CHPs have a lifetime of 12 years.

The electric power rating of the  $\mu$ -CHPs is 1 kW and they are expected to be installed in already existing houses, because they are especially attractive in houses with a large heat demand and thus less suitable for newly built, well-insulated houses. Furthermore, in Scenarios A and B the efficiency of the  $\mu$ -CHPs will not improve and the thermal power rating is 6 kW. In Scenario C the technology will further develop and the efficiency will increase; in this scenario, the  $\mu$ -CHPs will deliver 1 kW electrical power when generating 2.5 kW thermal power. The numbers for each of the scenarios are presented in Table A.2.

Table A.2: Numbers related to  $\mu$ -CHPs in Scenarios A, B and C (in 2040).

	Scenario A	Scenario B	Scenario C
Number of $\mu$ -CHPs sold per year	50,000	50,000	250,000
Electrical power rating	1.0 kW	1.0 kW	1.0 kW
Thermal power rating	6.0 kW	6.0 kW	2.5 kW

## Heat pumps

Because the air source heat pump is a well-suitable technology to replace gas boilers in existing buildings for basic space heating, the potential of these heat pumps to replace gas boilers in the Netherlands is investigated in [54]. In this study two scenarios are presented. In one scenario, the market share of air source heat pumps grows to a saturated market of 300,000 pieces per year, which corresponds to approximately three-quarter of the replacement market of gas boilers. The other scenario takes into consideration that other competing technologies are successful as well and assumes a moderate growth towards 150,000 pieces per year. In Scenario A presented in this thesis, only 20,000 heat pumps are installed in existing houses. In Scenario B the yearly sales of air source heat pumps is 300,000 in 2040. In Scenario C, the air source heat pumps have to compete with a relatively large number of  $\mu$ -CHPs that are installed as well, which results in the installation of 150,000 heat pumps per year. The adoption curves of air source heat pump in existing houses are presented in Figure A.2. In these numbers a lifetime of 15 years is taken into account.

Though most houses are connected to an extensive gas network in the Netherlands, an electricity infrastructure with heat pumps is nowadays often preferred to installing a gas network in newly developed residential areas and it is expected that in these new areas heat pumps will be one of the main technologies for heating [44]. The ground source heat pump is the heat pump technology that is mainly applied in these areas to supply space and tap water heating. On very cold days, an electric resistive heating element is used for additional heating. In Scenarios B and C, a ground source heat pump is installed in 80% of the houses that are built, according to the expectations in [44]. This number will be reached around 2020–2025. In Scenario A a more moderate growth of heat pumps is assumed: in this scenario the share of houses that are built and in which a ground source heat pump is installed, grows to 50%. The adoption curves of newly built houses with a ground source heat pump are presented in Figure A.3.

The efficiency of the heat pump is defined by the coefficient of performance (COP), which is the ratio between the heat delivered and the electrical energy used by the heat pump. When a low temperature heating system, like under-floor heating, is installed and the house is good insulated this value will be higher than with high

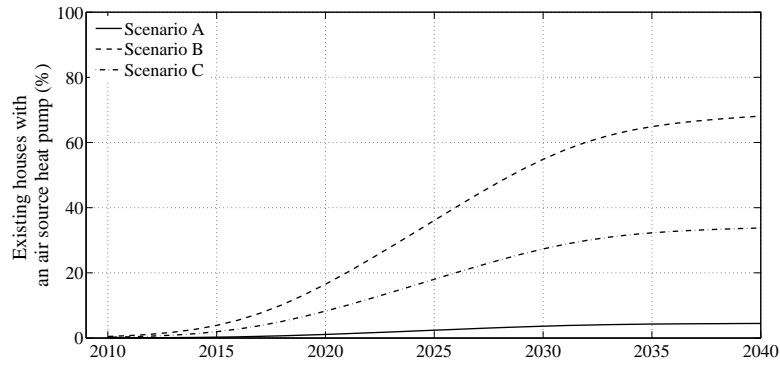


Figure A.2: Adoption curves of air source heat pumps presented as the percentage of existing houses with an air source heat pump.

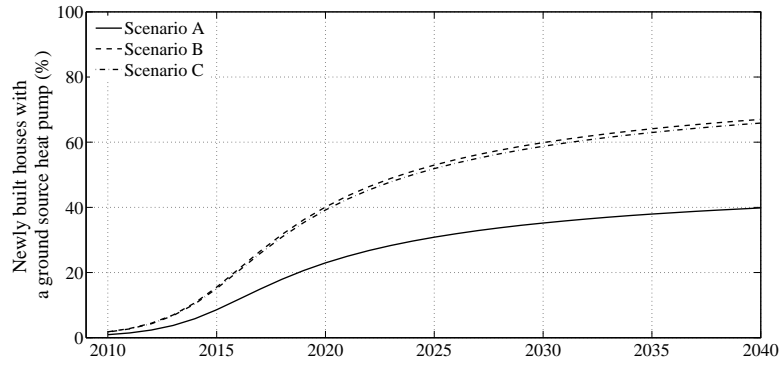


Figure A.3: Adoption curves of ground source heat pumps presented as the percentage of newly built houses with a ground source heat pump.

Table A.3: Numbers related to heat pumps in Scenarios A, B and C (in 2040).

	Scenario A	Scenario B	Scenario C
Number of air source heat pumps installed per year	20,000	300,000	150,000
Percentage of newly built houses that are equipped with ground source heat pumps	50%	80%	80%
COP-value air source heat pump	3.9	3.9	3.9
COP-value ground source heat pump	5.2	5.2	5.2

temperature heating and less insulated houses. In existing houses that are less well-insulated the COP-value for space heating lies at present around 3<sup>1</sup> [54]. The efficiency of ground source heat pumps is higher because the ground has a more equal temperature distribution in comparison with air. Currently, the COP-value of ground source heat pumps in well-insulated houses is about 4. The efficiency of heat pumps will increase over the years [59]. In the scenarios it is taken into account that the efficiencies will increase with 30% in 30 years, based on numbers mentioned in [54]. The numbers related to heat pumps for each of the scenarios are presented in Table A.3.

## Photovoltaic panels

In 2011 the installed power of PV panels in the Netherlands was 145 MWp [1]. In the forecasts of the development of installed PV power capacity large differences exist. In [123] an autonomous growth of installed capacity to 500 MWp in 2030 is expected without any governmental incentives to stimulate the development of PV technologies. With incentives, it is stated that the installed capacity can grow towards 6 GWp in 2030. In [118] the numbers related to installed PV power capacity vary from 350 MWp to 3 GWp in 2040 in various scenarios, and the amount of installed capacity in three scenarios described in [94] in 2040 varies between 5 and 44 GWp.

