Preventing capacity exceedance on existing local grids when heat pumps replace conventional heating systems

Assessment of possible measures and the cost-effectivity of primary energy saving and CO_2 mitigation

Master's thesis R.N.B. van Boxtel

Place:
Utrecht

Date:
22 December 2015

Student:
R.N.B. van Boxtel

Student number:
3708381

Contact details:
Phone number: 0620816356
E-mail: r.n.b.vanboxtel@gmail.com / r.n.b.vanboxtel@students.uu.nl

Master's programme:
MSc Energy Science

Course:
GEO4-2510 ENSM - Master's thesis

Nr. of ECTS:
30 ECTS

Supervision:

Supervisor:	Geert Litjens	G.B.M.A.Litjens@uu.nl
First reader:	dr. ir. Wina Crijns-Graus MSc	W.H.J.Graus@uu.nl
Second reader:	dr. ir. Machteld van den Broek	M.A.vandenBroek@uu.nl

ABSTRACT

In the residential sector there is a high energy saving potential, especially regarding heat demand. A promising energy technology is the heat pump. It operates at a higher efficiency than conventional heating systems and it eliminates the need for natural gas and as a results less primary energy is consumed and less CO_2 is emitted. The most common heat pump types use electricity. This means that heat pumps cause an additional load on the electrical grid. This additional load causes demand peaks that might exceed the current grid capacity. In that case not all heat demand is satisfied.

In order to satisfy all heat demand grid capacity exceedance should be prevented. A predictable solution would be to reinforce the grid capacity by replacing transformers and cables, however this is relatively expensive. Therefore other measures are assessed regarding their ability to prevent capacity exceedance and their costs. Besides grid capacity expansion also thermal energy storage, heat demand reduction, and heat demand shifting are assessed. Additionally limiting the number of heat pumps is included.

Grid capacity expansion, heat demand reduction and thermal energy storage, when implemented individually, can prevent capacity exceedance. Based on their annualized investement costs, capacity expansion and limiting the number of heat pumps are the least expensive measures at 40 resp. 0 €/household/year. Heat demand reduction and thermal energy storage and far more expensive at 1,100 resp. 700 €/household/year.

When all the costs are included, which are the annual change in energy costs and the annualized investement cost for the heat pump and measure, then grid capacity expansion and limiting the number of heat pumps are the least expensive at 690 resp. 690 €/household/year. The annual costs with heat demand reduction and TES are 1,090 resp. 1,560 €/household/year.

Primary energy saving and CO_2 mitigation is achieved with the implementation of heat pumps. The lowest specific costs for primary energy saving and emission mitigation costs are found for heat demand reduction with 120 €/$MWh_{primary}$ saved and 0.60 €/kg CO_2 mitigated.

Under the used base assumptions shiftin to heat pumps might not be economically viable, if all costs are included and charged to the end-consumer. The viabitily can be improved by lower investment costs, subsidies, larger price difference between electricity and gas and improving of the coefficient of performance. Also investment costs of measures can be reduced by finding combinations of measures and allocating measures to specific households.

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

ASHP	Air Source Heat Pump
CoP	Coefficient of Performance
DHD	Domestic Heat Demand
DSO	Distribution System Operator
EV	Electric vehicle
HHD	Heating Heat Demand
HP	Heat pump
kV	Kilo Volt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-hour
LVDS	Low-voltage distribution system
PV	Photovoltaics
TSO	Transmission System Operator
W	Watt
TES	Thermal Energy Storage
MWh	Megawatt-hour

1 INTRODUCTION

1.1 BACKGROUND

Due to increasing concern regarding energy security and greenhouse gas emissions there is an ongoing transition to a more sustainable energy supply (IPCC, 2012; Rijksoverheid, 2015b). The Dutch government set targets for the share of sustainable energy sources in the energy mix and more efficient energy use. It supports the adoption of more sustainable energy technologies for example by investment subsidies for these technologies and by taxing unsustainable energy sources, e.g. the energy tax rate on natural gas (Rijksoverheid, 2015b; RVO, 2015b).

One of the areas where the energy performance can be increased is heating in the residential sector. According to Agentschap NL (2012) cost-efficient savings are possible in this area. Less sustainable energy technologies in the residential sector, e.g. conventional gas boilers, can be replaced by micro-CHP, which combines heat and power production, or alternative heat generation technologies such as geothermal energy storage and heat pumps (HP) (Agentschap NL, 2012; Oirschouw, 2012). Heat pumps have a large potential for primary energy saving and CO_2 mitigation. With a large penetration rate of heat pumps the primary energy consumption and CO_2 mitigation associated with heating can be reduced by 19% in the Netherlands by 2030 (Harmsen, Breevoort, Planje, Bakker, & Wagener, 2009). Also, the technology is expected to further improve, which should lead to a decrease in investment costs of 20 – 30%, while the coefficient of performance can increase by 30 – 50% (IEA, 2013). This means that they will become more price competitive compared to conventional heating system which will improve the penetration rate of HPs.

The amount of HPs currently installed in the Netherlands is relatively small. Only 1-2% of the residential buildings are currently supplied with a HP, but the number of HPs in the residential sector is increasing. In the period 2004-2013 the average annual increase in the amount of HPs was more than 20% (Agentschap NL, 2012; CBS, 2014c, 2014d). In Germany the adoption rate is even higher as one third of new residential buildings is supplied with a heat pump (European Heat Pump Association, 2014). For some types of neighbourhoods electric heat pumps will be the cheapest heat supply method in 2050. This will account for a quarter of the Dutch residences (Schepers, Naber, Rooijers, & Leguijt, 2015).

An increasing number of heat pumps will affect the energy distribution grids. Conventional heating systems use natural gas, whereas most heat pumps use electricity (AgentschapNL, 2011). The increase in electricity demand for heat pumps is likely significant as the annual electricity demand for a household will more than double[1]. If no measures are taken this will result in increasing peak loads (Goes, 2014; Kassakian & Schmalensee, 2011; Oirschouw, 2012). The current low voltage distribution system (LVDS) is not designed for these loads, as the LVDS is designed assuming only a small annual increase of power consumption of approximately 3% (CBS, 2014a; Oirschouw, 2012). Existing electricity infrastructure in most likely insufficient to distribute these loads.

---

[1] Assuming an average annual consumption of 3,500 kWh electricity and 1,600 m^3 natural gas (Milieucentraal, 2015b); $LHV_{natural\ gas} = 35 MJ/m^3$ (Blok, 2007, p. 28); η_{gas} boiler = 100% ; $COP_{heat\ pump} = 3,5$ (Çengel & Boles, 2011, p. 284).

A possible scenario is the shift to all-electric neighbourhoods, where all energy demand is supplied by electricity. This is not an unrealistic scenario, in fact there is an increasing electrification in the residential sector is already occurring (van Roy, Verbruggen, & Driesen, 2013). A scenario with an all-electric grid, at least in some neighbourhoods, is a concept that DSOs consider (Dekker, 2012). The rise in power demand due to new electric appliances potentially results in a lack of grid capacity during certain periods which migt lead to blackouts.

1.2 PROBLEM DESCRIPTION

1.2.1 Problem description

As a result of an increasing number of heat pumps the load profile will change. The load, and especially the peak load, is expected to increase and potentially exceed the grid's capacity. This might result in outages. The problems will firstly entail the local low voltage distribution system (LVDS) in a neighbourhood. This includes the transformer and cables (Oirschouw, 2012).

For a traditional load profile, i.e. the load profile excluding power-to-heat applications, the grid capacity is lower than the sum of the individual connections' capacity, because a non-simultaneity of power demand is assumed. The heat demand profile on the other hand is similar for most households. Therefore, the grid capacity should more closely approach the sum of the individual connections' capacity for a combined load profile, i.e. the load profile including power-to-heat applications. An issue that especially concerns power demand for heating is the high simultaneity of demand, i.e. the timing of heat demand is the same for most consumers, especially during colder periods, and heat demand cannot, or only limited, be shifted in time (Oirschouw, 2012).

This is in contrast to for example charging of electric vehicles (EV) or photovoltaics (PV) power production. As long as the battery is fully charged before the next trip, the exact charging moment does not matter. Charging methods are being developed with which charging is shifted to off-peak hours (Clement-Nyns, Haesen, & Driesen, 2010; Sundstrom & Binding, 2012). With controlled charging capacity exceedance can be prevented (van Vliet, Brouwer, Kuramochi, van den Broek, & Faaij, 2011). The load for controlled charging is expectedly 2 – 4.5 kW (Oirschouw, 2012). Heat pumps would have a bigger effect in terms of load with 2 – 5 kW excluding the additional heater of 6 kW (Oirschouw, 2012). Also, the potential for demand shifting for heating is lower than for EV charging, as heat demand should be fulfilled instantaneously. While electricity demand for EV charging can be shifted to off-peak hours, the demand peak for heat pumps might be additional to the existing demand peak.

PV is also less demanding of the LVDS. Average PV systems can deliver 2-3 kW per household which causes a smaller load on the grid than heat pumps. Also, in the case of grid capacity exceedance a PV system can be shut off (Oirschouw, 2012). This is not desirable, but grid capacity exceedance is easily prevented. Also, this does not lead to unsatisfied demand, whereas capacity exceedance due to heat pumps in cold periods does result in unsatisfied (heat) demand.

To supply the required heat demand with heat pumps, without exceeding the capacity of existing LVDS, other measures are needed than for e.g. EV charging or PV power. While the latter currently receive more attention in current literature and smart-grid projects (TKI Switch 2 Smart Grids, 2015).

To handle the increased (peak) load, measures at the level of the local LV grid are necessary. With the implementation of the *Elektriciteitswet 1998* DSOs are responsible for the physical distribution infrastructure, which mainly includes the cables and transformers. The DSO is responsible for sufficient distribution capacity (Dunnik, Ard Jan de Rijke, 2014; Oirschouw, 2012). Due to this regulation the most obvious measure would be increasing the grid capacity. However, increasing the capacity of existing infrastructure is expensive, mainly due to high costs for excavation works (Spruijt, 2014).

Alternative measures, with which capacity exceedance can be prevented, should be assessed to compare the costs of capacity expansion. These measures are required for a large scale implementation of heat pumps, therefore the investement costs should be allocated to the heat pump. Then, the cost effectivity of heat pumps can be assessed. Heat pumps are more efficient than conventional heating systems and the benefit of replacing conventional heating systems by heat pumps is energy saving and CO_2 mitigation.

Different measures can contribute to prevent the demand load from grid capacity exceedance. Each measure might affect the load profile in a different way and at different costs. Also, the marginal cost curve for the 'quantity' of a measure, e.g. kilo-watt additional transformer capacity or kilowatt-hour storage capacity, might differ between types of measures. Society benefits of low-cost measures as this will reduce the costs for power distribution and will reduce the energy bill for consumers.

Heat demand differs between different building types and building periods. The heat demand is larger for building types with more façades, such as detached buildings, because heat is exchanged due to temperature differences between the interior and the exterior of the building. Heat demand is generally smaller for newer buildings due to the improved insulation standards (Agentschap NL, 2011). Consequently the increased power demand due to the installation of heat pumps differs between different types of buildings. This means that the cost effectivity of a certain measure might differ between neighbourhoods.

1.2.2 Previous research

Heat pumps have been the subject of a number of previous studies. It has been proven that heat pumps, for both heating and air conditioning, perform better regarding primary energy use and emissions (Michopoulos, Bozis, Kikidis, Papakostas, & Kyriakis, 2007; Self, Reddy, & Rosen, 2013). Also in economic terms a heat pump can outperform conventional heating systems, under the right conditions, e.g. low electricity price (Self et al., 2013). These studies do not include implications for the distribution grid, i.e. whether grid reinforcements are required, and the associated costs.

Another topic regarding heat pumps is the potential to overcome power production intermittency, especially from wind power (e.g. Blarke, Yazawa, Shakouri, & Carmo, 2012; Hewitt, 2012; Lund & Østergaard, 2000; Pedersen, Andersen, Nielsen, Starmose, & Pedersen, 2011). These studies entail the cost effectiveness of heat pumps as a measure to solve issues with power production intermittency. Electric heat pumps can contribute to grid stabilization and controlled operation might be a cost effective measure. This can even be combined with heat storage (Blarke et al., 2012; Pedersen et al., 2011). However this is an interesting approach, it does not assume an increasing penetration rate of heat pumps connected to existing LVDSs and the implication of that. Whether the current distribution grid can handle the increased power demand to fulfil the heat demand is not included, while this might be the biggest issue regarding limitations of the distribution grid capacity, and the associated costs for measures that prevent grid capacity exceedance (Oirschouw, 2012). Several measures are available which prevent grid capacity exceedance. Example of these measures are grid reinforcements, demand reduction, demand side management (DSM) or energy storage (Felix Covrig et al., 2014; U.S. Department of Energy, 2013; van Roy et al., 2013).

One specific study researched the cheapest option to supply heat to Dutch households (Schepers et al., 2015). They acknowledged the need for grid reinforcements when heat pumps would become the dominant heating system type and for a quarter of the Dutch residences heat pumps would still be the cheapest option to supply heat in 2050, when taking into account the additional costs for grid reinforcements. Other measures to prevent grid capacity exceedance are not considered in this research.

With energy storage and DSM power consumption from the grid can be shifted to off-peak hours, which reduces peak-load. Both energy storage and demand side management entail shifting the moment energy is taken from the grid. With DSM the energy has to be consumed directly when taken from the grid, which means that consumers must adapt behaviour. With energy storage the energy can be consumed at a later moment, as it is temporarily stored in a designated medium.

The implementation of energy storage might lower costs, ensures a higher reliability and might reduce the infrastructure investments (U.S. Department of Energy, 2013). Currently thermal storage is the most viable storage type, especially when the purpose of the stored energy is heating (van Roy et al., 2013). For energy storage investments are necessary and the question is whether this is cheaper than for example grid reinforcement.

Research has shown that DSM is a possible measure in the case of heating. However the amount of energy that can be shifted is limited assuming that residents do not want to compromise on comfort. Possibilities are heating the residence earlier or delaying turning on heating if temperature drops. Shifting consumption is possible without compromising the comfort of house residents too much (Pedersen et al., 2011). Additional potential for DSM lies in the heat buffer capacity of the floor. If underfloor heating is used, which is a likely combination with heat pumps, additional heat can be supplied to the heating system in periods of overcapacity. The large heat capacity of concrete floors can temporarily prevent undesired temperature fluctuation in the heated area (Tahersima, Stoustrup, Meybodi, & Rasmussen, 2011). Compared to energy storage the investment costs for demand response are much lower. Yet, little research in done on the costs of demand response. Spruijt (2014) evaluated the social costs for demand response in the case of variable pricing and concluded that the dead weight loss would be larger than the costs for grid reinforcements. However he assumed the price elasticity to power demand which might differ from price elasticity for heat demand. Also, the heat buffer capacity of buildings, which limits compromising the comfort if DSM is implemented, was not included.

Another way to reduce (peak) load is reducing heat demand. This can be achieved through insulating the outer layer of the building. Different insulation measures can be applied and some do pay back within their lifetime (AgentschapNL, 2011). This might be the most cost-effective measure to reduce peak load when the number of heat pumps increases, as it also reduces energy consumption.

1.2.3 Knowledge gap

Heat pumps is a research topic that is mainly put in the context of sustainability. Relatively many articles focus on the primary energy saving and CO_2 mitigation potential of this technology for space and water heating. Other research assumes heat pumps, combined with thermal storage, can help alleviate the impact of intermittent power production. Less focus is on the constraints of implementing heat pumps on a large scale and not to mention a quantitative assessment of this issue. Also, current literature mostly addresses the best way to supply heat in the future, but they do not assess the issues that arise from an increasing number of heat pumps if they are implemented in neighbourhoods with an existing electricity infrastructue. This is a relevant problem because firstly a scenario with an increasing number of heat pumps is not unlikely, especially when they become more cost competitive, and secondly because it is possible that a large increase in number of heat pumps happens within the projected lifetime of most existing neighbourhoods as buildings have a relatively long lifetime. Research on how to allow for an increasing number of heat pumps in existing neighbourhoods is necessary as this is not an unlikely scenario that has implications for the LVDS.

Available measures to reduce peak load are researched to some extent, but hardly in the context of an increasing number of heat pumps, that replace conventional heating systems, in the residential sector. Literature regarding this topic mostly addresses solving issues with intermittent power production. The same measures could be applied to prevent grid capacity exceedance on the LVDS.

When the number of heat pumps in the residential sector increases, the question remains how large the current capacity deficit at the level of the low voltage distribution system is; which measures are available to solve this issue; which of these measures is the cheapest, and what are the actual costs for energy saving.

By solving these questions, this research contributes to the field of energy science by assessing how existing LVDSs can be adapted or which measures can be implemented to facilitate the increasing number of heat pumps and what the additional costs are. With this the cost effectiveness of heat pumps regarding primary energy saving and CO_2 mitigation in the residential sector is assessed. To answer the main question a model will be developed to determine the expected electricity demand for heat pumps. For this research certain general assumptions for neighbourhood size and power demand will be used. Still the model can be applied to specific cases if associated data is available. The conclusion could also have implications for the responsibilities of e.g. DSOs if the most cost effective measure cannot be implemented by the DSO without alternations to current legislation.

1.3 Research question

How can grid capacity exceedance on the low voltage distribution system be prevented cost-effectively, when electrical heat pumps replace gas boilers in the existing building stock?

1. What is the expected capacity deficit on the LVDS when heat pumps replace gas boilers?
    a) What is the current capacity of the LVDS?
    b) What is the expected electricity demand for heat pumps of the neighbourhood?
    c) What is the expected total electricity demand of the neighbourhood?
2. What are the costs of available measures when LVDS capacity deficit is prevented?
    a) How does each measure affect the total load profile?
    b) When can a measure prevent LVDS capacity deficit?
    c) What are the costs of implementing each measures?
3. Are heat pumps still cost effective when the costs for required measures is included?

a) What are the total costs (or benefits) for switching to heat pumps, including the costs for the heat pumps and the costs for the required measures to prevent capacity exceedance?
b) How much primary energy can be saved and CO_2 mitigated, when all heat demand is supplied by heat pumps?
c) What are specific cost of energy saving and CO_2 mitigation cost with heat pumps, including costs of the required measures?

1.4 THESIS OUTLINE

In the previous section the problem description is found. This is followed by the methodology section. The relevant theoretical background is incorporated in this section for convenience, this way the theoretical background is more conveniently linked with the relevant methodology. This is followed by the results sections.

Both sections are structured in the following way: first the grid capacity deficit is determined, followed by the requirements regarding each measure to prevent capacity exceedance and finally the assessment of total investment costs, specific costs of primary energy saving and CO_2 mitigation costs.

It is concluded with a overview of all costs and an answer to the question regarging the costs-effectivity of measures and the implementation of heat pumps in general.

2 RESEARCH METHOD

2.1 ELECTRICITY GRID BACKGROUND INFORMATION

2.1.1 Electricity grid design

The electrical grid transports electricity from power producers to consumers. It is designed in such a way that transportation losses are minimized. These losses are caused by the resistance in cables and depends on the square of current. To reduce the demanded current level, while maintaining the power level, higher voltage levels are used for the bulk power transmission (Oirschouw, 2012).

The drawback of a high voltage is that it is closer to the breakdown voltage of the material surrounding the conducting material. This means more insulation and additional safety measures are required. Due to safety risks this is not desirable in the vicinity of the end-user. Therefore the voltage level is reduced using transformers, which happens in several steps, for residential and commercial users (Oirschouw, 2012).

2.1.2 Voltage levels

The electricity grid is divided in broadly three voltage categories: high, medium and low voltage. High voltage levels of 110, 150, 220 and 380 kV are used for the bulk power transmission across regions within a nation as well as for interconnections between nations to enable international power trading. Only a few industrial large consumers and large power producers are directly connected to this grid. This network is operated by the Transmission System Operator (TSO) (Hoogspanningsnet, 2015; Oirschouw, 2012).

The medium and low voltage levels are used for the more regional networks. These are called the distribution systems and operated by Distribution System Operators (DSO). The medium voltage networks typically use a voltage of 10 or 20 kV, but also voltage levels of 25 or 50 KV. Large consumers and relatively large distributed energy generators such as wind turbines or small combined heat power generators are connected to this network (Oirschouw, 2012).

All small companies (with a power demand smaller than 0.3 MW) and households are connected to the low voltage grid with a typical voltage level of 0.4 kV. Typically households use one single phase of 230 V or 400 V if a three phase connection is used. The latter is necessary for appliances with a high power demand, such as some electric stoves or heat pumps (Oirschouw, 2012).

2.1.3 Low-voltage distribution system

Structures Low-voltage distribution system

Regarding the design of the grid different structures are possible: radial, ring and meshed structures. The simplest form is the radial structure where every individual connection (in this case households) is connected to one substation. In the case of a failure no electricity is supplied to the households. More reliable structures are the ring and mesh networks. These kinds of structure offer connections to multiple substations (Oirschouw, 2012). If a disturbance occurs, then the power is rerouted and can still be supplied to the households (Max Planck Society, 2012; Oirschouw, 2012). The choice for either of the structures depends on the requirement for system reliability, which is regularly higher for commercial areas than for residential areas (Oirschouw, 2012).

Components

The LVDS's main components are the transformer, or substation, and the power cables. These components are the bottleneck for supplying the demanded power to connected households. The commonly used substation capacity is 400 kVA, or 630 kVA if the 400 kVA is insufficient (Spruijt, 2014). In the analysis a 400 kVA substation is assumed in the original situation. Load on transformers can temporarily exceed the specified capacity by approximately 40% without causing an outage. This is useful for unexpected short demand peaks. A typical number of households per transformer is 200.

The power is transported from the substation to the user through power cables. Due to safety concerns these power cables are often put underground. The drawback is higher costs for replacing cables due to excavation works which is approximately 80% of the total costs of replacing power cables (Spruijt, 2014). The voltage level differs slightly across the power cable. A decrease in voltage level can be observed with increasing distance from the substation. This is due to the power loads between the substation and the concerning load (Oirschouw, 2012).

Power factor

The demanded power differs from the transported power. This is caused when the current and the voltage are not in phase, which reduces the *real power* (expressed in Watt). To deliver the required power to the load, a higher current is required. As a result, the transported power, or *apparent power* (expressed in volt-ampere (VA)), has to be increased. The ratio between the real power and the apparent power is the power factor or cos φ.

Load and stochastic behaviour

An important consideration in determining the required capacity of a low-voltage distribution system (LVDS) is the stochastic behaviour of load. Throughout a day the average consumption pattern is similar for most households. This average pattern is shown in Figure 2.1, which is the actual average electricity consumption of small consumers in the Netherlands (NEDU, 2015). The load is lowest between 01:00 and 7:00 hours, it ramps up between 7:00 and 9:00 hours to remain relatively constant during the day. The electricity demand ramps up again between 16:00 and 20:00 hours to reach the demand peak, after which it ramps down to the minimum.

The individual loads follow the same pattern throughout the day, but within a smaller time period the individual loads behave stochastically and large differences in individual loads can be perceived. This is because not every household turns on the same appliances at the same time. This means that the expected maximum load on an LVDS will be smaller than the sum of the maximum loads of each individual connection. This is characteristic is taken into consideration when dimensioning the LVDS capacity. The capacity of the LVDS will be smaller than the sum of the maximum loads of each individual household (Oirschouw, 2012). This applies to the electricity demand without heat pumps. If heat pumps are implemented the stochasticity of the total load decreases, because heat demand is less stochastic than traditional electricity demand.

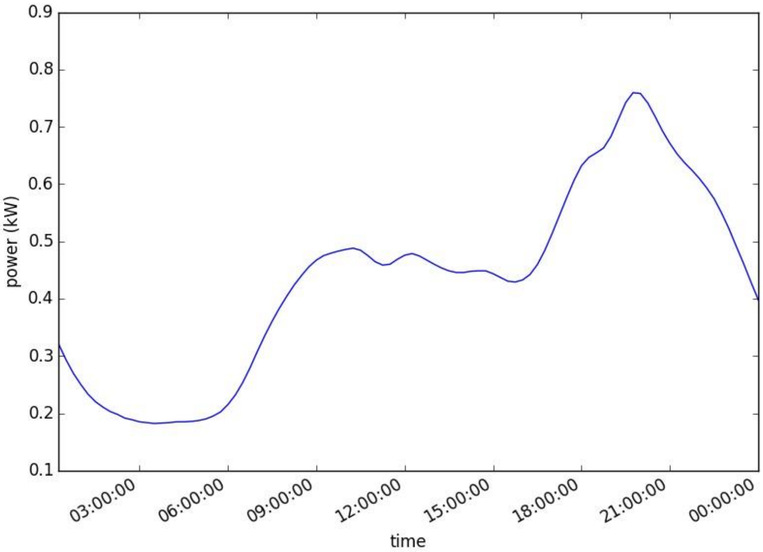

Figure 2.1: Aggregated electricity consumption profile for 21-03-2014 (NEDU, 2015).

