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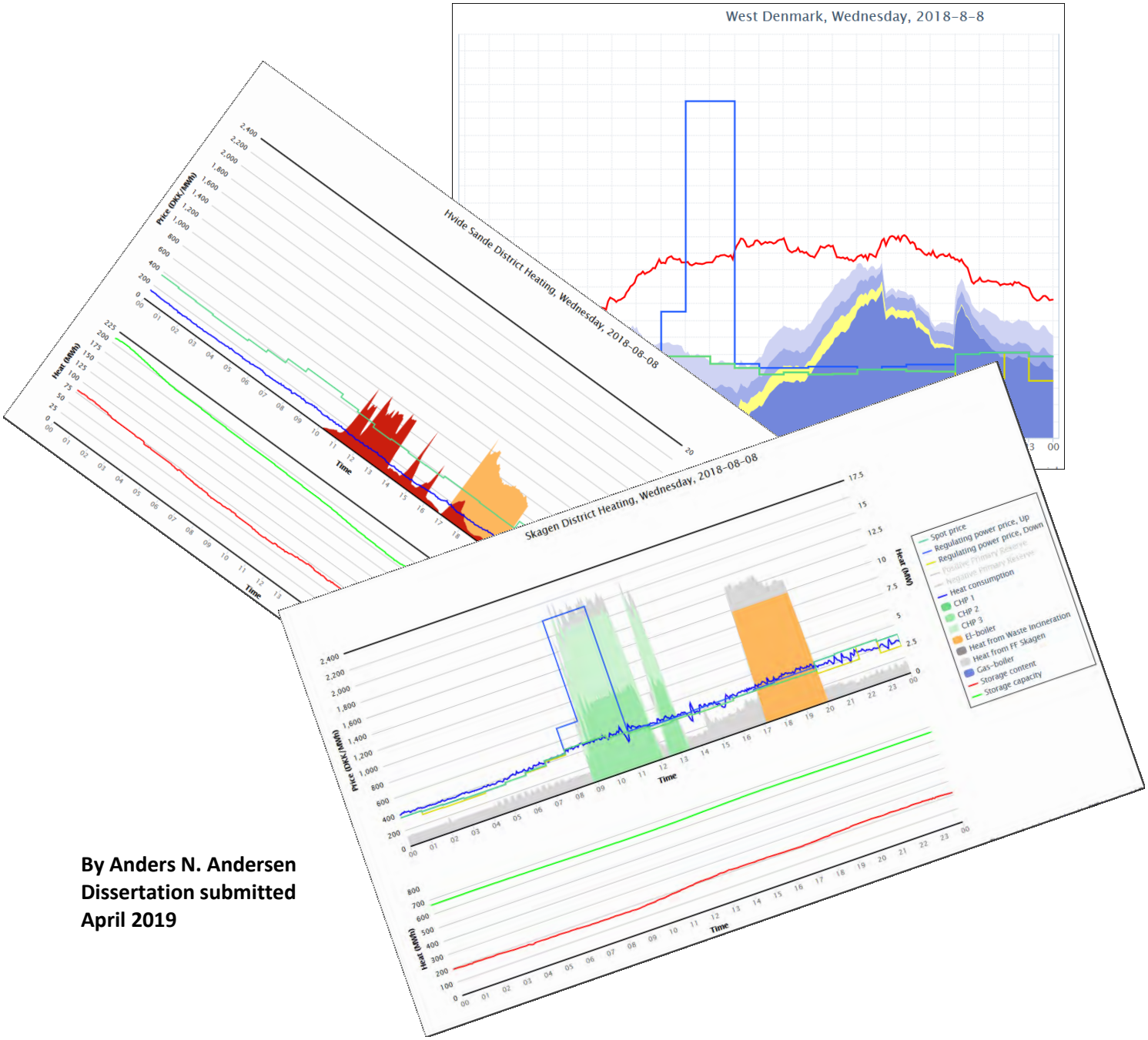
Development of next generation energy system simulation tools for district energy



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English summary

Energy systems in many countries are undergoing a transition from largely being based on few condensing mode central power plants, to among other being based on more geographically distributed productions at District Energy (DE) plants, where cogenerated electricity, heating and cooling creates efficient solutions for reducing greenhouse gas emissions and primary energy demand.
Furthermore, flexible DE plants have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with amongst others combined heat and power units and heat pumps producing both heating and cooling, and when equipped with large energy stores.
This integration of the DE plants with the rest of the energy system will often be based on biddings in electricity and fuel markets, being affected by availability of fluctuating energy sources, as well as being affected by complex subsidy schemes and energy taxes. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

The research made in this PhD study concerns the development of this next generation energy system simulation tools for designing and operating DE plants.

