NTNU – Trondheim
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Modelling Combined Heat and Power Plants

Modelling CHP Plants on a System Level in
the EMPS Power Market Model

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Problem Description

The project shall develop an improved modelling of Combined Heat and Power plants to be used in the EMPS power market model and implement this for one of Statnett's datasets.

Overall, this thesis is intended to improve the modelling of CHP plants in Denmark.

The modelling is to be implemented in the EMPS power market model.

It has to be verified whether the new modelling is an improvement or not. It is a part of the thesis to find an appropriate method of testing the changes and to compare the new modelling with the old.

More specifically, the problem to be solved consists of the following subproblems:

- Describe the existing CHP modelling at Statnett and discuss potential areas of improvement
- Describe the Danish CHP market with differentiation regarding plant size and characteristics
- Develop an operation strategy for a CHP plant with a gas fired boiler, electric boiler and heat storage
- Describe the SINTEF developed functionality for temperature dependent capacity correction
- Analyze the consequences of an improved modelling
- Simulate the model with new and old CHP modelling

Preface

This thesis contains original, unpublished, independent work by me, MSc. student and the author of this report, Per Arne Vada. The work is carried out in the course TET4905 - Energy Use and Energy Planning – Master's Thesis, at the Department of Electric Power Engineering at the Norwegian University of Science and Technology, Trondheim, during the spring semester of 2014. The course accounts for 30 credits in Norway. This thesis builds on the work done in the course TET4510 - Energy Use and Energy Planning, Specialization Project during the fall semester of 2013.

The subject is the modelling of combined heat and power plants on a system level in the EMPS power market model. The work has been carried out in co-operation with the section for power market analysis at Statnett's office in Nydalen, Oslo.

I am grateful to the multiple and very knowledgeable contributors to this thesis work. I would like to thank my supervisor, Prof. Gerard L. Doorman at NTNU and Statnett, for his guidance and patience. I would like to thank everyone at Statnett for having me in the office, and especially Ivar Husevåg Døskeland, co-supervisor and senior analyst at Statnett, for helping me understand and use the EMPS model, for forming the thesis problem along with Gerard and Anders Kringstad, for discussing my methods and results for the duration of this semester and report feedback. I would also like to thank Karin Lövebrant, analyst at Statnett, and Martin Kristiansen, fellow MSc. student at NTNU, for invaluable feedback on the thesis report.

There are also a few external contributors I am especially thankful of. Birger Mo at SINTEF has been very helpful when explaining the details of how the temperature dependent capacity correction function works and allowed me to use the function for academic purposes. Jens Pedersen and Geir Brønmo at Danish TSO Energinet have been most helpful when discussing how the Danish CHP market works and how Energinet have modelled CHP in the EMPS. I would also like to thank Kim Selch, operator at the Billund CHP plant, for showing me around his facility.

Despite all this help, the report may contain errors or mistakes. All errors or mistakes in this thesis are mine and mine alone.

The front page picture is taken through the glass window of a biomass boiler at the Billund CHP plant by the author.

Oslo, 19th of June 2014

Per Arne Vada

Abstract

Combined heat and power ("CHP") plants enable simultaneous production of electricity and useful heat allowing for high total fuel efficiency. 70 % of all electricity produced in Denmark in 2012 was produced from plants classified as CHP plants. Because of the close power market connection between Norway and Denmark, a sufficient modelling of the Danish production portfolio is important to Statnett, the Norwegian TSO.

CHP plants are very complex to model at a system level as they participate in both power and heat markets and exist with such technological diversity. The objective of this thesis was to uncover potential for improvements and to implement new modelling elements to the modelling of Danish CHP plants in the SINTEF developed EMPS power market model. The EMPS model does not explicitly model heat markets.

Three areas were found to have potential for improvements:

1. The average annual production profiles: the existing production profiles were too volatile, seemingly random and lacked documentation
2. The aggregation of small CHP plants: The existing aggregation of small CHP not sufficiently diversified to account for technological diversity at a system level
3. Temperature dependent capacity: the CHP production was not temperature dependent apart from a general seasonal variability.

It was assumed that CHP units' operation can be modelled by a linear feasible operating region describing the relation between instant heat and power production. CHP utilities must meet the heat load at all times. Based on assumptions about the heat load as a function of outdoor temperature and historical temperature data, new annual production profiles relating to average temperature were created. A new method of aggregating small CHP plants was developed based on decentral DH utility statistics and a new way of determining their marginal cost. In addition, a function developed by SINTEF that corrects the CHP production capacity according to the actual temperature was implemented. The new modelling elements were largely based on a CHP operation strategy developed for this thesis.

The new elements were implemented in steps to see the effect of each step. The implementations formed three new EMPS model datasets, in addition to the one for the pre-existing modelling. Each element was shown to have been implemented correctly and addressed the issues as intended.

When comparing thermal production per week [GWh] from observed data with modelling results for the period 2001-2008 it was shown to be a trend that modelled thermal production follows the observed thermal production in general for all datasets. This is largely due to general, seasonal variations in available back pressure capacity at a low MC.

However, the degree to which the data fitted with this trend varied amongst the model datasets. The new modelling elements proved to be incremental improvements with regards to following the observed thermal production from week to week. The pre-existing modelling performed worst and the new dataset with all three new modelling elements, *NewModTC*, performed best, with regards to matching observed thermal electricity generation. Introduction of the forced aggregated small CHP production was the most effective new modelling element to increase the R^2 to indicate a better fit with the overall trend that modelled thermal production followed the observed.

A comparison between observed data and results from the existing modelling showed that thermal electricity production in general was much more temperature dependent and less price dependent in reality compared to the model. The new modelling elements showed incremental improvements to the overall modelling, as thermal production became more temperature dependent and less price dependent, i.e. approaching the trends of the observed data. However, the comparisons also showed that there remains some work to increase temperature dependency and decrease price dependency for the modelled thermal production further.

The new model datasets resulted in more volatile prices in Denmark on average across all scenarios compared to the existing modelling. The increased temperature dependency was the main reason for this. Implementing new production profiles changed the available, low cost back pressure capacity, so that less was produced, compared to the existing modelling, during high load hours, increasing prices, and more was produced during low load hours, contributing to decreased prices. It is likely, but not shown here, that this was due to a new, flat distribution of CHP production capacity over the week's 168 hours. Overall, the new small CHP aggregation resulted in a moderate price reduction, as production was forced at zero MC, increasing production especially during the winter. The function for temperature dependent capacity correction showed to change the prices for certain hours significantly, but no overall increase or decrease for neither initially low nor high price hours. The prices changed mainly due to the function regulating available back pressure capacity down, increasing prices, or up, lowering prices for individual hours.

Sammendrag

Kraftvarmeverk ("CHP") er anlegg som produserer nyttig varme og elektrisitet samtidig. Disse anleggene kan operere med en høyere total effektivitet enn vanlige termiske kraftverk. Omtrent 70 % av all elektrisitet produsert i Danmark i 2012 ble produsert av anlegg i kategorien kraftvarmeverk. På grunn av den tette markedskoblingen mellom kraftsystemene i Norge og Danmark er den norske TSOen Statnett opptatt av å ha en så god som mulig modellering av den Danske produksjonsporteføljen.

Det er en kompleks oppgave å modellere CHP-anleggene av to grunner. De deltar både i et kraftmarked og et varmemarked. I tillegg finnes det nært sagt utallige kombinasjoner av teknologi og størrelse som gir anleggene forskjellige driftsmuligheter. Målet med denne oppgaven var å finne forbedringspotensial i den eksisterende modelleringen av CHP anlegg i Danmark i Samkjøringsmodellen og å implementere nye elementer for å forbedre denne modelleringen.

Den eksiterende modelleringen hadde 3 konkrete forbedringsområder:

1. De årlige produksjonsprofilene var for volatile, tilfeldige og manglet dokumentasjon
2. Den eksisterende aggregeringen av små gassfyrte CHP-enheter var ikke modellert diversifisert nok for å representere det totale systemet av små enheter
3. Temperaturavhengig korrigering av produksjonskapasitet: CHP produksjonen varierte ikke med temperaturen i scenariene bortsett fra en generell sesongvariasjon.

Det ble antatt at forholdet mellom kraft- og varmeproduksjonen fra CHP enheter kan modelleres ved et lineært driftsområde, med elektrisk- og varmeeffekt på hver akse. CHP anlegg må møte varmelasten til enhver tid. Basert på varmelasten som en funksjon av utendørs temperatur og gjennomsnittlig temperaturdata ble nye produksjonsprofiler for anleggene laget. En ny aggregering av små CHP anlegg ble laget på bakgrunn av en nyansert diskusjon om marginalkostnader og en gjennomgang av ny statistikk for denne typen anlegg. En funksjon som korrigerer produksjonskapasiteten for CHP anlegg i henhold til faktisk ukentlig temperatur utviklet av SINTEF ble brukt med mål om å øke temperaturavhengigheten til CHP produksjonen.

De nye elementene ble implementert stegvis for å tillate en sammenligning mellom hvert nye element i modellen. Hvert steg ga da et nytt datasett i modellen, og i tillegg til basisdatasettet til Statnett, som er den eksisterende modelleringen, ble det 4 datasett totalt. De nye elementene i modelleringen ble implementert korrekt og virket til sin hensikt når det gjaldt modelleringen av CHP anleggene.

En sammenligning mellom observasjoner og modellresultater for termisk produksjon per uke i perioden 2001-2008 viste at det var en trend for alle datasettene at termisk

produksjon i modellene fulgte observert termisk produksjon. Dette var i stor grad på grunn av en generell sesongvariasjon i tilgjengelig billig mottrykks kraftproduksjon.

Det var derimot betydelige variasjoner mellom datasettene når det gjaldt hvor godt datapunktene passet med denne trenden, dette ble vist ved hjelp av en lineær regresjonsmodell. De nye datasettene, med de nye elementene i modelleringen, viste seg å være inkrementelle forbedringer fra basisdatasettet når det gjaldt å matche observert produksjon, og det siste datasettet, *NewModTC*, med den komplette nye modelleringen traff best. En økt R^2 betød at datapunktene nå nærmere regresjonsmodellen som representerte trenden. Det var den nye aggregeringen av små CHP anlegg som viste seg å gi størst forbedring for et enkelt datasett.

Det viste seg også at observert termisk produksjon varierer mer med temperatur enn med pris, dette i motsetning til resultatene i den eksisterende modelleringen., som er svært prisavhengig og mindre temperaturavhengig. Videre viste det seg at de nye datasettene med den nye modelleringen nærmet seg tendensen i observert data. Termisk produksjon ble mindre prisavhengig og mer temperaturavhengig i de nye datasettene, også her med det siste datasettet med den komplette nye modelleringen som det best presterende. Det må derimot sies at observert termisk produksjon fremdeles er betydelig mindre prisavhengig og mer temperaturavhengig enn for det best presterende datasettet i modelleringen.

Prisene blir mer volatile i datasettene med ny modellering enn i det eksisterende datasettet. Generelt er det slik at jo mer temperaturavhengig termisk produksjon er jo mindre kan den respondere på prissignaler og dette resulterer i mer volatile priser. Ved implementering av de nye produksjonsprofilene ble tilgjengelig produksjonskapasitet for de relativt sett billige mottrykksanleggene endret slik at mindre var tilgjengelig i timer med høy last og mer var tilgjengelig i timer med lav last, relativt sett sammenlignet med eksisterende modellering. Dette skyldtes også nye effektprofiler som fordelte kapasiteten annerledes enn de tidligere effektprofilene hadde gjort.

Implementeringen av ny aggregering av små enheter, som i hovedsak ga mer og tvungen produksjon, bidro generelt til å senke prisene og spesielt på vinteren, da mye mer tvungen termisk produksjon kom inn på markedet med den nye aggregeringen. Funksjonen for korrigering av CHP kapasitet bidro ikke til noen generell endring i prisnivået, men viste helt tydelig å kunne både senke og øke prisen for enkelttimer, hovedsakelig gjennom å øke eller senke tilgjengelig, billig produksjon fra mottrykksanlegg.

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Abbreviations

AD	-	Aggregate Demand for Power
AS	-	Aggregate Supply of Power
BID	-	Power market model developed by Pöyry
Biofuels	-	Biomass and biogas
BP	-	Back pressure
CHP	-	Combined Heat and Power
Cond	-	CHP Extraction Plant, Condensing mode
COP	-	Coefficient of Performance
DECC	-	UK Department of Energy and Climate Change
DH	-	District Heating
EMPS	-	Multi-area Power-market Simulator
EOPS	-	One-area Power-Market Simulator
EPS	-	Energy and Power Flow, extension to the EMPS
FOR	-	Feasible Operation Region
MC	-	Marginal cost [€/MWh or €c/kWh]
O&M	-	Operation and Maintenance
ROR	-	Run-of-river Hydro production
TSO	-	Transmission System Operator
W	-	Watt [Instantaneous Power, electric or heat]
Wh	-	Watt hour [Energy, electric or heat]

1 Introduction

Combined heat and power ("CHP") plants comprise of technologies that enable simultaneous production of useful heat and electric power. In general, these plants operate at a higher total fuel efficiency compared to regular thermal power plants [1]. As opposed to regular thermal based power plants, the excess heat from a CHP plant is used for specific purposes. Examples of such purposes can be residential district heating or industrial processes. Therefore, a CHP plant must be set up to serve both heat and electricity demands.

In 2012, just above 30 % of all electricity produced in Denmark was produced by wind farms [2]. The remaining 70 % was produced by plants categorized as CHP plants [2]. In 2012, 74.6 % of all thermal electricity produced was co-generated with heat [2], and 73.0 % of all district heat was co-generated with electricity [2]. These statistics show that CHP technologies are well developed and widely used in Denmark. They also illustrate the significance of the role CHP technology plays in Danish heat and power markets.

The Norwegian and Danish electricity systems are closely connected both technically and in market terms. Participants in both countries trade electricity at the Nord Pool Spot market, and physically, the countries are connected by DC-lines in the North Sea and AC-lines through Sweden. The Norwegian Transmission System Operator ("TSO"), Statnett, has to take this region into consideration when carrying out its mission. To do this, Statnett use several power market models. Denmark is represented in a few of these, also in the EMPS. It is important to Statnett that the Danish power market is represented as realistic as possible in this model. The EMPS (EFI's Multi-Area Power-market Simulator) is developed by SINTEF [3].

The purpose of this thesis is to discover potential improvements to the existing modelling of CHP in Denmark and implement these improvements within the framework of the EMPS model.

Chapter 2 provides an introduction to CHP prime movers and other equipment found in CHP plants. Chapter 3 presents the EMPS power market model, which is used as a platform to test the modelling of CHP. Chapter 4 presents a short literature review of how problem of cogeneration production planning can be formulated and solved with linear operational research methods. Chapter 5 provides an introduction of how CHP was modelled in the existing modelling. Chapter 6 presents the main discussion on how CHP should be modelled in general and in the EMPS. This chapter also presents the main findings with regards to potential improvements in the modelling of CHP in the existing EMPS. Chapter 7 presents how the new modelling elements have been implemented in the EMPS and the resulting datasets. Chapter 8 presents the verification of the implementation of each new modelling element and the analysis of thermal power production comparing the models with observed data. Chapter 9 presents a discussion on potential sources of error or other aspects of this thesis that could have been carried out in other ways. Chapter 10 presents the conclusions drawn from this thesis.

This problem has previously been addressed in a project work report [4]. This report [4] is added as a digital appendix to the submission of this thesis, but it is not a pre-requisite to reading this master's thesis. However, for interested readers, it can be provided upon request.

2 Combined Heat and Power Technology

Combined Heat and Power ("CHP") is the simultaneous production of useful heat and electric energy. The main argument for combined heat and power production is the advantages in terms of total fuel efficiency [1]. Compared to a conventional thermal power generator, where the excess heat is not used, CHP systems utilize that heat. In addition, distributed CHP, strategically located at energy point of use, can avoid substantial costs of transporting heat or electric power over long distances. CHP is versatile and can be used for several industrial, commercial and residential purposes [5].

This chapter gives an introduction to CHP technology. As a reference the *Catalog of CHP Technologies* provided by the U.S. Environmental Protection Agency and their *CHP Partnership* is used [5]. The CHP Partnership is a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP [6]. The UK Department of Energy and Climate Change's ("DECC") *CHP Focus* [7] is used as a backing reference. Both sources have a potential of being biased towards CHP technology, but should be expected to provide a sufficiently impartial theoretical background on the subject.

The catalog presents five main CHP prime mover technologies: Gas turbine, reciprocating engine, steam turbine, micro turbines and fuel cells. Micro turbines are characterized by a typical electrical high end capacity of 0.25 MW_e [5]. Fuel cells for micro CHP systems have been tested and are currently tested in demonstration projects in Denmark [8] [9]. Fuel cells are categorized with a high end power capacity of 2 MW_e [5]. These technologies can become influential technologies in power and heat systems. However, because of their current status on unit size and commercial viability, micro turbines and fuel cells are not considered further in this report.

In the next sections, gas turbine, reciprocating engine and steam turbine CHP prime movers are presented.

2.1 Gas Turbines

Gas turbines can range from 0.5 to 250 MW_e installed capacity, and are used for both power-only and CHP applications [5] [10]. Gas turbines operate on the Brayton cycle, where atmospheric air is compressed, heated and expanded [5]. Excess thermal energy is converted to mechanical energy in the expansion. This mechanical energy goes on to the generator and is converted to electrical energy. Available thermal energy that is not converted into electrical energy can then be used directly for heating purposes or run through a steam turbine (Combined-cycle technology), to produce more electrical energy [5].

Figure 1 shows a gas turbine with a heat recovery steam generator ("HRSG"). Heat is recovered from the gas turbine exhaust and can either be used directly (simple cycle) or run through a steam turbine to make more electrical energy (combined cycle).

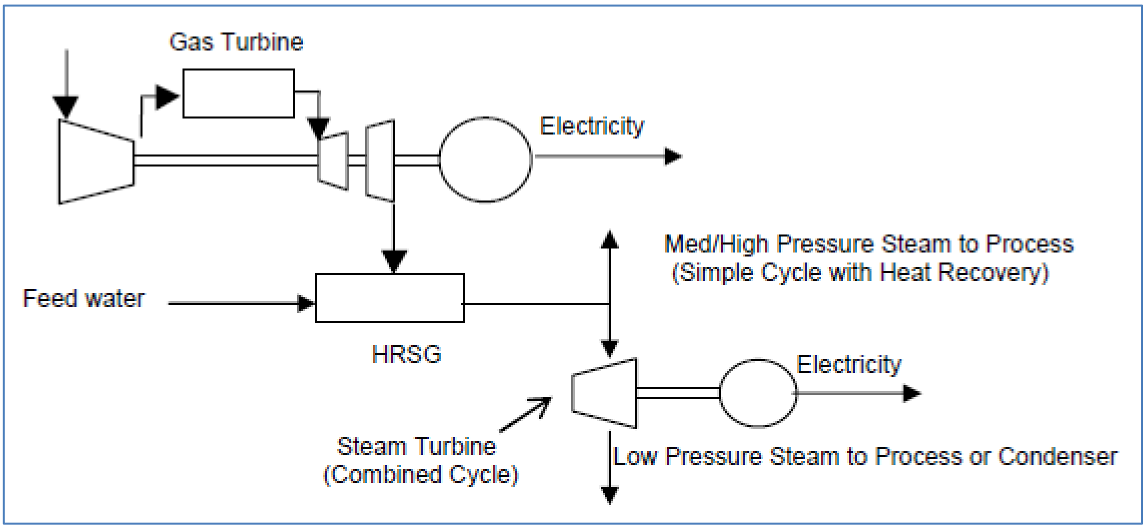

Figure 1: Combined-cycle and Simple-cycle w/ heat recovery components [5]

Gas turbine systems can operate at a power to heat ratio (the amount of electricity generation [MW_{el}] per unit of heat generated [MW_{heat}]) between 0.5-2 [5] or 0.33-0.67 according to another source [10]. These estimations of power to heat ratios are very different, and possibly not meant to cover the same variety of gas turbine prime mover based CHP technologies.

2.2 Reciprocating engine

Reciprocating internal combustion engines vary in typical sizes from a few kilowatts to over 5 MW [5] (15 MW according to [11] for compression ignition engines, as opposed to 4 MW for spark ignition engines) and a wide range of applications, both mobile and stationary. They start quickly, follow load well, have good part load efficiencies and generally high reliabilities [5]. There are two main types, the spark ignition (Otto-cycle) and compression ignition (Diesel-cycle) engine [5]. The mechanical components are largely the same, and the main difference is how the explosions within the cylinders are started, either by spark or compression [5].

The spark ignition engines are largely run on lighter fossil fuels such as natural gas or propane, but also other gaseous fuels such as biogas or landfill gas, while compression ignition engines run on diesel fuel or heavy oil [5]. The explosions within the cylinders drive a shaft which is connected to an electric generator. Heat can be recovered from two main sources after the process, the exhaust and engine cooling systems, in the form of hot water or low pressure steam [5].

Reciprocating engines can typically operate at a power to heat ratio of 0.5-1 [5] [11].

2.3 Steam turbines

Whereas an engine or a gas turbine can be seen as one unit co-generating heat and electricity, the steam turbine prime mover systems has a different characteristic. Steam turbine prime mover CHP systems typically consist of two separate units, one for heat production, the boiler, and one for electricity generation, the steam turbine.

Heat, in the form of high pressure steam, is generated in a boiler. This steam is then directed onto a steam turbine, where it expands and turns a shaft which is connected to a generator that produces electricity. Not all of the generated heat can be extracted and converted to electrical energy. This excess heat can either be run through another steam turbine or used directly for various purposes.

Steam turbine CHP units are normally categorized into two main types: back-pressure and extraction steam turbines. The main difference between these is presented in the next two sections.

2.3.1 Back-pressure steam turbine

Back-pressure steam turbines exhaust the entire steam flow [5] and are regarded as the most simple of the steam turbine prime mover types [12]. This means that for a given amount and quality of heat demanded from the turbine, the electricity output is given. This is shown in Figure 2. A back-pressure unit produces power and heat at a given, fixed power to heat ratio of 0.1-0.3 [5] (0.1-0.33 [12]).

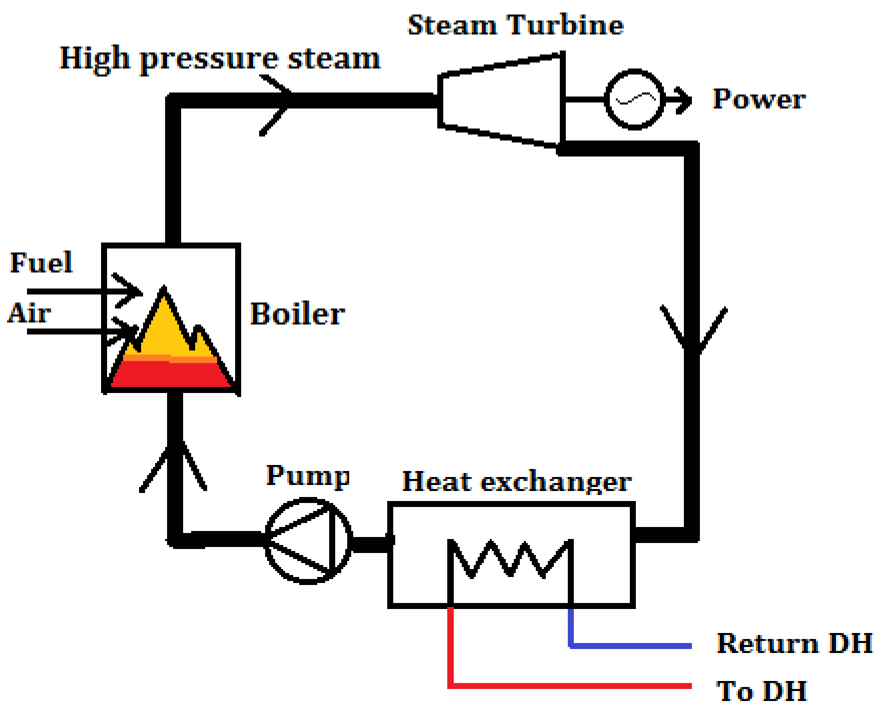

Figure 2: Diagram representing the principle of back-pressure CHP units [1]

This means the unit can increase or decrease its heat output, and the power output will automatically change as well. We have the following equation:

$$\frac{\Delta P_{el}}{\Delta P_{heat}} = b \quad (1)$$

Where a change in heat output, ΔP_{heat}, will result in a change in power output, ΔP_{el}. b is always positive and constant for a back pressure steam generator.

2.3.2 Extraction steam turbine

An extraction steam turbine has openings in its casing, which allows the operator to extract steam at different pressures and temperatures from different stages in the turbine [5]. The rest of the steam is run through the whole steam turbine. It is possible to maximize power output by expanding the steam down to vacuum [12]. After such a process, the leftover heat is normally considered useless [12]. Therefore, as opposed to a back bressure steam turbine CHP system, an extraction steam turbine system can allow for more electricity generation when heat demand is low, i.e. more flexible plants. An extraction steam turbine can operate at essentially any power to heat output [5]. This principle is shown in Figure 3.

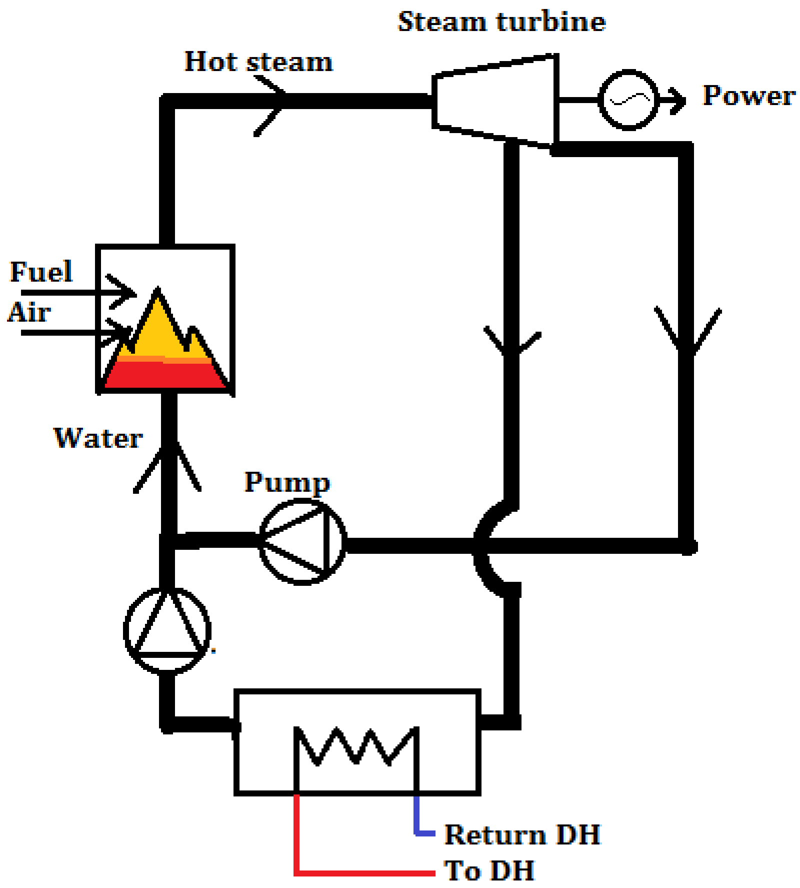

Figure 3: Diagram of the principle of extraction CHP units [1]

2.3.3 Combined cycle

In a combined cycle, the exhaust of a gas turbine, in the form of pressurized steam, is run through a steam turbine, enabling higher plant total efficiency [13] and increased electricity generation. This was shown in Figure 1.

2.4 CHP plants

In chapters 2.1 through 2.3, the typical prime movers for CHP plants are presented. CHP units will be named according to their prime mover. As an example, a gas turbine CHP unit is a CHP unit with a gas turbine prime mover. The definition of a CHP unit is that these are units capable of producing heat and electricity simultaneously. However, extraction plants are also able to produce electricity without simultaneous heat production.

For this report a CHP plant is not limited to a single CHP unit, but may include units only for producing heat or other technologies that directly impacts on the CHP plant operation strategy. In chapters 2.4.1 through 2.4.3 main additional technologies are presented.

Coal, biomass and natural gas are the dominant fuels for heat and power production in thermal plants in Denmark. A short introduction to the Danish power market is given in appendix 1, 13.1.

2.4.1 Boilers

Boilers are units that only produce heat, and are not to be confused with steam turbine boilers. They are incapable of producing electricity. In addition to CHP units, most CHP plants will have boilers, either because it is the best choice financially or simply as a back-up unit to deliver heat in case the CHP unit fails.

Boilers (without CHP in any form, but including heat pumps and boilers) represented 27.4 % of all district heat produced in Denmark in 2012; the rest was produced by CHP units [2]. Out of these 27.4 %, 12.2 % were produced from biomass and 9.3 % from natural gas.

2.4.2 Electric boilers and heat pumps

Electric boilers are similar to other boilers. They enable heat production from electricity, and they are mentioned especially in this section because of their direct impact on the power market compared to other boilers. Electric boilers must buy electricity from the grid to produce heat.

Heat pumps are another way to convert electric power into heat. On average they might operate with a COP of around 3 [14], which would imply significantly lower operating costs compared to an electric boiler of a COP of below 1.

According to Energistyrelsen and Energinet the investment cost (€ per MW of installed heat output capacity) of an electric heat pump is about ten times of that of an electric boiler [14].

In 2012 a total of 44 electric boilers and heat pumps were installed with a total heating capacity of 379 MW in Denmark [2]. They produced 0.4 % of all district heat in Denmark the same year [2]. As the total capacity for all only heat producing units is 13 233 MW [2], the heat pumps and electric boilers are largely neglected on a system level.

2.4.3 Accumulator

An accumulator tank is used to store hot water. This enables the operator of the system to decouple production of electricity and heat. For example, if the demand for heat is low, but the electricity spot price is high, a CHP plant could run its CHP unit, storing the heat for later use and selling the electricity instantly.

Heat to supply a district heating ("DH") system for anywhere between a few hours [15] and a few days [16] can be stored in such a tank, depending on both tank size and system heat load. Almost all DH systems in Denmark are equipped with an accumulator tank [16].

Figure 4 shows how different units at a CHP plant in Skagen, Denmark were operated during fourteen days in October 2013. The numbered list below explains some observations made on the operation of the Skagen plant. The explanation can be found in Figure 5.

1. Electric boilers (orange) are used to produce heat, possibly due to low spot prices (green) or favorable prices for down regulation (yellow), meaning the plant was rewarded for using electricity.
2. When running the electric boilers, more heat was produced than demanded; therefore surplus heat from this production was stored in the accumulator tank (red).
3. During a few hours of high electricity spot prices, the CHP units (motors, green), was started, and then shut down as prices fell.
4. CHP motors are run during hours with sufficiently high electricity prices; surplus heat from this production is stored in the accumulator tanks.
5. No heat produced at the CHP plant, only from secondary producers (industry, grey) and delivered by accumulator tanks.

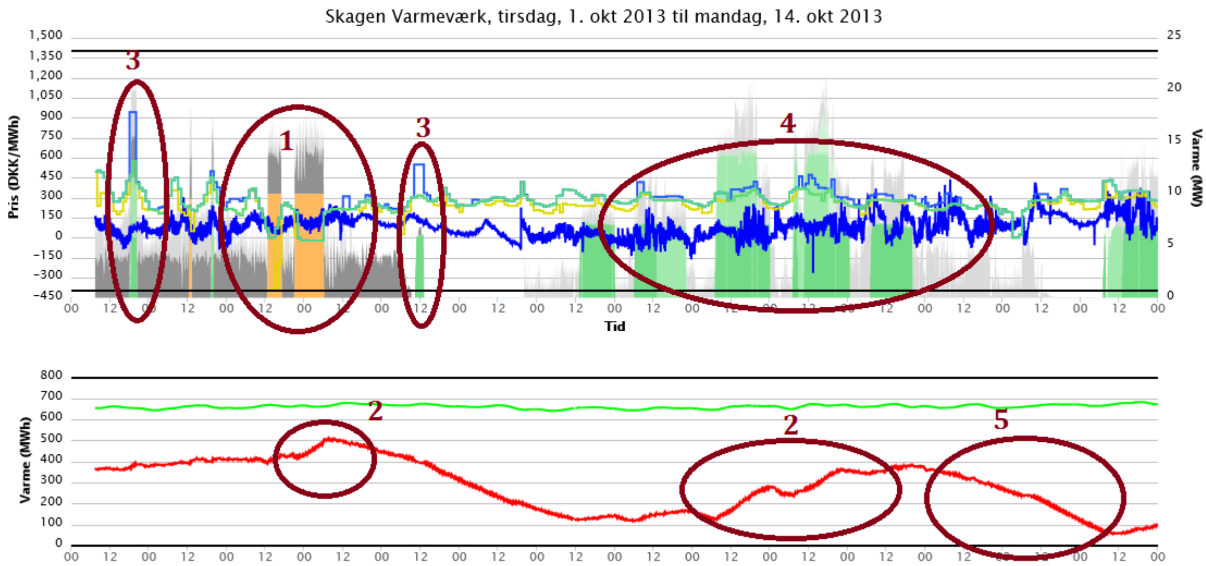

Figure 4: Operation at Skagen CHP plant from 1.10.2013 to 14.10.2014 [17]

Figure 5: Explanation Figure 4 [17]

Describing these technologies and the subsequent CHP plant operation strategy in mathematical terms using relevant information, such as system price and outdoor temperature, is on of the main challenges of this thesis.

In the next chapter the EMPS model is presented.

3 The EMPS model

3.1 Why was the EMPS chosen?

Power market models are used by market participants for decision support [18]. Statnett uses several models, with different strengths and weaknesses, for different types of analyses. Power market models attempt to describe some characteristics of the power system and its market mechanisms. Such models have various areas of focus and degree of detail depending on what purpose the model is used for.

The Statnett EMPS model contains a mathematical and numerical description of the Northern European power system, a solver algorithm to optimize the operation of the system according to an objective function and data handling software for analyzing the output. The reasons for choosing the EMPS model as a platform for this thesis are presented in this section.

The section for power market analysis at Statnett works with analysis of the Nordic and northern European power system on a daily basis. They use a few power market models including Pöyry's *BID* model and the SINTEF/Powel developed EMPS model. The EMPS with a detailed load flow model (EPF, Energy and Power Flow [19]) is the most important tool for integrated analysis Statnett has [20].

The EMPS model is part of a larger modelling regime developed by SINTEF. This modelling regime first consisted of the EOPS (One-area Power-market Simulator), which was made to optimize hydro power scheduling within an area with no significant transmission constraints and some degree of homogenous hydrological characteristics [18].

Later it became necessary to model a system where several EOPS-areas could interact and exchange power [21]. The EMPS model was developed to include a simplified description of the transmission grid and certain fundamental market mechanisms to optimize the operation of the entire system. A detailed grid description can be added to the EMPS model. This model is called the EPF, and it enables detailed load flow calculations.

The theme of this thesis is the modelling of CHP in Denmark. CHP is a thermal power producer, and the EOPS model could have been used to assess the impacts of new CHP modelling in Denmark. However, the impacts on the Danish power system as a result of a new CHP modelling are strongly impacted by the entire Nordic electricity system. Therefore the EOPS is not a sufficient model for this exercise. In addition, the detailed grid description offered by the EPF model is considered unnecessary for this exercise. The EMPS modelling framework provides a comprehensive description of the Nordic power system and sufficient functionality for modelling CHP.

3.2 The model

This introduction to the EMPS model is based on the latest updated version of the document called *Håndbok for Samlast – Del 1: Beskrivelse av Samlastmodellen,* which is a description of the EMPS/EPF model, by Anders Kringstad at Statnett. The document is dated to October 2010. For completely updated information on standard EMPS practices within Statnett today, Ivar Husevåg Døskeland has been consulted. This section only explains the elements in the EMPS necessary for modelling CHP. For a more comprehensive introduction to the EMPS hydro power modelling, the reader is referred to [18], [20] or [21].

The EMPS is a relatively large and complex model and it mainly consists of two parts, input data and algorithm/solver software. The input data describes the Nordic power system with its production portfolio and transmission grid (simplified) amongst others. Different sets of system descriptions are called *datasets*. The EMPS model solver algorithm optimizes the operation of the system over a certain period of time, a year in this case.

The system is simulated in parallel for a number of weather scenarios – inflow, wind, solar and temperature. This is very important to the model as one of the main strengths of the EMPS is hydro power modelling and optimizing production given uncertainty in inflow. Algorithms and solvers are used to optimize the system. The output data can be used for different analyses. The EMPS is a fundamental model. This means that the model tries to recreate the system by describing its physical properties.

The EMPS assumes a perfect competition power market, i.e. there are no market participants acting strategically to optimize their own profit at the expense of the overall system economic efficiency. In addition, the EMPS does not include start or stop costs for thermal units.

The following sections of this chapter are meant to present the most important aspects of the EMPS model, in terms of thermal power generation and the subsequent CHP modelling.

3.2.1 Price areas

The power system is divided into several bidding areas in the EMPS, as it is in the Nord Pool power market, but not in the exact same way. Most of these areas are modelled as a bus bar with firm demand, price elastic demand, hydro power, thermal production, other renewables, curtailment option and export/import capacities to other, adjacent price areas. The areas are shown in Figure 6. Even though the model as a whole contains all areas shown in Figure 6, this thesis focuses mainly on the four areas in Denmark, Denmark East, Fyn, Jylland North and Jylland South.

Poland, GB, Netherlands and Germany are represented by price series. This means that areas connected to these areas can trade power as long as there is a price difference and the trade is not restricted by the transmission capacity. To model an area entirely fundamentally can be both resource-demanding and unnecessary, and using firm price series is one way of forming the system boundaries [18].

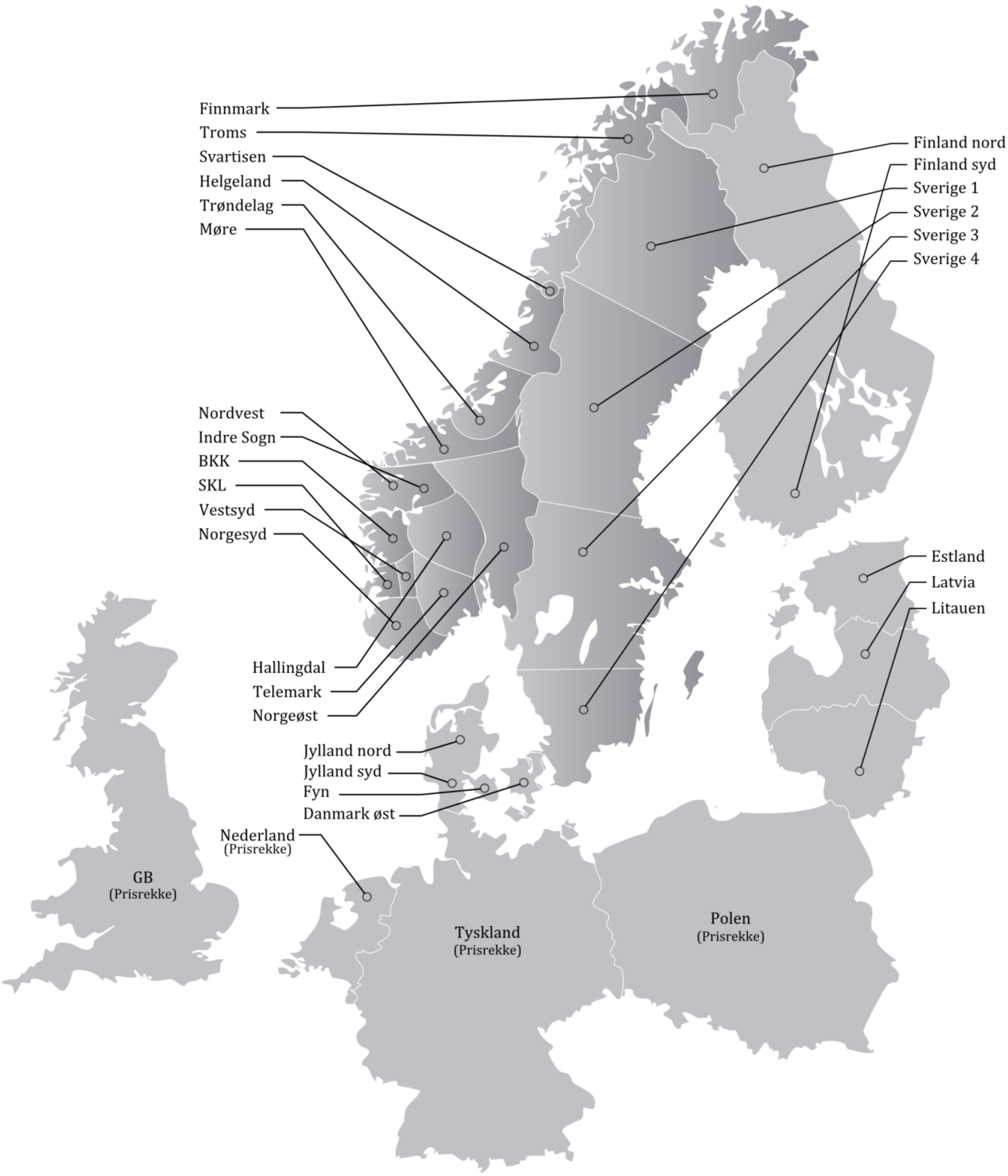

Figure 6: Price areas in the EMPS model (Statnett)

3.2.2 Market equilibrium

Each single area can be looked at as a bus bar. Firm demand, price dependent demand, hydro power, thermal production, other renewable generation, an option of curtailment are connected to each bus bar. In the Nord Pool Spot market, each producer and load bid for sale and purchase of power. They specify volume and price in their bids. This market mechanism is used in the EMPS.

Bids from producers (hydro, other renewables and thermal) make up the aggregated supply ("AS") curve and bids from consumers (firm and elastic demand) make up the aggregated demand ("AD") curve. The bids contain a quantity of electricity [MW] and a price at which the producer (consumer) is willing to sell (purchase) this quantity. This principle is shown in the AD-AS plot in Figure 7 [20]. Where supply equals demand there is market equilibrium, and that intersection decides both price and quantity. If it is assumed that there are no failures (unpriced pollution, exerted market power etc.) in this market, this method of pricing and production allocation maximizes the socio-economic surplus of the power market. The EMPS assumes a perfect competition market.

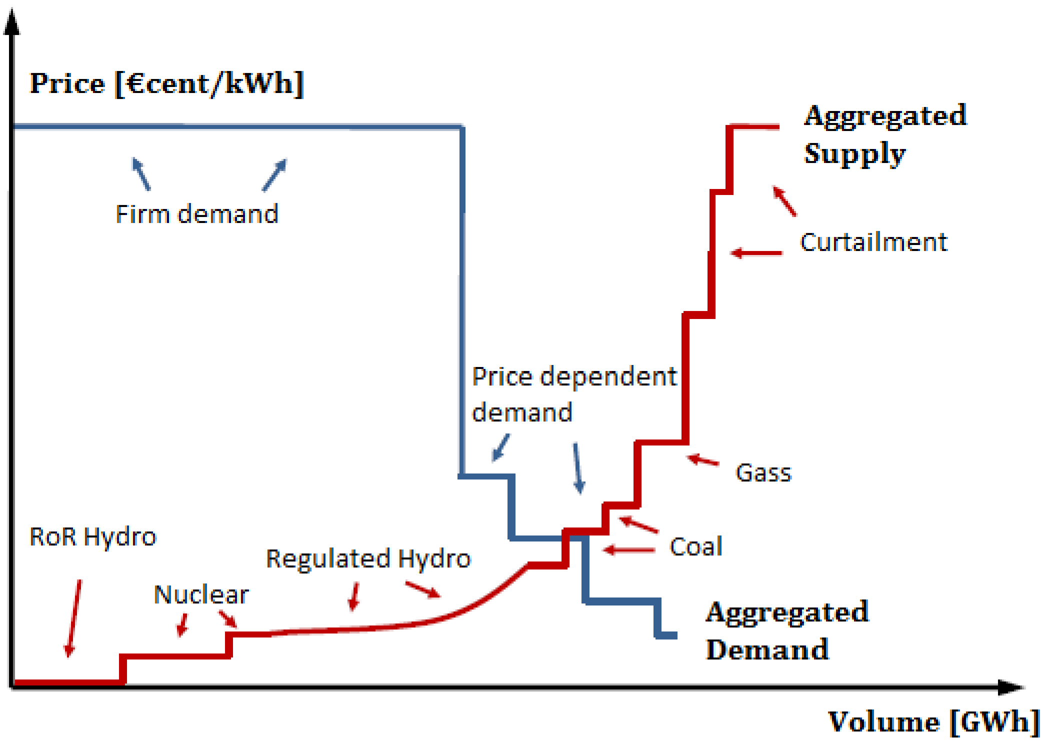

Figure 7: Example of market equilibrium [20]

When simulating the EMPS model market equilibriums are created for each area for every time step. If the prices are different in two areas between which there is transmission capacity, power will be traded from the area with the highest price to the area with the lowest price to such an extent that the price is equal or that the quantity traded is restricted by the transmission capacity. Therefore the price in one area is not determined only by market situation in that area.

For a comprehensive introduction on the theory of electricity spot market pricing chapter 4 of [21] is recommended.

3.2.3 Load blocks

The overall time resolution for the EMPS model is weekly. The hours of the week are categorized in load blocks. Statnett use the EMPS with either 5 or 56 load blocks. When using 56 load blocks every three sequential hours of the week are grouped together. Using 5 load blocks each of the 168 hours of the week is assigned to one of the load blocks. The hours are grouped according to their firm demand. For this thesis, 5 load blocks have been chosen. This principle of how the week is divided into 5 load blocks is shown in Figure 8.

