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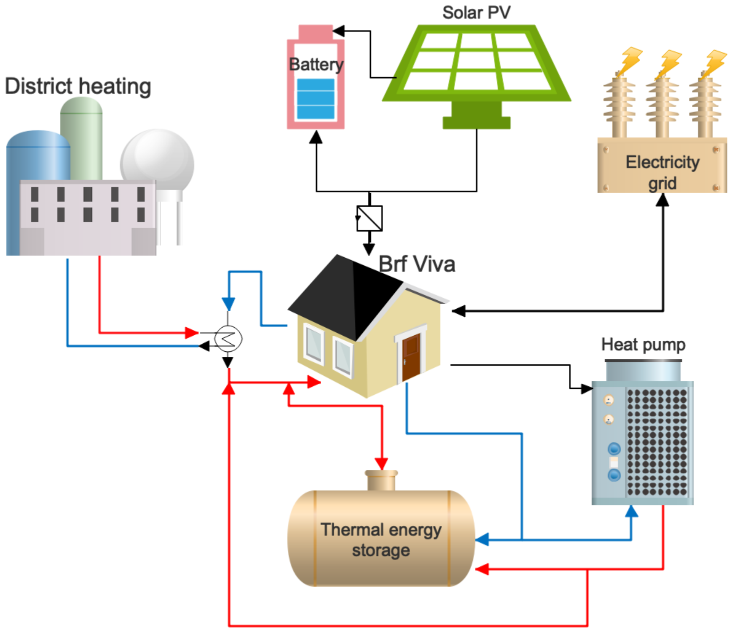

Impact of Demand Charges on Cost Optimal Energy System Management

- A case study of the Brf Viva energy system

Master's thesis in Sustainable Energy Systems

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Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
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Cover: Schematic picture over the Brf Viva energy system, with batteries, solar PVs, a thermal energy storage and heat pumps. The system is also connected to the electricity grid and the local district heating network.

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Acronyms

AC	Alternating Current
BEMS	Building Energy Management System
BES	Battery Energy Storage
COP	Coefficient of Performance
DC	Direct Current
DES	Distributes Energy Sources
DH	District Heating
DoD	Dept of Discharge
DSO	Distribution System Operator
DR	Demand Response
HP	Heat Pump
LP	Linear Programming
MILP	Mixed Integer Linear Programming
MIP	Mixed Integer Programming
PCC	Point of Common Coupling
PV	Photovoltaic
SOC	State of Charge
SPT	Step Wise Power Tariff
TES	Thermal Energy Storage
ToU	Time of Use
TSO	Transmission System Operator
VRE	Variable Renewable Energy

Input data Variables

C_{grid}	Price of purchased electricity	(SEK/kWh)
C_{sell}	Price of sold electricity	(SEK/kWh)
COP	Coefficient of performance	$\frac{(kWh_{heat})}{(kWh)}$
H_{el}	Electricity load of the housing	(kWh)
H_{heat}	Heat load of the housing	(kWh_{heat})
PV_{prod}	Electricity generation from Solar PVs	(kWh)

Calculation Variables

DC_{cost}	Demand charge cost	(SEK/kW)
DH_{buy}	Cost of purchased district heating	(SEK)
DH_{cost}	Price of district heating	(SEK/kWh_{heat})
EL_{buy}	Cost of purchased electricity	(SEK)
EL_{cost}	Total electricity cost	(SEK)
$EL_{cost_{Base}}$	Cost of purchased electricity with Base structure	(SEK)
$EL_{cost_{DC}}$	Cost of purchased electricity with demand charge structure	(SEK)
EL_{sell}	Cost of sold electricity	(SEK)
$HEAT_{cost}$	Total heat cost	(SEK)
$Peak_{Base}$	Power peak in electricity with Base structure	(kW)
$Peak_{DC}$	Power peak in electricity with demand charge structure	(kW)
$Power_{cost}$	Total power cost of electricity	(SEK)
$Power_{cost_{DC}}$	Total power cost of electricity with demand charge structure	(SEK)
$Total_{cost}$	Total energy cost	(SEK)

Parameters

bat	Battery charge/discharge efficiency	(%)
B^{-}	Electricity discharged from the batteries	(kWh)
$B_{charge_{max}}$	Maximum charge capacity of the batteries	(kW)
$B_{dis_{max}}$	Maximum discharge capacity of the batteries	(kW)
B_{eff}	Battery storage efficiency	(%)
B^{+}_{G}	Electricity charged from the grid to batteries	(kWh)
B^{+}_{PV}	Electricity charged from the solar PVs to batteries	(kWh)
B_{state}	State of charge of the batteries	(kWh)
$B_{state_{max}}$	Maximum state of charge of the batteries	(kWh)
$C_{addition}$	Additional revenue of sold electricity	(SEK/kWh)
$C_{DH_{energy}}$	Energy price of district heating	(SEK/kWh_{heat})
$C_{DH_{power}}$	Power price of district heating	(SEK/kW_{heat})
$C_{grid_{rev}}$	Grid revenue of sold electricity	(SEK/kWh)
C_{sold}	Price of sold electricity	(SEK/kWh)
C_{spot}	Spot price of electricity	(SEK/kWh)
$Current_{max}$	Current power peak of district heating, in T	(kW_{heat})
$day1_{buy_{limit}}$	First daily limit of purchased electricity	(kWh)
$day2_{buy_{limit}}$	Second daily limit of purchased electricity	(kWh)
DH_{buy}	Amount of district heating purchased	(kWh_{heat})

DH_{max}	Maximum peak of purchased district heating	(kW_{heat})
DH_{use}	Amount of district heating used in the housing	(kWh_{heat})
E	TES charge/discharge efficiency	(%)
E_{eff}	Effectiveness of peak shaving	(%)
$EL_{buy_{off-peak}}$	Electricity purchased during off-peak hours	(kWh)
$EL_{buy_{part-peak}}$	Electricity purchased during part-peak hours	(kWh)
$EL_{buy_{peak}}$	Electricity purchased during peak hours	(kWh)
$extra_1$	Electricity above the first limit, below the second limit	(kWh)
$extra_2$	Amount of electricity above the second limit	(kWh)
H	Efficiency for purchased district heating	(%)
HP_{el}	Amount of heat produced from the heat pumpss	(kWh_{heat})
HP_{use}	Amount of heat used in the housing from the heat pumps	(kWh_{heat})
$Mean_{max}$	Daily mean of district heating power	(kW_{heat}/day)
P	Continuous variable	(units)
P1	Continuous variable	(units)
P2	Continuous variable	(units)
P3	Continuous variable	(units)
P_{max}	Largest peak of bought electricity from previous solutions	(kW)
$P_{max_{off-peak}}$	Peak of purchased electricity during off-peak hours	(kW)
$P_{max_{part-peak}}$	Peak of purchased electricity during part-peak hours	(kW)
$P_{max_{peak}}$	Peak of purchased electricity during peak hours	(kW)
$P_{max_{peak1}}$	Largest peak of purchased electricity	(kW)
$P_{max_{peak2}}$	Second largest peak of purchased electricity	(kW)
$P_{max_{peak3}}$	Third largest peak of purchased electricity	(kW)
$P_{off-peak}$	Continuous variable	(units)
$P_{part-peak}$	Continuous variable	(units)
P_{peak}	Continuous variable	(units)
PV_{use}	Electricity from Solar PVs transported to the housing	(kWh)
T	Complete time period	(h/year, season, month)
t	Time period of a single model solution, $t \in T$	(h)
t_{peak}	Time period of peak hours	(h)
$TES_{charge_{max}}$	Maximum charge of the TES	(kW_{heat})
TES^{+}_{DH}	District heating used to charge the TES	(kWh_{heat})
$TES_{dis_{max}}$	Maximum discharge of the TES	(kW_{heat})
TES^{+}_{HP}	Heat from the heat pumps used to charge the TES	(kWh_{heat})

TES^{-}	Heat discharged from the TES	(kWh_{heat})
TES_{state}	State of charge of the TES	(kWh_{heat})
$\mathrm{TES}_{state_{max}}$	Maximum state of charge of the TES	(kWh_{heat})

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Abstract

An increased digitalisation and electricity usage in our society, in combination with ageing electricity grids with larger shares of variable renewable energy in the energy mix, has created new challenges for the current electricity system. To reduce congestion issues and free up flexibility for the grid, new types of electricity tariff structures could be utilised. To achieve the desired effects from such tariff structures the active control and the energy use in buildings becomes of great importance. One such building is the housing complex Brf Viva in Gothenburg. Its energy system consists of solar PVs, batteries, heat pumps and thermal energy storage and is connected to the local electricity grid and district heating network.

The aim of this project is to investigate how optimal system management for the minimised total energy cost of Brf Viva is affected by changes in electricity tariff. An additional aim is to establish recommendations for a real-time energy management system over Brf Viva, currently under development by RISE, when demand charges are implemented to the tariff structures. The project is sprung from a collaboration between the companies Göteborg Energi and RISE. The aim is fulfilled by the construction of an optimisation model over the energy system, written in Python and utilising the optimisation software CpleX. Four different types of demand charge structures are imposed on the modelled energy system.

The results show that savings in energy cost can be made if the building management system is optimised in accordance with the aim of the imposed electricity tariff. The real-time control system should optimise the system management for the tariff type in place, with a few exceptions. An estimated default value of the peak is used in the model, of which the value should be close to the largest peak obtained for the same month the previous year. When the model is optimised for short time periods in a step-wise manner within a month, e.g. 24 hours, the length of the resolved part of the 24 hours should be longer compared to the saved solution values. The importance of a trustworthy forecast increases when demand charges are implemented to the system. Depending on future district heating prices, it might become more important to focus on optimisation of the thermal energy storage, rather than the heat pumps. In conclusion, the results show that there is a lot of flexibility available to aid the large scale electricity grid from energy systems like Brf Viva if smart tariff structures on electricity are imposed to the system.

Keywords: building energy management system, demand charge, electricity tariff, power demand, flexibility

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Mimmi Engvall and Julia Renström, Gothenburg, June 2020

Contents

List of Figures

List of Tables

1 Introduction

Global urbanisation and climate change mitigation targets are at present driving society towards increased digitalisation and electrification of many sectors and appliances [2]. Simultaneously, large amounts of variable renewable energy (VRE), such as wind and solar production, are introduced to the electric power system. The increased power demand and the decreased instantaneous reliability, connected to the intermittent nature of VRE production, present large challenges for the electricity system. Examples are the risk of shortages, congestion and frequency issues that spring from uneven electricity production, as well as the limited capacity of ageing transmission lines in the electricity grid [3]. Transformation of power systems are currently taking place all over the world, resulting in the *flexibility* of the system becomes of high priority [4]. Power system flexibility includes the ability to facilitate clean, reliable, resilient and affordable energy.

The Swedish power system is no exception to this global trend of increased challenges.To properly investigate the severeness of the congestion issues, related to the increased demand in electricity, the *Energimarknadsinspektionen*, on behalf of the Swedish government, is issued to construct a status report regarding the magnitude of the capacity deficiency [5]. The report, scheduled to be finished in October 2020, should also address potential measures to mitigate these problems. One option is to increase system flexibility, and worldwide several different strategies for increased flexibility are being investigated [2]. Some of these strategies are tariff structures with demand charges, storage facilities for VRE production and different types of demand-side management. One aim with introducing demand charges is to achieve a shift of peaks in power demand and thereby smooth out the demand curve [6].

In Sweden, some Distribution System Operators (DSOs) have already established a demand charge tariff structure for all end-users, and more are predicted to follow with similar structural changes [6, 7]. A demand charge is a power-based charge which reflects the users actual capacity utilisation, and is added to the total cost of electricity. Demand charge tariffs also work as an incentive for end-users to invest in potential solutions such as smart meters, solar PVs or battery storage and a driving factor is the possibility of obtaining reduced electricity costs [8].

Positive Footprint Housing is a project that has sprung from the desire to sustainably consume energy, and simultaneously achieve increased flexibility on the grid [9]. The studied housing is a cooperation amongst several local stakeholders in Gothenburg, where Riksbyggen, Göteborgs Stad, Göteborg Energi and Chalmers University of Technology are some. The goal of the project is to develop sustainable housing for the future, and Brf Viva is the first residential housing complex realised from the project. Brf Viva works as a type of small micro-grid that contains a complex energy system, with district heating (DH), heat pumps (HP), solar PVs (PV), battery energy storage (BES) and thermal energy storage (TES). To control these features, a proper management system is required. At present, RISE is developing a real-time control system for management of the Brf Viva energy system, with the aim to achieve more efficient and cost-optimal energy flows. The development of the control system is executed on behalf of Göteborg Energi. This master thesis will contribute to the control system by investigating how implementation of demand charges to the electricity tariff will impact management of Brf Viva's energy system.

1.1 Aim

The purpose of this project is to investigate how the total cost of heat and electricity for an energy system like the one in Brf Viva can be reduced when tariffs on peaks in power demand, so-called demand charges, are included in the cost of electricity. An additional aim of this thesis is to obtain knowledge about how optimal system management for reduced energy costs, in systems containing demand charges, should be included in the real-time control system developed by RISE.

1.2 Questions at issue

The research questions that this thesis aims to answer are listed in this section.

- How can the energy system management of Brf Viva be optimised to obtain the lowest possible total energy cost?
- How is the cost optimal management of the Brf Viva energy system affected by changes in structure and demand charge level?
- How is the different energy equipment unit in the Brf Viva energy system affected by tariff structure changes?
- What happens to the cost optimal management system of Brf Viva if perfect foresight of electricity generation and demand cannot be assumed?
- What information is most important to know about when managing the real-time control system of the Brf Viva energy system, and how is this affected by implementation of demand charges on the electricity tariff?

1.3 Limitations

The project will be limited to only consider the currently existing energy system in the housing complex Brf Viva. The sizes and capacities of the installed equipment are therefore already set, and no investment costs will be considered.

The energy demand that will be accounted for is that of the building as a whole. Thereby, the ability to utilise single loads, like the indoor temperature, household appliances, electric vehicle charging or discharging, are excluded as management tools for the energy system.

2
Background

Information about how the Swedish electricity system works and the current challenges that it is facing will be presented in this chapter, as well as how these challenges are pushing for transition of the system. What this transition will entail and how this will affect the future of Swedish electricity consumption is also presented here. This is followed by a section describing the energy system within Brf Viva. Finally, a segment about linear programming is presented.

2.1 The Swedish electricity system and its challenges

At present, the electricity market of Sweden is dependent on a Nordic collaboration, where the price of electricity, called *spot price*, is set on a market place called Nord Pool [10]. The prices set by Nord Pool affect the prices that the electricity supplier, who distributes the electricity to costumers, will set on their products. In Sweden, the spot price is determined by the production facility which is on the margin for each hour of the next coming day [11]. The electricity price that reaches the consumers mainly consists of three parts; the amount of electricity consumed, grid fees and taxes [12]. The grid fee is determined by the location at which the electricity is to be used and paid to the local network operator [13]. Extra charges such as surcharge and green certificates paid to the retailer are usually paid to the local network operator. Historically, the grid fee has consisted of two parts, one set, and one variable. The set part is determined by the size of the fuse installed in the building, which is limiting the power output capacity of electricity. The cost of the other part depends on the amount of electric energy that the consumer uses. The consumers' ability to affect their electricity cost is rather limited with this system, since a large share of the costs are fixed or relatively fixed.

The Swedish electricity grid was last extended in the seventies, and the consequences of its ageing process are becoming more and more evident [14, 15]. The combination of the ageing electricity grid and an increasing population with a more electrified society, has enlarged capacity deficiency problems at many locations in Sweden. The limited capacity in the grid have already affected the society and grid owners have had to decline producers from starting new facilities or expand existing ones. The company Pöyry, on behalf of Energiföretagen Sverige, has issued a report of the utilisation regarding the capacity issues of the electricity grid [16]. The focus of the report is to establish potential actions to mitigate occurring capacity deficiencies and to highlight the losses in socioeconomic benefits. In 2018, the yearly losses due to grid limitations corresponded to a value of 80 billion SEK and are predicted to reach a value of 150 billion SEK by the year 2030. Thus, the need to mitigate the limitations of the electricity grid is of large economic interest. The most obvious and, in the long-term, the uttermost beneficial solution, is to expand the electricity grid. However, due to time-consuming concession processes the grid, capacity is predicted to be exceeded before the expansion is completed [16]. At present, suggestions of short-term solutions to postpone the capacity issues are under development.

2.2 The future of the Swedish electricity grid

The limitations of the Swedish electricity grid are affecting the society on a holistic level and to find solutions has become increasingly important. The Energimarknadsinspektionen has issued a status report containing potential actions for the capacity deficiencies, which is currently under progress [5]. Several reports propose potential actions to restrict occurring capacity deficiency. One area of focus is increased flexibility of the electricity grid, which at present is limited due to the restricted possibility for stakeholders to meet and trade with flexibility services [14]. Increased flexibility could be realised by changing the electricity price structure for end-consumers to a demand charge based structure [16]. When applying demand charges, the power-based part of the electricity price will no longer be based on the installed capacity of the building, that is the size of the fuse[8, 17]. Instead, it will reflect the actual capacity utilisation.

2.2.1 Demand charge structures

The Energimarknadsinspektionen is currently running a project aiming to come up with regulations regarding how distributors should structure their electricity tariffs in the future. The aim is to ensure efficient utilisation of the electricity grid [18]. Implementation of demand charges for all end-consumers as a part of the electricity tariffs is proposed as a strategy to mitigate current, and future, problems with transmission capacity shortages in the electricity system [2]. The mitigation should be realised by making the price of electricity more related to the actual consumption patterns of the electricity user, as well as the instantaneous capacity situation of the electricity grid, through a demand charge. The effect of such an implementation is strongly dependent on the structure and dimension of the demand charge, as well as local factors like the state of the distribution grid and type of consumer [17]. A demand charge is dependent on the measured capacity used by the consumer, rather than the installed or subscribed potential capacity usage. The charge can be determined in two ways. It can either depend on the peak capacity used by the consumer during a specific period of time, for example a month. The peak demand pricing structure could also be used for a mean of about two to five peaks in power consumption. The second option is to let the cost dependent on the peak of measured capacity used by the consumer during the peak load hour of the system, or a few peak load reference hours. These reference hours could also be seasonally dependent instead of vary with the hours of the day.

A more dynamic tariff structure is a so-called Time of Use (ToU) tariff. ToU is an energy based tariff where the customer pays different tariffs for electricity usage during different hours of the day, that is at off- and on-peak load hours. An extended version of a ToU tariff is presented in the journal *Multiobjective Model of Time-of-Use and Stepwise Power Tariff for Residential Consumers in Regulated Power Markets* by Zhou et al. [19]. The extended tariff structure introduced by Zhou et al. contains a step wise power (SPT) component, in addition to the ToU part. The idea with a STP tariff is to minimise the total amount of electricity purchased during a specified time period, by establishing levels for amount of electricity allowed to purchase. If the set level is exceeded, the price of electricity in SEK/kWh$_{el}$ is increased for the amount bought above the set level. In the work by Zhou et al., the ToU structure and the SPT structure are combined into one tariff with the purpose to improve the correlation of the current situations and challenges on the electric power grid with the instantaneous cost of electricity.

All types of demand charge strategies can act as economic incentive for implementation of so-called demand response (DR) strategies, like load shifting, for end-consumers [8]. Several studies show evidence of DR resulting in reduced peak loads, effectively increasing the flexibility of the grid [8, 20, 21, 22]. There is however no guarantee that implementation of demand charges will raise the awareness regarding end-costumer electricity consumption and generate changes in consumption patterns [10]. Consumers often find it difficult to keep the amount of electricity used and the power demand apart [23]. The largest impact of their adjusted electricity utilisation is therefore more likely the decreased use of electricity volume, rather than shaved power demand peaks. In addition, the actual electricity consumption constitutes a small share of the total electricity bill due to taxes and fixed charges [12, 23]. The end-user's potential savings thereby become a small part of the total electricity cost. Sufficient marketing strategies for implementation of new tariff structures, as well as an increased amount of automated DSR technologies, are therefore vital to achieve a significant increase in flexibility towards the grid [17, 19, 24]. Increased flexibility is important for the future of the entire electricity grid, since it could generate large benefits of avoided acute need for grid expansion, which would otherwise require large investment costs [8, 22].