The starting point for this research has been if it possible to develop a generalized tool, which is able to analyse very different alternatives for DE plants providing heating and cooling, thus making it manageable by managers of DE plants and their consultants to compare radically different alternatives in one tool.

It is assumed that it will promote better alternatives for DE plants to be chosen, when carefully choosing sufficient detailing of each component of the energy system and avoiding needless detailing, which could compromise the ambition of comparing very different alternatives in the same tool.

The research has been delimited to those tools needed for the following tasks in DE plants:

- Investment analysis of alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation is determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

Thus, the focus in this PhD study is on heating, cooling and electricity demands in more buildings supplied from DE plants, typically equipped with energy stores, such as heating, cooling, fuel or electricity stores. The operation is often market-based and optimized across different energy types, of which each may be subject to restricted grid capacities between the DE plants and the buildings. The focus in the development is on optimizing the operation of the production units and the energy stores at the plants. However, optimization across plants, grids and buildings are dealt with in some detail.

The main research question is formulated as:
Is it possible to develop a tool which is able to analyse sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions have been formulated:

Sub question 1: *How can the optimization of market-based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

The thesis is divided into the following seven sections:

For establishing the research's novelty and general applicability, Section 1 presents a literature review, which is split into six subsections, each dealing with aspects of the sub questions. These aspects are the societal benefits of DE, the needed flexibility of DE plants, the changing roles of combined heat and power at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large TES, the needed support schemes promoting necessary flexibility at DE plants and the estimated yearly investment in production capacity at DE plants.
Based on this review, Section 1 states the scope and research questions for this thesis.

Section 2 describes the methodology used in this thesis and it is stressed how the methods developed in this thesis have benefitted from the methods met in several of the completed PhD courses.

Section 3 deals with Sub question 1 by comparing different unit commitment (UC) methods at DE plants. A complex generic DE plant case has been designed. Two significantly different UC methods are presented and applied to the case. The application shows that these two UC methods provide same optimizations of the market-based daily operations of such complex generic DE plants with large TES, hence offering more solutions how the optimization of market-based daily operation of DE plants with large TES can be solved in a sufficient detail and sufficiently fast.

Section 4 deals with Sub question 2 by presenting a method for analysing coordinated investments in production and storage capacity. It is demonstrated in this section that the presented method

returns reliable results, when dealing with the complex generic DE plant considered and when being based on one of the two UC methods described in Section 3.

Section 5 deals with Sub question 3 by presenting a method for comparing the effect of support schemes at DE plants. The methods are used to compare two support schemes, one of a Feed-in premium type and one of a Feed-in tariff type. The effect of these two support schemes are demonstrated on the complex generic DE plant, when using the method for analysing coordinated investments in production and storage capacity presented in Section 4. It is shown that the societal cost for providing a certain production capacity, measured as the support in the planning period, is around three time larger when using the presented Feed-in premium type as when using the Feed-in tariff type.

Section 6 presents DE plants, that differ significantly from the generic DE plants studied in this PhD study, therefore needs further to be researched in the future.

Finally, Section 7 concludes on the work done in this PhD study as an important step towards the development of next generation energy system simulation tools for district energy being able to analyse very different alternatives for DE plants providing heating and cooling.

Dansk Resumé

Forskningen i dette PhD studie vedrører udviklingen af næste generation af energisystemanalyse-værktøjer til design og daglig driftning af fjernvarmeværker.

Udgangspunktet for forskningen har været, om det er muligt at udvikle et generaliseret værktøj, der gør det overkommeligt for fjernvarmeværkerne og deres rådgivere at analysere og sammenligne meget forskellige alternativer til fjernvarmeværkerne. Det er antaget, at ved omhyggeligt at vælge en tilstrækkelig detaljeringsgrad af hver komponent i energisystemet og undgå unødvendige detaljer, vil man i det samme værktøj kunne sammenligne meget forskellige alternativer, dermed fremme at bedre alternativer til fjernvarmeværkerne vil blive valgt til at løse de opgaver værkerne har ved omstillingen af det samlede energisystem til vedvarende energi.

Forskningen er afgrænset til at omfatte et værktøj, der er nødvendig for følgende opgaver på værkerne:

- Investeringsanalyser af alternativer for komplekse fremtidige fjernvarmeværker, der opererer på komplekse energimarkeder underlagt komplekse støtteordninger og energiafgifter.
- Daglig planlægning af driften af disse værker, når denne drift bestemmes af bud på el- og brændstofmarkederne og påvirkes af fluktuerende produktion på f.eks. store solvarmeanlæg, samt når der skal tages højde for store energilagre og begrænsede kapaciteter i varme- og kølenet.