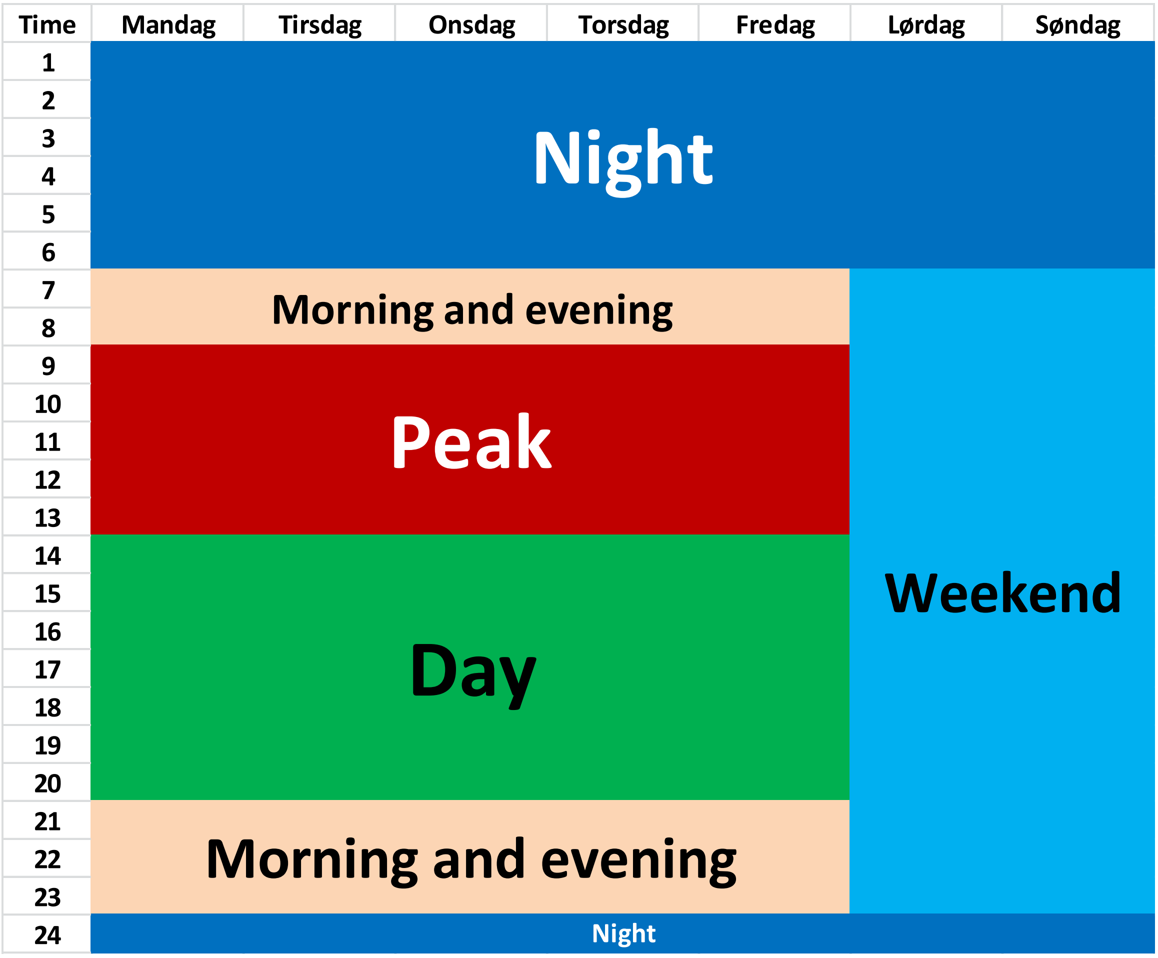

Figure 8: Principle of how the week is divided into 5 load blocks: Night, Mo-Ev, Peak, Day, Weekend (Statnett)

3.3 Denmark in EMPS

The focus in this report is on the CHP modelling for Denmark. Therefore it is necessary to discuss some characteristics of these areas in more detail. As shown in Figure 6, Denmark is divided into four separate price areas in the EMPS model, *Jylland North*, *Jylland South*, *Fyn* and *Danmark East*. Within these areas all larger energy plants are modelled individually, while smaller CHP, biofuel and waste plants are modelled at an aggregated level. In all, there are about 75 modelled units in Denmark, including the groups of aggregated small CHP.

A more complete description of the important characteristics of the Danish power system can be found in [4].

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Oversikt over innleste prisavhengige krafttyper
------------------------------------------------------------------------------
Type : Kate- : Navn              :Eg| Type : Kate- : Navn              :Eg:
-nr  : gori  :                   :et| -nr  : gori  :                   :et:
------------------------------------|-----------------------------------------
  1  : Kjref : Decentral         :  |  28  : Kjref : HKV               :  :
  2  : Kjref : Affald            :  |  29  : Kjref : HOEK              :  :
  3  : Kjref : AMV2M             :  |  30  : Kjref : DTU               :  :
  4  : Kjref : AMV2K             :  |  40  : Kjref : AMV1-NY           :  :
  5  : Kjref : AMV3M             :  |  60  : Salg  : EXCH DKO-FYN      :  :
  6  : Kjref : AMV3K             :  |  61  : Salg  : EXCH DKO-GER      :  :
  7  : Kjref : ASV2              :  | 101  : Gjenk : GJENNKJ_83_31     :  :
  8  : Kjref : ASV4              :  | 104  : Gjenk : GJENNKJ_83_34     :  :
  9  : Varme : ASV5D             :  | 105  : Gjenk : GJENNKJ_84_31     :  :
 10  : Kjref : AVV1M             :  | 108  : Gjenk : GJENNKJ_84_34     :  :
 11  : Kjref : AVV1K             :  | 109  : Gjenk : GJENNKJ_85_31     :  :
 12  : Kjref : AVV2TM            :  | 112  : Gjenk : GJENNKJ_85_34     :  :
 13  : Kjref : AVV2KM            :  | 113  : Gjenk : GJENNKJ_86_31     :  :
 14  : Kjref : AVV2HM            :  | 116  : Gjenk : GJENNKJ_86_34     :  :
 15  : Kjref : AVV2TK            :  | 117  : Gjenk : GJENNKJ_87_31     :  :
 16  : Kjref : AVV2KK            :  | 120  : Gjenk : GJENNKJ_87_34     :  :
 17  : Kjref : AVV2HK            :  | 121  : Gjenk : GJENNKJ_88_31     :  :
 18  : Varme : KYV21             :  | 124  : Gjenk : GJENNKJ_88_34     :  :
 19  : Varme : KYV22             :  | 125  : Gjenk : GJENNKJ_89_31     :  :
 24  : Kjref : STV1              :  | 128  : Gjenk : GJENNKJ_89_34     :  :
 25  : Varme : STV2              :  | 998  : Flomk : SPILL             :  :
 26  : Kjref : HCV7V             :  | 999  : Rasjo : Rasjonering       :  :
 27  : Kjref : SMV7D             :  |      :       :                   :  :
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Figure 9: Plants in the EMPS area "DANM-OST" in the pre-existing modelling (Screenshot, EMPS, 05.05.14)

Figure 9 shows the pre-existing CHP plants modelled in the Denmark East area in the Statnett EMPS given by their type numbers between 1 and 40. Those with a type number above 40 are not CHP plants. Some examples of plants found in the Denmark East area are:

- Type nr. 1: Many small, decentral CHP plants aggregated into one group. (the exact number is unknown. Some sources suggest there are about 665 CHP in Denmark in total, of which most are small [22], while others again suggest 897 CHP units in total [2])
- Type numbers 10 and 11: Back pressure and condensing parts, respectively (AVV1***M*** for back pressure (**M**ottrykk) and AVV1***K*** for condensing (**K**ondens)), of the Avedøre unit 1. This is a large, central CHP plant. The difference between condensing and back pressure parts are explained in detail later, but they represent one extraction CHP plant.
- Type nr. 30: A CHP plant at the Technical University of Denmark (DTU) campus in Copenhagen is one of several medium sized CHP plants that are not aggregated in the pre-existing CHP modelling in the EMPS.

Exactly how these are modelled in the pre-existing model is presented in chapter 5. This area is similar to the other price areas in Denmark in the EMPS.

4 Literature review

This thesis is based on implementing a new CHP modelling within the EMPS framework. To improve the CHP modelling it is necessary to have some idea of what is considered the best practice CHP modelling, regardless of whether it is feasible within the EMPS framework or not. This literature review is meant to provide a theoretical background on the subject of mathematical CHP modelling regardless of available modelling tools.

This chapter presents the main findings of a survey on short-term operation planning on cogeneration (CHP) researches by Fabricio Salgado and Pedro Pedrero at the University of Concepcion, Chile. In addition, some of the more relevant researches on the subject are presented in more detail.

4.1 Salgado and Pedrero

In 2007, Salgado and Pedrero ("S&P") published a paper named "Short-term operation planning on cogeneration systems: A survey" [23]. S&P have made a survey of researches on this subject published between 1983 and 2006. The findings of the survey are presented in this section.

The interdepence between the variables heat and electricity production makes operation planning of cogeneration systems a difficult task, which many researches has tried to solve [23]. Publications on the field vary between focusing on modelling the problem, evaluating different operation strategies and developing efficient solution methods [23].

The most common way to propose the optimization problem in a cogeneration system has been the cost minimization economic dispatch and scheduling problem. The problem has been stated as a linear programming problem, non-linear programming problem, mixed-integer programming problem and a multi-objective programming problem by several researches each. The solution methods are several including well known methods such as simplex, dynamic programming, lagrangian relaxation and Newton's method.

Many researches based its problem formulation on a convex feasible operation region ("FOR") for a typical cogeneration unit. This means representing the possible technical operation of the unit in a two dimensional plot, where electricity production, P_c, is plotted against heat production, Q_c. Two examples of this plot, the FOR, is shown in Figure 10.

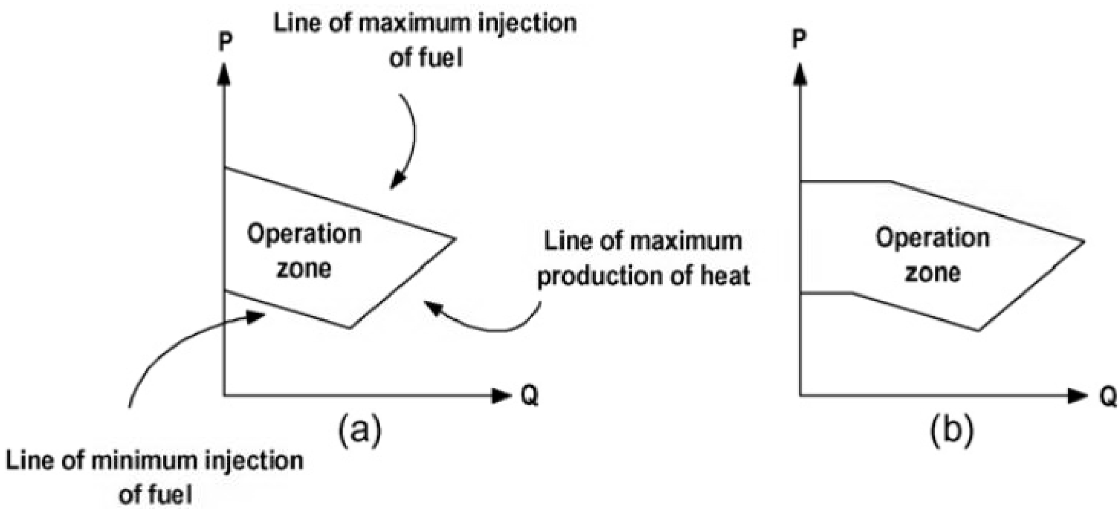


Figure 10: a) One-segment FOR, b) Two-segment FOR [23]

Based on the feasible operating region for a CHP unit, in general, the economic dispatch problem has been formulated in two ways. Rao and Lahdelma et al. presents two different solution methods to the economic dispatch problem.

4.2 P. S. Rao

Rao presents a direct solution to the economic dispatch problem using the classic method of lagrangian relaxation [24]. He proposes a system consisting of several electricity producing units ($\in e$), heat producing units ($\in h$) and CHP units ($\in c$), each with a quadratic cost function. The cost function for the CHP unit would also include a **coupling-term** to link the heat and electricity costs:

$$c_{i\in c} = c_{i\in c}(p_i) + c_{i\in c}(q_i) + \boldsymbol{\delta_i * p_i * q_i} \tag{1}$$

The heat and electricity units output would be restricted by ordinary minimum and maximum constraints, while the CHP unit would be restricted by equations representing lines composing each unit's FOR.

The objective function is then given as the total cost of production:

$$C = \sum_{i\in e} c_{e,i}(p_i) + \sum_{i\in c} c_{c,i}\,(p_i, q_i) + \sum_{i\in h} c_{h,i}(q_i) \tag{2}$$

In addition to each unit's production restrictions for either heat, electricity or both, there are also global constraints. These constraints are the system heat and electricity balances:

$$\sum_{i\in e} p_i + \sum_{i\in c} p_i = p^{demand} \tag{3}$$

$$\sum_{i\in c} q_i + \sum_{i\in h} q_i = q^{demand} \tag{4}$$

Hence, the solution to the problem of minimizing (2) subject to only (3) and (4) gives the system lambdas corresponding to the situation where none of the units violate their limit. The solution then satisfies the first order Kuhn-Tucker conditions given by:

$$\frac{\partial c_{e,i}}{\partial p_i} - \lambda_p = 0, \quad \forall i \in e \tag{5}$$

$$\frac{\partial c_{c,i}}{\partial p_i} - \lambda_p = 0, \quad \forall i \in c \tag{6}$$

$$\frac{\partial c_{c,i}}{\partial q_i} - \lambda_q = 0, \quad \forall i \in c \tag{7}$$

$$\frac{\partial c_{h,i}}{\partial q_i} - \lambda_q = 0, \quad \forall i \in h \tag{8}$$

λ_q and λ_p are then interpreted as the marginal cost of heat and power. These lambdas are then applied to calculate p_i and q_i for each unit. Rao also present a method of handling violations of a unit's constraints in the optimal solution, but this will not be explained further here. This problem could be solved as an hourly model. Rao, as well as many other operational researches on this subject, does not consider the possibility of using electricity for heat production or heat storage.

This direct solution is suitable for a utility with several units for power, heat or co-generation under a centralized planning regime (i.e. not market based (decentralized) production planning) within a limited geographical area for a few reasons. First, this solution relates to a total electricity balance, eq. (3), while a utility with electricity generation in the Nordic region today relates to prices settled in the spot market. Secondly, a large geographical area with a developed DH system, such as Denmark, there are many isolated DH pipeline systems, each with its own heat producing units.

This means that there could be some challenges associated with only considering one heat balance for all units for a utility covering a large geographical area.

4.3 Rong, Hakonen and Lahdelma

Rong, Hakonen and Lahdelma have published several papers on a linear programming algorithm based on the assumption of a convex, linear FOR for a CHP unit. The region of Figure 10 a) is a convex region, while Figure 10 b) is not. The simple explanation is that one cannot draw a straight line between all extreme points in Figure 10 b) that is within or at the boundaries of the region itself. This is shown drawing the line D-F (red) in Figure 11.

It is suggested that a two-segmented FOR could be solved as two separate FORs [23], giving a piecewise linear problem, but this is not a topic for further elaboration in this thesis.

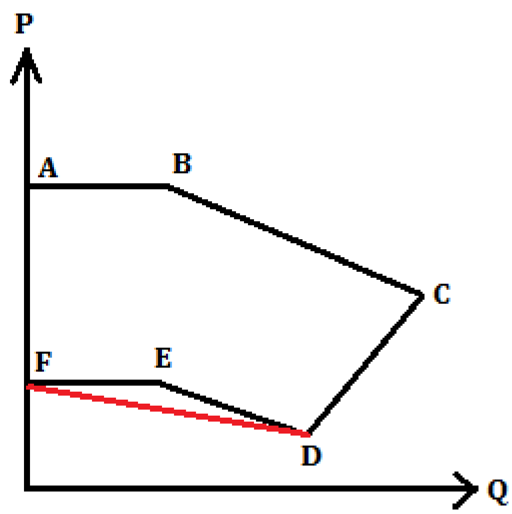


Figure 11: Example of a non-convex space

Lahdelma et al. assume a convex feasibility region to allow for a linear programming algorithm [25]. Any solution that is a combination of only the extreme points F and D (along the red line of Figure 11) would be infeasible and not valid. It has been suggested that a two-region FOR does not offer significant benefit compared to the complexity it brings [26].

Lahdelma et al. claim that their model is suitable for regional energy companies supplying electricity to the grid and heat for district heating. They have developed a solution method called *Power Simplex*, which is included in the EHTO NEXUS energy optimization system, which is used commercially by several Finnish energy companies and industrial power plants [25].

The main concepts to take away from this literature review is that CHP plants can be represented by non-convex, linear FORs and the economic dispatch and operation planning problem can be solved by linear solution methods. These assumptions are used in the new CHP modelling presented in the rest of this report.

5 Existing CHP modelling in EMPS

In this chapter the existing modelling of CHP is presented. Understanding the current modelling method is a pre-requisite when it comes to improving the modelling. The first section of this chapter presents how power production capacity from a CHP plant is calculated as an input to the aggregated supply curve. Substantial parts of the pre-existing modelling method will be kept for the new modelling; therefore the description of the existing modelling is highly relevant to the new modelling.

5.1 Power production

Production from CHP is given as a total amount of energy [GWh] available for blocks of weeks over one year. Although this is not always the case, it is assumed in this explanation that the total energy volume is given for one block of weeks, week 1 through 52. One could, for example, specify 100 GWh for weeks 1-26 and 150 GWh for 27-52. The principle is the same regardless of what number of weeks each energy volume is specified for. Therefore, an explanation with only one volume for all weeks of the year is sufficient.

Looking at an imaginary CHP unit "*A*", unit A has a total available amount of energy, X_A, for all 52 weeks. Available production for each single week is given according to an annual profile. This profile distributes the total annual energy over the weeks. The production of unit A in week *i*, $x_{i,A}$, is given as:

$$x_{i,A} = X_A \times \frac{k_{i,A}}{K_A} \tag{9}$$

Where

$$K_A = k_{1,A} + k_{2,A} + k_{3,A} + \cdots + k_{52,A} = \sum_{i=1}^{52} k_{i,A} \tag{10}$$

$k_{i,A}$ is a value with no unit given in the profile named "production profile" in this report (Known as *lastprofil* or *preferansefunksjon*). An example of a production profile is shown in Figure 12.

Figure 12: Production profile "PL_Decentral" from the EMPS model

At this point the production available for week i is given in the parameter $x_{i,A}$. This is then distributed over the 168 hours of that week. In the same way as distributing annual production over the weeks, weekly production is distributed over the hours.

Available production for unit A, week i, hour j is given as:

$$x_{j,i,A} = x_{i,A} \times \frac{l_{j,i,A}}{L_{i,A}} = X_A \times \frac{k_{i,A}}{K_A} \times \frac{l_{j,i,A}}{L_{i,A}} \tag{11}$$

Where

$$L_{i,A} = \sum_{j=1}^{168} l_{j,i,A} \tag{12}$$

$l_{j,i,A}$ is a value with no unit given in the profile named "power profile" in this report (known as *effektprofil* or *preferansefunksjon*). A power profile consisting of values of $l_{j,i,A}$ can look like the the one presented in Figure 13.

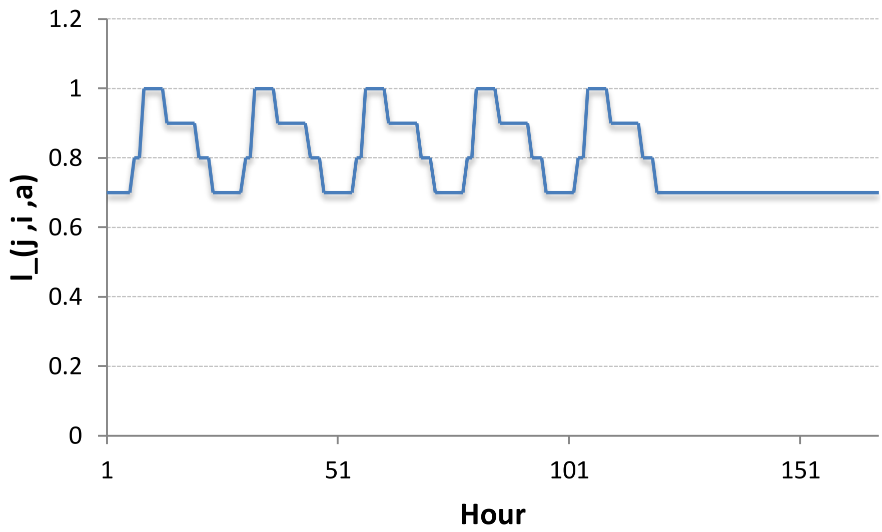


Figure 13: Power profile "PE_Decentral" from the EMPS model

Although available production has been calculated for the hour, it is not given that this amount of energy is actually produced. If the marginal cost of the unit is above the system price, as determined by the supply and demand curves and the market equilibrium, the unit will not produce.

Furthermore, when the SINTEF function for temperature dependent capacity correction is introduced later, the unit production might be restricted by the unit's installed capacity. In the pre-existing modelling, this is not the case.

Available production that is not actually produced in the hour it is available may not be produced at a later time. This is not related to the possibility of energy storage, as discussed in chapter 2.4.3.

The background, theoretical or practical, for the existing production and power profiles is not known as no documentation has been available.

5.2 Example: Calculating CHP production

This example will illustrate a simple calculation of available production from a CHP unit following the procedure described above.

All the following variables are chosen at random and not based on an existing CHP plant. For this example the CHP unit is named A, it is week 3 (*i*), hour 1 (*j*).

5.2.1 Weekly production

Variable	Value
X_A	50 GWh
K_A	200
$k_{3,A}$	10

From (9) we find that

$$x_{3,A} = X_A \times \frac{k_{3,A}}{K_A} = 50\ GWh \times \frac{10}{200} = 2.5\ GWh$$

There is 2.5 GWh available for production in week 3.

5.2.2 Hourly production

Variable	Verdi
$L_{1,A}$	40
$l_{1,3,A}$	4

From (11) we find that

$$x_{1,2,A} = x_{3,A} \times \frac{l_{1,3,A}}{L_{1,A}} = 2{,}5\ GWh\ \times \frac{4}{40} = 0.25\ GWh$$

$k_{3,A}$ and $l_{1,3,A}$ are given in the production and power profiles respectively. There is 0.25 GWh available for production in hour 1 of week 3. If the marginal cost ("MC") is lower than the system price for this hour, and the unit has a maximum capacity of at least 250 MW, actual production for this hour will equal 250 MWh, 0.25 GWh. Given that 250 MWh are available during this hour, essentially, the available generation capacity is 250 MW as the 250 MWh are divided by 1 hour [h].

5.3 Marginal cost

For a bid of production to be a valid to the aggregated supply curve it needs both a specified price [given as €cent/kWh in the EMPS] and a specified volume [GWh].

Price, or rather the MC, i.e. the cost of producing the next kWh for a unit, can be specified by inserting a value for the weeks that the value is valid. For example, one could specify a price p_1 to be valid for weeks 1 through 52. Or, one could specify p_1 for weeks 1-26 and p_2 for weeks 27-52, or many other possible combinations. This allows the user to specify varying MCs for plants to account for seasonal fuel price variations.

The marginal cost can be a result of various different conditions, depending on the producer's perspective on its own power production. For regular non-CHP thermal plants, the marginal cost will consist of fuel, variable O&M and CO_2 costs for the most part. For hydro power plants the marginal cost is based on the water value, which is based on the reservoir levels, expected inflow and the alternative cost for power, i.e. the MC of thermal plants, amongst other.

CHP plants are participants in two different energy markets; power and heat. The MC of various CHP plants and production is greatly influenced by this, and this is discussed in detail in chapter 6.3. If the MC of a unit is lower than the equilibrium market price, the unit's bid to produce will be accepted, and the unit will run for that hour. If the MC is above the equilibrium market price, however, the unit will not produce. This is shown in Figure 7 in chapter 3.2.2.

To summarize this section, important parameters to the existing CHP modelling in the EMPS are the production and power profiles, the total available energy and the individual unit's marginal cost.

5.4 Modelling within the framework

Using the EMPS entails some limitations for the new CHP modelling. These limitations are discussed in this section.

Most CHP plants in the EMPS are modelled as a specific type of power production unit, "Kjref". "Kjref" is put together by the words "Kjøp", which means that the system can purchase power production from the unit, and "referanse", which means that the production is related to the production and power profiles. It is not within the scope of this thesis to alter this or to create a new type of power production unit. Therefore any new CHP units or changes made to existing units must be the same type as in the pre-existing modelling. This means that fixed production and power profiles must be the given as input to every unit. In addition, a fixed amount of total available production must be given for the whole year and a marginal cost must be set.

The EMPS does not model any heat market or heat load explicitly. Power production from CHP units is highly dependent on the heat market in which they participate. Therefore, other methods of implicitly modelling the heat demand must be found. It is presented in chapter 6.2 that this can be done partially using time series for actual temperature. The SINTEF developed temperature correction method can be a very helpful contribution in this regard. This function is described thoroughly in chapter 6.4 and implemented in the new CHP modelling.

6 .Modelling CHP

This chapter presents the main discussion on how CHP should be modelled both in general and in the EMPS.

6.1 District heating markets

This section gives a short introduction to the DH market in Denmark.

The district heating market in Denmark consists of a large number of individual DH pipeline systems to serve residential areas, both large cities and lower density local areas [27]. This means that there are a large number of DH markets, as opposed to the electricity market, in which all producers and loads are connected. The district heating markets are exempt from competitions and are regulated as natural monopolies [27]. Therefore, the scheduling of heat production to meet the heat demand is a centralized task, without bids to buy or sell heat, again as opposed to the electricity market. Therefore, there is no real market mechanism in place for any DH system. The DH utilities set their tariffs to cover the costs of heat production, provided that they are lowering the costs [28].

It is assumed that:

- Each DH system heat load is met by only one DH utility
- This DH utility can allocate its resources as it chooses, but it is required that it produces enough heat to cover the heat load at the lowest cost possible
- The heat load for DH utilities is determined only by the outdoor temperature of its surrounding geographical area.

DH utilities with CHP units are called CHP plants. It is shown in Figure 14 that about 75 % of all district heat produced was produced by CHP units. Autoproduction is typically surplus heat from industrial processes.

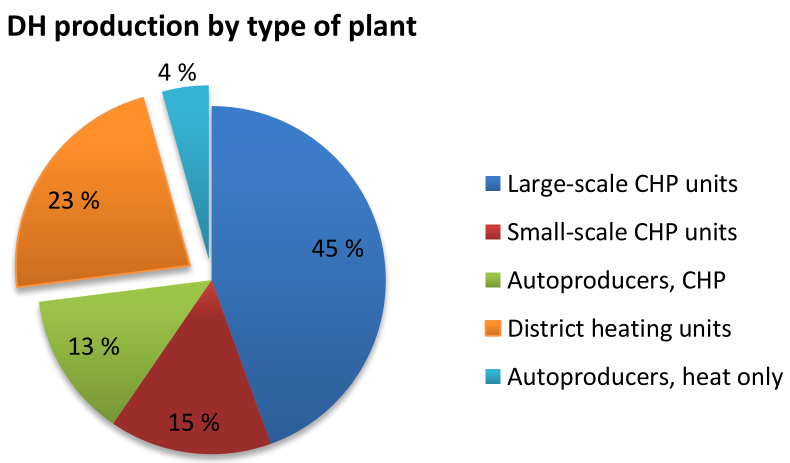


Figure 14: District heating production by type of plant [2]

6.2 Electricity production

This section presents how hourly available electricity generation from CHP plants can be obtained given the outdoor temperature as an input. This chapter and chapter 6.3, on marginal costs, aims to outline a CHP plant operation strategy, based on different possibilities of producing heat and the assumption that heat demand must be met at all times.

6.2.1 Representing plants by FOR

In this section the assumption that CHP plants can be represented by a linear, convex feasibility operating region is presented in further detail.

As discussed in chapter 4, the feasible operating region, or FOR, is commonly used to describe the relation between heat and power output of a CHP plant. Figure 15 illustrates the FOR of two separate, very different examples of CHP systems. As discussed in chapter 2.4, CHP plants can consist of several CHP units, other heat producing units and other CHP related technologies such as heat storage. The example systems presented in Figure 15 are realistic examples, but they are not based on any specific, existing systems.

The complex system has numerous units for production of heat or both heat and power. It has one extraction CHP unit, possibly several boilers running on different fuels, including biomass, natural gas and electricity. It also has a heat pump installed. This CHP system could operate with a high degree of flexibility to meet the heat load, at least in terms of available operating strategies (It is difficult to generalize over time dependent flexibility). It could also be operating at several points on the FOR-diagram at the same time given that several units are available at the same time. In addition, most CHP systems in Denmark have accumulator tanks installed at their facility for heat storage. Modelling all of these relations perfectly can be challenging. Still, this flexibility should be represented in the model to a certain extent.

On the other hand there is the simple system. This system has one back pressure CHP unit, which gives very little flexibility on how to meet the heat load. In principle this is not a very difficult system to model within the EMPS framework, as long as the heat load and heat-to-power ratio is known. An accumulator tank would complicate the modelling, but still, there is only one way heat could actually be produced.

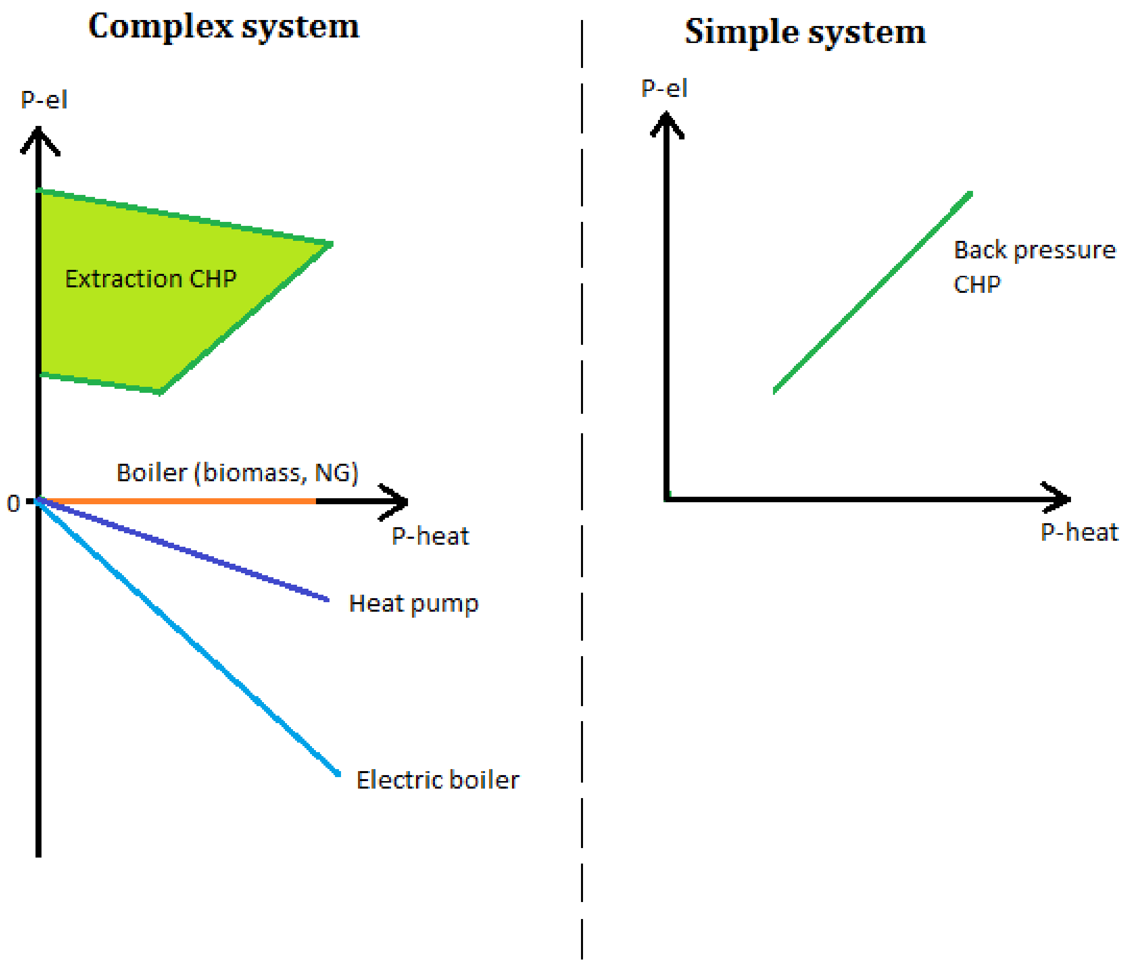


Figure 15: Modelling a complex vs. a simple CHP-system by using the FOR

In practice, the heat load of a residential district heating system has to be covered at all times. Assuming a CHP plant is the only heat producing utility in its DH system, this plant would need back up heat producing units in addition to the CHP unit. This would rule out the simple system, where there is only one available heating unit.

In addition, depending on plant size, heat load, financial strength, human resources and the DH system it belongs to, utilities make different strategic decisions on what equipment to invest in. No consistent evidence on the significance of technical diversity has been found comparing large and small CHP plants. However, given higher heat and electricity volume, investment in a more diverse production portfolio, approaching the complex system, is likely to be more economically and practically feasible.

Considering these two arguments and the fact that there are well over 500 CHP plants in Denmark it is difficult to quantify whether the simple or complex system is more common. It is likely that most plants are somewhere in between. In practical modelling, most plants are represented either as an extraction or a back pressure unit with other heating units mainly represented through the MC of the CHP unit.

It is necessary to model the relations given by the FOR mathematically. It is assumed that all line segments of the FOR in Figure 15 (for both the complex and simple system) can be represented by linear functions [24] [29] of the form:

$$y = bx + a \tag{13}$$

With

$$P_{el} = bP_{heat} + a \tag{14}$$

When modelling CHP units in the EMPS model, other boilers at the same plant can either be modelled explicitly, such as the electric boiler, or through the marginal cost of the CHP unit, as for other boilers. In the following discussion only the FOR of the CHP unit (green in Figure 15) is considered. The impact of the other units is discussed mainly in the marginal cost discussion of chapter 6.3.

6.2.2 Estimating power production

This section presents how power production is obtained from both a back pressure and an extraction steam turbine CHP unit. It is assumed that gas turbines and reciprocating engines can be modelled in a similar way. This is a very important assumption, and the reason is that Pedrero and Salgado [23] does not put much emphasis on what prime mover technology is modelled when discussing the convex, linear FOR assumption.

Further it has been shown that [4]

$$P_{heat}(T) = \begin{cases} 0{,}90 & for \quad T \leq -10 \\ -0{,}0258 * T + 0{,}627 & for \quad -10 < T < 20 \\ 0{,}10 & for \quad T \geq 20 \end{cases} \tag{15}$$

Where P_{heat} is given as a share of its maximum installed heating capacity. The linear equation for P_{heat} is not defined at the limits -10 and 20 C°, and rounded values (close to the corresponding value of the linear equation, but not precisely equal) are used at and outside the limits.

This is a weighted average result based on data from three medium-to-small sized CHP plants in Denmark. This is assumed to be an acceptable approximation for all CHP plants in Denmark. Further it is assumed that every CHP plant in Denmark must cover a heat load corresponding to P_{heat} for any given temperature T.

It is assumed that the FOR of a CHP unit can be simplified from that of the extraction CHP unit in the complex system of Figure 15 into a triangle, thus ignoring minimum production limits. These two key assumptions on the FOR of CHP units and $P_{heat}(T)$ are summarized in Figure 16 and Figure 17, respectively.

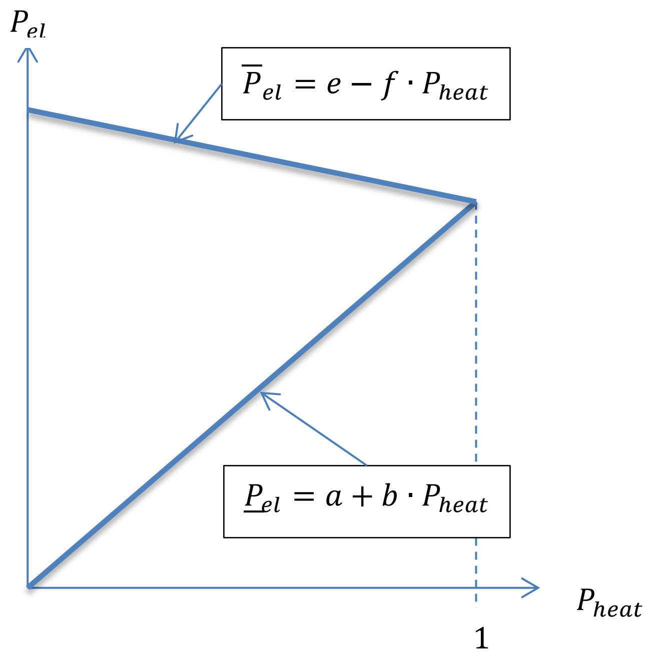


Figure 16: Assumtion on all CHP units FOR

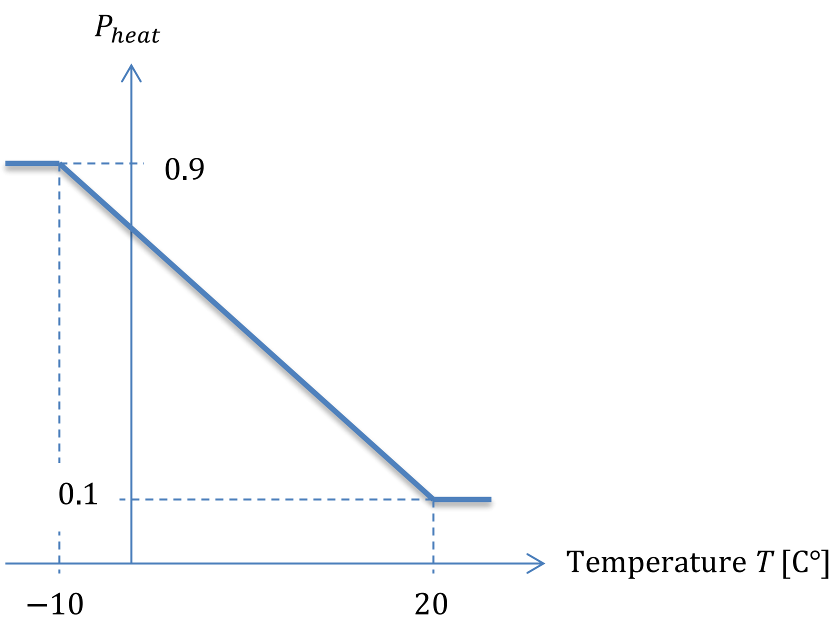


Figure 17: Assumption of heat load as a function of temperature

Figure 16 and Figure 17 shows the two necessary assumptions for deriving equations for power production from CHP for both back pressure and extraction units. $\overline{P}_{el}$ is the upper limit of power production in condensing operation and given as a linear function of P_{heat} and parameters e and f. $\underline{P}_{el}$ is the lower limit in back pressure mode and also given as a linear function of P_{heat} and parameters a and b. P_{heat} is given as a linear function of temperature T, given in C°, and parameters c and d between maximum and minimum temperature limits, eq. (15). If the temperature is outside the temperature range between -10 and 20 C°, P_{heat} is given as shown in Figure 17 at levels 0.90 or 0.10. Therefore P_{heat} can never reach 0 or 1, which means that $\underline{P}_{el}$ and $\overline{P}_{el}$ can never be zero.

It is emphasized here that production along the line of $\underline{P}_{el}$ is forced electricity production for back pressure units and in *back pressure mode* for extraction units. Production between $\underline{P}_{el}$ and $\overline{P}_{el}$ or at the line $\overline{P}_{el}$ is not forced but optional electricity generation in *condensing mode* for extraction units, and not a possibility for back pressure units. It is necessary to separate production in back pressure and condensing mode when discussing MCs.

Further we assign numbers to the equations given in Figure 16:

$$\underline{P}_{el} = a + bP_{heat} \tag{16}$$

$$\overline{P}_{el} = e - fP_{heat} \tag{17}$$

$$P_{heat} = d - cT \tag{18}$$

Where a, b, c, d, e and f are all positive parameters.

As discussed earlier, $\underline{P}_{el}$ is equal to forced power production in back pressure mode. Therefore (16) directly gives back pressure production $P_{el,bp}$. Available production in condensing operation for an extraction plant is given as $\overline{P}_{el} - \underline{P}_{el}$:

$$\begin{aligned} P_{el,cond} = \overline{P}_{el} - \underline{P}_{el} &= (e - fP_{heat}) - (a + bP_{heat}) \\ &= (e - a) - (f + b)P_{heat} \end{aligned} \tag{19}$$

Furthermore, (18) can be inserted into (16) and (19) to create equations for production depending on temperature T instead of P_{heat}:

$$P_{el,bp} = a + b(d - cT) = a + bd - bcT = (a + bd) - (bc)T \tag{20}$$

$$\begin{aligned} P_{el,cond} &= (e - a) - (f + b)(d - cT) = e - a - fd - bd + fcT + bcT \\ &= (e - a - fd - bd) + (fc + bc)T \end{aligned} \tag{21}$$

6.2.3 Estimating parameters

This section shows how the parameters a, b, c, d, e and f can be estimated, as a specific value is needed for the practical implementation of the new CHP modelling. To estimate these parameters, operation data from real plants are used.

Table 1 presents some values for maximum power generation with no or full heat production, to help estimate the value of both e and f for the DONG Energy owned Avedøre plant outside Copenhagen [30]. This plant is considered a large plant.

Unit name	Technology	$\overline{P}_{el}(P_{heat}=0)$ [MW]	$\overline{P}_{el}(P_{heat}=1)$ [MW]	f
Avedøre 1	Coal steam turbine	250	215	$\frac{250-215}{250} = 0.14$
Avedøre 2	Biomass	425	355	$\frac{425-355}{425} = 0.165$
Avedøre 2	Biomass w/ gas turbine.	575	495	$\frac{575-495}{575} = 0.139$

Table 1: Data for estimating parameters e and f [30]

The estimations for parameter f might vary significantly from one plant to the other. Given that it has not been possible to obtain data for each plant in the EMPS model, an assumption has to be made on a general basis. From the examples in Table 1, an assumption of a 15 % decrease in electrical capacity moving from no heat output to full heat output is made for all extraction plants.

Given:

$$P_{heat}(T) = \begin{cases} 0{,}90 & for \quad T < -10 \\ -0{,}0258 * T + 0{,}627 & for \quad -10 < T < 20 \\ 0{,}10 & for \quad T > 20 \end{cases} \tag{15}$$

It is feasible to assume that a is equal to 0 [31], which means that $\underline{P}_{el}(P_{heat} = 0) = 0$, no electricity production without heat production, except from condensing mode extraction plants. Given that P_{heat} cannot be above 1, the parameter b is decisive to determine the absolute value of the parameters e and f. Therefore, b has to be decided first.

b, the power-to-heat ratio, can vary greatly between not only the various CHP prime mover technologies, but also internally within each main technology category. Relevant documentation on power-to-heat ratio is available for some of the larger CHP plants in Denmark. Power and heat output in full load back pressure operation and resulting power-to-heat ratios are given in Table 2.

Unit Name	Technology	MW_{el}	MW_{heat}	*b*
Avedøre 1 [30]	Coal, steam turbine	215	330	0.65
Avedøre 2 – Main [30]	Natural gas turbine	140	90	1.55
Avedøre 2 – Wood/Straw [30]	Steam turbine	355	485	0.73
Amager 2 [32]	Straw, steam turbine	68	250	0.27
Amager 3 [32]	Coal, steam turbine	250	330	0.75
Asnæs 2 [33]	Coal, steam turbine	147	244	0.60
Hillerød [34]	Gas, Combined cycle	77	78	1
Helsingør [35]	Gas, Combined cycle	60	60	1
DTU [36]	Gas, Combined Cycle	38	31	1.33

Table 2: Data for determining parameter b

Power to heat ratios for gas turbine prime mover technologies typically range between 0.33 and 0.67 [10], while steam turbine prime mover power to heat ratios are rarely higher than 0.33, and can be below 0.10 [12]. The power to heat ratio for reciprocating engines is somewhat similar to gas turbines ranging from 0.5 to 1.00 [11].

From the gathered data, it is fair to assume a power-to-heat ratio of 1 for smaller combined cycle CHP units, such as Hillerød, Helsingør and DTU. Based on data from Avedøre 1 and 2, Amager 3 and Asnæs 2 it can be assumed for large coal fired steam turbine CHP plants that their power–to-heat ratio is about 0.68, which is their calculated average. This is in contradiction to other sources such as [5] and [12], but observed data is preferred over generalized assumptions. For gas turbine or gas engine back pressure units the ratio is assumed to be 0.75 based on the UK DECC suggested ratio. Amager 2 represents a problem in this discussion as its power to heat ratio value is far from the value given for the seemingly technologically similar Avedøre 2 unit, which is also fuelled by wood and straw, but still consistent with the DECC's suggested lowest ratio of 0.10. Given that there are two, very different indications of power-to-heat ratios for biomass fuelled CHP units, the average of the two could be chosen. This is not an optimal solution as the values are so far apart and the standard deviation is very large, but due to the lack of information this is necessary. It is calculated as (sum electricity capacity) divided by (sum heat capacity) for both units:

$$\frac{355 + 68}{485 + 250} = 0.58$$

Obviously, this value should not be applied for any of the two concerned units, as their power to heat ratio is already known. 0.58 is applied to similar biomass fuelled plants for which the power to heat ratio is not known. Seemingly, this estimation is a considerable source of error. However, in the final discussion, it is shown that this is not the case.

Thus, parameter *b* is decided for different prime mover and fuel technology combinations. This is summarized in Table 3.