In this thesis, the growth of installed PV power capacity is set to 3 GWp in 2040 in Scenarios A and B; in these scenarios this technology is not stimulated. The PV panels will mainly be installed on roofs of houses in these scenarios. In Scenario C, electricity produced by PV panels is stimulated and applied on a larger scale. The installed power grows to 20 GWp in 2040; half of it will be placed on houses and half at other locations (commercial and public buildings, industrial applications, etc.). The efficiency of various types of solar panels will increase with

<sup>1</sup>This is the COP-value under test conditions (based on the European standard EN 14511). Seasonal conditions influence the performance of a heat pump. The COP-value on a cold winter day will be lower than this value.

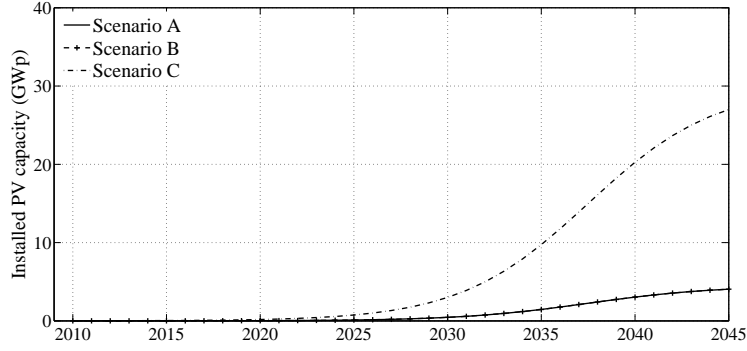


Figure A.4: Adoption curves of installed PV power capacity.

Table A.4: Numbers related to PV panels in Scenarios A, B and C (in 2040).

	Scenario A	Scenario B	Scenario C
Installed capacity	3 GWp	3 GWp	20 GWp
Percentage of PV capacity installed on roofs of houses	70%	70%	50%
Percentage of PV capacity installed at other locations	30%	30%	50%
Percentage of existing houses with PV panels	6.4%	4.2%	24%
Percentage of newly built houses with PV panels	6.6%	4.7%	29%

a few percent [16] and an average efficiency of  $200 \text{ Wp/m}^2$  in 2040 is taken in all scenarios. The adoption curves of the installed PV power capacity are presented in Figure A.4 and the numbers related to PV panels for each of the scenarios are presented in Table A.4.

The amount of installed capacity of solar panels in each scenario is translated in the average size of the panels per house, based on the available roof area of various types of existing and newly built houses that can be found in [102] and [108]. When building a new house, the installation of PV panels can be taken into account, therefore, the number of solar panels is higher in newly developed areas. Furthermore, in more densely populated areas houses are smaller, so less roof area is available for solar panels. This results in the values of the average square meter of PV panel area as presented in Section 3.5.

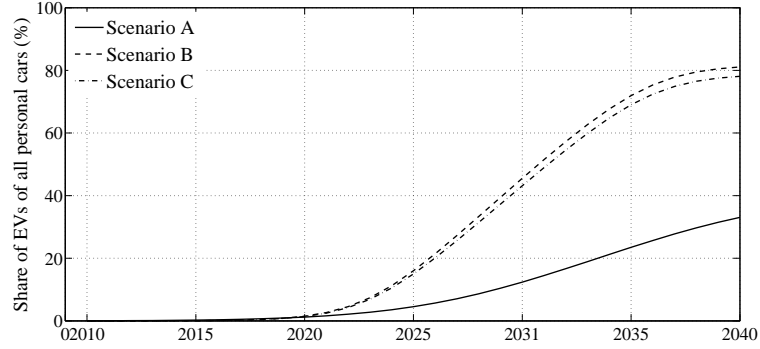


Figure A.5: Adoption curves of EVs presented as the share of EVs in the total amount of personal cars.

## Electric vehicles

The target set by the Dutch government is to have 200,000 EVs in the Netherlands in 2020 and 1 million in 2025, which corresponds to a mature market in which around 75% of the new bought cars are electric [104]. A benchmark executed in 2012 shows that compared with other countries this is a very ambitious target [80]. Looking at the realisation of the number of EVs in 2012, the Netherlands belong to the top five countries worldwide.

In Scenarios B and C presented in this thesis, these ambitions are realised. Due to an economic downturn in Scenario A, the market share of EVs will not grow that fast as in the other two scenarios and in 2040 a market share of 40% of new bought cars will be reached. This results in the adoption curves for EVs presented as the share of EVs in the total amount of personal cars in the Netherlands as depicted in Figure A.5. In these numbers a growth of the total personal car fleet is taken into account, which is different in each scenario (see the number of vehicles per household presented in Table A.5). Also, an average lifetime of cars of 13 years is assumed in these numbers. Depending on vehicle design and driver behaviour, typical EVs achieve roughly 4.8–9.7 km/kWh [109]. In this thesis, an efficiency of 5 km/kWh is taken.

To determine the driving distance of EVs per household, the number of vehicles per household, the number of persons per household, and the growth in travel distance by car per person (see Table A.5) are used. Like the number of vehicles and persons per household, the growth in travel distance is based on the scenarios in [118]. These numbers are used in combination with data about current driving distances in various residential areas from [106] to determine the driving distances per house in the ten typical residential areas as presented in Section 3.5.

Table A.5: Numbers related to EVs in Scenarios A, B and C (in 2040).

	Scenario A	Scenario B	Scenario C
Share of EVs in the total amount of new bought personal cars	40%	75%	75%
Number of vehicles per household	1.10	1.17	1.13
Number of persons per household	2.26	1.95	2.20
Growth in travel distance by car per person	7.0%	22%	16%
Efficiency EV	5 km/kWh	5 km/kWh	5 km/kWh

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## Future electricity price

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In this appendix, background information is given on how the future electricity price is created. This price is used in the optimisation problem that is presented in Section 5.3.2. The method described here is adopted from [146].

### Electricity markets

In liberalised power systems, various electricity markets exist where electricity can be traded. For creating a price a day-ahead spot market where electricity producers and retailers trade electricity, and a balancing market where reserve and regulating power is traded, are considered. The time resolution of the day-ahead market is mostly one hour and the balancing market is a real-time market that has a time resolution of one quarter of an hour. This is a simplification of actual markets where other options to trade electricity exists, e.g. via bilateral agreements or on intraday spot markets, but it captures the markets structure of most liberalised power systems: a day-ahead market in combination with a market to settle imbalances. In the market-oriented smart grid concept, an aggregator that represents a number of customers with flexible demand participates on the wholesale market. He could either do this directly on the day-ahead market, but a construction where he acts as some form of intermediate party between electricity providers and consumers is also possible. Essential is that the aggregator buys and sells power with a time-varying price based on the day-ahead price.

### Electricity prices

The future electricity price is based on a combination of the total demand, and the currently and future installed (renewable electricity) generation capacity in the system. The total demand and future installed generation capacity depend on the energy scenario that is regarded. When modelling future electricity prices, it is not attempted to give an accurate prediction of the prices, but rather to approximate the shape of the time series that respect the main characteristics of electricity prices: high prices when demand is high (and/or renewable generation is low) and low prices when demand is low (and/or renewable generation is high).