Formålet med forskningen er som nævnt at afdække, om det er muligt at udvikle et fælles generaliseret værktøj, der er i stand til at gennemføre ovenstående opgaver, men forskningen er afgrænset til at afdække følgende delspørgsmål:

- Hvordan kan man beregne en markedsoptimeret drift af et fleksibelt fjernvarmeværk, udstyret med stor produktions- og lagerkapacitet?
- Hvordan kan man analysere samtidig investering i produktions- og lagerkapacitet på fjernvarmeværkerne?
- Hvordan kan virkningerne af forskellige støtteordninger beregnes?

I denne afhandling er der også arbejdet med bl.a. de samfundsmæssige fordele ved fjernvarme, den nødvendige fleksibilitet af værkerne og den ændrede rolle af kraftvarme når der udbygges med vindkraft og solceller.

I afhandlingen er beskrevet og sammenlignet to væsentligt forskellige metoder til beregning af optimeret daglig drift. Der er beskrevet en metode til at analysere samtidig investering i produktions- og lagerkapacitet, samt beskrevet en metode til at sammenligne virkningen af væsentligt forskellige støtteordninger. Der er bl.a. vist et eksempel på at for at fremme den samme produktionskapacitet på værkerne skal den samlede støtte over en planperiode være rundt regnet tre gange større hvis man anvender et fast elproduktionstilskud tillagt spotprisen end hvis man anvender en treledstarif.

Afslutningsvist er diskuteret mere specielle fjernvarmeværker og diskuteret deltagelse på tværs af flere elmarkeder. Denne diskussion ender ud i en anbefaling om yderligere forskning i næste generation af energisystemanalyse værktøjer til design og daglig driftning af fjernvarmeværker, hvor også disse mere specielle tilfælde analyseres.

Acknowledgements

The work presented in this dissertation is part of the research activities of the Strategic Research Centre for 4th Generation District Heating (4DH), which has received funding from Innovation Fund Denmark, grant number 0603-00498B.

The work started a little more than three years ago when my supervisor, Professor Poul Alberg Østergaard, asked me why I did not commence a PhD study, researching my yearlong striving concerning the development of one generalized tool which - in the best company perspective of the societal Choice Awareness theory - should be able to analyse very different alternatives for District Energy plants providing heating and cooling. My answer was clear-cut: if he was willing to supervise me, I would be very happy to do so. Without his support and endless fighting for always making me think 360° at each problem and his ceaseless commitment to improving my Google English, this work would not have been possible.

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I would like to thank the lecturers of the PhD courses conducted as a part of my PhD study. Amongst others I would like to thank Professor Andres Ramos from Comillas Pontifical University in Spain for introducing me to using solvers for calculating optimal daily operation of energy systems (unit commitment), which has inspired me to use these in my research. Professor Moises Graells from Technical University of Catalonia and Associate Professor Eleonora Riva Sanseverino from University of Palermo introduced me to methods on how to formulate different energy system optimization problems in a broader perspective, which raised my interest to compare analytic and solver-based methods. Thanks to Associate Professor Thomas Arildsen from Aalborg University´s PhD Consult for assisting me in setting up the Mixed Integer Linear Problem in Gurobi Optimizer interfaced by Python. Thanks to Associate Professor Derso Sera and Associate Professor Tamas Kerekes from Aalborg University, who made me fully appreciate that Photo Voltaic is one thing when looked upon as a single component, but when being part of an energy system, e.g. when located within a wind farm that creates shadows from the wind turbine blades, is quite another thing. Furthermore, I would like to thank Dr. Daniel Stroe and Dr. Erik Schaltz, Aalborg University, who made me aware of the complexity of modelling electrical battery ageing, performance degradation and lifetime estimation of batteries.

Being responsible together with Poul Alberg Østergaard for the Energy System Analysis course offered by The Sustainable Energy Planning Research Group, Department of Planning, Aalborg University, I would like to thank the students on this course through the years for many fruitful discussions about my vision of having only one tool capable of analysing very different alternatives

for District Energy plants. Their abundance of examples was certainly a challenging inspiration to this vision.

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Finally, I would like to thank the Energy Group in the community Stærhøj, where I am living and where the 16 houses are connected with a neighbour district heating scheme, for fruitful bottom up discussion about sustainable very different heating solutions for this small-scale district energy system.

And finally, and not least, of course, thanks to my wife, Kamma Raunkjær, for accepting and supporting me during the many hours in the last three years I have spent developing this work. Without your support this thesis would not have been possible.