Given b, a 15 % decrease in condensing electrical capacity moving from no heat output to full heat output and $P_{heat,max} = 1$ as a share of the installed capacity. The rest of the parameters can be calculated. For a coal fired steam turbine CHP unit the parameters are calculated as follows:

$$b = 0.68$$

The calculation of e can be done as shown:

$$e = \frac{b}{0.85} = \frac{0.68}{0.85} = 0.8$$

The absolute value of f is then calculated as:

$$f = \frac{e - b}{1} = 0.12$$

Which is $0.12 \div 0.80 = 0.15 = 15$ %. 0.12 is the absolute value of a 15 % decrease in total power capacity for a plant moving from no heat output to full heat output.

Based on technology dependent assumptions for parameter b, parameters e and f can be calculated. This is summed up in Table 3.

Description/Tech.	*b*	*e*	*f*	*a*
Coal fired, steam turbine	0.68	0.8	0.12	0
Gas turbine/engine	0.75	0.88	0.13	0
Combined cycle	1	1.18	0.18	0
Biomass, steam turbine	0.58	0.68	0.10	0
Amager 2, biomass	0.27	0.32	0.05	0
Avedøre 2, biomass	0.73	0.86	0.13	0

Table 3: Values for parameters of linear FOR

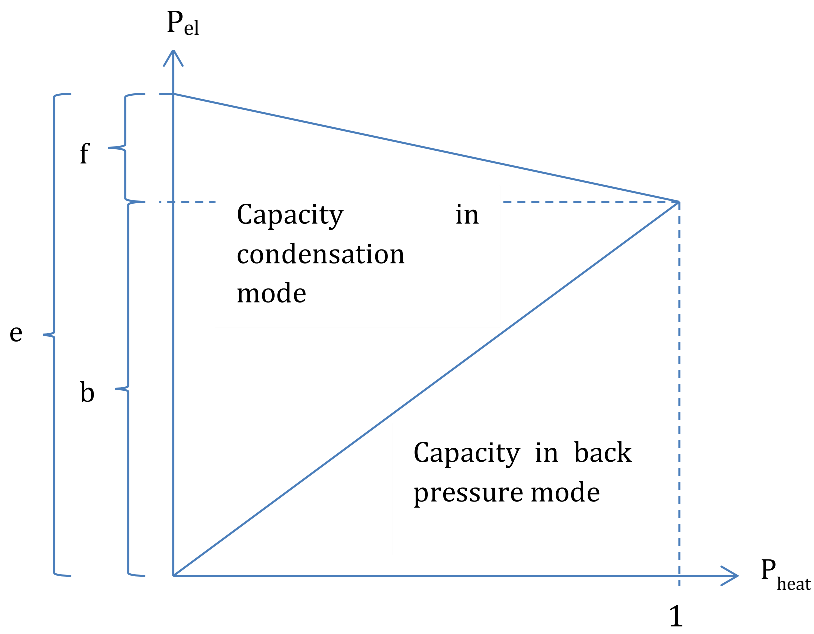


Figure 18: Summary of the significance of parameters b, e and f as Pheat,max=1

These values can be inserted into equations (20) and (21), to create linear equations for power output for back pressure and condensing parts for each of the main technologies listed in Table 3 depending on temperature only:

Description/Tech.	$P_{el,bp}$	$P_{el,cond}$
Coal fired, steam turbine	$0{,}43 - 0{,}018 * T$	$0{,}3 + 0{,}021 * T$
Gas turbine/engine	$0{,}47 - 0{,}019 * T$	$0{,}33 + 0{,}023 * T$
Combined cycle	$0{,}63 - 0{,}026 * T$	$0{,}44 + 0{,}03 * T$
Biomass, steam turbine	$0{,}36 - 0{,}015 * T$	$0{,}25 + 0{,}018 * T$
Amager 2, biomass	$0{,}17 - 0{,}007 * T$	$0{,}12 + 0{,}008 * T$
Avedøre 2, biomass	$0{,}46 - 0{,}019 * T$	$0{,}32 + 0{,}022 * T$

Table 4: Equations for power production capacity

Back pressure CHP plants should be modelled only by the equation for $P_{el,bp}$, while extraction CHP plants should be modelled as one back pressure unit, using equations for $P_{el,bp}$, and one condensation unit using equations for $P_{el,cond}$ as these would interact in "opposite phases". It is important to note that these calculated $P_{el,bp}$s and $P_{el,cond}$s are available production. Whether it is produced or not is still depending on the marginal cost and market conditions.

6.2.4 Applying the equations

The equations for available power production for CHP plants summarized in Table 4 are primarily used for two purposes in the implementation of the new CHP modelling elements. Firstly, it is used together with weekly average temperatures to create new production profiles. Secondly they are used to describe the linear correction of the production for a given difference in average and actual temperature.

6.3 Marginal cost

As mentioned in chapter 5.4, a MC is a necessary input for each CHP power plant in both the new and pre-existing CHP modelling. This section presents a discussion on appropriate MC estimates for different type of CHP power production.

MC is defined as the cost of delivering one additional unit of energy (€/MWh or NOK/MWh) [21].

The MC of electricity production from CHP units depend on fuel cost, technology, other heating options and whether the unit is operating in back pressure or condensing mode. It has proven difficult to obtain information on marginal costs from market participants Therefore, the subject of MC must be assessed mainly based on theory and assumptions.

Two different types of operation are illustrated in Figure 19. The red line represents back pressure mode for extraction units and the only possible operation for back pressure units. If the CHP unit is running, the red line represents forced electricity production.

The red dot in point A of Figure 19 represents a CHP unit operated in condensing mode. It is producing more electrical energy than what is forced by the back pressure mode line. This production is voluntary. The difference in marginal cost assessment is presented in the following sections.

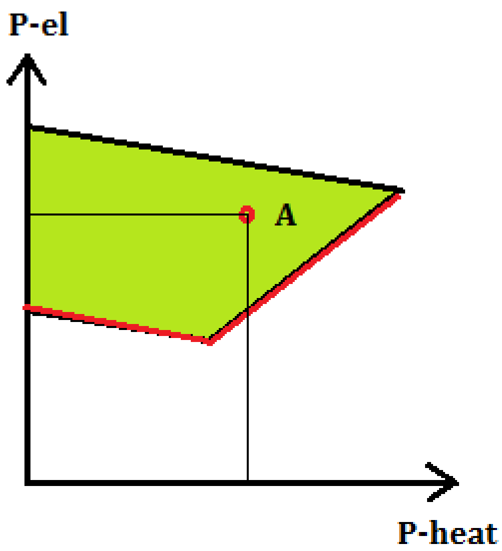


Figure 19: FOR of an extraction CHP unit

6.3.1 Back pressure

For a back pressure CHP plant or an extraction plant operating in back pressure mode, the electricity marginal cost is dependent on the availability and cost of other heat producing units. An example plant is presented here to illustrate this. This example

CHP plant has three ways of meeting the heat load. It has an electric boiler, a gas-fired boiler and a gas-fired back pressure CHP unit.

To use the electric boiler, power is bought in the market at the spot price. Thus, the cost of producing heat from the electric boiler will increase as the spot price increase. The gas-fired boiler provides heat at a price which depends on the gas price and its total efficiency, not on the power spot price. In other words, with regards to the power spot price, the gas fired boiler has a fixed cost of heat. The CHP unit buys gas at the same price as the gas-fired boiler and produce heat and electricity. The electricity can then be sold to the market at spot price. The income from selling the electricity can then be subtracted from the cost of heat. Therefore, the cost of heat for the CHP unit is lower as the power spot price increase. It is assumed that the gas-fired boiler has a higher heating efficiency than the gas-fired CHP unit. The cost of heat for these three options can be plotted as a function of the power spot price as shown in Figure 20.

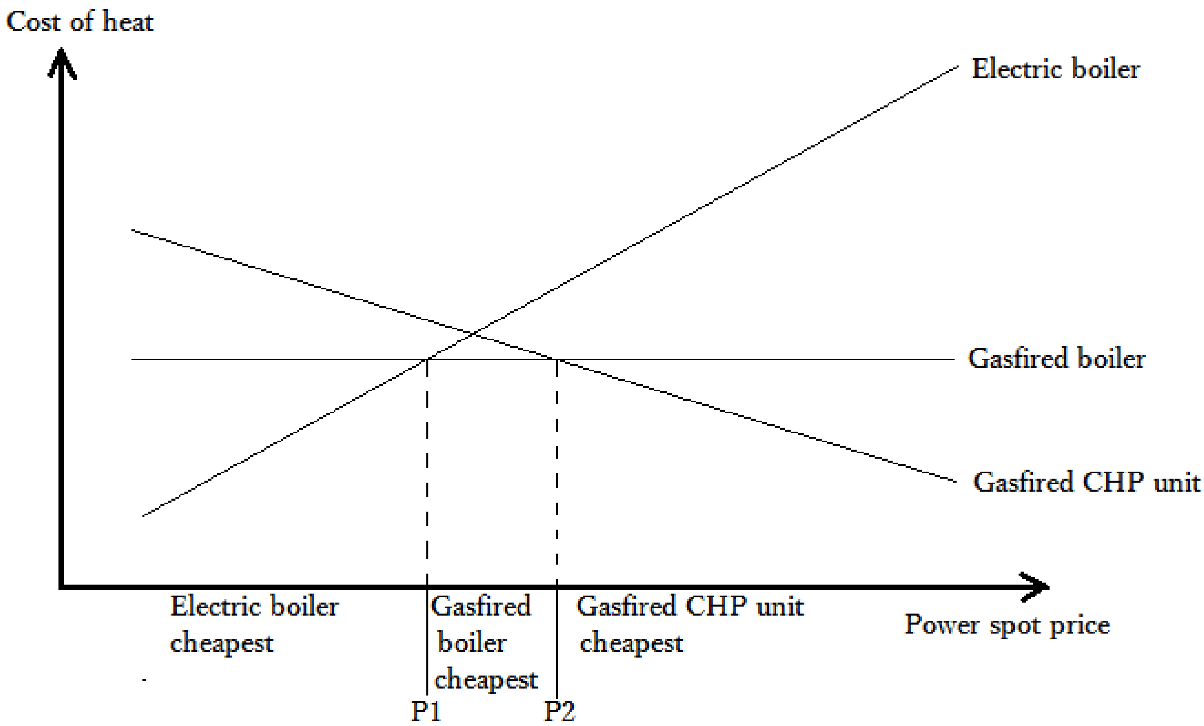


Figure 20: Cost of heat as a function of power spot price

This is only an example and the functions for cost of heat depending on power spot price for these technologies might be different in reality.

Given a cost minimizing CHP utility, the correct choice of heat producing unit is the one with the lowest cost at the given spot price. Figure 20 shows that for a spot price p, where $p < p_1$, the electric boiler is the correct choice. For a spot price p where $p_1 < p < p_2$, the gas-fired boiler is the correct choice. The CHP unit would only be the correct choice given a price $p > p_2$. For this example the CHP utility would need a spot price of p_2 to start the CHP unit, assuming no start up costs. Therefore it would bid its electricity capacity to the market at p_2 and, essentially, this becomes the unit's marginal price. Furthermore, at a power spot price below p_1 the utility would buy electricity to use the electric boiler to cover the heat load.

This is how other units at a CHP plant are represented as an alternative cost to the CHP unit through the MC of the CHP unit.

The lines in Figure 20, representing the cost of heat for a technology at a given electricity price, could intersect each other in several other ways or not at all. This would vary between plants and equipment.

If the utility also had a biomass boiler this would be represented by a straight line similar to that of the gas-fired boiler, but at a lower level if a lower fuel costs and similar fuel efficiency is assumed. This would increase the gap between p_1 and p_2 and the gas-fired boiler would be a reserve unit for all ps. This is shown in Figure 21.

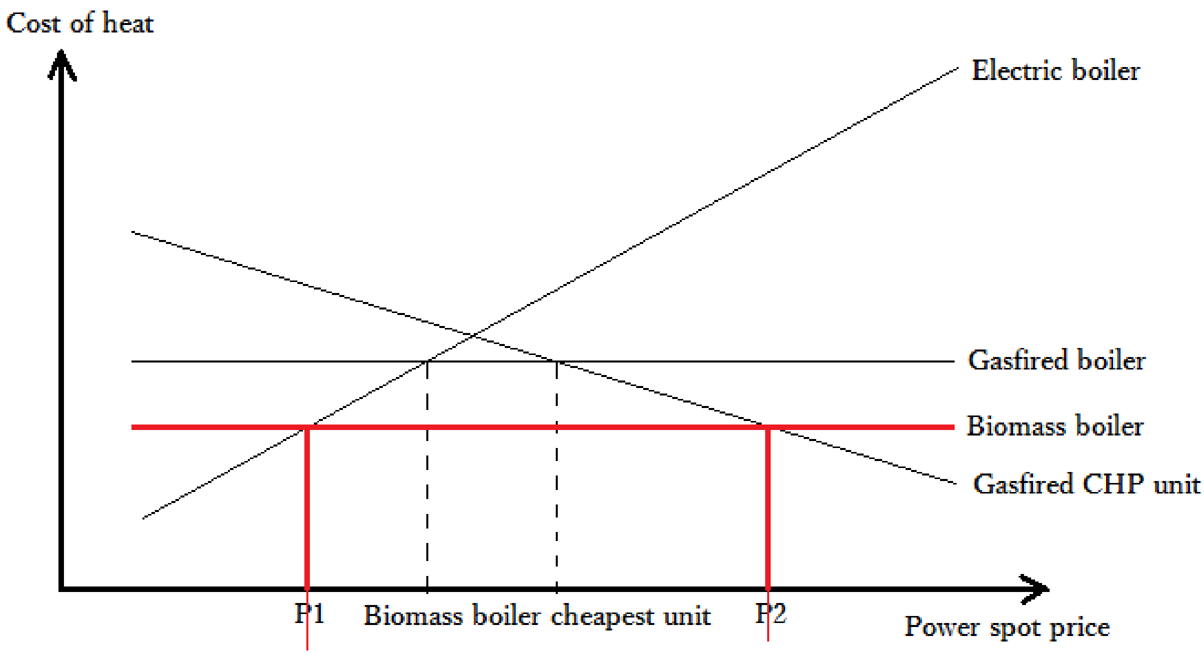


Figure 21: Cost of heat as a function of power spot price including a biomass boiler

Consider a situation where $p > p_2$ in Figure 20 and there is no biomass boiler available. If the CHP unit was at its maximum output, unable to further increase its heat output to meet a rising heat load, the gas-fired boiler would have to be started.

If there were no other options for producing the heat than the CHP unit, p_2 would approach 0, and the MC of the CHP unit production would be 0.

What happens to the MC of the CHP unit if the gas price increases? Take an example plant that has one gas fired back pressure CHP and a gas fired boiler. The cost of heat for both units will shift up from $P_{\text{Gas boiler},1}$ and $P_{\text{CHP},1}$ to $P_{\text{Gas boiler},2}$ and $P_{\text{CHP},2}$ as shown in Figure 22. The read lines in the same figure illustrate the lowest cost alternative at a given spot price before and after the gas price increase. As it is drawn in Figure 22 the MC of the CHP unit actually decrease because of the increased gas price. Had the functions for cost of heat and their shifts been drawn in another way the result could have been the opposite. This depends on taxes and unit efficiency.

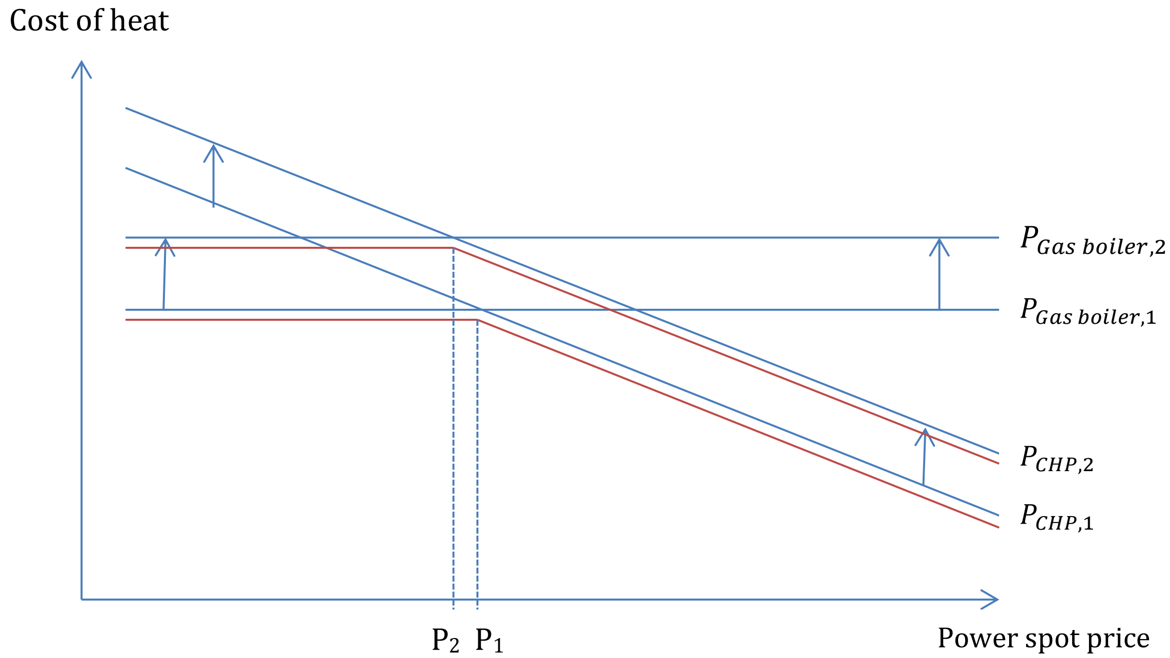


Figure 22: Example of CHP marginal cost development if fuel price increases

6.3.2 Condensing operation

This section discusses the marginal cost of electricity for an extraction plant operating in condensing mode, point A of Figure 19. This is voluntary production for the individual CHP unit, and not dependent on other units. Therefore the marginal cost of this production has different characteristics than that produced in back pressure mode.

The marginal cost in condensing mode is found exactly as for other non-CHP thermal generation, and it includes fuel costs, variable O&M and CO_2 costs [€/MWh] divided by electrical efficiency. Within each prime mover technology, the marginal cost in condensing operation is likely to be significantly higher than that of back pressure operation.

To summarize this section on marginal cost, the MC depends to a large degree on three factors:

- The units own parameters such as fuel cost and efficiency
- The cost of and availability of other heat producing units
- What mode of operation the electricity is produced in

A back pressure unit can only operate in back-pressure mode at a cost dependent on its own fuel cost and efficiency and on the cost of heat from other heat producing units as shown in Figure 20. For an extraction unit operated in back pressure mode, the argument is the same as for a back pressure unit. For an extraction unit operating in condensing mode it is slightly more complicated. All excess electricity produced above back pressure capacity has a higher marginal cost given by fuel, variable O&M and CO_2 costs. This is illustrated in Figure 23. At any given level of P_{heat}, except from 0, there cannot be condensing production without back pressure production. Additionally, the description of “higher” and “lower” MC in Figure 23 has to be viewed as high or low relative to each other, as the actual MC levels might vary significantly from one CHP plant to the next. It was also shown that changing fuel prices are not necessarily reflected as expected in the CHP marginal cost.

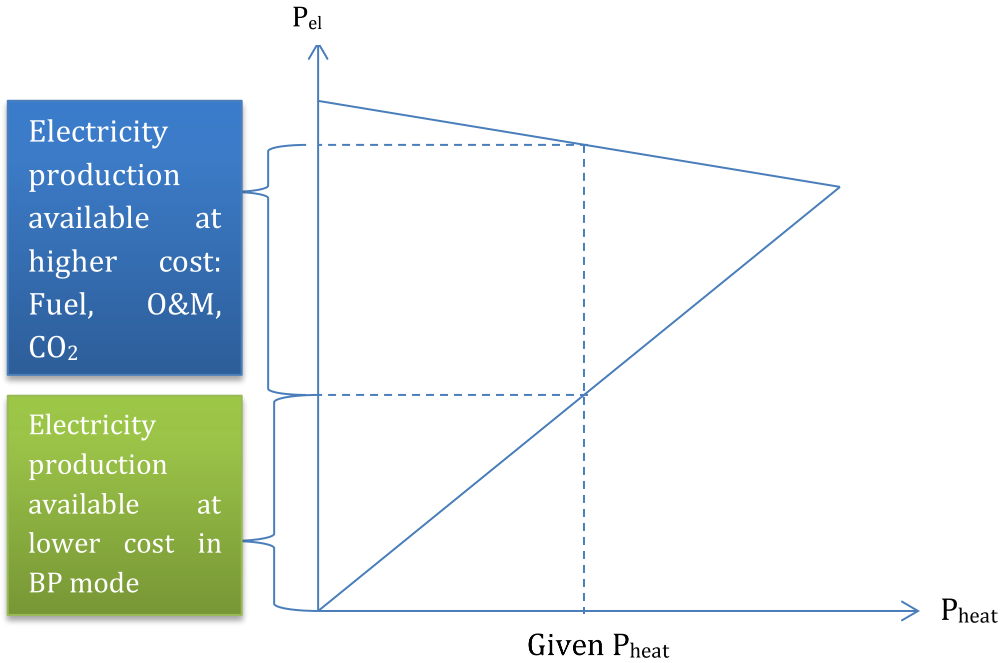


Figure 23: Illustrating production available at different MC at a given heat load

Chapters 6.2 and 6.3 have covered what a CHP plant has to consider when planning its production of both heat and electricity and presented a strategy of how it can achieve this. The plant has to meet the heat load as determined by the outdoor temperature somehow. By comparing what heat production options has the lowest total cost of heat, CHP units and electric boilers can be bid into the market to produce or consume electric power. If a CHP unit is capable of producing more than required to cover the heat load, it is called an extraction plant and can operate in condensing mode. A CHP unit that does not have this option can only operate in back pressure mode. Production in back pressure mode is relatively cheaper than in condensing mode.

Heat accumulator tanks were not included in this strategy. To do this, a time dependent strategy should be developed, keeping track of variables over time, to cover changes in stored heat, electricity prices and heat load over time. Further work remains to include such a strategy. The strategy developed in this thesis does not look at the future or past; it is only concerned with covering the instant heat load.

6.4 SINTEF CHP function

As shown in chapter 6.2 the production of electrical energy from CHP plants is highly dependent on outside temperature. As explained in chapter 5.1, the EMPS framework dictate that CHP generation is determined based on production profiles that do not change from one scenario to the next, despite different temperature data for different scenarios. The SINTEF function corrects the CHP production capacity according to the actual temperature of the scenario being simulated.

In short, the function corrects the available production, originally given by the production profiles, according to the difference in the week's average temperature and the actual temperature.

The reference for this introduction to the function is SINTEF's own documentation on the function provided by Birger Mo and interviews with Birger.

6.4.1 Average and actual temperature

To illustrate the purpose of the function an example is presented in this chapter. Figure 24 shows actual weekly temperatures for weeks 1 through 10 for the years 1978-1982. These values are examples, and not taken from any actual measurements. Orange represents the *average* value for each week across all years. The production profiles for CHP plants in the EMPS should then be based on the average temperature.

Looking closely at week 6, it is obvious that a CHP generation based on the average temperature of the years 1978-1982 would not be suitable when simulating a scenario with the actual temperatures of 1982. For week 6, the average temperature is about 15 degrees higher than in 1982. The SINTEF function will then correct the available CHP production using the difference between average temperature and actual temperature for week 6.

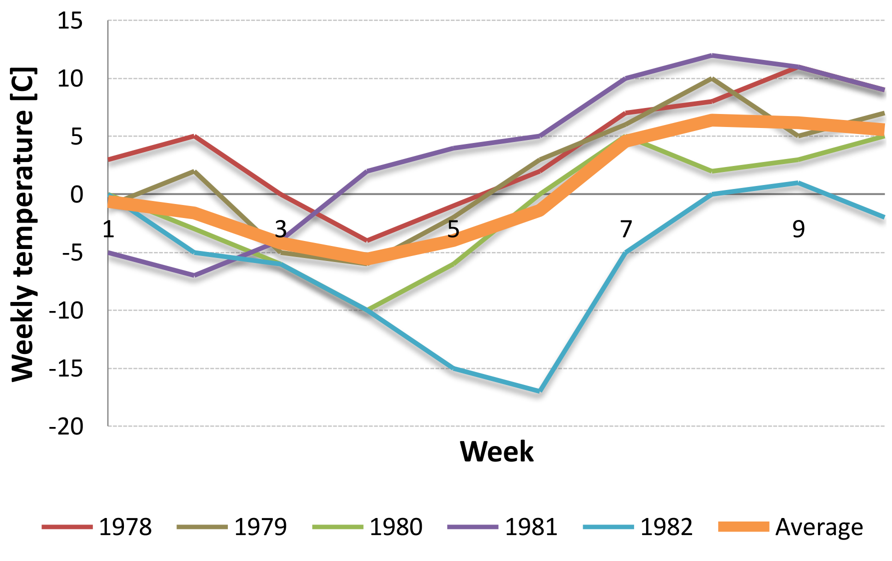


Figure 24: Example of weekly actual temperatures by year and averaged

To show how what is meant exactly by actual and average temperatures, a data and calculation example is presented here for a fictional week 20 in 1982 as a part of a time series that span from 1978 to 1982.

Week 20, 1982	
Day	**Temperature [C°]**
Monday	13
Tuesday	15
Wednesday	16
Thursday	15
Friday	12
Saturday	15
Sunday	16

Table 5: Example temperature data week 20, 1982

The actual temperature for week 20, 1982 is then calculated as:

$$T_{20,1982} = \frac{13 + 15 + 16 + 15 + 12 + 15 + 16}{7} = 14.57\ C°$$

1978-1982	
Year	**Avg. week 20, actual [C°]**
1978	10
1979	20
1980	15
1981	17
1982	14.57

Table 6: Example actual weekly temperatures for week 20

The weekly average is then calculated as:

$$T_{20,AVG} = \frac{10 + 20 + 15 + 17 + 14.57}{5} = 15.3\ C°$$

The production capacity is then corrected within its week, for each scenario based on the temperature difference between actual and average temperature. For this example the correction here would be based on the difference:

$$T_{20,1982} - T_{20,AVG}$$

6.4.2 Mathematical formulation

In this chapter the mathematical formulation of the function will be presented. As explained in chapter 6.4.1, one parameter for the function is the difference between the week's average temperature over several years and the actual temperature. The function gives a linear correction around the average temperature ($T_{20,AVG}$) at a given actual temperature ($T_{20,1982}$).

The second important parameter is the temperature sensitivity of the available capacity. This parameter describes how much the available capacity changes per C°

difference between average temperature and actual temperature. It is a positive or negative value given as % of original capacity given from the production and power profiles per C°. It is the gradient of the linear correction.

In addition there is the input temperature, actual temperature, and the temperature boundaries for correction. Input temperature is given from data series for each scenario/year simulated. The temperature boundaries are inserted and constant for each CHP unit modelled. The formulation is as follows:

P_{orig}	=	Original capacity, $x_{j,i,A}$ as discussed in chapter 5.1
P_{new}	=	New capacity (new $x_{j,i,A}$) for generation after correction
P_{max}	=	Maximum allowed capacity, specified for each plant
K_{CHP}	=	Gradient of temperature dependency. [% of $x_{j,i,A}$ per ΔT (=$T_{chp} - T_{mid}$)]
T_{mid}	=	Average weekly temperature based on weekly temperatures for all scenarios
T_{chp}	=	Actual temperature of the week as a basis for correction
T_{reg}	=	Actual temperature of the week given from a data series for each scenario
T_{min}	=	Minimum temperature for correction
T_{max}	=	Maximum temperature for correction

$$\begin{aligned} T_{chp} &= T_{reg} \quad if \quad T_{min} \leq T_{reg} \leq T_{max} \\ T_{chp} &= T_{min} \quad if \quad T_{reg} < T_{min} \\ T_{chp} &= T_{max} \quad if \quad T_{reg} > T_{max} \end{aligned} \tag{22}$$

$$P_{new} = P_{orig} \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) \tag{23}$$

$$0 \leq P_{new} \leq P_{max} \tag{24}$$

Formula (23 performs the actual correction. It must be specified here that it is not the value directly from the production profile that is changed, it is the one from the power profiles, $x_{j,i,A}$, which is the production available for the load block. The correction for an hour is based on the difference in temperature of the week the hour belongs to. In the implementation an assumption of a flat power profile will be made. The Danish TSO, Energinet, have also assumed flat power profiles in their modelling [31].

6.4.3 Example plant

To illustrate the effect of the correction on the available capacity during a given week for an extraction CHP unit an example plant will be presented in this chapter. The temperature boundaries and their potential effects are neglected for this example.

Assume an extraction unit in the EMPS model. To represent both the back pressure and condensing parts the unit is modelled as two separate units who interact through the parameter K_{CHP}. This will be explained shortly. Figure 25 shows the FOR of this example extraction unit and three separate heat load situations marked 1-3.

Further the week is assumed to consist of 7 individual time steps, one per day of the week, instead of 168 time steps, which is the number of hours per week. This is not exactly as Statnett's EMPS operates, but the difference is not important when explaining the functionality. These 7 time steps can then be assigned to different load blocks, but this is not investigated further here.

For a given time step the production and power profiles will calculate P_{el} for the back pressure part (under the blue line) and the condensing part (between blue and red line) of the extraction unit separately. It is assumed that the profiles are made so that these P_{el}s are related to a P_{heat} that in turn is based on the week's average temperature over several years. This is a requirement for the function described in 6.4.2 to work as intended.

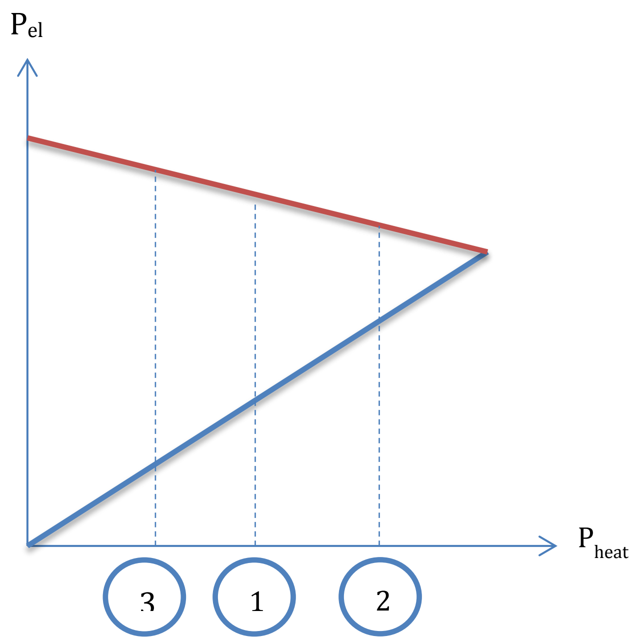
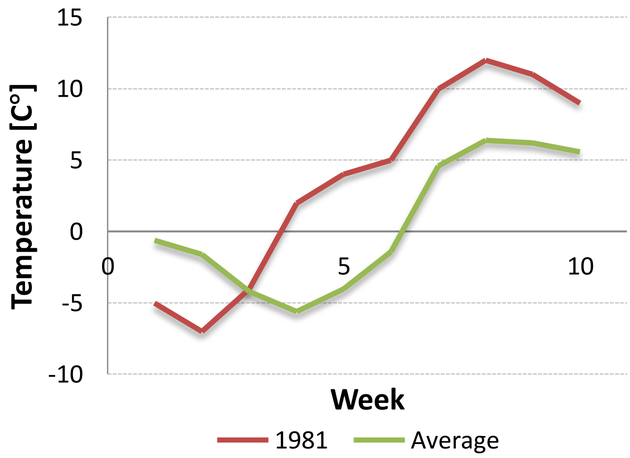


Figure 25: FOR of an example extraction unit and three different heat loads

Assume that the production and power profiles dictates state 1 for this exact time step and week based on average temperature. If actual temperature is lower than average temperature, heat load is higher and the actual state should be number 2. The result would be that $P_{el,condensing}$ would decrease, and $P_{el,back\ pressure}$ would increase. If actual temperature was higher than average temperature, the opposite would be the result in state 3. How much state 3 and 2 differ from 1 in terms of power production depends on the actual temperature difference and the applied K_{CHP}. To refer this to formula (23), P_{el}s in states 2 and 3 would be calculated as P_{new} and P_{el}s in state 1 would represent P_{orig}. One new, corrected P_{el} is calculated for each part of the extraction unit for each time step within the week.

Week 2 and 8 of year 1981 are evaluated for this example calculation to illustrate the function. The table and graph under shows average and actual temperatures for weeks 1 through 10, based on the same example data as Figure 24.

Week	1981 [°C]	Average [°C]
1	-5	-0,6
2	-7	-1,6
3	-4	-4,2
4	2	-5,6
5	4	-4
6	5	-1,4
7	10	4,6
8	12	6,4
9	11	6,2
10	9	5,6



An assumption has to be made regarding the original available capacity given from the profiles for both weeks 2 and 8. These assumptions are given in Table 7. These values are only examples of results from production and power profiles. Further, it is assumed that the heat load decrease during time step 6 and 7 (weekend), which lowers back pressure capacity and increases condensing capacity.

Time step	Back pressure part	Condensing part
1	100	120
2	100	120
3	100	120
4	100	120
5	100	120
6	80	140
7	80	140

Table 7: Original capacity given from production and power profiles for week 2 and 8

It is assumed a K_{CHP} (sensitivity) of 5 for the condensing part and -5 for the back pressure part for this example. For the actual implementation the equation for a theoretical K_{CHP} will be derived. The temperature difference for week i is calculated as $\Delta T_i = T_{chp,i} - T_{mid,i}$. This gives

$$\Delta T_2 = -7 - (-1.6) = -5{,}4\ C°$$

And

$$\Delta T_8 = 12.0 - 6.4 = 5{,}6\ C°$$

Calculating the corrected available capacity for time step 1 week 2 for both unit parts is then done using eq. (23):

Back pressure part:

$$P_{new} = P_{orig} \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) = 100 \cdot \left(1 + \frac{(-5) \cdot (-5{,}4)}{100}\right) = 127\ MW$$

Condensing part:

$$P_{new} = P_{orig} \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) = 120 \cdot \left(1 + \frac{5 \cdot (-5{,}4)}{100}\right) = 87{,}6\ MW$$

So in week 2, the temperature is lower than the average and back pressure capacity has increased and condensing capacity has decreased. This is as expected. For week 8, the temperature difference has the opposite sign and the opposite effects on production capacity.

A similar calculation must be done for all time steps of both week 2 and 8, where ΔT_i is positive. The calculation results are shown in Figure 26 and Figure 27. Of course, in the actual implementation this calculation is carried out for all units for every hour in every week in every scenario.

For week 2 the result is, as already shown, that production from the back pressure part is increased given the negative ΔT_i.

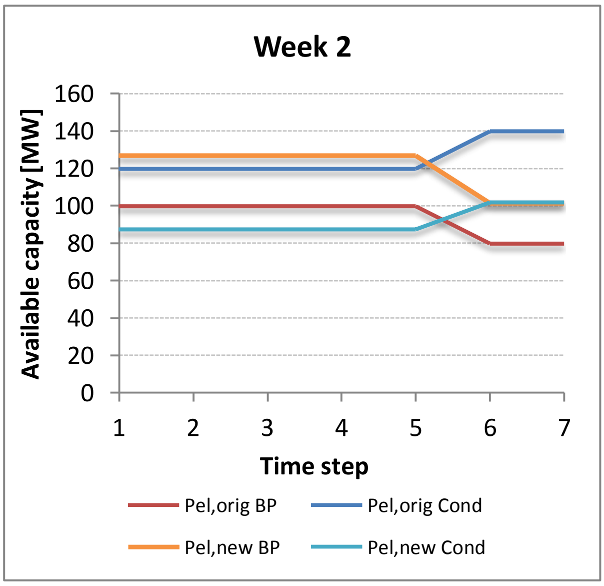


Figure 27: Changes in capacity for week 2

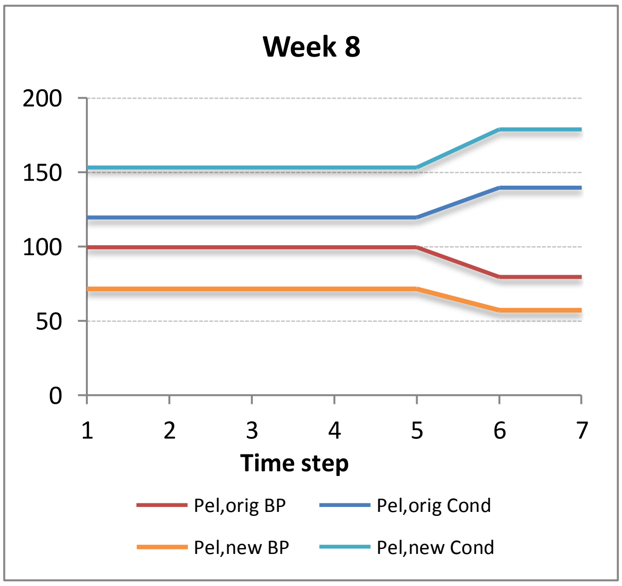


Figure 26: Changes in capacity for week 8

It is interesting to see that because P_{orig} for the BP part is lower during the weekend, the correction $(P_{orig} - P_{new})$ is lower, despite an unchanged ΔT. This means that P_{new} is not what it should be according to the temperature. This is because the K_{CHP} is unchanged. K_{CHP} should vary as a result of a varying P_{orig}. If $P_{orig} = 0$ for either of the CHP unit parts at any given time, the correction would be zero since:

$$P_{new} = P_{orig} \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) = 0 \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) = 0$$

This means that for the function to be able to correct a low P_{orig} a high K_{CHP} should be applied. So, how should K_{CHP} be calculated?

6.4.4 Sensitivity, K_{CHP}

Regardless of the initial production capacity given by the production and power profiles, the capacity after the correction should be given by the equations in Table 4, chapter 6.2.3. For the following discussion; assume the simple form of $P_{el,cond/BP} = \beta + \alpha T$, where values for β and α for either a back pressure or a condensing part are actually given in the aforementioned Table 4. The correction function is given as follows:

$$P_{new} = P_{orig} \cdot \left(1 + \frac{K_{CHP} \cdot (T_{chp} - T_{mid})}{100}\right) \tag{25}$$

Assuming that P_{orig} is given as:

$$P_{orig} = \beta + \alpha T_{mid} \tag{26}$$

And the expected new available production capacity is given as:

$$P_{new} = \beta + \alpha T_{chp} \tag{27}$$

Inserting (26) and (27) into (25), we obtain the following relation:

$$\beta + \alpha T_{chp} = (\beta + \alpha T_{mid}) \cdot \left(1 + \frac{K_{CHP} \cdot \left(T_{chp} - T_{mid}\right)}{100}\right) \tag{28}$$

The following derivation aims to solve the equation for K_{CHP}, which is the only initially unknown variable in the equation along with T_{chp}:

$$\beta + \alpha T_{chp} = (\beta + \alpha T_{mid}) \cdot \left(1 + \frac{K_{CHP} \cdot \left(T_{chp} - T_{mid}\right)}{100}\right)$$

$$\cancel{\beta} + \alpha T_{chp} = \cancel{\beta} + \alpha T_{mid} + (\beta + \alpha T_{mid}) \cdot \left(\frac{K_{CHP} \cdot \left(T_{chp} - T_{mid}\right)}{100}\right)$$

$$\alpha T_{chp} = \alpha T_{mid} + \beta \frac{K_{CHP} \cdot T_{chp}}{100} + \alpha T_{mid} \frac{K_{CHP} \cdot T_{chp}}{100} - \beta \frac{K_{CHP} \cdot T_{mid}}{100} - \alpha T_{mid} \frac{K_{CHP} \cdot T_{mid}}{100}$$

$$\alpha \cancel{\left(T_{chp} - T_{mid}\right)} = \beta \frac{K_{CHP}}{100} \cancel{\left(T_{chp} - T_{mid}\right)} + \alpha T_{mid} \frac{K_{CHP}}{100} \cancel{\left(T_{chp} - T_{mid}\right)}$$

$$K_{CHP} = \frac{100\alpha}{\beta + \alpha T_{mid}} \tag{29}$$

This result means that to achieve an equal linear correction around T_{mid}, regardless of what T_{mid} actually is and securing that equation (27) is fulfilled, K_{CHP} has to vary according to the T_{mid}. For this reason, SINTEF has built the function so that an individual K_{CHP} can be entered for each week**.** Formula (29) will be used to calculate

K_{CHP} for each plant, inserting values for β and α given in Table 4 and weekly average temperatures given from the chosen temperature data series.

6.4.5 Input for implementation

This section presents the additional needed input data for this function to work as intended in the EMPS model.

The function is embedded in the EMPS model and an environment variable has to be set correctly to activate the function. This variable functions as a password, which Birger Mo and SINTEF have kindly provided for this thesis work.

In addition to this, all CHP plants that are to be modelled with the temperature correction have to be connected to the function and temperature data in some way. This is done using .sdv-files, which are automatically generated from Excel-sheets provided by SINTEF. All input data concerning each plant is inserted into this sheet as shown in Figure 28.

- **Number:** This is a number to list each CHP plant in the spreadsheet, without any further significance. Each row contains information about one CHP unit.
- **Area:** The number of the area the CHP unit belongs to.
- **Type num:** Identifies the unit that is described in that row with its EMPS type number.
- **Text:** Describes the unit. For example the first row "AMV2M" is the back pressure part of Amagerværket's unit 2.
- **Temp. series:** Tells the function what temperature data to use for the correction. The unit's production profiles should be based on this series.
- **Profile nr.:** This tells the function which series/profile of K_{CHP}s to use. The profiles are given in the spreadsheet "kraftvarmeprofiler" as shown in Figure 29. The profiles are numbered in row 3, and given a value per week (column A).
- **Min/Max temp limit:** Acts as T_{min} and T_{max} in eq. (22). The function is instructed to use T_{min} if the T_{reg} is lower than T_{min}. The same is the case for T_{max}.
- **Maximum cap. [MW]:** Remember how the correction is not correcting the total weekly output directly, but the hourly generation as a result of the power profile (which is flat in the actual implementation). So the resulting capacity after the correction is a GWh/h value. This simply restricts the production per hour to go above the unit's capacity.

Kraftvarmeverk

Eksportér kraftvarmeverk sdv-fil

Number	Area	Type nun	Text	Temp. series	Profile nr.	Min temp limit	Max temp limit	Maximum cap. [MW]
1	22	3	AMV2M	9007-C	5	-10	20	400
2	22	4	AMV2K	9007-C	11	-10	20	460
3	22	5	AMV3M	9007-C	1	-10	20	400
4	22	6	AMV3K	9007-C	7	-10	20	460
5	22	7	ASV2	9007-C	1	-10	20	400
6	22	10	AVV1M	9007-C	1	-10	20	400
7	22	11	AVV1K	9007-C	7	-10	20	460
8	22	12	AVV2TM	9007-C	2	-10	20	400

Figure 28: Screenshot of the spreadsheet for input data to correction function

Kraftvarmeprofiler

Eksportér kraftvarmeprofil sdv-fil

Uke\Profilnavn	1	2	3	4	5	6	7
1	-4.076661	-3.940447	-4.020625	-4.058279	-4.011762	-4.0239	7.3288384
2	-4.209642	-4.064554	-4.149916	-4.190043	-4.140475	-4.153406	6.9349991
3	-4.311015	-4.158982	-4.2484	-4.290463	-4.238506	-4.252056	6.676366
4	-4.326868	-4.173734	-4.263795	-4.306165	-4.253829	-4.267478	6.6386973
5	-4.261813	-4.113171	-4.200609	-4.241727	-4.190936	-4.204184	6.7979063
6	-4.293357	-4.142545	-4.231251	-4.272974	-4.221436	-4.234878	6.7191618
7	-4.236327	-4.089426	-4.175848	-4.21648	-4.166288	-4.17938	6.8637716
8	-4.147539	-4.00663	-4.089551	-4.128514	-4.080383	-4.09294	7.1103918

Figure 29: Screenshot of the spreadsheet for giving profiles of K_{CHP}s

Chapter 7 will present more exactly how these parameters and inputs are determined for all CHP plants to be modelled with this correction functionality.

6.5 Analysis of decentral CHP plants

This chapter presents an analysis of decentral CHP plants in Denmark. This analysis is based on benchmarking data from the financial year of 2012/2013 provided by *Dansk Fjernvarme*, an industry organization for 405 DH utilities in Denmark [37]. This organization publishes annual statistics reported by their members for benchmarking [38].

In the EMPS, many of the larger CHP plants are modelled individually, while the small CHP plants are aggregated into groups. The goal of this analysis was to describe an optimal aggregation of small CHP plants in Denmark.

There are 205 DH utilities in the statistics in total. They have in total reported 24.8 TWh of heat sold. The five largest utilities account for about 50 % of the total heat sold by utilities in the statistics. Dansk Fjernvarme state that for an analysis of small CHP plants, these should be removed from the statistics [39]. The benchmarking statistics does not include all decentral CHP and DH plants in Denmark, but it is assumed that the selection is representative. DH plants of various sizes are included in the statistics. Figure 30 shows the utilities sorted by volume of heat sold. Figure 30 does not include the five largest utilities. Still, there are plants in the statistics that are modelled individually in the EMPS model. This can cause some confusion as this analysis is aimed at the smallest CHP plants in Denmark.

The utilities are very different in terms of production units, data measurements and human resources and they are responsible themselves for reporting the numbers. Among the reported data some discrepancies have been discovered. For example some utilities have reported different data in kWh or GWh instead of in MWh. Others have not reported spending fuel for CHP units, but still produced electricity. While the former is an example of a human error, the latter might depend on what measurements the utilities themselves can access as several of them are small. This analysis has been at risk of overlooking or not discovering similar errors. In cases where an error or false data is suspected, the statistic for 2011/2012 has been used as a backing reference. In cases where neither older statistics nor other sources can give sufficient information the utility has been excluded from the sample space.