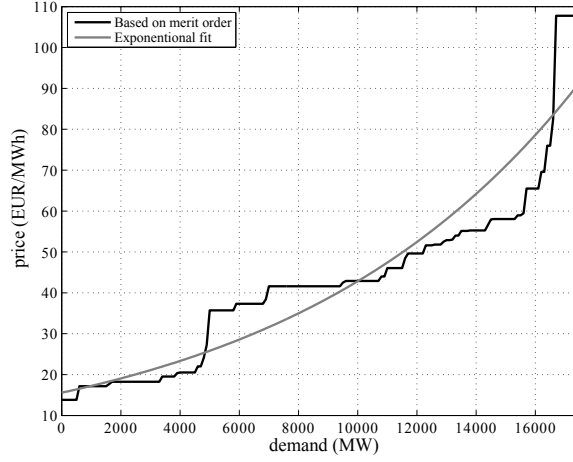


Figure B.1: Supply cost curve in the Netherlands and exponential fit [146].

The future load is the net load in each of the three scenarios that includes the total residential load as well as electricity generation at residential areas (by PV panels and  $\mu$ -CHPs). A list of all currently installed production capacity in the Netherlands are taken from [134]. The supply cost curve (i.e. the ranked list of the marginal cost of all installed production capacity) is constructed using data from [40]. Figure B.1 shows this curve together with an exponential fit. In this figure, one distinguishes a number of base load plants (coal and nuclear) with relatively low marginal cost, followed by more expensive natural gas plants. For modelling wind power generation a time series of Danish wind power is used [89]. The normalised wind power time series can be multiplied with the appropriate amount of installed wind capacity and is subtracted from the electricity load to find the net load that has to be supplied by the power plants. The net load is then compared with the supply cost curve to find the electricity price. This method and its validity are discussed in more detail in [145].

The day-ahead prices are modelled using the exponential fit rather than the merit order because it gives a smoother, more realistic profile which is also observed in real market prices, while, to some extent, respecting the shape of the merit order. Additional advantages of using the exponential fit are that relatively small variations in demand lead to different prices (this is not the case when using the merit order, because of its stepwise shape) and it allows for an easy calculation of price-sensitivity (the derivative of the supply cost curve) that is used in the optimisation.

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## Aggregated residential net load profiles

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The profiles of all ten typical areas in the three scenarios are presented in this appendix. The definition of the residential areas can be found in Table 3.3. The Scenarios A, B and C, and the numbers related to the technologies applied in the ten residential areas that are used to construct the profiles, are described in Section 3.5.

### No smart grid strategy

#### Summer profiles

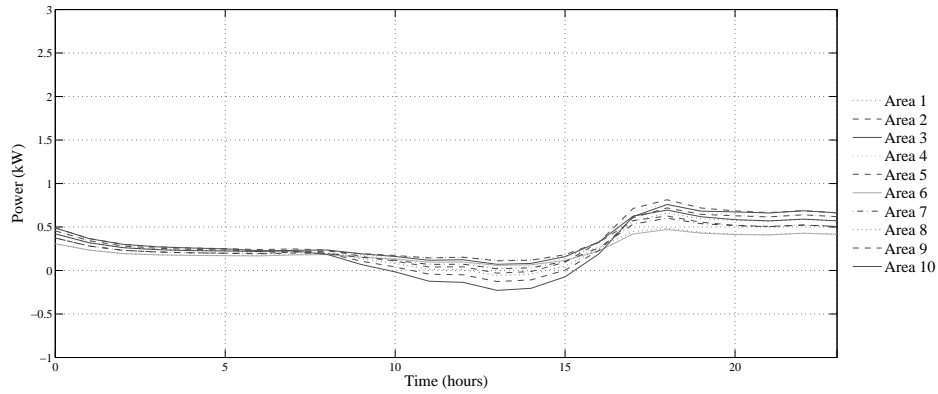


Figure C.1: The aggregated net load profiles of ten typical residential areas in Scenario A during summer time on a day with maximum generation and minimum load (the profiles are scaled back to one household).

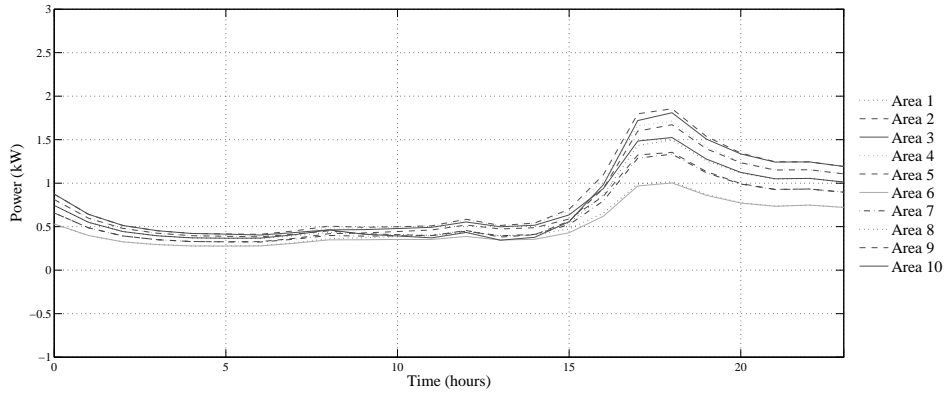


Figure C.2: The aggregated net load profiles of ten typical residential areas in Scenario B during summer time on a day with maximum generation and minimum load (the profiles are scaled back to one household).

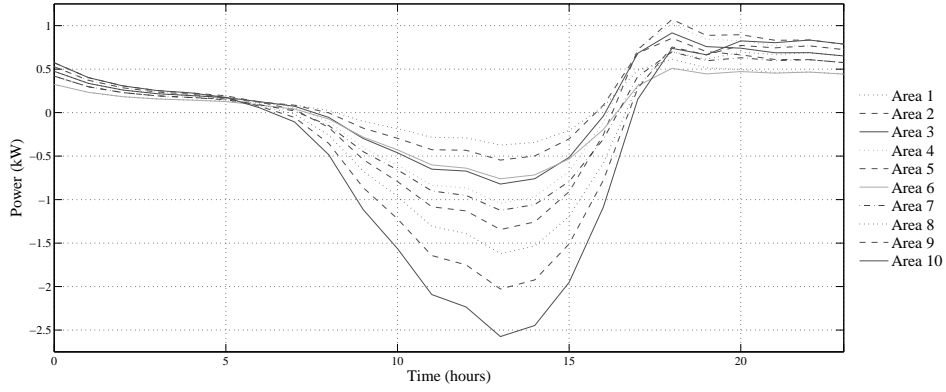


Figure C.3: The aggregated net load profiles of ten typical residential areas in Scenario C during summer time on a day with maximum generation and minimum load (the profiles are scaled back to one household).