Contents

Annexes:

Papers appended:

List of appended papers

This dissertation is based on four journal papers and an article in an international magazine, which are included as appendices.

I. Andersen, Anders N.; Østergaard, Poul A. *A method for assessing support schemes promoting flexibility at district energy plants*. Accepted and published in Applied Energy September 2018, doi.org/10.1016/j.apenergy.2018.05.053

II. Andersen, Anders N.; Østergaard, Poul A. *Analytic versus solver-based calculated daily operations of district energy plants*. Accepted and published in Energy May 2019, https://doi.org/10.1016/j.energy.2019.03.096

III. Andersen, Anders N.; Østergaard, Poul A. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy*. Under review for second review round in Energy

IV. Østergaard, Poul A.; Andersen, Anders N. *Booster heat pumps and central heat pumps in district heating*. Accepted and published in Applied Energy December 2016, doi.org/10.1016/j.apenergy.2016.02.144

V. Andersen, Anders N.; Østergaard, Poul A. *New roles of CHPs in the transition to a Renewable Energy System.* Accepted and published in HOT/COOL - International Magazine on District Heating and Cooling, Vol. 1, 2017

Other relevant publications, which are not included in the appendices:

Østergaard, Poul A.; Andersen, Anders N. *Economic feasibility of booster heat pumps in heat pump-based district heating systems*. Energy July 2018, doi.org/10.1016/j.energy.2018.05.076

List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
CHP	Combined Heat and Power
DE	District Energy
DH	District Heating
ECU	Energy Conversion Unit
GAMS	General Algebraic Modelling System
HP	Heat Pump
MINLP	Mixed integer nonlinear programming
MPPT	Maximum power point tracker
NHPC	Net Heat Production Cost
NPC	Net Production Cost
NPV	Net Present Value
PL	Priority List
RES	Renewable Energy Sources
SBL	Start Block List
TES	Thermal Energy storage
UC	Unit Commitment
VBA	Visual Basic for Application

1. Introduction

Energy systems in many countries are undergoing a transition from largely being based on few condensing mode central power plants and on individual or communal boilers producing only heat, towards among other more geographically distributed productions at DE plants, where cogeneration of electricity, heating and cooling creates efficient solutions for reducing greenhouse gas emissions and primary energy demand.
Furthermore, flexible DE plants have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with CHPs, heat consuming absorption chillers and heat pumps producing both heating and cooling. This integration of the DE plants with the rest of the energy system will often be based on biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids. Adding to this complex subsidy schemes often are needed. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

For establishing the research's novelty and scope this section presents a literature review focusing on the societal benefits of DE, the needed flexibility of DE plants, the changing roles of CHP at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large energy stores, the needed support schemes promoting necessary flexibility at DE plants and the estimated yearly investment in production capacity at DE plants.

The novelty of the research in this PhD has also been dealt with in detail in the five papers that this synthesis is based upon. Parts of the text in this chapter is copied verbatim from these five papers, however, being synthesised and made coherent.

Based on this review, the specific objective of the thesis is established at the end of the section.

1.1 Societal benefits of District Energy

The development of modern (i.e., energy-efficient and climate-resilient) and affordable DE systems in cities is one of the least-cost and most-efficient solutions for reducing greenhouse gas emissions and primary energy demand [1]. A transition to such systems, combined with energy efficiency measures, could contribute as much as 58% of the carbon dioxide (CO_2) emission reductions required in the energy sector by 2050 to keep global temperature rise within 2–3 degrees Celsius [1].

Another important reason for this development of DE systems, is that an increasing number of people live in urban areas, with 55 % of the world's population residing in urban areas in 2018. In 1950, 30 % of the world's population was urban, and by 2050, 68 % of the world's population is projected to be urban. Today 74% of the European population live in urban areas [2]. Especially in cities with high heat densities it becomes feasible to establish DE plants providing heating and cooling to more buildings [3]. The reason is amongst others that it promotes the exploitation of waste heat from power plants and industry [4]; that a significant economy of scale-effect in solar collectors makes communal systems much cheaper to build compared to solar collectors at each building [5]; that heat pumps (HP) get access to a broader range of heat sources, e.g. heat from

sewage systems [6] and that for many cities it will be possible to exploit geothermal energy [7]. Similarly, more cooling sources become available, e.g. free cooling from lakes, rivers or seas [8].

Furthermore, flexible DE plants providing heating and cooling to cities have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with CHPs, heat consuming absorption chillers, HPs producing both heating and cooling and large Thermal Energy Storage (TES).