Several Swedish electricity suppliers already have some type of power based tariff as part of their electricity bill. These fees commonly apply to high voltage customers like individual companies, or costumers in the lower voltage level with a main fuse size larger than 63A [25]. To deal with the impending capacity issues and to free up flexibility, supplier companies like Vattenfall, Nacka Energi and Karlshamn Energi with several, plan to change their tariff structures in the upcoming years by implementing demand charges for all end-consumers [6, 7, 17]. There has been a recent change in the electricity law (4 kap. 4 a § ellagen) with the purpose to facilitate the Swedish DSOs ability to test new structures of electricity tariffs that may increase the demand side flexibility in their region [22]. The new addition to the law is active from the first of January 2019, and makes it possible for the DSOs to conduct pilot projects on a smaller number of costumers for a three year period. Different demand charge structures work better in some regions and with some type of customers [17]. As more trials are conducted and they become increasingly common on the electricity market for low voltage customers, the more evident it will be whether or not it is an effective structure for mitigation of the upcoming capacity issues on the electricity grid.

2.3 Micro-grids

For demand charges to achieve the desired effect on the end-consumers' energy and power consumption, the consumers must be able to respond to changes in electricity price. The changes could be achieved by shifting some of the loads to lower peak load hours. However, the flexibility gain from peak shifting is rather limited [8]. At present, there are many potential actions that could be utilised to achieve a more efficient energy usage and assist societal energy distribution networks by contributing with increased flexibility to the electricity grid. An example of a system with such qualities and promising prospects are micro-grids.

A micro-grid comprises a low-voltage distribution system with storage devices, flexible loads and distributed energy sources (DES), like solar PVs and battery energy storage systems (BESS) [26]. Several different DES are interconnected and combined with a centralised control that correlates the DES and also assures power quality, reliance and protection. Installations of DES into micro-grids are expected to increase significantly in the coming decades [4]. A micro-grid is connected to the electricity grid in a single point, via the point of common coupling (PCC). Through the PCC, the micro-grid should be able to operate in either grid-connected or islanded mode [27].

The utilisation of micro-grids have several functions, some being to work as a network service provider and as a load controller [26]. The micro-grids can thereby act as facilitators for economic, technical and environmental aims by promoting higher shares of VREs and achieving a more efficient energy usage. Other important attributions are their ability to provide ancillary services, mainly regarding voltage support and active services, to the grid. Risks of shortages can also be reduced since, in case of emergencies or natural disasters, the micro-grid can be used in islanded mode and still provide energy to the system.

2.4 Smart energy system management in individual buildings

In 2019, 20% of the world total energy consumption was allocated to the building sector, including commercial as well as residential buildings [28]. The fact that buildings account for such a large part of the world's total energy consumption indicates that there is a lot of potential for energy saving in such commodities. A large share of the energy consumption could be reduced by achieving more efficient energy usage during the life time of the buildings. An idea of how to accomplish an increased energy efficiency in buildings, and at the same time reduce their dependence on local distribution grids, is to construct buildings that can act as individual micro-grids in themselves [29].

To manage a small scale micro-grid can be difficult due to the complexity of the system [27]. Many DES and loads should be correlated and able to run without fault in grid-connected as well as islanded mode. Therefore, micro-grids require a proper building energy management system (BEMS) [29]. The energy system in such a building will be both time-dependant and capacity-constrained, due to storage and production limitations. A smart BEMS requires certain technical components to coordinate the DES with the building loads, the external distribution grid and the weather, in real-time. Such components could be different types of agents that operate as artificial intelligence programs, who collect information and act upon it in accordance with their assigned task.

For a BEMS to work properly as a smart, small scale micro-grid, the operating agents have to constantly communicate and cooperate. The utilisation of the DES should be as efficient as possible, while a security of energy supply, as well as frequency and voltage control, has to be maintained. Dynamic factors affecting the utilisation of the DES are the residents' behaviour, varying cost of electricity and heat, and the production of renewable energy [30]. The ability to predict these factors is key to achieve efficient energy utilisation. Renewable energy generation in micro-grids are commonly produced from weather dependent technologies as solar PVs or wind turbines, indicating that the accuracy of the weather forecast affects the efficiency and reliability of the micro-grid [30, 31]. There is also a risk that collection of data to predict the energy usage patterns of residents in a building can be experienced as offensive [31].

2.5 Energy system of Brf Viva

Brf Viva is a housing complex with several types of DES installed for both electricity and heat production and storage. These DES are connected to the loads of the building, and to each other in some extent, and together they act as a small scale micro-grid. However, the energy system of Brf Viva does not have the capacity to sustain the building in islanded mode for a significant amount of time. A smart BEMS is vital to properly manage the installed DES of the building in an as efficient way as possible. Such a management control system is in progress today, and this thesis aims to contribute to that system. To enable the control system, a proper display of the Brf Viva energy system, with the connections and functions of the different equipment units, are displayed in Figure 2.1.

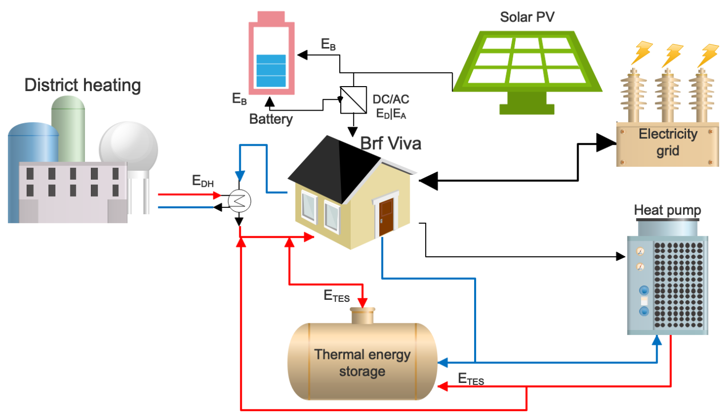


Figure 2.1: Flow chart of the energy system, heat and electricity, in Brf Viva. The black connections represents the routes of electricity. The red connections represents heated water and the blue connections represents water in need of heating. A two way arrow represents transportation of water or electricity in both directions. The letter E marks losses in the system, either due to energy equipment properties or to required AC/DC redirection of the electrical current.

The energy system of Brf Viva is connected to both the electrical grid and to the local district heating network, as can be seen in Figure 2.1. The energy equipment units are solar panels, Li-ion batteries, heat pumps and thermal energy storage tanks which are used to store hot water. The heat pumps connect the electrical and the heating system, and together these units make up the energy system of the housing.

2.5.1 Electrical system

The Brf Viva building works as a connection point for the electricity route, as displayed in Figure 2.1. The housing is connected to the grid via the PCC, the solar photovoltics (PVs) are located on the roof, and the batteries (BES) are located in the basement. The housing also contains heat pumps (HPs) which uses electricity to produce heat. The housing can use electricity from three different sources; from the grid, directly produced from the solar PVs or discharged from the batteries. Both the electricity produced from the solar PVs and the electricity discharged from the batteries can be exported to the grid, via the housing. The batteries can be charged with electricity produced from the solar PVs, as well as electricity from the grid. Charge of the batteries from solar power is more energy beneficial than grid charging, due to that the batteries and the PVs work with direct current (DC) while the housing loads and the electrical grid uses alternating current (AC). AC/DC conversion is therefore required when electricity is transported between the housing and the batteries, which causes additional energy losses.

2.5.2 Heat system

To fulfil the space heating and hot water demand, the Brf Viva housing uses district heating (DH) from the local network or heat produced from the installed heat pumps. In this project, the hot water demand is not considered due to that these demands have separate heating systems. The heat pumps connect the housing's electrical system with the space heating system since electricity is used to produce heat. The hot water produced is either fed to the house for space heating, or stored in one of the thermal energy storage tanks (TES) for later usage.

2.6 Linear programming

Linear programming (LP) is a method that can be used to find the optimal solution to a mathematical problem that is made up of linearly related relationships [32]. This method consists of the construction of a so called *objective function* that holds the final aim of the problem. The aim could be to either minimise or maximise the objective function.

In an optimisation problem, the objective function is subject to linear constraints that make up the boundaries of the problem. These constraints could be either equality or inequality constraints and are set to limit the function design variables. A design variable is a model property that can take on any value, within the boundaries of the model and variable constraints. If all design variables utilised in an optimisation problem are real or continuous values in some time frame, the problem is said to be continuous. There are a lot of solver software available commercially today that can utilise this method. Examples of software are CpleX, Gurobi, Xpress and MatLab.

3
Method

To answer the research questions presented in section 1.2, a linear optimisation model over the Brf Viva energy system is constructed. The goal is to generate results of how the energy system should be managed to obtain the cheapest possible total energy cost for the housing, dependent on price structure of bought electricity. In this chapter, the methodology utilised to construct the optimisation model is presented. Thereafter, a description of the problem setup for each case constructed to examine how the modelled energy system is affected by changes in electricity tariff structure is provided. A section about required input data for the different cases thereby follows. Finally, some key system management performance indicators that are important for evaluation of the model optimisation are presented.

3.1 Constructing the model

The model created to illustrate the energy system of Brf Viva is constructed using the programming language Python, together with the optimisation software package CpleX from IBM, version 12.10 with an academic licence. The overarching problem to be solved is to minimise the cost of energy, electricity and heat, of the housing for a specific time period *t*. The objective function is displayed in Equation 3.1.

$$\mathrm{Total}_{cost} = \mathrm{EL}_{cost} + \mathrm{HEAT}_{cost} + \mathrm{Power}_{cost} \tag{3.1}$$

Where Total_{cost} is the total energy cost for Brf Viva and EL_{cost} is the total cost of electricity bought from the electric grid. HEAT_{cost} is the total cost of district heating bought from the local district heating network. Power_{cost} is the cost of the amount of bought electricity that triggers the demand charge. All equation variables are in the unit SEK.

The electricity and heat costs in Equation 3.1 are calculated with Equations 3.2 and 3.3.

$$\mathrm{EL}_{cost} = \sum_{i=1}^{t} [\mathrm{EL}_{buy}(i) \cdot \mathrm{C}_{grid}(i) - \mathrm{EL}_{sell}(i) \cdot \mathrm{C}_{sell}(i)] \quad \mathrm{i} \in \mathrm{t} \tag{3.2}$$

$$\mathrm{HEAT}_{cost} = \sum_{i=1}^{t} [\mathrm{DH}_{buy}(i) \cdot \mathrm{DH}_{cost}(i)] + \mathrm{DH}_{power} \cdot \mathrm{DH}_{power_{cost}} \quad \mathrm{i} \in \mathrm{t} \tag{3.3}$$

Where EL_{buy} and EL_{sell} is the amount of electricity bought and sold by the Brf Viva energy system in kWh_{el}, and C_{grid} and C_{sell} are the prices for buying and selling electricity in $\mathrm{SEK/kWh}_{el}$. Similarly, DH_{buy} is the amount of energy bought as district heating from the local network in kWh_{heat} and DH_{cost} is the price in $\mathrm{SEK/kWh}_{heat}$. DH_{power} is a power component added onto the cost of district heating for the peak heat demand during a year in kW_{heat}, and $\mathrm{DH}_{power_{cost}}$ is the price for this peak in $\mathrm{SEK/kW}_{heat}$. The notation *i* represents a specific hour within the model objective solution time period t.

An example of how the cost for the demand charge in the objective function from Equation 3.1 can be calculated is displayed in Equation 3.4. However the exact formulation of the equation depends on the demand charge type.

$$\mathrm{Power}_{cost} = \max_{i \in t} \mathrm{EL}_{buy}(i) \cdot \mathrm{DC}_{cost} \quad \mathrm{i} \in \mathrm{t} \tag{3.4}$$

Where the maximum expression indicates the largest peak of bought electricity within the time period t, in $\mathrm{kWh}_{el}/\mathrm{h}$. DC_{cost} is the cost of the demand charge for the largest obtained peak of bought electricity, in SEK/kW.

To obtain the required input arguments for the objective function in Equation 3.1, energy balances describing the physical energy system of the Brf Viva are constructed. The energy balances are written into mathematical expressions, presented in the Appendix A.1. The energy balances constructed are formulated into mathematical constraints, subject to the objective function of the optimisation model from Equation 3.1. Equation 3.5 is an example of one such mathematical constraint. It describes the state of charge of the batteries, and should be accurate for each hour of the model solution time period t.

$$B_{eff} \cdot \mathrm{B}_{state}(i-1) + bat \cdot \mathrm{B}^{+}_{PV}(i) + bat \cdot \mathrm{B}^{+}_{G}(i) - \frac{\mathrm{B}^{-}(i)}{bat} = \mathrm{B}_{state}(i) \quad \mathrm{i} \in \mathrm{t} \tag{3.5}$$

Where B_{eff} is the storage efficiency, referring to the losses of energy obtained when electricity is stored in the battery. B_{state} is the state of charge of the batteries at a specified hour within time period t and *bat* is the charge and discharge efficiency of the batteries. B^{+}_{PV} and B^{+}_{G} are the amount of charged electricity from the solar PVs and the grid respectively. B^{-} is the amount of electricity discharged from the batteries. All constraints used in the final optimisation model constructed in Python are presented in Section A.2 in the appendix.

3.2 Model setup for the investigated cases

The constructed basic optimisation model from Section 3.1 is tested with a setup of cases that vary with type of demand charge. The aim of testing a variety of cases is to investigate how optimal energy system management of Brf Viva is affected by change in structure and dimension of the imposed tariff. The basic model can be subjected to any type of demand charge, by varying the power cost component of the objective function, displayed in Equation 3.4, for each case. Each case is solved with the optimisation model in a step wise manner, more closely described in Section 3.3. These optimisations of the model are solved for a time period t, which constitutes a part of a full investigated time period, T. For example, if T is the number of hours in a month, then t can be 24 hours within that month. The results from each time period t are added together to obtain the final result of the optimised energy management system for the full time period T.

An overview of all the cases tested in this thesis is showed in Table 3.1. Five types of tariff structures are investigated, were two of the tariff structures have three dimensions of the demand charge, which adds up to a total of nine cases. The number in the case name refers to the dimension of the demand charge, if the structure has several ones. The five types of tariff structures are all further described in the following sections.

Table 3.1: Cases tested with different demand charges

Case name	**Demand charge structure**
Base Case	None
One Peak 35	Peak load per month
One Peak 55	Peak load per month
One Peak 85	Peak load per month
Three Peaks 35	Mean of top three peak loads per month
Three Peaks 55	Mean of top three peak loads per month
Three Peaks 85	Mean of top three peak loads per month
Seasonal	Mean of top three peak loads each quarter
TOU + SPT	Dynamic structure with limit of energy & power

3.2.1 Base Case

In Base case, the tariff on purchased electricity does not include a demand charge. The model thereby only has to consider the amount of electricity bought in kWh_{el} when attempting to minimise the electricity part of the objective function in Equation 3.1. Thus, the Power_{cost} in the objective function is equal to zero for the Base Case.

3.2.2 One Peak

The first cases tested with a demand charge added to the objective function are the One Peak cases. Here, the largest peak of bought electricity for every month of the year sets the demand charge. The length of each month constitutes the full time period T. To find the size of the largest peak of bought electricity, a new continuous variable called P is introduced to the optimisation model. P has a lower boundary of 1 and only takes on one value for each time period t. P is introduced to the model through a new constraint, which is displayed in Equation 3.6.

$$\mathrm{EL}_{buy}(\mathrm{i}) \leq \mathrm{P} \cdot \mathrm{P}_{max} \qquad \mathrm{i} \in \mathrm{t} \tag{3.6}$$

$$1 \leq \mathrm{P}$$

Were P_{max} is a model input value for each solution of a time period t, that represents the largest peak of purchased electricity obtained from previous time periods t within T. For each hour of every solution of the objective function for time period t, the amount of electricity bought has to be less than the maximum peak obtained from previous solutions, P_{max}, multiplied with a factor set by the variable P. If the model finds it possible and profitable to buy electricity below the amount set by P_{max}, P remains equal to 1. However, if the energy demand makes it impossible for the model to stay below the amount set by P_{max}, P takes on a larger value. The value of P_{max} is fixed during the time period t, but updated as the largest value of purchased electricity obtained this far for the next optimisation of a new time period t within T.

When solving the model, the max[EL_{buy}] in Equation 3.4 is replaced by the multiplication of P_{max} and the obtained value of the variable P. The expression is displayed in Equation 3.2.2.

$$Power_{cost} = P \cdot P_{max} \tag{3.7}$$

Through the alteration of Equation 3.4, by replacing the maximum expression, the model remains linear. A linear model demands less computational effort and therefore it is desirable to keep the model linear. When all smaller time periods t are solved, the final value of the largest peak of bought electricity during all time periods t is used to calculate the demand charge for the month.

3.2.3 Three Peaks

In the Three Peaks cases, a mean of the three largest peaks of purchased electricity is used to calculate the demand charge for each month. The idea with the three peak mean is that the incentive to reduce peak demand of electricity should remain for the duration of the time period T, even if single large peak loads should occur.

Obtaining the sizes of the three largest peaks of bought electricity within the model is more complicated than finding the size of the largest peak, as in the One Peak cases. There is no maximum expression that can be utilised, as in Equation 3.4, to retrieve more than one maximum value. Generating successful results for the Three Peaks cases, without compromising the linear nature of the model, therefore requires a slightly different approach.

The approach utilised to induce a model behaviour with peak shaving abilities for the Three Peaks cases used in this project, is based on a version of the model constraint applied in Equation 3.6 for the One Peak cases. The idea is that the amount of electricity purchased for each hour in time period t should remain the same, or less than, the size of the third largest peak of purchased electricity obtained during previous solutions. If this is impossible, due to an increase in demand, the amount of electricity purchased each hour should at least be kept below the level of the second largest peak obtained previously. Exceeding the second level causes an increase in both the second and the third largest peak, resulting in a higher demand charge than if only the third largest peak was increased.

A new constraint is introduced to the model to relate the approach for keeping the amount of electricity purchased each hour within time period t below the levels of the previously purchased peaks. The constraint is displayed in Equation 3.8, where three new continuous variables called P1, P2 and P3 are also provided.

$$\mathrm{EL}_{buy}(\mathrm{i}) \leq [\mathrm{P1}(i) + \mathrm{P2} + \mathrm{P3}] \cdot \mathrm{P}_{max_{peak3}} \qquad \mathrm{i} \in \mathrm{t} \tag{3.8}$$

$$0 \leq \mathrm{P1(i)} \quad \mathrm{i} \in \mathrm{t}, \quad 0 \leq \mathrm{P2} \leq \frac{\mathrm{P}_{max_{peak1}} - \mathrm{P}_{max_{peak2}}}{\mathrm{P}_{max_{peak3}}}, \quad 1 \leq \mathrm{P3} \leq \frac{\mathrm{P}_{max_{peak2}}}{\mathrm{P}_{max_{peak3}}}$$

Where $P_{max_{peak3}}$ is the third largest peak, $P_{max_{peak2}}$ is the second largest peak and $P_{max_{peak1}}$ is the largest peak of bought electricity obtained in previous solutions of time period t, within the entire time period T. The constraint in Equation 3.8 is limited by the size of the three largest peaks obtained previously. The three P variables in Equation 3.8, through their boundary values, works in a step wise manner by weighting the energy costs for each time period t in the model so that it is more expensive to increase the value of P1 than P2, and P2 than P3. The P3 variable will always obtains its upper boundary value before P2 is utilised and P3 can only take on one value for each time periods t. If P3's upper boundary, displayed in Equation 3.8, is obtained but P2 and P1 remain equal to zero, the peak of purchased electricity of time period t is limited by the value of the second largest peak obtained previously, $P_{max_{peak2}}$. P2 also take on one value per t period, and if both P2 and P3 becomes equal to their respective upper boundary value, the amount of purchased electricity is limited by the value of $P_{max_{peak1}}$.