### Winter profiles

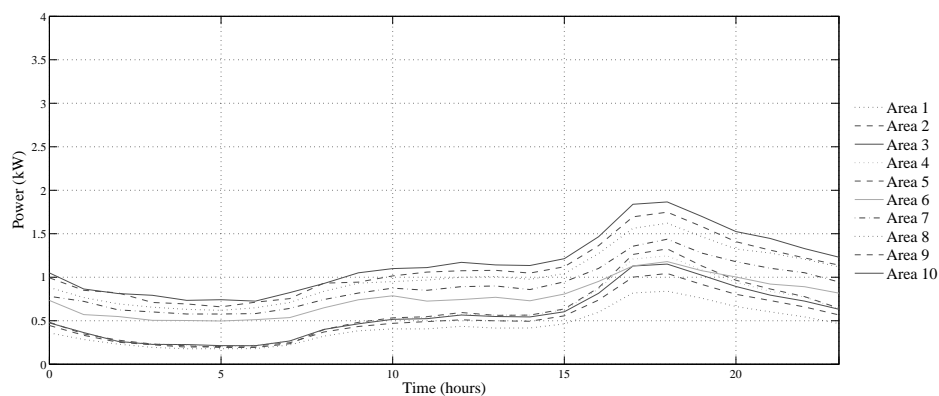


Figure C.4: The aggregated net load profiles of ten typical residential areas in Scenario A during winter time on a day with minimum generation and maximum load (the profiles are scaled back to one household).

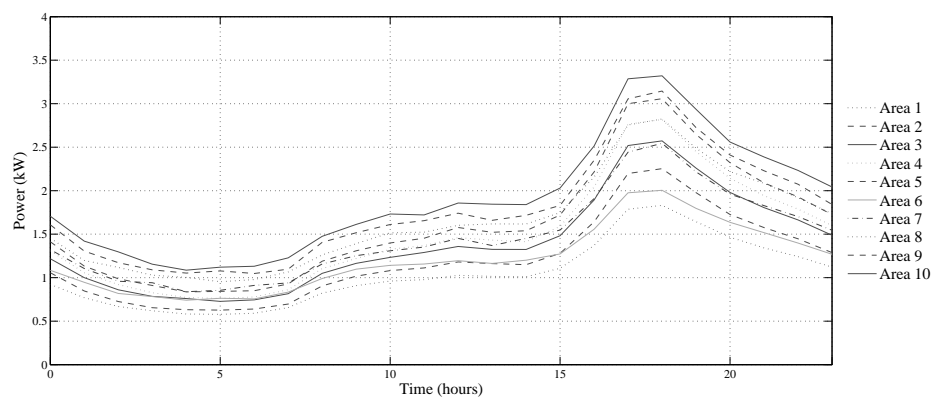


Figure C.5: The aggregated net load profiles of ten typical residential areas in Scenario B during winter time on a day with minimum generation and maximum load (the profiles are scaled back to one household).

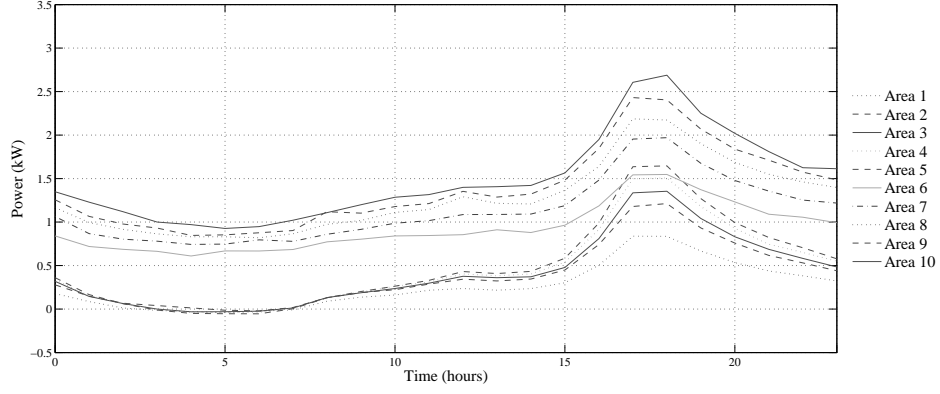


Figure C.6: The aggregated net load profiles of ten typical residential areas in Scenario C during winter time on a day with minimum generation and maximum load (the profiles are scaled back to one household).

### Minimising network load strategy

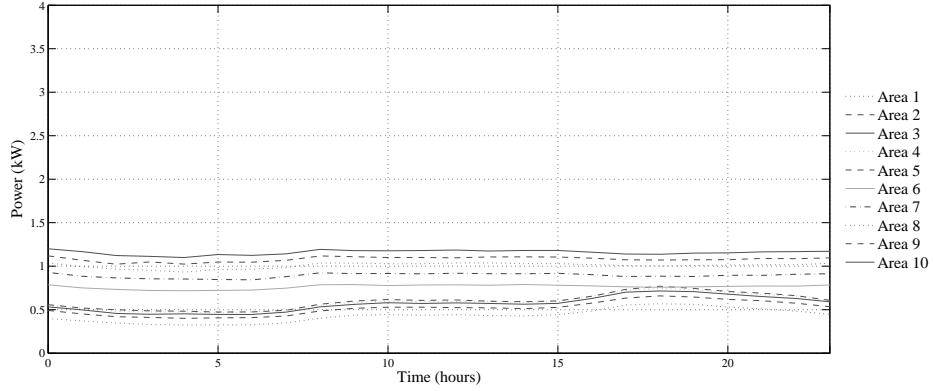


Figure C.7: The aggregated net load profiles of ten typical residential areas in Scenario A in case of mobilising flexible load of EVs, heat pumps and a part of the regular residential electricity use to minimise network load on a day with maximum loading (the profiles are scaled back to one household).

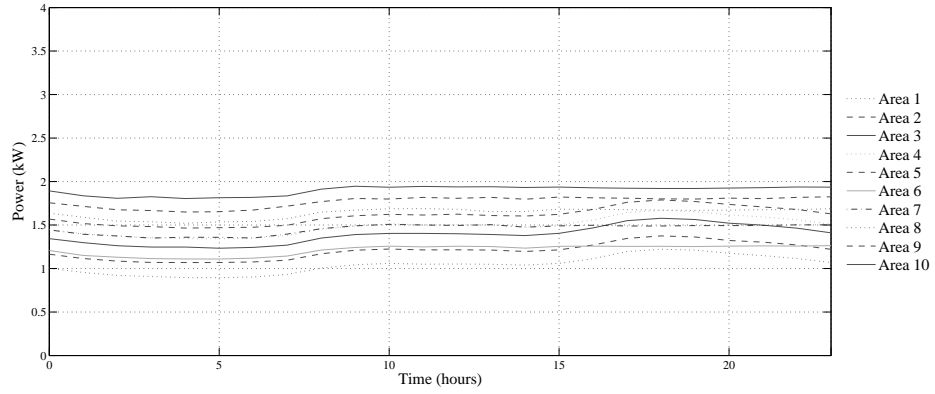


Figure C.8: The aggregated net load profiles of ten typical residential areas in Scenario B in case of mobilising flexible load of EVs, heat pumps and a part of the regular residential electricity use to minimise network load on a day with maximum loading (the profiles are scaled back to one household).