The EU has set a long-term goal of reducing greenhouse gas emissions by 80-95% by 2050, when compared to 1990 levels. The EU Energy Roadmap 2050 explores the transition of the energy system in ways that would be compatible with this greenhouse gas reduction target [9]. The conclusions of Energy Roadmap 2050 are that decarbonising the energy system is technically and economically feasible in the long run, that all scenarios that achieve the emissions reduction target are cheaper than the continuation of current policies and that increasing the share of renewable energy and using energy more efficiently is crucial, irrespective of the particular energy mix chosen.

In the European Union (EU) heating and cooling represent around half of the final energy consumption. It is a bigger end-use sector than transport and electricity, and today only 15% is covered by Renewable Energy Sources (RES) [10]. Energy Roadmap 2050 has not detailed how to cover heating and cooling demands, but only proposed electrification of the heating sector (primarily using HPs) and implementation of electricity and heat savings. However, this detailing has been made in the research project Heat Roadmap Europe [11] which concludes that a 30-40% reduction of the existing heat demand in Europe is socio-economic feasible, and approximately 50% of the remainder should be covered by DE. The results of this research project indicate that with this large-scale implementation of DE, compared to not implementing DE, the EU energy system will be able to achieve the same reductions in primary energy supply and carbon dioxide emissions at a lower cost, with heating and cooling costs reduced by approximately 15%, which is a €100 billion per year [10], down from €675 to €575 billion per year.

More factors contribute to societal benefits of DE compared to individual supply in each building of heating and cooling. Improved insulation standards reduces heat to be delivered to the buildings, thus influencing the expansion of DH grids. Möller & Nielsen [12] established a so-called *heat atlas* to investigate heat demands in Denmark to be able to assess the potential for DH expansion. Sperling & Möller [13] found that *"end-use energy savings and district heating expansion combined in the existing energy system improve the overall fuel efficiency of the system".* Furthermore, Østergaard [14] points at the systems effects of realising heat savings in DH areas as it impacts the operation of CHP plants providing ancillary services – and reduces their ability to integrate RES-based electricity production. Likewise, Thellufsen & Lund [15] stress the need for assessing the benefits of savings on an energy systems level.

Lund et al. [16] conclude that *"A suitable least-cost heating strategy seems to be to invest in an approximately 50% decrease in net heat demands in new buildings and buildings that are being renovated anyway, while the implementation of heat savings in buildings that are not being renovated hardly pays"*. This calls for tools to be able to divide heat demands connected to DE plants

in different types depending on the age of buildings in the different areas. Mosgaard & Maneschi [17], however, stress the complexity of energy renovations and the circumstance that even economically favourable energy savings are not always carried out. All in all, this calls for integrated studies of optimal heating solutions – individual or DH combined with savings – in future high-RES energy systems, as performed in e.g. [11].

An important factor when estimating the societal benefits of DE concerns CHP. Fossil-based CHP has no long-term future in an energy system switching to RES, thus DH will need to rely on other heat sources. Low electricity prices and high natural gas prices lower the profitability of CHP units to the extent that some swap to heat only boilers. This may push the balance between DH and individual heating solutions including individual HPs. Also, progressively more energy-efficient houses and a steadily improving HP performance for individual dwellings are straining the societal advantage of DE plants as grid losses are growing in relative terms due to decreasing heating demands of buildings.

1.2 Needed flexibility and efficiency of DE plants

The determination of needed flexibility and efficiency of DE plants takes its starting point in the complexity that may be envisaged at DE plants.

The DE plants may e.g. include combinations of the following Energy Conversion Units (ECUs):

- CHP being operated in both extraction and condensing mode
    - Heat pumps, even producing both heat and cooling
    - Tri-generation plants with absorption cooling units, where electricity, heat and cooling are coproduced
    - Biogas plants, where the fuels are restricted
    - Biomass plants, where the start-up time of CHP-production is significant
    - Wind farm and Photo Voltaic connected in a private wire to the DE plant
    - Solar thermal
    - Fuel factories, where waste heat from the plant may cover heat demand
    - Heat-only boilers

The DE plant may include a large range of energy types, e.g.:

- Electricity
- Steam
- Process heat
- Hot water
- Cold water
- Natural gas
- Wood chips
- Gasified biomass
- Hydrogen
- Biogas
- Coal

Furthermore, dump of energy for each energy type may be included e.g.:

- Cooling towers
- Flaring of biogas

The ECUs at the DE plant may be situated at more sites. Similarly, the heating and cooling demands supplied by the DE plant may be situated at more sites. The transmission between sites of the different energy types may be restricted, and there may be stores of each energy type in each site.