2.1.4 LVDS simplifications

In this research only the LVDS is considered, because this part of the system is the most susceptible to blackouts due to capacity exceedance (Oirschouw, 2012). The LVDS grid is assumed to have a radial structure, thus the households are connected to one substation. It is further simplified by not considering differences in voltage levels across the power cable. In reality voltage slightly drops with distance from the substation. The LVDS capacity is dependent on the load the transporting cables can handle and the capacity of the low voltage transformer / substation. It is assumed that the cables have the same capacity as the substation, and if capacity expansion is required the cables must be replaced as well.

The substation capacity is the power that can be transported through it, i.e. the apparent power. Therefore the load demand should be adjusted with the power factor to calculate the apparent power through the substation. A fixed cos φ of 0.90 is assumed (De Energieconsultant, 2015; Oirschouw, 2012). This means that a substation with an apparent power capacity of 400 kVA can supply a real power demand of 400 kVA *0.90 = 360 kW. Furthermore, this is assumed to be a fixed capacity. While in reality the load on the substation can temporarily exceed the specified capacity. This is not taken into consideration because the data is the average load over a 5-minute period, thus small peaks are not registered. Peaks might occur during this period, but this will not be problematic because the LVDS can handle these peaks for short duration.

2.2 FLEX STREET DATA

2.2.1 Description

For this research data on electricity demand and heat demand is needed. Also, data on the energy demand of individual households is preferred. This is why the Flex Street data is used (Claessen et al., 2014). The Flex Street data represents the electricity demand, heating heat demand and domestic heat demand for 400 households htat are connected to the electricity and gas grid.

The electricity demand is the electricity demand including all the electric appliances which are normally present in a typical household, e.g. lighting, white goods and consumer electronics. Non-conventional applications, such as electric vehicles, photovoltaics and most of all heat pumps are not included. This will be referred to as the *traditional electricity demand*. This data is modelled based on the average power demand of appliances and the usage times. Households differ in the appliances they own which results in differences between annual electricity demand between households. Stochasticity is considered as well because it is modelled that appliances are turned on at different times, simulating the stochastic behaviour of load discussed above (Claessen et al., 2014).

Datasets for HHD and DHD are created using a heating demand model (Verbeeck, 2007) and a tap water model, respectively (Claessen et al., 2014). The heating heat demand (HHD) is the heat demand for space heating. The HHD dataset represents the heating heat demand of terraced buildings. It is assumed 25% of the buildings are corner houses. The model included ten different insulation levels, which are evenly distributed across the households in the dataset (Claessen et al., 2014).

Because the dataset concerns terraced buildings, the results of this research will be mainly applicable to neighbourhoods with mostly this building type. This means that the results are applicable to a large share of the residential sector, because terraced houses represent over 40% of the Dutch building stock (Agentschap NL, 2011).

Domestic heat demand (DHD) is the modelled use of hot tap water. Households differ in the hot water consuming appliances they own and the time on which they use these appliances. This simulates the stochastic behaviour of demand (Claessen et al., 2014).

The electricity demand and the heating heat demand datasets are scaled by a factor such that the annual demand matches the expected demand in the concerned year. Domestic heat demand remains constant. The expected annual electricity demand and HHD are respectively 4.2 and 6.25 MWh/household in 2050. Annual demand growth rates of +0.5% and -1.125% for electricity and HHD are assumed (Claessen et al., 2014). This means an annual energy demand for electricity, HHD and DHD of respectively 3.510, 9.411, and 1.875 MWh/household for 2014.

2.2.2 Adjustments

Some adjustments are made to the data. The time interval of the original dataset is 15 minutes. This is reduced to 5 minutes. Missing values, due to re-indexing, are interpolated. This results in a higher level of detail under the assumption that the interpolated data is correct. Still this implies that during the 5-minute period the load is constant.

The Flex Street model represents the modelled energy demand of 400 households. However, per substation only 200 households are connected on average. Therefore the original dataset is reduced from 400 to 200 households. It is assumed that the building types (terraced or corner house) and insulation levels are randomly assigned to the households in the dataset. Therefore simply the first 200 households from the dataset can be used, while maintaining a dataset that is approximately equal to the original. The dataset with 200 households is compared to the original dataset with 400 households to check whether they do not deviate too much, by comparing the annual average energy demand and the distribution across households. The comparison is shown in Table 2.1 and Figure 2.2. The average annual energy demand per household for electricity, heating heat and domestic heat deviates with resp. 0.69%, 0.90% and 0.29% (see Table 2.1). This is a negligible difference. The boxplot (see Figure 2.2) shows the distribution of annual energy demand per household. This distribution is similar if the dataset with 200 households and 400 households are compared with each other. Therefore it is concluded that the dataset with 200 households is sufficiently similar to the original dataset.

Table 2.1: The average annual energy demand for households in the neighbourhood for a dataset with 400 and 200 households.

	Electricity (MWh_e)	Heating heat (MWh_{th})	Domestic heat (MWh_{th})
400 HHs	3.510	9.411	1.875
200 HHs	3.534	9.496	1.880
Difference (%)	0.69%	0.90%	0.29%

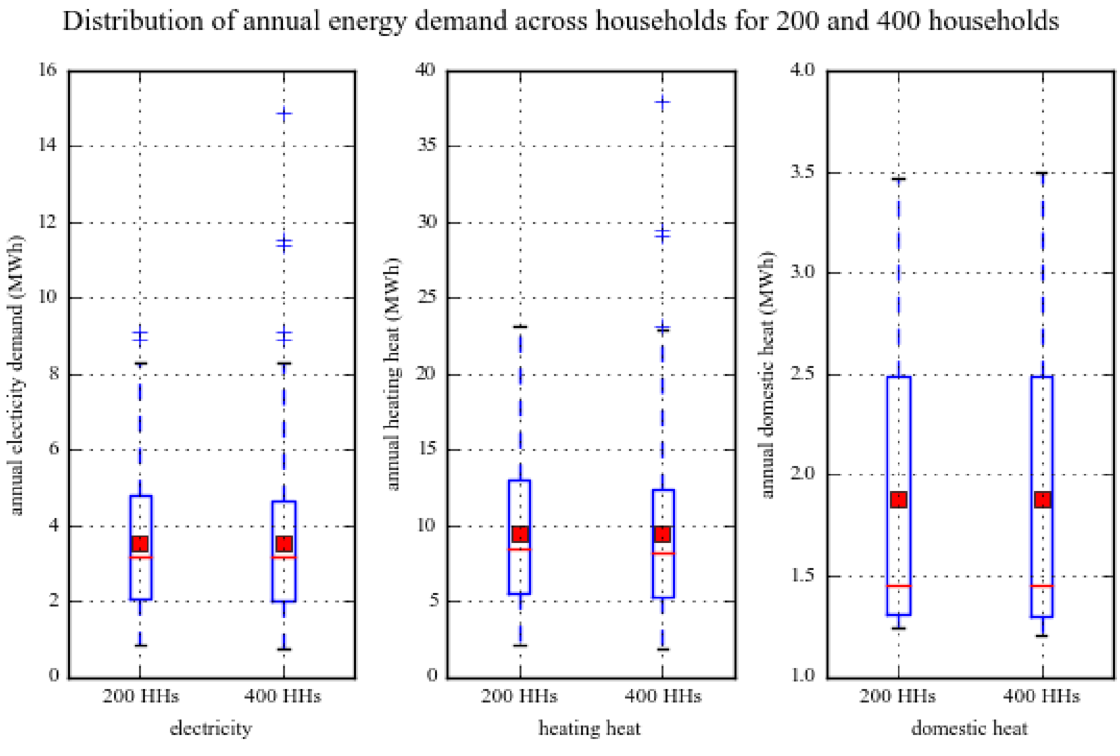

Figure 2.2: Distribution of annual energy demand per household. Showing the similarity between the dataset with 200 resp. 400 households. The red line is the modal energy demand. The red squared markers represent the mean annual energy demand.

2.2.3 Demand profiles

Figure 2.3 shows daily electricity and heat demand profiles for winter, spring and summer from the Flex Street data. This figure shows the variances in demand between households. Firstly this is caused by differences in total energy demand between households; not every household has the same annual energy consumption. The second reason is that the load profiles of individual households are not equal; peaks, relative to the households average demand, occur at different moments for different households. This shows the stochastic behaviour of load in the Flex Street dataset. The figure shows that the variance between households' demand is much higher for electricity than for heat demand. For electricity the standard deviation approximates the mean demand, while for heat the standard deviation is much smaller than the mean demand. This shows that the distribution of electricity demand across households is more random than the distribution of heat demand, or that heat demand has a high simultaneity.

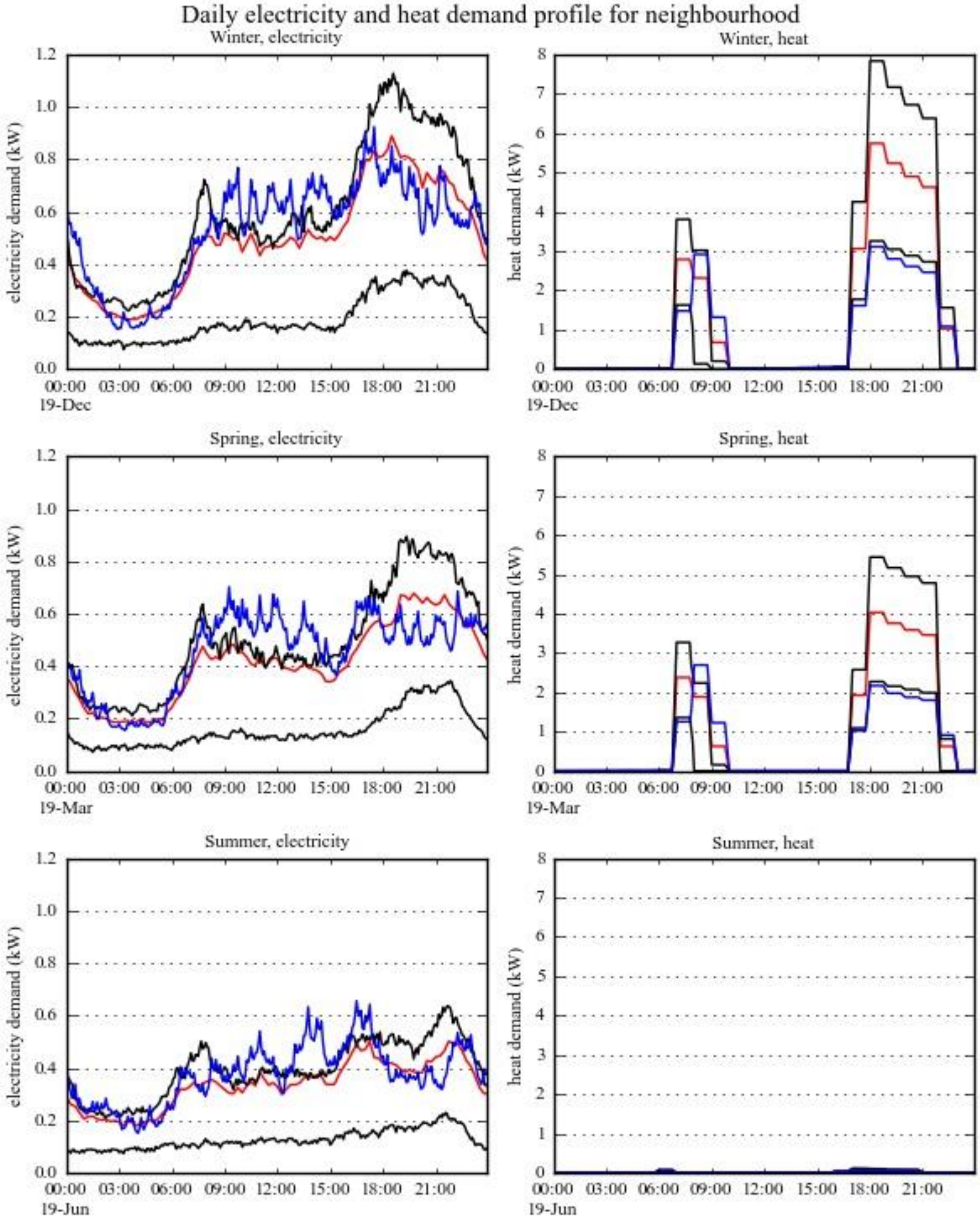

Figure 2.3: Daily electricity and heat demand profiles for a weekday in the winter (top row), spring (middle row), and summer (bottom row) of the households in the neighbourhood. The red line shows the mean energy demand of a household, the black lines show the first and third quartiles of energy demand, and the blue line shows the standard deviation. It shows that the variance in demand is much larger for electricity than for heat, compared to the mean demand. The seasonal variance is much larger for heat and is almost zero in the summer. Based on Flex Street data (Claessen et al., 2014).

2.3 CALCULATING LOAD ON LVDS

First the total load, including electricity demand for heat pumps, is determined. The total load is the sum the traditional electricity demand plus the electricity demand for the heat pump to fulfil the HHD and DHD (see equation(2.1)).

Important parameters are the maximum grid capacity deficit and the unsatisfied heat demand. The maximum grid capacity deficit is the maximum occurring load minus the LVDS capacity. The unsatisfied heat demand is the sum of the heat demand that is not fulfilled due to the lack of available LVDS capacity over the year.

In this research all calculations and modelling is done using Python programming language. Pandas and Matplotlib libraries are imported. Pandas is used for its convenient data structures and data analysis tools. Matplotlib is used to make graphical representations of data and results.

2.3.1 Heat pump load

The traditional electricity demand is directly retrieved from the dataset of electricity use. The electricity demand of the heat pump has to be calculated. The heat pump delivers the heat for space heating and for domestic hot water. The electricity demand for the heat pump is dependent on heat demand and the coefficient of performance (CoP) (see equation (2.2)). Because the CoP itself is temperature dependent and because heating heat and domestic heat requires different output temperature, the electric power demand is calculated for both separately and then summed.

$$\mathrm{P_{e,total\ load,t}\ [kW] = P_{e,traditional\ load,t}\ [kW] + P_{e,heat\ pump\ load,t}\ [kW]} \tag{2.1}$$

$$\mathrm{P_{e,HP\ load,t}\ [kW] = \frac{P_{th,heating\ heat,t}\ [kW]}{CoP_{heating\ heat,t}} + \frac{P_{th,domestic\ heat,t}\ [kW]}{CoP_{domestic\ heat,t}}} \tag{2.2}$$

2.3.2 Grid capacity deficit and unsatisfied heat demand

If the total electrical load is smaller than or equal to the LVDS capacity all the demand is simply fulfilled. Deficit occurs if the total electrical load is larger than the LVDS capacity. The total load of the neighbourhood on the substation is considered. The LVDS capacity deficit is the total load minus the LVDS capacity (see equation (2.3)), where the total electrical load is the sum of all individual loads, for the concerned period. The maximum occurring deficit in the year is found, which is associated with the maximum demand load.

Allocating capacity

There are three *components* that demand electricity: traditional demand, heat pump HHD and heat pump DHD. In case of a deficit the available capacity must be allocated to these components. Due to this research focus on heat and unsatisfied heat demand the traditional electricity demand is first in the order of priority, heating heat demand second and domestic heat demand third. The reason that DHD is put last is because its lower CoP compared to HHD, due to the higher required temperature of DHD. Which means that more heat can be supplied for HHD than for DHD with the same electricity input (and if thermal storage is implemented this heat is best used for DHD, with which more capacity is available for HHD).

If there is a capacity deficit, then the following steps are taken. First the traditional electricity demand is subtracted from the LVDS capacity (2.4). This gives the available power capacity for the heat pump. Then the HP electric power demand for HHD and the HHD supplied by the heat pump are calculated, for which the electricity input is limited to the available power capacity for the heat pump (2.5) and (2.6).

$$P_{e,capacity\ deficit,t}\ [kW_e] = \max(P_{e,total\ load,t} - P_{e,LVDS\ capacity}\ , 0\ ) \tag{2.3}$$

$$P_{e,remaining\ for\ HP,t}\ [kW_e] = P_{e,LVDS\ capacity,t} - P_{e,traditional,t} \tag{2.4}$$

$$P_{e,HP,HHD,t}\ [kW_e] = \min(\frac{P_{th,HHD,t}}{CoP_{heating\ heat}}, P_{e,remaining\ for\ HP,t}) \tag{2.5}$$

$$P_{HHD\ supplied\ by\ HP,t}\ [kW_{th}] = \min(P_{th,HHD,t}\ , P_{e,remaining\ for\ HP,t} * CoP_{heating\ heat}) \tag{2.6}$$

This is repeated for the DHD supplied by the HP (see equations (2.7) – (2.9)).

$$P_{e,remaining\ for\ HP,DHD,t}\ [kW_e] = P_{e,LVDS\ capacity,t} - P_{e,traditional,t} - P_{e,HP,HHD,t} \tag{2.7}$$

$$P_{e,HP,DHD,t}\ [kW_e] = \min(\frac{P_{th,DHD,t}}{CoP_{domestic\ heat}}, P_{e,remaining\ for\ HP,DHD,t}) \tag{2.8}$$

$$\begin{aligned} P_{DHD\ supplied\ by\ HP,t}\ [kW_{th}] \\ = \min(P_{th,DHD,t}\ , P_{e,remaining\ for\ HP,DHD,t} * CoP_{domestic\ heat}) \end{aligned} \tag{2.9}$$

The total heat that is supplied is the sum of the supplied HHD and DHD (2.10), with this the unsatisfied heat demand is calculated at each moment (2.11), this is summed to find the annual unsatisfied heat demand (2.12). The unsatisfied heat demand expressed in power (kW) is the average power for 5 minutes, this value is divided by 12 to convert to kWh.

$$P_{total\ heat\ supplied\ by\ HP,t}\ [kW_{th}] = P_{HHD\ supplied\ by\ HP,t} + P_{DHD\ supplied\ by\ HP,t} \tag{2.10}$$

$$P_{heat\ unsatisfied,t}\ [kW_{th}] = \left(P_{th,HHD+DHD,t}\right) - P_{total\ heat\ supplied\ by\ HP,t} \tag{2.11}$$

$$E_{heat\ unsatisfied}[kWh_{th}/year] = \sum_{i=1}^{8760*12} P_{heat\ unsatisfied,t}\ [kW_{th}]\ /12 \tag{2.12}$$

2.3.3 Coefficient of performance

The coefficient of performance (CoP) is the units heat delivered by the heat pump per unit of electricity used. The CoP depends on the relative temperature difference between the heat source (T_{high}) and the heat sink (T_{low}), according to equation (2.13) (Çengel & Boles, 2011). Available heat pumps will operate at a CoP below the theoretical maximum.

For an air source heat pump (ASHP) the heat source is air, therefore the ambient temperature is important. The CoP of an ASHP will fluctuate because ambient temperature fluctuates. Therefore a relationship between CoP and temperature had to be established. The air source heat pump is assumed because this is currently the most installed heat pump type and because ASHPs are more easily retro-fitted in existing buildings (European Heat Pump Association, 2014)

Heat pump test results for CoP are retrieved from the Wärmepumpen-Testzentrum of the NTB Interstaatliche Hochschule für Technik Buchs for air source heat pumps (Wärmepumpen-Testzentrum, 2015). For 59 heat pump models the CoP is tested at specific combinations of T_{high} and T_{low}. To be able to determine the CoP at every temperature a relationship between CoP and temperature has been established.

For every combination of T_{high} and T_{low} the relative temperature difference (equation (2.14)) and the average CoP of all heat pump models is calculated. Logarithmic regression is used to find the relationship between the CoP and the relative temperature difference (see Figure 2.4). The resulting regression line ($R^2 = 0.9847$) is equation (2.15). This equation will be used in the model to calculate the CoP. The relative temperature difference equation (2.14) is used, where T_{low} is the ambient temperature and T_{high} is the desired output temperature. The desired output temperature depends on the purpose of the heat. For T_{high} the values from Table 2.2 are assumed.

Furthermore it is assumed that the minimum CoP is 1, because heat pumps are equipped with an auxiliary electric heater with a heating efficiency of 100%, which is used if the CoP would otherwise be below 1.

$$\mathrm{CoP}_{\mathrm{theoretical\ maximum}} = \frac{\mathrm{T_{high}}\ [\mathrm{K}]}{\mathrm{T_{high}}\ [\mathrm{K}] - \mathrm{T_{low,t}}\ [\mathrm{K}]} \tag{2.13}$$

$$\Delta \mathrm{T_{relative}} = \frac{\mathrm{T_{high}}\ [\mathrm{K}] - \mathrm{T_{low,t}}\ [\mathrm{K}]}{\mathrm{T_{high}}\ [\mathrm{K}]} \tag{2.14}$$

$$\mathrm{CoP} = -2.914 * \ln(\Delta \mathrm{T_{relative}}) - 2.9857 \tag{2.15}$$

Table 2.2: Input values for T_{high} for determining the CoP.

Type of heat	**Assumption T_{high}**
Heating heat	45 °C Assuming low temperature heating (Milieucentraal, 2015c)
Domestic heat	60 °C (Milieucentraal, 2015a)
Stored heat	60 °C (Milieucentraal, 2015a)

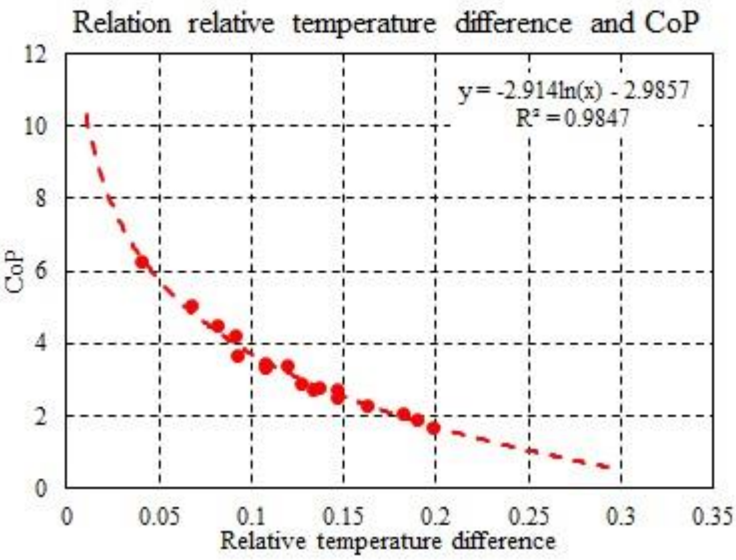

Figure 2.4: Logarithmic regression for the CoP and the relative temperature difference. The red markers show the average CoP from tested ASHPs for each relative temperature difference at which the heat pumps are tested. The dotted line is the regression line (Wärmepumpen-Testzentrum, 2015).

2.3.4 Temperature data

Temperature affects the expected electric power demand. Lower temperature leads to higher heating heat demand and lower CoP, thus will increase the electric power demand for heat pumps. Records of the ambient temperature of the period 1995 – 2014 are obtained from the Royal Dutch Meteorological Institute (KNMI, 2015). The data is resampled from an hourly interval to a 5-minute interval. The data points in between the original data points are interpolated.

If not indicated otherwise, the temperature records from 2014 are used. This is a relatively warm year with 15.5% less degree-days than the average of 1995 – 2014 (see Appendix B). This results in a relatively high CoP, which reduces the electricity demand for heat pumps. The effect of temperature is assessed by testing different scenarios for temperature and heating heat demand (see Table 2.1). These scenarios is applied on the maximum number of households that can use a heat pump without causing grid capacity exceedance and on the required "quantity" of a measure that is required to prevent capacity exceedance when all households would switch to heat pumps.

The scenarios differ in the used temperature profile and the heating heat demand profile. Four different temperature profiles are used: the year with resp. the lowest, average and highest number of degree-days (in scenarios 1 – 3) and the year with the longest cold spell (in scenario 4 – 6). The limitation is that the HHD and temperature profile do not exactly correspond. The deviation is strongest for extreme temperatures for that time of the year. The longest cold spell occurs between 30 Jan. – 8 Feb 2012 (KNMI, 2015). The HHD profile has been adjusted so that the HHD better corresponds with a demand that can be expected during a cold spell. The coldwave is simulated in the HHD data by applying the HHD of the day with the highest heat (i.e. 12 Jan.) demand peak on all the days in the period of the 2012 cold spell, from 30 Jan. – 8 Feb. (scenario 5). In an even more extreme scenario the duration of the cold spell is doubled. This is simulated by copying the HHD of 12 Jan. to all days in the period 30 Jan. – 18 Feb. and applying the KNMI data of 30 Jan.– 8 Feb. 2012 on 9 Feb. – 18 Feb. (scenario 6).

In the model the temperature only affects the CoP, as the heat demand profiles are "fixed", however in reality the temperature would also affect the heat demand. Therefore the effect of temperature would have been only partially included in the model. In order to make a more accurate estimation of the electricity demand of heat pumps during the coldest period, the highest peak of heat demand is alligned with the cold spell of 2012 where the lowest temperature are found.