P1 can take on any positive value for every hour of the time period t, but only becomes larger than zero if both P2 and P3 have obtained their upper boundaries. The idea of having P1 vary between hours is that the amount of electricity should be reduced as much as for possible every hour, so that the model still has the possibility of obtaining just one or two large peaks throughout the time period t. How the cost calculation is weighted as Power_{cost} in Equation 3.4, with the purpose to obtain a peak shaving behaviour, is displayed in Section A.2 in the appendix.

The final demand charge cost obtained for time period T, when all optimisation rounds of time periods t are completed, is equal to the mean of the three largest peaks of purchased electricity multiplied with the demand charge price.

3.2.4 Season

The demand charge of electricity varies seasonally in the Season case. Here, the months of the year are divided into quarters. During each of the resulting three month intervals, a mean of the three largest peaks of purchased electricity generates the demand charge. This three peak mean price structure is the same as in the Three Peaks cases but with a changed time period T. The time periods, T, are January to March, April to June, July to September and October to December. The demand charge cost is higher for winter and fall quarters and lower during spring and summer quarters. As the tariff structure is based on a three peak mean of bought electricity, but with an average for each quarter, the same constraints are used as for the Three Peaks structures, and these can be seen in Section A.2 in appendix.

3.2.5 TOU + SPT

The final demand charge structure presented in Table 3.1 is called TOU + SPT. This demand charge is billed on a monthly basis, just as the One and Three Peaks cases, but contains two charges instead of one. The first component is the TOU, which is an hourly based demand charge that varies with the hours of the day, similar to a normal ToU tariff. However, the hourly dependent component used in the constructed TOU + SPT case depends on the peaks of purchased electricity, that is the power usage, rather than the amount of energy bought. The division of off-peak, part-peak and peak hours of the day used in the TOU + SPT case are presented in Table 3.2.

Table 3.2: Hours of a day divided into off-peak, part-peak and peak hours

TOU + SPT																								
Hour	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Table 3.2 displays the off-peak, part-peak and peak hours with the colours green, yellow and red respectively for the tariff structure TOU + SPT. The highest generated cost, obtained when multiplying the largest peak of purchased electricity in each peak category with corresponding price in SEK/kW, is used as that month's demand charge. Thereby, the highest peak of bought electricity might not generate the price of the demand charge, if it occurs on an off-peak hour. This charge is added as Power_{cost} in Equation 3.1.

To describe the TOU part of the TOU + SPT case in the optimisation model, additional constraints are required. Three versions of the constraint in Equation 3.6 are used, but with a new P variable for each peak category, $\text{P}_{off-peak}$, $\text{P}_{part-peak}$ and P_{peak}. The ability to purchase electricity during time period t is limited by the highest peak obtained previously for each peak category. An example of the constraint for peak hours is displayed in Equation 3.9.

$$\text{EL}_{buy_{peak}}(\text{i}) \leq \text{P}_{peak} \cdot \text{P}_{max_{peak}} \qquad \text{i} \in \text{t}_{peak} \in \text{t} \tag{3.9}$$

Where $\text{EL}_{buy_{peak}}$ is the amount of electricity bought during each peak hour, and $\text{P}_{max_{peak}}$ is the largest peak of bought electricity obtained this far during peak hours. Each P variable have an individual time period within each time period t. For the constraints off-peak and part-peak hours that correspond to the one for peak hours in Equation 3.9, the time period t_{peak} is replaced accordingly. Together the three time periods cover all hours of the time period t, and the summation of all time periods, t, makes up the entire time period T.

The second component of the TOU + SPT demand charge structure is a stepwise power tariff (SPT). The SPT charge is included in the optimisation model by dividing the amount of bought electricity into three price levels. No additional charge is added to the cost of electricity if the total load of purchased electricity is kept at, or below, the first level. Otherwise, an extra charge is added onto the amount of electricity purchased above the level, and the magnitude of the charge increases for each level. The additional charges obtained from the TOU + SPT components are added to the final cost of energy when all short time periods t are solved. The specific constraints implemented to the model for this tariff structure can be seen in Section A.2 in appendix.

3.3 Model solution window

In the real-time system control of the Brf Viva energy management system, perfect foresight of input data cannot be assumed. Forecasts of weather and energy loads can be wrong, and the spot price of electricity is only available 24 hours prior to the time of utilisation [33, 34]. Therefore, the model is provided with much smaller windows of input information compared to the full investigated time period T. Errors are also applied to the input data in order to see how the modelled energy system reacts to an incorrect forecast. These alterations to the input data are described in detail this section.

3.3.1 Rolling horizon

The optimisation model over the Brf Viva energy system is solved in two ways for all cases, with a perfect foresight time-frame and a rolling horizon approach. When solving a case using perfect foresight, the model has all the necessary input data for the entire investigated time period, T, provided from the start of the optimisation. Thereby, only one solution of the objective function in Equation 3.1 is generated.

In the rolling horizon approach, the model is initially provided with data for a given time window t, significantly smaller than the entire investigated time period T. The model is thereafter continuously provided with input data, all with the same size t. Thereby, the model has to solve the objective function for each time period t until the sum of these time periods add up to the complete investigated time period T. Thus, each time period t is solved optimally as a single entity, compared to perfect foresight where the complete time period T is solved optimally.

The time period t in the rolling horizon is varied in three different versions. In the first version, the model is optimised for a period t of 24 hours, in the second for 36 hours, and 48 hours in the third. In each optimisation, the solution data for the twelve first hours of the time period is saved. The remaining hours, the simulated forecast, are rerun through the model for the next time period t, together with twelve new hours. The state of charge of the batteries and the thermal energy storage from the previous solution is saved and used as a starting point for the next solution. For the Base, TOU + SPT and One and Three Peaks cases, the time period T is one month. For Season, the time period T is equal to three consecutive months.

3.3.2 Forecast error

All input data to the optimisation model utilised in this thesis are based on historic data. This data consists of heat and electricity loads, electricity generation from solar PVs, electricity prices, district heating price and COP of the heat pumps. Consequently, the forecast in the rolling horizon is always correct. To further mimic more lifelike situations, disturbance is added onto the historic data in simulations for all cases. Correct data is used for the first twelve hours of the time period t. For the remaining hours of the time period t, a randomised factor is multiplied with the original input data. The error is tested for different degrees of uncertainty which are errors up to 5%, 20% and 50% larger or smaller than the correct input data. For the next time period t, the altered data is restored to the correct values, which causes disturbance to the planned management of the previously incorrect twelve hours.

3.4 Input data

The data utilised for each case presented in Section 3.2, as well as any required modifications of the data, is explained in detail in this section. Information and data about specific loads and costs of both electricity and district heating has been provided from the companies *RISE* and *Göteborg Energi*.

3.4.1 Collected data of loads and PV production from Brf Viva

Data from Brf Viva has been collected since the housing was built in 2018. However, since the apartments were inhabited successively, the earliest data is not representative and therefore discarded. The collected data from Brf Viva that is utilised in this project covers from the first of June 2019 to the last of March 2020. From this point on, this time period is described as a full year. Results obtained for different cases on a yearly basis is therefore only accurate for a ten month period, not a complete year.

Some minor modifications of the data collected from Brf Viva were necessary. These alterations, together with input data of the heat and electricity loads and PV generation, are presented in Appendix A.3.

3.4.2 Brf Viva energy equipment

The sizes, storage efficiencies and capacities for charge and discharge of the batteries and the thermal energy storage are displayed in Table 3.3.

Table 3.3: Properties of the batteries and thermal energy storage within Brf Viva

Unit	Energy storage capacity (kWh)	Charge/discharge capacity (kW)	C-factor	Charge/discharge efficiency (%)	Storage efficiency (%)
Batteries	159.6	84.0	0.53	99.0	99.95
Thermal energy storage	160	160.0	1.00	85.0	99.9

As evident from the C- factor in Table 3.3, the batteries can be completely charged or discharged within two hours, while the TES can do the same in one hour. The presented size of the batteries, also utilised in the optimisation model, is equal to an interval of 20-80% of the actual battery size. Other limitations, like the installed amount of solar PVs and heat pumps, are presented in Appendix A.4.

3.4.3 Purchased electricity price

The spot price of electricity is only one of several factors affecting the electricity cost paid by consumers in Sweden. The different components of the electricity price are displayed in Table 3.4.

Table 3.4: The components of the electricity price

Component	öre/kWh
Spot price	32.2
Grid fee	7
Surcharge	6.9
Green certificates	3
Energy tax	35.3
Value-added tax	25%
Total	**105.5**

The costs presented in Table 3.4 are based on information from both Energiföretagen Sverige and Göteborg Energi [35, 36]. The spot price presented in Table 3.4 is an average of the tested year. In the optimisations for each case, the actual hourly spot price, collected from NordPool, is used [33]. The component in Table 3.4 that can be altered by the electricity supplier companies is the surcharge. If the electricity supplier is the same as the grid owner, the grid fee can also be changed. To avoid increasing the total cost of electricity for the consumers when a demand charge is implemented, the changeable portion of the energy part of the electricity price would have to be reduced. In the cases tested with demand charges in this thesis, the cost of electricity, presented in Table 3.4, is therefore modified before implementation in the model.

The demand charge and the average cost of electricity for each of the tariff structures in the tested cases are presented in Table 3.5. The average cost of electricity, presented in öre/kWh in the table, is an alteration of the electricity price presented in Table 3.4. When modifying the average electricity cost, the existing tariffs in the Nordic countries have been used as inspiration [37, 38, 39, 40].

Table 3.5: Energy and power part of the electricity costs for all tariff structures tested

Tariff structure	Demand charge SEK/kW	Avg cost (öre/kWh)
Base	0	105.5
One Peak	35, 55, 85	99.5, 95.6, 90.6
Three Peaks	35, 55, 85	99.5, 95.6, 90.6
Season (spring/summer, fall/winter)	25, 85	100.6, 90.6
TOU + SPT (off-peak, part-peak, peak)	20, 50, 80	98.1

Displayed in Table 3.5 are the electricity costs of the tested tariff structures. The idea is to reduce the energy part of the electricity price just enough to shift some of the total cost towards the implemented power component of the electricity cost. The dimension of the demand charge determines the reduction in the energy part of the electricity price, and a larger reduction is performed for a higher demand charge dimension.

As can be seen from Table 3.5, the demand charge for One Peak and Three Peaks structures have three dimensions. In the cases presented in Table 3.1, the number in the case's name corresponds to the demand charge dimension, either 35, 55 or 85 SEK/kW. In Season, the lower demand charge in Table 3.5 is used for spring and summer months and the higher cost is used for fall and winter months. For the TOU + SPT case, the off-peak hours have the lowest demand charge and the peak hours have the highest. The average cost of electricity is based on the mean of the demand charge costs for three different peak hours.

Apart from the power tariff corresponding to a peak during off-peak, part-peak or peak hours, the TOU + SPT case also contains an extra charge that depends on the total amount of electricity bought. The additional energy charge is presented in Table 3.6.

Table 3.6: Limits on bought electricity for a SPT with corresponding charges

Limit no.	Load (kWh)	Cost increase (%)	Cost (SEK/kWh)
1	0 - 40 000	0	98.1
2	40 000 - 80 000	20	117.7
3	> 80 000	40	137.3

The energy cost in Table 3.6 is a percentage of the average cost displayed in Table 3.5. The cost increase varies from 0 to 40% for the three levels. The limit on the total electricity load allowed to buy before proceeding to the next price level is set on a monthly basis.

3.4.4 Sold electricity price

The price for sold electricity is often similar to the spot price, with the addition of a grid revenue. A potential extra revenue can also be received from the buyer, often the electricity supplier company, depending on the type of agreement [41]. The price for selling electricity used in the model optimisation is shown in Equation 3.10.

$$\mathrm{C}_{sold} = \mathrm{C}_{spot} + \mathrm{C}_{grid_{rev}} + \mathrm{C}_{addition} \tag{3.10}$$

Where C_{sold} is the price for sold electricity, C_{spot} is the electricity spot prise, $\mathrm{C}_{grid_{rev}}$ is the grid revenue and $\mathrm{C}_{addition}$ is the potential additional revenue from the buyer. All the components in Equation 3.10 have the unit *öre/kWh*. The grid revenue has a value of 6 öre/kWh and the addition is set to 0 öre/kWh [42].

The producer can also gain additional revenue from sold renewable electricity certificates. The revenue from these certificates depends on the market price of the certificates and the amount of electricity produced from renewable energy sources, regardless if the electricity is utilised for self-consumption or sold to the grid [43]. In the model, this source of income is therefore added onto the final total energy cost for each case. The cost of renewable electricity certificates are based on price trends from Svensk Kraftmätning [44].

3.4.5 District heating price

The cost equation used to calculate the price of bought district heating from the local network consists of an energy and a power component. For all cases tested, a price structure for projected district heating prices for the year 2026 is utilised. The price structure was provided by Göteborg Energi and is an example of a potential future price model which reflects a society with more varied loads and higher peak hours of power. The price structure is utilised to test what happens when a larger part of the heat cost is allocated to the power part of the price, rather than the energy part as for today's prices [1].

The total cost of the 2026 price model is segmented into price steps as a function of the outside temperature and the amount of heat purchased. Due to confidentiality restrictions, no specific values of the district heating price model are provided in this thesis. The temperature profile is retrieved from historic data provided by the website *Temperatur.nu* [45]. Equation 3.11 is an illustration of how the cost of district heating is calculated.

$$\mathrm{DH}_{cost} = \mathrm{C}_{DH_{energy}} \cdot X + \mathrm{C}_{DH_{power}} \cdot Y \tag{3.11}$$

Where X is the total amount of bought district heating in kWh$_{heat}$ and Y the largest peak of bought district heating in kW$_{heat}$ during a specific time period. $C_{DH_{energy}}$ is the price for the amount of purchased district heating in SEK/kWh$_{heat}$, and $C_{DH_{power}}$ is the price of the largest peak of purchased district heating in SEK/kW$_{heat}$.

Some cases are tested with both district heating price models to evaluate the impact of the potential future price structure on the modelled energy system of Brf Viva. To show how the potential future price model differs from the current 2020 price model, an example of the mean hourly cost of district heating over a year is displayed in Table 3.7.

Table 3.7: Example of mean hourly cost of district heating for two price models

Year of price model	Energy price (SEK/kWh$_{heat}$)	Power price (SEK/h)
2020	0.32	13.1
2026	0.099	29.0

The prices displayed in Table 3.7 are the obtained mean of the total cost of heat when each price structure was used in the optimisation model. The Base Case with a rolling horizon forecast together with input data obtained from Brf Viva was utilised in the optimisation. The largest peak of bought district heating during the year sets the power cost for the 2026 price structure. For the 2020 price model, the mean power of the three peak load days of the year sets the value of the power price. In year 2020's price model, the cost associated with return water temperature, which usually constitutes about five percent of the total district heating cost[1], is neglected.

3.5 Indicators for the real-time system control

To better evaluate the management performance of the constructed model, some performance indicators are highlighted and applied to the optimisation results of the Brf Vivas energy system. These indicators are used to evaluate each of the tariff structures presented in in Table 3.1, and the performance indicators are presented in this section.

3.5.1 Effectiveness

The impact that various tariff structures have on the model's ability to smooth peaks of purchased electricity can be evaluated with an indicator called Effectiveness (E_{eff}). The Effectiveness indicates how well the tariff structure reduces peaks of bought electricity compared to the difference in electricity cost when a the demand charge is added, the Effectiveness is calculated according to equation 3.12.

$$E_{eff} = \frac{(\text{Peak}_{DC} - \text{Peak}_{Base})/\text{Peak}_{Base}}{(\text{EL}_{cost_{DC}} + \text{Power}_{cost_{DC}} - \text{EL}_{cost_{Base}})/\text{EL}_{cost_{Base}}} \tag{3.12}$$

Where Peak$_{DC}$ and Peak$_{Base}$ is the size of the largest peak of bought electricity obtained for a tariff structure with a demand charge and the Base Case, respectively. For the cases Three Peaks and Season, the Peak$_{DC}$ is the mean of the three largest peaks.

As indicated from Equation 3.12, the Effectiveness compares how tariff structures, with demand charges, affects both the size of power peaks and the cost of electricity. Both components are compared to those from the Base Case. The purpose is to demonstrate the peak shaving impact of the management system when optimising for a power tariff, in relation to the cost payed for electricity while attempting to shave those peaks. A negative value of the Effectiveness could indicate that the demand charge effectively generates peak shaving due to the additional cost of power added to the electricity price.

3.5.2 Energy storage utilisation

The utilisation of the batteries and the TES in Brf Viva can be evaluated from the number of full charge cycles through the storage. A full charge cycle is when the storage has been discharged with the amount of energy that is equal to 100% of the storage size [46, 47]. The discharge does not have to be continuous since a full charge cycle is independent of both time and power usage. Only energy utilisation of the storage is evaluated with this indicator.

To further understand how the energy storage units of Brf Viva are exploited for the cases tested, the Depth of Discharge (DoD) can be used as an indicator. The DoD displays the discharge of the storage in relation to its full size [47]. A discharge of 1 kWh from a storage that has the size 5 kWh thereby has a DoD of 20%. It is important to consider the DoD of the batteries since a deep DoD, which is close to 100%, can shorten the life time of a battery.

3.5.3 Warm and cold start

In the tested cases with demand charges, the addition of the constraints showed in Equations 3.6, 3.8 and 3.9 introduces a peak shaving behaviour on purchased electricity to the model. When a rolling horizon approach is applied, this behaviour could cause the model to set a low limit on peaks of bought electricity in the beginning of the month, only to later be required to exceed the initial peak value. Unnecessary peak shaving could cause the model to purchase electricity in a way that increases the final total energy cost. In a case with perfect foresight, the model establishes the final value of P_{max} from the first hour, and purchases electricity in relation to this level throughout the investigated time period, T. To reduce the effect of a too low start value of peak limits for the rolling horizon approach, a so called *warm start* could be introduced to the model. With a warm start, a start value of a likely final P_{max} is used as an input value to the optimisation model for the first time period t optimised. In a *cold start*, which is utilised for all cases tested in this thesis unless something else is stated, the input value of P_{max} is 1 kW for the first time period t.

The potential of a warm start, with the purpose to reduce the total energy cost, is evaluated by implementing different warm start values to some of the cases from Table 3.1. Obtained peak values from optimisations with cold starts for the same cases are utilised to estimate likely final values of P_{max}. A good start value is assumed to be about 95% of the size of the obtained value of the peak from each cold start case. High and low warm start values are also tested, which referrers to 130% and 70% out of the obtained cold start value respectively.

4

Results and discussion

Results from the cases tested with the optimisation model are presented in the this chapter. The aim is to review how the optimal energy system management in the Base Case is affected by implementation of demand charges. A rolling horizon window, t, of 24 hours is applied for all results presented, as long as nothing else is stated. The financial outcome for energy costs are presented first, followed by a description of how specific energy equipment and electricity purchase patterns are affected by implemented tariffs. Next, impact of the length and accuracy of the forecast window is presented. Lastly, recommendations regarding optimal management of the Brf Viva energy system are provided, together with a discussion of how such housings can affect the electricity system at large.

4.1 Financial outcome

The financial outcome of the cases tested with the optimisation model of the Brf Viva energy system is provided in this section. The aim is to review how the system can be optimised to generate the lowest total energy cost, and how this cost is affected by implementation of demand charges. The total energy cost of the Brf Viva energy system for all cases tested with demand charge structures, compared to the total cost of the Base Case, is displayed in Figure 4.1.