Research in needed flexibility of DE plants is extensive. Mathiesen & Lund [18] conclude that *"Large-scale heat pumps prove to be especially promising as they efficiently reduce the production of excess electricity".* Connolly & Mathiesen [19] propose that after the introduction of DH the introduction of small and large-scale heat pumps is the second stage in a transition to Renewable Energy (RE) supply. Østergaard [20] finds that compression HPs can play a role in the integration of wind power as they limit boiler-based DH production as well as electricity excess – though at the same time also tend to increase condensing-mode power generation. The same author investigates different optimisation criteria for assessing the optimal introduction of HPs in DH, finding that *"different optimisation criteria render different optimal designs"* [21]. The above-mentioned research have mainly focused on the macro-scale, and often based on simplified analyses using fixed COP values and without detailed analyses of temporal variations in losses or demand-specific losses in the DH system, which is expected to be important features to be handled in a future generation of energy system analysis tools.

In general, in the future, a shift towards further electrification of the energy systems may be foreseen [22], often being based on HPs. This stress the importance of temperature levels in the energy system. A main driver for forward temperature in DH is the requirements for domestic hot water (DHW) production. This raises the question if electrification is optimally made with central solutions at DE plants, with individual solutions at each building or with a combination of central and individual solutions. Østergaard and Andersen [23] have investigated two alternatives for DHW supply: a) DH based on central HPs combined with a heat exchanger, and b) a combination of DH based on central HPs and small booster HPs using DH water as low-temperature source for DHW production. The results indicate that applying booster HPs enables the DH system to operate at substantially lower temperature levels, improving the COP of the central HP while simultaneously lowering DH grid losses significantly. Thus, DH performance is increased significantly.

Specifically on booster HPs providing DHW, Köfinger et al. [24] found that *"Booster for DHW preparation are possible solutions if the grid temperature is too low or DHW needs to be stored e.g. in larger buildings like Hotels"* and Zvingilaite et al. [25] analysed low-temperature DH systems in combination with small booster HPs with the purpose of supplying DHW in DH systems with forward DH temperatures below the required DHW temperature. In one typology, DH water was split in two streams; one passing the condenser and one passing the evaporator of a booster HP, thus creating 53°C hot water from 40°C DH water; sufficient to produce DHW at 45°C with a reasonable heat exchanger temperature difference. Similarly, Ommen et al. [26] present analyses of booster HPs in the actual DH system of Copenhagen, Denmark, with operation being optimised against hourly Day-ahead market prices. The work however is primarily based on CHP and how lowering DH forward

temperatures benefit the operation of CHP units using temperature performance curves. The authors *"recommend the use of 65-70°C as the optimal forward temperature for DH networks, since lower temperatures require high investment, among others DH booster HP units in each dwelling".* Likewise, Elmegaard et al. [27] investigate low-temperature DH systems combined with booster units. These analyses are also based on the combination of CHP and DH and are furthermore based on yearly average consumption rates and not a high temporal resolution. The authors find that *"Conventional systems with higher temperatures in the network have a better utilization than low temperature solutions, as the decrease in heat loss does not compensate the electricity demand to cover the energy consumption."*

Lund et al. [28] have demonstrated that, in general, low temperature is preferable due to lower DH grid losses, thus noticing that DH development has seen a decline in temperatures over the past century. In addition, they state that when turning to HPs, lowering DH forward temperatures improves the COP of HPs producing DH, thus the DH development towards lower temperature levels facilitates a switch to HPs.

1.3 The changing roles of CHP at DE plants when developing renewable energy

Next generation energy system tools for simulating DE plants must as a minimum be able to simulate the changing roles of CHP at DE plants when developing renewable energy. This is in this section exemplified by a description of the changing roles that have been observed at distributed CHP plants in Denmark. The Danish Energy Agency has illustrated how the development of CHP changed the Danish energy system – see Figure 1. From a few power plants in the beginning of the 1980s to thousands of power producing units today where, besides the central power plants, 285 distributed DE plants, 380 industrial and private plants are equipped with CHP. Added to this more than 5000 on-shore wind turbines and more than 500 off-shore wind turbines are in operation [29].