Table 2.3: Heat pump electricity demand scenarios. The scenarios differ in expected annual electricity demand. Differences are due to used temperature data and adjustments of the Flex Street heating heat demand data. The scenarios will have an increasingly large expected electric power demand.

Scenario	Description	Year of KNMI data	Flex Street HHD profile
1	Warm year: Low number of degree-days	2014	Normal
2	Average year: Average number of degree-days	2009	Normal
3	Cold year: High number of degree-days demand	1996	Normal
4	Cold spell	2012	Normal
5	Cold spell, matching HHD and temperature	2012	Adjusted; HHD of days in cold spell of 2012 (i.e. 30 Jan. – 8 Feb.) is replaced with the HHD of the day with highest occurring total HHD (i.e. 12 Jan.)
6	Cold spell extended, matching HHD and temperature	2012 adjusted; Temperature records of 9 Feb. – 18 Feb. are replaced with records of 30 Jan. – 8 Feb.	Adjusted; HHD of days in cold spell of 2012 (i.e. 30 Jan. – 8 Feb.) and the next 10 days (i.e. 9 Feb. – 18 Feb.) is replaced with the HHD of the day with highest occurring total HHD (i.e. 12 Jan.)

2.3.5 Maximum number of heat pumps

It is assessed how many households can be equiped with a heat pump without causing capacity exceedance on the LV-DS. Only the heat demand (both heating and domestic) of a limited number of households is included. The maximum number of heat pumps for which the maximum occurring total electric load does not exceed the grid capacity has been determined for the a set of scenarios. Households differ in annual heat demand and the maximum allowable number of heat pumps thus depends on which households are equipped with a heat pump.Three scenearios for assigning heat pumps to households are assessed:

- Heat pumps are assigned to households with a low annual heating heat demand firstly. This will give the maximum number of households that can be equipped with heat pumps.
- Heat pumps are assigned to households "randomly". Here the households are selected in order of how they are numbered in the dataset (first HH_001, second HH_002, etc.) which is assumed to be sufficiently random.
- Heat pumps are assigned to households with a high annual heating heat demand firstly. This will give the lowest number of households that can be equipped with heat pumps.

The scenarios regarding temperature data and heating heat demand (see section 2.3.4) are taken into account as well.

2.4 POTENTIAL OF MEASURES

A number of measures available which can be used to prevent capacity exceedance and with which all energy demand can be fulfilled. Of these measures are important their characteristics, i.e. how they affect the load profile, and their costs. The potential for preventing LVDS capacity exceedance and reducing unsatisfied heat demand is assessed.

Information about possible measures and their costs is acquired through literature. The following options are mentioned in previous research (e.g. Schepers et al., 2015; Felix Covrig et al., 2014; van Roy, Verbruggen and Driesen, 2013; U.S. Department of Energy, 2013) and can contribute to mitigating grid capacity deficit.

Capacity exceedance can be prevented by simply increasing the LVDS capacity. A smarter solution might be reducing (peak) demand, with a focus at heat demand. Peak demand can be reduced by (thermal) storage, where unused LVDS capacity during off-peak hours is used to store energy which can be used in peak hours; demand shifting, where the demand peak of a number of consumers is shifted to reduce the peak demand; or energy saving, with which heat demand reduced for all periods.

When a measure cannot prevent capacity exceedance when implemented individually, it will be assessed whether the measure can contribute to reduce the total costs of a measure that can prevent capacity exceedance when implemented individually. The costs for the combination of the two measures is assessed and compared to the costs of the individual measures.

2.4.1 Grid capacity expansion

Description

Probably the most logical measure is increasing the capacity expansion, because the DSO is responsible for providing enough capacity and they are currently limited to improving distribution capacity. The LVDS capacity can be increased by replacing the transformer or adding transformers. Also, the cables have to be replaced to carry the increased load. These two components determine the costs for implementing this measure. If capacity expansion is implemented as an individual measure, then the capacity should be larger than or equal to the maximum total load in the neighbourhood.

Model

In the model the minimum required capacity expansion is derived from the the maximum occurring electricity demand of the neighbourhood, $\mathrm{P_{e,capacity\ deficit}}$ $[\mathrm{kW_e}]$, calculated with equation (2.3). This is the real power demand, while the capacity of the grid is expressed as apparent power demand (kVA). The required capacity expansion, expressed in kVA, is calculated with equation (2.16), where cos φ is 0.90. Capacity can only be expanded in steps, based on the available transformer sizes, therefore the actual capacity expansion might be larger than the minimum required capacity expansion.

$$\text{Required capacity expansion [kVA]} = \mathrm{P_{e,capacity\ deficit}}\ [\mathrm{kW_e}]/\cos\varphi \qquad (2.16)$$

Costs

The costs for grid capacity expansion are associated with replacing/adding transformers and replacing cables. Only the costs for the LV grid are included. Capacity is expanded stepwise, because the size of the expansion is dependent on the capacity of available transformers. Considered transformer capacities are 400 kVA or 630 kVA. Also the option of replacing the existing (400 kVA) transformer with a 630 kVA transformer is included, with which effectively 230 kVA is added. Replacing an existing transformer is cheaper than adding a new transformer because it is not necessary to build a new unit (Spruijt, 2014).

There was little data available for the costs of transformers for the electrical grid. The costs of a 400 kVA transformer are estimated at €30,000 by Rooijers & Leguijt (2010). The other data are estimates made by Pellis, as cited in Spruijt (2014). Pellis, the primary data source, is an expert from a DSO and assumed to be a credible source. Table 2.4 shows the overview of costs per option.

Cables are purchased per meter. A street is assumed with connections on both sides of street, so 100 out of 200 households are on one side and the estimated space between households is 10 m. Then the required cable length for the neighbourhood of 200 households is estimated at 1000 meter, which equals the assumption in Spruijt (2014). It is assumed that all cables are replaced if any capacity expansion is required

Table 2.4: Costs for increasing LVDS capacity. Source: (Spruijt, 2014).

Option	Size	Investment costs	Lifetime
Replace transformer	400 kVA	€ 7,800	30 years
Replace transformer	630 kVA	€ 11,100	30 years
Additional transformer	400 kVA	€ 30,000	30 years
Additional transformer	630 kVA	€ 33,300	30 years
Extra cable	1 m	€ 83.00	30 years

Costs depend on the combination of options that is used and the lowest costs combination is persued with which the required capacity expansion can be satisfied. For a range of required capacity expansion the lowest-costs combinations are found. Replacing the 400 kVA transformer with a 630 kVA transformer expands the capacity by 230 kVA. Adding a 400 or 600 kVA transformer expands the capacity by resp. 400 kVA or 630 kVA. Replacing is limited to a maxium of 1, while adding transformers is not limited to a maximum. Figure 2.5 is a graphical representation of the actual capacity expansion if the combination of options with the lowests costs is choosen, for a range of values for required capacity expansion. The data is shown in Table 7.5 in Appendix D.

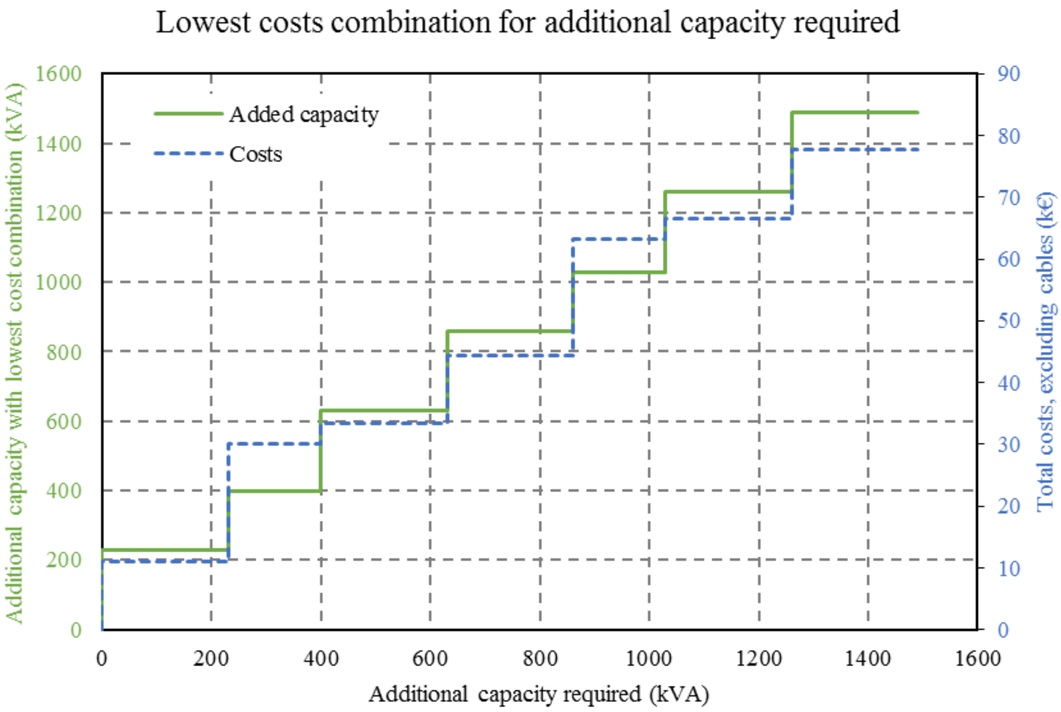

Figure 2.5: Lowest costs combinations of capacity expansion for required capacity expansion. Capacity can only be increased in steps of resp. 230, 400 or 630 kVA. This figure shows the grid capacity that will be added and the costs when the combination of options with the lowest costs is used.

2.4.2 Thermal energy storage

Description

Thermal energy storage (TES)[2] is "a technology that stocks thermal energy by heating or cooling a storage medium so that the stored energy can be used at a later time for heating and cooling applications and power generation." (ETSAP/IRENA, 2013, p. 1). When TES is implemented to prevent capacity exceedance, the LVDS capacity that is not required for fulfilling direct power demand is used to generate and store heat.

Different forms of TES exist: *sensible heat storage*, where the storage medium, e.g. water, is heated or cooled; *latent heat storage*, which utilizes the latent heat when a substance changes phase, e.g. from liquid to sold; and *thermal-chemical storage*, where the heat that is absorbed and released during chemical reactions (ETSAP/IRENA, 2013). Sensible heat is the cheapest form of TES, but sensible heat TES systems require more volume due to the low energy density. The costs for a sensible heat TES system ranges between €0.10 – €10/kWh, whereas the costs for latent heat or thermal-chemical systems range between €10 – €50/kWh and €8 – €100/kWh respectively (ETSAP/IRENA, 2013).

[2] Only thermal storage is considered in this research, because thermal storage is relatively cheap compared to e.g. energy storage in batteries, and because the purpose of the stored energy is fulfilling heat demand.
Thermal energy costs range from 0.1 – 100€/kWh (ETSAP/IRENA, 2013), compared to current battery prices just below 300 €/kWh (derived from 300 $/kWh) and an optimistic prognosis of 150 €/kWh. (Nykvist & Nilsson, 2015). Still, more thermal than battery capacity is required because the CoP is larger than 1, i.e. more heat is generated than electricity used. Assuming the average CoP = 3,5 (Çengel & Boles, 2011, p. 284) the "corrected" costs for thermal storage are 0.35 – 350 €/kWh. The lower limit is far below the costs of energy storage in batteries.

It is expected that on a day with an average heat demand the storage is fully charged between periods of grid capacity deficit. Issues arise when the available grid capacity during off-peak hours is not sufficient to fully recharge the heat buffer. This means that the This means that the buffer capacity on the previous day should be larger than the daily heat demand from the buffer, in order to save enough for the next day's heat demand. The storage capacity should be dimensions for these periods, with a number of consecutive days with insufficient grid capacity to fully recharge the buffer in between peak-hours.

Model

When thermal energy storage is implemented in the model most of the equations from section 2.3.2 are used, with some adjustments that enable storing heat and utilizing the stored heat.

If the total electrical load is smaller than the LVDS capacity, then the remaining capacity is used to store heat. The LVDS capacity surplus is calculated by subtracting the total electricity load from the LVDS capacity (2.17). The available electricity is used to generate heat with the heat pump, which is then stored. The heat that can be stored at each moment is limited to the remaining storage capacity (2.18), where $E_{\text{heat stored}}$ is the heat stored at the beginning of the time period. The storage capacity and the heat stored are neighbourhood totals. The average storage per neighbourhood is derived from this value.

At the start of each period the heat loss from the storage is taken into account as an efficiency (2.19). An efficiency of 99.95%/15 minutes is assumed (Claessen et al., 2014), which is $0.9995^{(1/3)}$/5 minutes. This latter is used because this corresponds with the 5 minute periods in the data.

$$\mathrm{P}_{\text{e,capacity surplus}}\,[\mathrm{kW_e}] = \max(\,\mathrm{P}_{\text{e,LVDS capacity}} - \mathrm{P}_{\text{e,total load}}\;, 0\,) \tag{2.17}$$

$$\mathrm{E}_{\text{storage capacity remaining}}[\mathrm{kWh_{th}}] = \mathrm{E}_{\text{storage capacity}} - \mathrm{E}_{\text{heat stored}} \tag{2.18}$$

$$\mathrm{E}_{\text{heat stored}} = \mathrm{E}_{\text{heat stored}} * \eta_{\text{heat loss}} \tag{2.19}$$

The LVDS capacity surplus is used to store heat. A CoP for storage is used assuming a constant storage temperature T_{high} of 60°C. The power output is the average for the 5 minute period, hence the division by 12 to convert to kWh (2.20). Then the new buffer capacity is calculated (2.21), which is used in equation (2.18) for the next 5 minute period. The thermal storage is full initially, thus initially $E_{\text{heat stored}} = E_{\text{storage capacity}}$.

$$\begin{aligned}\mathrm{E}_{\text{heat to storage}}[\mathrm{kWh_{th}}]\\ &= \min\left(\frac{\mathrm{P}_{\text{e,capacity surplus}} * \mathrm{CoP}_{\text{storage}}}{12}, \mathrm{E}_{\text{storage capacity remaining}}\right)\end{aligned} \tag{2.20}$$

$$\mathrm{E}_{\text{heat stored,new}}[\mathrm{kWh_{th}}] = \mathrm{E}_{\text{heat stored}} + \mathrm{E}_{\text{heat to storage}} \tag{2.21}$$

In the case of LVDS capacity deficit, the stored heat is used. Heat supplied by the storage had to be added to equation (2.11) from section 2.3.2. The heat supplied by the storage is the demand minus the heat supplied by the heat pump (from (2.10)), with a maximum of the currently stored heat (2.22).

The new value for stored heat is then calculated (2.23), which is used in equation (2.22) for the next period. If storage is applied the unsatisfied heat demand from equation (2.11) is expanded with $E_{\text{heat from storage}}$ (2.24). Then the cumulative unsatisfied heat demand is calculated with equation (2.12).

$$E_{\text{heat from storage}}[kWh_{th}] = \max\left(\frac{(P_{th,HHD} + P_{th,DHD}) - P_{\text{total heat supplied by HP}}}{12}, E_{\text{heat stored}}\right) \tag{2.22}$$

$$E_{\text{heat stored,new}}[kWh_{th}] = E_{\text{heat stored}} - E_{\text{heat from storage}} \tag{2.23}$$

$$P_{\text{heat unsatisfied}}\ [kW_{th}] = (P_{th,HHD+DHD}) - P_{\text{total heat supplied by HP}} - E_{\text{heat from storage}} * 12 \tag{2.24}$$

A range of values for storage capacity ($E_{\text{storage capacity}}$) is tested. The goal is to find the TES capacity of the neighbourhood for which no grid capacity deficit or unsatisfied heat demand occurs. The original LVDS capacity of 360 kW is assumed.

Costs

The costs for TES are mainly the costs for the heat exchangers, storage medium and container. The costs for a complete TES system, with sensible heat storage using storage tanks, are estimated at €0.5-3.0 per kWh (ETSAP/IRENA, 2013, p. 14).

The costs for TES are mainly the costs for the heat exchangers, storage medium and container. The costs for a complete TES system are 20 ± 5 €/kWh. How the cost range is determined can be found in Appendix E.

2.4.3 Heat demand reduction

Description

Heating heat demand is the largest contributor to power demand (see Table 2.1). Reducing HHD might help with reducing the grid capacity deficit. Heating heat demand in the residential sector can be reduced by improving the buildings' insulation level. Besides preventing capacity exceedance this also reduces the overall energy use.

Model

Increasing insulation levels is simulated by reducing the values in the HHD dataset. This is done by multiplying the HHD with a demand-factor, which is the factor of the current HHD that remains after implementing a set of energy saving measures. With the reduced HHD the grid capacity deficit and the unsatisfied heat demand are calculated with according to the description in section 2.3.2. The effect on the grid capacity deficit and the unsatisfied heat demand of a range of values for the demand-factor will be assessed. The goal is to find the demand-factor for which all the demand can be fulfilled.

Costs

To get more insight in the HHD reduction potential a survey on the Dutch building stock by Agentschap NL (2011) is consulted. This is a survey on the most common building characteristics of specified categories of building types and building year, or *example buildings*, with special regard to energy demand. For each example building the maximum, but realistically possible, energy performance is determined, which is represented as *energiebesparingspakket* (Agentschap NL, 2011). The data for terraced buildings is used, so it matches the energy demand from the Flex Street data. In the example buildings more energy saving is possible, i.e. *energiebesparingspakket extra*. But this represents implementing measures that do not affect the heating heat demand, e.g. PV or solar boiler, and is therefore not considered. The assumed set of energy saving measures includes improved insulation levels for all wall, roof and floor area (R_c = 2.5 m^2*K/W, representing 9.5 cm glass or glass or rockwool) and all glass is replaced with insulated glazing (U = 1.80 W/m^2*K) (Agentschap NL, 2011; AgentschapNL, 2011). The HHD in the current situation is compared to the HHD in the situation where the set of measures is implemented. For the set of measures an estimation of investment costs from Agentschap NL (2011) are used. The demand-factor is the ratio between the heating heat demand in both situations and is given in Table 2.5.

It is important to match energy saving potential of an example building with the required investment costs for that specific example building. A building with a low insulation level can relatively achieve more energy saving at lower costs, whereas a building that already has a high insulation level can probably only save a few percentage on heating, and probably an expensive measure is required.

The mean annual HHD per household in the Flex Street dataset is 9.50 MWh (see Table 2.1). This matches most closely with the terraced buildings of building year 1975 – 1991 (see Table 2.5). For this example building an average HHD-fraction of 53% is achievable and the investment costs are estimated at €9,970. Therefore, it is assumed that an average HHD-fraction of 0.53 is realistically possible. An optimistic estimation of the required investment costs is the average investment costs of 165 €/% HHD reduction.

Table 2.5: Heating heat demand reduction potential for terraced buildings of different building periods. The average HHD in the current situation and the situation with a set of implemented energy saving measures is compared. With the set of measures the maximum realistically possible energy saving is achieved. For each building period the required investment costs are shown as well. These values represent averages for each example building. Derived from Agentschap NL (2011).

Building year	HHD current (MWh)	HHD with set of energy saving measures (MWh)	Achievable HHD-fraction with set of energy saving measures	Investment costs for set of energy saving measures (€)	Specific investment costs (€ / kWh saved)	Specific investment costs (€ / %HHD reduction)
t/m 1945	32.3	6.6	20%	13,270	0.516	166.84
1946-1964	21.3	5.7	27%	9,630	0.615	131.11
1965-1974	19.0	6.4	34%	10,970	0.873	165.57
1975-1991	***11.7***	***6.2***	***53%***	***9,970***	***1.823***	***213.28***
1992-2005	6.9	6.3	92%	1,250	2.190	150.02
average	18.2	6.2	45%	9,018	***0.752***	***165.36***

2.4.4 Heat demand shifting

Description

Demand shifting entails postponing or bringing forward the use of energy consuming appliances, mostly from peak to off-peak hours for the purpose of demand peak shaving. Heat demand must be met instantaneously which limits the potential of demand shifting. However, a large part of the peak demand is for raising the indoor temperature to the desired level when most people return to their homes in the afternoon. If a share of the homes starts reheating earlier, then the demand peak for those households will be earlier. Shifting a part of the peak might reduce the peak load of the neighbourhood, which also reduces the need for grid capacity improvement or energy storage.

Model

Heat demand shifting will be simulated by shifting all the heating heat demand of *n* households one hour forward. For *n* a range of 0 – 200 is used. For which households the demand is shifted might also be relevant. If the demand of a household with a large HHD is shifted, this might have a larger impact than shifting the demand of a household with a small HHD. Two options are assessed:

1. Shifting the HHD of the households in the order in which they are listed, e.g. if *n*=30, then the demand of household 1 to household 30 is shifted. With regard to annual HHD this means the dataset is unsorted.
2. Shifting the HHD of the households in order of annual heating heat demand; e.g. if *n*=30, then the demand of the 30 households with the highest annual HHD is shifted. The households are sorted bases on annual HHD, in descending order.

Shifting all the HHD of a household is a simplification. The demand then peaks one hour earlier, but also drops an hour earlier, which would effectively mean that the thermostat is turned down one hour too early. The effect on the results might by small, because this occurs during off-peak hours. Another implication is that shifting the HHD means that a different ambient temperature applies, which is not taken into account now. But in can be assumed that the ambient temperature change in one hour is limited and smaller than the change in indoor temperature before and after reheating.

Costs

No data is available for the costs of a system that enables demand shifting. However, live demand measuring is required which will involve costs. Therefore the estimated costs are bases on the maximum price of a smart meter for consumers, which is €71.40 (Rijksoverheid, 2015d). It can be assumed that investement costs for demand shifting will be in this order of magnitude and are estimated at €100,- per household on which demand shifting is applied.

2.4.5 Limiting the number of heat pumps

Description

As discussed in section 2.3.5, the existing grid might be able to fulfil the power demand of a limited number of heat pumps. The number of heat pumps is limited to the the maximum number of heat pumps the grid can handle in heat pump electricity demand scenario 6, if the households with the lowest heat demand are equipped with a heat pump firstly.

Model

The maximum number of heat pumps is found using the method in section 2.3.5. The number found in heat pump electricity demand scenario 6, when the households with a low heat demand are equipped with a heat pump firstly, is assumed.

Costs

Because the number of heat pumps is limited to an amount that can be handled by the existing LVDS, no additional measures are required. This means that there are no additional investment costs. However, the natural gas infrastructure is still necessary. The costs for the natural gas infrastructure are estimated at 199 €/year/household (see Appendix C). This assumption is based on the annual costs for a connection, which presumably represent the costs for the infrastructure. For households with a heat pump a connection to the gas grid is not required any more. For these households the standing tariff for the retaioler for gas connection is not applicable any more as well as the capacity tariff that is paid for the connection to the gas grid. This implies that the costs for the gas infrastructure in the neighbourhood as a whole would decrease with the same fraction as the fraction of households that are equipped with a heat pump. This would be partly true, because there are less connections which is a direct cost reduction and the lower demand presumably improves the grid's lifetime. On the other hand the cost reduction might be smaller, because a fraction of the costs will not be relative to the amount of gas transported.

2.5 CALCULATING SYSTEM BENEFITS AND COSTS

The goal of the research is twofold. On the hand hand the possible measures are compared based on the their investment costs to prevent grid capacity exceedance when the entire neighbourhood switches to heat pumps. On the other hand the costs-effectivity of energy saving and CO_2 mitigation of switching to heat pumps is assessed, where also the investment costs for measures to prevent grid capacity exceedance are included.

Firstly the required investment costs to prevent grid capacity exceedance when all households use heat pumps are compared. Only the investment costs for the required measures are compared. The methods for calculating investment costs for each measure are described in section 2.4. The range for the investment costs will be based on the range of the quantity of a measure that is required to prevent capacity exceedance. The latter is based on the scenarios for expected electricity demand for the heat pumps. All scenarios are included here.

Secondly the measures are compared based on the annual costs when measures are implemented. Here the costs due to the possible change in energy demand, as a result of implementing a measure, are also considered. The annual costs is the sum of the annualized investment costs and the change in annual energy bill for households. The investment costs are annualized by multiplying the investment cost with the annualization factor (2.25), where r is the discount rate and L the product's lifetime. A relatively low discount rate of 4% is assumed, which corresponds to a discount rate from the social perspective. The social perspective is appropriate when evaluating infrastructure projects (Blok, 2007). The annual energy costs are calculated using equation (2.26). The average annual energy costs per household are compared to the annual energy costs when conventional heating, i.e. natural gas, is used. The annual energy costs are based on the average annual energy demand. This is represented by heat pump electricity demand scenario 2, with an average amount of degree-days and the normal HHD. The investement costs for each measure are based on the costs in the heat pump electricity demand scenario with the highest electricity demand, i.e. scenario 6. This is because the energy infrastructure should be able to always fullfill all energy demand. This condition is satisfied when the infrastructure is sufficient in the most demanding scenario. Furthermore it is assumed that switching to an all-electric grid results in the redundancy of the gas infrastructure. The financial benefit of not needing a gas infrastructure is taken into account. This is assumed to equal the annual tariff for a gas connection for households (199 €/year/household).