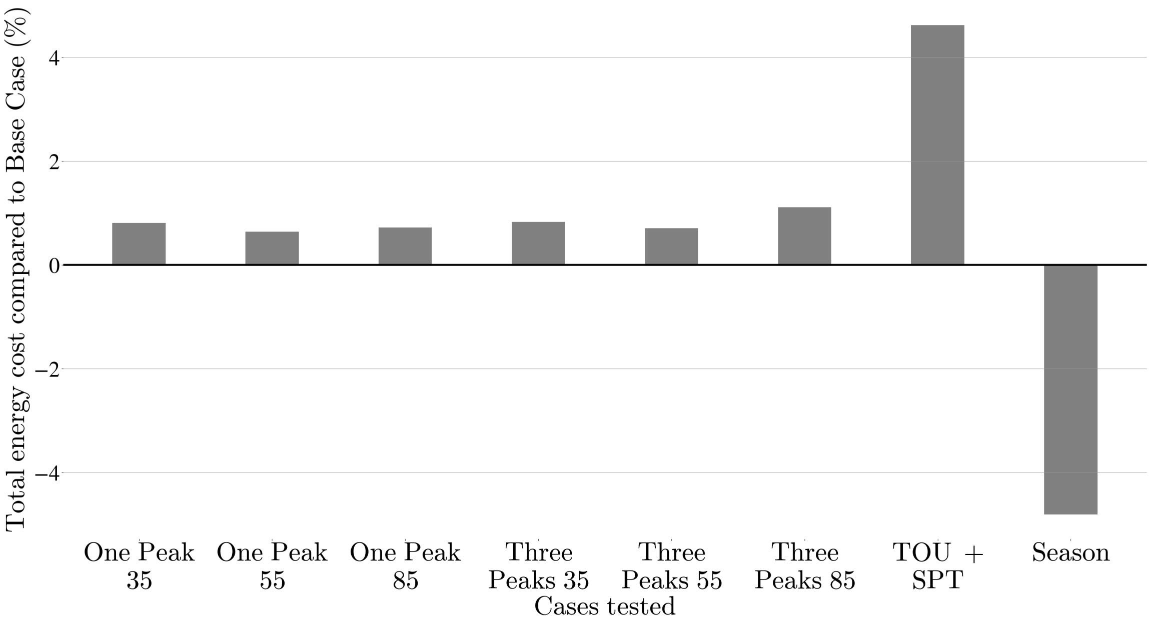


Figure 4.1: The difference in total energy cost during the year, including district heating, for all cases tested with demand charges compared to the total cost of Base Case.

From Figure 4.1, it can be noticed that all cases tested, except Season, have a higher total cost than Base case. The figure also shows that implementation of tariffs on power demand have a rather small impact on the total energy cost for Brf Viva, since almost all bars remain below a two percent increase. The small increase in total energy cost implies that a housing with the ability to produce and store some electricity and heat, can minimise the impact of changed tariff structures on total energy cost. From Figure 4.1 it can be seen that the One Peak and Three Peaks cases follow the same pattern, with similar final costs but with demand charge 55 SEK/kW generating a lower total cost than the other two dimensions of the demand charge tested. The reduced costs of the 55 SEK/kW cases indicate that there is a tipping point where the energy system of Brf Viva is not capable of reducing peaks any further, even with increased incentive through increased level of the demand charge.

The results in Figure 4.1 also show that the largest increase in total cost is generated for the TOU + SPT case. The reason for the high cost could be due to that the TOU + SPT case purchases electricity in a similar way as the Base Case but also contains two additional charges. A comparison of how the two cases purchase electricity for the first two days in December is displayed in Section A.6 in the appendix.

The lowest total energy cost presented in Figure 4.1 is generated by the case Season. The low total energy cost for Season is likely due to the combination of a low energy part of the electricity price during fall and winter, and a power part that is paid for a three month period. Since the demand charge is divided over a three month period, it constitutes a small share of the total electricity cost. How small a share can be viewed in Figure 4.2, where the impact of demand charges on the electricity cost is displayed. The demand charge part of the electricity cost is shown in the figure.

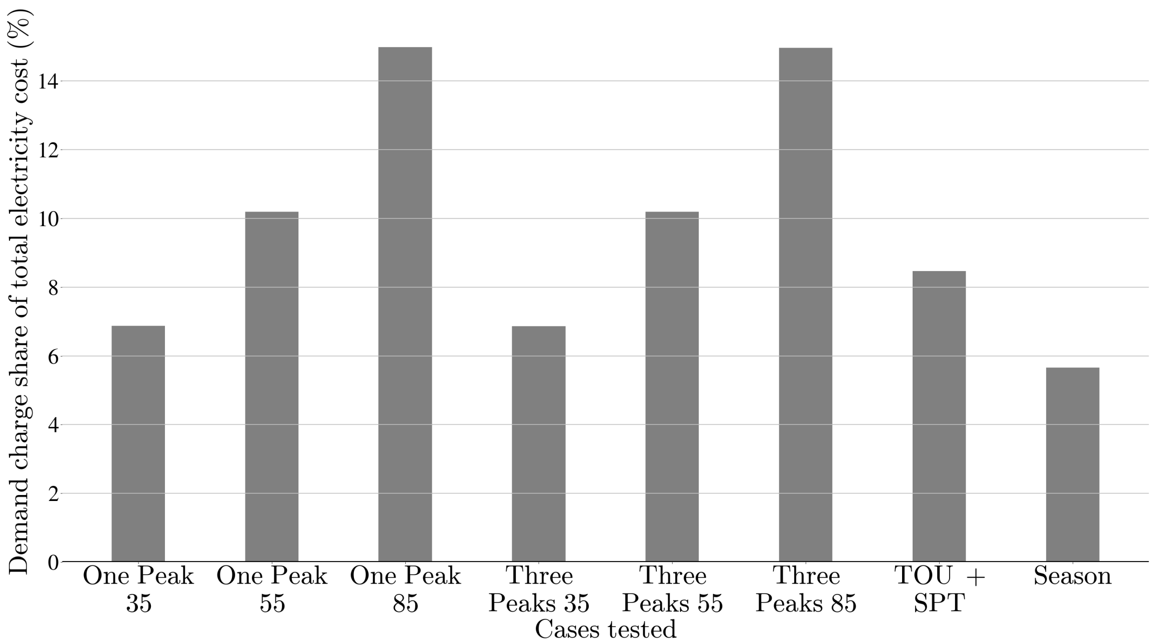


Figure 4.2: The share of the yearly electricity cost for Brf Viva constituted by the demand charge, for all cases tested containing a demand charge.

From Figure 4.2, it can be noticed that the demand charge share of the electricity cost becomes larger as the level of the demand charge increases. The demand charge share is largest for 85 SEK/kW and lowest for 35 SEK/kW in both One Peak and Three Peaks. The average demand charge cost of TOU + SPT has a value of 50 SEK/kW, and the value of the demand charge share is thereby, compared to the other cases, reasonable.

To further review how sensitive the modelled Brf Viva energy system is to change in structure and dimension of a demand charge, as well as how important this is for the final cost of the energy system, a sensitivity analysis was conducted. The sensitivity analysis investigates how implementation of demand charges impact the management of Brf Viva, and how this affects the electricity cost. The result is displayed in Figure 4.3.

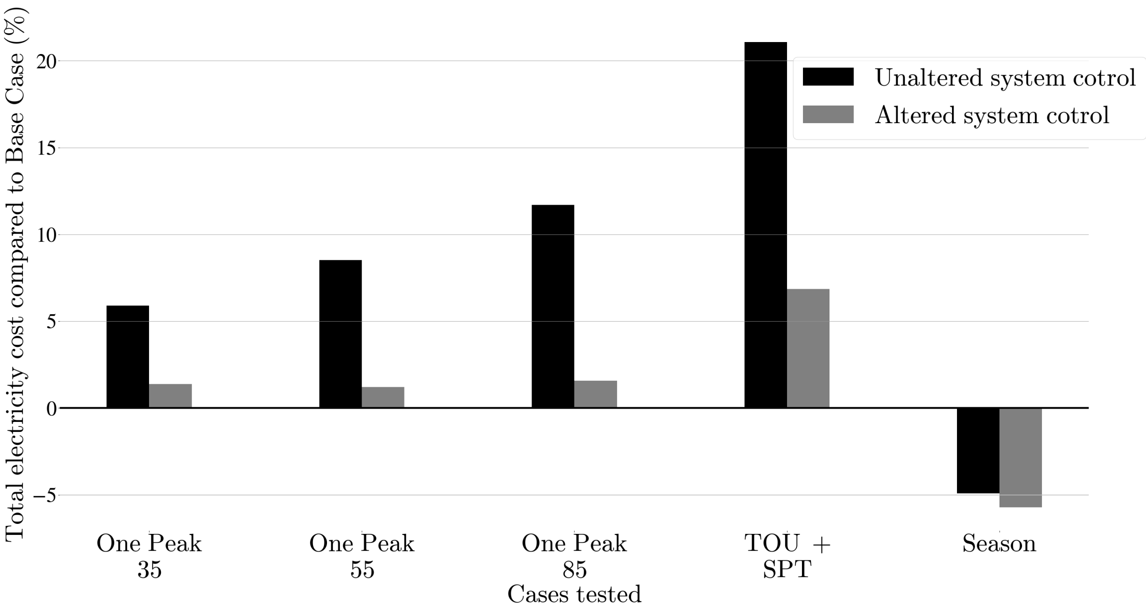


Figure 4.3: Comparison of Brf Viva's yearly electricity cost between cases tested with some selected tariff structures and Base Case. In both scenarios, showed as black and grey bars, the demand charge tariff structure displayed on the x- axis is applied as price model for the final calculation of the electricity cost. The black bars represent the change in electricity cost, compared to Base Case, when the model is optimised for the Base Case tariff structure. The lighter bars show the change in electricity cost when the model instead is optimised for the demand charge in question.

The impact on total electricity cost when an electricity tariff, containing a demand charge, is implemented to the model is displayed in Figure 4.3. The darker bars display the comparison of total electricity cost when no changes in the management strategy are performed, relative the total electricity cost obtained with the Base Case. From Figure 4.3, it can be observed from the darker bars that if the current electricity tariff was changed to one that includes a demand charge, the cost of electricity would increase compared to the Base Case for all tariff structures and dimensions tested except Season, if no changes in system management were made. The exception regarding the Season case is due to the low demand charge for each quarter of the year, in combination with reduced electricity prices, as showed in Figure 4.1. If changes in system control are made so that the model optimises the energy system in accordance with the new demand charge price structure, as indicated by the lighter bars in Figure 4.3, the impact of the new tariff structure on electricity cost could be reduced. Thus, an increased electricity cost could potentially be avoided if the energy system is optimised for the implemented tariff structure containing a demand charge, compared to an unaltered system control.

To visualise how well the the optimisation model can smooth peaks of bought electricity in relation to the electricity cost paid for the cases tested, compared to Base Case, the performance indicator Effectiveness is utilised. The Effectiveness indicator, explained in Section 3.5.1, indicates the robustness of the demand charge and the price elasticity of the modelled system. The results obtained with this indicator is shown in Figure 4.4.

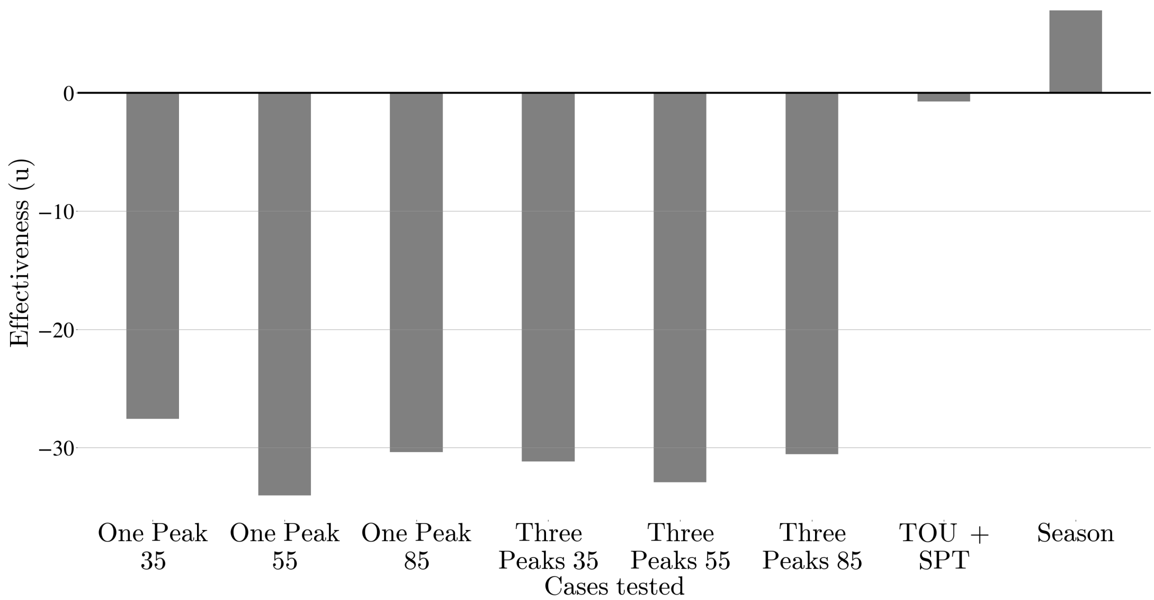


Figure 4.4: Effectiveness of peak shaving of the Brf Viva energy management system for the different cases with demand charge structures tested, compared to Base Case.

From Figure 4.4, it can be noticed that all cases tested with demand charge structures obtain a negative Effectiveness, except for the Season case, which generates a positive value. As explained in Section 3.5.1, negative values of the Effectiveness could indicate that the model effectively shaves peaks of bought electricity in relation to the total electricity cost payed. For the cases with a negative value in Figure 4.4, this is true since they all result in a reduction of peaks in power demand.

The largest negative value of the Effectiveness showed in Figure 4.4 is for the One Peak 55 case, followed by the Three Peaks 55 case. The large values indicate that the 55 SEK/kW tariff structures induces the most efficient management of the Brf Viva energy system regarding peak shaving in relation to the change in total electricity cost paid. The smaller Effectiveness obtained for the other dimensions of the peak cases further supports the theory from Figure 4.1, that there is a tipping point at which the energy system of Brf Viva cannot further reduce the peaks of purchased electricity regardless of the level of the demand charge. The TOU + SPT case generates a small negative value of the Effectiveness, shown in Figure 4.4. The negative value is due to that the TOU + SPT case has a larger increase in total energy cost than the other cases with demand charges, showed in Figure 4.1. The reduction of the largest peak of bought electricity is also significantly less with this demand charge structure than for the other cases.

As showed in Figure 4.4, the obtained value of the Effectiveness for the Season case is positive. Both the total electricity cost and the power peaks have been reduced here, compared to Base Case. A reduction in electricity cost, causing the Effectiveness to become positive, could indicate a poorly designed demand charge structure from the grid owner's perspective. The reduction in total energy cost showed in Figure 4.1 indicates that the energy part of the electricity cost is reduced too much in relation to the power part for the Season case. The energy management system uses this flaw to purchase larger volumes of electricity than required, and can therefore be viewed as less efficient for Seasons than for the other cases tested.

4.2 Evaluation of energy equipment utilisation

The following section seeks to investigate how the energy equipment of Brf Viva is exploited during cost optimal management for the tested tariff structures. The Brf Viva energy system contains heat pumps, batteries, thermal energy storage and solar panels. The heat pumps are utilised to cover the heat demand of the housing complex by either direct usage or by charging the thermal energy storage, which can also be charged by district heating purchased from the local network. The share of the total heat load covered by heat pumps, during the investigated year, is presented in Figure 4.5. The results are compared with the share covered by heat pumps when the model is optimised with regards to the district heating price model of year 2020.

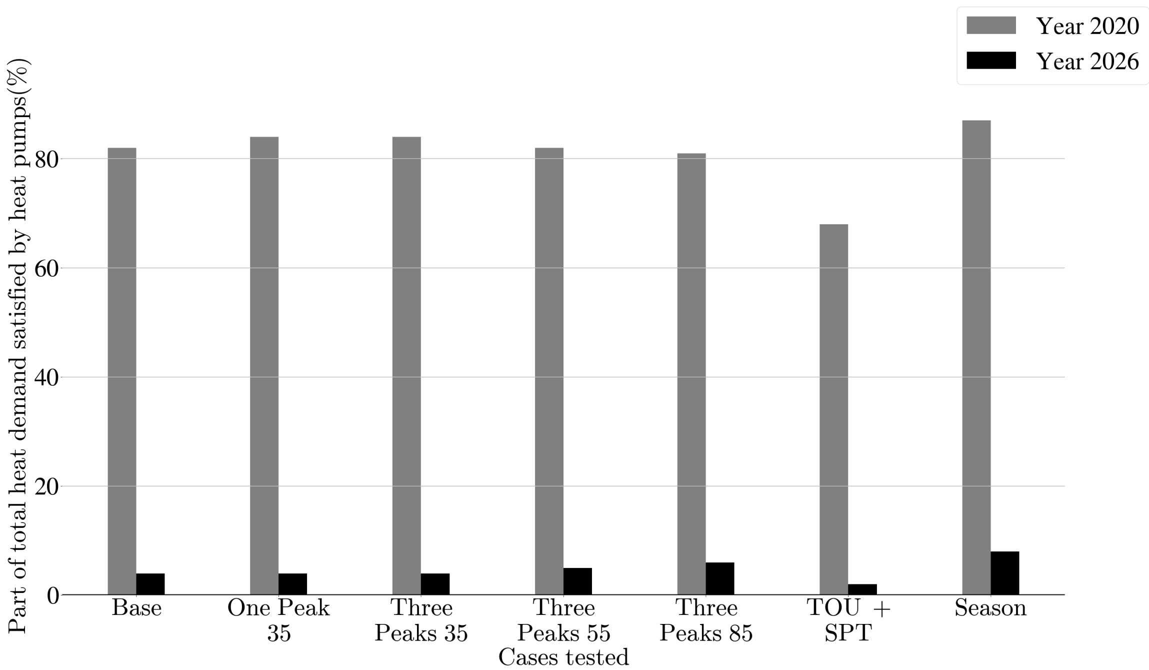


Figure 4.5: Share of the Brf Viva yearly heat load covered by heat pumps for some cases tested, depending on district heating price model. The price model for year 2020 is the current one utilised by Göteborg Energi [1], and the 2026 prices are a potential future price structure for societies where instantaneous power outputs of heat is more important.

Figure 4.5 indicates that the heat supply provided to Brf Viva by heat pumps differ significantly depending on the price structure of bought district heating. The difference can be noticed for all demand charge structures tested. The district heating prices of 2020 are, with exception for the power component, fixed over the seasons of the year, as described in Section 3.4.5. Thereby, no hourly variations in prices exist and the power component is billed according to a daily mean for three days a year. The power part of the 2020 prices constitutes a smaller share of the total heat cost than the energy part, compared to the potential price model for the 2026 district heating prices, as presented in Section 3.4.5. The potential price model for the year 2026 depends on the outside temperature and is therefore dynamic, unlike the one for the year 2020. The dynamic property of the year 2026 price model could be an explanation for the large differences in heat pump utilisation. When the district heating price structure of year 2026 is implemented, the system can charge the thermal energy storage from district heating at low price hours. No such low price hours in district heating occurs with the price model of year 2020. Instead, the heat pumps can be utilised at low electricity price hours to fulfil the heating demand of the housing. Even though the utilisation of heat pumps and the district heating differs significantly when the district heating price model of year 2020 is used compared to year 2026, the generated total energy costs for the 2026 cases are only about 10% lower. The small decrease is likely due to the increased flexibility offered by the dynamically varying 2026 price model, which a smart control of the Brf Viva energy system can exploit.