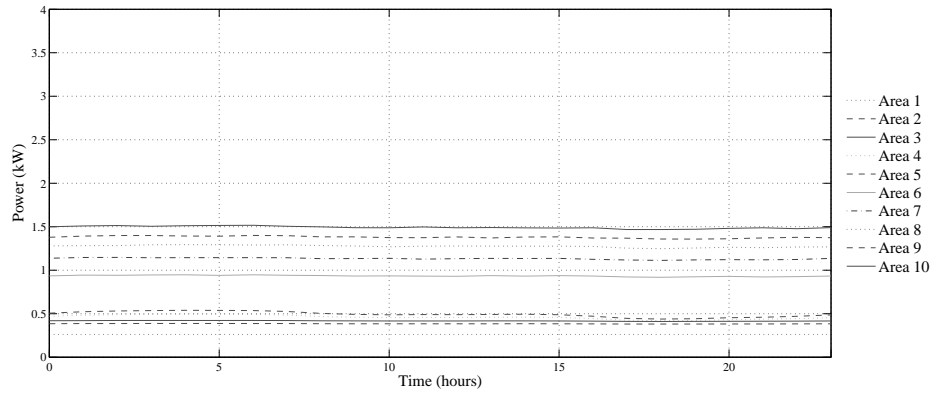


Figure C.9: The aggregated net load profiles of ten typical residential areas in Scenario C in case of mobilising flexible load of EVs, heat pumps and a part of the regular residential electricity use to minimise network load on a day with maximum loading (the profiles are scaled back to one household).

### Minimising electricity supply costs strategy

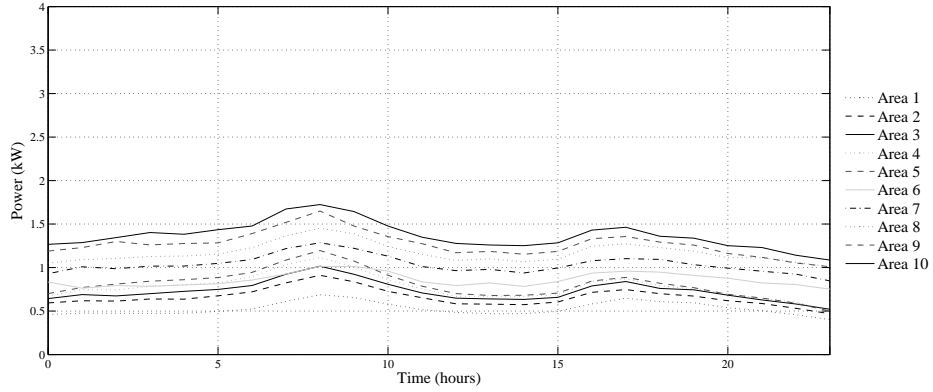


Figure C.10: The aggregated net load profiles of ten typical residential areas in Scenario A in case of mobilising flexible load of EVs to minimise electricity supply costs on a day with maximum loading (the profiles are scaled back to one household).

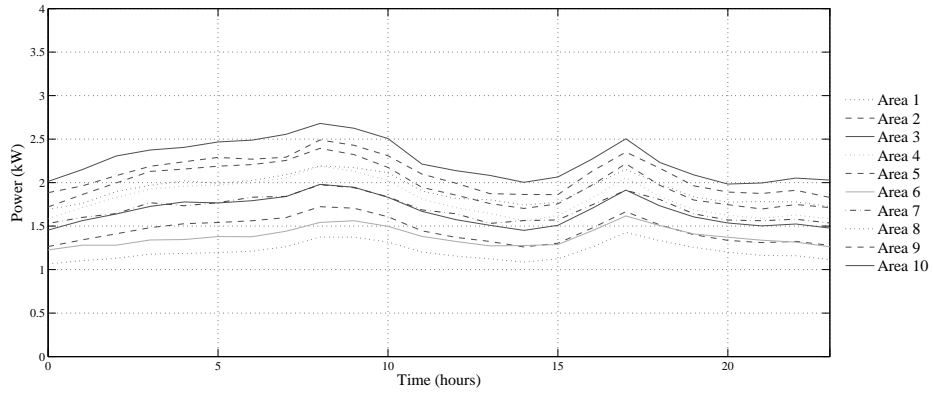


Figure C.11: The aggregated net load profiles of ten typical residential areas in Scenario B in case of mobilising flexible load of EVs to minimise electricity supply costs on a day with maximum loading (the profiles are scaled back to one household).

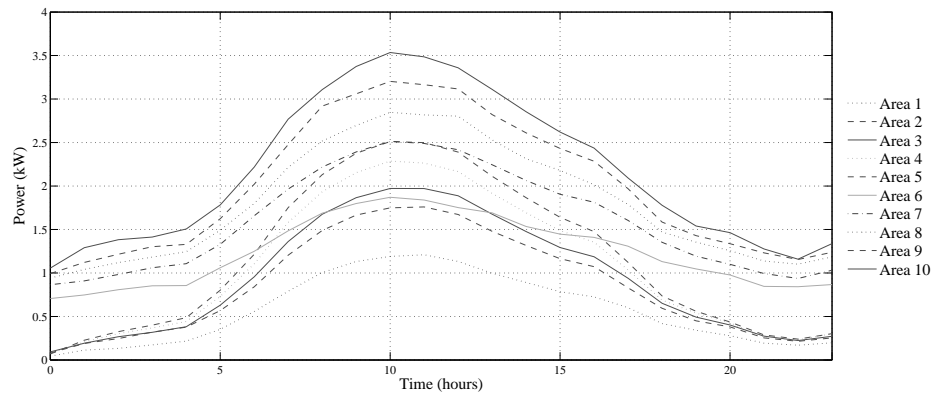


Figure C.12: The aggregated net load profiles of ten typical residential areas in Scenario C in case of mobilising flexible load of EVs to minimise electricity supply costs on a day with maximum loading (the profiles are scaled back to one household).



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## Load duration curves

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In this appendix, the load duration curves are presented for an average household in all three scenarios. The load duration curve equals the load profile, but the data is ordered in descending order of magnitude, rather than chronologically.