Thirdly the cost effectivity of energy saving and CO_2 emission mitigation of switching to heat pumps is calculated. The cost effectivity is expressed as resp. the specific costs for energy saving (2.27) and the specific costs for CO_2 mitigation (2.28). The costs minus benefits is the change in annual energy bill. The energy bill with conventional heating and heat pump heating are calculated with equation (2.26). The energy saving is calculated by comparing the primary energy consumption of the neighbourhood with heatpumps with the neighbourhood with conventional heating. This is calculated for the implementation of each measure. A first order representation for energy consumption is used. This means that for electricity the conversion efficiency for electricity production is taken into account (40% (ECN, 2012)). For CO_2 mitigation the emission factors for natural gas and electricity production are taken into account (see Table 2.6). The investment costs in this case are the investment costs for the required measure and heat pump. It is assumed that an appropriate heat distribution system is available in the buildings, e.g. costs for a floor heating system are not included. Again the investment costs for each measure of scenario 6 are assumed and the annual energy costs for scenario 2.

See Table 2.6 for overview of assumed values in analysis. Under these assumption the average annual energy bill, primary energy demand, and CO_2 emissions per household in the reference scenario, where natural gas is used to fulfil heat demand are calculated (see Table 2.6).

$$\alpha = \frac{r}{1-(1+r)^{-L}} \qquad (2.25)$$

$$\begin{aligned} C_{energy}[€/HH/year] &= E_e[MWh_e/HH/year] * C_e[€/MWh_e] + C_{e,fixed}[€/HH\,/year] \\ &+ E_g[MWh_g/HH\,/year] * C_g[€/MWh_g] + C_{g,fixed}[€/HH\,/year] \end{aligned} \qquad (2.26)$$

$$C_{spec} = \frac{\alpha * I + C - B}{\Delta E} \qquad (2.27)$$

$$C_{spec,\,CO_2} = \frac{\alpha * I + C - B}{\Delta CO_2} \qquad (2.28)$$

Table 2.6: Assumed values for calculating costs, primary energy use and CO_2 mitigation.

Unit	Value	Source
Traditional electricity demand	3.534 MWh_e/household	see section 2.2
Total heat demand	9.496 MWh_{th}/household	see section 2.2
LHV natural gas	35 MJ_{LHV}/m^3 (LHV)	(Blok, 2007)
Electricity price	0.2398 €/kWh	see Appendix C
Natural gas price	0.6911 €/m3	see Appendix C
Fixed costs electricity	-32 €/year/household	see Appendix C
Fixed costs gas	199 €/year/household	see Appendix C
Investment costs heat pump	€10,000	(DHPA, 2015; Warmtepompplein, 2015b)
Discount rate, r	4%	Discount rate from social perspective (Blok, 2007)
Emission factor natural gas	56 kg CO2 /GJ(LHV), or 201.6 kg CO2 /MWh (LHV)	(Blok, 2007)
Emission factor electricity production	0.480 kg CO2/$kWh_{e,\ produced}$	Based on: (Brouwer, Kuramochi, van den Broek, & Faaij, 2013; CBS, 2014b; CE Delft, 2015) (see Table 7.7 in Appendix F)
Efficiency electricity production	40%	(ECN, 2012)
Heating efficiency conventional / natural gas	100% (LHV)	
Lifetime heat pump	20 years	(Zottl, Lindahl, Nordman, & Rivière, 2011)
Lifetime electricity grid	30 years	(Spruijt, 2014)
Lifetime insulation	20 years	Reported: 20 – 30 years (Isolatie.net, 2015)
Lifetime TES system	20 years	Reported: 10 – 30+ years (ETSAP/IRENA, 2013)
Lifetime heat demand shifting	30 years	Equal to lifetime electricity grid

Table 2.7: Average annual energy bill, primary energy demand, and CO_2 emissions per household when natural gas is used to fulfil heat demand.

Variable	Value
Average energy bill	1,823 €/household/year
Average primary energy demand	20.2 MWh/household/year
Average CO2 emissions	3,990 kg CO2/household/year

3 RESULTS

3.1 TOTAL EXPECTED LOAD WITH HEAT PUMPS

In this section the expected electrical load of heat pumps and the expecting capacity deficit is presented. First an overview of the annual electricity demand per household is given, followed by the demand profile to assess the demand peaks.

3.1.1 Distribution of electricity demand across households

Figure 3.1 shows the distribution of annual electricity demand across households. A distinction is made between traditional electricity demand and the electricity demand for the heat pump. The mean electricity demand for the heat pump (total for HHD and DHD) is 3.63 MWh_e/year (assuming the 2014 temperature records), compared to the traditional electricity use is 3.53 MWh_e/year. This means that the annual electricity demand will approximately double if heat pumps are implemented. Traditional and heat pump electricity demand follow different profiles and show more variation throughout a year (see Figure 2.3), therefore the total electrical load at each moment is assessed.

Figure 3.2 shows the average annual electricity demand and the seasonal average CoP in the different heat pump electricity demand scenarios. In the “average demand” scenario (scenario 2) the average electricity demand for the heat pump for fulfilling HHD and DHD is respectively 3.07 MWh_e/household/year and 0.75 MWh_e/household/year, with a seasonal average CoP of 2.98.

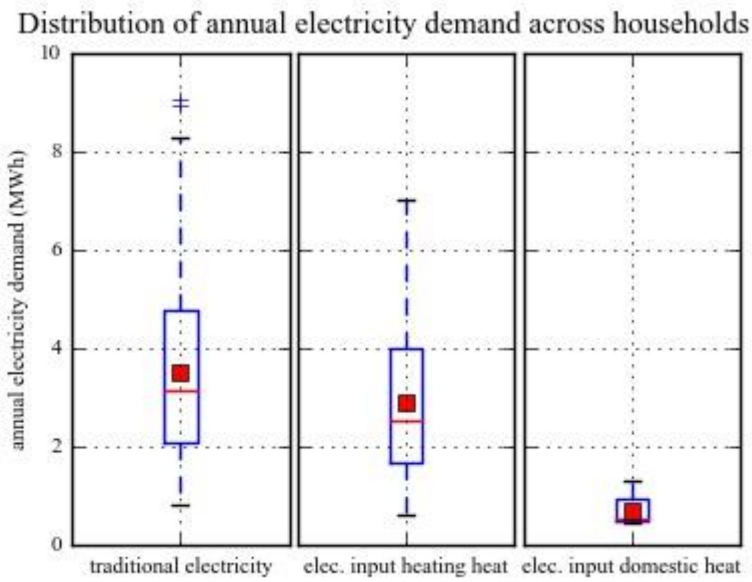

Figure 3.1: Distribution of annual electricity demand for households. Divided in the traditional electricity demand and the electricity demand for the heat pump for supplying both the heating heat demand and the domestic heat demand. The red squared marker represents the mean annual electricity demand. These are 3.53, 2.91, and 0.72 MWh_e, for traditional electricity demand, heat pump electricity demand for HHD, and heat pump electricity demand for DHD respectively. Scenario 1 for heat pump electricity demand is assumed here, i.e. normal Flex Street HHD and temperature records of 2014.

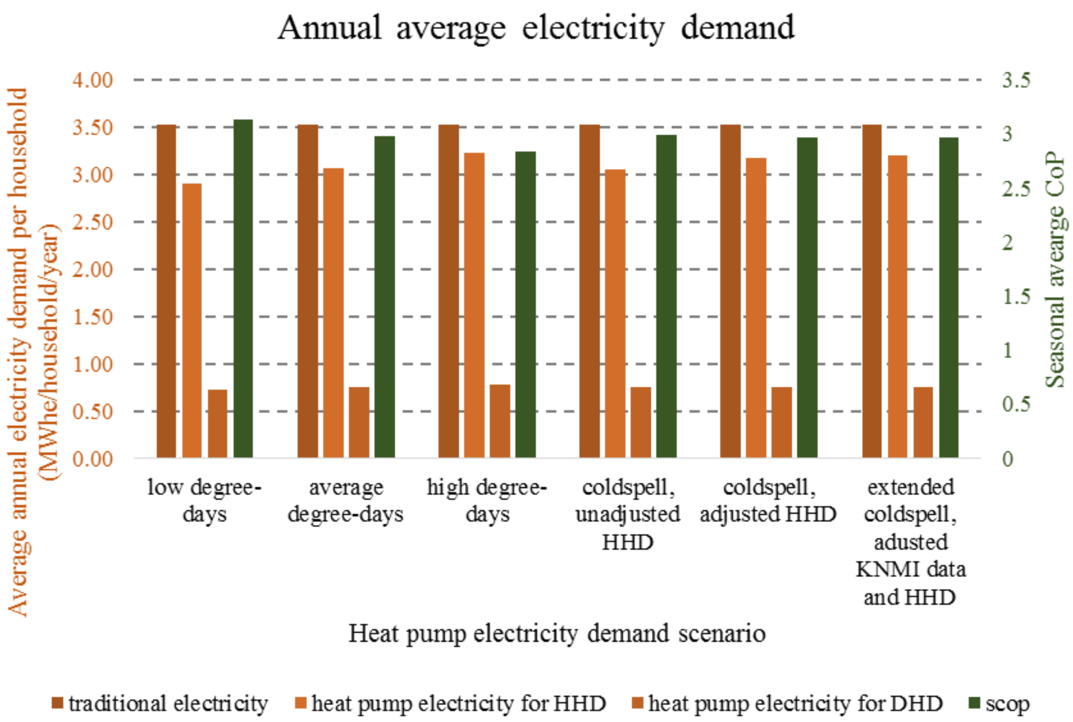

Figure 3.2: Annual average electricity demand for different heat pump electricity demand scenarios

3.1.2 Capacity deficit and unsatisfied heat demand in original LVDS with heat pumps

Figure 3.3 shows the total demand during the period with the highest electricity demand peak. This peak occurs during a period of low temperatures at a time where most residents start heating their homes (on 27 December 2014, 18:35:00). If all 200 household would have heat pumps, then the maximum total load of the neighbourhood is 970.0 kW, or 1077.7 kVA. 4/5th of this peak is due to the heat demand which shows the significance of electricity demand of heat pumps during demand peak hours. Figure 3.4 shows the load duration curve for the total load on the LVDS grid. This figure also shows that when the total electric load is high, the electric power demand of the heat pump to fulfil all heating heat demand is especially high. The traditional electricity demand is a relatively small contribution to the total electric power demand during the total demand peaks. Grid capacity deficit occurs approximately 1000 hours on an annual bases.

This means that shifting to heat pumps in the neighbourhood causes a maximum capacity deficit of almost 700 kVA, which is more than twice the current LVDS capacity. Not all heat demand can be fulfilled without taking measures. The unsatisfied heat demand is 456 MWh$_{th}$/year which is 24.0% of the total heat demand 2275 MWh$_{th}$/year for the neighbourhood.

The total electricity demand is 7.16 MWh$_{e}$/year/household, thus 1432 MWh$_{e}$/year for the total neighbourhood. The average load is 163 kW and because this is lower than the LVDS capacity of 360 kW this means that on an annual basis the grid capacity is sufficient. However, to fulfil this demand at every moment a form of demand side management is required, e.g. energy storage or demand shifting.

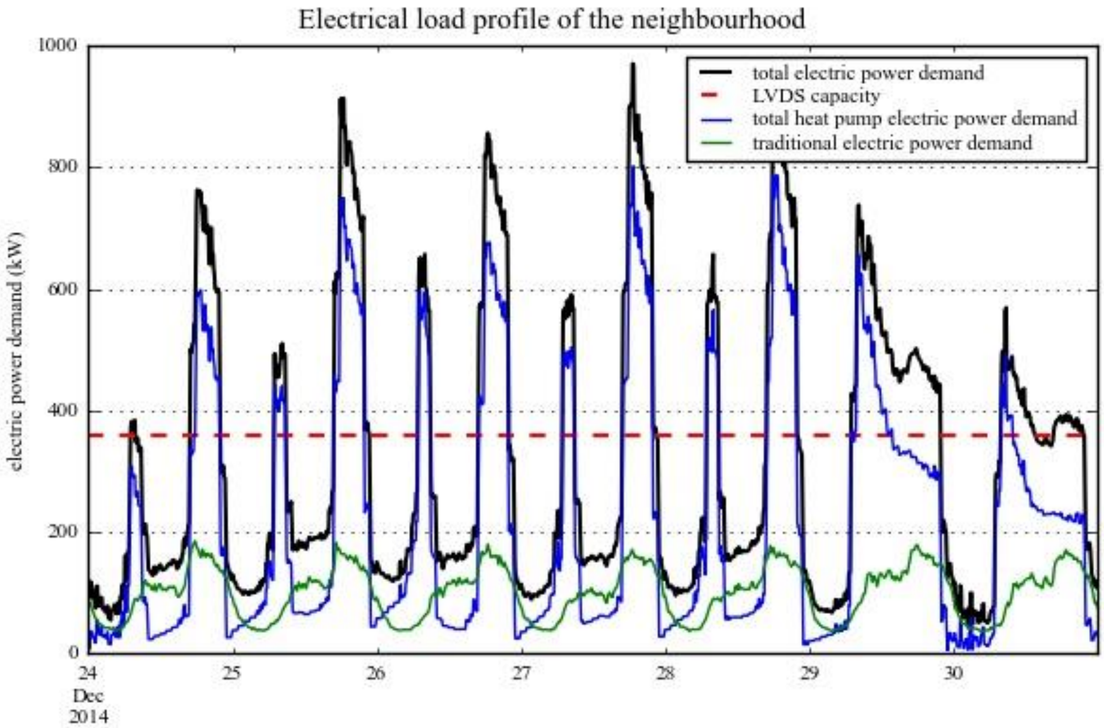

Figure 3.3: Total electric power demand of the neighbourhood during the period with the highest peak power demand. This is the electric power demand for traditional appliances and the heat pump. When heating in turned on the grid capacity is exceeded most of the time. Scenario 1 for heat pump electricity demand is assumed here, i.e. normal Flex Street HHD and temperature records of 2014.

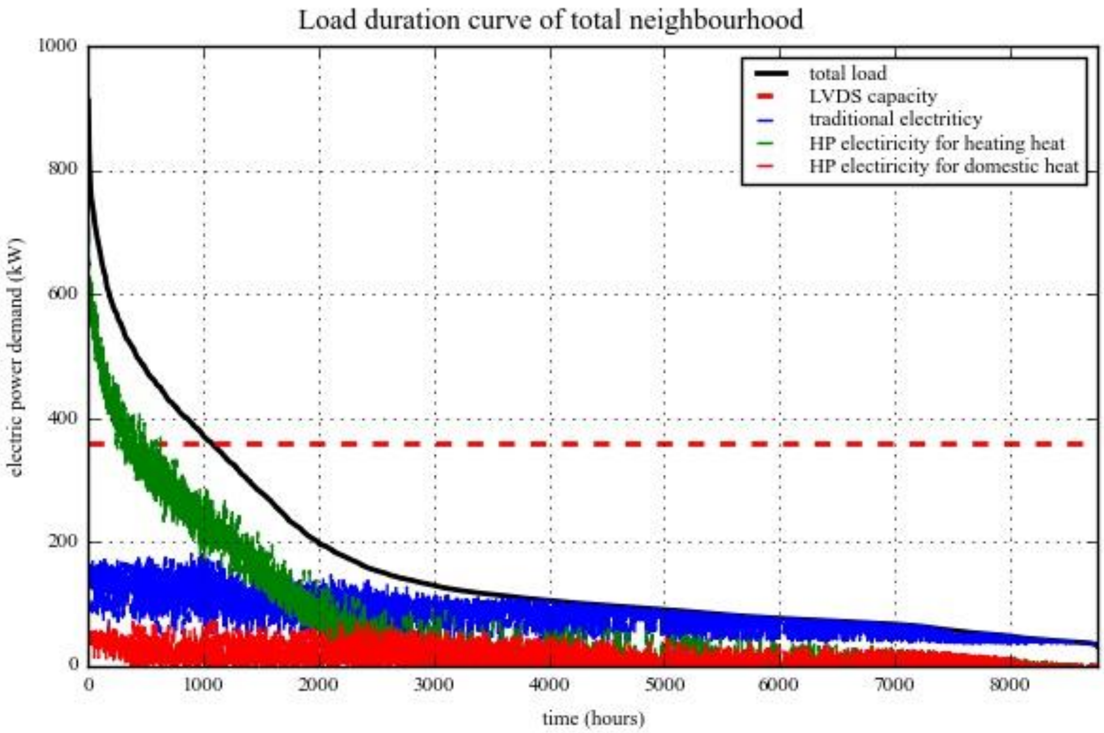

Figure 3.4: Load duration curve of the total electricity demand. It shows the amount of hours with a certain total load. The contribution of the traditional electricity demand and the heat pump electricity demand for HHD and DHD is given for each moment that correspond with the concerned total load (those individual loads are load duration curves). Also the

grid capacity is given. Scenario 1 for heat pump electricity demand is assumed here, i.e. normal Flex Street HHD and temperature records of 2014.

3.2 IMPLEMENTING MEASURES

In this section the available measures are assessed. First the potential of the individual measure is assessed. Here the grid deficit for the highest occurring power demand and the undelivered heat demand is calculated for different quantities, or implementation rate, of a measure. The reason why undelivered heat demand is chosen, rather than undelivered electricity demand, is that the undelivered energy demand is heat demand at all instances. If not indicated otherwise, the results are for heat pump electricity demand scenario 1, i.e. normal Flex Street HHD and temperature records of 2014. Secondly the costs are calculated for the required implementation rate. If the measure cannot prevent capacity exceedance by itself, then the possibilities of a combining the measure with another measure are assessed.

3.2.1 Grid capacity expansion

Potential

Figure 3.5 shows the potential of grid capacity expansion for preventing capacity exceedance and fulfilling heat demand. The LVDS should be able to deliver 969.96 kW or 1077.7 kVA. Therefore capacity should be expanded by 609.93 kW or 677.7 kVA. The relation between capacity expanded and maximum grid capacity deficit is linear; for every added kW capacity the maximum LVDS deficit reduces by one kW. In heat pump electricity demand scenario 6 the highest peak demand is 1419 kVA, thus a capacity expansion of at least 1019 kVA is required.

The relation between capacity expanded and undelivered heat demand follows a convex line. Every added kW of capacity causes a larger decrease in undelivered heat demand than the following added kW of capacity. The higher demand peaks occur less frequently (see Figure 3.4). Thus, for every next kilowatt capacity added, a smaller number of peaks is fulfilled additionally. This means that providing sufficient LVDS capacity for these relatively higher demand peaks is also relatively more expensive than fulfilling the demand of the smaller peaks.

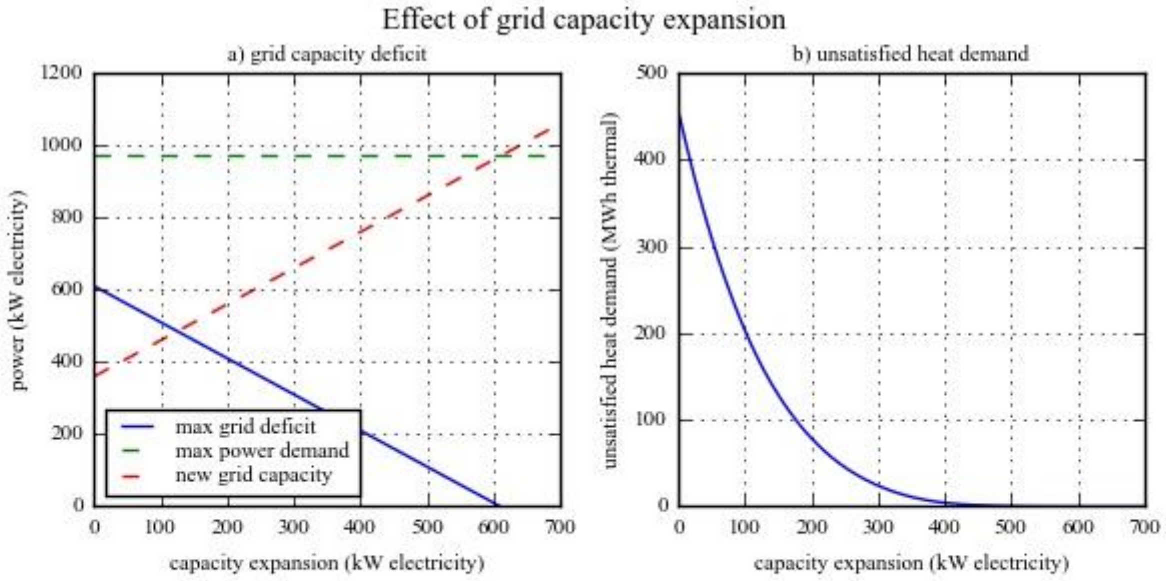

Figure 3.5: Effect op grid capacity expansion on (a) the grid capacity deficit during the highest power demand and on (b) the undelivered heat demand annually. Figure a shows the maximum occurring grid capacity deficit plotted against the capacity expansion. Figure b shows the unsatisfied heat demand plotted against the capacity expansion. Based on heat pump electricity demand scenario 1.

Costs

The required grid capacity of 1419 kVA (at least 1019 kVA expansion) can be achieved with different combinations of transformers. The least expensive combination to achieve this is adding one 400 kVA transformer and one 630 kVA transformer. The new grid capacity is 1430 kVA. The total investement costs are 146,300 €, which is an annualized investement costs per household of 42 €/household/year.

3.2.2 Thermal energy storage

Potential

To fulfil all energy demand a total storage capacity of 14.2 MWh_{th} is required (see Figure 3.6), assuming heat pump electricity demand scenario 1. In scenario 6 a storage capacity of 96.0 MWh_{th} is required, which is an average storage capacity of 0.480 MWh_{th}/household. Due to the heat loss the energy demand increases from 7.35 MWh_e to 8.22 MWh_e per household.

Figure 3.6 shows the maximum grid capacity deficit and unsatisfied heat demand for a range of storage capacities. Note that these results are based on heat pump electricity demand scenario 1. The relationship between grid capacity deficit and storage capacity does not follow a determined pattern. This is because in between peaks with grid capacity deficit the available grid capacity determines how much heat is accumulated.

For example, when increasing the total storage capacity from 6.5 to 10 MWh, the maximum grid capacity deficit is not reduced, while the unsatisfied heat demand is. This can be explained if this peak is at the end of longer cold period. After a few days the heat buffer will be empty if the capacity is insufficient and a period with unsatisfied heat demand will follow. Heat is stored in the buffer again when possible, but the rate at which it is stored is dependent on the available grid capacity. If the peak follows shortly after, then the available stored heat is only dependent on the available grid capacity, and not on the storage capacity. Increasing the storage capacity results in a delay of the first time (time A) the heat storage is depleted and there will be less unsatisfied heat demand. The next time the heat storage is depleted (time B) the accumulated heat will be the same, disregard the storage capacity. Unless the storage capacity is increased by an amount with which all heat demand between time A and time B is fulfilled. Then increasing the storage capacity means that sufficient energy is stored for the demand peak. The required storage capacity is highly dependent on the length of a cold period, rather than the minimum temperature during a year. For the minimum temperature that will occur for the next decade an estimate can be made more safely than for the expected duration of cold periods. This makes TES a relative uncertain measure with regard to satisfying all heat demand.

With the used data the period where the storage capacity is fully utilized is 12 to 15 January. Figure 3.7 shows this period. The available grid capacity during off peak hours is insufficient to fully recharge the heat storage, as a result the heat buffer will be lower at end of each day. It shows that during periods when total electricity demand is smaller than the capacity of the grid, the remaining grid capacity is used to charge the energy storage. During periods where power demand exceeds the grid capacity the stored heat is used fulfil heat demand, which would otherwise be fulfilled by the heat pump . In the night of 14 January the buffer reaches the minimum, after which the demand decreases below the grid's capacity which allows for recharging the storage.

The heat loss rate will affect the required storage capacity. Table 3.1 shows the required storage capacity assuming different values for the heat loss rate. If there would be no heat loss, the required storage capacity decreases by only 4% so the assumed 0.05%/15 min heat loss rate has a relatively small effect. A heat loss rate of 0.1 %/15 minutes increases the required storage capacity by 5%, which might still be acceptable. Above 0.1 %/15 min the heat loss rate starts to have a larger impact, e.g. with a heat loss rate of 0.2 %/15 min the required storage capacity increases by 23%.