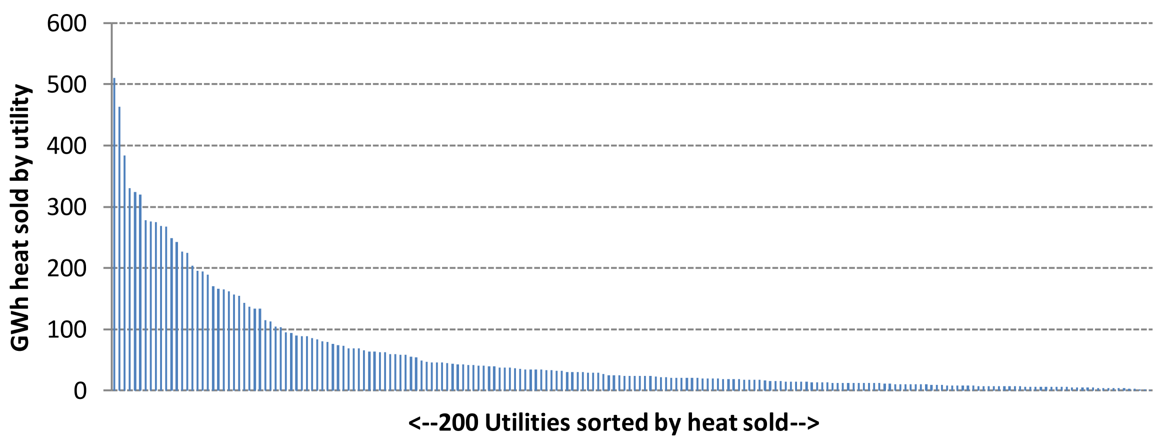


Figure 30: Distribution of CHP utilities by heat sold, excluding the five largest utilities

More specifically, the goal of this analysis was to quantify how small DH utilities produce heat, either by CHP or boiler, and what fuels are used. Table 8 shows that the smallest 141 (out of 205) CHP plants only represents about 10 % of the total heat sold. These smallest plants should comprise most of the small CHP aggregation groups.

Table 8: Categorization of utilities by size

Description	Number of utilities	Total heat sold [TWh]
All plants	205	24.78
Excluding largest five plants (under 510 GWh)	200	11.89
Under 200 GWh heat sold	184	7.04
Under 100 GWh heat sold	167	4.50
Under 50 GWh heat sold	141	2.63

Figure 31 shows the share of DH utilities that have reported using only CHP, only other options or both other options and CHP for heat production. It is assumed that this distribution is valid also for the smallest CHP plants.

It is assumed that plants who have not reported the use of any other units than CHP do not have other heating options (such as boilers) that become the economically feasible choice at any power spot price. This implies that 15 % of the DH utilities operate with a CHP unit with zero marginal cost.

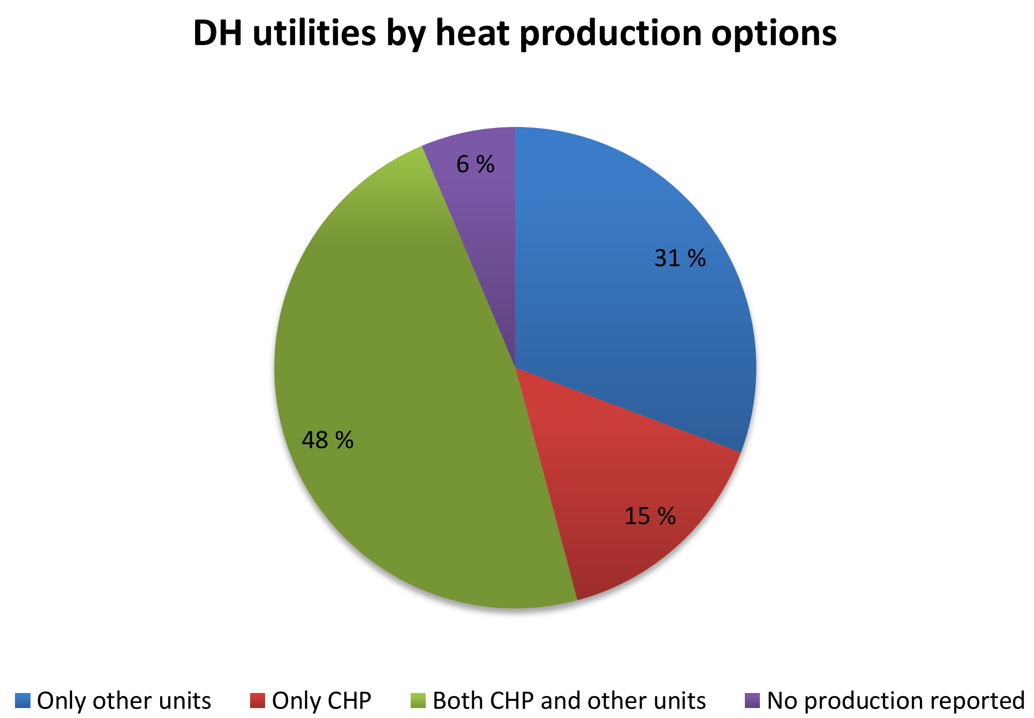


Figure 31: CHP utilities in benchmarking statistics by available options for producing heat

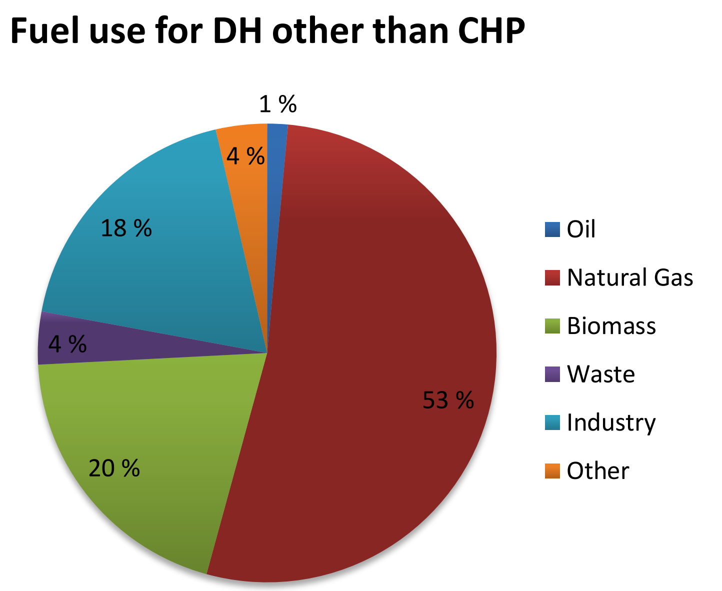


Figure 32: Energy used for district heating by other units than CHP

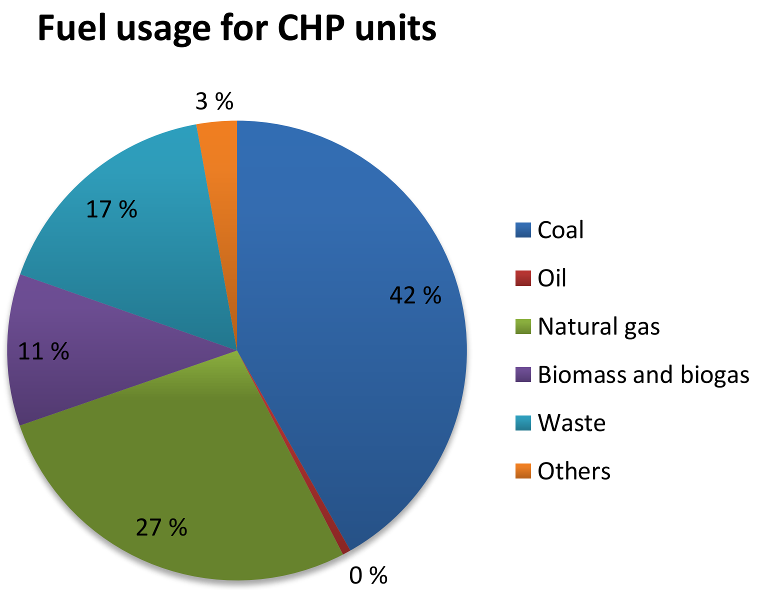


Figure 33: Fuel usage for CHP units for the 166 smallest CHP plants

Figure 31 also shows that 48 % of the DH utilities have reported using a CHP unit and a boiler of some sort. These CHP units will have a marginal cost determined by the cost of the boiler, which is not zero. Figure 32 shows that natural gas and biomass are the dominant fuels for boiler use. “Industry” can not be evaluated in the same way as other fuels in this context, as this heat production is not controlled by the DH utility and it is not a feasible option for all small CHP plants. Several individually modelled CHP plants in the existing EMPS are industry based CHP plants. Therefore, with regards to the aggregated small CHP analysis, industry is ignored.

Some of the plants in this statistics might already be modelled as individual CHP plants in the existing EMPS model, either as large extraction or medium back pressure plants. Therefore it is necessary to remove many of the large plants, to make sure that only the smallest plants are represented, and no large plants are counted twice.

Figure 33 shows the fuel usage for CHP units in the statistics excluding the 44 largest plants. Coal is the dominant fuel. However, this is caused by a single DH utility, Aalborg municipality, who has reported very little heat sold, but approximately 1.1 TWh of coal spent in CHP units. This production is too high to be accounted for in this analysis and should be dropped from the sample space, as this production is most likely covered by the individually modelled, large CHP plants.

Waste and biomass/biogas CHP plants are modelled in separate aggregated groups. Therefore, these are not included in this aggregation of small CHP plants, and natural gas is the sole fuel used in these small CHP plants.

Therefore, aggregated groups of small gas fired CHP plants should be diversified to represent forced CHP production (MC = 0) and CHP units with different back up boilers and different MC.

The small CHP plants should be aggregated in three groups:

1. Gas fired CHP plants with MC = 0
2. Gas fired CHP plants with gas fired boilers as optional heating source
3. Gas fired CHP plants with biomass fired boilers as optional heating source.

Further, the total available generation for these plants in the EMPS is divided between these groups. Therefore, the available generation is not changed, only how it is distributed over three different MCs.

Amongst the 63 % of small gas fired DH utilities that reported using a CHP unit, 25 % (15 % of 63 % as shown in Figure 31) reported using only a CHP unit. Therefore, 25 % of all small gas fired CHP units should have zero marginal cost.

The DH utilities that reported using both CHP and other units, the remaining 75 % of all small gas fired CHP plants are then divided between those that have gas and those that have biomass boilers. As shown in Figure 32, ignoring industry, fuel spent for boilers is about 2/3 natural gas and 1/3 biomass. Therefore 50 % of small gas fired CHP heat production is produced with a gas fired boiler option and 25 % is produced with a biomass boiler option.

This short analysis serves as the basis for the implementation of a new aggregation of small CHP, and will be taken further in chapter 7.4.3.

6.6 Shortcomings of existing modelling

Chapter 5 covered how CHP has been modelled in the EMPS previously, while chapter 6 presents how CHP could be modelled in general and in the EMPS particularly. Chapters 6.2, 6.3, 6.4 and 6.5, outline some key modelling characteristics that are not or only partially implemented in the existing Statnett EMPS CHP modelling.

In this section, the main shortcomings of the existing modelling are presented.

6.6.1 Existing production profiles

In chapter 6.2 it was explained how average temperature data could be used to create the annual CHP plant production profiles. This would create smooth profiles, and an example of this is shown in chapter 7.2. This is also the current practice for the EMPS CHP modelling in Energinet [31].

The origins of the existing profiles are unknown. Documentation on the theoretical background and foundation of the profiles has not been found.

Some of the existing production profiles have very specific shapes, seemingly random, with very volatile shifts between operating in back pressure and condensing mode. The production profiles for one of the larger plants (that are represented by one back pressure and one condensing part) are shown here in Figure 34. Additional profiles to illustrate this can be found in the appendix, chapter 13.1. These profiles are not as smooth as those based on the discussion in chapter 6.2.

It is a requirement for the CHP temperature dependent capacity correction function presented in chapter 6.4 that the production profiles are based on the weekly average temperatures in the time series that apply for each CHP plant.

Therefore is it not only advisable [31], but also required, to create new production profiles based on the weekly average temperatures measured over several years for the EMPS implementation. How these temperatures and profiles come about is presented in chapter 7.2.

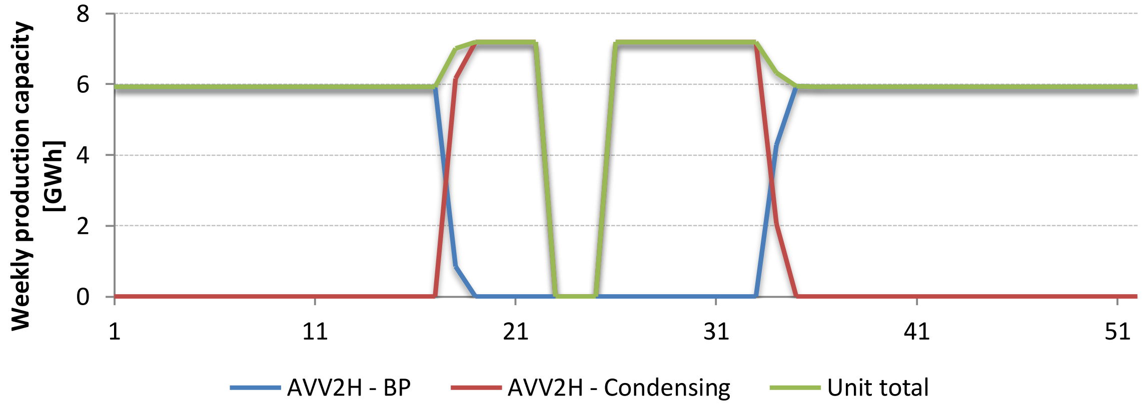


Figure 34: Available production capacity [GWh] per week based on existing profile for EMPS CHP unit AVV2H

6.6.2 Temperature dependent capacity correction

The production profiles, as discussed in chapter 6.6.1, are used in the optimization for every scenario. This means that CHP production is only dependent on an average temperature measured over multiple years. The temperature dependent capacity correction function developed by SINTEF, presented in chapter 6.4, is intended to make CHP production capacity dependent on the actual temperature of the scenario.

Testing this function was one of the main tasks in the thesis problem description.

6.6.3 Aggregation of small plants

The analysis of decentral CHP plants in chapter 6.5 showed that there are reasons to model small gas fired CHP plants with some degree of diversity to reflect different MCs. This type of plants is aggregated into only one group in the existing modelling.

The MCs in the existing modelling are higher during the winter than the summer. This is done to reflect seasonal dependencies in the gas price, which intuitively would increase the MC of gas fired CHP units. However, it was shown in Figure 22 in chapter 6.3.1 that this is not certain. Am assumption was made that gas fired CHP units MCs should not follow seasonal gas price variations.

These two aspects of the aggregated small CHP plants should be addressed in the new modelling.

If other types of plants, such as industry, waste and biomass CHP plants had been reviewed, it is likely that the level of modelling detail could have been increased also for these.

In short, the shortcomings of the existing EMPS CHP modelling are mainly related to the temperature dependency of production. The production profiles and temperature dependent capacity correction function relates to all CHP plants, while only small CHP plants are concerned with the new aggregation of these. The new aggregation of small CHP plants is a matter of increasing the level of detail in the model, while new production profiles and temperature based generation capacity correction relates to the best practice modelling in theory.

The specifics of implementing these new modelling elements are presented in chapter 7.

7 Implementation

This chapter describes how the new CHP modelling has been implemented practically in Statnett's EMPS model.

In chapters 5, 6.4 and 6.5 a few important aspects for the implementation of the new modelling was discussed, such as:

- The need for new production and power profiles
  - Existing production profiles are not suitable
  - SINTEF correction function needs production profiles based on average temperature
- The needed input for the temperature dependent correction function
  - Temperature series
  - Calculating the K_{CHP}
- The new aggregation of small CHP plants

In this chapter it is shown how temperature data, new production profiles and the sensitivity parameter K_{CHP} have been implemented. In addition, the actual implementation for each plant, including the new aggregation of small CHP plants is shown here.

7.1 Temperature data

At first there were no available time series for temperature data suitable for Denmark in the original Statnett EMPS model. To establish an average weekly temperature series one needs several years of data, and it was not possible to find this for any location in Denmark. However, the Swedish Meteorological and Hydrological Institute have made daily temperature observations in the period 1955-2013 available for Malmö.

Not only is this a substantial amount of data, but it also overlaps all scenarios in the Statnett EMPS model, which range from the year 1962 to 2008. Based on Malmö's relative proximity to Copenhagen and the lack of better options, this was considered a suitable set of temperature data for all CHP plants in the whole of Denmark. The data contains daily temperature observations, so the weekly averages per year and across all years are calculated similar to the method shown in chapter 6.4.1. This yields a curve containing the average weekly temperatures across 1955-2013 as shown in Figure 35. Figure 35 also shows the maximum and minimum weekly temperatures, and thus their corresponding heat load that CHP plants might have to cover.

This temperature data was implemented as a temperature time series using the HYDARK-program in the EMPS model under the name *9007-C*. The SINTEF function is designed to find the temperature series itself as long as the temperature series is connected to the CHP unit via .sdv-files.

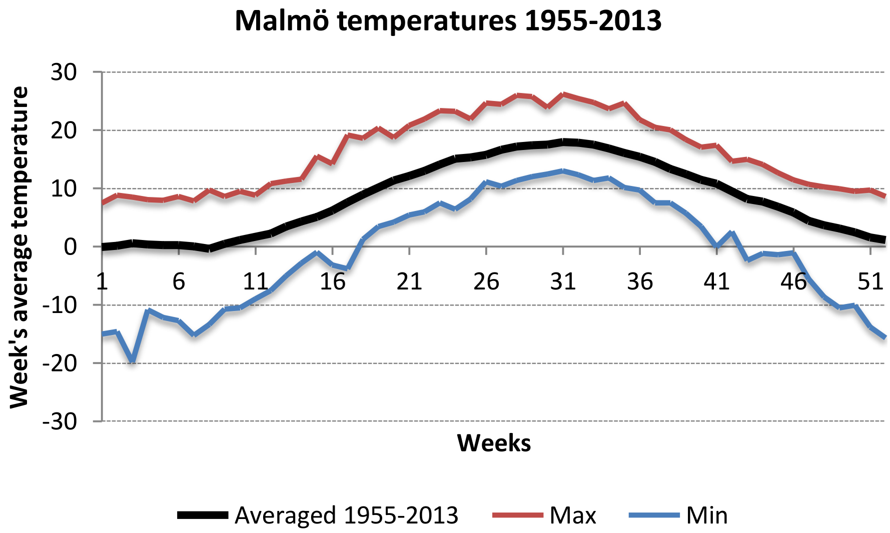


Figure 35: Average, maximum and minimum weekly temperatures Malmö 1955-2013

7.2 Production and power profiles

In chapter 6.2.3 a set of equations were derived to calculate available power production capacity given a temperature for a small range of technologies and their back pressure and condensing part. The table is presented here once more:

Description/Tech.	$P_{el,bp}$	$P_{el,cond}$
Coal fired, steam turbine	$0,43 - 0,018 * T$	$0,3 + 0,021 * T$
Gas turbine/engine	$0,47 - 0,019 * T$	$0,33 + 0,023 * T$
Combined cycle	$0,63 - 0,026 * T$	$0,44 + 0,03 * T$
Biomass, steam turbine	$0,36 - 0,015 * T$	$0,25 + 0,018 * T$
Amager 2, biomass	$0,17 - 0,007 * T$	$0,12 + 0,008 * T$
Avedøre 2, biomass	$0,46 - 0,019 * T$	$0,32 + 0,022 * T$

Table 9: Equations for power production capacity

To determine the production profiles for these technologies the average temperature shown in Figure 35 is used as the temperature, T, in Table 9. An example is shown here, using the $P_{el,bp}$ and $P_{el,cond}$ of the coal fired steam turbine, in Figure 36. This was done for all technologies in Table 9.

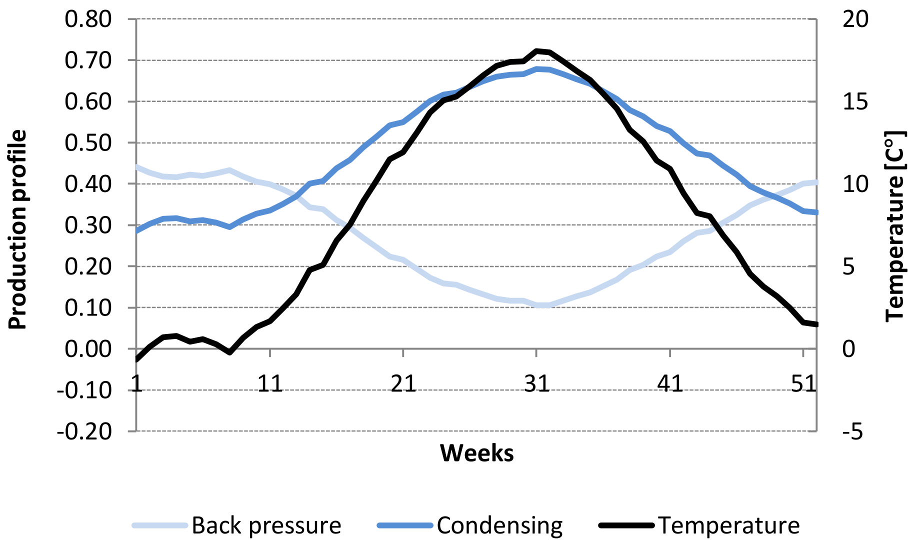


Figure 36: Production profiles for BP and Condensing parts of coal fired steam turbines

All units modelled as CHP with temperature correction has been given flat power profiles. There are three reasons for this. First of all it is not possible to set K_{CHP} on an hourly basis. Therefore the correction (discussed in chapter 6.4.4) will be wrong for some hours of the week. A flat power profile will avoid this, although the error might have been insignificant. Secondly, although it is completely feasible that the heat load has a weekly profile, it remains unknown as no significant amount of data has been found to confirm it. Third, Energinet assumes flat power profiles as the daily variations in heat load are negligible.

7.3 Sensitivity, K_{CHP}

The sensitivity parameter K_{CHP} is an important input to the temperature dependent capacity correction. As shown in chapter 6.4.4, K_{CHP} can be calculated using eq. (29):

$$K_{CHP} = \frac{100\alpha}{\beta + \alpha T_{mid}} \tag{29}$$

Adding subscript i, to represent the week i, and u, to represent each technology as found in Table 9, (29) can be rewritten as:

$$K_{CHP,u,i} = \frac{100\alpha_u}{\beta_u + \alpha_u T_{mid,i}} \tag{30}$$

Where $T_{mid,i}$ is the average temperature as found in Figure 35, and β_u and α_u are found as

$$P_{el,BP/cond} = \beta_u + \alpha_u * T$$

In Table 9.

Inserting values for α_u, β_u and $T_{mid,i}$ gives a value for the sensitivity for every technology for every week.

Summarizing chapters 7.1 through 7.3:

- The temperature data gives average weekly temperatures across all years and for each single year in the period 1955-2013
- Average weekly temperatures across all years are used to create production profiles corresponding to the expected temperature for a small range of technologies
- Power profiles are flat
- Average weekly temperature and temperature dependencies for a small range of technologies are used to calculate the sensitivity factor $K_{CHP,u,i}$ for the temperature dependent capacity correction function.

The next section presents how various CHP plants have been handled specifically in the implementation.

7.4 Implementation in Practice

This section presents how the new CHP modelling has been implemented in practice and how every existing and new CHP units have been handled for the new modelling.

CHP plants in Denmark range from a few very large to several hundred small plants, all running on different prime mover technologies and fuels. There lies a significant challenge in categorizing the plants in the best possible way for the new modelling. The new modelling will rely heavily on the existing modelling for which large to medium sized plants to model explicitly and their existing prime mover information. This is described in more detail in chapter 7.4.1 and 7.4.2.

It is obviously a very time consuming task to model every single small CHP unit in the EMPS, and therefore they have to be aggregated in some categories. Small CHP plants are aggregated in the existing modelling, however, the decentral CHP plant analysis presented in chapter 6.5 discovered that there is some diversity amongst small gas fired CHP plants. A new method of aggregating the small CHP is described in chapter 7.4.3.

In addition, there are industry, biomass and waste CHP plants in the existing CHP modelling. The handling of these existing plants is explained in chapters 7.4.4 through 7.4.6.

To visualize more clearly what is actually discussed here, all existing CHP units in one of the areas in Denmark are presented in Table 10.

Table 10: All CHP units in EMPS price area "JYLL-SYD" in the existing modelling

Group	Name in EMPS	Description	Fuel	Technology
Waste	DKV BIO	Aggregated Bio	Straw	Waste Burner
Small CHP	DKV NG	Aggregated small chp	Gas small	Gas Engine
Waste	DKV WASTE	Aggregated Waste	Waste	Waste Burner
Industry	QBASF	BASF	Fuel Oil	Oil
Medium-to-large	QBJ	Bjerringbro CHP	Gas small	Natural Gas
Industry	QCN	Cheminova	Gas small	Natural Gas
Industry	QDS	Maricogen	Gas small	Natural Gas
Medium-to-large	QGR	Grenå CHP	Straw	Straw
Medium-to-large	QHL	Mårbjeg CHP	Waste	Waste Burner
Medium-to-large	QHO	Horsens CHP	Waste	Waste Burner
Medium-to-large	QMAA	Esbjerg CHP	Waste	Waste Burner
Medium-to-large	QRV	Randers CHP	Coal	Coal
Medium-to-large	QSE	Skive CHP	Gas small	Natural Gas
Medium-to-large	QSI	Silkeborg CHP	Gas small	Natural Gas
Medium-to-large	QSL	Shell	Gas small	Natural Gas
Medium-to-large	QSOE	Sønderborg CHP	Gas small	Natural Gas
Medium-to-large	QTOE	Toftlund CHP	Gas small	Natural Gas
Medium-to-large	VKHM1	Herning CHP	Straw	Straw
Large	SVSB3	Skærbækværket, Unit 3, Backpresure part	Gas	Natural Gas
Large	MKSB3	Studstrupværket, Unit 3, Backpresure part	Coal	Coal
Large	MKSB4	Studstrupværket, Unit 4, Backpresure part	Coal	Coal
Large	SHEV3	Enstedværket, Unit 3, Backpresure part	Coal	Coal
Large	VKEB3	Esbjerg, Unit 3, Backpresure part	Coal	Coal
Large	SVSB3B	Skærbækværket, Unit 3, Condensation part	Gas	Natural Gas
Large	MKSB3B	Studstrupværket, Unit 3, Condensation part	Coal	Coal
Large	MKSB4B	Studstrupværket, Unit 4, Condensation part	Coal	Coal
Large	SHEV3B	Enstedværket, Unit 3, Condensation part	Coal	Coal
Large	VKEB3B	Esbjerg, Unit 3, Condensation part	Coal	Coal

7.4.1 Large units

This group includes the largest CHP units in Denmark that are already modelled as extraction units. Typically, these units have an installed capacity of 200 to 600 MW [40] combined for back pressure and condensing parts. These are the only units that should be modelled as extraction units [31]. They are modelled as two parts, back pressure and condensing, with new profiles for production and K_{chp}. The profiles are assigned based on what technology group the unit belongs to, this is given in the documentation of the existing modelling and will not be changed.

This group of units are not aggregated or divided further; therefore their total annual available energy is not changed for the new modelling. The assumed installed capacity for the back pressure part is chosen to be 400 MW, based on the knowledge of the capacity range [40], this is an average value. Given that the condensing part is determined to have 15% more capacity at no heat output than the back pressure part at full heat output it is calculated as $400 * 1.15 = 460\ MW$. These values for installed capacity are applied to all large CHP units.

The marginal costs will not be changed, as there are no indications that this is needed for the large plants. The marginal cost of the back pressure parts should be significantly lower than for the condensing parts. The existing estimations of MC for large plants will remain unchanged, as no documentation has shown that a significant change is warranted.

Table 11 shows that the MC of back pressure parts is considerably lower than for the corresponding condensing parts. The existing estimations of MC for large plants will remain unchanged, as no documentation has shown that a significant change is warranted.

Table 11: Data for some large CHP plants in JYLL-SYD

Unit	Fuel	Marginal Cost [€c/kWh]	Total annual energy [GWh]
Skærbækværket 3 - BP	Natural gas	0.70	420
Skærbækværket 3 – Cond	Natural gas	6.00	1500
Studstrupværket 3 - BP	Coal	0.70	711
Studstrupværket 3 – Cond	Coal	3.11	1675
Studstrupværket 4 - BP	Coal	0.70	675
Studstrupværket 4 – Cond	Coal	3.11	1725

7.4.2 Medium-to-large sized units

These units include all units modelled individually as back pressure units in the existing modelling. They are given production and K_{chp} profiles according to their prime mover technology. The Hillerød, Helsingør and DTU CHP plants has installed capacities at maximum heat output of 77, 68 and 38 MW_{el}, respectively, with an average of about 60 MW. This will set the precedence for similar plants. Therefore the installed capacity of medium-to-large sized plants will be set at 60 MW.

As with the largest plants, none of these plants will be further divided or aggregated, therefore their annual available production will not be changed. Nor will marginal costs be changed for any of these units. The main difference between medium and large plants is that large plants are modelled as extraction plants in the existing modelling, while medium plants are modelled as back pressure plants only.

7.4.3 New aggregation of small CHP units

This is the most challenging group of plants, given there are a few hundred of them and the significant technological diversity. However, this type of CHP plants, known as *decentral* CHP plants only represented about 11 % of the total electricity generation in 2012 [2]. Table 10 shows that there is only one group of aggregated small CHP plants in the existing CHP modelling. This is the same for the other areas in Denmark as well.

The analysis of small CHP plants in chapter 6.5 showed that the existing total annual production capacity for small gas fired plants should be distributed over three groups with a MC determined by other options of heat production in the new modelling.

The existing modelling of small CHP has a MC that reflects seasonal variations in gas prices. However, it was shown in chapter 6.3.1 that the impact of changing fuel prices on CHP MCs is unknown. It is assumed that the total effect of fuel price seasonal variations can be neglected at an aggregated level.

The following paragraphs outline the determination of marginal costs for each of the two groups with heating options. The MC for one of the groups has been set to zero.

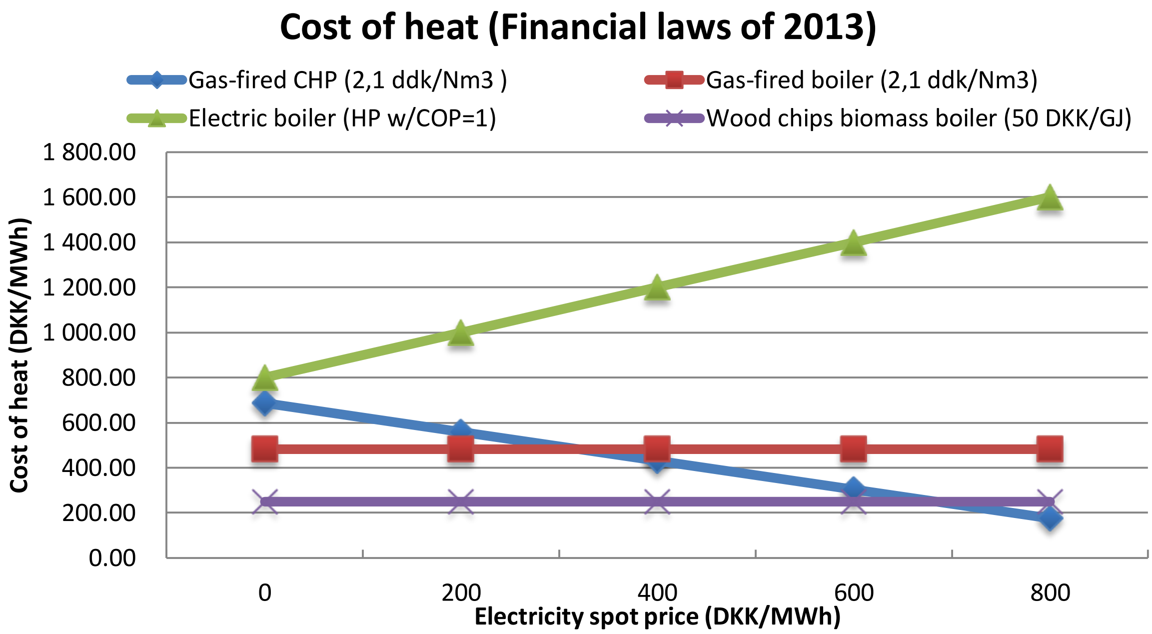


Figure 37: Cost of heat (Dansk Fjernvarme)

The functions for cost of heat Figure 37 are developed and provided by Dansk Fjernvarme. They include all energy costs, fees and taxes. The electric boiler is actually a heat pump modelled by a COP of 1, which in theory is an acceptable assumption, but might incur some changes to fees and taxes, altering the overall cost. Therefore the electric boiler should be ignored in this part.

To estimate the MC of CHP units with other heating options, Figure 37 is used. As discussed in chapter 6.3, the marginal price of the CHP unit can be found at the intersection at which the CHP becomes the lowest cost alternative.

Based on the intersections in Figure 37, the marginal price of the CHP with a gas fired boiler as a back-up unit is 300 DKK/MWh and 700 DKK/MWh for a CHP with a biomass fired boiler. Using exchange rates of 24th of april 2014 given by Norges Bank, this can be calculated into €/MWh, and €cent/kWh, which is the input format of the EMPS model.

$$300\frac{DKK}{MWH}*\frac{110.88\,NOK}{100.00\,DKK}*\frac{1\,€}{8.2785\,NOK}=40.18\approx 40\frac{€}{MWh}=4\frac{€cent}{kWh}$$

$$4\frac{€cent}{MWh}*\frac{700}{300}=9.33\,{}^{€cent}/_{kWh}$$

Therefore, the existing production from "Aggregated small CHP" will be divided further into three categories as summarized in Table 12. All will be given production profiles and K_{CHP}s as back pressure gas turbine CHP units. This is shown in principle in Figure 38.

Category nr.	CHP unit	Other heating unit	Marginal cost $[€cent/kWh]$	Share of original annual production [%]
1	BP gas turbine	Gas-fired boiler	4	$75\,\%*2/3=50\,\%$
2	BP gas turbine	Biomass boiler	9.33	$75\,\%*1/3=25\,\%$
3	BP gas turbine	No	0	25 %

Table 12: New categories for aggregated small CHP plants

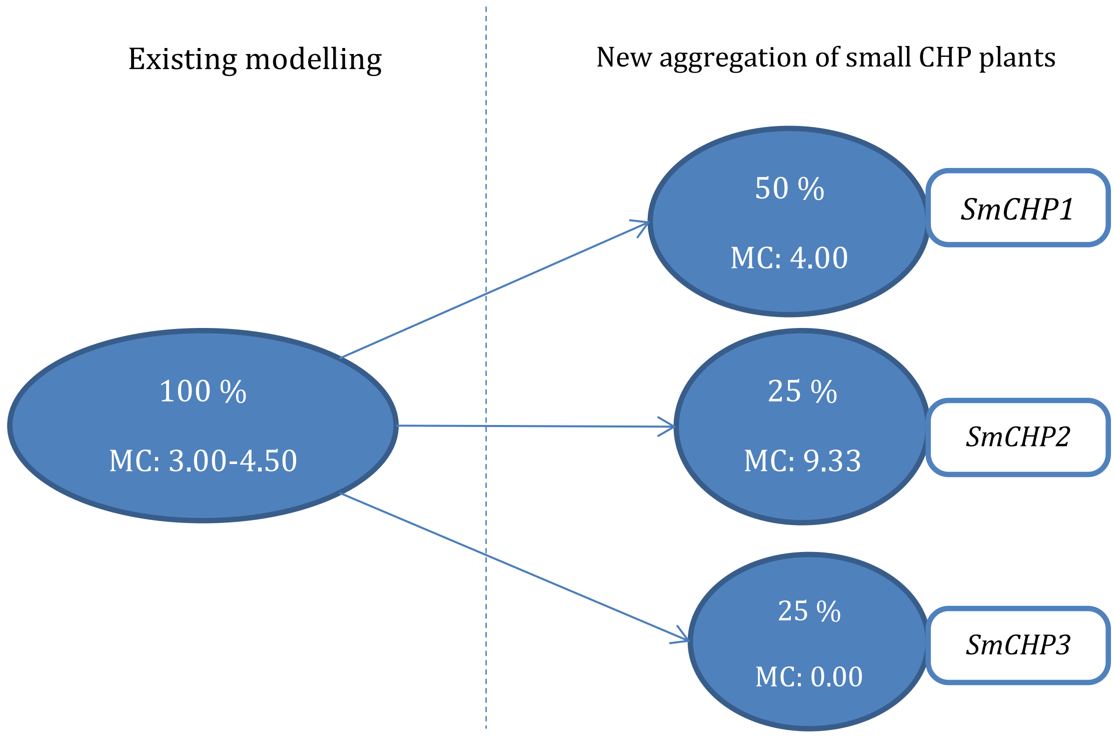


Figure 38: Principle for new aggregation of small CHP plants

How can maximum capacity for aggregated small CHP be set? Can it be set at reasonable level at all? If a few hundred small plants each have a capacity of around 5 MW, then their total capacity would reach a few thousand MW. However, this estimate would be left to guesswork in its entirety. Therefore, it is found best to set it at a very high level, approaching unlimited, so it would not act as a limit to how a few hundred CHP plants would co-interact when reaching a certain limit. This is better than setting a limit that would not be applicable in reality.

7.4.4 Aggregated biomass

It is assumed that these are not plants that are covered by the aggregation of small CHP plants. The pre-existing group for aggregated biomass will remain unchanged. The marginal cost will be unchanged, it will be given temperature dependency and correction at the same production and K_{CHP} profiles as other biomass plants are. Installed capacity will be set at a high level, for the same reasons as discussed about small CHP plants.

7.4.5 Waste

Waste plants have a flat annual production profile, at a very low marginal cost [31]. In the pre-existing modelling, they have been attached to the same profile as small CHP, which has some seasonal dependency (low at summer, higher during winter). These units will now be given flat profiles throughout the year. The marginal cost should be very low. It is unknown how willing they would be to shut down in case of slightly negative prices, therefore the marginal cost will remain unchanged. It is also assumed that these have no temperature dependency; therefore no temperature correction will be applied.

7.4.6 Industry

It is assumed that the industrial sites regard their power production as a waste product, and sell it to the market at any price they can obtain, except from negative prices. Given that the EMPS model cannot produce hours with negative prices, only 0, the marginal cost of industry power production should be set at 0.1 €cent/kWh. Some industry sites is likely to have some sort of profile for their power production, but this is unknown, therefore the profile will be flat assuming no seasonal, temperature dependency.

As both waste and industry are assumed to be independent from temperature, the function for temperature based correction will not be applied to these units. Therefore K_{CHP} profiles and installed capacities are not applicable, as these parameters are only input to the temperature correction function.

7.4.7 Other types of plants

As discussed in chapter 5.4 the CHP plants that are intended to have temperature correction must be of the type "kjref". Four large CHP plants in the Denmark East area are of a different type, "varme" (or "heat"). This is a type of plant that has a maximum capacity for intervals of weeks, availability in % and a marginal cost. That means that a production profile and the correction function cannot be applied to this type of plant. It is supposed to respond only to price signals if it is available.

As of May 2014, they are all mothballed or closed down in reality. Therefore, in the initial trials of implementing the new modelling their availability was set to 0 %. However, when comparing the results of a new and an old modelling of CHP it is not correct to take them out in the new modelling. Taking them out may improve the modelling if compared to reality, but this distorts the results when comparing the models.

They should be transformed to “kjref” plants so they can be modelled as CHP plants with production profiles and the correction function. All these plants are 100 % available all year except for a few weeks in the summer where the capacity is set to 0 MW. This is probably meant to model summer revisions.

Table 13: The four large plants of the type "varme"

Name	Area	Cap [MW]	MC [€c/kWh]
ASV5D	DANM-OST	608	3.16
KYV21	DANM-OST	130	18.58
KYV22	DANM-OST	130	18.58
STV2	DANM-OST	242	3.21

It is not likely that changing the KYV21 and KYV22 plants to “kjref” will change anything significantly as their MC is very high. However, both ASV5D and STV2 could impact the result, because their MC is not that high.

To evaluate what total annual energy should be available for the ASV5D and STV2 plants, production results from the existing modelling are used. Average annual production per scenario is 2483 GWh for ASV5D and 782 GWh for STV2. KYV21 and KYV22 have no production in any scenario in Statnett’s existing EMPS model. According to the existing documentation they are both coal fired steam turbine plants, and since they are not modelled as two parts in the existing model, it is assumed that the plants are back pressure plants.

7.4.8 Summary

Table 14 summarizes what has been discussed in this chapter. In the cases of technology dependent variables such as production and K_{CHP} profiles these are discussed in chapters 7.2 and 7.3.

Plant Group	Temperature correction	Production profile	K_{CHP} profile	Installed capacity [MW]	New units with new modelling?	Changed marginal costs?
Large BP	Yes	Tech. dependent	Tech. dependent	400	No	No
Large Cond	Yes	Tech. dependent	Tech. dependent	460	No	No
Mid-Lg BP	Yes	Tech. dependent	Tech. dependent	60	No	No
Small	Yes	Gas BP	Gas BP	10,000	Yes	Yes
Aggregated Biomass	Yes	Biomass	Biomass	10,000	No	No
Industry	No	Flat	N/A	N/A	No	No
Waste	No	Flat	N/A	N/A	No	No

Table 14: Summary of discussion regarding the determination of CHP units for new modelling

7.5 Datasets

Trough chapters 6.2, 6.4 and 7 different theoretical and practical measures of improving the modelling of CHP in Denmark in the EMPS model are presented. With the existing modelling as the basis, the measures for creating a new modelling should be taken in steps to show the effect of each new element. These elements are in short:

1. Giving new production profiles for all temperature dependent CHP plants, including those previously of the type “varme”. This procedure was largely explained in chapters 6.2 and 7.2.
2. Dividing aggregated small CHP into three different groups of small CHP with new MC. The method was described in chapter 6.5 and 7.4.3.
3. Implementing the function for temperature dependent correction of production capacity developed by SINTEF. This procedure was described in chapters 6.4.4 and 6.4.5.

This means that four versions of the EMPS should be compared against each other. One version to represent the existing modelling and one additional version per step as described above. The term *Dataset* is used for a version of the EMPS model. Thus, four datasets should be compared against each other.

7.5.1 Ext – Existing modelling

Ext is the name of the dataset representing the existing modelling. This dataset is the Statnett basis dataset. No new CHP modelling measures have been taken on this dataset. This dataset provides the modelling of the entire power market, with all power production, demand and exchange capacities for all areas. All changes to this dataset are made on aspects concerning the modelling of CHP plants in Denmark.

7.5.2 NewProfiles – New production profiles

This dataset is a copy of the *Ext* dataset. In addition to this all CHP plants in Denmark have been given new production profiles that refer only to the average weekly temperature across all scenarios (years) and flat power profiles. Small CHP has not yet been changed, and the existing groups of aggregated small CHP plants are given the production profiles of back pressure gas turbine units. The plants previously of the “varme”-type have been changed to the “kjref”-type and given the same production profiles as similar CHP plants and a total annual production capacity based on their average annual production.

7.5.3 NewProfileSmall – New aggregated small CHP

This is a copy of the *NewProfiles* dataset. In addition, the new method of aggregating small CHP plants in three groups instead of one is implemented. This procedure is described in detail in chapters 6.5 and 7.4.3.

7.5.4 NewModTC – Temperature correction

This is a copy of the *NewProfileSmall* dataset. In addition, the temperature dependent correction is implemented for all CHP plants in Denmark. This procedure was described in chapters 6.4.4, 6.4.5 and 7.3.

Figure 39 is illustrates how the datasets relate to each other, the changes from one to the next beginning with the Statnett basis dataset *Ext* moving to a new, complete CHP modelling at *NewModTC*.

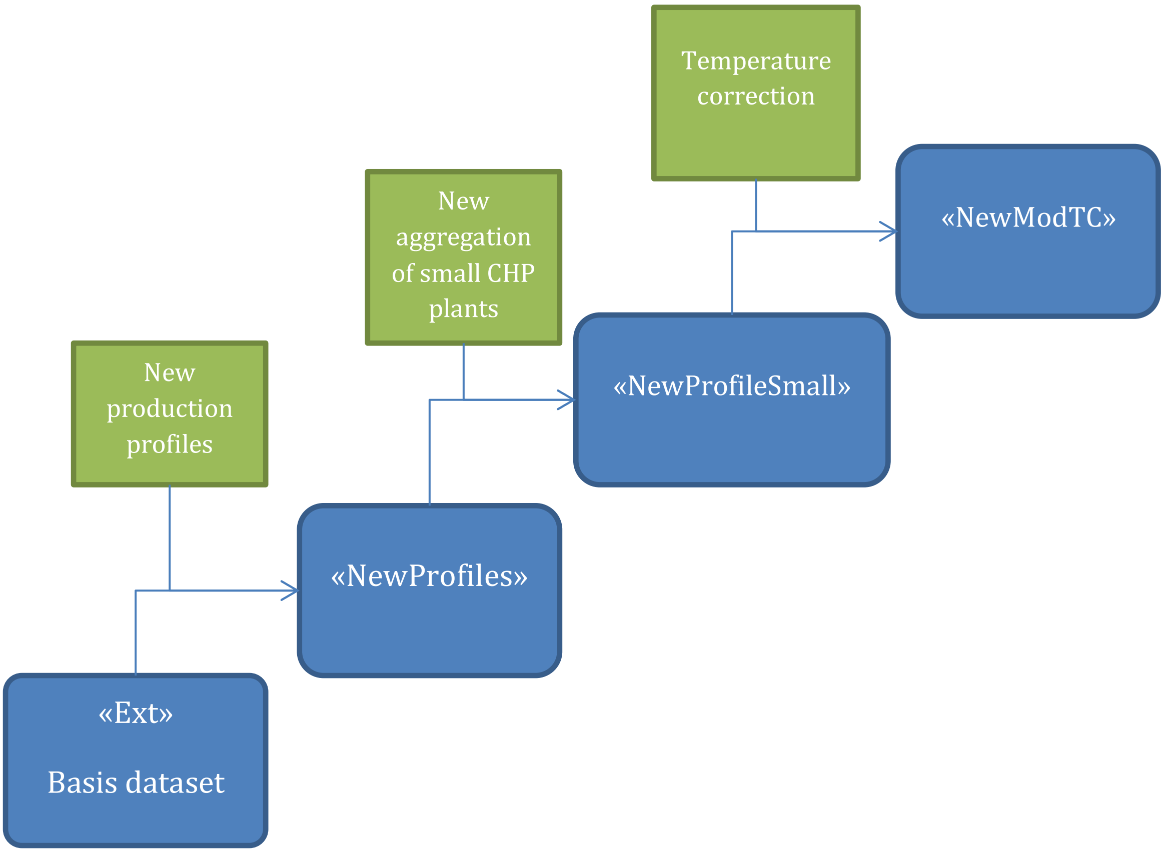


Figure 39: Illustration of how the datasets relate to each other starting with the *Ext* dataset

8 Results and Analysis

The objective for this thesis was to improve the modelling of CHP in the Statnett EMPS model using Denmark as a case study. The model is meant to reflect the real system. If the model can reflect reality better, intuitively this means that the modelling is improved. This means that if new modelling results, such as prices and production, are more similar to observed data than modelling results using the existing modelling, the new modelling is improved. This is a simplified back testing exercise, as real wind, solar and load conditions are not considered in the model. Therefore a comparison between observed data and model results are not expected to correlate perfectly.