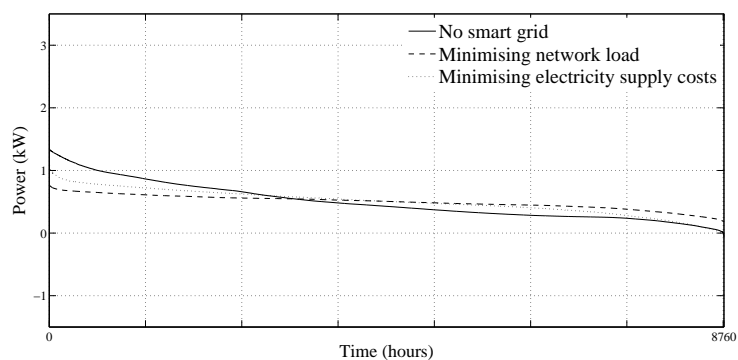


Figure D.1: The load duration curve for an average household in Scenario A.

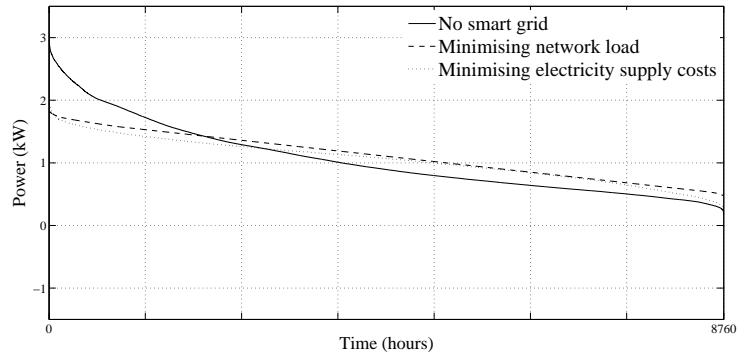


Figure D.2: The load duration curve for an average household in Scenario B.

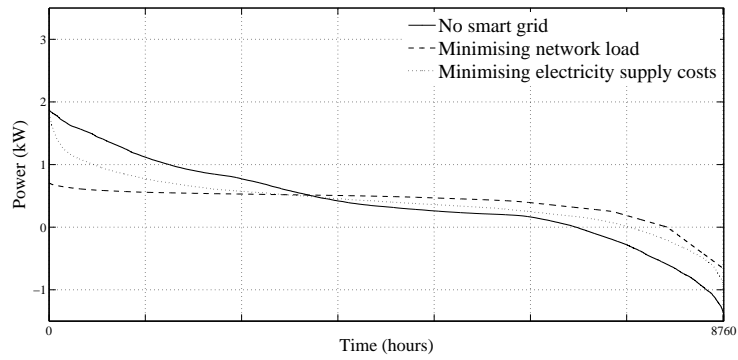


Figure D.3: The load duration curve for an average household in Scenario C.

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## Load characteristics

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In this appendix, more information is given on modelling of the aggregated residential loads in the load-flow calculations. First, modelling of the load behaviour is discussed. Because for the load-flow calculations the complex power values of the loads are used, the power factors of the individual load and generation elements of the residential demand that were introduced in Chapter 5 are given as well.

### Load behaviour

In load-flow calculations, the loads connected to the distribution networks are typically specified by the complex power consumed. Because the voltages at the nodes to which the loads are connected are not known beforehand, an iterative process is required to calculate the currents and the actual operating load voltages based on initially assumed voltages. To model the loads for this iterative process, the voltage dependency of the load characteristics can be represented by the following exponential model [81]:

$$P = P_0 \left( \frac{V}{V_0} \right)^a \quad (\text{E.1})$$

$$Q = Q_0 \left( \frac{V}{V_0} \right)^b \quad (\text{E.2})$$

In these equations,  $P$  and  $Q$  are the active and reactive components of the load when the node voltage magnitude is  $V$ . The subscript 0 identifies the value of the respective variables at the nominal operation condition. The parameters of this model are the exponents  $a$  and  $b$ . With these components equal to 0, 1, or 2, the model represents the following load characteristics:

- Constant power ( $a = b = 0$ ): the active and reactive power of the load are independent on the voltage. This implies that a decrease of voltage results in an increase of the current drawn by the load.

- Constant current ( $a = b = 1$ ): the current drawn by the load is independent on the voltage. The power is linearly dependent on the voltage.
- Constant impedance ( $a = b = 2$ ): the power is quadratically dependent on the voltage. The current drawn by the load decreases when the voltage decreases.

Load behaviour can also be modelled with a combination of the above characteristics. In this research, the load behaviour of the aggregated residential loads is simplified by using one of these models, because they are a combination of a large number of devices with different load characteristics. The real values of the currents drawn by these loads will lie in between the values calculated by the constant power and constant impedance models.

The load-flow calculations are first executed while using the constant power load model for the loads. In standard load-flow routines an algorithm is used for control actions like adjusting tap changers of transformers [119]. When loads are connected on the secondary side of the transformers, applying the constant power model may cause convergence problems in load-flow calculations. A low voltage results in an increase in current drawn by the load. This results in a further decrease of the voltage which might be enhanced by extra reactive power consumption of the transformer [119]. This might cause the load-flow calculation to diverge. For Scenario B, a scenario with high power demands of the connected loads, using the constant power model resulted in convergence problems of the load-flow solution for some of the analysed MV networks. If the loads are modelled as constant impedances, the load-flow calculations of all MV networks in all scenarios are solved.

The maximum loadings of the network assets in Scenario B that are calculated using the constant power model (for the MV networks that are solved) are on average 3–7% higher compared to the maximum loadings of the network assets that are calculated using the constant impedance model. This is caused by lower values of the node voltages due to high power demands of the connected loads. On the other hand, in Scenario A and C the maximum loadings of the network assets that are calculated using the constant power model are on average 2–4% lower compared to the maximum loadings of the network assets that are calculated using the constant impedance model. In these scenarios the node voltages are on average higher than the nominal voltage; using the constant impedance model therefore results in an increase in the current drawn by the loads.

Note that in this research the required investments in future scenarios are based on the values of the calculated maximum loadings of the assets. If new assets are installed, it should be checked if the voltage deviations stay within the specified limits. This might result in some additional reinforcements.

## Power factor individual load and generation elements

The individual load and generation elements that are introduced in Chapter 5 are presented in real power. To use the loads in the load-flow calculations the aggregated net load profiles are converted to complex power by combining the individual elements taking into account the values of the power factor as presented in Table E.1.

Table E.1: Values of the power factor ( $\cos \phi$ ) applied to the individual load and generation elements.

	Regular residential electricity use	PV panels	EVs	$\mu$ -CHPs	heat pumps
$\cos \phi$	0.95	1.00	0.99	1.00	0.75



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## Reinforcement options

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Reinforcement takes place if the capacity of an asset is not sufficient to facilitate the demand. In this situation, the asset is either replaced by another asset with a higher rated capacity or another asset is added to the existing configuration, increasing the overall capacity of the configuration. The various reinforcement options that are applied are described in this appendix.

### Reinforcement HV/MV transformer substations

Reinforcement of a HV/MV transformer substation involves either replacing a HV transformer by one with a higher rated capacity or adding a HV transformer (including a new connection to the HV grid). These options are illustrated in Figure F.1.