From Figure 4.5, it is clear that the utilisation of the heat pumps is strongly related to the difference between the price of electricity and the price of district heating. Figure 4.5 also shows that the TOU + SPT case has the lowest share of heat from the heat pumps, true for both district heating price models. The reason for the low heat pump utilisation for the TOU + SPT case is likely due to its similarity to the Base Case, but with an extra charge on the amount of total electricity purchased over a specific level. Therefore, excessive usage of the heat pumps could result in two extra costs, both in the form of increased demand charges and as a SPT charge.

The utilisation of the thermal energy storage and batteries in the Brf Viva energy system are displayed as number of full charge cycles in Figure 4.6. As explained in Section 3.5.2, a full charge cycle is achieved when the amount of discharged energy is equal to 100% of the storage size and is not dependent on time or power, only total amount of energy.

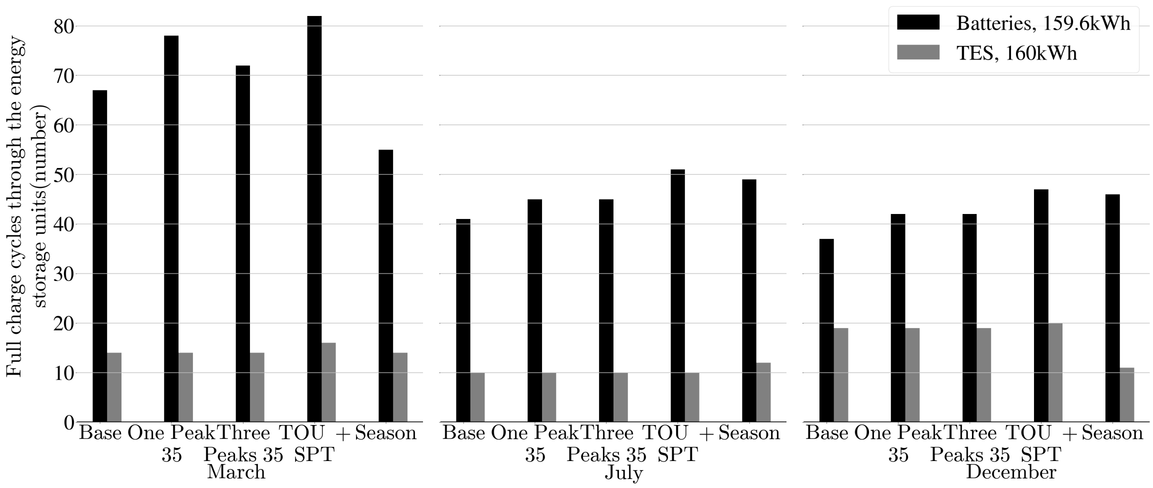
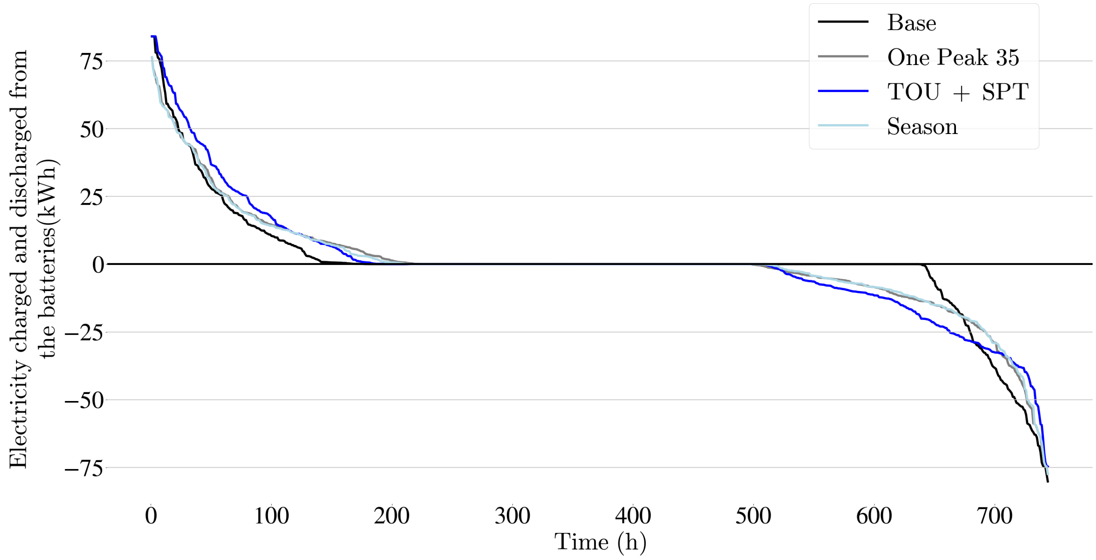


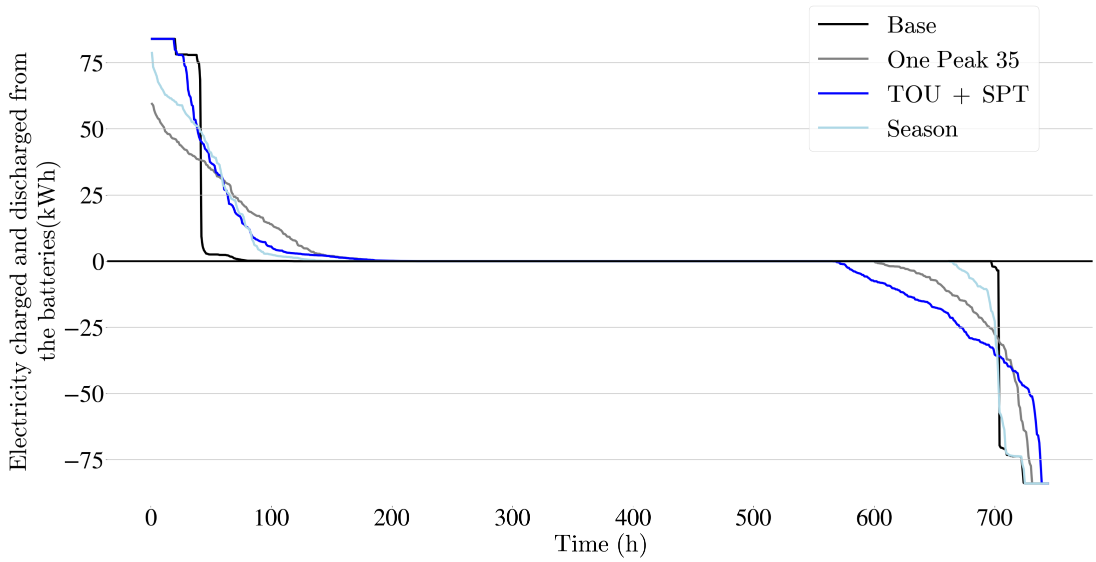
Figure 4.6: Number of full charge cycles through the Brf Viva energy storage units, depending on time of the year and demand charge structure.

Figure 4.6 shows that the utilisation of the batteries in number of full charge cycles is greater than the usage of the thermal energy storage, for the months displayed. The number of full cycles of the batteries are also higher for all months of the investigated year compared to the full cycles of the TES. The highest number of full charge cycles of the TES is obtained during December, when the heat load is the greatest. As evident from Figure 4.6, March has the highest number of cycles for the batteries, indicating a greater utilisation during this month than for the rest of the year. The increased utilisation of the batteries could be due to larger weather variations during the spring than the rest of the year, causing the price of electricity to vary more. The weather variations can be exploited by the energy system through charging of the batteries during low cost hours, and discharging when the prices are increased. Figure 4.6 shows that the utilisation pattern of the batteries amongst the cases tested is similar for all months displayed. The number of full charge cycles are especially high for the TOU + SPT case. The TOU part of the tariff structure causes the energy system to often utilise the batteries to a greater extent, compared to the other structures, when shifting the daily load away from peak hours.

To further understand the results provided in Figure 4.6, the utilisation of the batteries are provided as a combined charge and discharge profile of electricity for the cases Base Case, One Peak 35, TOU + SPT and Season. These profiles are displayed in Figure 4.7 for the months July and December, where positive values indicate charge and negative values discharge.



(a) July



(b) December

Figure 4.7: Combined charge and discharge profile of the batteries for the cases Base, One Peak 35, TOU + SPT and Season, during (a) July and (b) December.

The cases presented in Figure 4.7a all have similar charge and discharge patterns of the batteries. However, the cases One Peak 35 and TOU + SPT utilises the batteries for a few more hours than the other cases, while the Base Case has the least hours of utilisation. The usage pattern is similar for all dimensions of the One and Three Peaks cases, motivating why these are not displayed in Figure 4.7. Comparing the results showed in Figure 4.7a with the net charge displayed in Figure 4.7b, it can be observed that the batteries are charged or discharged for less hours in December than in July. The reason for the increased utilisation of the batteries during July is likely due to the higher electricity generation from the solar PVs during the summer, when the batteries are used to store the produced electricity for later usage.

Combining the results from Figure 4.6 and Figure 4.7, it can be observed that the batteries generally are used for more hours in July, with a higher number of full charge cycles than in December. The DoD is however generally larger in December, and more charges occur closer to the full capacity of the batteries. A higher DoD could indicate that the utilisation of the batteries put more strain on the batteries during the winter months, as explained in Section 3.5.2. Comparing the individual cases, the DoD of the batteries for both the Base Case and TOU + SPT is greater than for the other cases tested. The reason that these cases have a larger DoD could be due to the larger energy part of the price of electricity for the Base Case than the others, and that TOU + SPT acquire an additional cost if too much electricity is purchased. Thereby, there is a higher incentive for the energy management system to utilise the batteries for storage of larger amounts of electricity during low cost hours, and discharge the batteries during more expensive hours. The other tariff structures cause the energy management system to be more inclined towards shaving peaks of bought electricity and smoothing out the demand curve. Therefore, purchasing large amounts of electricity during low cost hours is not as profitable for systems with these tariff types, since it would increase the demand charge cost. Small amounts of energy are instead continuously charged and discharged to the batteries when either One Peak, Three Peaks or Season is implemented to the model.

It is apparent from Figures 4.6 and 4.7 that both the batteries and the TES are far from utilised to their full capacity during the year. An expansion of the storage facilities might therefore not make the model more profitable. The hypothesis about low increase in profitability is confirmed by results from a sensitivity analysis performed over the storage size and capacities of the TES and batteries, displayed in Section A.5 in the appendix. The results show that neither a large increase or decrease in size or capacity of the storage units will significantly affect the total cost of the Brf Viva energy system, for any of the cases tested.

4.3 Purchased electricity pattern due to management strategies

To gain a deeper understanding of how the management of the energy system is affected by implementation of demand charges, a closer look at specific cases and their electricity purchase patterns is necessary. In this section, results from such case studies are provided. These are intended to act as guidelines for the real-time model of the Brf Viva energy management system.

Figure 4.8 shows how the model chooses to purchase electricity during the first days of June, when a fake peak in electricity demand is added early in the input data set, for the cases One Peak 85 and Three Peaks 85. The purpose of the fake peak is to highlight how an early peak in electricity demand affects the system, and how this can impact the intended peak shaving behaviour of the two tariff structures. The aim with the investigation is to provide guidelines to the real-time system control of how the management should be altered in a system with large variations in electricity demand.

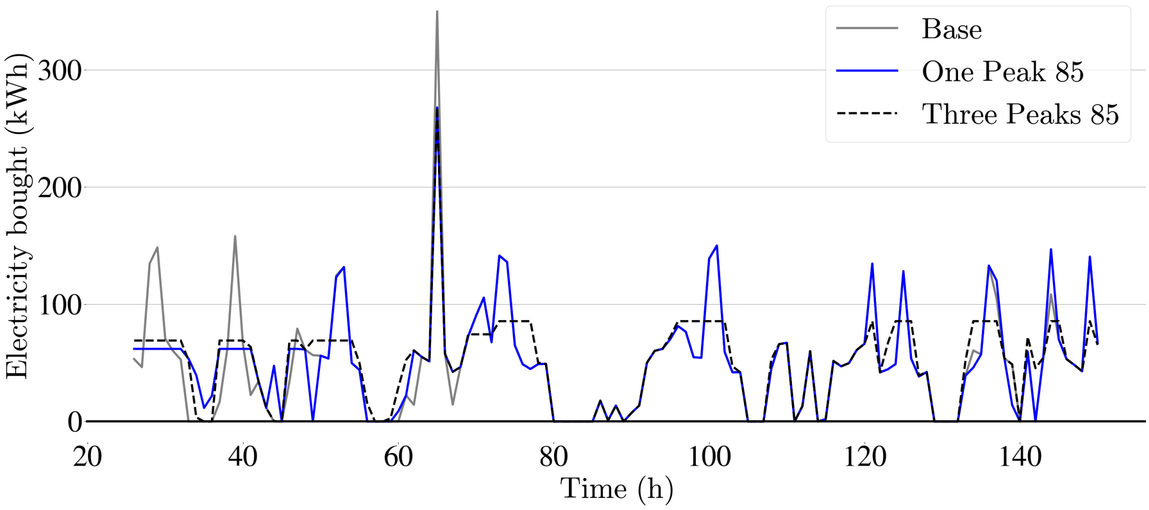


Figure 4.8: Electricity bought during the first days in June with a large fake peak of 350 kWh in electricity demand at hour 65. The tariff structures presented are Base Case, One Peak 85 and Three Peaks 85.

As can be seen from Figure 4.8, the generated fake peak of 350 kWh of required electricity at hour 65 removes the incentive for the One Peak 85 case to smooth the curve of purchased electricity. The One Peak 85 case starts to purchase electricity in the same way as the Base Case from the hour that the forecast perceives the fake peak and onward. For the case Three Peaks 85, the incentive to smooth out the peaks of purchased electricity remains after the fake peak of 350 kWh in electricity demand has occurred, displayed in Figure 4.8. Compared to One Peak 85, the tariff structure Three Peaks 85 uses the mean of the three largest peaks of bought electricity as foundation for the demand charge. The possibility to minimise the demand charge thereby remains after one large peak of bought electricity is obtained early during the billing period. Similar results were obtained for the two lower dimensions of the demand charge and therefore the results are not presented in the report.

To investigate further potential recommendations for the real-time system control, the impact of a warm start is evaluated. A warm start refers to when the model is provided with a guessed likely initial peak value, rather than starting from scratch, as in the cold case, described in Section 3.5.3. In Figure 4.9 the purchase pattern of the case One Peak 85 with a warm start compared to a cold start is displayed.

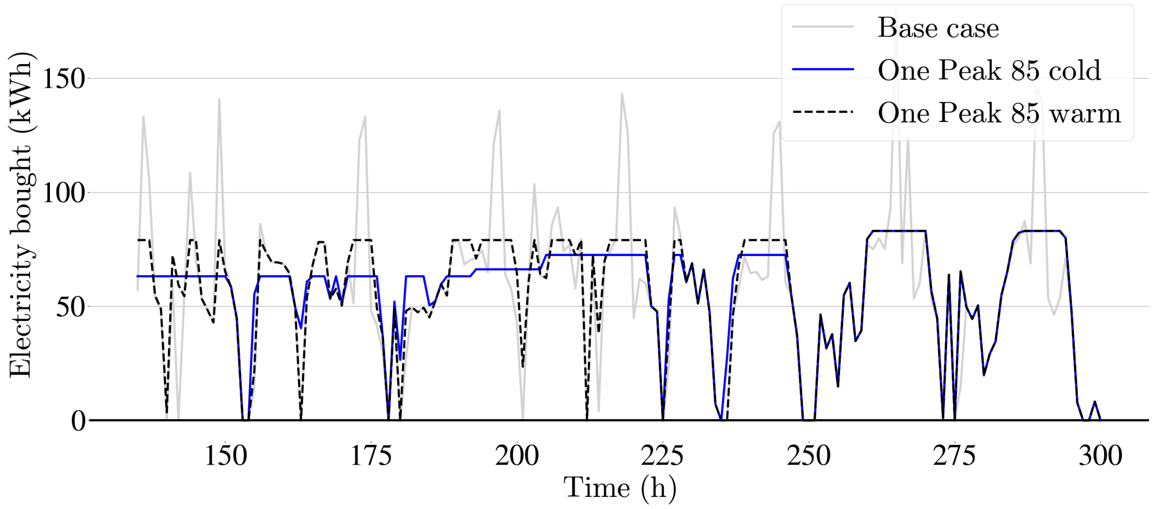
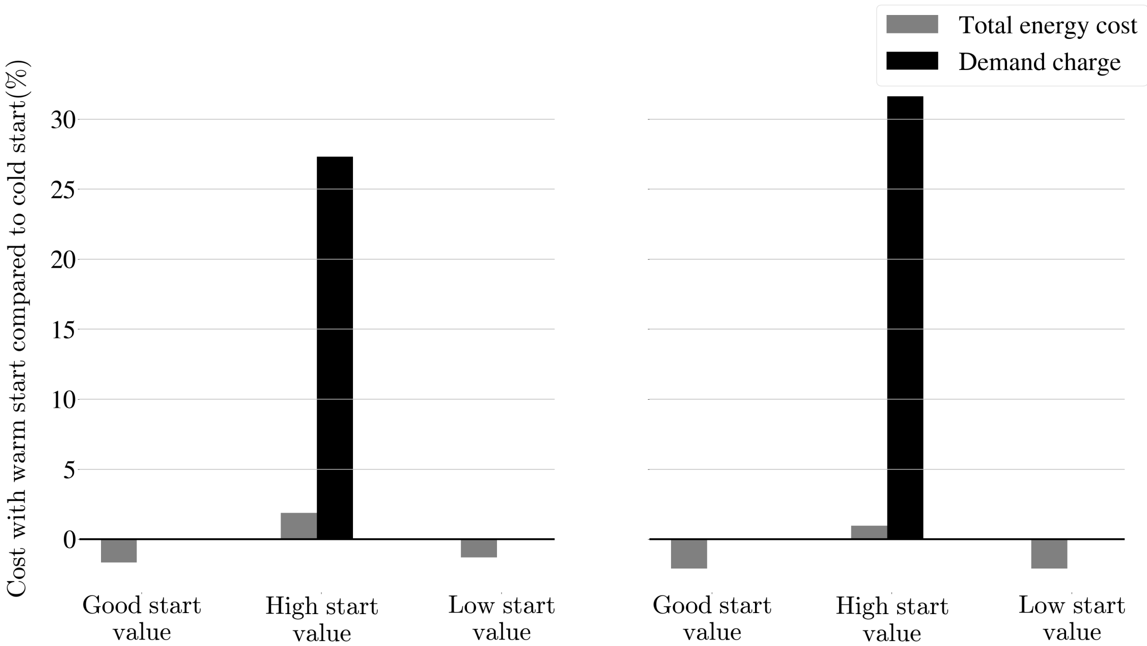


Figure 4.9: Purchase pattern during a week in June when a warm start is implemented compared to a cold start for the case One Peak 85. The Base Case purchase pattern is shown to highlight the peak smoothing behaviour of the tariff structures.

Figure 4.9 displays the difference in electricity purchase patterns for the case One Peak 85 between implementation of a warm start and a cold start. When a cold start is used in the case One Peak 85, the model attempts to limit the peaks of bought electricity to a greater extent than when a warm start is implemented, due to limited information of the entire time period. This behaviour can be observed since the cold start sets a lower limit than the warm start case in the beginning of the modelled time period, but reaches the same limit at hour 250. From Figure 4.9 it can also be observed that the chosen warm start value sets the upper limit of peaks of purchased electricity, since the warm start value used is 79 kWh. Therefore, a warm start could reduce unnecessary limitations on peaks of bought electricity, resulting in a better planned management control and a potentially lower total energy cost.

If implemented, a selected warm start value could potentially affect the total cost of energy for Brf Viva. The change in demand charge and in total energy cost when three levels of accuracy of the warm start value are applied, to the cases One Peak 85 and Three Peaks 85, are presented in Figure 4.10. The demand charge and total cost are compared to those from the same cases but with a cold start.