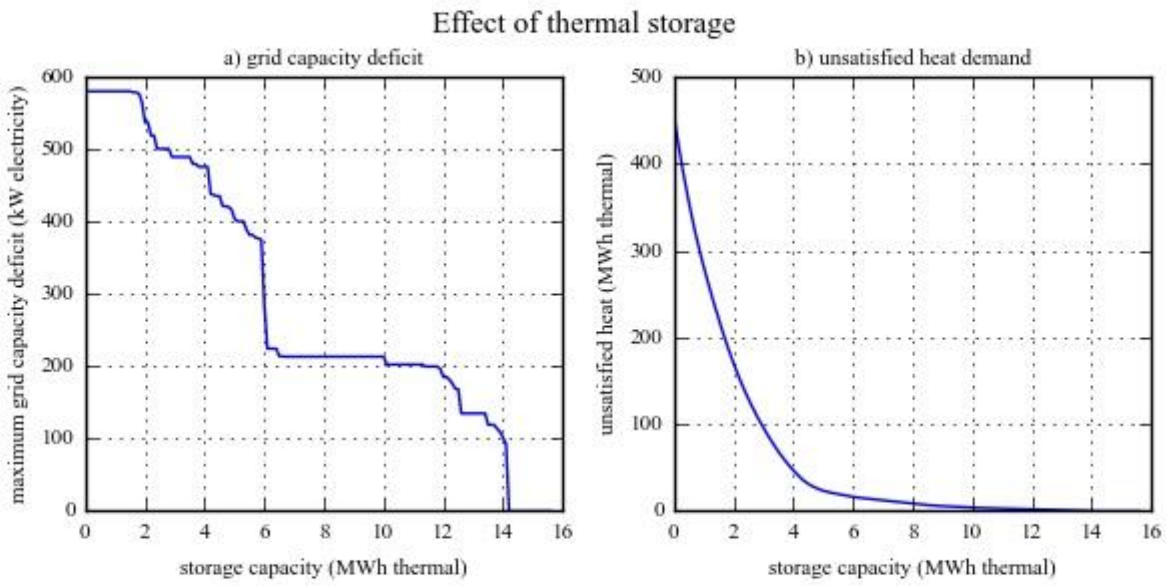

Figure 3.6: Effect of x thermal storage capacity on (a) the maximum occurring grid capacity deficit during the highest power demand and on (b) the undelivered heat demand annually.

Costs

For the neighbourhood the estimated total costs are 96.0 MWh of storage capacity is 1.92 (± 0.48) million euro. The costs per household for a complete TES system with an average size of 480 kWh are € 9,600 (±2,400). The annualized investement costs are estimated at 707 (±177) €/household/year

Table 3.1: Sensitivity analysis for heat loss rate of the thermal storage on required storage capacity to prevent heat shortage

Heat loss % / 15 minutes of stored heat	**Required storage capacity in neighbourhood in heat pump electricity demand scenario 1 (MWh)**	**Average required storage capacity per household in heat pump electricity demand scenario 1 (kWh)**	**Change of required storage capacity compared to assumed value**
0.00%	13.6	68.0	-4%
0.05%	14.2	71.0	0%
0.10%	14.8	74.2	5%
0.20%	17.5	87.6	23%
0.30%	51.3	256.4	261%
0.40%	>100	>500	

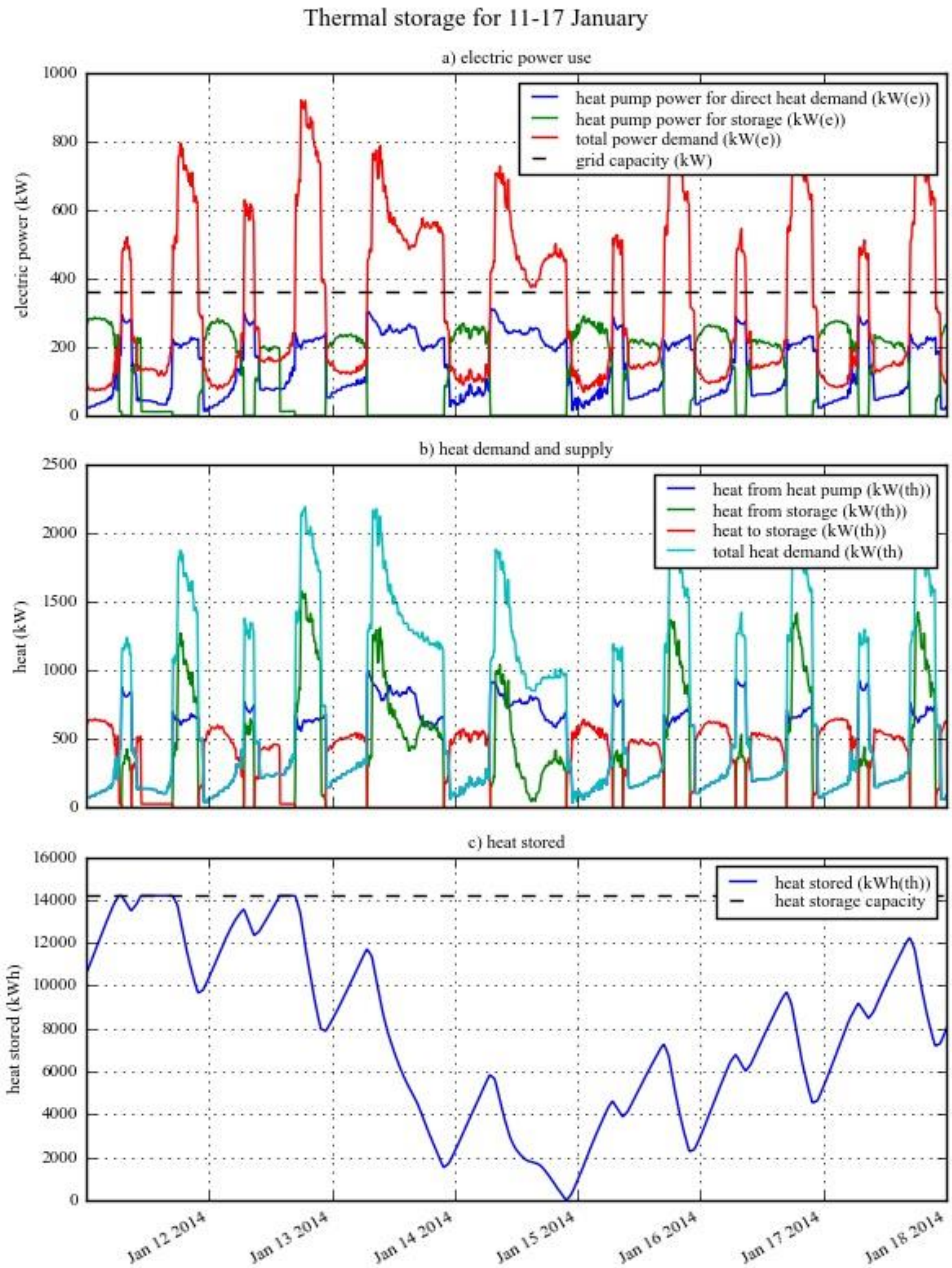

Figure 3.7: Load profile and energy buffer for the period where the entire storage capacity is used. A storage capacity of 14.2 MWh_{th} for 200 households is assumed.

3.2.3 Heat demand reduction

Potential

Figure 3.8 shows the effect of heat demand reduction on the grid capacity deficit and the undelivered heat demand. To prevent capacity deficit and heat shortage the heat demand should be reduced by approximately 90%. However, only a heat demand reduction of 47%, i.e. an HHD-fraction of 0.53, is assumed to be realistically possible for terraced buildings with the initial energy demand that reflects the Flex Street data. Heat demand reduction will only mitigate the grid capacity deficit. With this demand reduction the maximum grid capacity deficit and unsatisfied heat demand are still resp. 288 kW_e and 62 MWh_{th} (2.7% of total annual heat demand), assuming heat pump electricity demand scenario 1.

For terraced buildings build before 1945 the saving potential is 80% for similar costs (167 €/%HHD reduction, compared to €165.36/ %HHD reduction for most terraced buildings) (see Table 2.5). But, this reduction in HHD is only possible because the HHD would be higher in the original situation due to the low insulation levels. The price for HHD reduction only applies to these buildings. Reducing HHD by 90% for the buildings that match the Flex Street data would be much more expensive, if it would be possible in the first place.

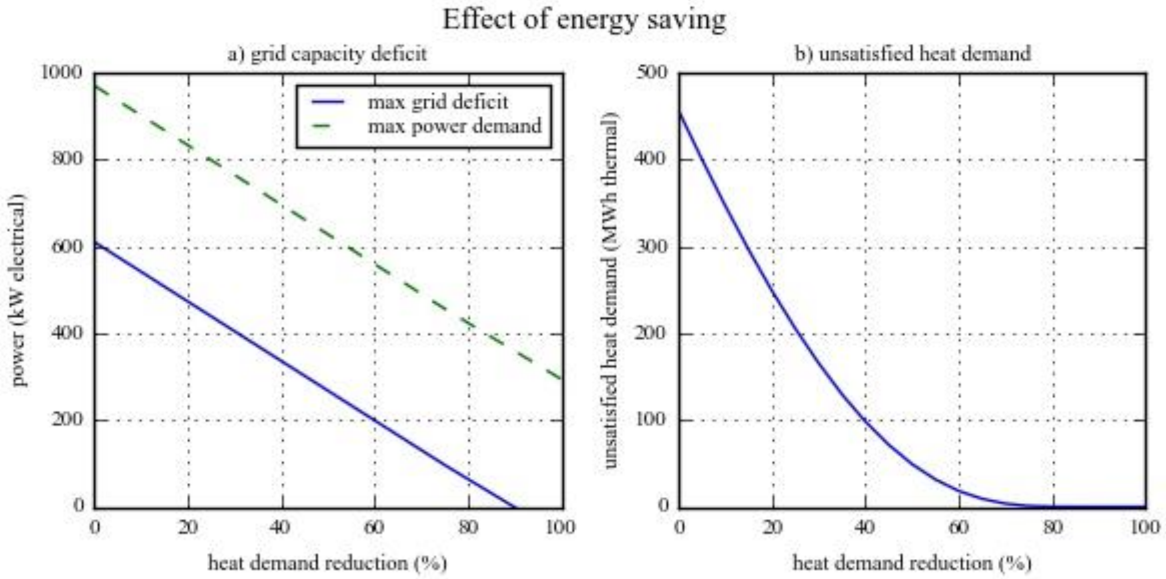

Figure 3.8: Effect of heating heat demand reduction by x% on (a) the maximum occurring grid capacity deficit during the highest power demand and on (b) the undelivered heat demand annually. Bases on heat pump electricity demand scenario 1.

Because implementing heating heat demand reduction measures alone does not prevent capacity exceedance, the costs for preventing grid capacity cannot be calculated. Still, with 47% HHD reduction the grid capacity deficit is approximately reduced by half the initial grid capacity deficit and the unsatisfied heat demand is reduced by almost 90% compared to the initial value. Further analysis in the viability of this measure in combination with other measures are needed.

Costs

Table 3.2 shows the results. These are based on a heat demand reduction of 93%. The estimated costs are €3 million for the neighbourhood, i.e. €15,300 per household. This is a higher investment costs that reported by Agentschap NL (2011) of €9,970, but then again a larger heat demand reduction is assumed now.

Table 3.2: Costs for heat demand reduction

	Investment costs (€/%HHD reduced)	Investment costs for neighbourhood (M€)	Investment costs per household (€/household)	Annualized investement cost (€/household/year)
Estimated	€ 165	3.1 M€	€ 15,300	€ 1,100
Pessimistic	€ 213	4.0 M€	€ 19,800	€ 1,500

3.2.4 Heat demand shifting

Potential

Figure 3.9 shows the potential for heat demand shifting. With heat demand shifting capacity exceedance cannot be prevented. The grid capacity deficit can at a maximum be reduced by 8% and the unsatisfied heat demand by 7 – 9% (see Table 3.3), assuming heat pump electricity demand scenario 1. The results do show that firstly shifting the HHD of the households with a higher annual HHD results in a smaller number of households for which the demand has to be shifted to reach the maximum potential.

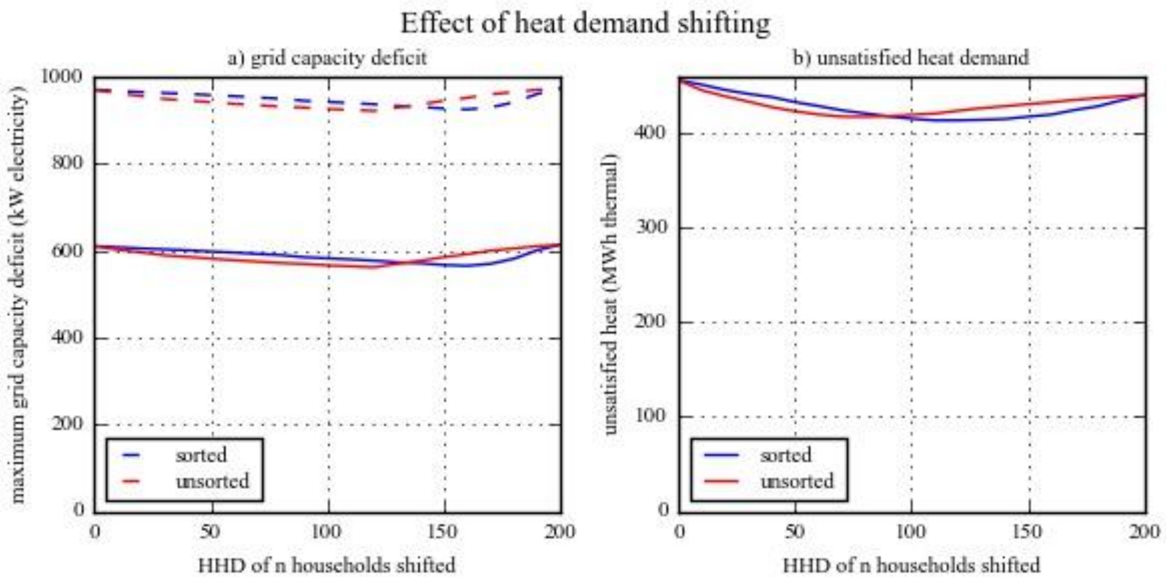

Figure 3.9: Effect of shifting heat demand of n households on a) the maximum grid capacity deficit and b) the unsatisfied heat demand. In a) the solid line represents the maximum occurring grid capacity deficit and the dotted line the maximum occurring total load. In both figures the results are given for shifting the demand of households in a random order and in sorted for the households' annual energy demand. The demand is shifted one hour forward for n out of 200 households.

Table 3.3: The potential of heat demand shifting for reducing max grid capacity deficit and unsatisfied heat demand compared to the original situation. The maximum achievable reduction is given and the number of households for which the heating heat demand has to be shifted.

	Minimum at n households	Reduction compared to initial original situation
Sorted for annual HHD		
max grid capacity deficit (kW)	120	8%
unsatisfied heat demand (MWh)	80	8%
Not sorted for annual HHD		
max grid capacity deficit (kW)	160	7%
unsatisfied heat demand (MWh)	110	9%

Costs

Shifting the demand for 80 – 120 households requires a total investment of €8,000 – €12,000, or 80 – 120 €/household.

3.2.5 Limiting the number of heat pumps

Potential

Figure 3.10 shows the maximum number of households that can be equipped with a heat pump without causing capacity exceedance. It shows the maximum for the six scenarios regarding temperature records and heat demand and for each of these scenarios the maximum when different houses are equipped with a heat pump.

8% – 42% of households can be maximally equipped with a heat pump. The exact percentage depends on the assumed scenario. Which households are equipped with a heat pump has a stronger effect on the maximum allowable number of heat pumps (approx. 30%-point difference within the scenarios regarding temperature/heat demand) than the temperature/heat demand scenarios (maximum of 6%-point difference within one scenario for allocating heat pumps).

If only the best-insulated buildings are equipped with a heat pump and if it is assumed that the grid capacity should be dimensioned based on the coldest period, then a maximum of 35% of the buildings can be equipped with heat pumps without causing capacity exceedance. Assigning heat pumps to certain households, i.e. the best-insulated, is an effective way to prevent capacity exceedance. For instance, if households are assigned “randomly”, then only 23% of the buildings can use a heat pump or only 8% if exactly those households with a high heat demand would be equipped with a heat pump.

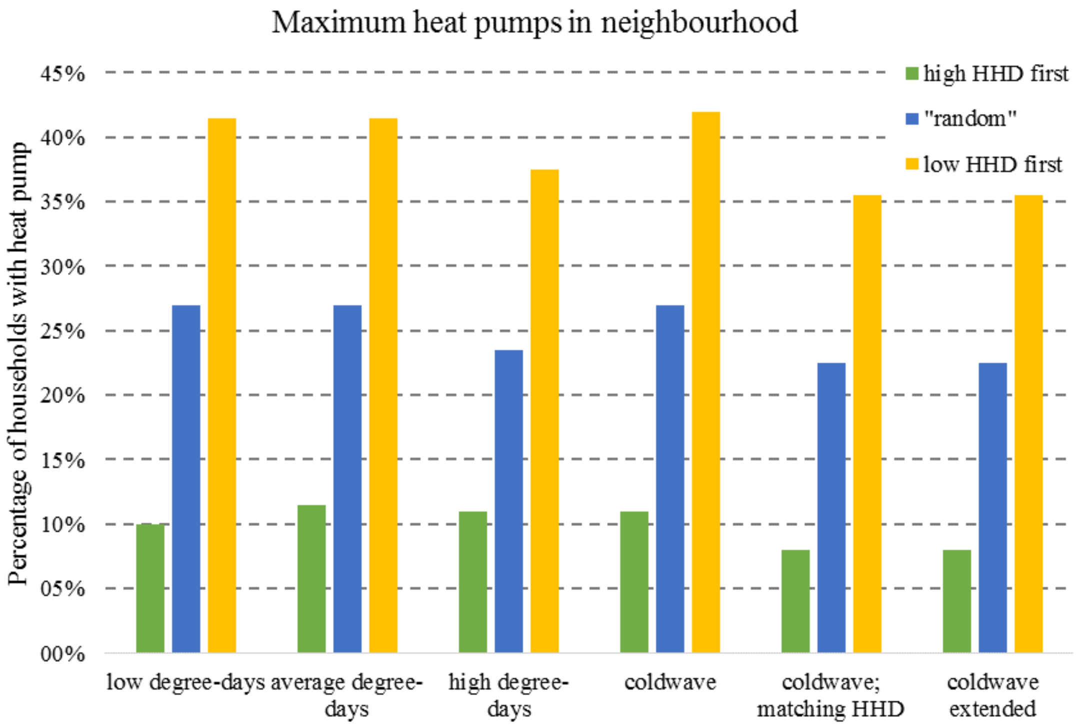

Figure 3.10: Maximum percentage of households with heat pumps the LV-DS can support in different scenarios. Firstly the different scenarios regarding temperature/heat demand are assessed and secondly different scenarios for assigning which households are equipped with a heat pump.

As shown in Figure 3.10, the existing grid can fulfil the power demand of a limited number of heat pumps. In the scenario with the highest electricity demand from heat pumps the grid can provide enough power for a heat pump penetration rate of 35.5%, or 71 heat pumps, if the most energy efficient buildings are equipped with a heat pump. Table 3.4 shows the resulting energy demand of the households in the neighbourhood. In this case roughly 5.90 * 35.5% / 11.38 = 18% of the total annual heat demand can be supplied by heat pumps.

Table 3.4: Energy demand for the households with and without heat pump, assuming the "average" heat pump electricity demand scenario 2. The households without heat pump use natural gas for heating. 71/200 households are equipped with a heat pump, the other 129/200 households use a gas boiler.

Variable (Annual average per household of …)	**For households with heat pump**	**For households with conventional heating**	**Neighbourhood weighted average per household**
HHD (MWh_{th})	4.56	12.21	9.50
DHD (MWh_{th})	1.34	2.18	1.88
total heat demand (MWh_{th})	5.90	14.39	11.38
traditional electricity demand (MWh_e)	1.75	4.52	3.53
electricity demand for heat pump (MWh_e)	2.00	-	0.71
total electricity demand (MWh_e)	3.75	4.52	4.24
gas demand for HHD (MWh_{gas})	-	12.21	7.88
gas demand for DHD (MWh_{gas})	-	2.18	1.41
total gas demand (MWh_{gas})	-	14.39	9.28

Costs
As explained in section 2.4.5, there are no investment costs allocated to this measure. This measure does differ from other measure because the costs for the gas infrastructure are still applicable (included in section 3.4).

3.2.6 Sensitivity to heat pump electricity demand scenarios
Above the required quantity of each measure is shown for heat pump electricity demand scenario 1, with the low number of degree-days. Here the effect of the temperature is shown.

Figure 3.11 shows the required quantity of each measure that is required to prevent capacity exceedance in the six heat pump electricity demand scenarios. This figure shows the required capacity compared to scenario 1. Figure 3.12 shows the resulting investment costs per measure, in each scenario. The measures heat demand shifting and limiting the number of heatpumps are not included, because heat demand shifting alone cannot prevent capacity exceedance and for limiting the number of heatpumps no investment costs are required for this measure.

It shows that the required quantity of TES is most strongly affected by the chosen scenario. More than six times the required capacity is required in scenario 6, compared to scenario 1. In the scenarios without the coldspell the required storage capacity only increases by maximally 60%. This shows that a cold spell significantly increases the required storage capacity and that the required capacity is strongly dependent on the duration of cold periods, rather than on the lowest occurring temperature.

Required capacity expansion increases by 50% in scenario 6, compared to scenario 1. Required heat demand reduction deviates from +30% to -30% compared to scenario 1. These are relatively small deviations compared to the deviation in required storage capacity. This is because the required capacity expansion is dependent on the maximum occurring electricity demand peak. The duration of the period with low temperature and high heat demand does not affect the requirements for capacity expansion or insulation level.

The investement costs are the lowest for capacity expansion, and the highest for heat demand reduction. The investment costs for TES differ greatly between the scenarios. Based on investment costs capacity expansion seems the most viable option, but then again heat demand reduction will lower the annual costs (which will be discussed in section 3.4).

According to these results, the required insulation in the high degree-days scenario is lower than in the scenario with a low or average amount of degree-days. This unexpected result is caused by the fact that the temperature and Flex Street HHD profiles do not exactly match. The electricity demand for the heat pump consists of the components heat demand and ambient temperature. The lowest recorded temperatures during the assumed year of the high degree-days scenario, i.e. 1996, are not at the same time as the highest heating heat demand in the Flex Street data, thus the expected maximum electricity demand for the heat pump does not show in this data.

Still, these results do show the effect of temperature on the requirement for the different measures. It especially shows a large uncertainty in the required storage capacity with which capacity exceedacne can be preventen and in fact a large uncertainty whether a chosen capacity is sufficient. This is because relatively save estimations for minimum occurring temperature in the Netherlands can be made (temperatures below -20°C are already an exception) whereas an estimation regarding the duration of cold periods is much more uncertain. This might mean that thermal energy storage might not be a desirable measure, at least not without additional measures. It can be said that for grid capacity expansion or heat demand reduction a "quantity", with which grid capacity exceedance is prevented, can be chosen with greater certainty.

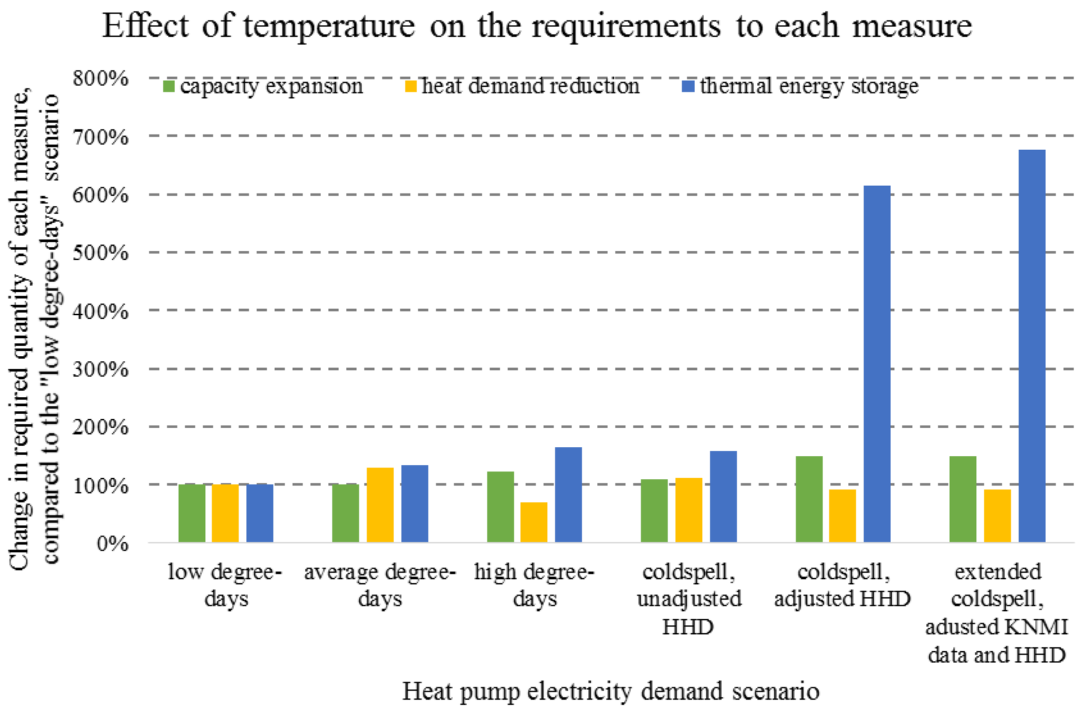

Figure 3.11: The difference in required quantity of each measure between the different heat pump electricity demand scenarios. The percentage represents the amount that is required compared to the "low degree-days" scenario (scenario 1). The measure heat demand shifting not included, because heat demand shifting alone cannot prevent capacity exceedance. Limiting the number of heatpumps is not included, because no investment costs for this measure are required.