At the substation two, three, four, five or six transformers are installed. Because of the (n-1) criterion, there is always at least one back-up transformer installed. This additional transformer must be able to take over the load if another transformer fails in order to guarantee continuity of supply. In case of two transformers, this means that both transformers must be able to carry the load individually. If in this situation the transformer is overloaded, both transformers must be replaced. In the situation of three or more transformers, the grid designer has more degrees of freedom to reinforce the HV substation: all transformers are replaced, one transformer is added, or one transformer is replaced and one transformer is added. The applied

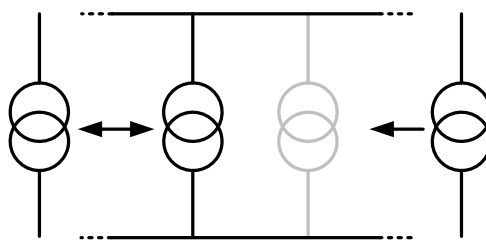


Figure F.1: Two options to reinforce a HV/MV transformer substation.

Table F.1: Reinforcement options HV/MV transformer substation.

Installed capacity before reinforcement (MVA)	Action	Installed capacity after reinforcement (MVA)	Safe capacity (MVA)	Extra capacity (MVA)
2 x 20	replace transformers	2 x 30	30	10
2 x 30	add transformer	3 x 30	60	30
2 x 40	add transformer	3 x 40	80	40
2 x 60	add transformer	3 x 60	120	60
2 x 80	add transformer	3 x 80	160	80
3 x 20	replace transformers	3 x 30	60	20
3 x 30	add transformer	4 x 30	90	30
3 x 40	add transformer	4 x 40	120	40
3 x 60	add transformer	4 x 60	180	60
3 x 80	add transformer	4 x 80	240	80

Table F.2: Characteristics of HV/MV transformers.

$P_{\text{nom}}$ (MVA)	$P_{\text{iron loss}}$ (kW)	$P_{\text{load loss}}$ (kW)
30	23.3	129.8
40	23.2	163.5
60	22.2	213.7
80	43.5	247.0

reinforcement options in case of two or three transformers are presented in Table F.1. The characteristics of the new installed transformers can be found in Table F.2.

### Reinforcement MV transmission cables

In general, MV transmission cables have straightforward configurations. The transmission cables exist of parallel cable bundles that meet the (n-1) criterion (see Section 4.2.3). To reinforce a cable bundle, an additional cable is installed (see Figure F.2). The cable types that are used for the reinforcements are presented in Table F.3.

### Reinforcement MV distribution cables

In case of the risk of an overloading of an MV distribution cable, there are several reinforcement options possible. These options are illustrated in Figure F.3 and described in Table F.4. A copper cable with a cross-sectional area of 35 mm<sup>2</sup> or

an aluminium cable with a cross-sectional area of 50 mm<sup>2</sup> or smaller is assumed to be relatively old and therefore replaced one-by-one. In other cases, the other reinforcement options are randomly applied following the distributions presented in Table F.4. The applied cable types are presented in Table F.3.

Table F.3: Characteristics of cables used to reinforce MV transmission and distribution cables.

Cable type	$I_{\text{nom}}$ (A)	R ( $\Omega/\text{km}$ )
50 Al	125	0.6210
150 Al	285	0.2086
240 Al	370	0.1308
400 Al	475	0.0788
630 Al	605	0.0511

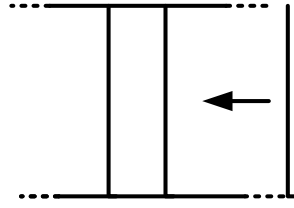


Figure F.2: Reinforcement of an MV transmission cable.

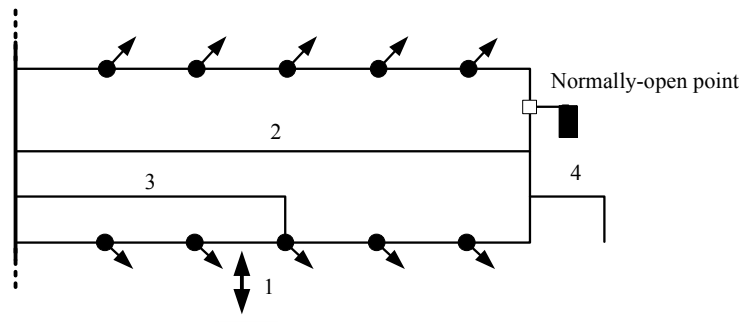


Figure F.3: Reinforcement options MV distribution cables.

Table F.4: Distribution of various options to reinforce MV distribution cables.

Reinforcement option	Action	Applied to
1	replace cable 1:1	specified cable types
2	add long diagonal	50% of the cases
3	add short diagonal	35% of the cases
4	add cable to other ring	15% of the cases

### Reinforcement MV/LV transformers

There are two options to reinforce MV/LV transformers: replace the transformer with a transformer with a higher capacity or add a transformer (see Figure F.4). In case the transformer has a rated capacity lower than 630 kVA, it is replaced by a transformer with a higher rated capacity. The MV/LV transformers in the networks have one of the capacities that are presented in Table F.5. Transformers with a higher rated capacity than 630 kVA are not installed because of safety reasons. In this situation an additional transformer is installed.

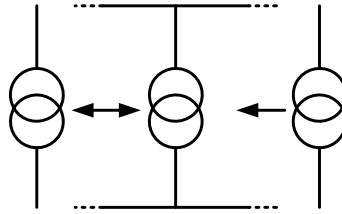


Figure F.4: Reinforcement options MV/LV transformers.

Table F.5: Characteristics of MV/LV transformers.

$P_{\text{nom}}$ (kVA)	$P_{\text{iron loss}}$ (W)	$P_{\text{load loss}}$ (W)
50	115	840
100	190	1350
160	260	1905
250	365	2640
400	515	3750
630	745	5200

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## List of publications

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### Reviewed journal publications

1. E. Veldman, D.A.M. Geldtmeijer, J.D. Knigge, and J.G. Slootweg. Smart grids put into practice: Technological and regulatory aspects. *Competition and Regulation in Network Industries*, 11(3): pages 287-306, 2010.
2. E. Veldman, M. Gibescu, J.G. Slootweg, and W.L. Kling. Scenario-based modelling of future residential electricity demands and assessing their impact on distribution grids. *Energy Policy*, 56: pages 233-247, 2013.
3. E. Veldman, and R.A. Verzijlbergh. Distribution grid impacts of smart electric vehicle charging from different perspectives. *IEEE PES Transaction on Smart Grid*. Under review.