First, the new elements to the modelling must be verified, to see if they have been implemented correctly, and if they are working as intended. Therefore, chapter 8.1 focus on verifying the new production profiles, small CHP aggregation and temperature correction. Secondly, it should be measured how well the existing and new modelling performs when compared to observed thermal production in Denmark. The thermal production temperature and price dependencies for observed data and modelling results are compared in chapter 8.2. Some of the larger overall system impacts, such as changes in prices, of the new modelling are assessed in chapter 8.3.

8.1 Verification

It is necessary to confirm that the CHP modelling elements introduced for each dataset have actually been implemented and works as intended. This chapter presents evidence that the implementation of three new CHP modelling elements was successful.

8.1.1 New production profiles

The Avedøre 1 ("AVV1" is the model name) plant is used an example plant to confirm that the implementation of new production profiles was successful. The extraction CHP plant is modelled as a back pressure and a condensing part, and these parts should interact.

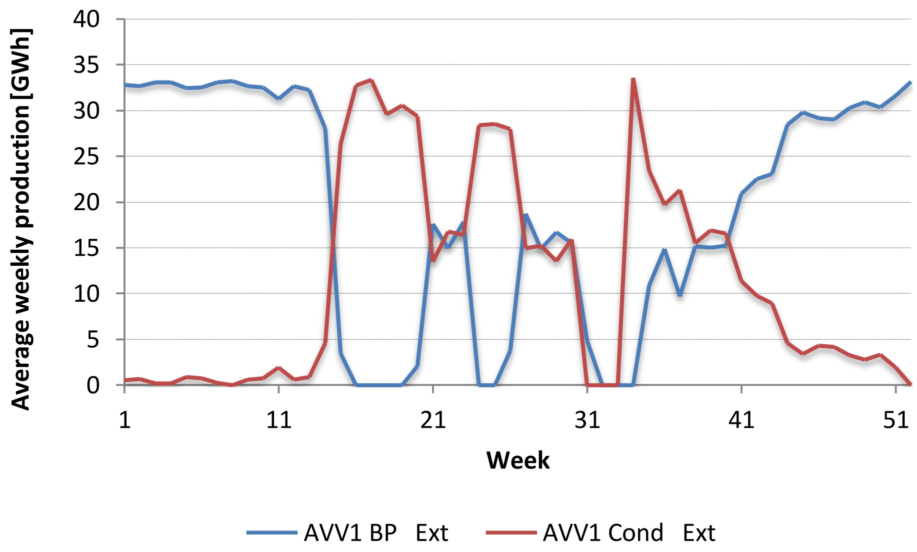


Figure 40: Weekly production [GWh] averaged across all scenarios for the Ext dataset

Figure 40 shows the weekly production [GWh] averaged across all scenarios (1962-2008) in the *Ext* dataset. This is the production as a result of the existing modelling and the old production profiles. It was discussed in chapter 6.6.1 that these profiles should be changed.

Figure 41 shows the similar result for the *NewProfiles* dataset for the same plant. It is obvious that the production is changed on an average to a smoother curve, without the same volatile shifts from back pressure to condensing mode as found in the *Ext* dataset. This was the intention for implementing new production profiles.

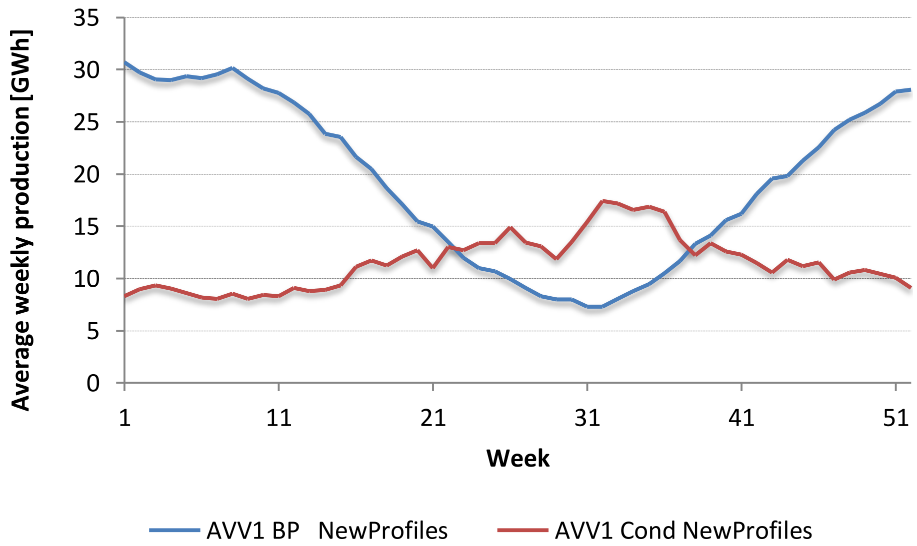


Figure 41: Weekly production [GWh] averaged across all scenarios for the *NewProfiles* dataset

Multiplying the production profiles with the total annual energy gives the weekly production capacity for each part of the unit, as discussed in chapter 5.1. The difference in weekly production capacity and actual production can then be evaluated. Total available capacity for the back pressure part is 1003.5 GWh and 787.09 GWh for the condensing part. The resulting weekly production capacity is shown in Figure 42.

Figure 42 shows the new production capacities that were implemented for the Avedøre 1 plant, red is condensing and blue is back pressure. When comparing the production capacity (Figure 42) and actual production (Figure 41) from the back pressure unit, the blue curves, look very similar in shape. However, doing the same comparison for the condensing part (red curves of Figure 41 and Figure 42) shows a significant difference in shape.

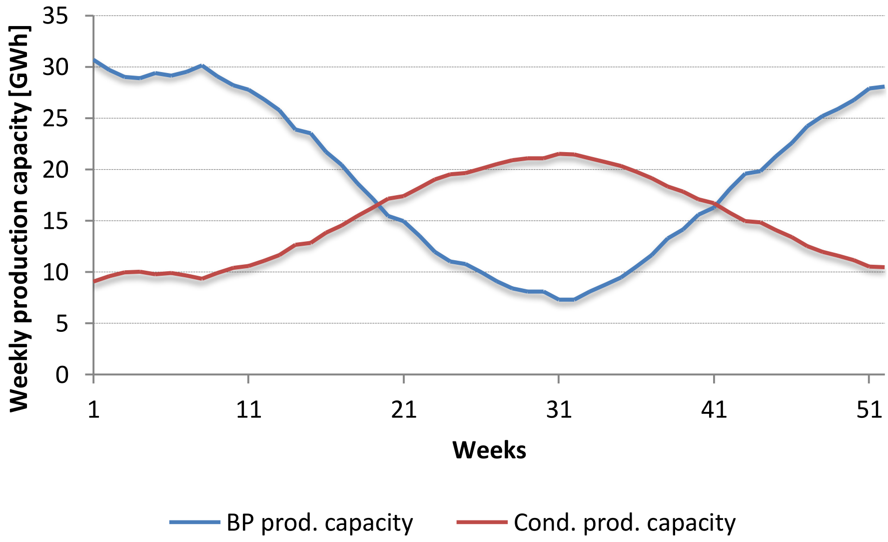


Figure 42: Weekly production capacity [GWh] for the two parts of the Avedøre 1 unit

Subtracting actual weekly production (averaged across all scenarios) from the production capacity for both back pressure and condensing parts yields the curve in Figure 43. The difference in capacity and actual production is practically zero for the back pressure part but significant for the condensing part.

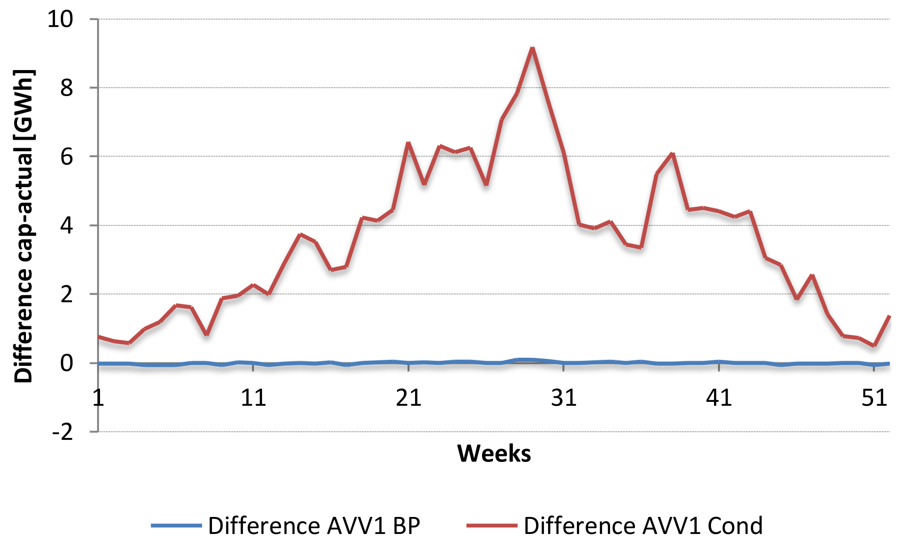


Figure 43: Difference between weekly production capacity and actual production

There is one main reason why there is such a difference between the actual production and capacity for the condensing part, and it is the system and area price. The condensing part is modelled with a MC of 2.96 €c/kWh, while the back pressure part has a MC of 0.89 €c/kWh. If the plant's area's price is below 2.96 €c/kWh, the condensing unit will shut down. This means that the condensing part will shut down more often than the back pressure part. Looking at the price duration curve, averaged across all scenarios for the DANM-OST area, as shown in Figure 44, prices often go below 30 €/MWh (=3.00 €c/kWh).

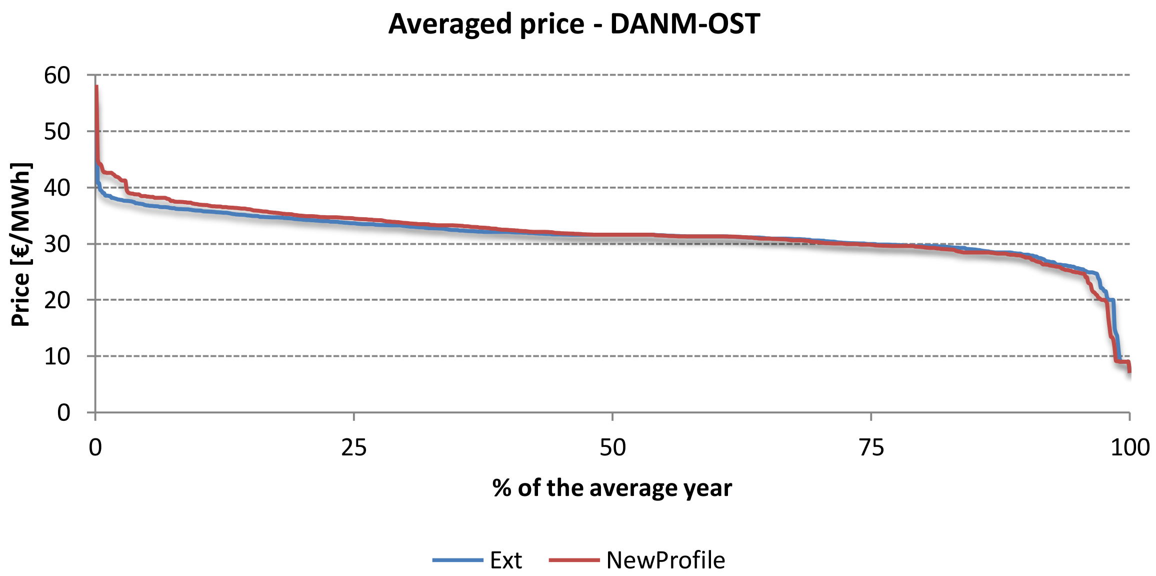


Figure 44: Average price across all scenarios for datasets *Ext* and *NewProfile*

Why is this effect more significant during the summer? The price is lower during the summer due to high seasonal reservoir inflows and lower electricity demand. The general seasonal price pattern is shown in Figure 45. In addition, the production capacity is lower for the condensing unit during the winter; therefore the difference is lower in GWh.

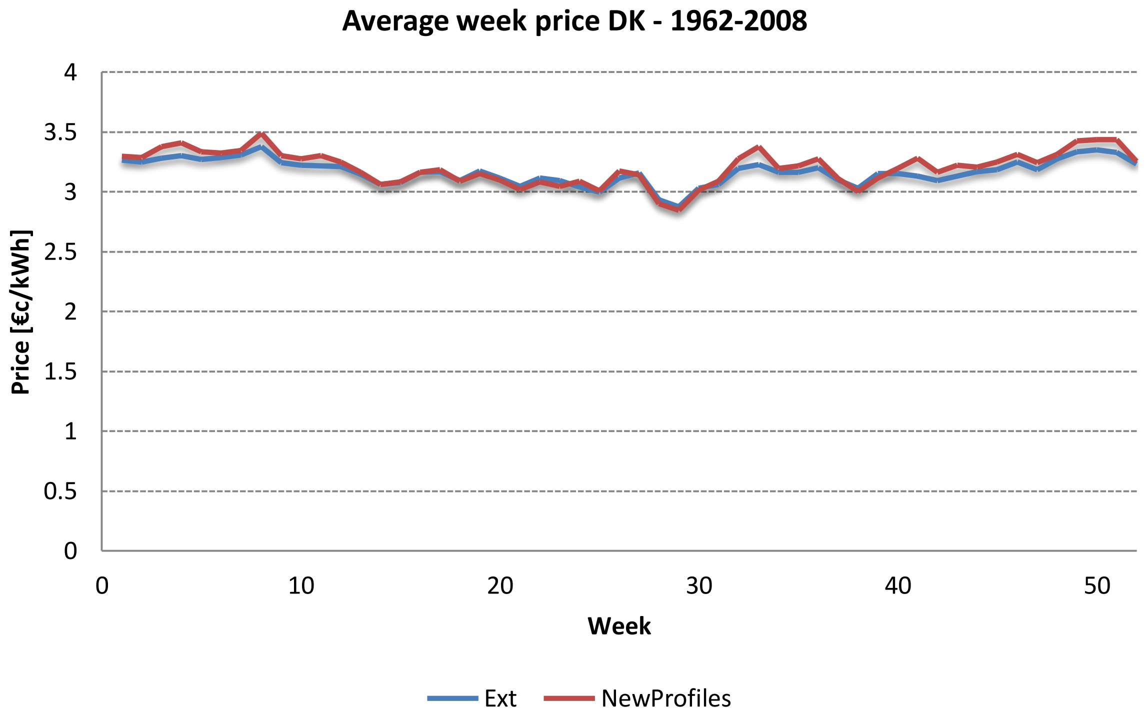


Figure 45: Avg. weekly price 1962-2008, across five load blocks and four DK price areas

Avedøre 1 has been used here as an example to illustrate a successful implementation of the production profiles. New production profiles have been implemented successfully for all plants as intended.

8.1.2 New aggregation of small CHP plants

The second step in the new modelling was to introduce a new method of aggregating small CHP plants, taking the technical diversity and a new marginal cost discussion into consideration. In this section the effects on total small CHP power production are assessed. In short, the change to the modelling of small CHP plants is that the total production available is the same, but is has been redistributed on several groups with different MCs. This principle and the new small CHP groups' names are shown in Figure 46. This new aggregation method is carried out for each of the four Danish price areas, who all had one group of aggregated small gas fired CHP in the existing modelling. The total effect on actual small CHP production is unknown and not intuitively given. This effect is assessed in this chapter.

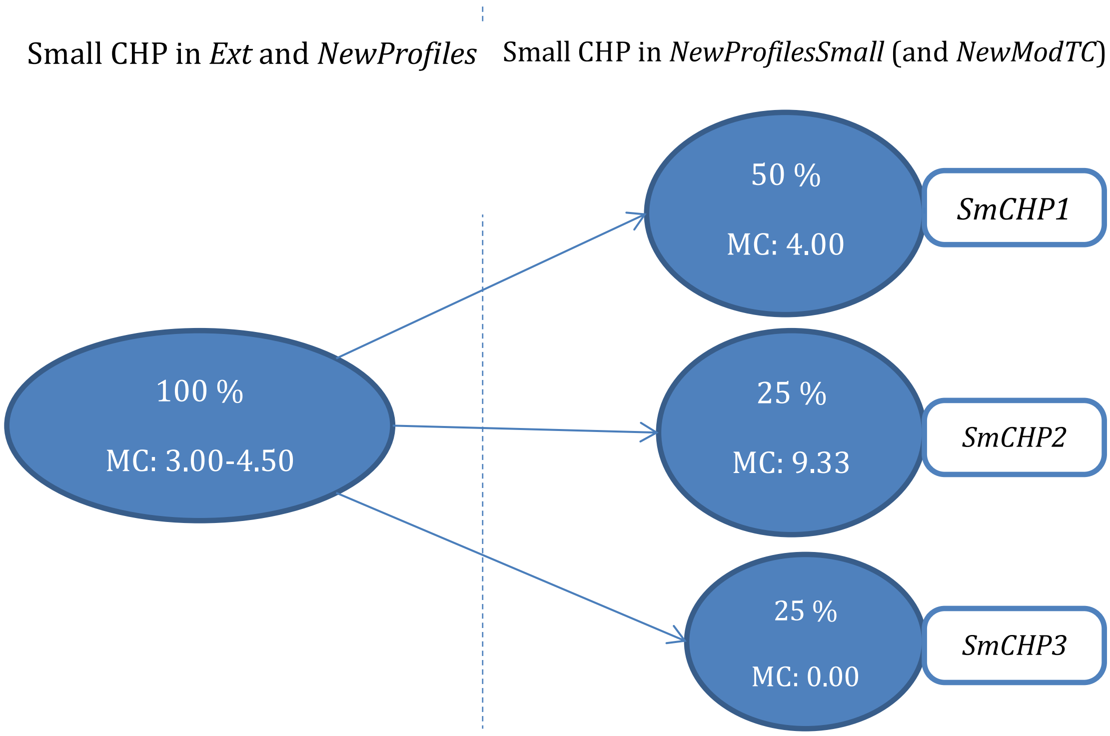


Figure 46: Changed aggregation of small CHP with division of production capacity [%] and new MCs [€c/kWh]

Total power production from small CHP plants in all Danish areas are given in Figure 47.

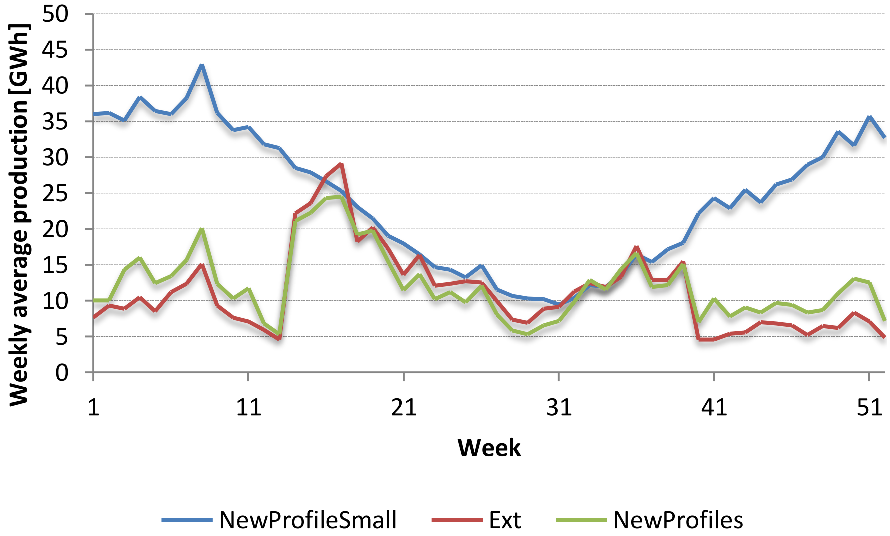


Figure 47: Weekly production from small aggregated CHP plants in Denmark averaged across all scenarios added per load block

The production from small CHP plants has changed significantly, and there are especially large differences during the winter, and the production profiles are very similar for the datasets. The small CHP production has increased from 3.3 % to 6.7 % of the total thermal production from *NewProfile* to the *NewProfileSmall* dataset.

There are two main reasons for the difference. The MCs for small CHP plants in the *Ext* dataset (and also *NewProfiles*) are given in intervals as shown in Table 15. There is an increase in the MC during the winter, weeks 40 to 13. The reasoning for this is that it follows the seasonal variations in gas price. However, it was shown in chapter 6.3.1, that the impact on back pressure CHP MC of a fuel price increase is unknown. The high MCs contribute to decreased production during the winter. As shown in Figure 44 the model price level range mostly between 3 and 4 €c/kWh. This is the key reason why production from small CHP plants is so low in *Ext* and *NewProfiles.*

Table 15: MC for aggregated small CHP plants in each area for *Ext* and *NewProfiles*

From week	To week	DANM-OST	JYLL-NORD	JYLL-SYD	FYN
1	**13**	3.47	4.26	4.26	4.26
14	**26**	3.06	3.85	3.85	3.85
27	**39**	3.08	3.85	3.85	3.85
40	**52**	3.49	4.28	4.28	4.28

Figure 48 shows what the total aggregated small CHP production consist of in the *NewProfileSmall* dataset. It shows the total small CHP production for all price areas in Denmark averaged across all scenarios per new small CHP type, which of there are three as shown in Figure 46. SmCHP3 is the type with a MC of 0. This production is forced, and it comprises most of the small CHP production in the *NewProfileSmall* dataset. SmCHP1 has the largest annual production capacity, but it is largely priced out of the market due its relatively high MC of 4.00 €c/kWh, while SmCHP2 is completely priced out at a MC of 9.00 €c/kWh.

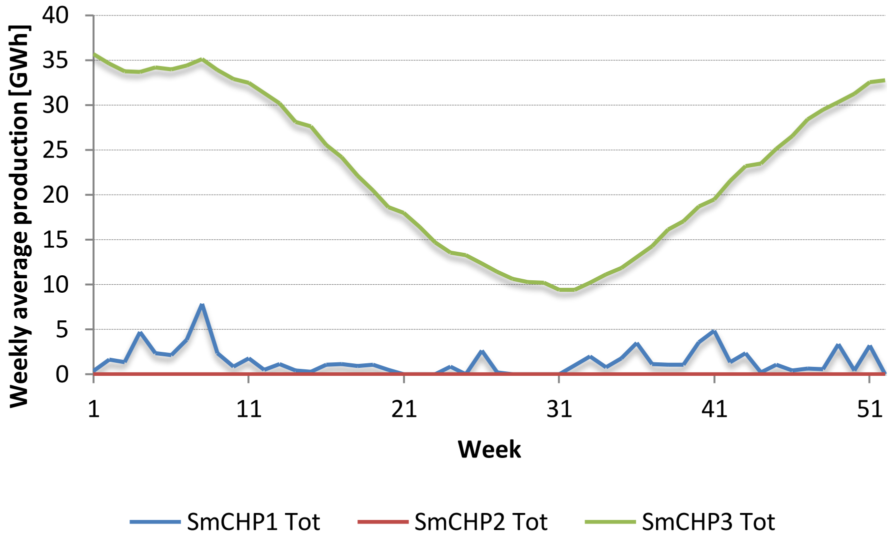


Figure 48: Break-down of aggregated small CHP production in the *NewProfileSmall* dataset

8.1.3 Temperature correction

To show that the temperature correction is working as intended, again the Avedøre 1 plant is used as an example plant. In short, the function should increase the production of back pressure units if the actual temperature is lower than the average temperature and lower the production if the temperature is higher. The opposite is the case for the condensing units.

For this function to work as intended, it is required that the production profiles are based on the average temperatures. For this reason the production results from the *NewModTC* dataset must be compared to the *NewProfileSmall* dataset. The Avedøre 1 plant is chosen as the example plant and 2005 is the example year to provide actual temperature.

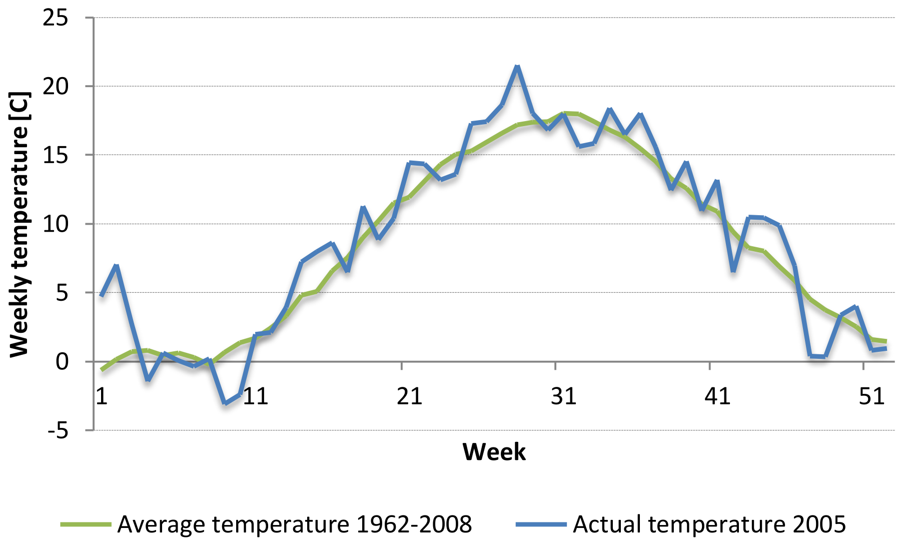


Figure 49: Average weekly temperature across all years and actual temperatures of 2005

The weekly production for the back pressure part of Avedøre 1 for the NewProfileSmall and NewModTC for 2005 (for both) is shown in Figure 50, and one can see that there are some considerable differences between many of the weeks. The next step is to look at how those weekly production differences align with the temperature differences.

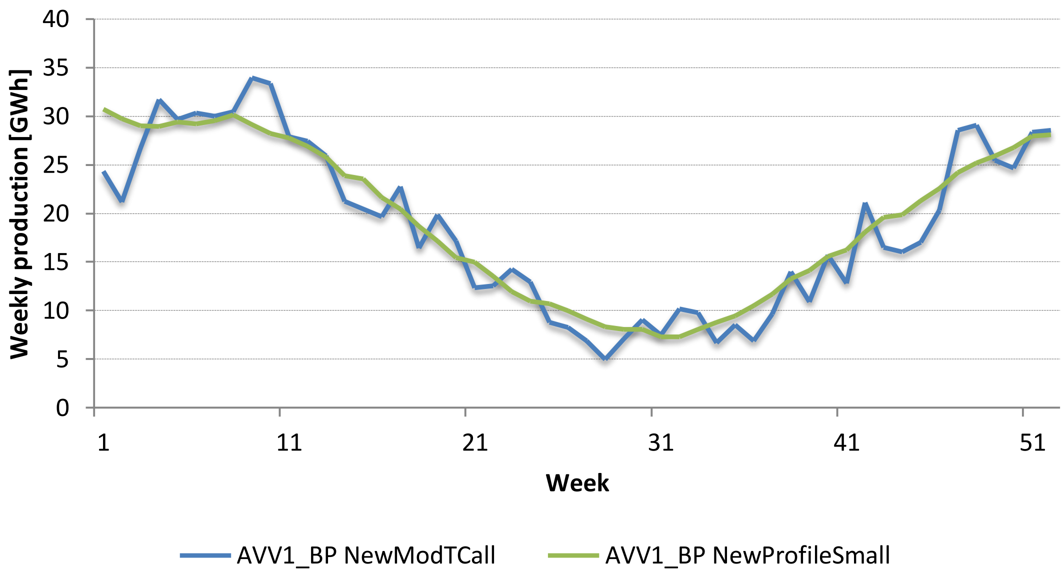


Figure 50: Avedøre 1 Back pressure production of 2005 for *NewProfileSmall* and *NewModTC*

Production difference is calculated as $P_{NewModTC} - P_{NewProfileSmall}$ and shown in Figure 51.

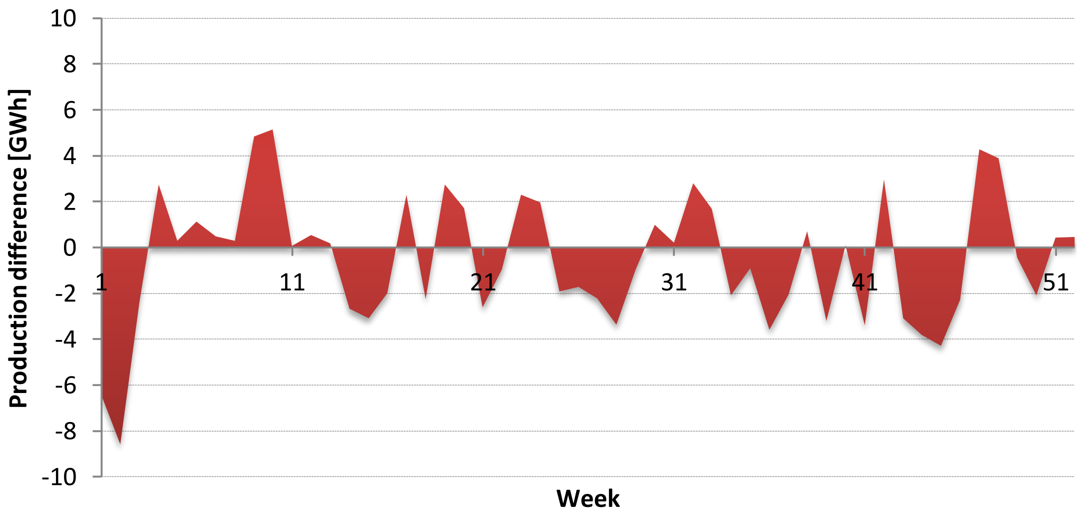


Figure 51: Difference in BP production between NewModTC and NewProfileSmall datasets in 2005

Plotting the difference in temperature and production in the same figure will show if the function for temperature dependent correction works as intended. Figure 52 shows that the sign and size of the difference in actual and average temperature correlates almost perfectly negative with the difference in production with and without temperature correction.

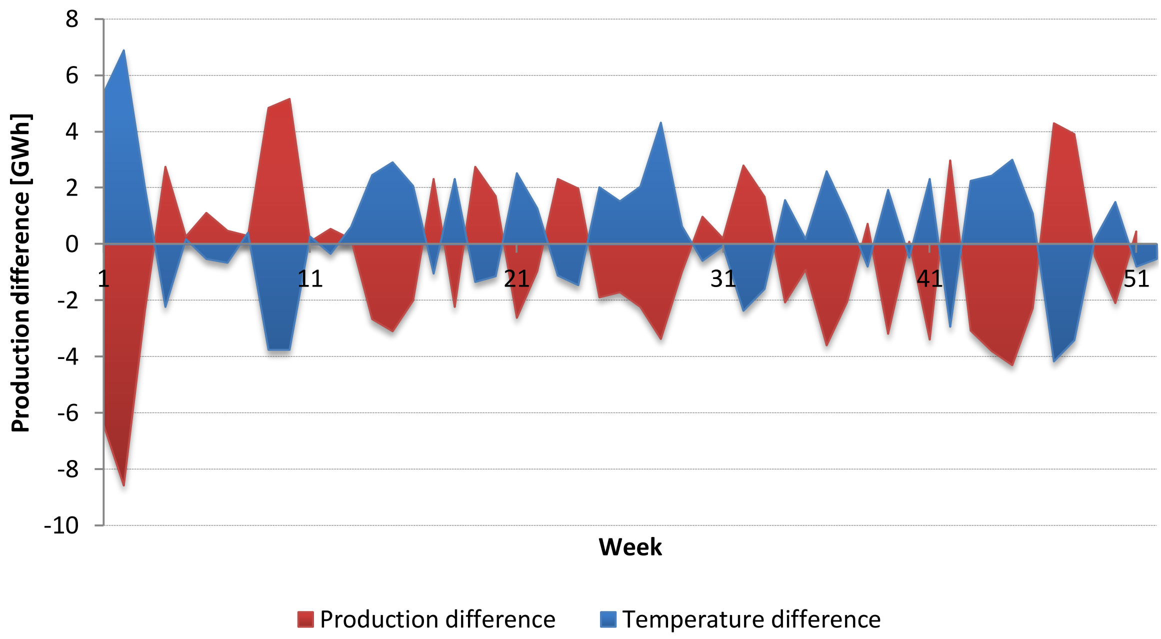


Figure 52: Differences in temperature and production for the AVV1 BP unit

Figure 53 shows that the production from AVV1M has not changed significantly on average across all years and all scenarios. This was the intention.

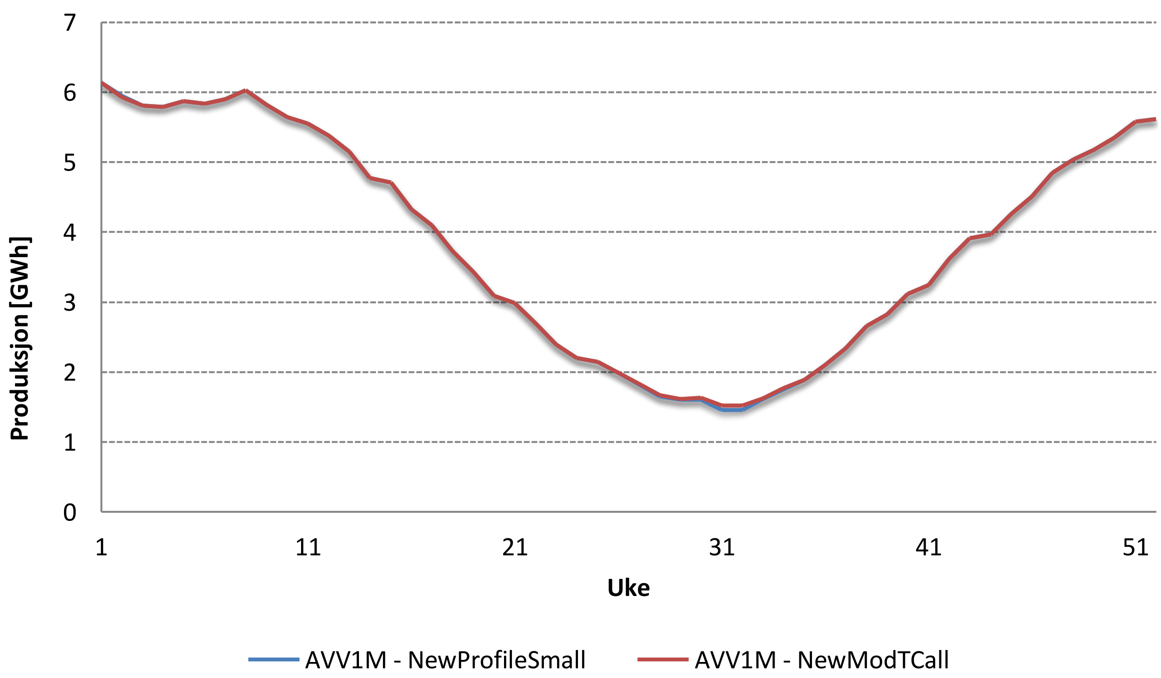


Figure 53: AVV1M production averaged across all scenarios and load blocks

As in chapter 8.1.1, Avedøre 1 has been used as an example in this chapter. The temperature function has been implemented successfully for all CHP plants as intended.

8.2 Modelling performance

The modelling of CHP has been changed with the aim of improving it. To measure whether this has succeeded or not, the modelling results should be compared to some historical observed data. This is called backtesting. However, as not all observed data is given as input to the model, wind and demand most notably, this is not a complete backtesting exercise.

The Statnett EMPS model has scenarios from 1962-2008. This means that prices and production as a result of the model datasets and temperatures can be extracted for this period. However, it has only been possible to obtain observed historical market prices after 1st of January 2006. Observed historical thermal production in Denmark has been obtained from 1st of January 2001. Both historical prices and production have been downloaded from Energinet's website.

8.2.1 Total thermal production

Total thermal production per week for all of Denmark from observed data and the modelling results are compared in this section. It is a reasonable estimation that all thermal production in Denmark, both modelled and observed, is some sort of CHP production.

For the years 2001-2008 there are 416 weeks. For each week there is observed data and model results for each dataset that contain information on the total thermal production for all four price areas of Denmark. In the case of a perfect modelling, the relation between observed and model thermal production would be 1:1. Plotting pairs of

$$(P_{observed}, P_{model})_{i,j}$$

For week *i* where

$$i = 1, 2, \cdots, 416$$

And *j* represents each dataset, *Ext*, *NewProfile*, *NewProfileSmall* and *NewModTC* is shown as a scatter plot in Figure 54.

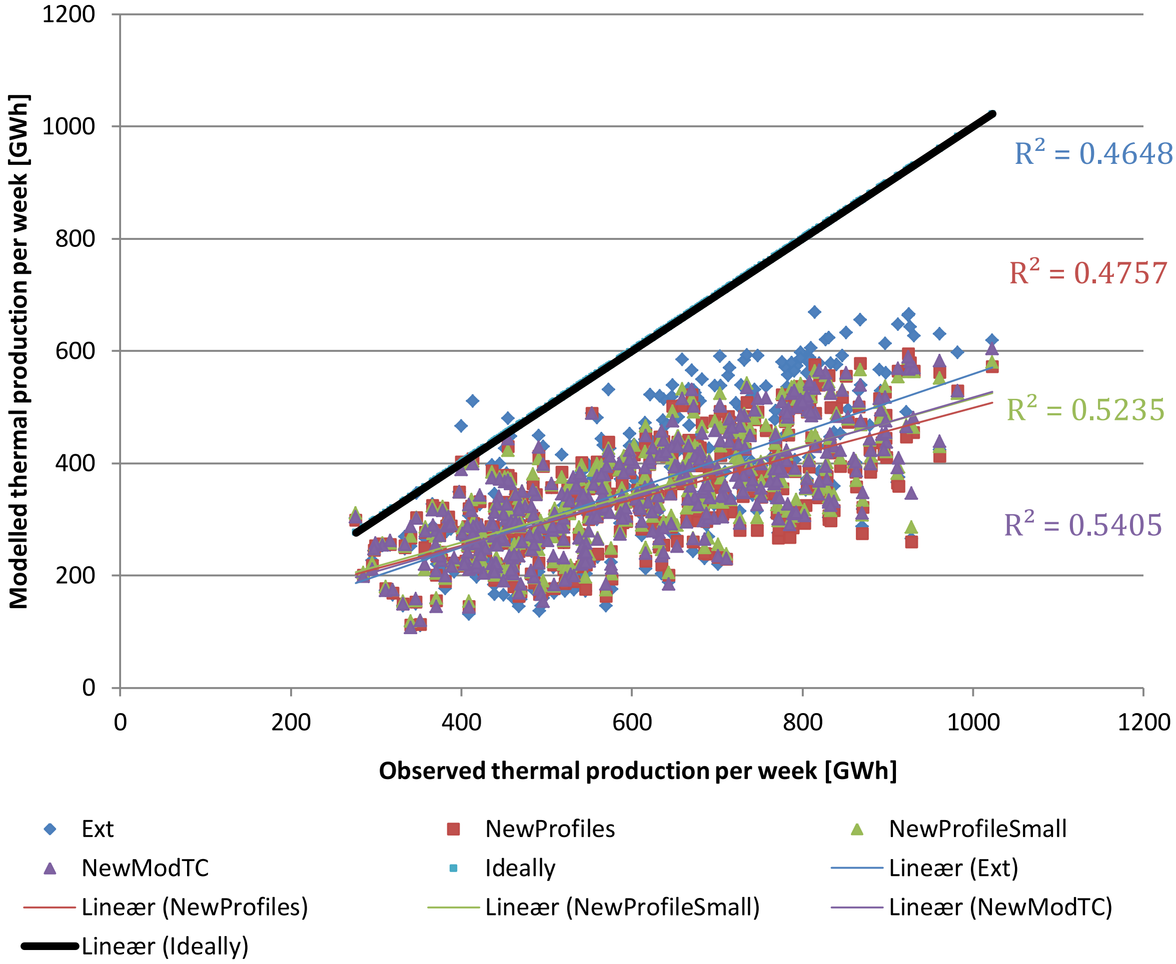


Figure 54: Observed vs. modelled thermal generation per week 2001-2008

Figure 54 shows that the observed total thermal production is consistently higher than the modelling results. The "ideally" line shows the model results for an imagined perfect model. Observed production is only rarely lower than the corresponding model production, regardless of dataset. There are a few reasons for this. First, it is important to remember that the *Ext* dataset, the basis dataset from which all other datasets are built on, is the Statnett 2013 basis dataset. This means that it is supposed to reflect the 2013 power production portfolio, using only inflow and temperature data from 2001-2008.

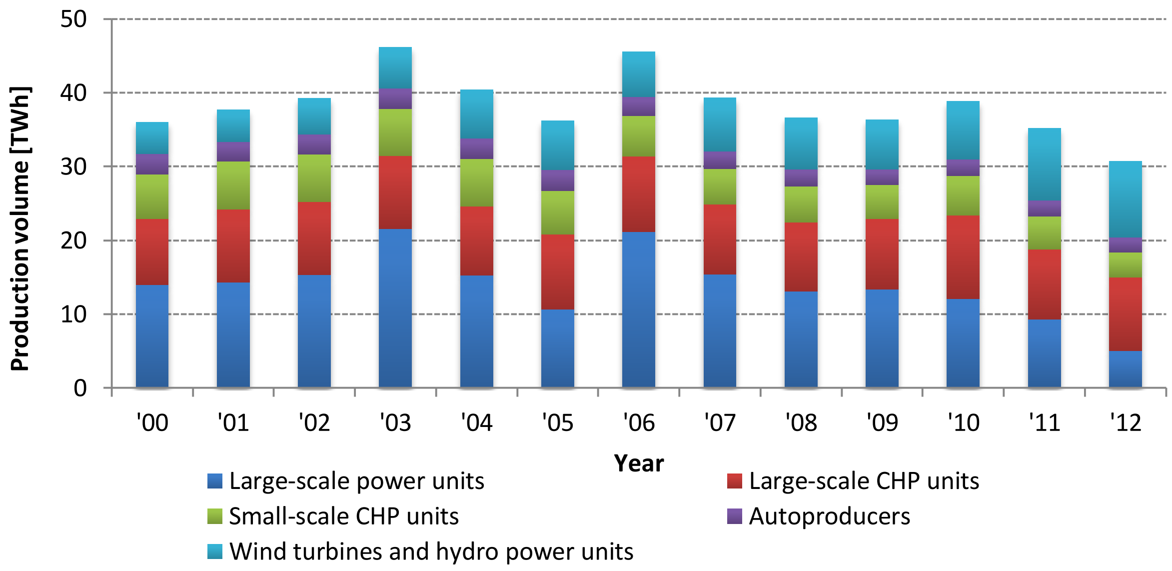


Figure 55: Electricity by producer type in Denmark [2]

Figure 55 shows how thermal production in Denmark (all types but wind/hydro) has fallen by 48 % from 2006 and 2003 to 2012. "Large-scale power units" is power produced in condensing mode at CHP plants. This might explain the entire difference in the level of production. Given the approximate linear regression lines in Figure 54, it would seem that production in the model (for all datasets) is about half of the observed production, so a decreased observed production from 2006 to 2012 of 48 % would explain much of the production level difference.

Matching the exact historical level of production is not a goal in itself, therefore the modelling of CHP does not need to be changed to accommodate observed production levels.

The *Ext* dataset matches observed production mainly because of the general, seasonal variations in available back pressure capacity. In both existing and new modelling, more cheap back pressure capacity is available during winter than during summer. This is determined by the production profiles. Because of generally high prices during the winter, more thermal generation is triggered in the model. It will be shown later that temperature is a less important parameter for thermal production in Denmark in the model than in reality.

In Figure 54 the linear regression models are shown for each scatter plot (observed vs. model/dataset), and they are very similar. The scatter plots themselves however, are not. This is illustrated by the R^2-values. The R^2-values are color coded by what dataset they belong to, and repeated in Table 16.

Table 16: R^2-values for linear regression of observed vs. model/dataset thermal production

Dataset	R^2-value
Ext	0.4648
NewProfiles	0.4757
NewProfileSmall	0.5235
NewModTC	0.5405

What information does the R^2-value contain? In words, R^2 indicates how well data points fit with a statistical model. In this case, how well scatter plots of the type

$$(P_{observed}, P_{model})_{i,j}$$

Fits with the linear regression models. The higher R^2, the better the data points fit with the regression model. For an $R^2 = 1$, all points are on the regression model line, meaning there is perfect correlation between observed and modelled production. This means that the dataset with the highest R^2 follows the historical observed data closest. Table 16 shows that all new datasets perform better than the *Ext* dataset and *NewModTC* performs best, in this regard.