(a) One Peak 85 (b) Three Peaks 85

Figure 4.10: Total energy cost, heat included, and demand charge during June for cases with warm start compared to the costs obtained for the same cases with a cold start. For the tested cases, three different warm start values are presented, a high, a low and a good start value. (a) The difference in cost for the case One Peak 85. (b) The difference in cost for the case Three Peaks 85.

Figure 4.10 shows that the demand charge remains unchanged, compared to the cold case, for either a good or low warm start value for the One Peak 85 and Three Peaks 85 cases. The definition of a good, high and low start value is provided in Section 3.5. The reason for the lack of change in demand charge is that the system eventually ends up purchasing the same peak of electricity regardless of the start value, provided that the start value was lower than the final peak value, as can be observed in Figure 4.9. The demand charge cost increases noticeably when a high start value is used, whereas only a small increase in total energy cost can be observed in Figure 4.10. The impact of the increased demand charge on the total energy cost is relatively small since the model is provided with an increased flexibility due to the a higher peak limit. The model can therefore utilise more low cost hours of electricity. The results also displays that both a good and low warm start value can provide a small reduction in total energy cost. The reduction potential is marginally larger for the Three Peaks 85 case. The small total energy cost reduction is due to a better planned management since knowledge of the size of the peak is provided to the model from the beginning of the optimisation. Thereby, less effort has to be allocated to limit the peaks.

The same impacts on the total energy cost and demand charges as in Figure 4.10 for June can be observed in December, displayed in Section A.6 in appendix. In December, even less effect on the total energy cost due to implementation of warm starts can be noticed. The outcome of warm starts are both dependent on the type of tariff structure used and the nature of the starting value. Savings are possible, but at the risk of generating an increase in the total energy cost, if the start value is higher than necessary.

4.4 Impact of solution window

In this section, the impact of the solution window's length and accuracy on optimal energy system management is disclosed. As predicted, a longer forecast window enables the model to control the energy system in a more efficient way. For all cases when a larger time window was applied, reduction in total energy costs were obtained. The results obtained when a perfect foresight solution window is implemented to the model are presented in Section A.7 in appendix.

As described in Section 3.3.2, an error is applied to the input data of the model to mimic an incorrect forecast. In Figure 4.11, the added error is up to 50% larger or smaller than the correct input data value.

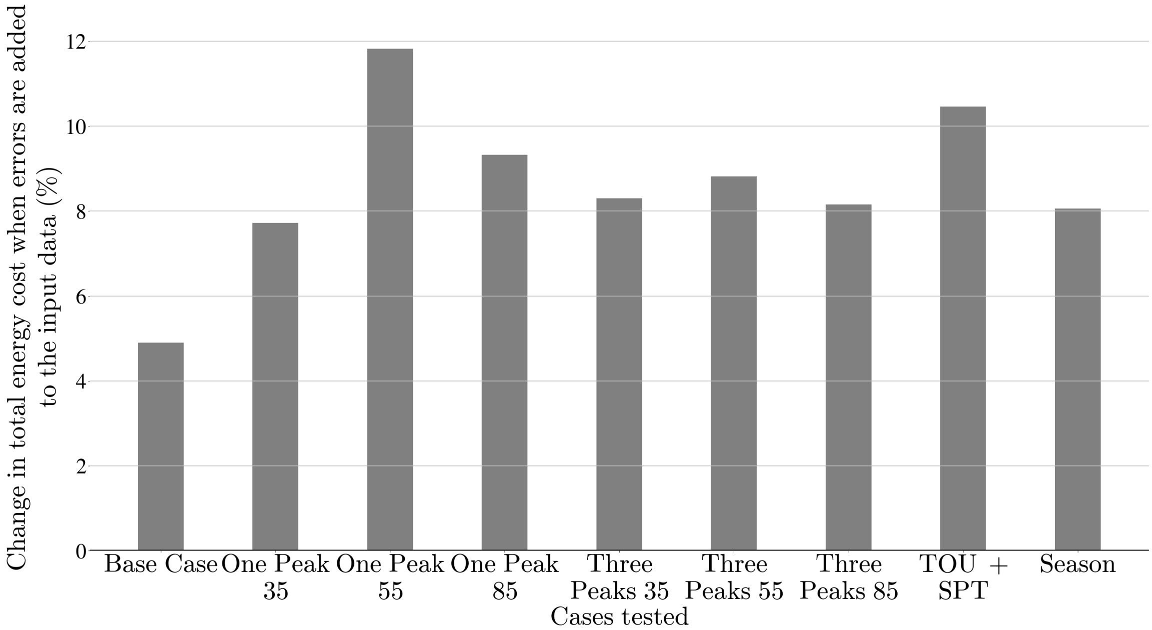


Figure 4.11: Impact on total yearly cost when a deviation of up to 50% from the correct values are added to the input data to resemble an incorrect forecast. The total energy cost of the tested cases are compared to the total energy cost obtained with a correct forecast.

A misleading forecast should result in higher total energy cost, which the results in Figure 4.11 confirms. The highest increase in total energy cost can be observed for the tariff structure One Peak 55, followed by TOU + SPT and Three Peaks 55. The pattern indicates that the cases with the highest Effectiveness for peak shaving, as indicated in Figure 4.4, is greatly impacted by an incorrect forecast. The impact on the TOU + SPT case is also large since the ability to shift loads away from peak hours is hindered by the reduced knowledge of load sizes and electricity costs. From Figure 4.11 it can also be observed that the Base Case has the lowest increase in total energy cost. The Base Case differs from the other tariff structures since it does not contain a demand charge and the electricity cost is only dependant on the hourly electricity price. The impact of an incorrect forecast seems to be greater when demand charges are included in the tariff structure. However, since the error is applied as a random factor that varies between 0.5 to 1.5, it is difficult to draw any specific conclusions about the different tariff structures. Figure 4.11 indicates that with this type of incorrect forecast, the total energy cost increases with approximately 5-12% for the tested cases.

Figure 4.12 illustrates change in energy system management when the forecast regarding electricity load is predicted inaccurately. The figure shows the situation when the electricity peak load hour in December is estimated to 0 kWh instead of the real value of 168 kWh/h.

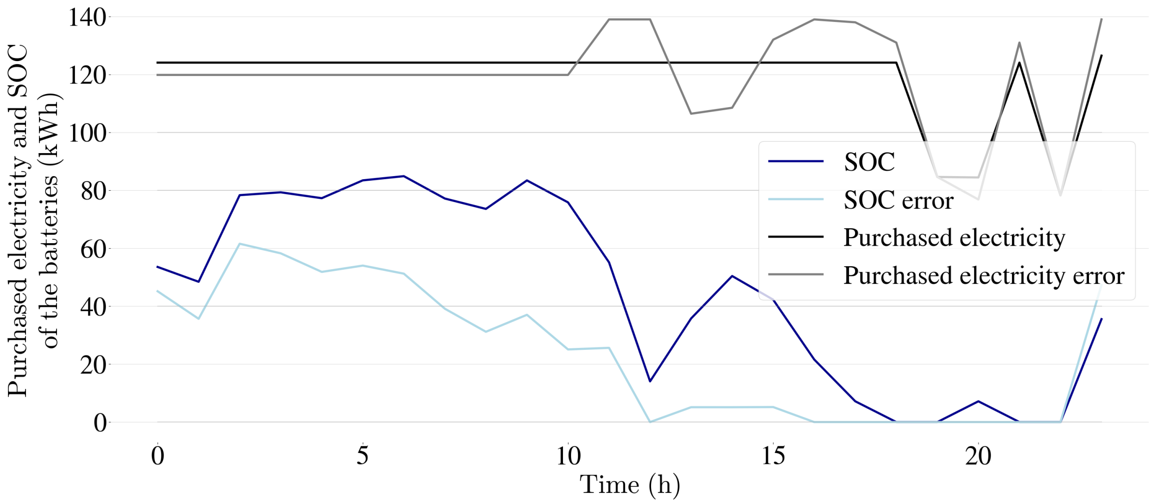


Figure 4.12: Impact on energy system management for case One Peak 85 when the peak load hour, hour 13, of 168 kWh is estimated to 0 kWh¢. Lighter lines represent the case with an error in electricity load prediction, and the darker lines the reference case. Blue lines are state of charge of the batteries and the black lines represents bought electricity.

Figure 4.12 shows that the error in predicted peak load makes the model poorly prepared for the peak hour of 168 kWh/h at hour 13. The batteries cannot discharge enough electricity since the state of charge of the batteries are too low. Therefore, the model fails to avoid increasing the peak of bought electricity at the peak load hour, hour 13. The case with the error in the forecast in Figure 4.12 results in a higher demand charge compared to the case with the correct forecast. However, the total energy cost in December is increased less than 2% due to the misinterpreted peak load hour of electricity.

4.5 Recommendations for the real-time control system

In this section, a summary of the results obtained from the optimisation cases performed, along with ideas of how these results can contribute to optimal system management of the real-time system control of Brf Viva, are presented. As evident from Figure 4.3, the control of the energy system should be adapted to fit the implemented tariff structure on electricity to avoid an increase in total energy cost. If the system control remains unchanged when the electricity tariff is altered from a cost with no charge on power demand to one that includes a demand charge, the total energy cost is increased. The increase is especially significant for cases in which the demand charge constitutes a large share of the total electricity cost, as in the cases One Peak 85 and Three Peaks 85. The impact is even larger for the TOU + SPT case since this structure has an additional charge depending on the amount of electricity purchased. It is therefore of importance that the real-time control system of Brf Viva always optimises for the tariff structure of electricity in question.

The results from the cases One Peak and Three Peaks are often similar and both prove to be effective tariff structures for shaving peaks of bought electricity, according to the Effectiveness displayed in Figure 4.4. However, the One Peak structure is more vulnerable to large, unpredictable variations than the Three Peaks structure. The vulnerability becomes evident if a large power peak in electricity demand is underestimated or missed, which causes the One Peak case to start purchasing electricity in accordance with the Base Case, as can be observed in Figure 4.8. The model's attempt to smooth power peaks of purchased electricity in the beginning of the month has therefore been in vain. This observed pattern in model behaviour generates a recommendation to not optimise the energy system management according to the One Peak structure when there is a lot of variation in the electricity demand. Large variations could come from single large loads. To have a large impact on the system control, the size of the peak loads have to be larger than the average load. The increase should be about the size of the installed capacity of the batteries. Regarding cases where the electricity load is more even, it is not recommended to optimise the system control according to a tariff structure based on several peaks. The control should instead be optimised to reduce peak demand to the level of the third lowest peak, for a three peak mean tariff structure. The reason for not optimising for the mean of several peaks for such cases is the low probability of achieving greater savings through this more complicated method.

From Figure 4.9, it can be observed that warm starts could generate profit since no unnecessary peak shaving will occur in the beginning of a billing period. However, as indicated from Figure 4.10, the potential savings in total energy cost for doing this is limited. More savings can potentially be achieved when tariff structures with a mean of several peaks are used as demand charge, especially during the summer months. However, there is a risk that the start value is set too high, resulting in increased total energy cost. The recommendation is therefore to choose a start value close to, but smaller than, the largest peak obtained for the month of issue during the previous year.

As mentioned in Section 4.4, a longer solution window makes the optimisation model more efficient at managing the energy system, as it generates a lower total energy cost. A larger forecast time period could however contain a greater amount of uncertainties, especially regarding weather conditions. To minimise the impact of errors in the forecast, the real-time system control should be resolved for a larger part of the time period t of the planned system management. The resolved part of time period should preferably constitute a larger part than 50% of t, which would provide the model with more room to act upon unpredicted events. Differentiating between the tested cases, errors have a larger impact on the total energy cost for cases with demand charge structures than for the Base Case, as can be observed from Figure 4.11. Potential future implementation of demand charges on the electricity tariff thereby generates the need for an extra precautionary system control. For such cases, it is recommended to make it a priority to obtain a more trustworthy forecast.

Regarding utilisation of individual energy equipment in the Brf Viva energy system, the obtained results seem to indicate that the dependence on type of electricity tariff structure implemented is relatively small. The number of full charge cycles for the batteries vary more between different months than between cases, in accordance with the electricity generation from the solar PVs, as indicated by Figure 4.6. The utilisation of the TES and the heat pumps are similar for all cases tested. However, the utilisation of the heat pumps decreases significantly when potential district heating prices of year 2026 is implemented to the energy system. If this price model would become reality, it is recommended to put more work into the control system of the TES than the one controlling the heat pumps. The current control system monitoring the TES could perhaps be expanded with more, better control agents to allow for increased flexibility to optimally exploit low cost hours of district heating. However, this recommendation depends on the design of the future district heating price model.

4.6 Model limitations

In this section, a short discussion about the limitations of the model used to optimise the Brf Viva energy system is provided. One thing that can have an impact on the results is that the data used as input data to the optimisation model is modified before implementation. Approximately nine percent of the data is corrected, corresponding to 661 hours out of a total of 7320 hours. However, since the aim with the results is to provide knowledge of future management, the impact of these alterations can most likely be discarded.

The results obtained from the Season case often deviates from those of the other cases, probably since the demand charge is divided over three months as opposed to one month. The level of the demand charge thereby becomes too small, causing the system to purchase more electricity than necessary, making the tariff less efficient in its energy utilisation than the other cases. The design of the Season case should therefore be altered to ensure that the demand charge constitutes a larger share of the electricity cost.

Another limitation of the constructed model is that the power part of the district heating price was assumed before each model optimisation. In the 2026 price model, the power cost corresponds to the largest peak of bought district heating. In the 2020 price model the power cost is composed of the three largest daily means of energy obtained. The assumed peak value was based on one trial run of the model for a full year with each district heating price structure and the Base Case. The output value of the peak was then used as assumed peak for all cases tested. If the value of the predetermined peak was exceeded at any occasion, the corresponding increase in power cost was added to the total energy cost. However, in most cases, the peak of purchased district heating remains below the predetermined power limit.

4.7 Prospects of demand charges in combination with BEMS

How similar energy systems as the one of Brf Viva could become of use to the energy system at large, and other further research within this topic that could be of interest, is discussed in this section. If similar tariff structures as the ones tested in this thesis would be established in Sweden, savings generated when changing the system control could promote installation of energy equipment in already existing housings. The tariff structures could also promote construction of new, similar buildings as Brf Viva, perhaps through the project *Positive Footprint Housing*. For the installation of DES, alterations of size and capacity compared to the Brf Viva equipment could be of interest, to achieve better equipment utilisation and more profitable housings.

Results obtained in this project, regarding change in optimal energy system management when different electricity tariff structures are applied, are not only of significance for the financial outcome for Brf Viva. It is apparent from the results that a change in electricity tariff structure has a large impact on the way that an energy system like this purchases electricity and utilise the installed energy equipment. A lot of flexibility could be unlocked to aid the general electricity grid by making use of the resources available in housings like Brf Viva. However, the potential flexibility from demand side response in the form of load shifting has not been considered in this project. More flexibility and potential savings could be utilised if the electric vehicles, household appliances and building integrated thermal energy storage were added as controllable loads to the modelled Brf Viva energy system. An important aspect to consider here is however the freedom for the building residents, and how they will perceive a more limited ability to utilise different commodities in Brf Viva. Additionally, a lot of information will be needed to optimally manage the energy system with demand side response. The demand of both electricity and heat must be estimated, which requires detailed information about the residents behaviour and living patterns. Therefore, a dilemma arises, and the willingness of the residents to share this information can have significant impact on the management performance of the real-time system control.

Provided a future with more risks of congestion on the electricity grid, as well as larger shares of VRE, peak shaving of electricity demand could be of great importance. As evident from Figure 4.4, the demand charge structure that is most efficient in peak shaving for the modelled cases is the tariff in the One Peak 55 case. In this scenario, the system has the ability to efficiently reduce peaks in purchased electricity, while not obtaining a large increase in total electricity cost. The tariff structure therefore seem to be well designed for achieving its intended goal of shaving power demand peaks, and generate a fair electricity cost for the consumers who alter their behaviour accordingly. However, if too many actors start to manage their small scale BEMS in the same way, demand charges like this could potentially lead to a shift of the peak load in time, rather than a reduction in peak load.

To reduce the potential load shift effect, local market places for flexibility could become important. The potential to contribute with flexibility by reducing peaks of electricity demand for certain hours, as well as the ability to store some electricity when there is too much available on the electricity grid, makes energy systems like the one in Brf Viva valuable for society. The possibility to trade flexibility services and energy between such actors could be an economic driving force to fully utilise the potential of these energy systems. A more dynamic tariff structure, like the one in the TOU + SPT case, might complement the flexibility market better than a classic peak shaving structure, especially if the hours of the power component of the tariff would work more dynamically to reflect the instantaneous situation on the electricity grid, similar to the spot prices. It could therefore be of great interested to investigate the potential of a flexibility market and if a more dynamic tariff structure would increase its potential in combination with BEMS.

5
Conclusion

A case study of how optimal system management of the Brf Viva energy system in Gothenburg is affected by changes in electricity tariff structure has been conducted. Four electricity tariff structures with different types of demand charges implemented as a power component have been investigated. The results are compared to those of a constructed Base Case, a tariff structure without an additional demand charge component. The impact of the forecast length, and implemented errors to the forecast, was also examined. An additional aim of the Master Thesis was to generate recommendations for how a real-time system control of the Brf Viva energy system should be managed if similar tariff structures where to be implemented.

The results generated show that the total energy cost of the Brf Viva energy system can be reduced. The reduction can be obtained if the management strategies of the system is modified to better fit the electricity tariff in place, compared to if the tariff structure is changed with a conserved energy usage. Peak shaving of electricity load can be achieved, as well as shift of peaks in time. The results show that One Peak and Three Peaks generates the lowest total energy cost. These electricity tariff structures can therefore achieve the highest savings when combined with a housing that has several types of DES in place, like Brf Viva. These tariff structures also generated the largest value for peak shaving Effectiveness. Both the One and Three Peaks tariffs could thereby induce a large increase of flexibility from buildings as Brf Viva, which has the ability to produce and store some energy. Out of the cases tested in this project, the TOU + SPT case provides the highest total energy cost. The tariff also has a lower Efficiency for peak shaving than the other cases tested.

The results from this project also show that the thermal energy storage is utilised to a small extent, for all tested cases and throughout the investigated year. The utilisation of the batteries are a bit more frequent, and the number of cycles and DoD varies with electricity tariff structure. The variation gained from different tariff structures is mainly driven by the electricity generation from solar PV behind the meter. A slightly lower DoD, generating a less degrading battery utilisation, can be observed for cases with peak shaving demand charge structures implemented.

The most important recommendations that this Master Thesis can provide for the real-time model of the Brf Viva energy system is to always attempt to optimise the system management for the tariff type in place. However, for systems where there is risk of obtaining single large electricity loads, and the tariff structure in place is in accordance with the One Peak structure, attempts to shave peaks of purchased electricity generates a risk for increased total energy costs compared to simply optimising for a Base Case tariff structure. The recommendation is therefore to optimise the system in accordance with the Base Case tariff structure for such systems. For the opposite case, when the system load variations are small and the tariff structure is similar to the Three Peaks case, the probability of generating additional savings when optimising the system in accordance to the tariff structure is low. The additional effort when constructing such a complicated control system is therefore redundant, and the system should instead be optimised after the third largest power peak.

To increase the performance of the management system, a warm start value should be implemented. The recommended warm start value should be close to, but less than, the largest peak obtained for the same month the previous year. Recommendations regarding the forecast window includes to resolve a larger part than 50% of the planned system management. The importance of obtaining a trustworthy forecast increases when tariffs with demand charges are implemented, and it should be of priority to achieve the best possible demand and weather forecast for such cases. As future trends points in the direction of more varied district heating prices, it is recommended to work on obtaining a better control agent for the TES, rather than to improve the control system surrounding the heat pumps.