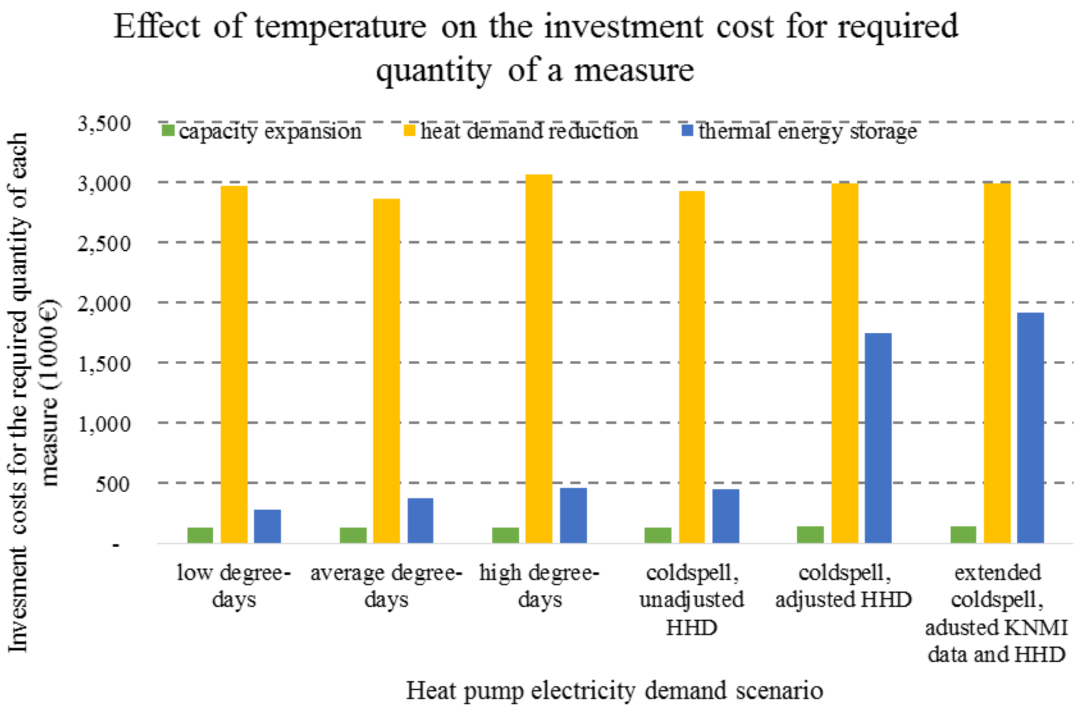

Figure 3.12: The difference in investment costs that are required to implement the required quantity of a measure to prevent capacity exceedance. Similar to Figure 3.11, but this is a direct comparison of the investment costs. The measure heat demand shifting not included, because heat demand shifting alone cannot prevent capacity exceedance. Limiting the number of heatpumps is not included, because no investment costs for this measure are required.

3.3 COMBINATIONS OF MEASURES

The previous analyses showed that grid capacity expansion and thermal energy storage can prevent grid capacity exceedance, whereas heating heat demand reduction and heat demand shifting cannot under the used assumptions. Still both measures show a potential for mitigation the capacity exceedance. Therefore they are combined with grid capacity expansion and thermal energy storage to assess whether a combination of measures can lower the required investment costs. The results below are based on heat pump electricity demand scenario 1.

Heat demand reduction and grid capacity expansion or thermal energy storage

Figure 3.13 shows the effect of reducing the heating heat demand by x% on the required grid capacity expansion and the required storage capacity to fulfil all energy demand, expressed in percentage change compared to the required grid capacity expansion resp. TES when implemented as individual measures. 47% HHD reduction was assumed to be achievable. For this amount of HHD reduction the required grid capacity expansion is reduced by 52.8% and the required storage capacity by 86.1%. Assuming heat pump electricity demand scenario 1.

Instead of 677.7 kVA capacity expansion, only 319 kVA capacity expansion is required, and instead of 14.2 MWh_{th}, only 1.97 MWh_{th} storage capacity is required, or 10 kWh_{th} per household.

Table 3.5 shows the total costs that are required for preventing capacity exceedance. The lowest investement costs are found if no heat demand reduction is implemented, but this is due to the high investment costs for insulation measures. For a better comparison the annual change in energy costs should be included.

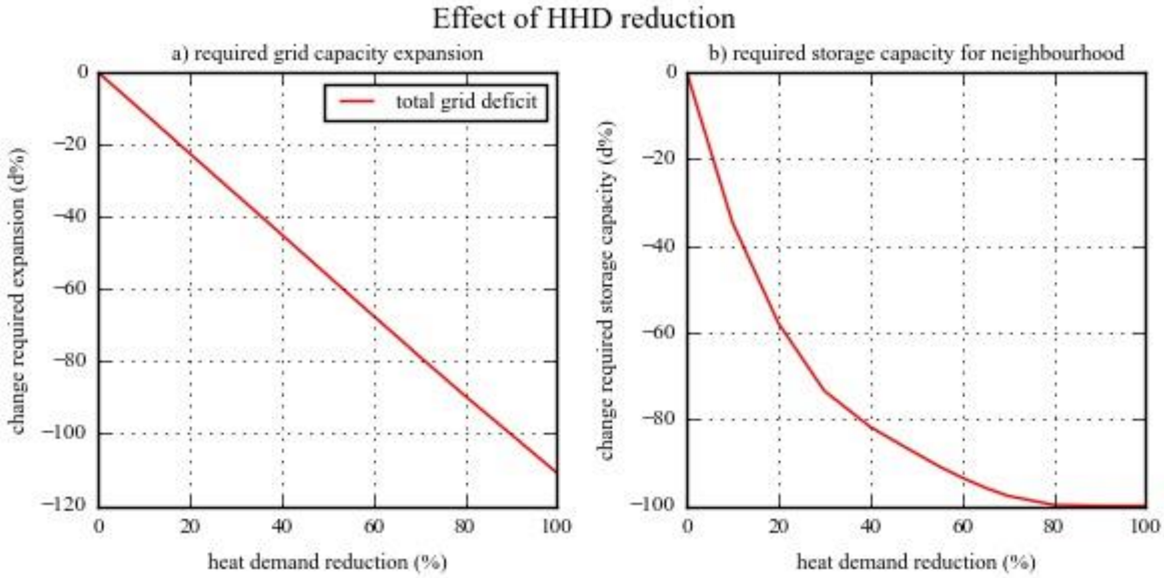

Figure 3.13: Effect of heating heat demand reduction on a) required capacity expansion and b) the required thermal storage capacity with which capacity exceedance is prevented.

Table 3.5: Total costs of different combinations of HHD fraction and grid capacity added. With each combination all energy demand must be fulfilled in heat pump electricity demand scenario 1.

Heating heat demand reduction	investment costs for energy saving measures (€/ household)	Additional capacity required (kVA)	Investment costs grid capacity expansion (€)	Investment costs grid capacity expansion (€/ household)	Total investment combi-nation (€/ household)	Required storage capacity (MWh_{th}/ household)	Investment costs for TES systems (€/ household)	Total investment costs combi-nation (€/ household)
0	0	678	127,400	637	**637**	14.2	284	**284**
0.1	1,650	602	116,300	582	**2,232**	9.3	186	**1,836**
0.2	3,300	526	116,300	582	**3,882**	6	120	**3,420**
0.3	4,950	450	116,300	582	**5,532**	3.8	76	**5,026**
0.4	6,600	373	113,000	565	**7,165**	2.6	52	**6,652**
0.47	7,755	320	113,000	565	**8,320**	2	40	**7,795**

Heat demand shifting with grid capacity expansion or thermal energy storage

Demand shifting cannot negate grid capacity exceedance when implemented as individual measure, but it can reduce the required quantity of other measures. Such combinations can reduce the total costs.

Figure 3.14 shows the effect of shifting the heating heat demand for n households, on the required grid capacity expansion and the required storage capacity to fulfil all energy demand, expressed in percentage change compared to the required grid capacity expansion resp. TES when implemented as individual measures. The figure shows a possible decrease in the grid capacity deficit of 7.8% and a decrease in required storage capacity of 3.8%. Again the most reduction is possible if the households of which the heating heat demand is shifted are chosen based on their annual HHD. These results are based on heat pump electricity demand scenario 1.

Instead of 677.7 kVA capacity expansion, only 625 kVA capacity expansion is required, and instead of 14.2 MWh_{th}, only 13.7 MWh_{th} storage capacity is required, or 68 kWh_{th} per household. Figure 3.15 shows the estimated costs for the combination of demand shifting with grid capacity expansion resp. thermal energy storage. Due to the high costs compared to the benefits (in mitigated grid capacity deficit) the combination with demand shifting increases the costs for grid capacity expansion and thermal storage. There is one exception which is occurs when the grid capacity deficit is decreased by an amount for which one less additional transformer is required. One 400 kVA transformer less is required, which reduced the total investment costs to €126,300. Due to the relatively small gain implementing a demand shifting mechanism for this purpose only is not an interesting solution to prevent capacity exceedance.

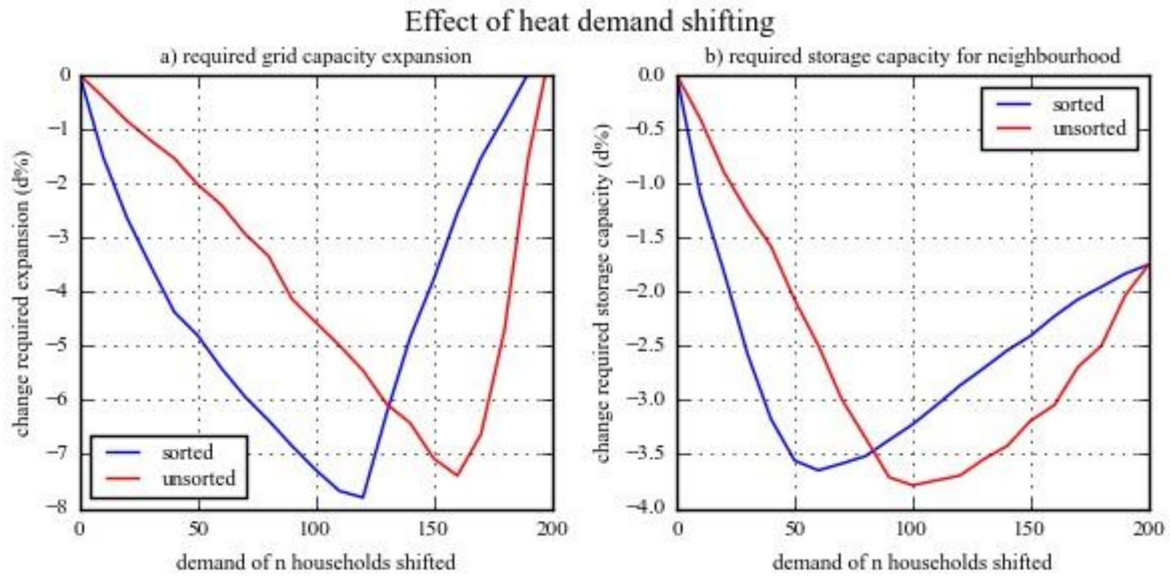

Figure 3.14: Effect of heat demand shifting on a) required capacity expansion and b) the required thermal storage capacity with which capacity exceedance is prevented. It shows the percentage change in respectively the required capacity expansion and the required thermal storage capacity with which all energy demand is fulfilled. In a) the solid line represents the maximum occurring grid capacity deficit and the dotted line the maximum occurring total load. The demand is shifted one hour forward for n out of 200 households. Based on heat pump electricity demand scenario 1.

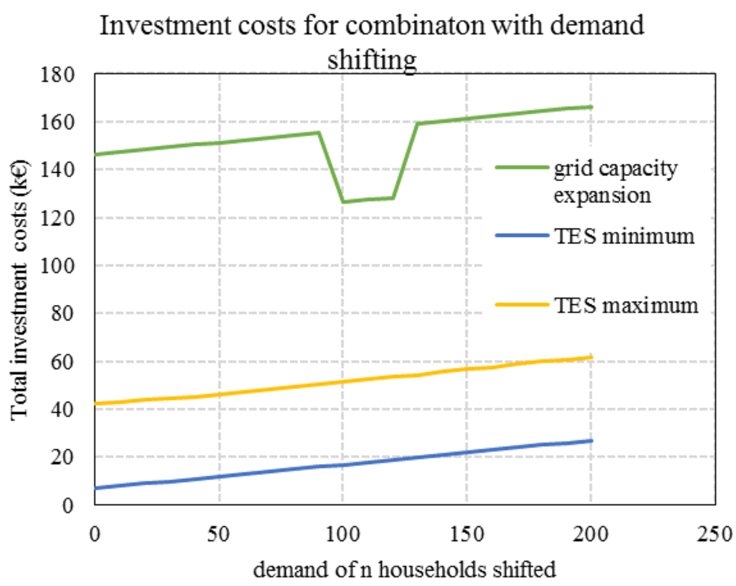

Figure 3.15: Total investment costs for the combination of demand shifting and grid capacity expansion resp. energy storage. Based on heat pump electricity demand scenario 1.

3.4 TOTAL COSTS

Table 3.6 shows the total costs and benefits of shifting from conventional heating to heat pumps including the investment costs for the required measure. The investment costs are based on heat pump electricity demand scenario 6. The other annual costs are based on the “average” heat pump electricity demand scenario 2.

Figure 3.16 shows the change in annual costs when heat pumps are implemented. The total annual costs are the lowest when grid capacity is expanded (685 €/HH/year) or when the number of heat pumps is limited to a fraction that the grid can sustain (691 €/HH/year). The annual costs are the highest for heat demand reduction (1,089 €/HH/year) and thermal energy storage (1,559 €/HH/year). The differences are caused by the the low investment costs for these measures.

With almost every measure the annual energy costs are reduced. With heat demand reduction the energy cost are reduced the most, but then again the investement costs for the measure are the highest. Only with thermal energy storage the energy costs increase. This is due to the heat loss from the storage system.

Figure 3.17 and Figure 3.18 show the primary energy saving and the CO_2 mitigation respectively, when heat pumps are implemented. Primary energy use and CO_2 emissions are reduced when heat pumps are implemented, in the combination with each required measure. Except if thermal energy storage is the implemented measure. In that case there is no primary energy saving, but still CO_2 emission mititagion. This is due to different assumed emission factors for natural gas and electricity from the grid.

The highest reduction in primary energy use and CO_2 emissions are achieved when heat pumps are implemented in combination with heat demand reduction. The total annual primary energy use and CO_2 emissions per household can be reduced by resp. 44% and 46% per household per year. Due to the high saving potential the specific costs for primary energy saving (122 €/$MWh_{primary}$ saved) and CO_2 mitigation (0.60 €/kg CO_2 mitigated) are also the lowest with the implementation heat pumps in combination with this measure. In this case the costs for primary energy saving and CO_2 mitigation are lower than in the case of heat pumps with grid capacity expansion. Then the specific costs would be 371 €/$MWh_{primary}$ saved and 1.48 €/kg CO_2 mitigated respectively.

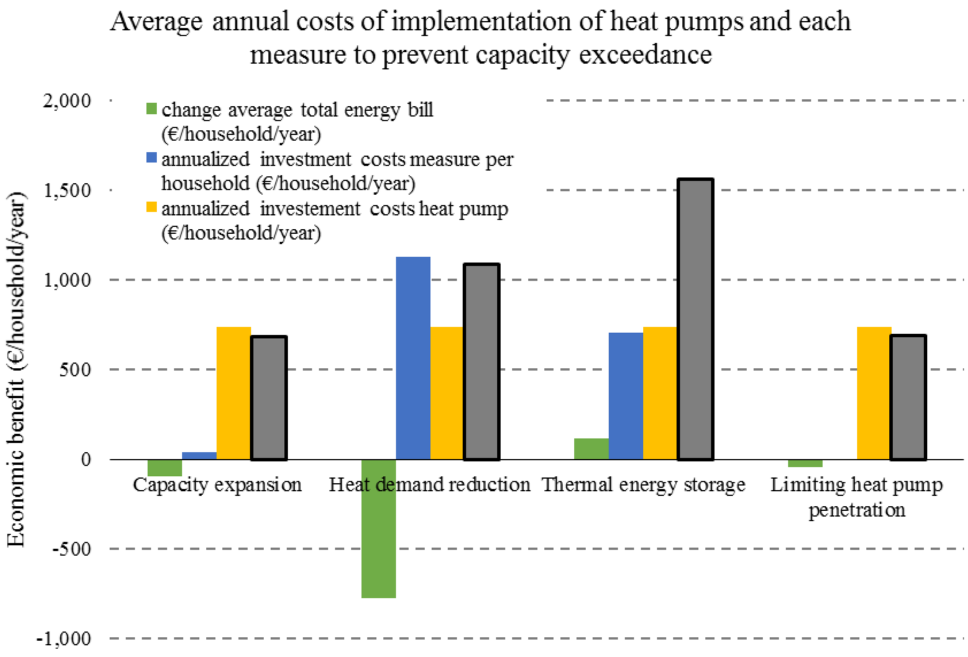

Figure 3.16: The annual costs of implementing heat pumps. The figure shows the change in annual energy costs for consumers; the annualized investement costs for the each measure; the annualized investement costs for the heat pump; and the total annual costs (see Table 3.6 for exact values). The investment costs are based on heat pump electricity demand scenario 6. The other annual costs are based on the "average" heat pump electricity demand scenario 2.

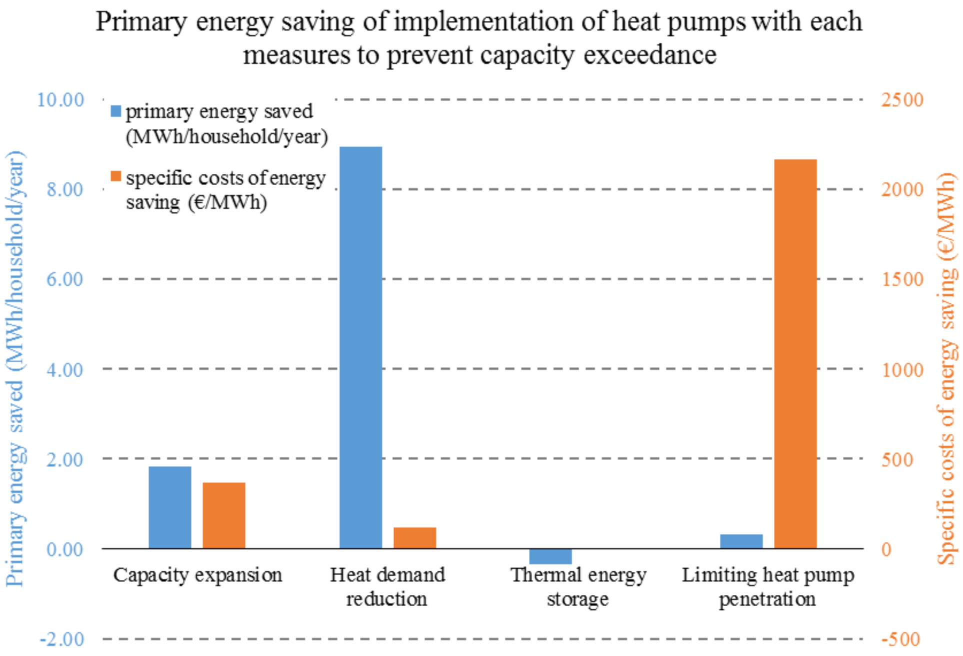

Figure 3.17: The primary energy saved with the implementation of heat pumps. The figure shows primary energy saved, due to shifting to heat pumps, in combination with each measure and the specific costs for energy saving. The specific costs are based on the change in annual energy costs for consumers, including the annualized investment costs for both the required measure and the heat pump (see Table 3.6 for exact values). The investment costs are based on heat pump electricity demand scenario 6. The other annual costs are based on the "average" heat pump electricity demand scenario 2.

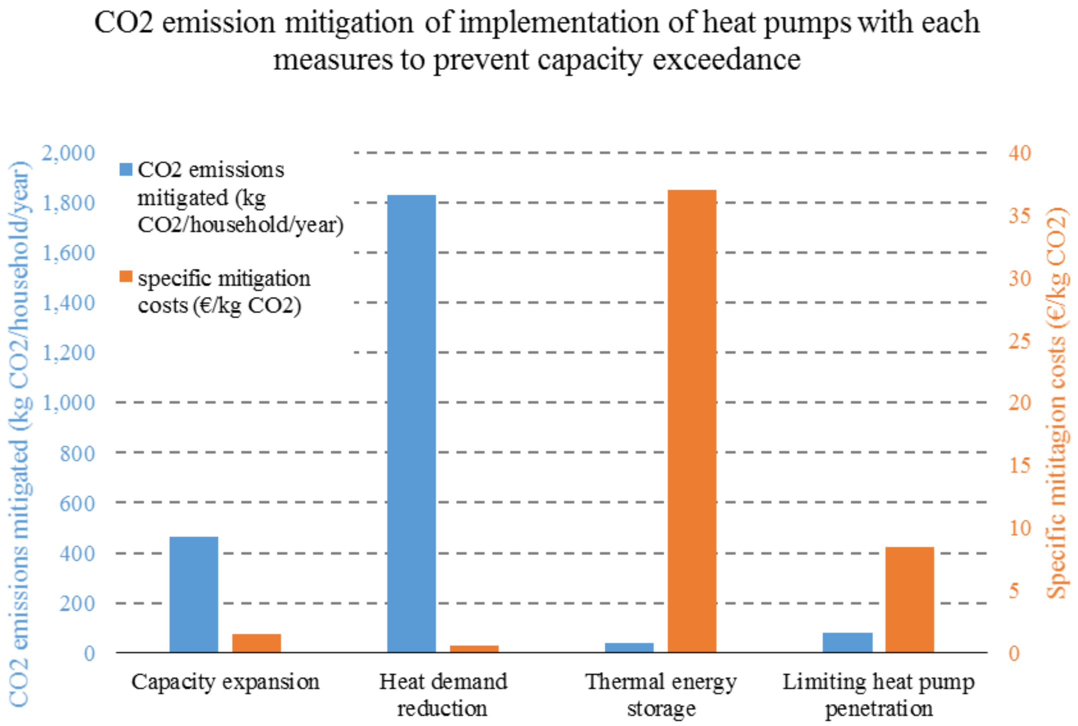

Figure 3.18: The CO_2 emissions mitigated with the implementation of heat pumps. The figure shows the mitigated CO_2 emissions, due to shifting to heat pumps, in combination with each measure and the specific mitigation costs The specific costs are based on the change in annual energy costs for consumers, including the annualized investment costs for both the required measure and the heat pump costs (see Table 3.6 for exact values). The investment costs are based on heat pump electricity demand scenario 6. The other annual costs are based on the "average" heat pump electricity demand scenario 2.