The new production profiles themselves (*NewProfiles*), does not "improve" the modelling as significantly as the temperature correction or the new aggregation of small CHP plants. The largest change in R^2 happens when implementing the new aggregation of small CHP plants, even though aggregated, small CHP plants group only accounts for 6 % of the total thermal production volume.

To explain these improvements it is necessary to look at observed and modelled thermal production as functions of temperature and price.

Total thermal generation per year averaged across all scenarios for the model datasets [TWh] can be found categorized by type of producer (BP, Condensing or Small CHP) and by area in appendix 4, chapter 13.4.

8.2.2 Thermal production vs. temperature

While *NewProfileSmall* was introduced to improve the modelling of small CHP plants with regards to their MCs, *NewProfiles* and *NewModTC* were introduced specifically to address the temperature dependency of a CHP based thermal production portfolio.

It is therefore very interesting to see how temperature dependent observed and modelled thermal production is, and whether the new elements in the modelling have had the wanted effect. Scatter plots on the form:

$$(P_{j,i}, T_i)_{i,j}$$

Where P is weekly thermal production [GWh], T is the actual weekly temperature[C°], *i* represent the week 1…416, and *j* now represents observed data and dataset results.

The period is still 2001-2008. The total production for each week [GWh] has been divided by average weekly production [GWh] so that production is standardized around 1:

$$P_{j,i,norm} = P_{j,i} * \frac{416}{\sum_i P_{j,i}}$$

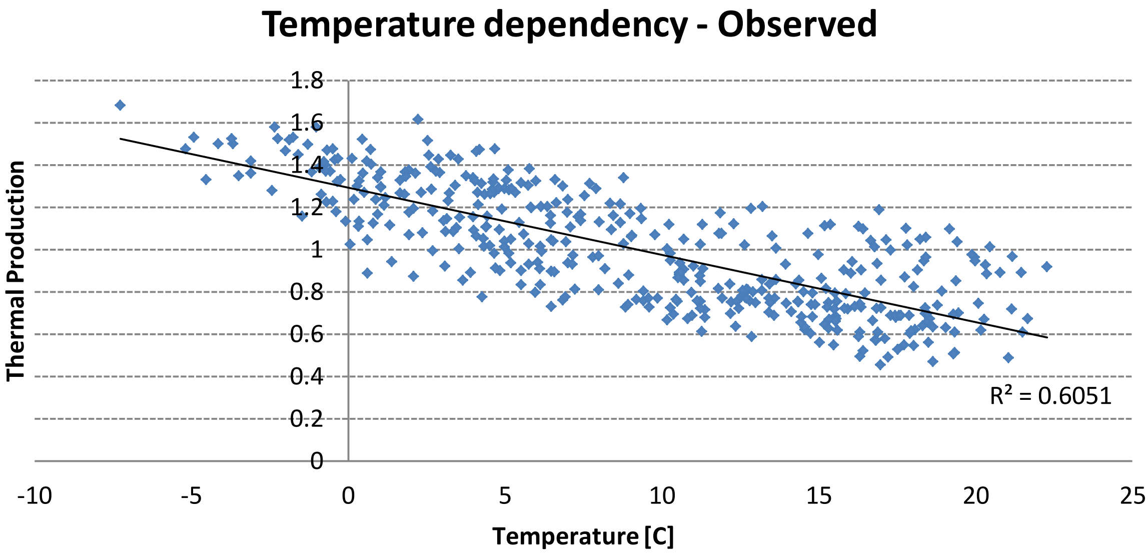


Figure 56: Observed weekly temperature and thermal production 2001-2008

Figure 56 shows the observed thermal production as a function of temperature. As expected the trend line shows that there is a close correlation. Figure 57 and Figure 58 shows the same plots for the *Ext* and *NewModTC* datasets. For *Ext* the correlation between thermal production and temperature there is much less obvious than for observed data. Although there is a downwards sloping trend line (as in Figure 56), the R^2-value indicates that the scatter plot fits poorly with this trend line.

The *NewModTC* is the best performing model dataset in this regards, with a downwards sloping trend line and a R^2-value of 0.35, which better than 0.21 (*Ext*), compared to 0.6 for observed. *NewProfiles* (R^2=0.25) and *NewProfileSmall* (R^2=0.32) performs better than *Ext*, and the biggest leap in R^2-value between the datasets is between *Ext* and *NewProfiles*. The trend line itself is also steeper for the observed data than the model.

The plots of thermal production vs. temperature can be found in appendix 3, chapter 13.3, for the *NewProfiles* and *NewProfileSmall* datasets.

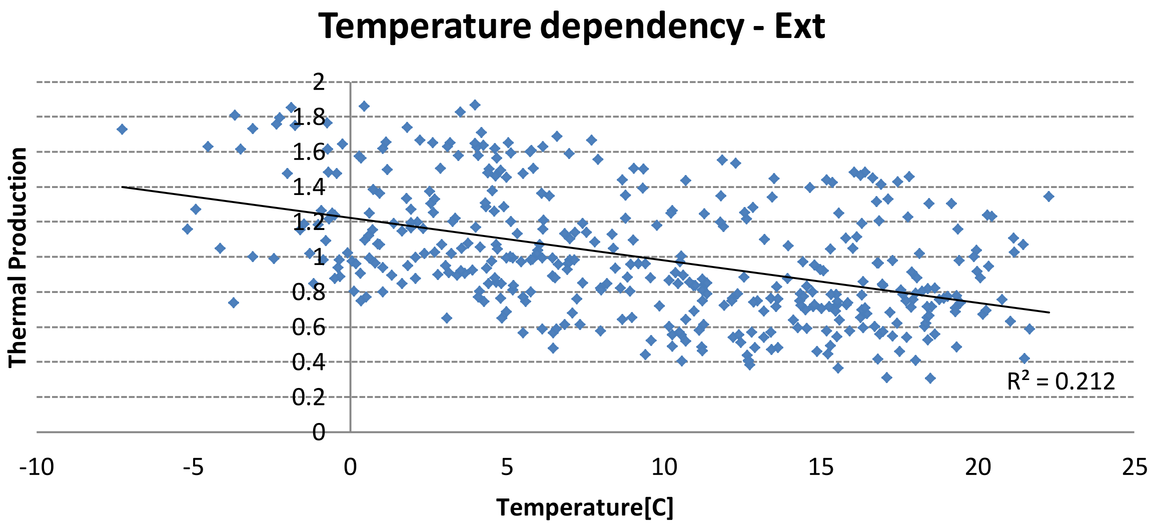


Figure 57: *Ext* weekly temperature and thermal production 2001-2008

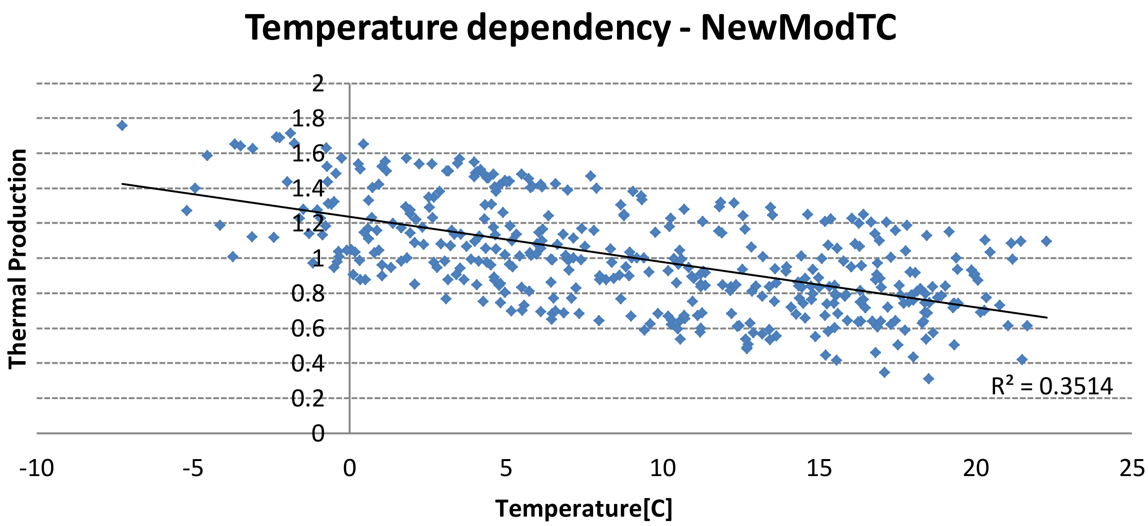


Figure 58: *NewModTC* weekly temperature and thermal production 2001-2008

Looking at seasonal differences it is shown that temperature dependency for thermal production is much higher during the winter than the summer. This is primarily shown by the linear regression trend lines in Figure 59 and Figure 60. In Figure 59 thermal production and temperatures during weeks 40-13 for the years 2001-2008 is shown, and the same for the summer weeks 14-39 in Figure 60.

During the summer, heat demand is low, and thermal production is mainly price driven. During the winter, heat load is high and thermal production is temperature driven. R^2 is generally higher for both model datasets and observed data during the winter than the summer. The *NewModTC* dataset is approaching the observed trends, moving away from the *Ext* results.

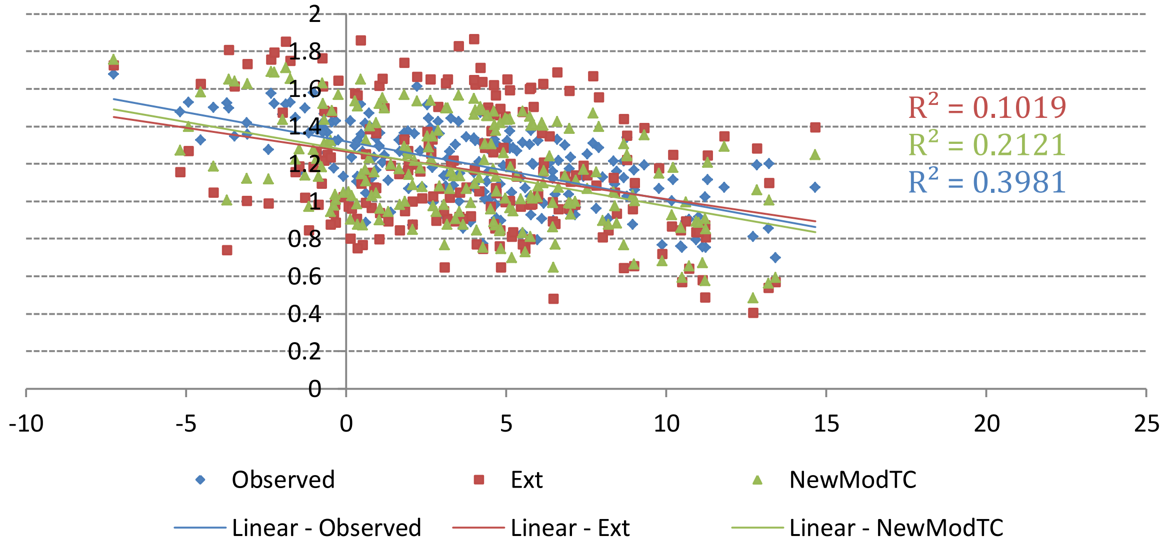


Figure 59: Scatter plot: Thermal production vs. temperature, winter weeks 40-13, 2001-2008

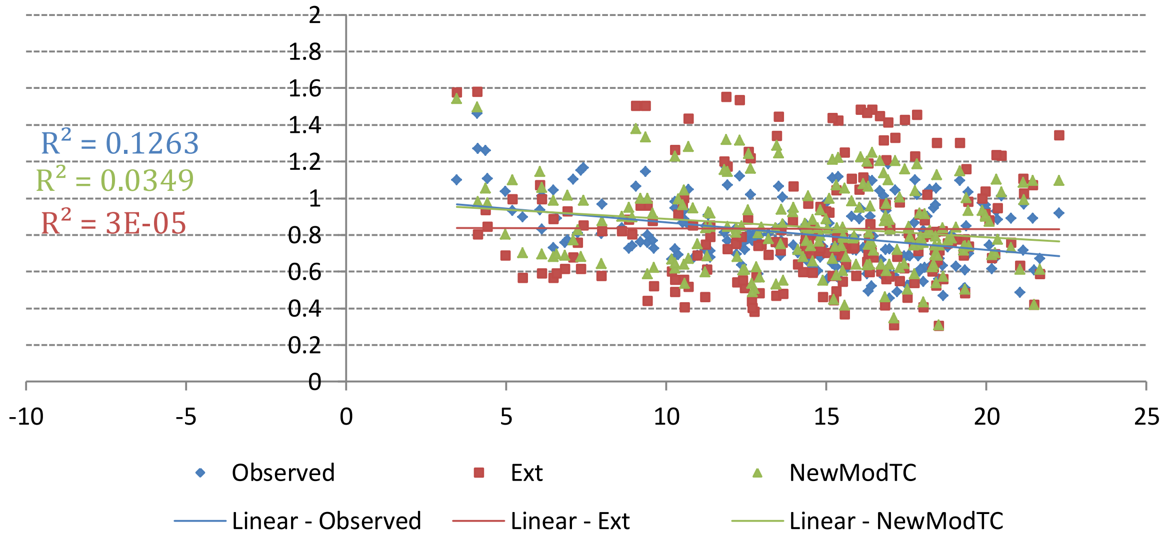


Figure 60: Scatter plot: Thermal production vs. temperature, summer weeks 14-39, 2007-2008

8.2.3 Thermal production vs. price

In this section thermal production as a function of price for observed data and modelling results is investigated. All weeks of 2006-2008 comprise the sample space. Weekly thermal production as normalized around 1 (Weekly GWh value divided by average weekly GWh) is compared with the weeks average spot price across all four EMPS areas (two areas for observed, DK1 and DK2).

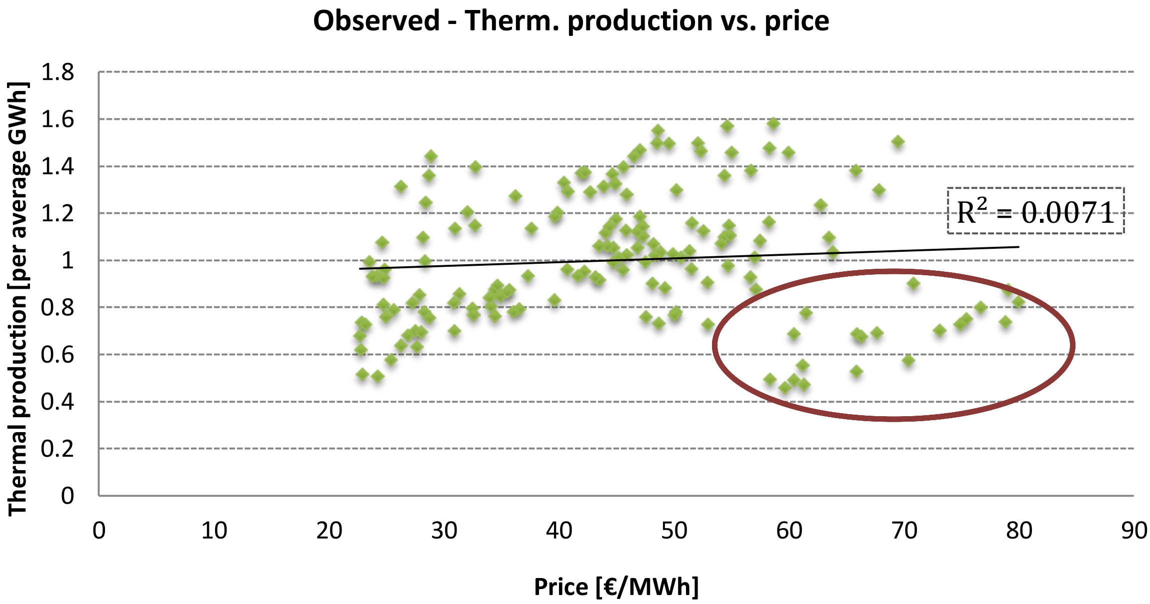


Figure 61: Scatter plot: Observed weekly avg. price vs thermal production

Looking at Figure 61, observed thermal production seems to be independent of price. However, this is not true. There is a cluster that might initially seem like random data points. Removing all weeks of 2008, this cluster disappear and a relation between thermal production and price appears more clearly, as shown in Figure 62. This cluster of weeks is largely during the summer of 2008, a year which experienced very high fuel prices [31], which shifted the price and thermal production trend for 2008. How does this compare with the modelling results?

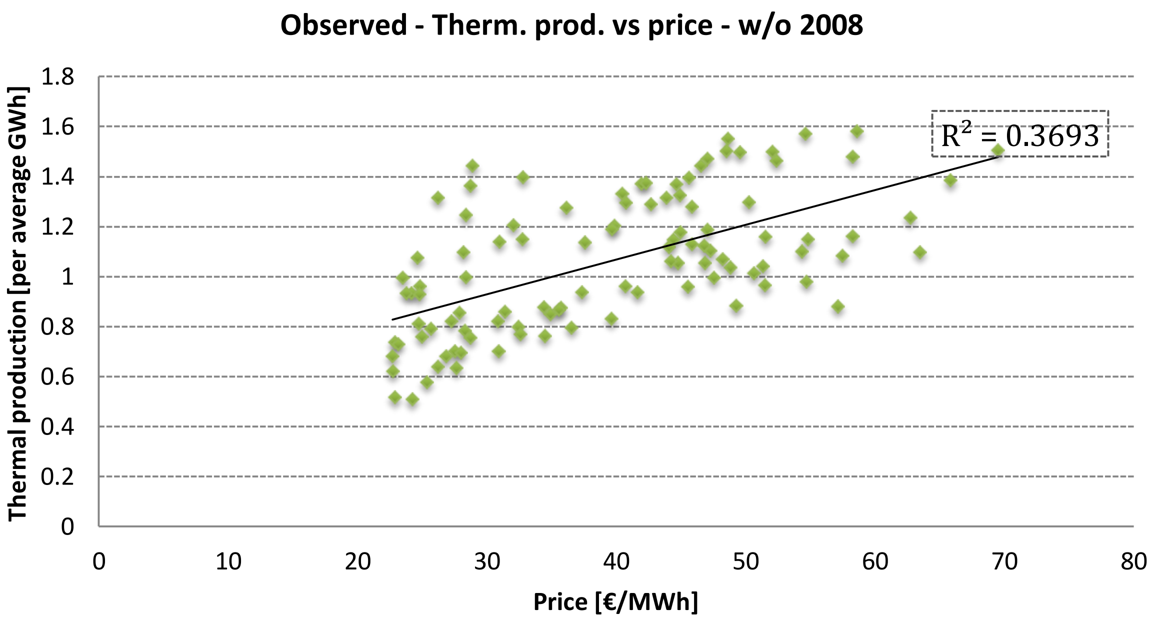


Figure 62: Scatter plot: Observed weekly price vs. thermal production, without 2008

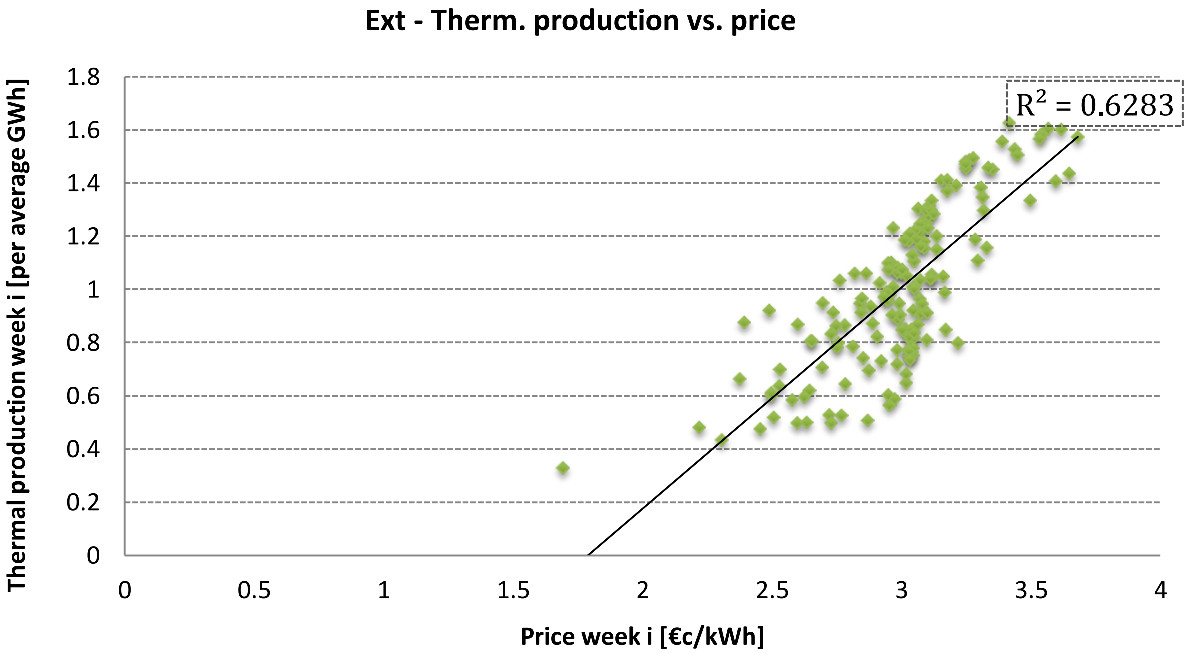


Figure 63: Scatter plot: Thermal production vs. price for Ext dataset, 2006-2008

Figure 63 shows that for all weeks of the year, 2006-2008, the thermal production for the *Ext* dataset is highly dependent of price, more dependent than observed thermal production. Figure 64 shows that the new modelling of *NewModTC* is less price dependent than the *Ext* and more similar to the observed data. But the new modelling is still much more price dependent than the observed data. The weeks of high prices and low thermal production in 2008 are not observed in the model, as the model has fixed MCs for all scenarios and do not pick up variations in real fuel prices. For an ideal backtesting exercise, real observed fuel prices should be used for each scenario in the optimization of the model.

The plots for thermal production vs. price can be found in appendix, chapter 13.3, for the *NewProfiles* and *NewProfileSmall* datasets.

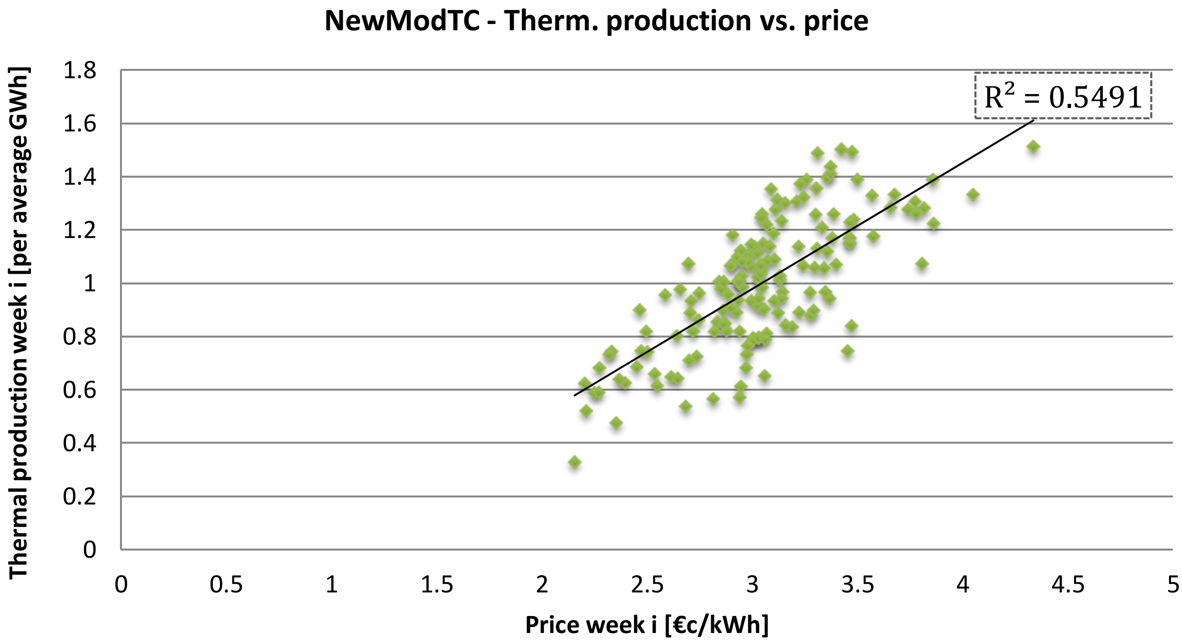


Figure 64: Scatter plot: Thermal production vs. price for NewModTC dataset, 2006-2008

The comparisons of thermal production price dependency regardless of season has shown that thermal production is less price dependent in reality compared to the models, but that the new modelling (*NewModTC*) is more similar to observed data than the existing modelling (*Ext*). However, this does not account for the seasonal variations.

Looking at price dependency for observed and modelled (*NewModTC*) thermal production for the winter (40-13) and summer (14-39) weeks, shows some significant seasonal variations. The price dependency is higher during the summer than during the winter for observed data. This is not observed to the same extent for the modelling results. This is shown in Figure 65 (summer) and Figure 66 (winter). Because of the high fuel prices during 2008 [31], both the summer and winter weeks of 2008 has been removed for this comparison, as they represented some distortion to the scatter plots for observed data, which are not represented in the modelling results.

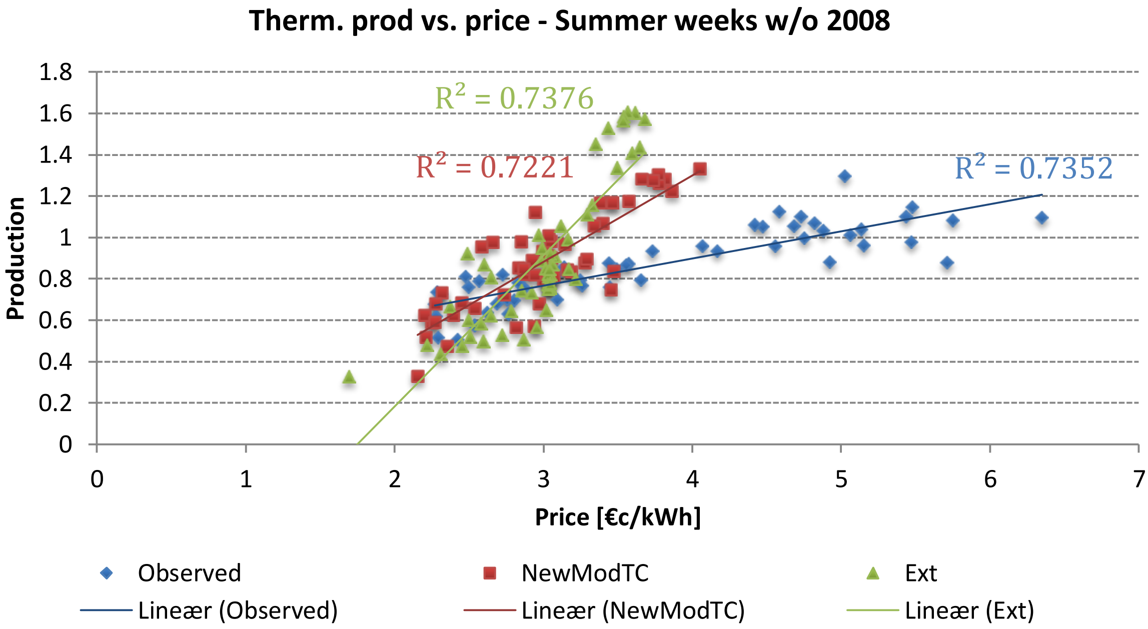


Figure 65: Scatter plot: Observed and *NewModTC* thermal production vs. price during summer weeks – 2006-2007

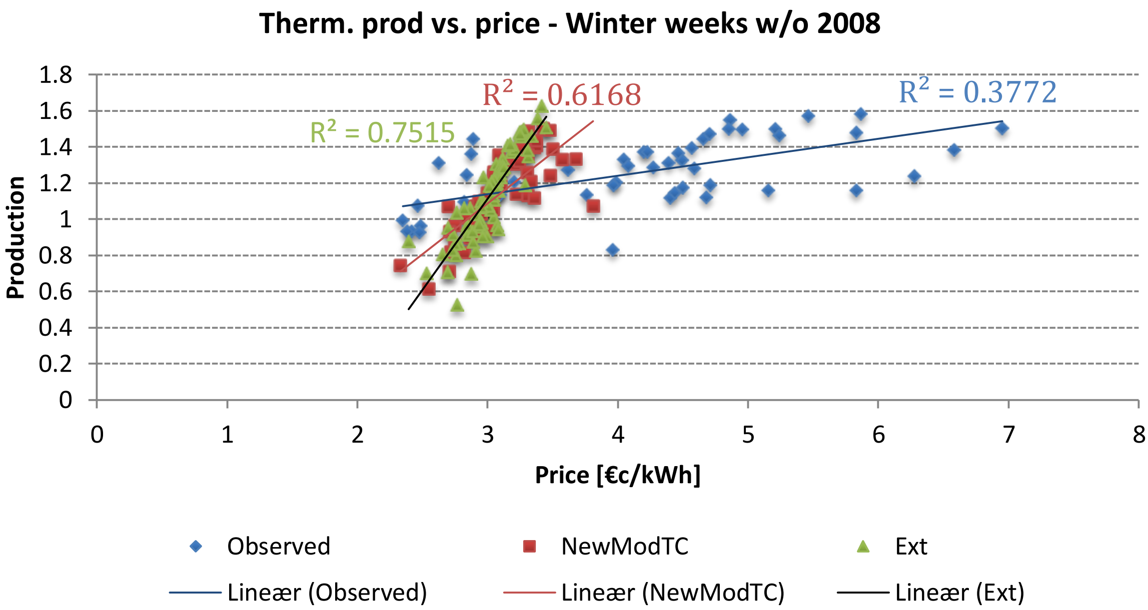


Figure 66: Scatter plot: Observed and *NewModTC* thermal production vs. price during winter weeks – 2006-2007

From Figure 65 and Figure 66 two things can be observed:

1. Observed thermal production is much less dependent on price during the winter than the summer. The same can be observed for the model and the *NewModTC* dataset, but not to the same extent.
2. The trend line for the model is much steeper than the observed data. This means that the production increase more rapidly with an increased price. It is

apparent that the prices in the model do not match observed prices when they are high.

1) During the summer, the heat load is much lower than during the winter because of higher temperatures. This enables CHP plants to respond with more flexibility to price signals, for example with turning down production when temperatures increase and prices decrease. During the winter, the CHP plants have to follow the heat load, as it is higher. This decreases their ability to respond to pricing signals. This effect is especially visible for the observed data, but also, although to a lesser extent, for the new model datasets results.

2) This is explained by the model price level in general, which seems to lay around 2.5 and 3.5 €c/kWh, which is similar to the plants' marginal costs in general. To approach the observed data on this point, one could try to diversify the MC of the CHP plants more, i.e. increase the already high MCs and lower the low MCs. However, the impact of this on thermal production and prices in Denmark is highly dependent on to what degree Denmark is a price taker or a price giver in the total system. If Denmark is a price taker for the most part a lot of thermal production might be priced out as a result of increased MCs, and low MC thermal production would not change. If Denmark is a price giver, these changes in MC would have a larger impact on the whole system price (for all EMPS areas), than on thermal production in Denmark. There are indications that Denmark is a price taker for the most part in reality [31]. The effects of this in the model are unknown, and could be carried out as further work.

8.2.4 Summary

This section summarizes how the new modelling performs compared to the existing modelling and the observed data.

In general, observed thermal electricity generation increase with decreasing temperature. This trend was also shown in the modelling results, for all datasets. It was also shown that observed thermal electricity generation increase with increasing power spot price. This trend was also shown in the modelling results, for all datasets. It was also shown as a trend that the modelled thermal production generally follows the observed thermal production. The *NewModTC* dataset follows the observed data better than *Ext*.

Given the general trends, it was shown that observed thermal electricity generation in Denmark is more temperature dependent and less price dependent than the EMPS model datasets show. It is also a general observation that the new model datasets, *NewProfiles*, *NewProfileSmall* and *NewModTC*, performs incrementally better than the existing modelling, *Ext*, in that order. The *NewModTC* dataset is an improvement compared the existing modelling, *Ext*, both in terms of representing the observed price and, especially, temperature dependencies.

R^2 is used to describe how close the models and observed data actually follow these trends. A general trend can be present, but if the data does not follow the trend closely, the trend is not necessarily explaining the observed data or model results. A high R^2 indicates that data follows a trend closely. The R^2s of the temperature and price dependencies for all datasets and observed data are presented in Table 17. The R^2s describing how closely modelled thermal production follows observed thermal production. Table 17 is illustrated in Figure 67.

When evaluating the price dependency of thermal production in Denmark there proved to be significant seasonal variations. In general, thermal production in both datasets *Ext* and *NewModTC* showed to be more price dependent than observed data indicates, especially during the winter weeks. However, during the summer, thermal production price dependency in the model (both *Ext* and *NewModTC*) follows the observed price dependency very well, with R^2-values around 0.72-0.73.

Table 17: R^2-values for the scatter plots for thermal production temperature and price dependency linear trend lines and the model match with observed thermal production

	Temperature dependency	Price dependency	Follow observed
Observed	0.605	0.348	
Ext	0.212	0.628	0.4648
NewProfiles	0.251	0.640	0.4757
NewProfileSmall	0.316	0.543	0.5235
NewModTC	0.351	0.549	0.5405

Following the green bars, for price dependency R^2, this is clearly reduced from *Ext* to *NewModTC*, but most significantly between *NewProfiles* and *NewProfileSmall*. It is likely that the reason for this is the forced production from small CHP, which does not account for more than 6.7 % of total thermal production volume, but is completely independent of price. The price dependency is still much higher for the model datasets than the observed.

Temperature dependency is more significant for observed data than for the model datasets. However, the temperature dependency has increased with the new datasets, and *NewModTC* performs significantly better than the *Ext* dataset.

The blue bar represents how well each dataset follows the observed thermal generation. It is evident that the new datasets follows the observed data more closely than the existing modelling.

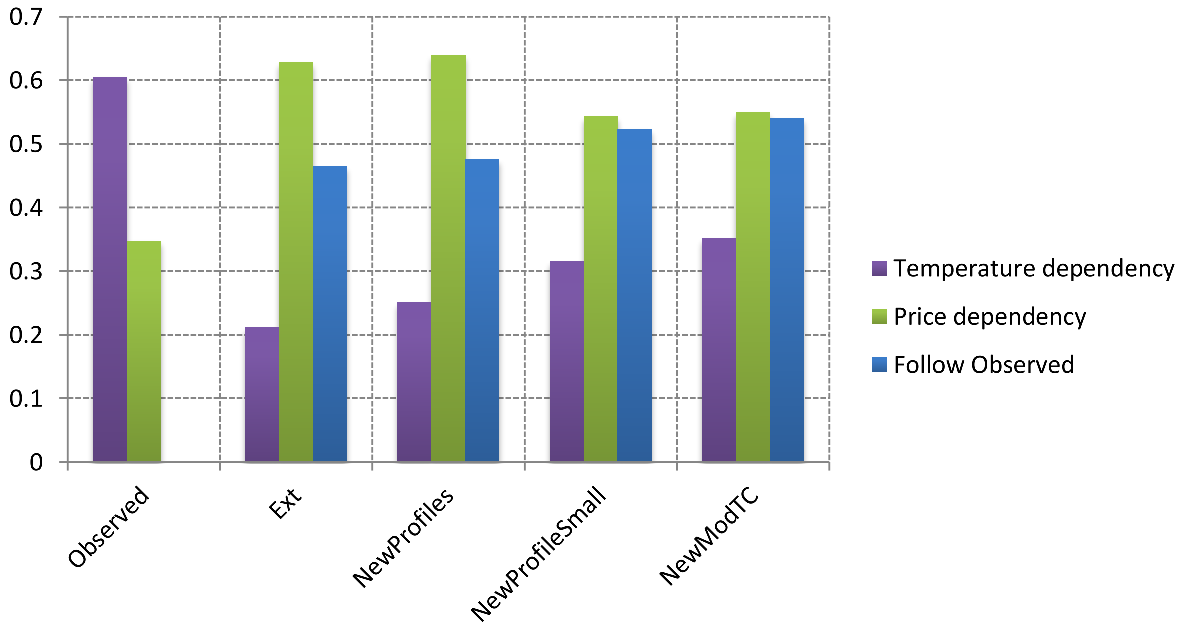


Figure 67: R^2-values for the scatter plots for thermal production temperature and price dependency linear trend lines and the model match with observed thermal production, graphical presentation

8.3 Other modelling results

In this chapter it is assessed how the new modelling impacts on general modelling results. Results from the *NewProfiles*, *NewProfileSmall* and *NewModTC* should be compared to the *Ext* dataset to compare what these changes have to say for the modelling.

Apart from the prices shown in this chapter, prices in the model datasets for *Peak* and *Night* load blocks the Denmark East area are presented with 0, 10, 50, 90 and 100 percentiles in appendix 5 in chapter 13.5.

8.3.1 More volatile DK prices for the new datasets

The new modelling affects prices in Denmark, and through those prices the entire system might be affected. In this section the impact on Danish prices of the new modelling is assessed.

Figure 68 shows the duration curve for the average price [€/MWh] across all scenarios (1962-2008) for each dataset for the DANM-OST price area. This curve is built by the Basta! software at Statnett. It looks at all scenarios in a series and takes every 500th hour (47 scenarios × 8760 hours divided by 500 ≈ 822 hours) and sorts them by price from high to low. Instead of representing the sorted hours by 1-822, a percentage system is used, where the sorted 822nd hour is 100 %, and it is assumed that the duration curve represents one typical year.

Figure 69 shows the same curve, but slightly zoomed in with regards to the y-axis to better illustrate the differences. The differences between the price duration curve for DANM-OST and the other Danish price areas are very small and insignificant.

The duration curves show that prices in general are more volatile in the new datasets than for the existing modelling. Because the CHP plants are intended to respond more to temperature with the new modelling they are unable to respond to price to the same extent as in the existing model. Therefore, in general, the prices are more volatile.

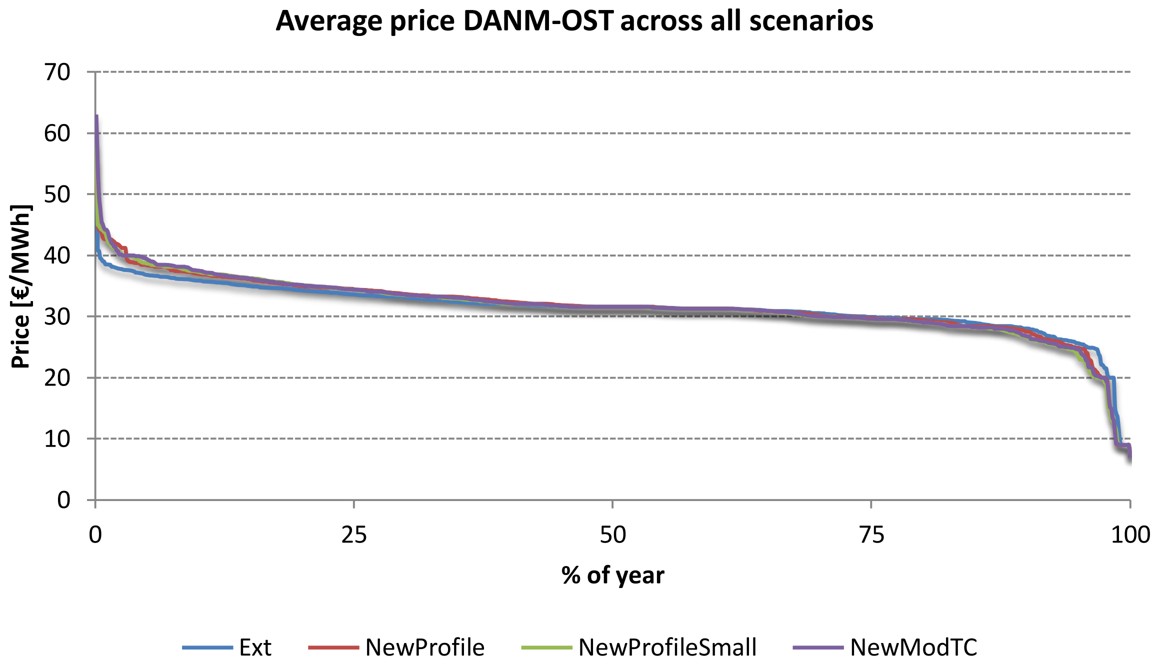


Figure 68: Average area prices DANM-OST across all scenarios for the datasets

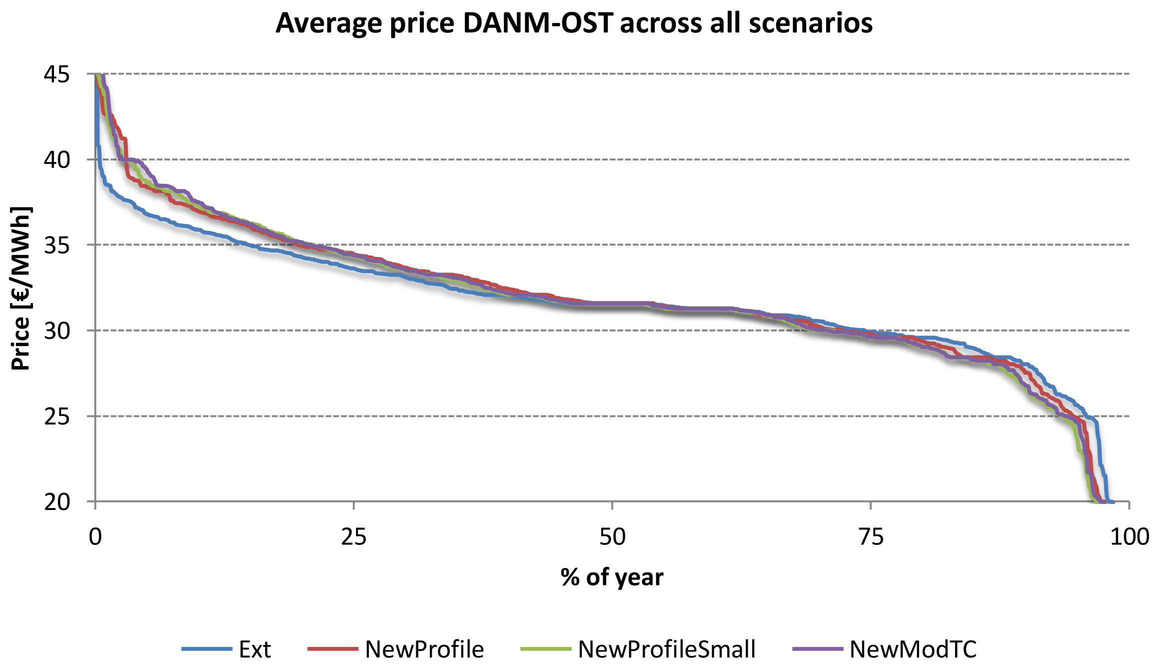


Figure 69: Average area prices DANM-OST across all scenarios for the datasets (zoomed in)

8.3.2 *NewProfiles* changes available back pressure capacity and prices

The overall increased price volatility has to originate from the changes that was made to the CHP modelling, as no other changes have been made. This section aims to discover what impact each new modelling element, each new dataset, has had on system prices. Beginning with the *Ext* dataset, the impacts of the introduction of new production profiles is assessed, as Figure 69 would indicate that is has a significant impact.

Figure 70 shows the prices and total and back pressure units thermal production averaged across 47 scenarios for the peak load block for the *Ext* and *NewProfiles* datasets.

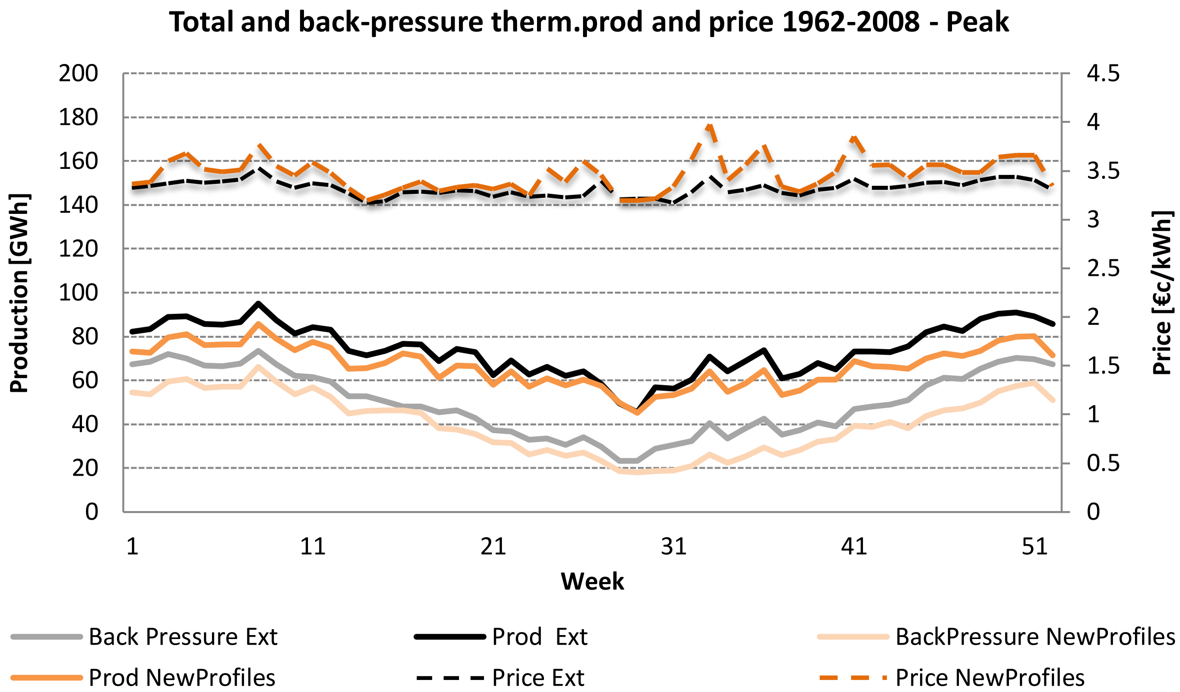


Figure 70: Total and Back pressure thermal production and price at peak load block averaged across all scenarios for *Ext* and *NewProfiles* datasets

If nothing else had changed from *Ext* to *NewProfiles* an increased price could only be due to increased external prices, in which case the thermal production would increase, if the price increase was enough to trigger the next unit's MC.