In conclusion, it is apparent that savings in energy cost can be obtained for housings like Brf Viva, if properly managed according to imposed tariff structures of electricity and heat. Furthermore, the potential aid that these type of buildings can provide in the future for the large scale energy system, if smart tariff structures on electricity and heat are established, are substantial. This since a lot of flexibility can be provided through proper management of the DES. As electrification and digitalisation enters more parts of society and the share of variable renewable energy sources increases, housings like Brf Viva in combination with smart design of electricity and heat tariffs, can become important cornerstones of a functioning, flexible energy system.

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A

Appendix

A.1 Energy balances

The energy balance for the electricity part of the housing, described in section in 2.5.1 in the Method, is showed in Equation A.1.

$$\mathrm{H}_{el} + \mathrm{HP}_{el} + \frac{\mathrm{B}_G^+}{bat} + \mathrm{EL}_{sell} = \mathrm{DC|AC} \cdot \mathrm{PV}_{use} + bat \cdot \mathrm{DC|AC} \cdot \mathrm{B}^- + \mathrm{EL}_{buy} \tag{A.1}$$

Where H_{el} is the electricity load of the building and its appliances, and HP_{el} is the electricity load of the heat pump. B is the batteries, and the notation +/- represents if they are being charged or discharged. B_G^+ indicates that the batteries are being charged from the local electricity grid. PV_{use} is the amount of electricity produced from the solar panels that is either used in the building directly or sold to the electricity grid. All variables have the unit kWh_{el}. *bat* is the charge and discharge efficiency. Losses from converting the electric current from DC to AC is expressed as DC|AC, and the other way around as AC|DC.

The energy balance for the heating part of the energy system of Brf Viva is showed in Equation A.2.

$$\mathrm{H}_{heat} + \frac{\mathrm{TES}_{DH}^+}{tes} + \frac{\mathrm{TES}_{HP}^+}{tes} = \mathrm{HP}_{use} + tes \cdot \mathrm{TES}^- + dh \cdot \mathrm{DH}_{buy} \tag{A.2}$$

Where H_{heat} is the heat load of the housing, DH_{buy} is the amount of district heating bought from the local network, HP_{use} is the amount of heat produced from the heat pump that is directly utilised to heat the building, both in kWh_{heat}. The thermal energy storage is marked as TES and charge and discharge is indicated with +/-. TES_{DH}^+ and TES_{HP}^+ indicate if the storage is being charged with district heating or from the heat pumps. The charge and discharge efficiencies of the thermal energy storage have the notation *tes*, and losses from buying district heating from the local network is showed as *dh*.

A.2 Model constraints

The constructed constraints, used in the Python model of the Brf Viva energy system, is presented in this section.

Electricity demand

$$H_{el}(i) + HP_{el}(i) + AC|DC \cdot \frac{B_G^+}{bat}(i) + EL_{sell}(i) = \\ DC|AC \cdot PV_{use}(i) + bat \cdot DC|AC \cdot B^-(i) + EL_{buy}(i) \quad (A.3)$$

Solar PVs

$$PV_{prod}(i) = D \cdot PV_{use}(i) + \frac{B_{PV}^+(i)}{bat} \quad (A.4)$$

$$PV_{use}(i) + DC|AC \cdot bat \cdot B^-(i) \geq EL_{sell}(i) \quad (A.5)$$

Batteries charge/discharge

$$B_{PV}^+(i) + B_G^+(i) \leq B_{max}^+ \quad (A.6)$$

$$B^-(i) \leq bat \cdot B_{state}(i-1) \quad (A.7)$$

$$B_G^+(i) + B_{PV}^+(i) \leq B_{state_{max}} - B_{state}(i-1) \quad (A.8)$$

$$B^-(i) \leq B_{state}(i-1) \cdot bat \quad (A.9)$$

$$B_G^+(i) + B_{PV}^+(i) + B^-(i) \leq B_{charge_{max}} \quad (A.10)$$

Batteries state of charge

$$B_{eff} \cdot B_{state}(i-1) + bat \cdot B_{PV(i)}^+(i) + bat \cdot B_{G(i)}^+(i) - \frac{B_{(i)}^-}{bat} = B_{state}(i) \quad (A.11)$$

Limitation of sold electricity

$$PV_{use}(i) + DC|AC \cdot bat \cdot B^-(i) \geq EL_{sell}(i) \quad (A.12)$$

Heat demand

$$H_{heat}(i) = HP_{use}(i) + TES^-(i) \cdot E + DH_{use}(i) \cdot H \quad (A.13)$$

Heat pumps

$$COP \cdot HP_{el}(i) = HP_{use}(i) + (1/E) \cdot TES_{HP}^+(i) \quad (A.14)$$

$$H_{heat}(i) = HP_{use}(i) + (1/E) \cdot TES^-(i) + H \cdot DH_{use}(i) \quad (A.15)$$

$$COP \cdot HP_{el}(i) \leq HP_{max_{power}} \quad (A.16)$$

District heating

$$DH_{buy}(i) = \frac{TES_{DH}^+(i)}{E \cdot H} + \frac{DH_{use}(i)}{H} \quad (A.17)$$

District heating power part year 2020

$$\frac{\sum_{i=1}^{t}[\mathrm{DH}_{buy}(\mathrm{i})]}{t} \leq DH_{max} * \frac{Mean_{max_1} + Mean_{max_2} + Mean_{max_3}}{3} \quad (A.18)$$

District heating power part year 2026

$$DH_{buy}(i) \leq DH_{max} \cdot Current_{max} \tag{A.19}$$

Thermal energy storage charge/discharge

$$TES^{+}_{DH}(i) + TES^{+}_{HP}(i) \leq TES_{state_{max}} - TES_{state}(i-1) \tag{A.20}$$

$$TES^{-}(i) \leq TES_{state}(i-1) \cdot E \tag{A.21}$$

$$TES^{+}_{DH}(i) + TES^{+}_{HP}(i) \leq TES_{charge_{max}} \tag{A.22}$$

$$TES^{+}_{DH}(i) + TES^{+}_{HP}(i) + TES^{-}(i) \leq TES_{charge_{max}} \tag{A.23}$$

Thermal energy storage state of charge

$$T_{eff} \cdot TES_{state}(i-1) + E \cdot TES^{+}_{DH}(i) + E \cdot TES^{+}_{HP}(i) - \frac{TES^{-}(i)}{E} = TES_{state}(i) \tag{A.24}$$

Special constraints for tariffs with demand charges

One Peak

$$EL_{buy}(i) \leq P \cdot P_{max} \tag{A.25}$$

$$0 \leq P \tag{A.26}$$

$$Power_{cost} = P \cdot P_{max} \tag{A.27}$$

Three Peaks

$$EL_{buy}(i) \leq [P_3 + P_2 + P_1(i)] \cdot P_{max_{peak3}} \tag{A.28}$$

$$0 \leq P_3 \leq \frac{P_{max_{peak2}}}{P_{max_{peak3}}} \tag{A.29}$$

$$0 \leq P_2 \leq \frac{P_{max_{peak1}} - P_{max_{peak2}}}{P_{max_{peak3}}} \tag{A.30}$$

$$0 \leq P_1(i) \tag{A.31}$$

$$Power_{cost} = \frac{[Peak_1 + Peak_2 + Peak_3]}{3} \tag{A.32}$$

$$Peak_1 = [P2 + \sum_{i=1}^{t} [\mathrm{P1(i)}] + 1] \cdot P_{max_{peak3}} \tag{A.33}$$

$$Peak_2 = [P2 + P3 + 1] \cdot P_{max_{peak3}} \tag{A.34}$$

$$Peak_3 = [P2 + 1] \cdot P_{max_{peak3}} \tag{A.35}$$

Season

The same constraints as in the Three Peaks case displayed above are utilised in the Season case. The demand charge is however only billed four times a year in the Seasons case, instead of twelve times as in the Three Peaks cases.

TOU + SPT
TOU part:

$$EL_{buy_{off-peak}}(i) \leq P_{off-peak} \cdot P_{max_{off-peak}} \tag{A.36}$$
$$0 \leq P_{off-peak} \tag{A.37}$$

$$EL_{buy_{part-peak}}(i) \leq P_{part-peak} \cdot P_{max_{part-peak}} \tag{A.38}$$
$$0 \leq P_{part-peak} \tag{A.39}$$

$$EL_{buy_{peak}}(i) \leq P_{peak} \cdot P_{max_{peak}} \tag{A.40}$$
$$0 \leq P_{peak} \tag{A.41}$$

$$EL_{buy}(i) = EL_{buy_{off-peak}}(i) + EL_{buy_{part-peak}}(i) + EL_{buy_{peak}}(i) \tag{A.42}$$

$$Power_{cost} = \max_{i \in t}[\mathrm{Peak}_{hour_{costs}}] \tag{A.43}$$
$$Peak_{hour_{costs}} = [P_{off-peak} \cdot P_{max_{off-peak}}, P_{peak} \cdot P_{max_{peak}}, P_{peak} \cdot P_{max_{peak}}] \tag{A.44}$$

SPT part:

$$extra_1 + extra_2 \leq 1 \tag{A.45}$$

Where $extra_1$ and $extra_2$ are binary variables.

$$\sum_{i=1}^{t}[\mathrm{EL}_{buy}(i)] = EL_{buy_{day}} \tag{A.46}$$

$$EL_{buy_{day}} \leq day1_{buy_{limit}} + (day2_{buy_{limit}} - day1_{buy_{limit}}) \cdot extra_1 + extra_2 \cdot M \tag{A.47}$$

Where M = 10000000.

$$EL_{buy_{day}} \geq day1_{buy_{limit}} \cdot (extra_1 + extra_2) \tag{A.48}$$

$$EL_{buy_{day}} \geq day2_{buy_{limit}} \cdot extra_2 \tag{A.49}$$

$$over_1 = EL_{buy_{day}} - [day1_{buy_{limit}} \cdot extra_1 + [day1_{buy_{limit}} + day2_{buy_{limit}}] \cdot extra_2] \tag{A.50}$$

$$over_2 = EL_{buy_{day}} - day2_{buy_{limit}} \cdot extra_2 \tag{A.51}$$

$$SPT_{cost} = SPT_{charge_1} \cdot over_1 + SPT_{charge_2} \cdot over_2 \tag{A.52}$$

Where the SPT_{cost} is added to the electricity cost EL_{cost} in the objective function in Equation 3.1. SPT_{charge_1} and SPT_{charge_2} are the costs of exceeding each SPT level respectively in SEK/kW_{el}.

A.3 Input data

To utilise the data collected from Brf Viva in the optimisation model, some modifications of the data set where necessary. This since some scattered data points of heat and electricity loads, solar production and COP of the heat pumps where missing. These hours where filled in with the average value of the hour pre and post the missing one. In addition, data of solar production is missing for a period of 9 days in the midst of August. Data from 9 days ahead of the missing ones, multiplied with random factors between 0.8 and 1.2, is used to fill the blanks. The same approach is used for some spread out hours of lost heat load data. At some occasions, the heat load displayed in the data set takes on an abnormally large or small value. It is assumed that these measurements are wrong and they where therefore replaced with an average of the hour pre and post the abnormal value.

The load of electricity and heat for Brf Viva during the entire investigated time period is displayed in Figure A.1.

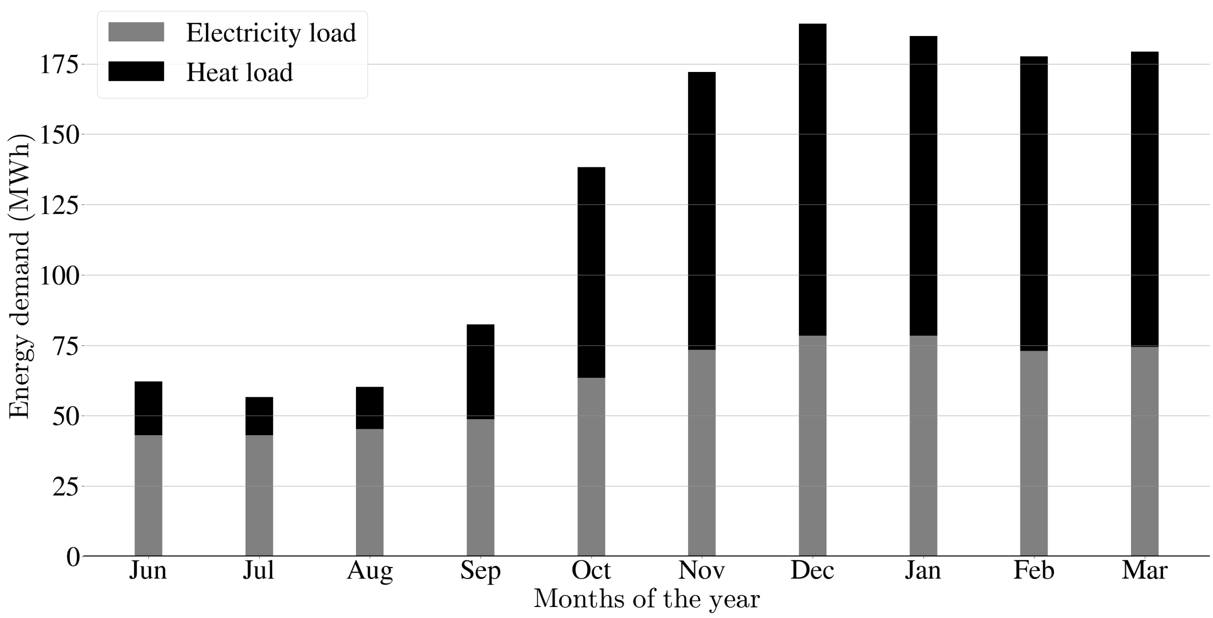

Figure A.1: Total energy load, that is electricity and heat, of the investigated year of Brf Viva in kWh. The share of electricity and heat is also visualised.

From Figure A.1 it is apparent that the total energy consumption is higher during the colder months of the year compared to the warmer months. The heat share is also increased for the fall and the winter months.

The solar PV production of the Brf Viva for the entire investigated time period is shown in Figure A.2.

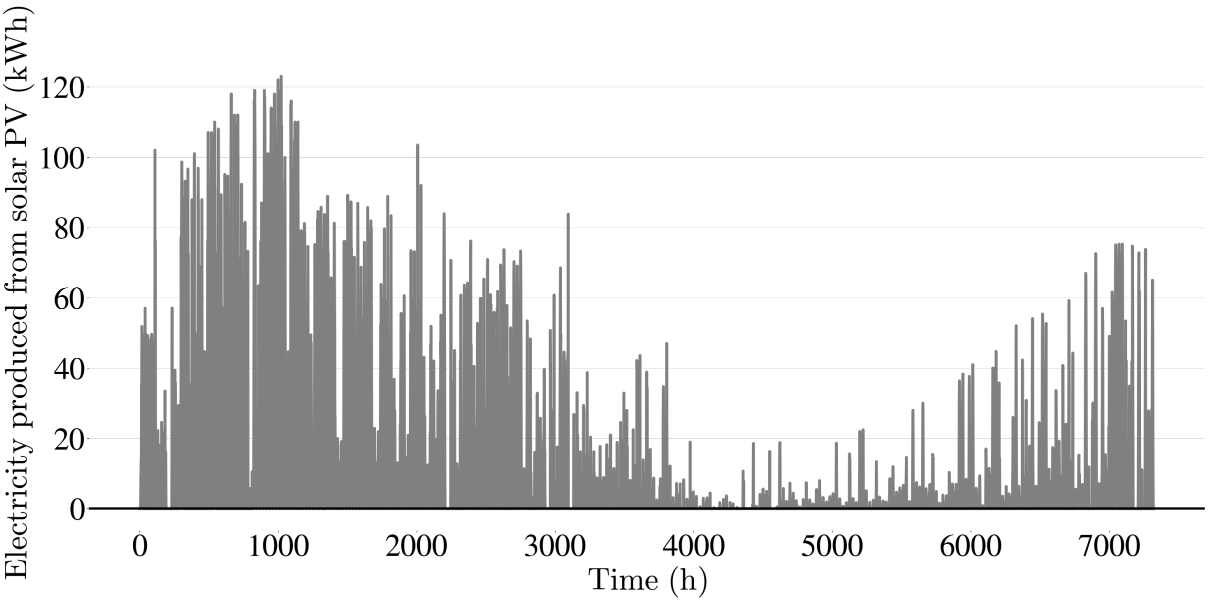

Figure A.2: The total solar PV generation in kWh during the investigated year of Brf Viva, starting from the 1st of June 2019 to the last of March 2020.

Figure A.2 shows the electricity generation from the installed solar PVs in Brf Viva. The solar production displayed is visible from the first of June in year 2019 to the last of March in year 2020. The production is highest at the summer months and almost no production is observed for the winter months.

A.4 Energy system limitations

Table A.1: The capacity and losses of some of Brf Vivas energy equipment.

Equipment	Capacity (kW)	Losses
Solar PVs	170	-
Heat pumps	195	-
AC|DC	-	2%
DC|AC	-	1.5%
DH	-	1%

Table A.1 displays the capacity of the solar PVs and the heat pumps as well as the efficiencies for the AC|DC converter and the heat exchanger with district heating.

A.5 Sensitivity analyses of energy equipment properties

To highlight the impact of each energy unit's size and capacity, the results from sensitivity analyses are presented in this section. In Figure A.3, the impact of battery storage size and capacity is showed.

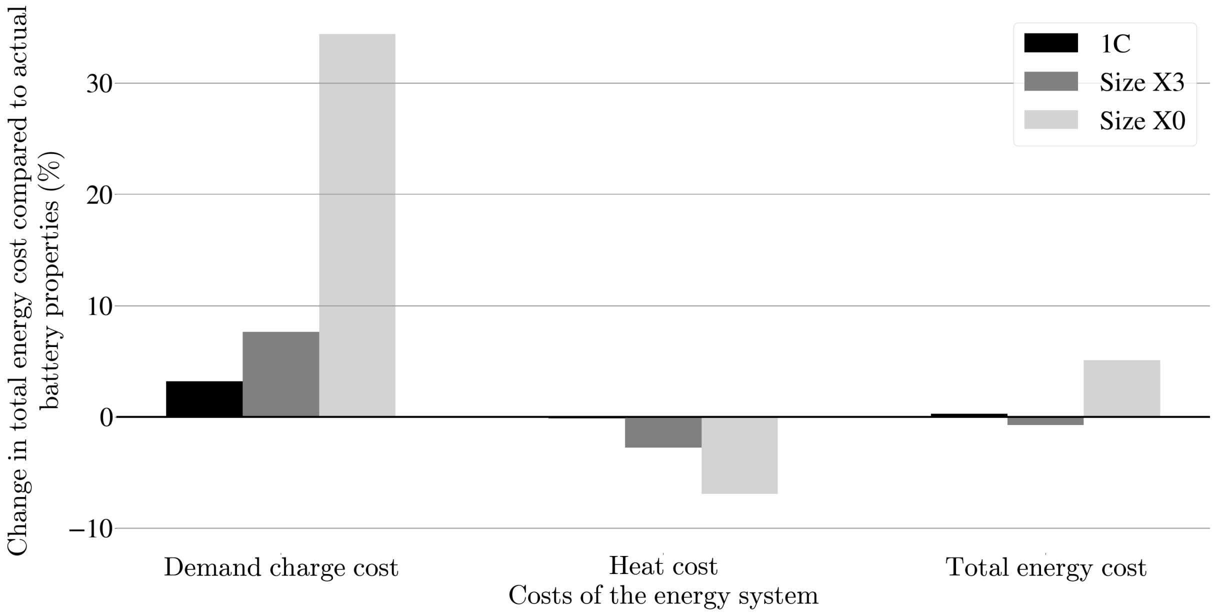

Figure A.3: Impact of size and capacity of batteries on total cost and demand charge cost in March with One Peak, 85 SEK/kW. The different bars represents increase in capacity and size as well as a system without batteries.