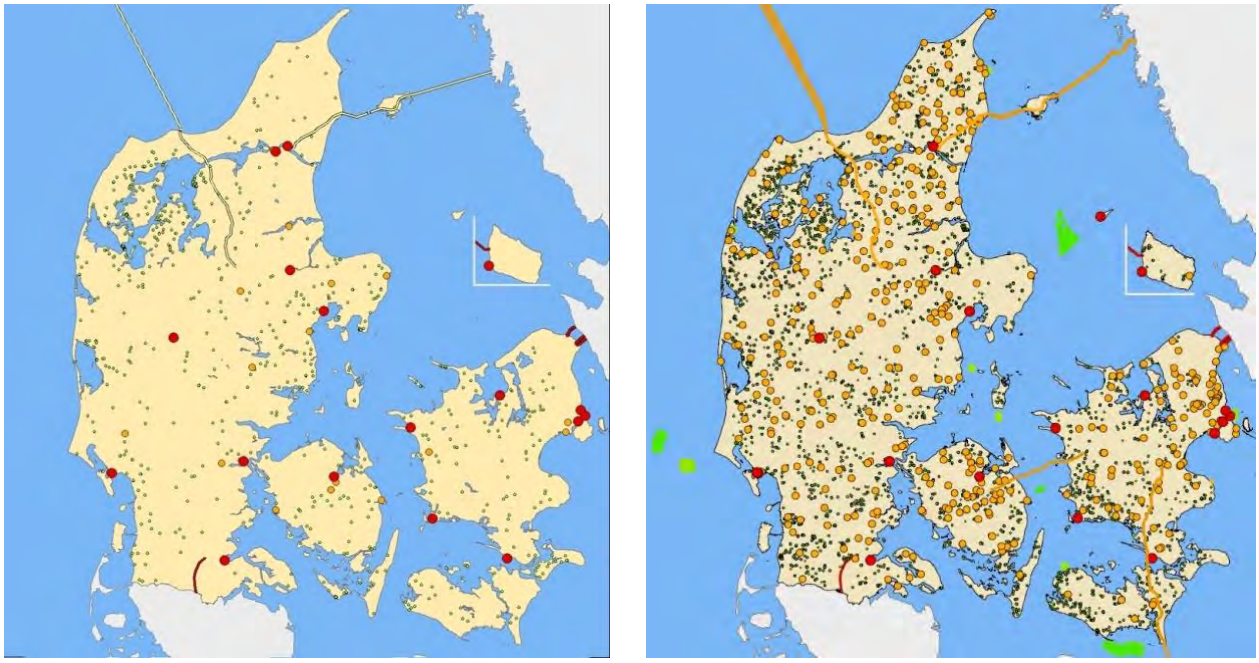

Figure 1: The electrical infrastructure in Denmark in 1985 (left) and 2013 (right). Red circles indicate central power plants, yellow circles DE CHPs and secondary producers above 500 kW. The green dots show wind turbines and green off-shore areas show off-shore wind farms [30]**.**

1.3.1 Phase 1: CHP displaces fossil fuelled power plants

In the first phase with an energy system largely based on condensing mode power generation and individual or communal boiler production of heat, the CHPs' task in Denmark was to displace the fossil fuelled condensing mode power plants as well as to displace production on individual and communal boilers – restricted of course by the heat demand that was served by CHP. With condensing mode power generation having efficiencies around 40% and CHP plants having a total efficiency of 90%, the CHP and DE combination offers clear advantages from an energy efficiency point of view, as each 1 MWh_e displaced on a condensing mode power plant saves 1 MWh_{fuel}. This efficiency potential is also in focus
on e.g. a European level [11,31].

The development of the electrical capacity in Denmark is shown in Figure 2. The development of Distributed CHP started in 1985 and was substantially finished around 2000, and the support for this development was based on a production time-dependent triple tariff providing incentives to produce during peak load hours. The paid price for electricity was high in the morning and late afternoon, low in night hours and weekend and in between in the other hours.