### Conference publications

1. Y.C. Wijnia, P.M. Herder, M.S. Korn, E. Veldman, and M. Poorts. Long term infrastructure risk management: problems in the use of the net present value criterion. In *3rd World Congress on Engineering Asset Management and Intelligent Maintenance Systems (WCEAM-IMS)*. Beijing, China, Oct. 2008.
2. M.S. Korn, and E. Veldman. Benefits of continuous risk management in (physical) asset orientated companies. In *1st International Conference on Infrastructure Systems and Services: Building Networks for a Brighter Future*. Rotterdam, the Netherlands, Nov. 2008.
3. E. Veldman, D.A.M. Geldtmeijer, and J.G. Slootweg. Smart grids put into practice. In *12th Annual International Conference on the Economics of Infrastructures*. Delft, the Netherlands, May 2009.
4. E. Veldman, M. Gibescu, A. Postma, J.G. Slootweg, and W.L. Kling. Unlocking the hidden potential of electricity distribution grids. In *CIREN 20th Conference and Exhibition on Electricity Distribution*. Prague, Czech Republic, June 2009.

5. E. Veldman, M. Gibescu, J.G. Slootweg, and W.L. Kling. Technical benefits of distributed storage and load management in distribution grids. In *IEEE PES PowerTech*. Bucharest, Romania, June 2009.
6. E. Veldman, M. Gaillard, M. Gibescu, J.G. Slootweg, and W.L. Kling. Modelling future residential load profiles. In *Innovation for Sustainable Production (I-SUP)*. Bruges, Belgium, Apr. 2010.
7. I. Lampropoulos, E. Veldman, W.L. Kling, M. Gibescu, and J.G. Slootweg. Electric vehicles integration within low voltage electricity networks & possibilities for distribution energy loss reduction. In *Innovation for Sustainable Production (I-SUP)*. Bruges, Belgium, Apr. 2010.
8. J.H.M. van Lierop, E. Veldman, G.M.A. Vanalme, and W.L. Kling. Evaluating the power capability of a Dutch MV grid incorporating sustainable technologies. In *45th International Universities Power Engineering Conference (UPEC)*. Cardiff, Wales, Aug. 2010.
9. J.G. Slootweg, E. Veldman, and J. Morren. Sensing and control challenges for Smart Grids. In *IEEE International Conference on Networking, Sensing and Control (ICNSC)*. Delft, the Netherlands, Apr. 2011.
10. R. Said, E. Veldman, G.M.A. Vanalme, and J.G. Slootweg. Investment strategy for low voltage networks regarding new technologies in new neighbourhoods. In *CIREN 21st Conference and Exhibition on Electricity Distribution*. Frankfurt, Germany, June 2011.
11. J.G. Slootweg, M.A.M.M. van der Meijden, J.D. Knigge, and E. Veldman. Demystifying smart grids – Different concepts and the connection with smart metering. In *CIREN 21st Conference and Exhibition on Electricity Distribution*. Frankfurt, Germany, June 2011.
12. E. Veldman, M. Gibescu, J.G. Slootweg, W.L. and Kling. Impact of electrification of residential heating on loading of distribution networks. In *IEEE PES PowerTech*. Trondheim, Norway, June 2011.
13. R.A. Verzijlbergh, Z. Lukszo, E. Veldman, J.G. Slootweg, and M. Ilic. Deriving electric vehicle charge profiles from driving statistics. In *IEEE PES General Meeting*. Detroit, Michigan USA, July 2011.
14. M.O.W. Grond, B.A. Schepers, E. Veldman, J.G. Slootweg, and M. Gibescu. Impact of future residential loads on medium voltage networks. In *46th International Universities Power Engineering Conference (UPEC)*. Soest, Germany, Sept. 2011.

15. E. Veldman, M. Gibescu, J.G. Slootweg, W.L. and Kling. Modelling method to assess the impact of future residential loads. In *Cigré International Symposium on the Electric Power System of the Future: Integrating Supergrids and Microgrids*. Bologna, Italy, Sept. 2011.
16. J.A.W. Greunsvan, E. Veldman, P.H. Nguyen, J.G. Slootweg, and I.G. Kamphuis. Capacity management within a multi-agent market-based active distribution network. In *3rd IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT Europe)*. Berlin, Germany, Oct. 2012.
17. E.A.M. Klaassen, E. Veldman, J.G. Slootweg, W.L. Kling. Energy efficient residential areas through smart grids. In *IEEE PES General Meeting*. Vancouver, Canada, Jul, 2013.
18. J.D. Knigge; E. Veldman; P.G. Matos. Changing the energy landscape - The need for regulatory changes. In *6th Annual Conference on Competition and Regulation in Network Industries*. Brussels, Belgium, Nov. 2013.

## Other publications

1. E. Veldman, A. Postma, J.G. Slootweg, M. Gibescu and W.L. Kling. Conexão de veículos elétricos à rede de energia: descobrindo um potencial oculto. *Electricidade Moderna*, pages 118-127, Apr. 2010. In Portuguese.
2. E. Veldman, A. Postma, J.G. Slootweg, M. Gibescu, and W.L. Kling. Electric vehicles charge ahead – Under the mobile smart grid concept, electric vehicles will give and get. *Transmission & Distribution World Magazine*, 63(3): pages 44-50, Mar. 2011.
3. W.L. Kling, K. El Bakari, and E. Veldman. Special report for session 1.9 – Active Distribution Networks. In *Cigré International Symposium on the Electric Power System of the Future: Integrating Supergrids and Microgrids*. Bologna, Italy, Sept. 2011.



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## Curriculum vitae

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Else Veldman was born on January 27th 1983 in Marum, the Netherlands. She attended secondary school at Het Drachtster Lyceum in Drachten, The Netherlands, where she obtained her Gymnasium degree in 2000. From 2000 to 2006 she studied Mechanical Engineering at the University of Twente in Enschede, the Netherlands. After finishing her first year, she was nominated for the CIVI-prize for best first year students. During her studies, she organised and took part in an international study tour to Indonesia, Malaysia and Singapore. From August 2005 till January 2006, she stayed in Ecuador for an internship. Her graduation project was carried out for the German engineering consulting company INPRO on the topic of optimisation strategies for metal forming processes. She obtained her MSc degree in December 2006.

After graduating, Else Veldman joined Essent Netwerk B.V., one of the largest distribution network operators in the Netherlands. Here, she enrolled in a two-year traineeship programme that included an extended personal development programme and two projects, which she carried out at the departments Strategic Development and Innovation (both part of the larger Asset Management Department). After these two years, she started in the position of Innovator at the Innovation Department of Enexis B.V., formerly Essent Netwerk B.V. The spearheads of this department are energy transition (including distributed generation and smart grids), asset condition assessment and increasing workforce productivity through new technologies. In the position of Innovator, Else contributes to the realisation of the innovation portfolio of Enexis B.V.

In 2008, she joined part-time the group of Electrical Power Systems at the faculty of Electrical Engineering at Delft University of Technology to start PhD research under supervision of prof. ir. W.L. Kling. From October 2009 onwards, this research has been pursued at the group of Electrical Energy Systems at the faculty of Electrical Engineering at Eindhoven University of Technology. The research focused on the impacts of flexibility in future residential loads on (medium voltage) distribution network utilisation and resulted in the work presented in this thesis.