However, total and back pressure thermal production decrease in this case, despite the increased prices. This means that the price increase must be a result of a decreased back pressure production capacity, or less available cheap back pressure capacity. The same effects are observed for the "day" load block.

Figure 71 shows how the prices in general decrease for low load hours such as for the night load block. From weeks 15-25 the prices are significantly lower for the *NewProfiles* dataset compared to *Ext*. During the same weeks, back pressure production is higher for *NewProfiles* than *Ext,* while the total production level is about the same. That means that more back pressure production must be available at a lower price in the *NewProfiles* than in the *Ext* dataset.

During weeks 31-36 the back pressure production is lower for the *NewProfiles* dataset than for *Ext*, but the price is lower as well. This must mean that not only the amount of available back pressure capacity, but what capacity is available at which price has changed for the *NewProfiles* dataset.

The changes in available back pressure capacity are not only due to changes to the production profiles. The power profiles, distributing the weekly total generation over the weeks 168 hours, are now flat, as opposed to the *Ext* dataset where they had some shape. The power profiles previously distributed more production over hours belonging to peak or high demand load blocks, and less to low demand load block hours, such as night. The production is now spread equally over all of the week's 168 hours. This might have made a significant contribution to the overall price changes. It would explain how more cheap back pressure capacity is available at night and less is available during high load hours.

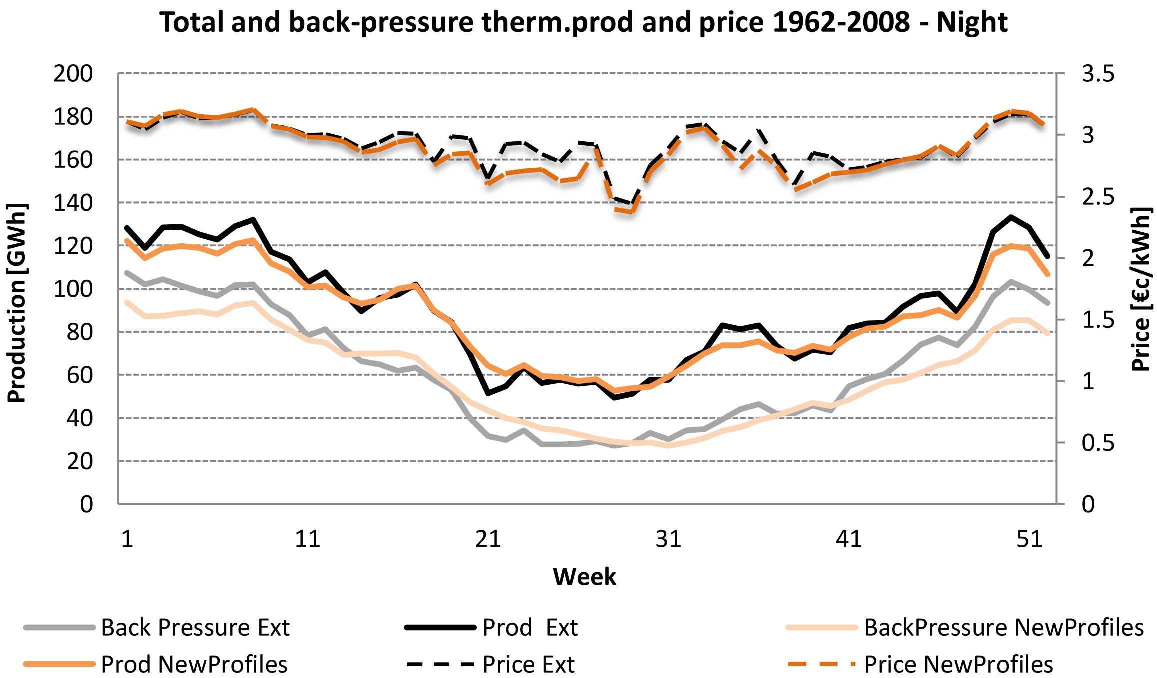


Figure 71: Total and Back pressure thermal production and price at night load block averaged across all scenarios for *Ext* and *NewProfiles* datasets

8.3.3 New aggregation of small CHP plants give moderate price reduction

As shown in Figure 48 in chapter 8.1.2, the total production from aggregated small CHP plants have increased significantly during the winter weeks, because of the forced production (MC=0). Most of the time, the price is lower for the *NewProfileSmall* compared to the *NewProfiles* dataset, as shown in Figure 69.

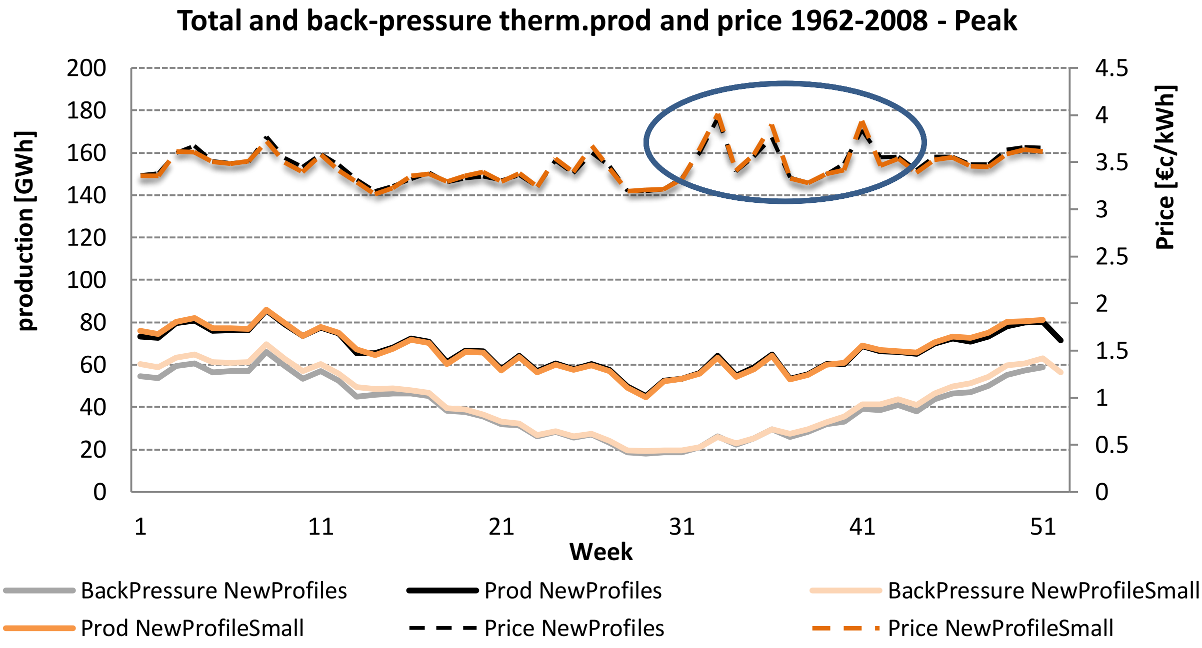


Figure 72: Total and back pressure thermal production and price per week at peak load block averaged across all scenarios for *NewProfiles* and *NewProfileSmall* datasets.

Figure 72 shows how back pressure production increase especially between weeks 40-15. In these weeks, in general the price is slightly lower for the *NewProfileSmall* dataset (the broken black line is constantly just above the broken orange line). Looking at the three price spikes (blue circle) in weeks 31-41, the price is actually higher for the *NewProfileSmall* despite the forced production. Most of the *NewProfiles* aggregated small CHP were available at a marginal cost between 3 and 4 €c/kWh. Having introduced the new aggregation, the next available small CHP is available at 4 €c/kWh. So there is a price increase for much of the aggregated small CHP capacity. This might contribute to increased prices when demand is high.

The same effects to generally lower the prices can be observed for all load blocks, while the effect to increase prices at high loads is only visible for high load periods, load blocks “peak” and “day”.

8.3.4 Impacts of temperature correction

The duration curve used in Figure 69 is taken from a function in software at Statnett called BASTA. It finds every 500 hour over the 47 scenario years and sorts them according to price. Therefore some of the hours in the duration curve will have been changed and rearranged from the *NewProfileSmall* to the *NewModTC* price duration curve. Looking at the price duration curve of Figure 69 the price of some hours should change from *NewProfileSmall* should change for the *NewModTC* dataset.

Figure 73 shows four single example weeks (denoted as 1-4) with a significant difference in actual 2005 and average temperature for the peak load block. Weeks denoted 1 and 3 have significantly higher temperatures than average, and the back pressure capacity and production is reduced, but there is no significant impact on the price. The temperature of the week denoted as 4 is significantly lower than average, and this increases available back pressure capacity. A small increase in back pressure production can also be observed that week. However, the price impact is not significant.

The week denoted as 2 has a higher temperature than average, and therefore less back pressure capacity is available. In theory this should increase prices. The price is higher for the *NewModTC* than the *NewProfileSmall* dataset for that week.

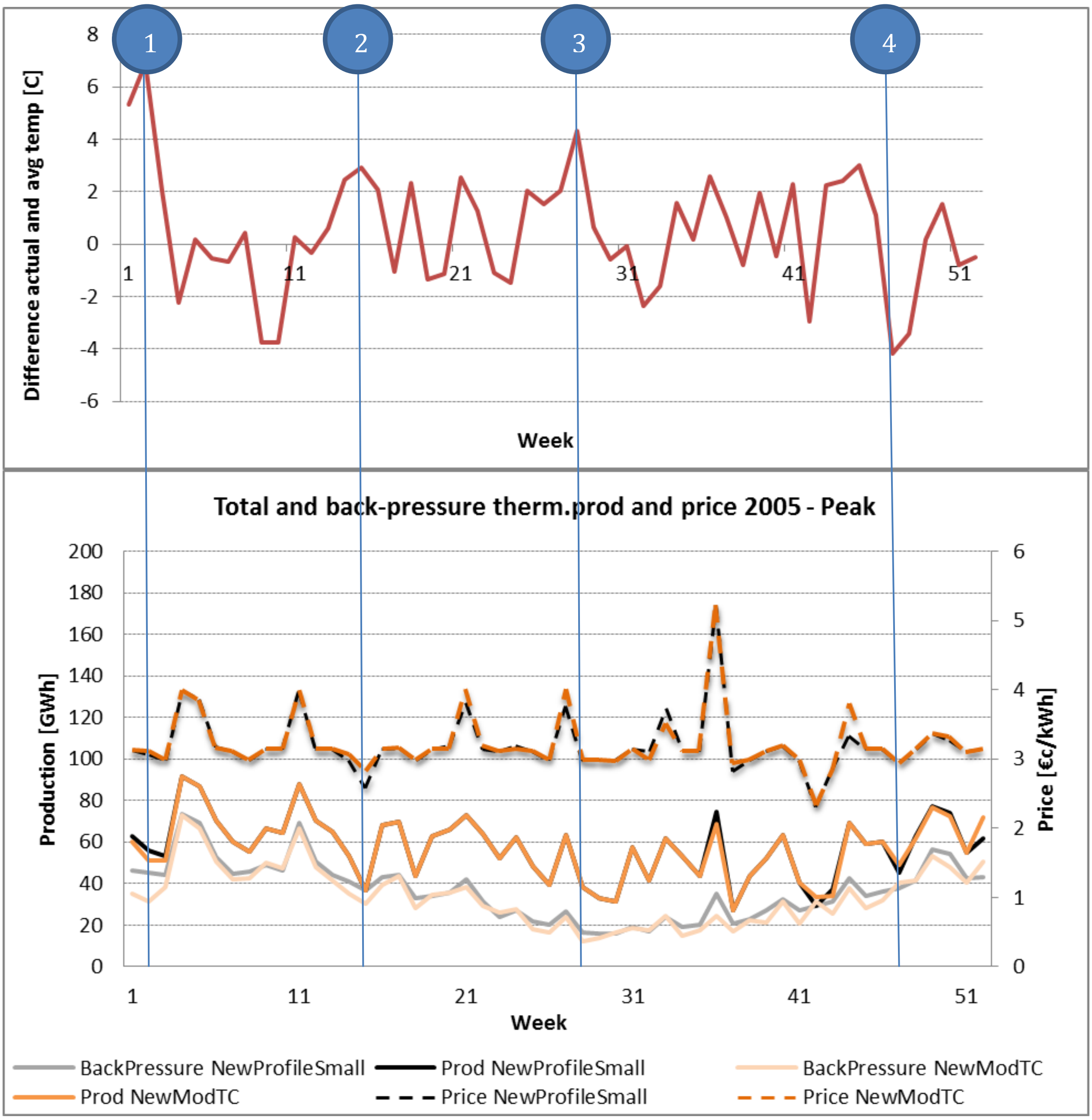


Figure 73: Total and back pressure production, price and difference between actual and average temperature per week 2005, peak load block for NewProfileSmall and NewModTC datasets

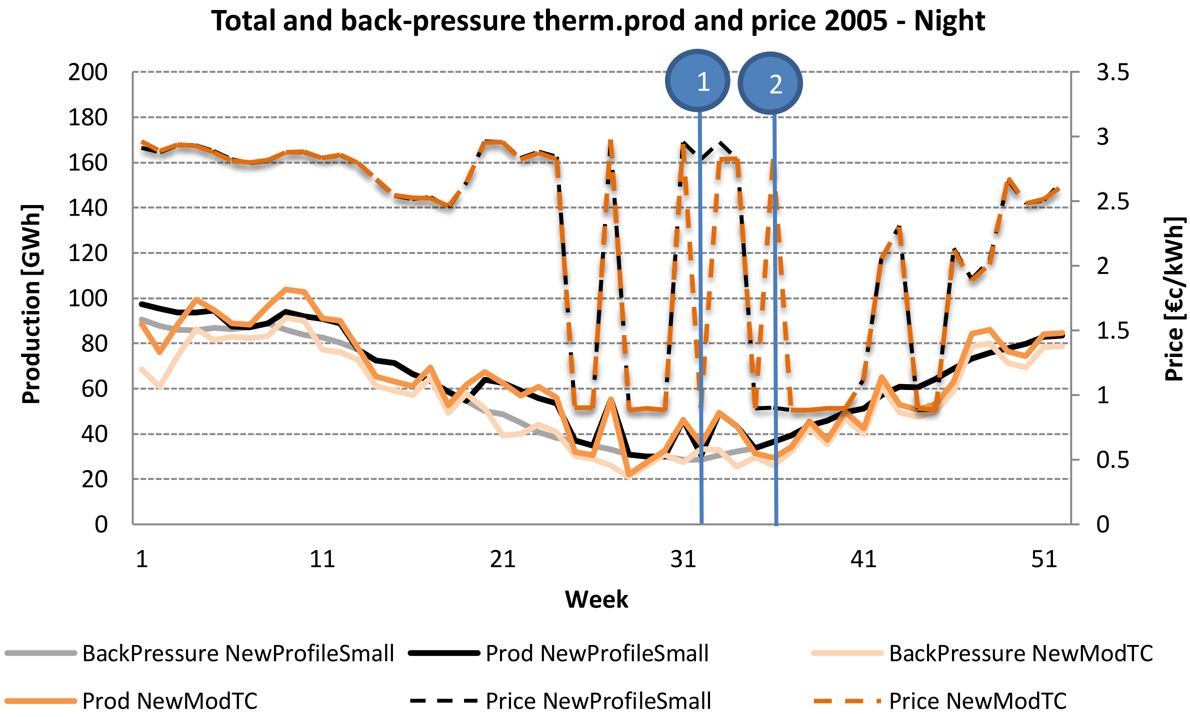


Figure 74: Total and back pressure production, price and difference between actual and average temperature per week 2005, night load block for NewProfileSmall and NewModTC datasets

Figure 74 shows production and prices for the "night" load block. Weeks denoted 1 and 2 shows how prices can be affected by the temperature correction.

For the week denoted 1, the temperature is lower than average, thus increasing the available back pressure capacity. The result is a significant price drop for the *NewModTC* compared to the *NewProfileSmall* dataset.

For the week denoted 2, the temperature is higher than average, thus decreasing the back pressure production capacity. While the price is very low for the NewProfileSmall dataset, the reduced back pressure capacity results in a significant price increase for the *NewModTC* dataset.

The temperature dependent capacity correction introduced for the *NewModTC* dataset shows no consistent pattern in changing prices either up or down, but can change prices significantly for individual hours. For 2005 it showed to change the prices more in low load hours than high load hours.

9 Discussion

The modelling of CHP plants on a system level, such as the EMPS model, faces some main challenges tied to the CHP technical diversity, available documentation on different types of plants and methods of quantifying the CHP production portfolio. Numerous simplifications and generalizations was made when going from discussing modelling individual plants in theory to modelling about 500 plants on a system level in practice.

This discussion presents some sources of error in this thesis, some aspects not previously addressed that might impact on the new modelling results and areas of further work.

Other methods of estimating heat load

In chapter 6.2.2 it was discussed how individual plant heat load as a function of temperature, $P_{heat}(T)$, could be quantified by using data from three decentral plants. Further, this relation and the power to heat ratio for each CHP prime mover technology was used to estimate the power production as a function of heat load. Observed system data could have been used to estimate electricity production directly as a function of temperature, as both were known from available historical data. However, the observed production data does not separate what production was back pressure or condensing production. Therefore a method was needed to estimate the back pressure production specifically, and the method chosen did that.

However, more data should ideally be available for several types of plants and prime movers. The reviewed data for heat load estimation was gathered from three similar, small, gas reciprocating engine CHP plants. These plants all had heat storage, but this does not affect the heat load in itself, so storage should not have had any impact on the data. The impact on heat load estimation of evaluating data from a larger range of CHP plants is unknown. Some sources suggest that the production profiles for individual back pressure plants can be estimated from looking at observed total decentral production on a system level [31].

The significance of the power to heat ratio

When calculating the back pressure power production as a function of heat load/temperature, the power to heat ratio was considered an important factor. It was assumed that $0 < P_{heat} < 1$, and that P_{el} had a slope of b as shown in Figure 75. A high b would mean a high power to heat ratio and a low b would mean the opposite. There is nothing wrong with this argument or method so far. However, as P_{heat} will vary between 0 and 1 (to follow the temperature) for all plants, P_{el} will vary between 0 and b for all plants accordingly. This means that b will be different for each plant, but P_{el} as a share of the plant's b will be similar for all plants. This means that the production profiles for all back pressure units will be equal in reality, except for a scaling factor determined by the relation between the plant's *b*s. This scaling factor then disappears when multiplying each production profile with the total annual production capacity [GWh].

The key assumption here is that all plants must follow the heat load similarly as a function of the uniform temperature, and that their electricity production as a share of maximum capacity is given by a linear function of the heat load. There is nothing wrong with these assumptions, but they reduce the significance of the individual plant's power to heat ratio to zero.

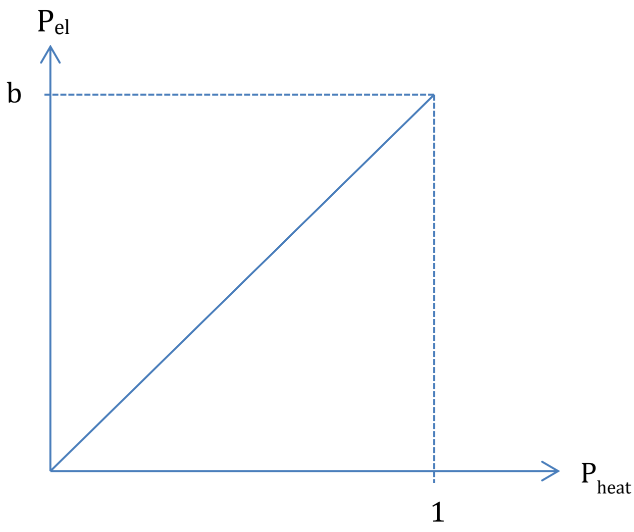


Figure 75: Back pressure operating region

Marginal costs and seasonal fuel price variability for small CHP

It was discussed and shown in chapter 6.3.1 how the MC of a CHP unit with a gas fired heating back-up unit is not necessarily affected by a rise in fuel prices, therefore it was assumed for the SmCHP1 group (with MC of 40 €/MWh, and 50 % of all small CHP production capacity) that the MC does not follow the same seasonal gas price variations as was assumed in the existing modelling, and would remain constant over the year. For the SmCHP3 group (forced production) a rise in the gas price would not affect the MC as it would still be zero. However, for the SmCHP2 group, with a biomass fired back-up heating unit, the MC would be affected by an increased gas price; still this was not considered or implemented. This is a potential source of error. It is shown in Figure 76 how an increase in the gas price shifts the cost of heat-curve for a gas-fired CHP unit upwards, while the cost of heat for biomass remains constant. The MC of the CHP unit then moves from P_1 to P_2.

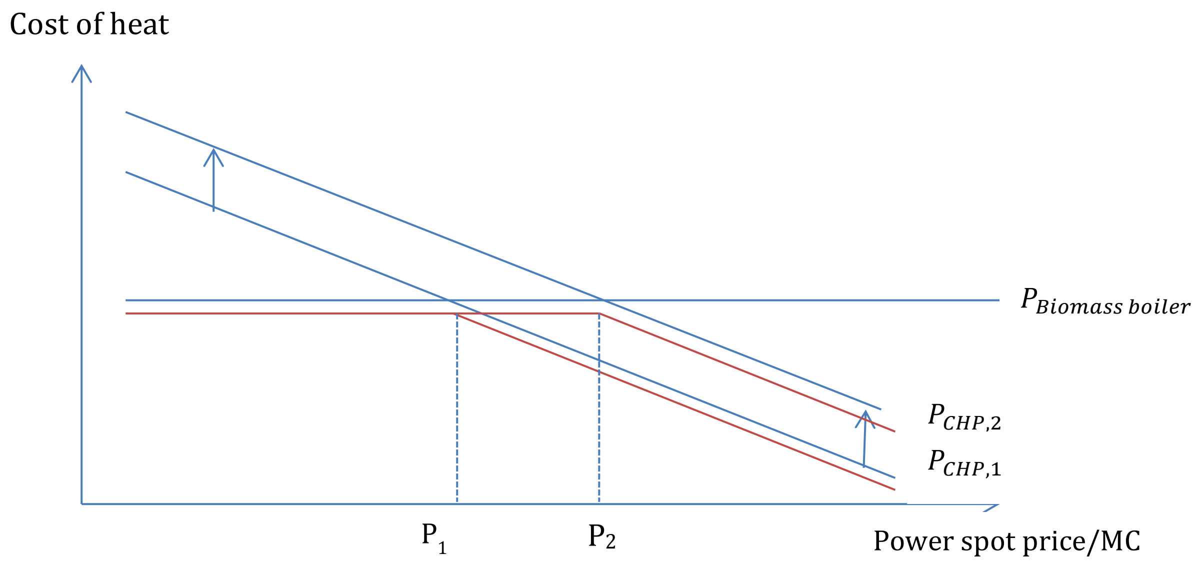


Figure 76: An increas in gas price affects the MC of a CHP unit

However, the MC of this unit is already 93.3 €/MWh, and a slightly higher cost during the winter or lower cost during the summer, is unlikely to have any significant impact.

Marginal costs for large back pressure plants

Marginal costs for large plants have not been changed for this modelling. The MC discussion for the new small CHP plants could have been carried out for large plants back pressure capacity as well, as there is no principal difference between small and large CHP plants back pressure capacity, only a matter of scale.

This was not done, and the existing marginal costs were used. It was discussed how the price range at which CHP production is triggered in observed data was much wider than in the model. Simulating a dataset with diversified CHP MCs would be interesting, and might contribute to discovering to what extent one would price high MC Danish CHP out of the market or if prices would change.

Full back testing exercise

When comparing modelling results with observed data, one should be aware that the observed thermal production and price is sensitive to wind production and fuel prices amongst other factors, in addition to temperature. To compare observed and modelled weekly thermal production of 2001-2008 historical data for these variables should be given as input to the model. As shown, the observed thermal production price dependency curve of Figure 61 was shifted for 2008 due to increased fuel prices, but this was not reflected in the model.

A more comprehensive back testing exercise could then be carried out to discover how each variable should impact on a complete CHP modelling. However, in the EMPS, this is a very time consuming task.

Perfectly rational participants and zero transaction costs

One of the most important results from this thesis was that thermal production is less price dependent in reality than what the model shows it to be, despite the new modelling. Therefore there can be elements affecting price dependency in thermal production that are not represented in the model at all.

First of all, the model does not include start-up costs. Accounting for start-up costs, participants would have to think more strategically, and not simply start up their unit as the price rose above their MC. They would have to expect the price to stay at a certain level for a certain period of time to pay back their production and start-up costs. This would reduce the price dependency of thermal production. In reality, these are actual costs impacting observed production, but are not accounted for in the model. The total number of start ups per year for all plants increases by about 40 % from 400 to 556 from the existing dataset to the new model datasets, who have roughly the same number of start ups. About 15-20 % of the plants start up more than 10 times during an average year for all new dataset, and about half of these are the condensing parts of extraction plants. About half of the plants have one or no start ups during a year. The effects of accounting for these in the model are unknown.

Secondly, there are other factors impacting on the ability of plants to switch from one mode of operation to the next. These are transaction costs. For example, for some plants a team of workers have to actively go out and start a unit. This has a direct transaction cost. There might also be a case that employees of small plants, in particular, are unable or unwilling to exploit all price signals from hour to hour and they might employ a wait-and-see tactic. This has no direct cost, but can still be viewed as a transaction cost. This means that the producer is not acting perfectly rational. To a certain extent, the transaction costs can be difficult to quantify and model, but might have a significant impact on observed data.

Price impact from new power profiles

As it was shown in chapter 8.3.2, back pressure production increased in low demand load blocks and decreased in high demand load blocks. It was discussed how this could happen, as there is really nothing to explain this night/day-shift of production. It is likely, but not shown in this thesis, that the change in power profiles from *Ext* to *NewProfiles* is the main reason for this.

The power profiles distribute the week's total production capacity over the 168 hours of the week. These are completely flat for all units in the *NewProfiles* dataset, while they have their original shape in the *Ext* dataset. The original shape of decentral plants' power profiles (as an example and shown in chapter 5.2.2) meant that more capacity was given to hours during the day than during the night. This explains why back pressure production increased in low demand load blocks and decreased in high demand load blocks.

It was argued in this thesis why flat power profiles were assumed, and this argumentation is not necessarily wrong. Energinet also assumes flat power profiles. However, the new, flat power profiles should have been implemented in a separate step, not at the same time as production profiles, creating a new dataset. Had this been done, the effects of this on price and production could have been evaluated isolated.

Revisions

Revisions and maintenance for large CHP plants were implemented with the existing production profiles, but are not taken into account for the new production profiles. This might contributes to more available generation capacity during the summer weeks. The effect of including revisions for the new datasets has not been evaluated. This is a suggestion for further work.

10 Conclusion

The main objective of this thesis was to implement an improved modelling of CHP plants in Denmark in the Statnett EMPS model. The existing modelling had some issues regarding the average annual production profiles, the aggregation of small CHP plants and the temperature dependent generation availability. In short, the existing production profiles were too volatile and seemingly random. The aggregation of small CHP led to lower production during the winter, when heat load is highest, than during the summer. For the small CHP plants there were also some concerns regarding their marginal cost. In addition, the CHP production was not temperature dependent apart from a general seasonal variability.

To address the first issue new production profiles, based on average weekly temperatures, were implemented. Secondly, a new aggregation of small CHP plants was implemented, and third, a SINTEF developed function for correcting production capacity according to the actual temperature was implemented. These new elements to the model was based on a CHP operation strategy developed for this thesis.

The new elements were implemented in steps so that the impact on modelling performance of each element could be assessed. The implementations formed three new EMPS model datasets, in addition to the one for the pre-existing modelling. Each element was shown to have been implemented correctly and addressed the issues as intended.

When comparing observed and model results it was shown to be a trend that modelled thermal production follows the observed thermal production week per week in general. However, the degree to which the data fitted with this trend varied amongst the model datasets. The new modelling elements proved to be incremental improvements with regards to following the observed thermal production from week to week, where the pre-existing modelling performed worst and the new dataset with all three new modelling elements, *NewModTC*, performed best. Introduction of the forced aggregated small CHP production was the most effective single modelling change in terms of increasing the R^2 to indicate a better fit with the overall trend that modelled thermal production followed the observed.

A comparison between observed data and results from the existing modelling showed that thermal electricity production in general was much more temperature dependent and less price dependent in reality compared to the model. The new elements were implemented in steps and showed incremental improvements to the overall modelling, as thermal production became more temperature dependent and less price dependent, i.e. approaching the trends of the observed data more closely. However, the comparisons also showed that there remains some work to increase temperature dependency and decrease price dependency for the modelled thermal production.

The new model datasets resulted in more volatile prices on average across all scenarios compared to the existing modelling. The increased temperature dependency was the main reason for this. Implementing new production profiles changed the available, low cost back pressure capacity, so that less was produced, compared to the existing modelling, during high load hours, increasing prices, and more was produced during low load hours, contributing to decreased prices. This was largely due to new, flat power profiles distributing the production equally over the week's 168 hours. The new power profiles should have been implemented in a separate dataset to isolate the effect from the new production profiles. That was not done.

Overall, the new small CHP aggregation gave a moderate price reduction, as production was forced, increasing relatively cheap back pressure power production during the winter, especially.

The function for temperature dependent capacity correction showed to change the prices, mainly through regulating available back pressure capacity down (increasing prices) or up (lowering prices) according to the actual temperature for individual hours, but no consistent, dominating price change.

To conclude, the existing modelling had some areas that could be improved. A new modelling was implemented based on a CHP operation strategy that was developed. The new EMPS datasets containing the new modelling elements showed to improve the modelling performance incrementally, mainly by increasing the temperature dependency of thermal power generation in Denmark. A comparison between the new modelling and observed data shows that the modelling still can be improved, mainly by reducing price dependency and increasing temperature dependency.

11 Further work

Alternative method for modelling the heat market in EMPS implicitly

In this thesis, a relatively small sample space (time period of one year, three decentral plants, high resolution data) was used to estimate the heat load for individual BP plants in the EMPS given the outdoor temperature. Through the heat load for a given temperature, the power production was estimated, thus implicitly modelling the heat market of each CHP plant.

Another way of modelling BP power production would have been to simply look at the system decentral CHP generation. This data can be found on Energinet's web page. In this way, the heat market would be estimated on a system level. The implications of using this alternative method should be evaluated.

Increase temperature dependency

There still remains some work to improve the modelling of CHP, as temperature dependency is higher in reality in the model and price dependency is lower in reality. Here are some suggestions as to how this could be achieved:

- The function for heat load at given temperatures could have had a higher volatility.
- Develop methods of addressing real and other transaction costs. Creating some sort of delay in CHP decision processes.
- Implement a method to account for start up costs of thermal units
- Develop and test a method of diversifying the marginal costs of the units and increase the share of forced thermal production
- Revisions during the summer season would, in theory, reduce the price dependency of thermal production in the models.

It has not been shown in this thesis that these suggestions are appropriate, and this would need to be investigated before they could be implemented.

Heat storage and heat from electricity

Heat storage should be modelled in some way. In theory, modelling of heat storage is likely to make thermal power production even more price dependent and less temperature dependent. This is because of a smoothing effect when electricity production and heat load is partially decoupled in time. It has not been found a way to do this in this thesis within the framework of the EMPS. An operational strategy looking into time is needed to implement an appropriate strategy for handling heat storage.

Electric boilers and heat pumps have been ignored for this thesis due to their negligible heat production volume at a system level. In principle, these can also be modelled through the MC of the CHP unit, or explicitly as price dependent demand.

Implement modelling for more EMPS areas

CHP technology is widely used in the Nordic region, and the general modelling principles presented for Denmark in this thesis can be applied to other areas such as Finland and Sweden to further assess the system implications of a new CHP modelling.

Increased modelling detail

In this thesis, the level of modelling detail of small gas fired CHP plants was increased. The modelling performance was significantly increased due to this. Several other types of plants could possibly be modelled in more detail to improve modelling performance.

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13 Appendix

13.1 Appendix 1: Short introduction to Danish electricity market

The Danish power market largely consists of thermal production plants, where the large scale CHP plants dominate the total electricity production, and wind turbines. Electricity generation from wind turbines has grown steadily for several years and is now the second most dominant electricity generator. This is shown in Figure 77. A total of 30.73 TWh of electric power was produced in Denmark in 2012.

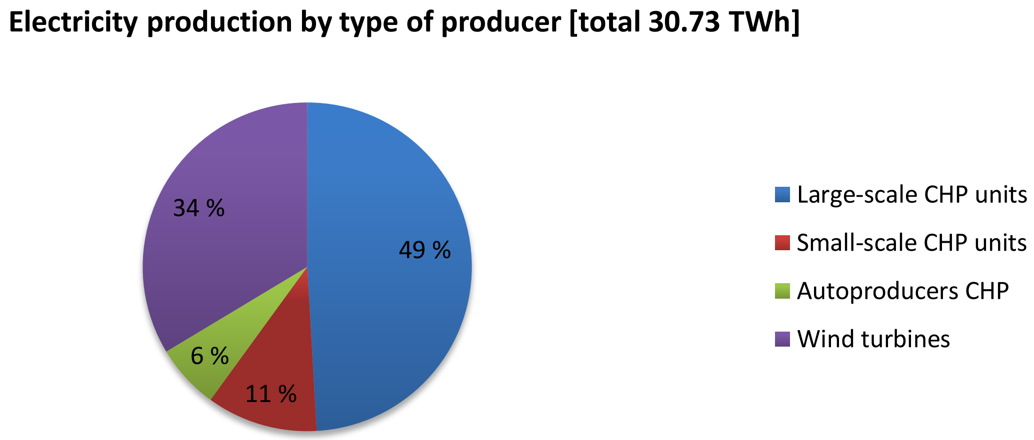


Figure 77: Electricity production in Denmark by type of producer 2012 [2]

Coal and wind have an equal share of electricity production as fuels, while biofuels (mostly biomass) and natural gas also have significant market shares. This is shown in Figure 78.

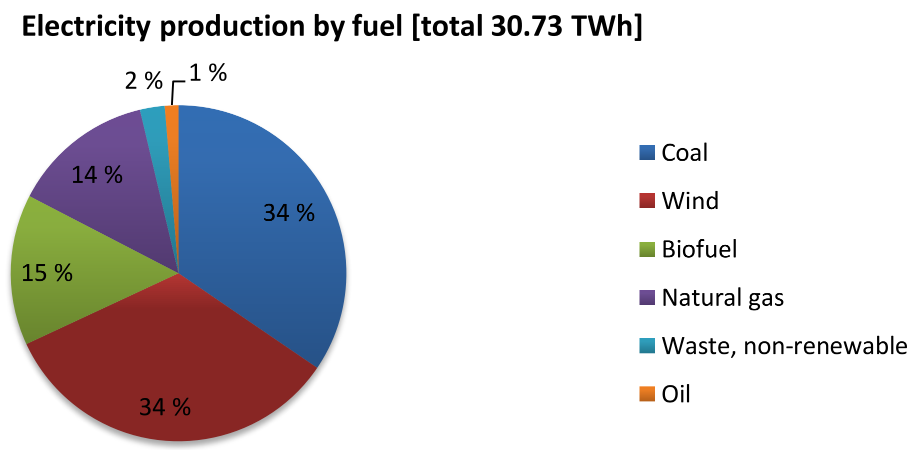


Figure 78: Electricity production by fuel 2012 [2]

Danish power producers and consumers in the two Danish price areas buy and sell power on the Nord Pool Spot market.

13.2 Appendix 2: Additional existing production profiles

This appendix contains some of the resulting available capacity profiles as a function of the production profiles and total annual production capacity for some of the existing CHP extraction plants.

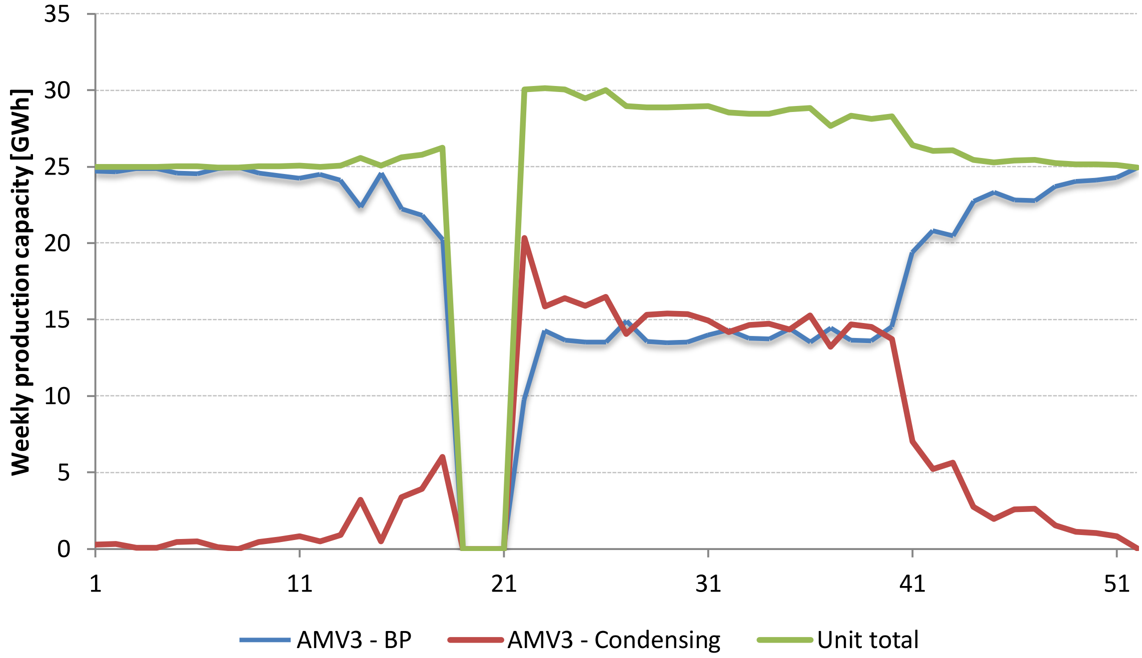


Figure 79: Available production capacity [GWh] per week based on existing profile for EMPS CHP unit AMV3

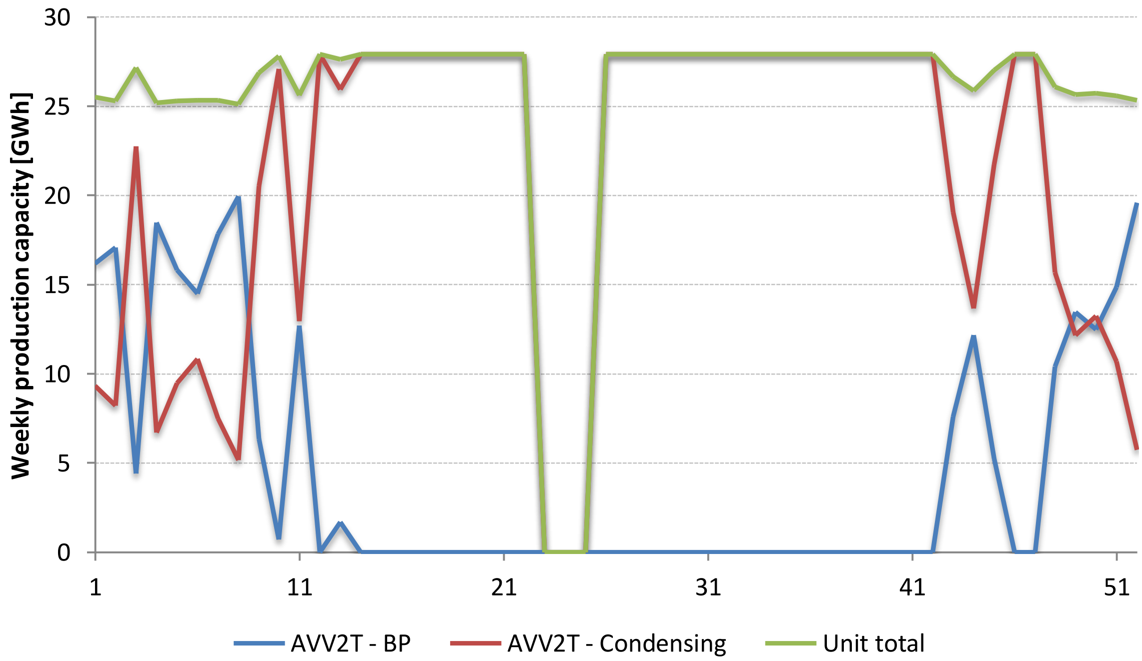


Figure 80: Available production capacity [GWh] per week based on existing profile for EMPS CHP unit AVV2T

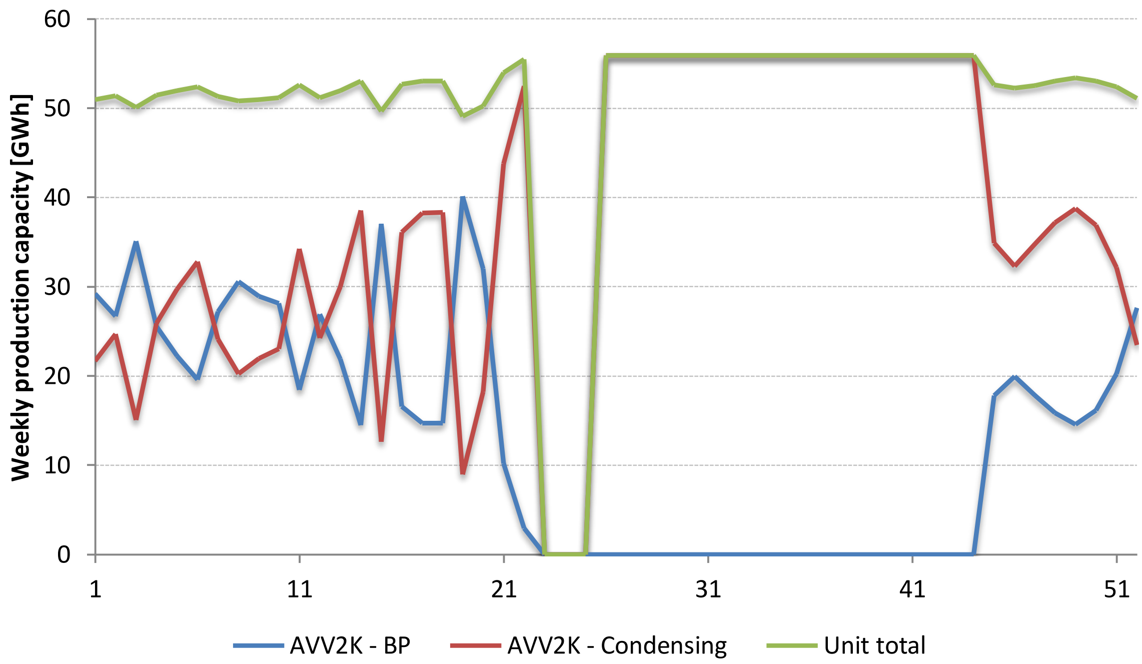


Figure 81: Available production capacity [GWh] per week based on existing profile for EMPS CHP unit AVV2K

13.3 Appendix 3: Temperature and price dependencies

This appendix contains the plots of weekly thermal production [GWh] vs. temperature and price for *NewProfiles* and *NewProfileSmall* datasets.