Figure A.3 displays how alteration in size and capacity of the batteries impact the demand charge cost and the total heat cost compared to unchanged storage properties. An increase in battery size or capacity has little effect on both the demand charge and the total heat cost, when a demand charge structure is implemented, which can be noticed from Figure A.3. Whereas when the batteries where removed from the energy system a large increase in demand charge could be observed. The management system compensates for this by utilising the increased limit set on bought electricity by utilising the HPs more and reducing the amount of heat bought, and thereby also reducing the impact on total energy cost. Similar results where also achieved for all the other tested cases.

A similar sensitivity analysis was also conducted for the thermal energy storage and the results are displayed in Figure A.4.

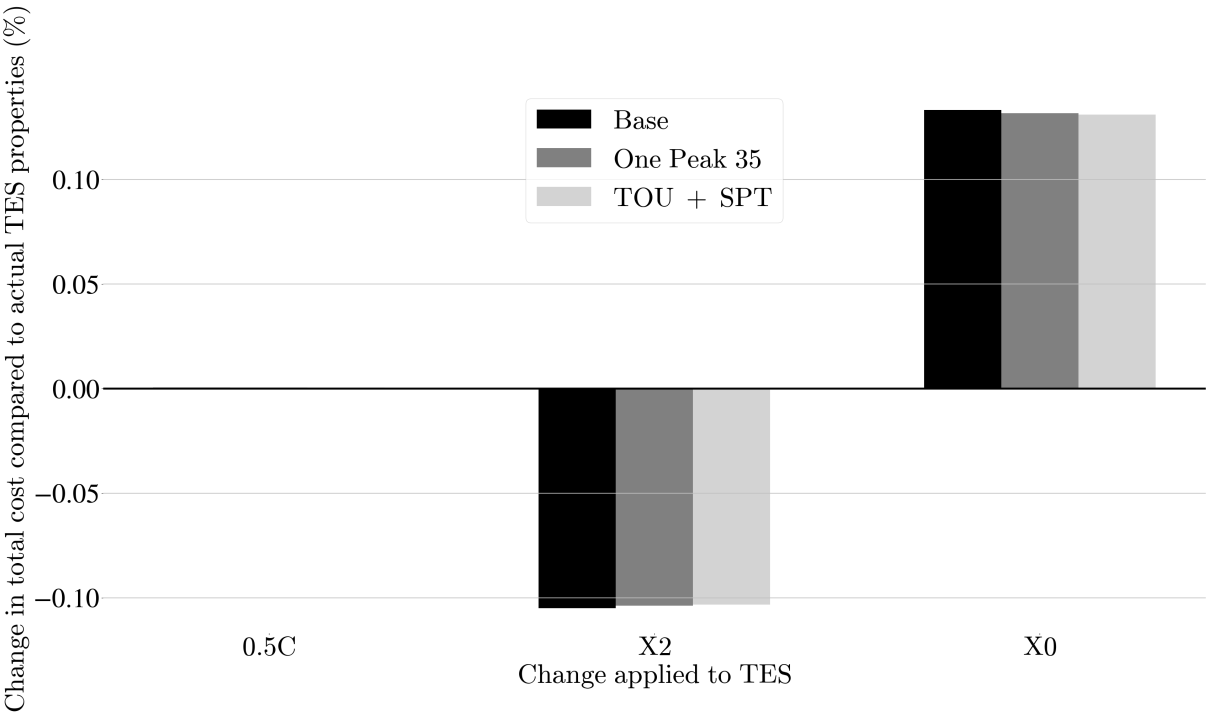

Figure A.4: Comparison of total cost when the size and capacity of the thermal energy storage is changed compared with unchanged storage.

The results show that both enlarging or completely removing the thermal energy storage have a small impact on the total cost of the energy system.

The impact of installed capacity of the solar PVs, as well as the price for sold electricity, on the total energy cost is presented in Figure A.5. The installed capacity of solar PVs and the sell price of electricity are both increased with 50% and 100% respectively.

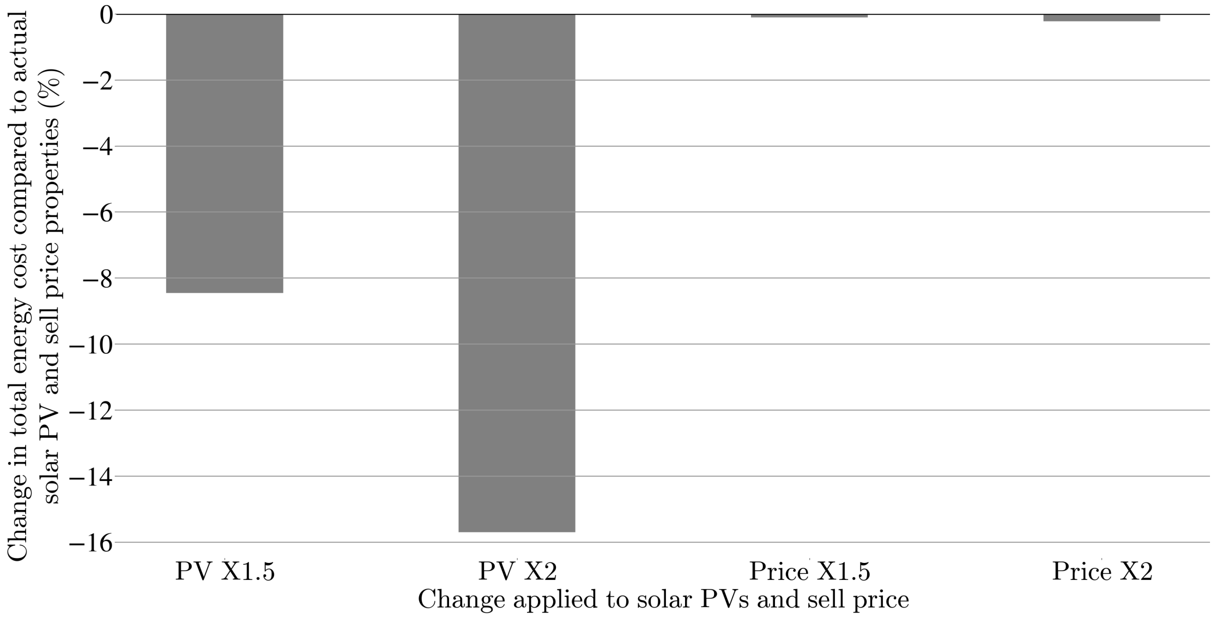

Figure A.5: The impact on total energy cost when installed amount of solar PVs or the sell price of electricity is increased, for Base Case in June. The total energy cost is compared to those of the actual solar PV installation and sell price of electricity.

Figure A.5 shows that the impact on total cost is greater when the installed amount of solar PVs are increased, compared to when the sell price of electricity is enlarged. However, on a yearly basis the reduction in total cost with a duplication of solar PVs is no larger than 1.2%.

The load duration curve of the TES is displayed in Figure A.6.

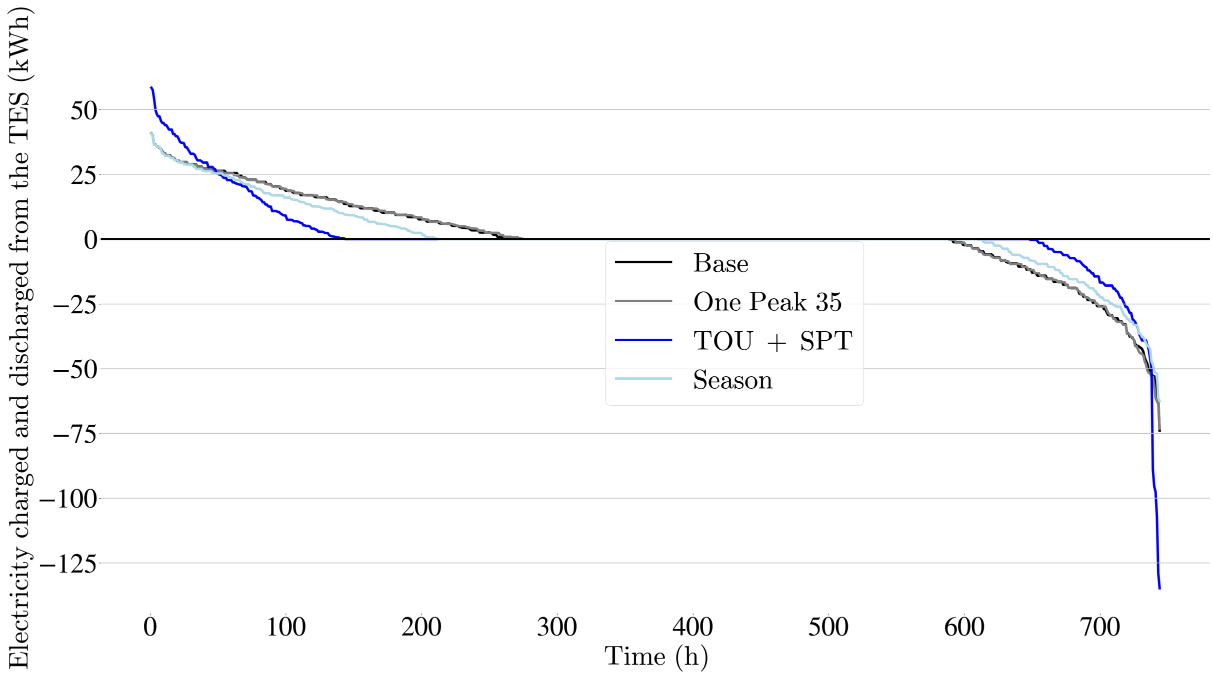

Figure A.6: Load duration curve of the TES in December for four demand charge cases tested, Base, One Peak 35, TOU + SPT and Season.

Figure A.6 indicates that the TES is utilised for about half of the hours in December. Out of these hours, the DoD is high for a few hours but most of the time, neither the TES size or capacity is utilised to its maximum.

A.6 Sensitivity analysis of patterns of purchased electricity

The impact on total energy cost and demand charge when different warm start values are implemented to the model in December are displayed in Figure A.7.

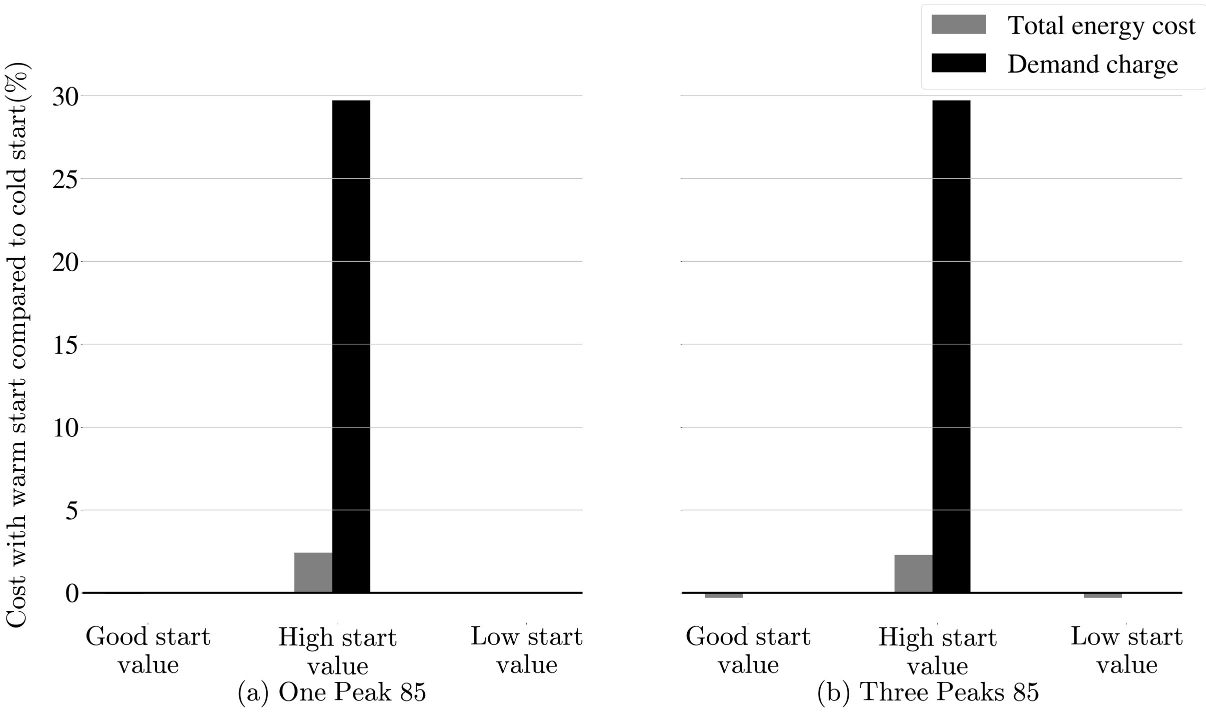

Figure A.7: Total cost and cost of the demand charge during December for cases with warm start compared to the costs of the same case with a regular cold start. The different warm start cases depend on the nature of the implemented warm start value for the electricity peak. A high, a low and a good start value are presented for each case. (a) The difference in cost for the case One Peak 85. (b) The difference in cost for the case Three Peaks 85.

It is apparent from Figure A.7 that introduction of warm start has a large impact on the demand charge than the total energy cost. However, the reduction in total energy cost when a good and low start value is used are very small. The results from One Peak 85 and Three Peaks 85 follow the same pattern for the different types of warm start values. In both cases when a higher start value is used the total energy cost could be increased as a result from a large increase in demand charge cost.

From the results provided in the section 4 in the report, it is evident that the results of the TOU + SPT structure and the Base Case often are similar. In Figure A.8 a comparison of the two cases behaviour during two days in December are displayed.

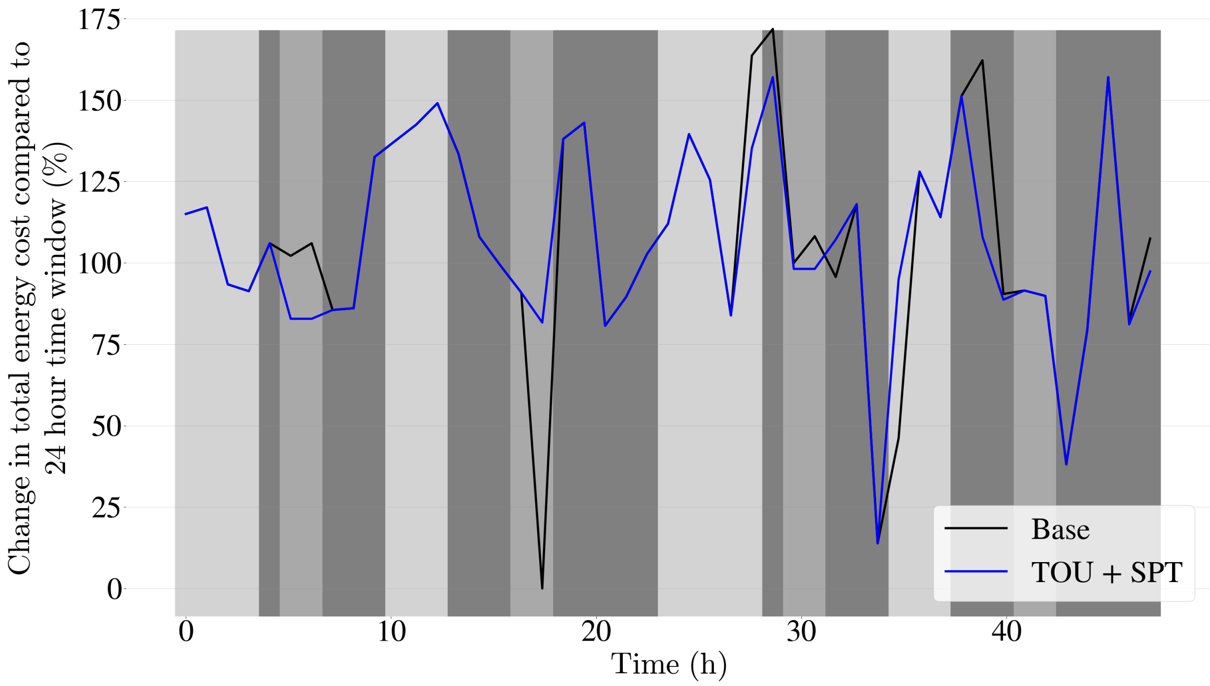

Figure A.8: Bought electricity during the first two days of December. The black line represents electricity bough with Base Case and the blue line electricity bought with the TOU 1 + SPT structure. The colours in the background represent the division of the hours into off-peak, part-peak and peak, by lightest to darkest areas. These are in accordance with the green, yellow and red hours described in Section 3.2.5 in the Method.

The curves in Figure A.8 show the behaviour of purchased electricity differs between the TOU + SPT and the Base Case. At the majority of the time, the two cases follow each other closely. However differences can be noticed around hour 18 and 38, where the TOU + SPT model chooses to purchase more electricity during the off-peak hours than the base case. This to reduce the peak of bought electricity during peak hours to avoid a high demand charge.

A.7 Sensitivity analysis of model solution window

The total energy cost obtained with a 24 hour time window is compared with that the total energy cost obtained with a perfect foresight window, and the results are shown in Figure A.9.

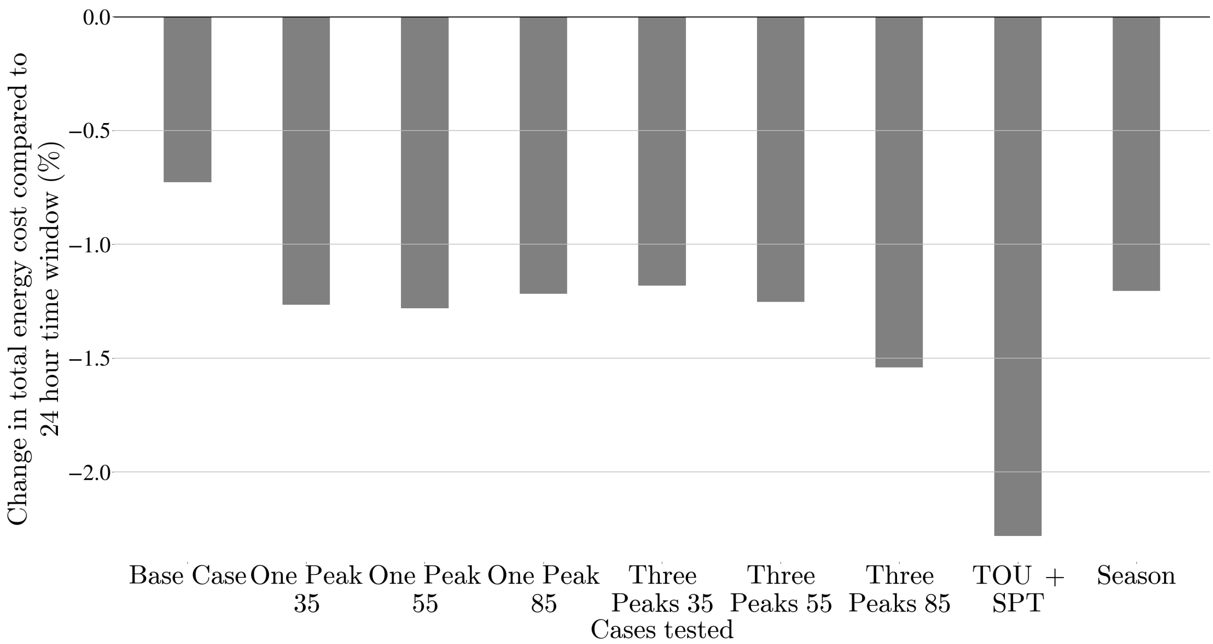

Figure A.9: Total cost of tested cases using perfect foresight compared to total cost when a foresight of 24 hours.

As seen in Figure A.9, the total energy cost decreases as the solution window is increased. The model can make better decisions when it receives input data for the entire solution period from the start of optimisation, since unnecessary precaution actions can be avoided.