Table 3.6: Overview of available measures: For each measure the required investment costs, annual costs, primary energy saving and CO_2 mitigation.The investment costs are based on heat pump electricity demand scenario 6. The other annual costs are based on the "average" heat pump electricity demand scenario 2.
** Heat demand shifting cannot prevent capacity exceedance when implemented individually. For heat demand shifting the values represent the maximum achievable reduction in maximum capacity deficit.*

	Capacity expansion	**Heat demand reduction**	**Thermal energy storage**	**Heat demand shifting***	**Limiting heat pump penetration**
Investment costs measure					
Minimum requirement, assuming heat pump electricity demand scenario 6	grid capacity expansion of >1019 kVA	Heating heat demand reduction of 93%	Storage capacity of 96.0 MWhth	Shifting HHD of 80 – 100 households	Limit heat pump penetration to 35.5%
Investment costs total (€)	146,300	3,069,677	1,920,391	10,000	0
Investment costs per HH (€/household)	732	15,348	9,602	100	0
annualized investment costs per household (€/household/year)	42	1,129	707	6	0
Average annual secondary energy demand per household					
total annual electricity demand (MWhe/household/year)	7.35	4.50	8.22	7.35	4.24

	Capacity expansion	Heat demand reduction	Thermal energy storage	Heat demand shifting*	Limiting heat pump penetration
annual electricity demand for heat demand (MWhe/household/year)	3.81	0.97	4.69	3.81	0.71
annual gas demand for heat (MWhg/household/year)	0.00	0.00	0.00	0.00	9.28
Average annual energy costs per household					
new average total energy bill (€/household/year)	1,730	1,047	1,940	1,730	1,778
change average total energy bill (€/household/year)	-93	-776	117	-93	-45
Total annualized costs per household					
total annual costs, excl. heat pump (€/household/year)	-51	353	824	-88	-45
total annual costs, incl. heat pump (€/household/year)	685	1,089	1,559	648	691
Primary energy saving					
primary energy demand (MWh/household/year)	18.37	11.25	20.56	18.37	19.89
primary energy saved (MWh/household/year)	1.84	8.96	-0.35	1.84	0.32
Primary energy saved (% of total annual emissions with conventional heating)	9%	44%	-2%	9%	2%
Specific costs of energy saving, excl. heat pump investment (€/MWh)	-28	39	NA	-48	-142
Specific costs of energy saving, incl heat pump investement (€/MWh)	371	122	NA	351	2,167
CO2 mitigation					
CO2 emissions (kg CO2/household/year)	3,526	2,160	3,948	3,526	3,908
CO2 emissions mitigated (kg CO2/household/year)	463	1,830	42	463	81
CO2 emissions mitigated (% of total annual emissions with conventional heating)	12%	46%	1%	12%	2%
Specific costs of CO2 mitigation, excl. heat pump investment (€/kg CO2)	-0.11	0.19	19.58	-0.19	-0.56
Specific costs of energy saving, incl heat pump investement (€/kg CO2)	1.48	0.60	37.07	1.40	8.49

4 DISCUSSION

4.1 METHOD

4.1.1 Costs

Costs perspective

The costs perspective from the end-user is assumed. This is done because in the end, the consumer pays for the additional costs. This means the, among other costs, energy taxes, VAT, and the standing charge for the retailer can be included. But the costs and benefits do depent on the delimitation. If a social perspective is used, then other costs have to be included, VAT and other taxes, and profit for the retailer and system operators, are not costs.

Heat pump investment costs

The investment costs for the heat pump is an estimation of the the current, Dutch, retail prices. The costs of technologies generally decrease as a function of number of units produced, and especially the costs of relatively new technologies reduce fastly over time (EHPA, 2015).

Not included are possible subsidies for heat pumps. From a consumer perspective these should be included. The Dutch government announced a subsidy program for investment in sustainable energy technologies (RVO, 2015a). This will increase the viability of heat pumps.

Measure investment costs

The costs for grid capacity expansion are assumed to be reliable, as the primary data source is an expert from a DSO, no costs range is applied to these results. For thermal energy storage and heat demand reduction the investement costs are less certain. A costs range is assumed and discussed in each results section.

Heat demand reduction in the pessimistic scenario becomes less viable. The higher costs could be assumed for households with a high initial insulation level, because further reducing energy demand for household that already have a high insulation level is relatively expensive, because the measures with the shortes payback period are already implemented. But then again, households with a good insulation level have a lower heat demand, and will contribute less to demand peaks.

Costs for thermal energy storage are based on current retail prices. For thermal energy storage the investement costs are relatively high, compared to capacity expansion, but does not bring an additional benefit like heat demand reduction does. Significant reduction of TES costs are required before this measure could be viable. It is not likely that a large cost reduction is achieved for sensible heat storage. It might be a future option if phase change materials become less expensive (ETSAP/IRENA, 2013).

Costs indexing

The assumed costs are not indexed, so the costs represent the costs in different years. However, no sources older than five years, are used for cost estimates. Because of the short time span, the difference between past and present value are assumed to be negligable, compared to uncertainties induced by other factors.

Energy price
The viability of switching to heat pumps mainly depends on the price difference between electricity and natural gas. The more expensive gas becomes compared to electricity, the more viable heat pumps become. This is a possible development, as natural gas prices might increase due to a decreasing supply (ENSOC, 2015).

4.1.2 Data input calculation power demand

CoP and ambient temparature
The input data for energy demand represents the electricity demand for traditional appliances, the heating heat demand, and the domestic heat demand. The electricity demand of the heat pump is calculated based on this data. The electiricty demand depends on the coefficient of performance and the temperature difference between the ambient temperature. The assumed CoP is based on test results from 59 models which improves the reliability. However, these results represent the CoP of current heat pump models and their performance is likely to improve (EHPA, 2015). An improved CoP reduces the electricity demand of the heat pump. As a result more heat pumps could be implemented without the need for any measures to prevent capacity exceedance. Also, it would further reduce the annual energy costs.

Heat pump type
In this research the maximum heat pump heat output is not considered to be a limitation, thus the heat output is at least equal to the highest demand peak. Heat pump investement costs are related to the power capacity, thus optimizing the heat pump capacity for heat households could also be a measure to reduce costs. Also, with thermal energy storage, in the case of a heat demand peak, a part of the heat is provided by the storage system and a lower heat pump capacity should be sufficient.

The heat pump type that is assessed is the air-source heat pump, because this heat pump type is most suitable for retro-fitting in existing buildings. Another heat pump type that could be used is the ground source heat pump (GSHP). A GSHP used heat in the ground. An advantage is a more constant, and higher, temperature, which means that the CoP increases and the electiricty demand decreases. If mainly GSHPs are implemented, then the capacity deficit is lower. The investment costs for the heat pump will be higher, but the annual energy costs will reduce.

Another option is the hybrid heat pump. This is a combination of a heat pump and a high-efficiency boiler. The heat pump supplies most of the heat. The boiler is used to provide heat during extreme cold periods and heat for tap water. This might also be an interesting option for the Netherlands due to the presence of the gas infrastructure (Warmtepompplein, 2015a). The advantage of the hybrid heat pump is that during heat demand peaks there will be a smaller additional peak in electricity demand compared to electric heat pumps, which might negate the need for additional measures.

Existing grid capacity
The capacity deficit is dependent on the capacity of the current grid. In this research it is assumed that 200 households are connected to one 400 kVA transformer. This is a specific situation and in other neighbourhoods these values can differ. Especcially in newer neighbourhood a larger grid capacity is used (Oirschouw, 2012).

Flex Street data
The final energy demand for the households is taken from the flex street data. This data represents the average energy demand for terraced buildings. Heating heat demand is dependent on ambient temperature. Because it is assumed that this is the demand for an average year, the temperature records of the year in which the amount of degree-days is closest to the average amount of degree-days. However, this temperature profile does not completely match the Flex Street heat demand profile. In the case of a high heating heat demand, but a disproportionately low ambient temperature the resulting calculated electricity demand will be lower than it would have been if the HHD and temperature profiles were an exact match. This could have been achieved by using actual energy demand profiles that are available on EDSN (2014), rather than modelled profiles. The disadvantage is that only average energy demand per household can be used, which would have limited the option for e.g. allocating measures to certain households, based on their annual energy demand.

The data represents the energy demand of a neighbourhood with terraced buildings. Semi-detached or detached buildings use approximaly 25% and 50% more natural gas (Milieucentraal, 2015b). These building types have a larger heating heat demand due to a higher surface area of the outer shell. The difference in heat demand between building types is larger than the difference in electricity demand. The LVDS capacity is, presumably, dimensioned on the traditional electricity demand. Under this assumption, the grid capacity deficit might be larger for neighbourhoods with mostly (semi-)detached buildings.

Also the costs for infrastructure might depent on the building density of a neighbourhood as discussed in a publication from CE Delft (Schepers et al., 2015). They found that the cheapest method for supplying heat is largely dependent on the type of neighbourhood. Switching to an all-electric grid is especially interesting when the building density is low, because only one infrastructure would be needed. In more densely build areas, the costs for the infrastructure per household are lower, and as a result a heat distribution infrastructure is an interesting option, instead of switching to heat pumps.

Development of energy demand
The energy demand is the current energy demand, however energy demand changes over time. The annual electricity demand for households annually increases by 1.7% (Compendium voor de Leefomgeving, 2015). This is partly due to the implementation of non-conventional electricity consuming appliances such as electric vehicles or heat pumps, but also to the increasing number of electricity consuming appliances in households. This means that on existing LVDSs the remaining capacity for heat pumps decreases over time and an increase of the required expansion of the infrastructure. On the other hand the natural gas demand decreases due to improved building standards and improved insulation of existing buildings. The latter is included in this research as a measure to prevent capacity exceedance.

4.2 External factors

Primary energy demand and emission factors
Due to improvements in efficiency of electricity production and the increasing use of sustainable energy technologies the primary energy demand and CO_2 emission factors decrease. In the period 2002 – 2012 the conversion efficiency increased by 1.6% annually and the emission factor for electricity

decreased by 0.1% annually (CBS, 2014b). This means that the primary energy demand and emission factors for electrictity use decrease, while the factors for natural gas consumption remain the same. This means that heat pumps will become increasingly better in that respect, while these improvements do not apply to conventional heating.

4.3 CONSIDERED MEASURES

In this research a number of possible measures to prevent capacity exceedance is assessed. Other measures that are not assessed might exist, but more importantly, other combinations of measurs can be implemented. We have seen that combining measures might reduce costs (based on heat pump electricity demand scenario 1), compared to implementing an individual measure, and that allocating measures to specific households also makes a difference. For example, the 8% most energy consuming households can be equipped with a heat pump, without the occurance of capacity exceedance, or the 35% least energy consuming households. In a similar way heat demand shifting is affected by allocating the measure to specific households. Dependent on which households' heat demand is shifted, heat demand shifting has to be implemented in 80 or 120 out of 200 households.

A recommendation for further research is combining measures and allocating measures to specific households and also assess the option of a mix of heat pumps with conventional heating. For example: equip energy efficient buildings with a heat pump, and implement insulation in other buildings. This way a more cost-effective way of primary energy saving and CO_2 mitigation might be found, whereas this research is mainly focussed on finding the most cost-effective measure with a 100% heat pump penetration rate.

Another measures that is not assessed are demand side management (besides heat demand shifting). If heat demand must be fulfilled instantaneously, and there is insufficient grid capacity, then demand side management could be applied on tradional electricity consuming appliances.

Furthermore, during this research it is assumed that heat demand should always be fulfilled instantaneously. However, if this is postponed then this does not cause an immediate large drop in temperature. Also, the heat distribution system and the floor itself is still relatively hot compared to the room temperature so heating of the room does not directly stop, but only the heating of the fluid in the heat distribution system. And if also a small decrease in temperature is allowed, then heating can be postponed, or even slightly reduced, which decreases the grid capacity deficit.

4.4 OTHER FACTORS

4.4.1 Limiting factor allocating grid capacity

An important consideration for using mainly neighbourhood averages and totals is the problem of grid capacity allocation. This problem arises when thermal energy storage is implemented. During periods where demand is larger than the grid capacity the TES system supplies a part of the heat, but the heat pumps are also supplying heat. The heat pumps and TES systems should be deployed in such a way, that not most of the households used all the accumulated heat before the end of the period with overdemand. Also, when system are recharged, the grid capacity should be allocated in such a way, that all households have a sufficient amount of accumulated heat to bridge the next period of overdemand. This means that households with a high expected heat demand should get more grid capacity allocated to them.

In the model the total required storage capacity is calculated, and simply divided by the amount of households. But this capacity is only sufficient if the capacity is properly allocated and when households all have a storage capacity suitable to there demand. This requires a complex demans side management system, or the households are equipped with more storage capacity for more flexibility, but this would increase the investement costs. Taking this and the high annual costs for thermal energy storage into consideration, probably means that thermal energy storage, when implemented as indivual measure, might not offer the reliabitily that is pursued, for reasonable costs. Which contradicts some earlier findings (U.S. Department of Energy, 2013).

4.4.2 Developments that affect the grid, apart from heat pumps

In this research only the penetration of heat pumps is included. But there are more developments that will affect the demand of the LVDS. Two of these are photovoltaics (PV), solar boilers and electric vehicles (EVs). In the introduction it is discussed that the heat pump might put the most strain on the current grid, but PV and EVs affect the energy demand nonetheless. The most important factor is the simultaneity of supply/demand of these technologies. The combined effect of heat pumps, PV and EVs could be researched further. Also, smarter solutions could be developed, where the technologies befit of each other, instead of causing grid capacity deficit together. For example, EVs could be used as energy storage system, of which the heat pump can use the stored electricity.

4.4.3 Research scope

This research is not about the most cost-effective method to design the energy infrastructure at the neighbourhood level, as not all possible options and combinations of options are assessed. But an assessment of a set of available measure that are more cost-effective than simply expanding the grid capacity, if a neighbourhood would switch to ASHPs.

Previous research (Schepers et al., 2015) indicated that the least expensive option to provide heat to Dutch households is using heat pumps for a large share of the Dutch building stock, even including the required grid reinforcement. This thesis showed that grid capacity expansion is amongst the least expensive measures to prevent capacity exceedance, but it did not show that heat pumps are cheaper than conventional heating, even though primary energy is saved and CO_2 mitigated. This contradiction is due to the differences in assumed electricity and gas prices. Increasing gas prices will increase the viability of heat pumps. This will be strengthened by if the coefficient of performance of heat pumps will improve. This also affects positively affects the primary energy saved anc CO_2 mitigated.

5 CONCLUSION

5.1 CAPACITY EXCEEDANCE WITH HEAT PUMPS

If heat pumps would become cost competitive to conventional heating systems they might be implemented in more households. The additional electricity demand for heat pumps might cause capacity exceedance for existing energy infrastructure. In a scenario of extreme cold the demand exceeds the current LVDS capacity by approximately 250%. Due to capacity deficit at least 1/4th of the annual heat demand cannot be supplied due to the limitations of the grid. Measures to prevent capacity exceedance are required.

5.2 INVESTEMENT COSTS OF REQUIRED MEASURES

Of the assessed measures, grid capacity expansion, heat demand reduction and thermal energy storage might prevent capacity exceedance. The required annualized investment costs are the lowest for capacity expansion at 42 €/household/year. Heating heat demand reduction and TES require more investment costs, these are resp. 1,130 and 707 €/household/year. The required quantity in the scenario with the long coldspell are assumed, because the infrastructure should be able to fullfill the energy demand at any time, and therefore the extreme scenario is the criterion.

The results showed that the required storage capacity is the measure that is most strongly affected by the heat pump electricity demand scenarios, because the capacity should be sufficient to bridge the period where only limited recharging is possible. The required quantity of other measures depend on the highest occurring demand peak, and the duration of a cold period does not affect the required quantity. An assumption for the minimum occurring temperature in the Netherlands will be more certain than an assumption for the maximum duration of cold periods for the following years. This means that TES as an indivual measure is highly expensive if security of supply is pursued.

Head demand shifting cannot prevent capacity exceedance as indivual measure. But it can reduce the required quantity and therefore investment costs of other measures. More research concerning this optimization is recommended.

Also limiting the number of heat pumps is assessed. If only the most energy efficient houses are equipped with a heat pump, then the LVDS can sustain a heat pump penetration rate of 35%. The advantage of this measure is that it required no additional investement costs, but the gas grid has to be sustained.

The total annualized investment costs, which include the investment costs for the heat pump, show that using heat pumps is more expensive than gas boilers. The combinations with heat demand reduction seem promising, but this is mainly due to the additional benefit of energy saving. It should also be said that reducing the heating heat demand cannibalises on the benefit of the heat pump which benefits from the difference in energy price and less energy demand means less total benefit.

5.3 PRIMARY ENERGY SAVING, CO_2 MITIGATION AND COST EFFECTIVITY

While households might switch to heat pumps for the econic benefit, there is also an environmental benefit of heat pumps, compared to conventional heating systems. Compared to the total electricity and gas consumption, the total primary energy consumption and CO_2 emissions per household might be reduced by resp. 9% and 12%. If heat pumps are implemented in combination with heat demand reduction, then a reduction of 44% resp. 46% might be achievable. Heat pumps with TES might only lead to marginal primary energy saving, if the electricity is produced more efficiently, and only marginal CO_2 emission mitigation. If the number of heat pumps is limited, then a small reduction in primary energy consumption and CO_2 emissions is achieved on average, per household.

If the investement costs for the heat pump and the required measure are included in the costs, then the switch to heat pumps might not be profitable for consumers. It is only profitable if the investement costs for heat pumps and/or measure decrease, or if the price difference between electricity and gas increases. This is not unlikely, as heat pump prices will most likely decrease due to increasing production and technological development (IEA, 2013) and gas prices might increase due to a decreasing supply (ENSOC, 2015). With the current assumptions, the total annual costs, which included the annualized investement costs for both the heat pump and the required measure, are the lowest for heat pumps in combination with grid capacity expansion or limiting the number of heat pumps at approximately 690 €/household/year. Heat pumps with heat demand reduction or TES is more expensive with resp. 1,090 €/household/year and 1,560 €/household/year.

Assuming the current assumption regarding costs, the specific costs of primary energy saving and the CO_2 mitigation costs are positive, i.e. it does not yield a profit. The the specific costs of primary energy saving and the CO_2 mitigation costs are the lowest if the implementation of heat pumps is combined with heat demand reduction at resp. 120 €/$MWh_{primary}$ saved and 0.60 €/kg CO_2 mitigated. Primary energy saving and CO_2 mitigation are higher if heat pumps are combined with grid capacity expansion at resp. 370 €/$MWh_{primary}$ saved and 1.48 €/kg CO_2 mitigated. Heat pumps in combination with the other measures are much more expensive with regard to primary energy saving and CO_2 mitigaiton, mainly due to low reduction of these factors.

Which measure, when implemented indivually, is the least expensive might depend on the perspective. From a purely economic perspective, where the total annual costs are considered and disregard environmental benefits, the most viable measures are capacity expansion or limiting the number of heat pumps. However, if heat pumps are implemented for primary energy saving and CO_2 emission mitigation, they are best combined with heat demand reduction. Then the most primary energy is saved and most CO_2 emission mitigated, and this is also more cost effective than heat pumps combined with other measures. Furthermore, heat pumps with combinations of measures are likely more cost-effective than implementing individual measures. More research on this option is recommended.

5.4 IMPLICATIONS

While switching to heat pumps might not be definitely cost-effective, when all costs are included, still capacity expansion seems to be among the least expensive measures to prevent capacity exceedance. However, more primary energy saving and CO_2 mitigation can be achieved, and more cost-effectively, if heat demand reduction is implemented. This also contributes to preventing capacity exceedance. Therefore it might be desirable from a societal perspective to put more emphasize on energy saving measures when heat pumps are implemented, otherwise more investements in the energy infrastructure are required.

Providing sufficient grid capacity is the concern of the system operators. Legally they are only allowed to implement capacity expansion, according to the *Elektriciteitswet 1998*. While this is still among the least expensive measures, expanding the possibilities for system operators might contribute to finding lower-costs solutions.

Still, heat pumps might or might not be a cost-effective energy saving measure. This research illustrated the costs that are included with shifing to heat pumps. Other options might be more cost-effective in energy saving and emission mitigation. There is no ready-made solution for each situation, as the costs depend on many variables. These are also location specific, e.g. building density (for infrastructure costs), predominant building type (for expected heat demand) or geologic structure (for heat pump type), so each situation should be assessed individually. More research on the differences between specific situations would contribute to a better understanding of factors that determine the costs of a more sustainable and cost-effective heat supply. This is necessary for delibate choices regarding the design of the energy distribution infrastructure. Hopefully, this research contributed to this knowledge base and delivered new insights regarding the challenges, and solutions, of a transition to a more sustainable heat supply.

6 BIBLIOGRAPHY

Agentschap NL. (2011). *Voorbeeldwoningen 2011: Onderzoeksverantwoording*. Den Haag.

Agentschap NL. (2012). *Monitor energiebesparing gebouwde omgeving 2012*. Den Haag.

AgentschapNL. (2011). *Detail gegevens voorbeeldwoningen 2011*. *Detail Gegevens Voorbeeldwioingen 2011*. Den Haag.

Blarke, M. B., Yazawa, K., Shakouri, A., & Carmo, C. (2012). Thermal battery with CO2 compression heat pump: Techno-economic optimization of a high-efficiency Smart Grid option for buildings. *Energy and Buildings*, *50*, 128–138. http://doi.org/10.1016/j.enbuild.2012.03.029

Blok, K. (2007). *Introduction to Energy Analysis*. Amsterdam: Techne Press.

Brouwer, A. S., Kuramochi, T., van den Broek, M., & Faaij, A. (2013). Fulfilling the electricity demand of electric vehicles in the long term future: An evaluation of centralized and decentralized power supply systems. *Applied Energy*, *107*, 33–51. http://doi.org/10.1016/j.apenergy.2013.02.005

CBS. (2014a). Energieverbruik sector particuliere huishoudens; energiedragers. Retrieved April 14, 2015, from http://statline.cbs.nl/Statweb/publication/?DM=SLNL&PA=82375NED&D1=0&D2=a&D3=a&HDR=T,G1&STB=G2&CHARTTYPE=1&VW=T

CBS. (2014b). *Rendementen en CO 2 -emissie van elektriciteitsproductie in Nederland , update 2012*. Den Haag.

CBS. (2014c). Warmtepompen; aantallen, thermisch vermogen en energiestromen. Retrieved March 23, 2015, from http://statline.cbs.nl/Statweb/publication/?DM=SLNL&PA=82380NED&D1=a&D2=a&D3=a&D4=a&HDR=T&STB=G2,G1,G3&VW=T

CBS. (2014d). Woningvoorraad naar eigendom; regio, 2006-2012. Retrieved March 23, 2015, from http://statline.cbs.nl/StatWeb/publication/?VW=T&DM=SLNL&PA=71446ned

CBS. (2015). CBS StatLine - Aardgas en elektriciteit, gemiddelde prijzen van eindverbruikers. Retrieved October 4, 2015, from http://statline.cbs.nl/Statweb/publication/?DM=SLNL&PA=81309NED&D1=1,8&D2=1-2&D3=a&D4=19,24,29,34,39-41&HDR=T,G2&STB=G1,G3&VW=T

CE Delft. (2015). *Emissiekentallen elektriciteit Kentallen voor grijze en " niet -geoormerkte stroom " inclusief upstream-emissies*. Delft.

Çengel, Y. A., & Boles, M. A. (2011). *Thermodynamics: an engineering approach* (7th ed.). New York: McGraw-Hill.

Claessen, F. N., Claessens, B., Hommelberg, M. P. F., Molderink, A., Bakker, V., Toersche, H. A., & van den Broek, M. A. (2014). Comparative analysis of tertiary control systems for smart grids using the Flex Street model. *Renewable Energy*, *69*, 260–270. http://doi.org/10.1016/j.renene.2014.03.037

Clement-Nyns, K., Haesen, E., & Driesen, J. (2010). The Impact of Charging Plug-In Hybrid Electric Vehicles on a Residential Distribution Grid. *IEEE Transactions on Power Systems*, *25*(1), 371–380. http://doi.org/10.1109/TPWRS.2009.2036481

Compendium voor de Leefomgeving. (2015). Energieverbruik door huishoudens. Retrieved from http://www.compendiumvoordeleefomgeving.nl/indicatoren/nl0035-Energieverbruik-door-de-huishoudens.html?i=6-40

De Energieconsultant. (2015). Berekening vermogen (P) aansluiting - Onafhankelijk Energieadvies - De

Energieconsultant. Retrieved September 10, 2015, from http://www.energieconsultant.nl/energiemarkt/energie-berekeningen-uit-de-praktijk/berekening-vermogen-p-aansluiting/

Dekker, V. (2012, May 11). Huizen krijgen over paar jaar geen gasaansluiting meer. *Trouw*.

DHPA. (2015). Veel gestelde vragen - Dutch Heat Pump Association. Retrieved November 8, 2015, from http://www.dhpa-online.nl/veel-gestelde-vragen/

Dunnik, Ard Jan de Rijke, M. (2014). Elektriciteitsopslag door de netbeheerder. Retrieved May 27, 2015, from http://birdbuzz.nl/2014/06/30/elektriciteitsopslag-door-de-netbeheerder/

ECN. (2012). *Berekening referentierendement voor de opwekking van elektriciteit*. Petten.

Econo. (2015). Econo. Buffervat. Retrieved December 15, 2015, from http://www.econo.nl/buffervat

EDSN. (2014). Platform verbruiksprofielen. Retrieved May 19, 2014, from http://www.edsn.nl/verbruiksprofielen/

EHPA. (2015). Key facts on the sector - EHPA. Retrieved July 6, 2015, from http://www.ehpa.org/market-data/key-facts-on-the-sector/

ENSOC. (2015). "Gasprijs kan stijgen door Groningen en Rusland" - Ensoc. Retrieved November 9, 2015, from https://www.ensoc.nl/nieuws/gasprijs-kan-stijgen-door-groningen-en-rusland

ETSAP/IRENA. (2013). *Thermal Energy Storage. Technology Brief*.

European Heat Pump Association. (2014). Heat pumps are chosen in 32,2% of new residential buildings in Germany. Retrieved March 16, 2015, from http://www.ehpa.org/about/news/article/german-home-owners-increasingly-deciding-for-heat-pumps/

Felix Covrig, C., Ardelean, M., Vasiljevska, J., Mengolini, A., Fulli, G., Amoiralis, E., … Filiou, C. (2014). *Smart Grid Projects Outlook 2014*. Petten.