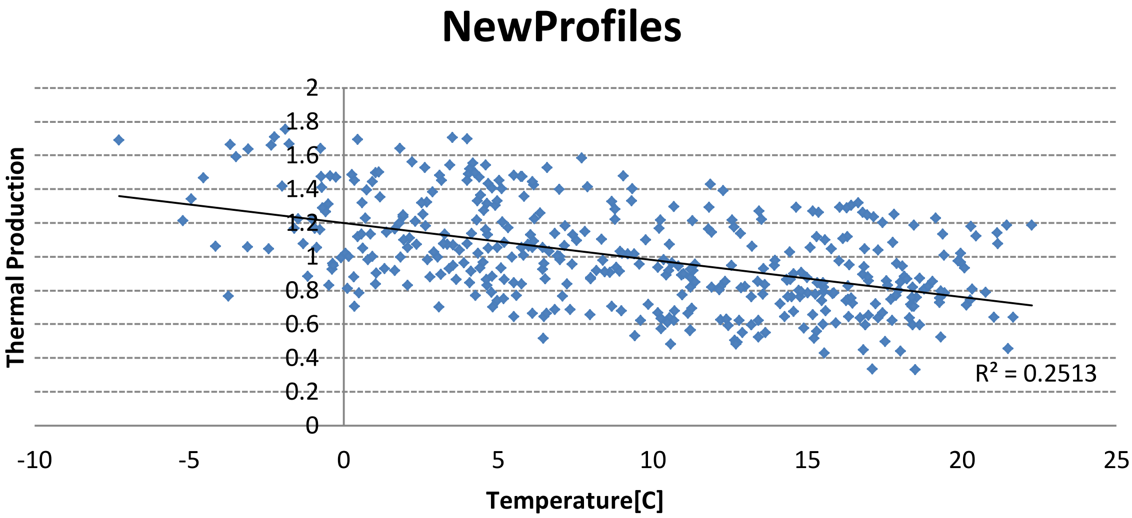


Figure 82: Thermal generation per week normalized around 1 vs. temperature for *NewProfiles* dataset

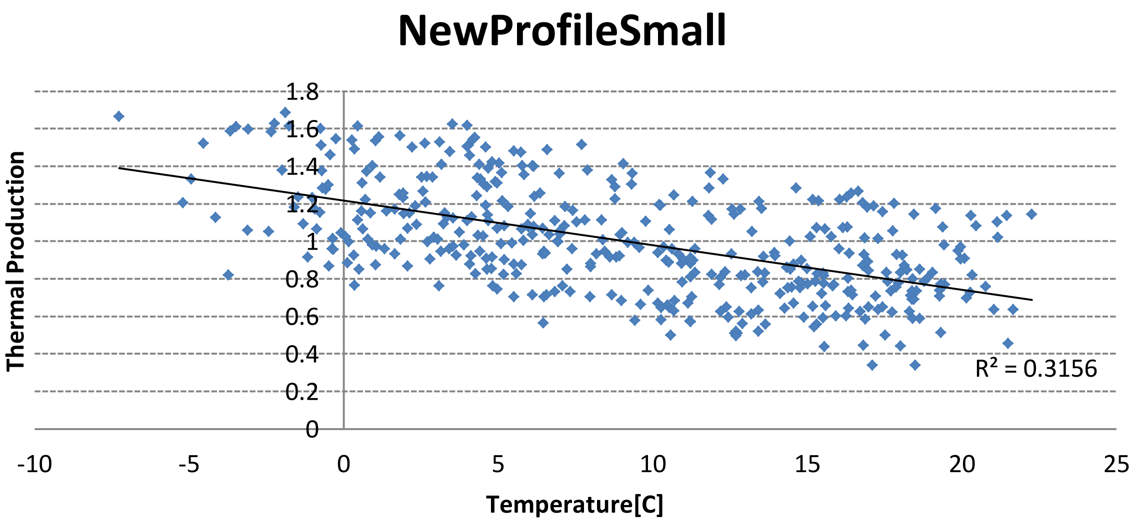


Figure 83: Thermal generation per week normalized around 1 vs. temperature for *NewProfileSmall* dataset

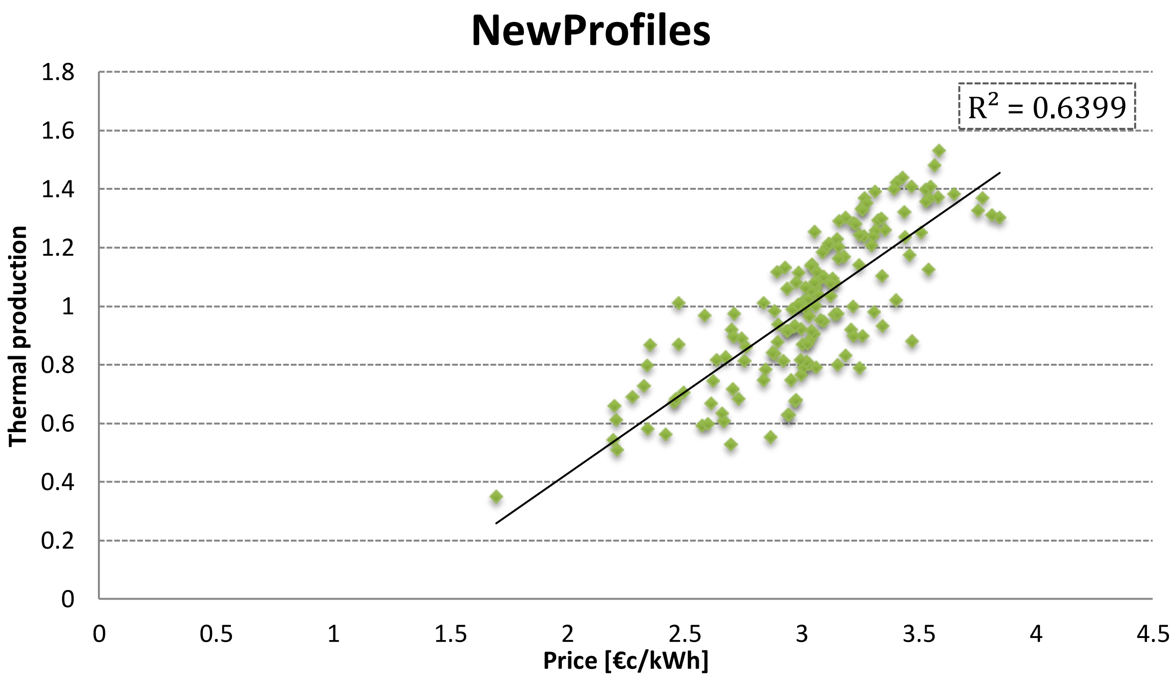


Figure 84: Thermal generation per week normalized around 1 vs. price for *NewProfiles* dataset

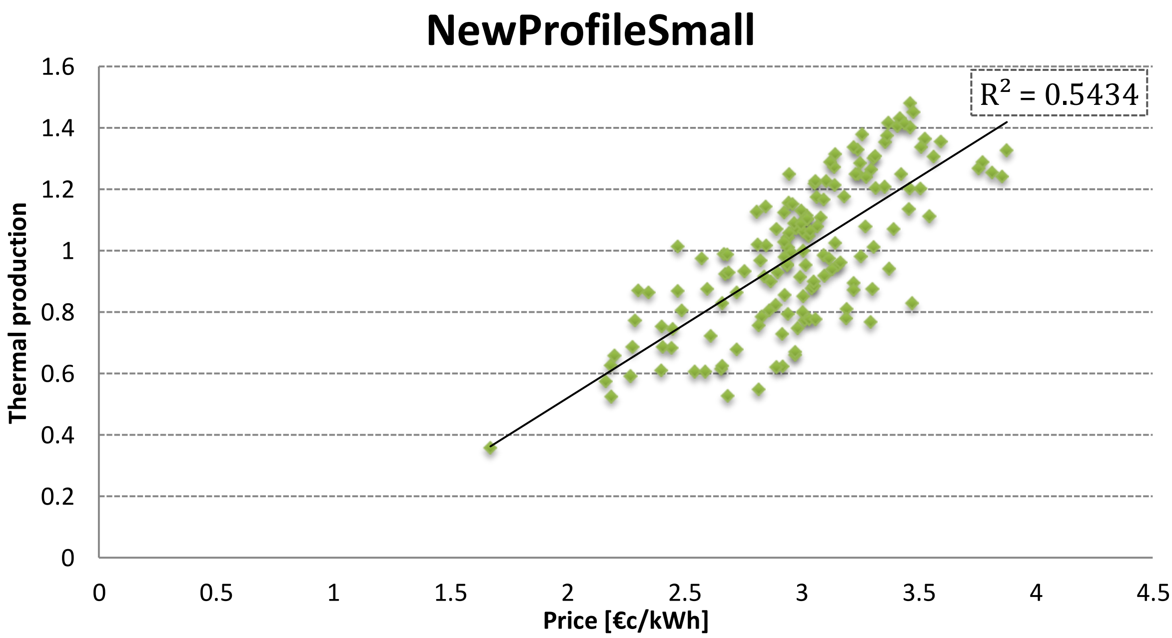
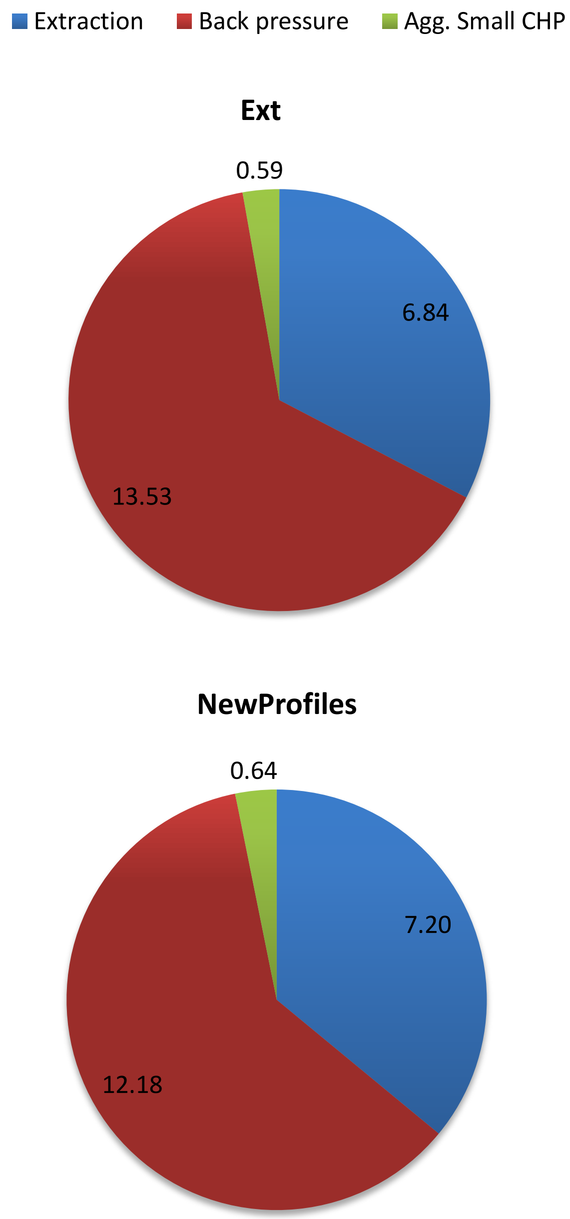


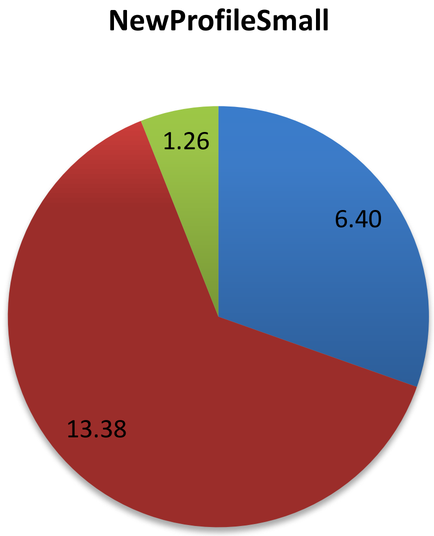
Figure 85: Thermal generation per week normalized around 1 vs. price for *NewProfileSmall* dataset

13.4 Appendix 4: Thermal electricity generation in the EMPS

In this appendix average thermal generation per year in the model datasets are shown per type of CHP production (BP, condensing or small CHP) and per area (Denmark East, Fyn, Jylland North or Jylland South).

Thermal generation per type of generation [in TWh]





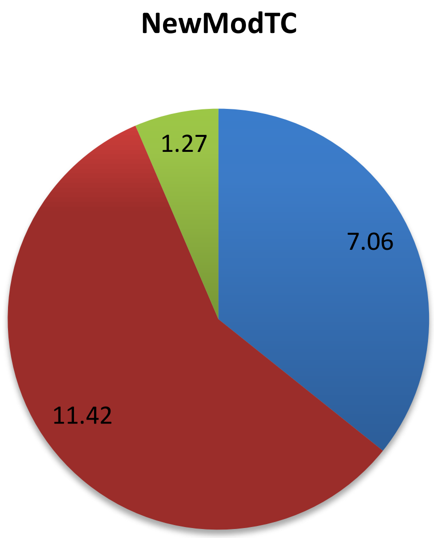
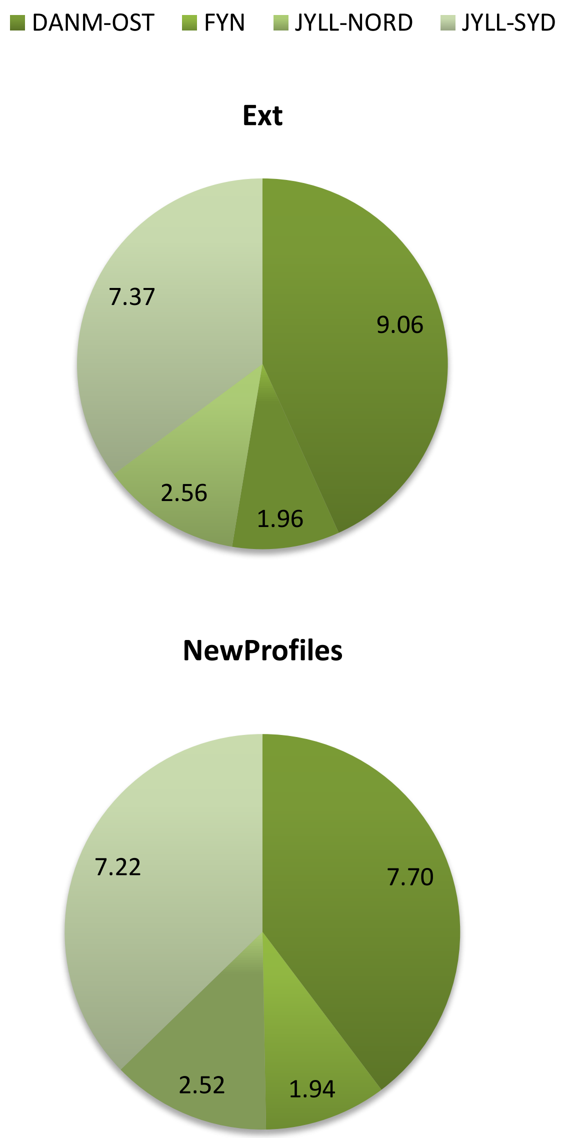
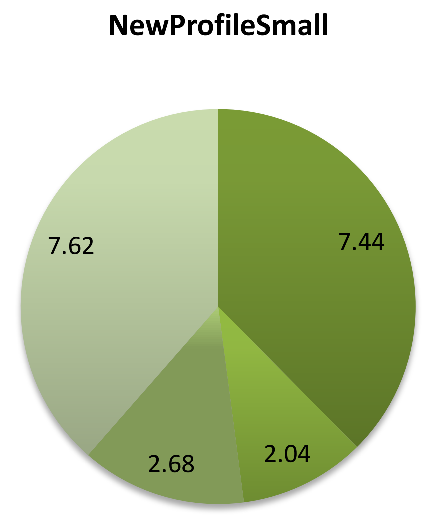


Figure 86: Averaged thermal generation [TWh] per year across all scenarios for each dataset

Thermal generation per price area [in TWh]





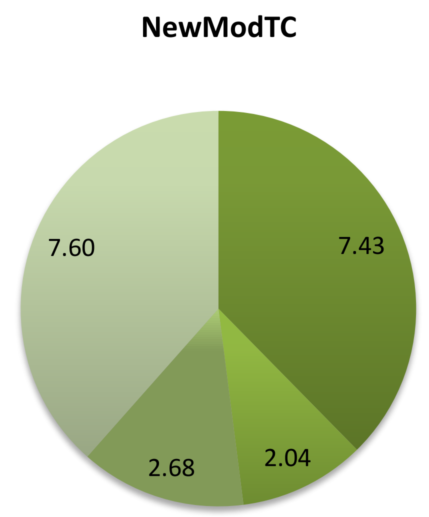


Figure 87: Thermal generation averaged across all scenarios per year [TWh] per price area

13.5 Appendix 5: Prices in the model

This appendix shows the price level per week in the model datasets for both *Peak* and *Night* load blocks for the 0, 10, 50, 90 and 100 percentiles for the Denmark East area. The figures are generated with the Basta! software at Statnett. *Peak* and *Night* prices for *Ext* and *NewModTC* are shown first.

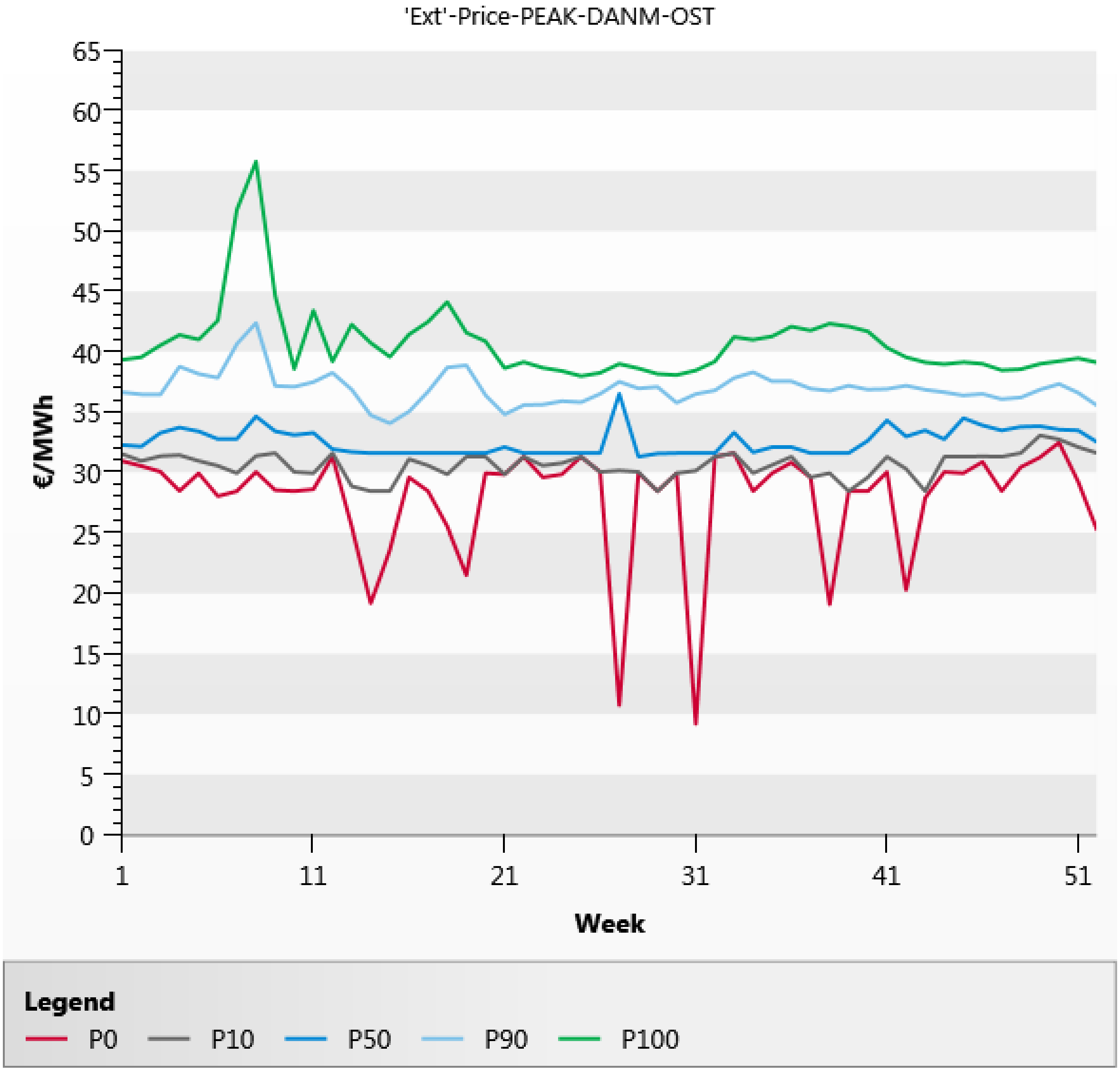


Figure 88: Peak load block prices for *Ext* dataset

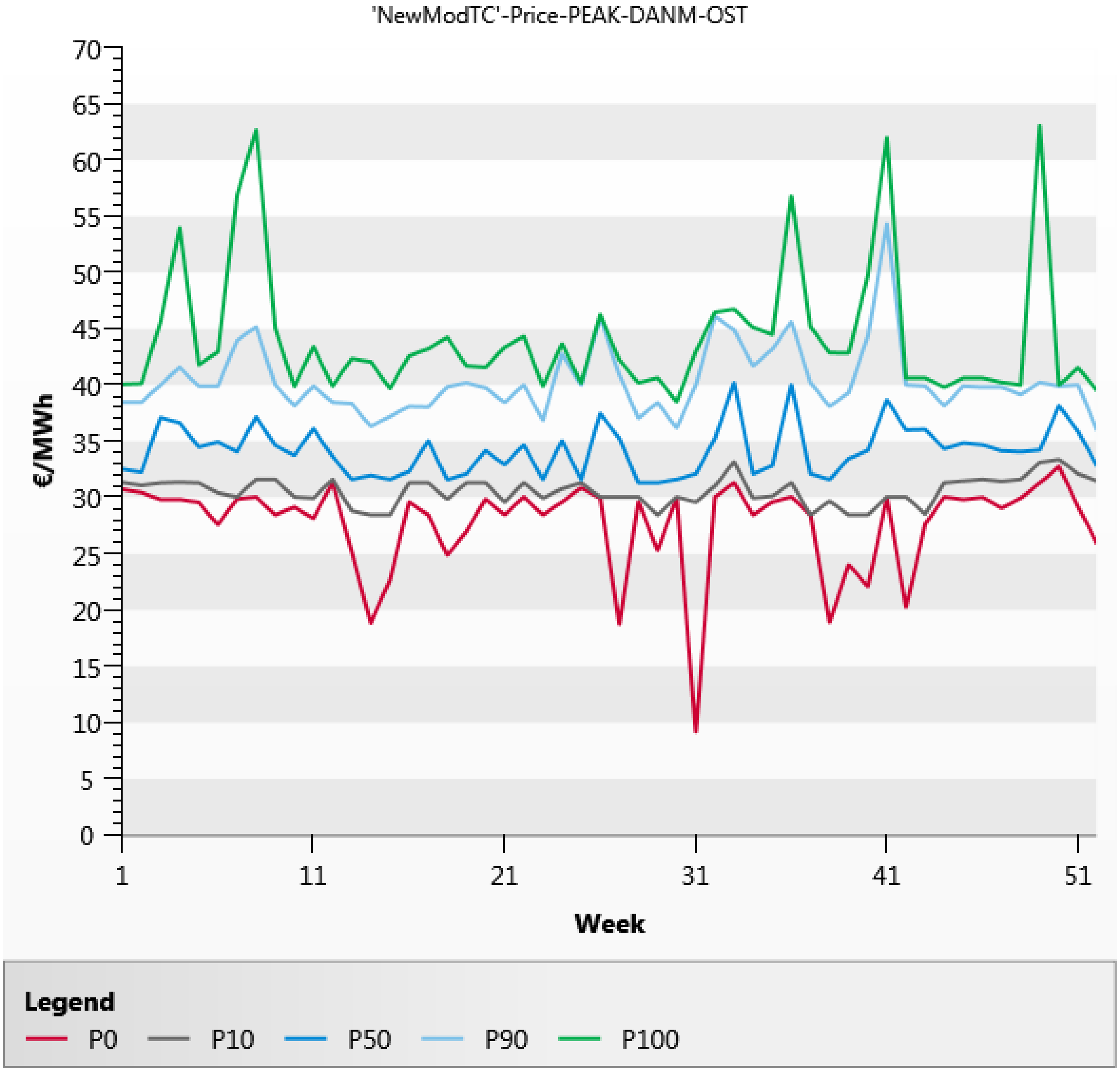


Figure 89: Peak load block prices for *NewModTC* dataset

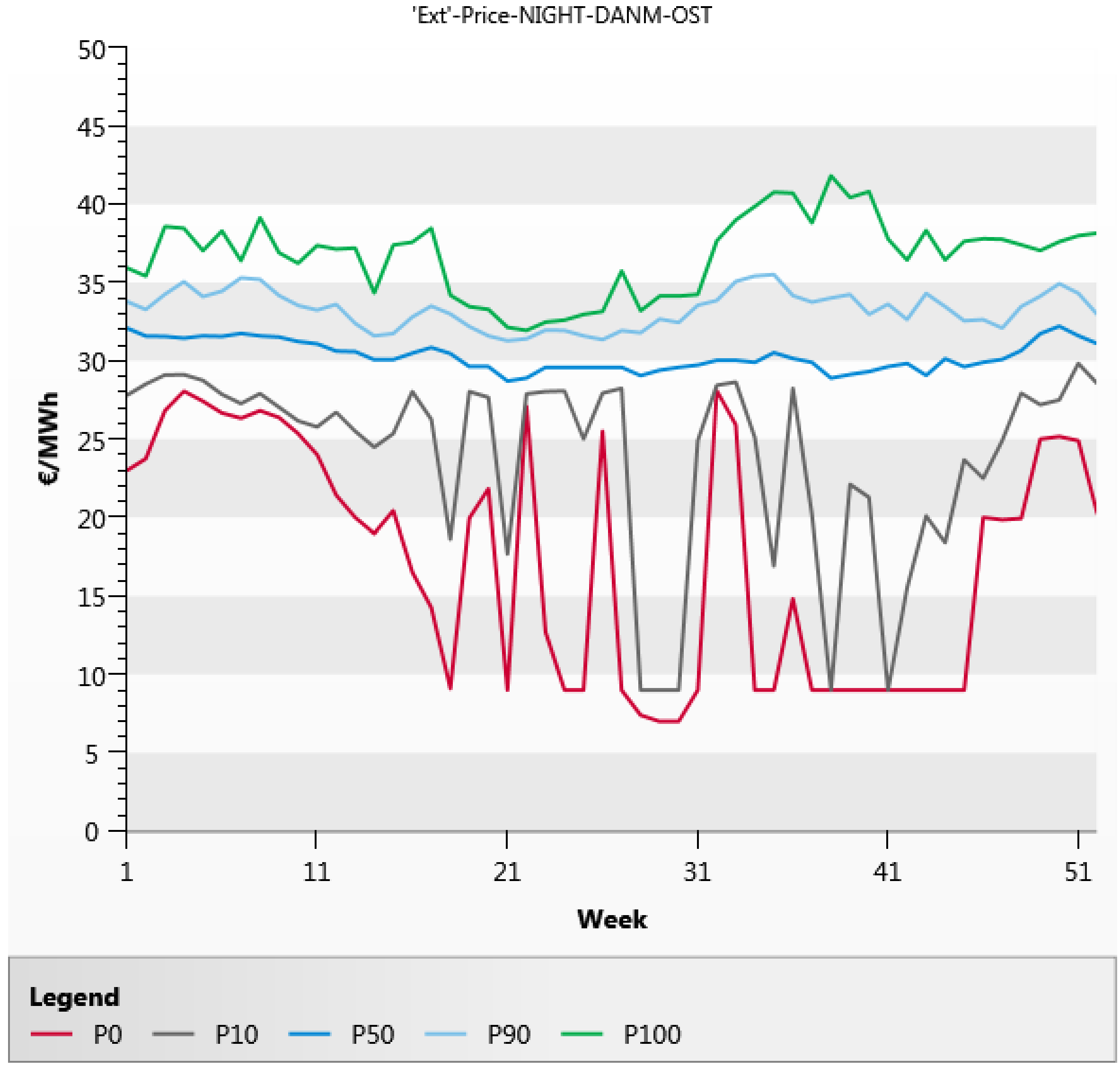


Figure 90: Night load block prices for *Ext* dataset

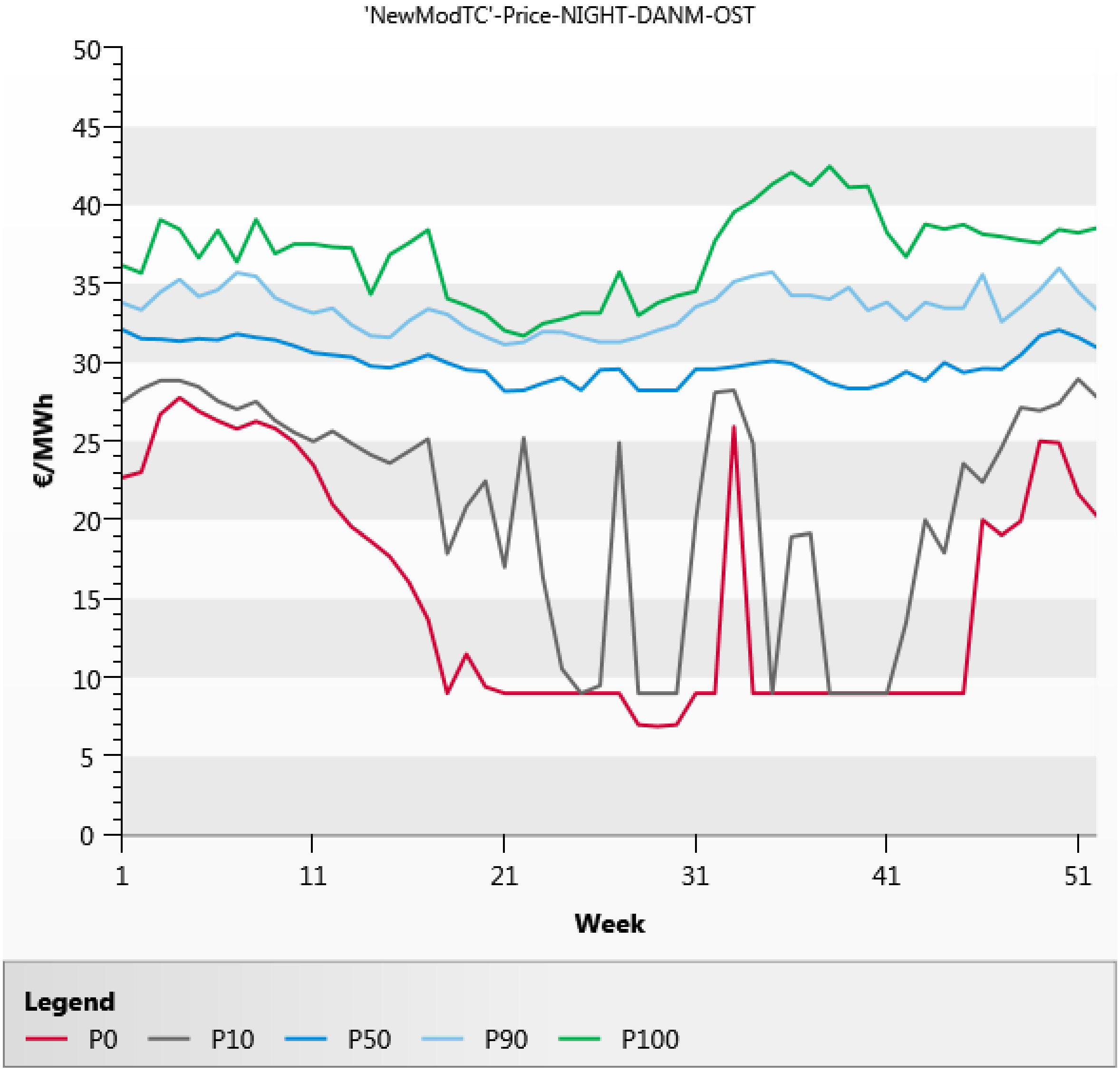


Figure 91: Night load block prices for *NewModTC* dataset

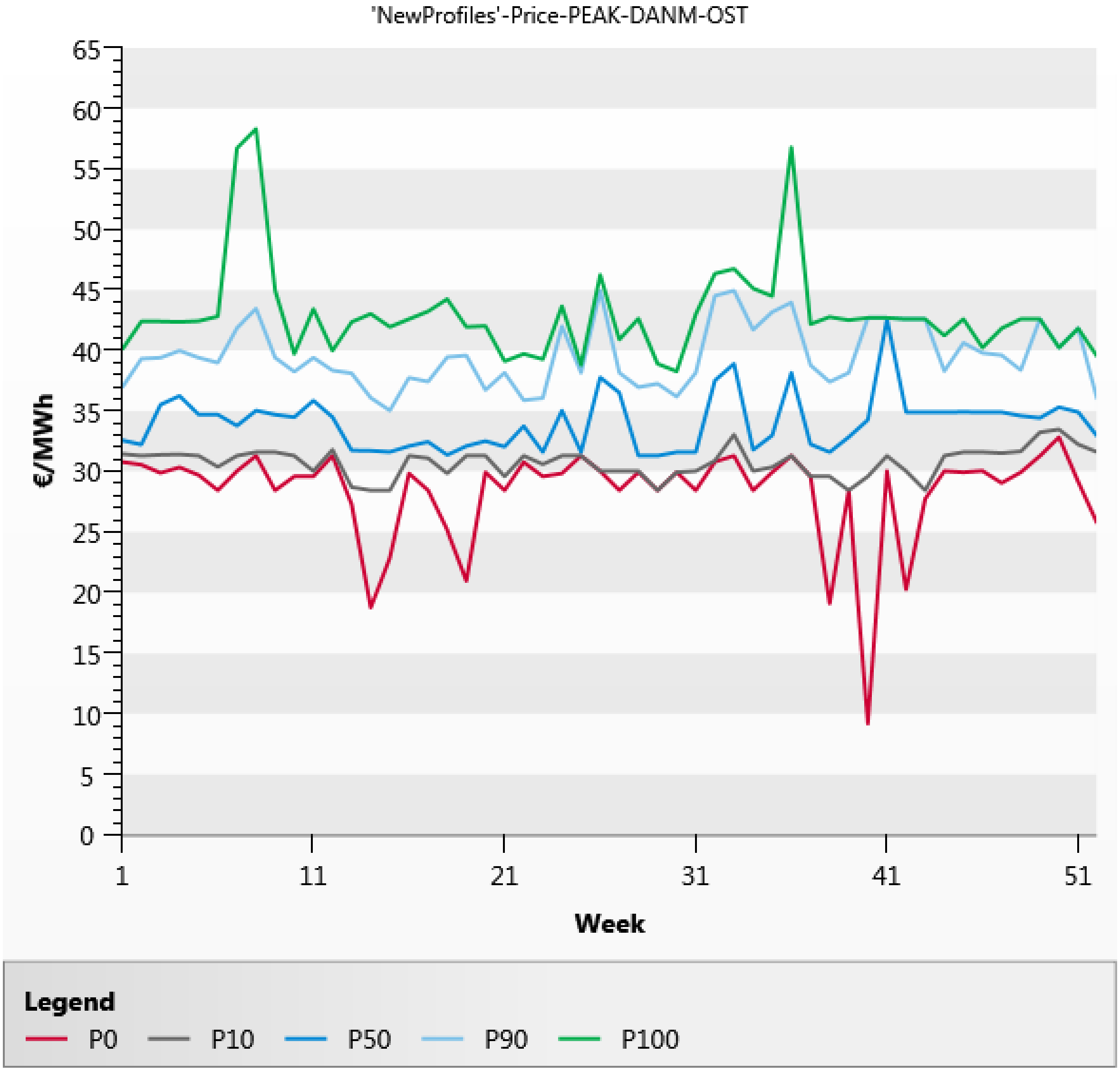


Figure 92: Peak load block prices for *NewProfiles* dataset

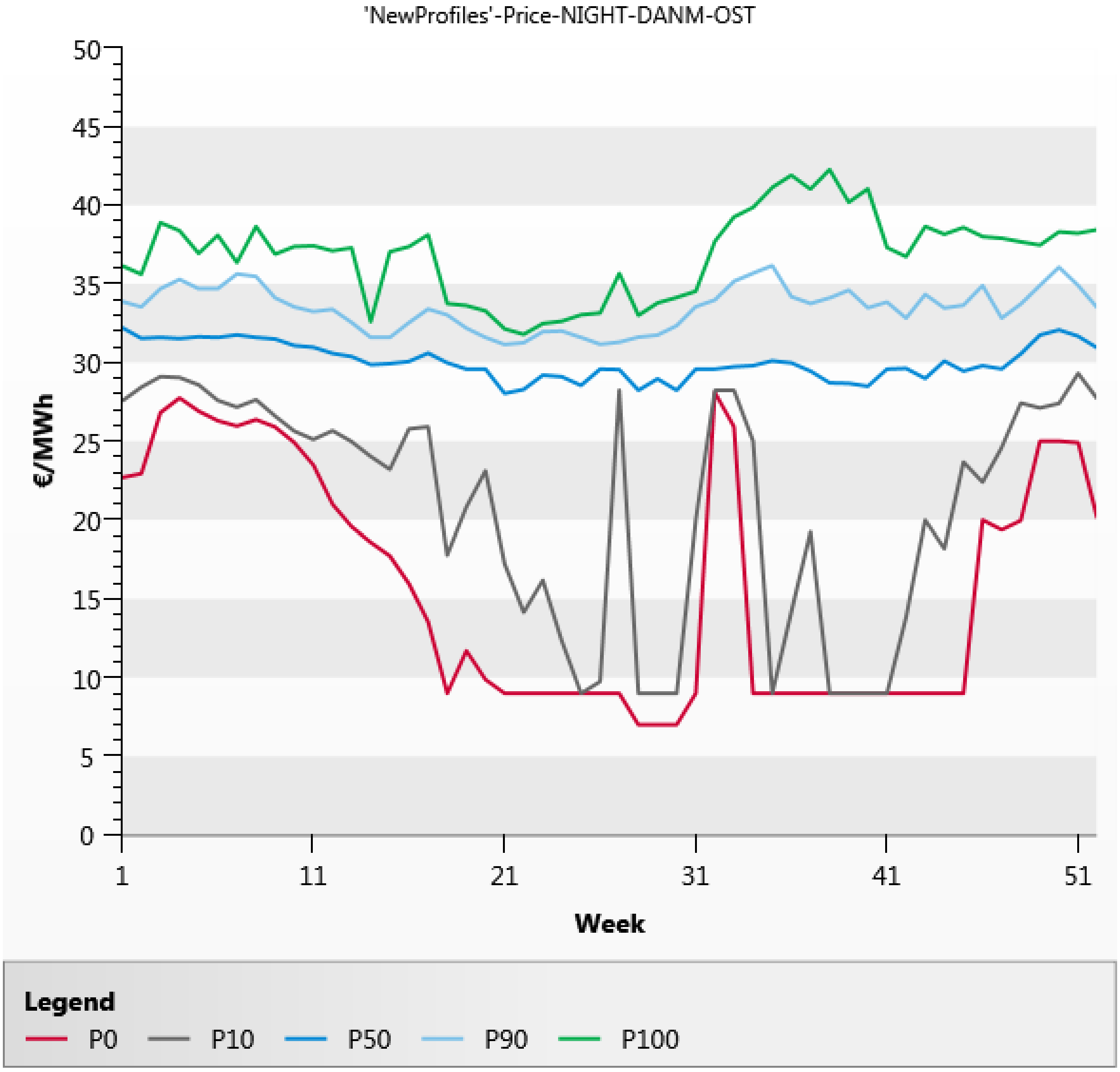


Figure 93: Night load block prices for *NewProfiles* dataset

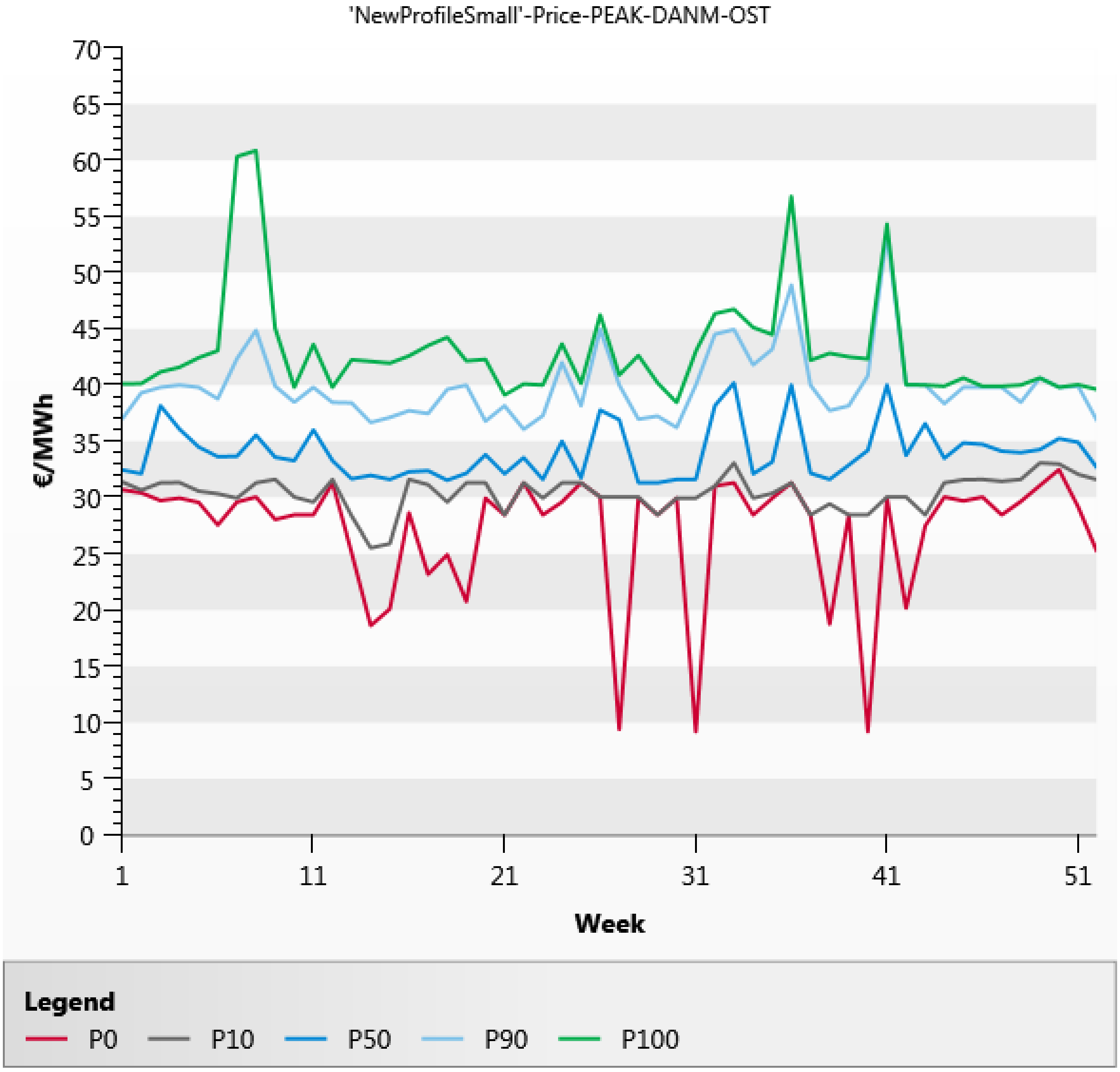


Figure 94: Peak load block prices for *NewProfileSmall* dataset

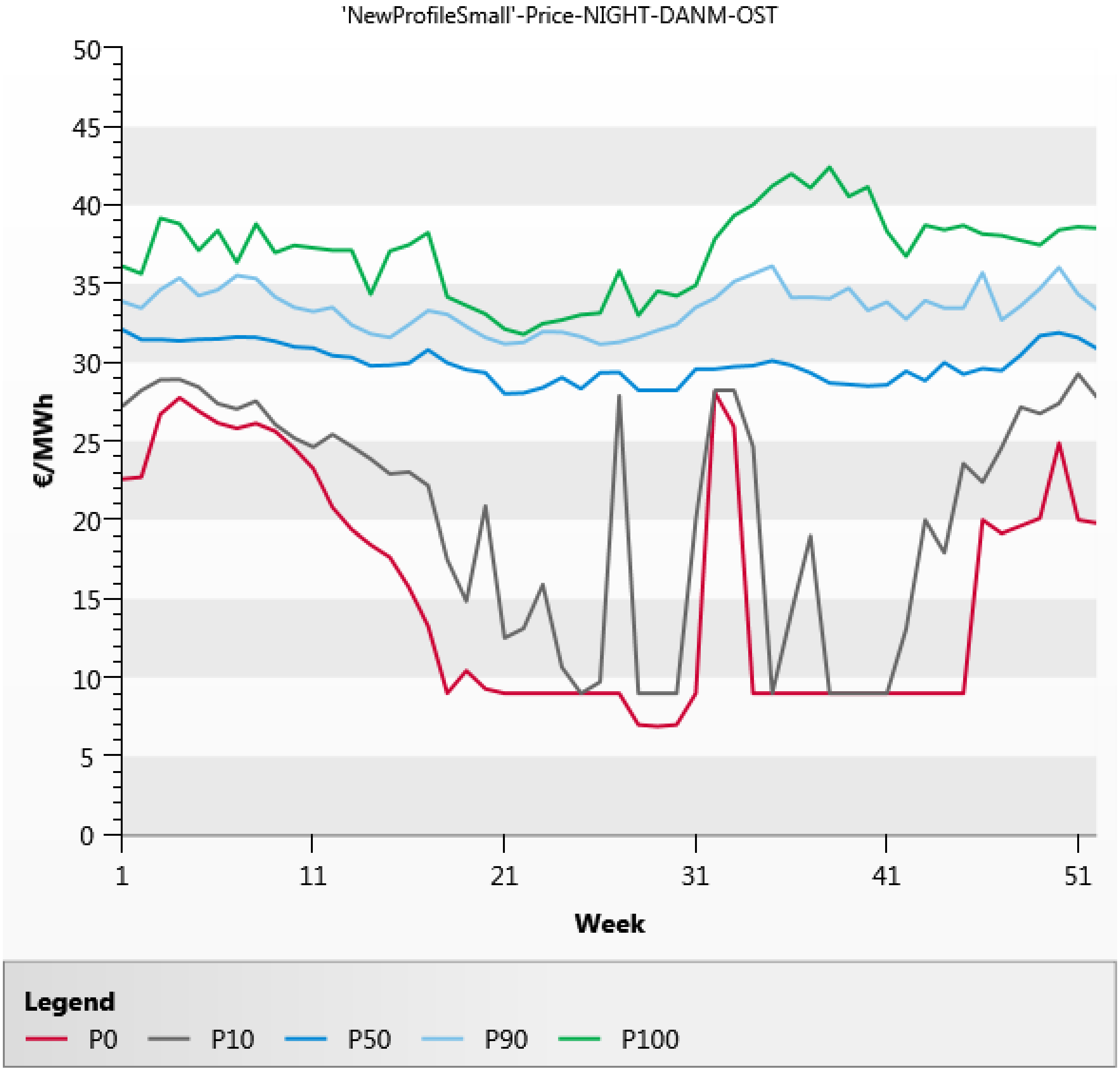


Figure 95: Night load block prices for *NewProfileSmall* dataset

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