Gaslicht. (2015). Het vastrecht voor gas en stroom verschilt enorm. Retrieved October 4, 2015, from https://www.gaslicht.com/nieuws/het-vastrecht-voor-gas-en-stroom-verschilt-enorm

Goes, R. (2014). Meerwaarde door innovatieve gastoepassingen. Retrieved February 10, 2015, from http://www.e2go.nl/site/wp-content/uploads/2014/09/Meerwaarde-door-innovatieve-gastoepassingen.pdf

Harmsen, R., Breevoort, P., Planje, W., Bakker, E.-J., & Wagener, P. (2009). *Energiebesparing- en CO2-reductiepotentieel hybride lucht/water warmtepomp in de bestaande woningbouw*. Utrecht.

Hewitt, N. J. (2012). Heat pumps and energy storage – The challenges of implementation. *Applied Energy*, *89*(1), 37–44. http://doi.org/10.1016/j.apenergy.2010.12.028

Hoogspanningsnet. (2015). 380 kV - HoogspanningsNet. Retrieved August 29, 2015, from http://www.hoogspanningsnet.com/hetnet/380kv/

IEA. (2013). Technology Roadmap heating. http://doi.org/10.1007/SpringerReference_7300

Interclima. (2015). Buffervaten - RVS buffervat | Maatwerk buffervat | Buffervat met flenzen. Retrieved December 15, 2015, from http://www.interclima.nl/buffervat/buffervaten/buffervaten.html

IPCC. (2012). *Renewable energy sources and climate change mitigation: special report of the Intergovernmental Panel on Climate Change*. *Choice Reviews Online* (Vol. 49).

Isolatie.net. (2015). Levensduur gevelisolatie. Retrieved December 16, 2015, from http://www.isolatie.net/levensduur-gevelisolatie/

Kassakian, J. G., & Schmalensee, R. (2011). *The Future of the Electric Grid*. Massachusets.

KNMI. (2015). KNMI - Uurgegevens van het weer in Nederland. Retrieved May 10, 2015, from http://www.knmi.nl/klimatologie/uurgegevens/selectie.cgi

Lund, H., & Østergaard, P. A. (2000). Electric grid and heat planning scenarios with centralised and distributed sources of conventional, CHP and wind generation. *Energy*, *25*(4), 299–312. http://doi.org/10.1016/S0360-5442(99)00075-4

Max Planck Society. (2012). Solar and wind energy may stabilise the power grid. Retrieved October 27, 2015, from https://www.mpg.de/6351135/power-grid-regenerative-energy

Michopoulos, A., Bozis, D., Kikidis, P., Papakostas, K., & Kyriakis, N. A. (2007). Three-years operation experience of a ground source heat pump system in Northern Greece. *Energy and Buildings*, *39*(3), 328–334. http://doi.org/10.1016/j.enbuild.2006.08.002

Milieucentraal. (2015a). Bespaartips warm water. Retrieved from http://www.milieucentraal.nl/energie-besparen/snel-besparen/bespaartips-warm-water/

Milieucentraal. (2015b). Gemiddeld energieverbruik. Retrieved May 25, 2015, from http://www.milieucentraal.nl/energie-besparen/snel-besparen/grip-op-je-energierekening/gemiddeld-energieverbruik/

Milieucentraal. (2015c). LTV lagetemperatuurverwarming. Retrieved from http://www.milieucentraal.nl/energie-besparen/energiezuinig-huis/energiezuinig-verwarmen-en-warm-water/ltv-lagetemperatuurverwarming/

NEDU. (2015). Verbruiksprofielen - NEDU. Retrieved May 10, 2015, from http://nedu.nl/portfolio/verbruiksprofielen/

Nykvist, B., & Nilsson, M. (2015). Rapidly falling costs of battery packs for electric vehicles. *Nature Climate Change*, *5*(4), 329–332. http://doi.org/10.1038/nclimate2564

Oirschouw, P. van. (2012). *Netten voor de distributie van elektriciteit*. Arnhem: Phase to phase. http://doi.org/31

Pedersen, T. S., Andersen, P., Nielsen, K. M., Starmose, H. L., & Pedersen, P. D. (2011). Using heat pump energy storages in the power grid. In *2011 IEEE International Conference on Control Applications (CCA)* (pp. 1106–1111). IEEE. http://doi.org/10.1109/CCA.2011.6044504

Rijksoverheid. (2015a). Betaal ik btw over mijn energiebelasting? | Vraag en antwoord | Rijksoverheid.nl. Retrieved October 4, 2015, from https://www.rijksoverheid.nl/onderwerpen/btw-omzetbelasting/vraag-en-antwoord/betaal-ik-btw-over-mijn-energiebelasting

Rijksoverheid. (2015b). Duurzame energie. Retrieved May 25, 2015, from http://www.rijksoverheid.nl/onderwerpen/duurzame-energie/meer-duurzame-energie-in-de-toekomst

Rijksoverheid. (2015c). Tabellen tarieven milieubelastingen. Retrieved October 4, 2015, from http://www.belastingdienst.nl/wps/wcm/connect/bldcontentnl/belastingdienst/zakelijk/overige_belastingen/belastingen_op_milieugrondslag/tarieven_milieubelastingen/tabellen_tarieven_milieubelastingen

Rijksoverheid. (2015d). Wat zijn de kosten van een slimme meter? Retrieved November 8, 2015, from https://www.rijksoverheid.nl/onderwerpen/slimme-meter/vraag-en-antwoord/kosten-slimme-meter

Rooijers, F. J., & Leguijt, C. (2010). *Net voor de Toekomst*. Delft.

RVO. (2015a). Investeringssubsidie duurzame energie (ISDE) | RVO.nl. Retrieved December 23, 2015, from http://www.rvo.nl/subsidies-regelingen/investeringssubsidie-duurzame-energie-isde?ns_source=google&ns_mchannel=cpc&ns_campaign={campaign}&ns_linkname={adgroup}&gclid=CNLSnqeA8ckCFYW4GwodQckLZw

RVO. (2015b). Stumilering Duurzame Energieproductie (SDE). Retrieved May 25, 2015, from http://www.rvo.nl/subsidies-regelingen/stimulering-duurzame-energieproductie-sde

Schepers, B. L., Naber, N. R., Rooijers, F. J., & Leguijt, C. (2015). *Op weg naar een klimaatneutrale woningvoorraad in 2050*. Delft.

Self, S. J., Reddy, B. V., & Rosen, M. A. (2013). Geothermal heat pump systems: Status review and comparison with other heating options. *Applied Energy*, *101*, 341–348. http://doi.org/10.1016/j.apenergy.2012.01.048

Spruijt, H. (2014). *A valutation of electricity distribution capacity*. Utrecht University.

Sundstrom, O., & Binding, C. (2012). Flexible Charging Optimization for Electric Vehicles Considering Distribution Grid Constraints. *IEEE Transactions on Smart Grid*, *3*(1), 26–37. http://doi.org/10.1109/TSG.2011.2168431

Tahersima, F., Stoustrup, J., Meybodi, S. A., & Rasmussen, H. (2011). Contribution of domestic heating systems to smart grid control. In *IEEE Conference on Decision and Control and European Control Conference* (pp. 3677–3681). IEEE. http://doi.org/10.1109/CDC.2011.6160913

TKI Switch 2 Smart Grids. (2015). TKI Switch2SmartGrids - Projecten. Retrieved March 30, 2015, from http://tki-switch2smartgrids.nl/projecten/

U.S. Department of Energy. (2013). *Grid Energy Storage*. Washington.

van Roy, J., Verbruggen, B., & Driesen, J. (2013). New tools for integrated building and district modeling. *IEEE Power & Energy Magazine*, 75–81.

van Vliet, O., Brouwer, A. S., Kuramochi, T., van den Broek, M., & Faaij, A. (2011). Energy use, cost and CO2 emissions of electric cars. *Journal of Power Sources*, *196*(4), 2298–2310. http://doi.org/10.1016/j.jpowsour.2010.09.119

Vastelastenbond. (2015). Netwerkkosten 2015 | Vastelastenbond.nl. Retrieved October 4, 2015, from https://www.vastelastenbond.nl/blog/netwerkkosten-2015/

Verbeeck, G. (2007). *Optimisation of extremely low energy residential buildings*. Leuven.

Wärmepumpen-Testzentrum. (2015). *Prüfresultate Luft / Wasser-Wärmepumpen basierend auf der EN 14511 : 2011 Test results of air to water heat pumps based on EN 14511 : 2011 Prüfresultate Luft / Wasser-Wärmepumpen basierend auf der EN 14511 : 2004 und EN 14511 : 2007 Test results of air to*. Buchs.

Warmtepompplein. (2015a). Hybride warmtepompen. Retrieved from http://www.warmtepompplein.nl/themas/de-warmtepomp/typen-warmtepompen/hybride-warmtepompen/

Warmtepompplein. (2015b). Wat kost een warmtepomp? - Warmtepomp informatie voor iedereen. Retrieved November 8, 2015, from http://www.warmtepompplein.nl/themas/de-warmtepomp/wat-kost-een-warmtepomp/

Zottl, A., Lindahl, M., Nordman, R., & Rivière, P. (2011). *Evaluation method for comparison of heat pump systems with conventional heating systems*.

7 APPENDIX

Appendix A HEAT PUMP COP PER (ABSOLUTE) TEMPERATURE DIFFERENCE

Figure 7.1 is a graphical representation of the heat pump test results (Wärmepumpen-Testzentrum, 2015). It shows the CoP for different temperature differences for 56 air-source heat pump types. This data is used to establish the relationship between CoP and temperature difference.

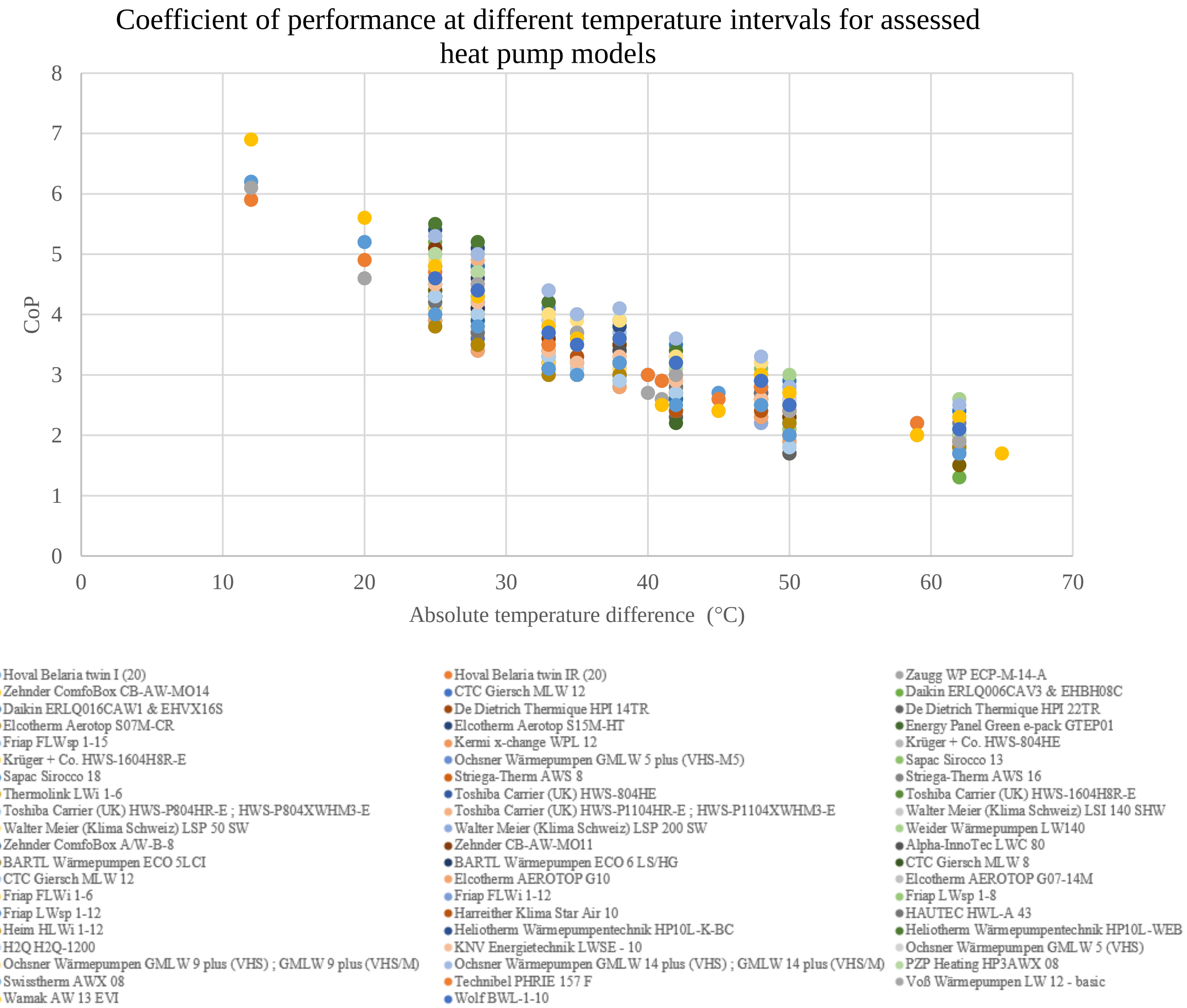

Figure 7.1: Graphical representation of the test results from Wärmepumpen-Testzentrum (2015). *The CoP is plotted against the temperature difference for the tested heat pump models.*

Appendix B DEGREE-DAYS

Temperature records for the period 1995-2014 are compared (KNMI, 2015). A measure of expected annual heating heat demand is the annual degree-days. For each year the number of degree-days is calculated using equation (7.1) (Blok, 2007), with T_{ref} = 18°C. The occurrence of (extreme) cold weather is assessed by summing the amount of hours with a temperature below a given T_{ref}, for each year. The results are shown in Table 7.1.

The year with the lowest expected heating heat demand is 2014 with 15.5% less degree-days. A cold year is 1996 with a 22.6% higher amount of degree-days than the average. The year that probably best represents the average temperature profile in the period 1995-2014 is 2009. Both the number of degree-days and the amount of hours with low temperatures correspond with the period's average.

$$D = \sum_{i=1}^{365} \max(T_{ref} - T_i, 0) \tag{7.1}$$

Table 7.1: Temperature statistics of the period 195-2014. The left side of the table shows the number of hours per year with a temperature below the specified temperature. The occurrence of low temperatures is assessed because heating heat demand peaks at low temperatures. High values are marked for each column. The right side of the table shows the number of degree-days (assuming indoor temperature of 18 °C) per year and the deviation from the average. A higher amount of degree-days represent a higher heating heat demand. A color scale is used for the degree-days ranging, from red for low number of degree-days to blue, for high number of degree-days.

	number of hours with temperature below x °C						degree-days	deviation from average
	18 °C	10 °C	0 °C	-5 °C	-10 °C	-15 °C		
1995	7377	4325	668	75	17	0	2989	2.6%
1996	7943	4802	1318	270	29	0	3561	22.3%
1997	7503	4406	543	183	46	5	2995	2.9%
1998	7833	4151	409	69	0	0	2882	-1.0%
1999	7484	4015	367	46	0	0	2760	-5.2%
2000	7714	3992	270	11	0	0	2738	-6.0%
2001	7582	4113	552	40	0	0	2944	1.1%
2002	7582	4125	423	75	0	0	2797	-4.0%
2003	7231	4444	712	116	3	0	3030	4.1%
2004	7659	4164	494	30	0	0	2949	1.3%
2005	7548	3974	505	32	6	0	2834	-2.7%
2006	7149	3807	549	32	0	0	2750	-5.6%
2007	7594	3842	340	12	0	0	2610	-10.4%
2008	7569	4269	396	34	0	0	2862	-1.7%
2009	7507	4054	643	112	5	0	2884	-1.0%
2010	7550	4595	1327	187	6	0	3393	16.5%
2011	7663	3832	354	11	0	0	2711	-6.9%
2012	7705	4411	530	204	45	8	2943	1.1%
2013	7577	4535	830	91	9	0	3149	8.1%
2014	7378	3553	128	0	0	0	2462	-15.5%
average	**7557.4**	**4170.4**	**567.9**	**81.4**	**8.3**	**0.6**	**2912.1**	

Appendix C Energy pricing

The costs for energy for consumers consist of three elements: the commodity price, the transportation costs and taxes. The consumer pays a fixed tariff and a variable tariff (see Table 7.2). The variable tariff includes the commodity price and taxes. The variable tariff is € 0.2398 per kWh and € 0.6911 per m3. The fixed tariff includes the standing charge, which is charged by the retailer (see Table 7.3 for tariff overview per retailer), the capacity fee, charged by the system operator (see Table 7.4 for tariff overview per system operator), and a tax refund. For the electricity and gas connection for households this is € 279.92 and €199.13 annually.

Table 7.2: Energy price for small scale consumers. Prices in 2015, unless indicated otherwise. [(1)]*2014 prices* (CBS, 2015), *gas price converted to €/m^3, assuming $HHV_{natural\ gas}$ = 35MJ/m^3* (Blok, 2007, p. 28)*;* [(2)](Rijksoverheid, 2015c)*;* [(3)]*Commodity price and energy taxes are taxed* (Rijksoverheid, 2015a)*;* [(4)](Gaslicht, 2015)*;* [(5)](Vastelastenbond, 2015).

	Electricity	Gas
Variable tariff		
Commodity price	€ 0.075 per kWh [(1)]	€ 0.3726 per m^3 [(1)]
Energy tax	€ 0.1196 per kWh [(2)]	€ 0.1911 per m^3 [(2)]
Sustainability tax	€ 0.0036 per kWh [(2)]	€ 0.0074 per m^3 [(2)]
VAT (21%) [(3)]	€ 0.0416 per kWh	€ 0.1199 per m^3
Total variable tariff	€ 0.2398 per kWh	€ 0.6911 per m^3
Fixed tariff		
Standing charge (retailer)	€ 43.68 per annum [(4)]	€ 40.45 per annum [(4)]
Capacity charge (system operator)	€ 236.24 per annum [(5)]	€ 158.68 per annum [(5)]
Tax refund (for electricity)	€ 311.84 per annum [(2)]	not applicable
Total fixed tariff	€ 279.92 per annum (excl tax refund) € -31.92 per annum (incl tax refund)	€ 199.13 per annum

Table 7.3: The standing charge paid to the energy retailer, for the 12 least expensive energy contracts for small scale consumers, according to Gaslicht.nl (2015), as of 31-01-2014. The average standing charge is €43.68 and €40.45 for electricity resp. gas.

Energy retailer	Contract duration (years)	Standing charge electricity (€/year)	Standing charge natural gas (€/year)	Annual total (€/year)
NLE	3 year	€ 22.20	€ 22.20	€ 44.40
Essent	1 year	€ 23.96	€ 23.96	€ 47.92
Greenchoice	1 year	€ 24.25	€ 24.25	€ 48.50
Eneco	1 year	€ 27.66	€ 27.66	€ 55.32
Delta	1 year	€ 38.77	€ 18.12	€ 56.89
Electrabel	3 year	€ 37.50	€ 37.50	€ 75.00
Nuon	1 year	€ 39.06	€ 45.00	€ 84.06
E.ON	3 year	€ 47.88	€ 47.88	€ 95.76
E.ON	1 year	€ 47.92	€ 47.92	€ 95.84
Energiedirect.nl	1 year	€ 59.53	€ 59.53	€ 119.00
Energiedirect.nl	1 year	€ 83.53	€ 59.53	€ 143.00
Budget Energie	1 year	€ 71.87	€ 71.88	€ 143.70
Average		**€ 43.68**	**€ 40.45**	**€ 84.12**

Table 7.4: Capacity charge, paid for the connection to the grid, indirectly paid to the system operator, for small scale consumers. Source (Vastelastenbond, 2015).

	electricity	gas
cogas	222.43	146.01
delta	252.58	152.99

endinet	208.59	150.11
enexis	227.63	154.44
liander	240.12	160.71
rendo	232.09	186.78
stedin	227.81	162.66
westland	278.69	155.73
average	**236.24**	**158.68**

Appendix D LOWEST-COSTS COMBINATION FOR GRID CAPACITY EXPANSION

The lowest costs combination of transformers for capacity expansion, as described in section 2.4.1.

Table 7.5: Lowest cost combination of transformers for required capacity expansion. It shows the number of transformers that are replaced or added when the lowest investement costs are persued. For each combination the actual capacity expansion and the total investment costs are shown.

Grid capacity expansion		Least expensive combination			Total investment costs	
Required capacity expansion (kVA)	Added capacity (kVA)	Replace existing transformer with 630 kVA transformer	Number of added 400 kVA transformers	Number of added 630 kVA transformers	Transfomer only, excluding cables (€)	Transformer, including cables (€)
0	0	-	-	-	0	83,000
0 - 230	230	1	-	-	11,100	94,100
230 - 400	400	-	1	-	30,000	113,000
400 - 460	630	-	-	1	33,300	116,300
460 - 630	630	-	-	1	33,300	116,300
630 - 860	860	1	-	1	44,400	127,400
860 - 1030	1030	-	1	1	63,300	146,300
1030 - 1260	1260	-	-	2	66,600	149,600
1260 - 1490	1490	1	-	2	77,700	160,700
1490 - 1660	1660	-	1	2	96,600	179,600
1660 - 1890	1890	-	-	3	99,900	182,900

Appendix E THERMAL ENERGY STORAGE COSTS

The costs for a thermal enegy storage system are determined by consulting websites of retailers (Econo, 2015; Interclima, 2015). Retailers are found by search queries "*kosten buffervat*". Table 7.6 shows the costs from the two retailers, for different system types. The price of TES systems are given in €, system capacity is expressed as litre. The specific costs (€/kWh) are derived from this data. A storage capacity of 70 – 90 kWh/m^3 is assumed by ETSAP/IRENA (2013, p. 14), howettver this entails relatively high temperature storage. Here a more conservative estimate of approx. 60 kWh/m^3 is assumed, based on the specific heat of water of 4.18 kJ/kg (Çengel & Boles, 2011) and a storage temperature difference of 50°C. The total required storage capacity is 14 – 96 MWh, or 70 – 480 kWh per household. Therefore systems with a capacity <1000 litre are not sufficient and their costs are not considered. Costs for systems with a storage capacity of 1000, 2000, 3000, 4000 5000 litre are included. Only the the costs for systems with one or two heat exchanger(s) are considered. Both retailers offer complete systems and insulated accumulators.

The average costs of the systems with one or two heat exchangers 20.7 €/kWh with a cost range of 14.2 – 29.8 €/kWh. Taking out the extremes this is rounded to 20 ± 5 €/kWh. The effect of storage capacity (kWh) on the specific costs (€/kWh) is relatively small. The price difference is mainly due to different retailers.

Table 7.6: Costs overviewof TES system based on prices of two Dutch retailers (Econo, 2015; Interclima, 2015). [(1)]*For the 3000, 4000, 5000 litre the costs for systems with 1 or 2 heat exchanger(s) are calculated using the costs for the system without heat exchanger and multiplying this with a cost-factor. The cost-factor is the average ratio between the costs for resp. the 1- and 2-heat exchanger systems and the costs for the system without heat exchanger.*

Capacity (liter)	Costs for system (€)			Specific costs (€/kWh)		
	No heat exchanger	1 heat exchanger	2 heat exchangers	No heat exchanger	1 heat exchanger	2 heat exchangers
Econo (2015)						
1000	700	964	1168	11.7	16.1	19.5
2000	1383	1698	1968	11.5	14.2	16.4
3000	2637	3116	3602	14.7	17.3	20.0
4000	2945	3506	4235	12.3	14.6	17.6
5000	4120	4674	5550	13.7	15.6	18.5
Average				12.8	15.5	18.4
Interclima (2015)						
1000	1385	1565	1790	23.1	26.1	29.8
2000	2470	2920	3370	20.6	24.3	28.1
3000 [(1)]	3145	3649	4860	17.5	20.3	27.0
4000 [(1)]	3975	4613	6142	16.6	19.2	25.6
5000 [(1)]	4785	5552	7394	16.0	18.5	24.6
Average				18.7	21.7	27.0
Total average				**15.7**	**18.6**	**22.7**
Range				**11.5 - 23.1**	**14.2 - 26.1**	**16.4 - 29.8**

Appendix F EMISSION FACTOR ELECTRICITY

A CO_2 emission factor of 0.480 kg CO_2/kWh_e is assumed. Table 7.7 shows the values on which this estimation is based.

Table 7.7: Estimation CO_2 emission factor for electricity production. It shows the assumed value and the data sources on which this value is based.

Source	Value (kg CO_2/kWh_e)
(CE Delft, 2015): grijs, incl brandstofproductie, een voor Nederland respresentatieve stroommix,	0.526
(CE Delft, 2015): grijs, excl brandstofproductie, een voor Nederland respresentatieve stroommix	0.464
(CBS, 2014b)	0.44 - 0.50
(Brouwer et al., 2013): BAU scenario	0.450 – 0.500
Average / assumed value	**0.480**