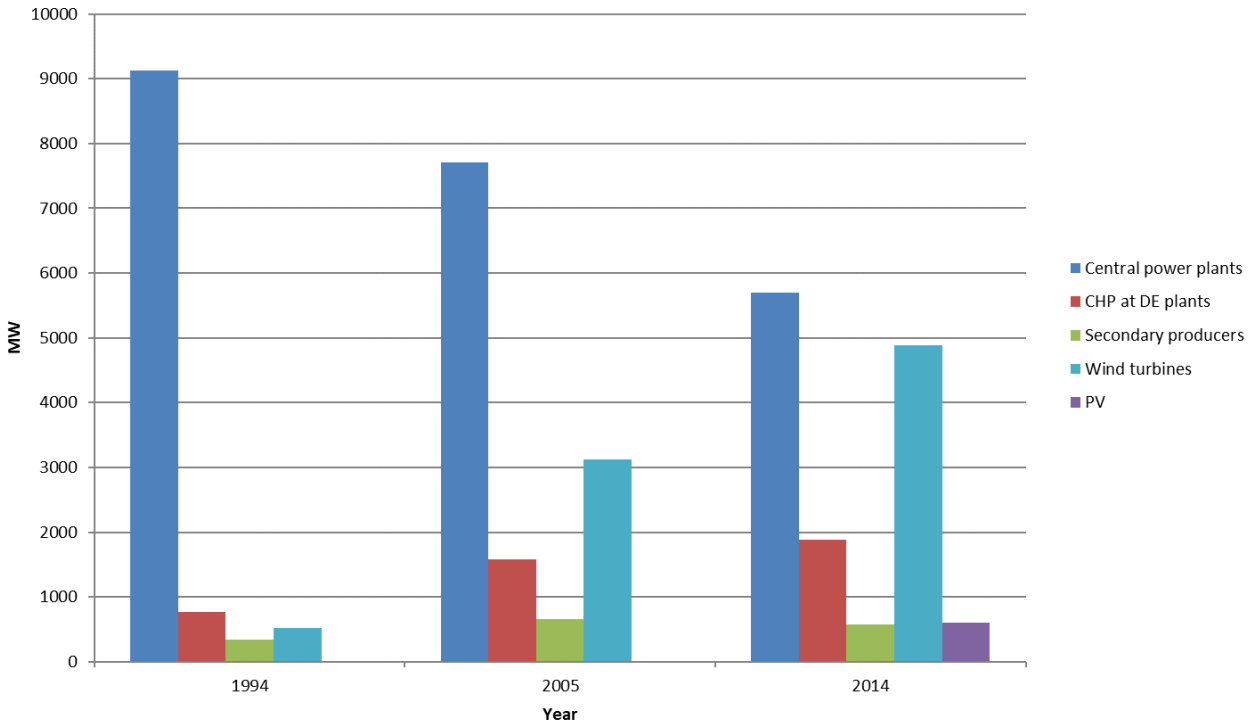

Figure 2: Electricity production capacity in Denmark in the last 20 years, according to data from [32]*. The central power plants are situated at 16 sites. The DE CHP is situated at DH companies. The secondary producers are industrial producers and waste incineration plants.*

The steepest increase in distributed CHP-capacity happened in the years from 1992 to 1997. Wind power experienced an even higher increase as also shown in Figure 2. During the same period of time, the installed capacity on central power plants decreased by more than one third in spite of a gradual increase in domestic electricity demand from 1990 to 2014 of 8.6 percent [32]. Thus, Danish power production has been effectively shifted to a more geographically distributed production. This required a whole new way of dispatching electricity production, from mainly a centrally dispatched electricity production in the 1980s to a distributed electricity production more based on many balancing responsible parties today.

1.3.2 Phase 2: CHP participates in the integration of fluctuating RES

The development of wind power in Denmark took place in parallel to the development of distributed CHP-plants, and after year 2000 it began to happen that wind turbines had to be stopped - amplified by the situation that CHPs at distributed DE plants continued to produce. The Danish Parliament thus decided that the triple tariff paid for CHP production at distributed DE plants, was to be phased out from 2005 to 2015 [33]. This meant that from 2005 many of the CHPs were market-operated and most of these were traded in the Scandinavian day-ahead market.

In Figure 3 is shown a simulation made in the energy system analysis tool energyPRO [34] of a market based operation of a DE CHP-plant in two weeks in the autumn of 2015. The simulation shows that

the two CHP units are only operated in hours with sufficiently high Day-ahead prices. In this way the CHPs participate in the integration of wind and PV production, as it will seldom happen that wind turbines have to be curtailed in hours with high spot prices, since the bidding prices in day-ahead market of the wind turbines are close to zero.

The size of the thermal store shown in Figure 3 is so large that it is possible for the two CHP units to operate in all hours with sufficiently high Day-ahead prices from Monday 28th of September to Friday 2nd of October.

Figure 3: Simulated operation against the Scandinavian day-ahead market in two weeks in the autumn of 2015 of a CHP-plant equipped with large electrical capacity and large thermal store. The simulation is made in the energy systems analysis tool energyPRO [34].

The fact that they stopped receiving the triple tariff and instead started receiving market prices created a financial problem for distributed DE plants. In most months market prices were lower than the triple tariff. The distributed DE plants had invested in CHPs with large electrical capacity and large TES, with the expectation that the triple tariff would be paid. To secure the investments that distributed DE plants had already made, the Danish Parliament made an electrical capacity market for each single distributed DE plant that already had invested in CHP units [33]. This capacity market is made so that in each month each distributed DE plant receives a production-independent payment equal to the difference between what this plant could have earned on the triple tariff and what it can earn in the Scandinavian day-ahead market.

Even if this capacity payment is different for each distributed DE plant, it was made easier to administer by calculating for a selected year before 2005, what this DE plant had earned in the triple

tariff and what it would have earned that year, if it had instead been paid the hourly prices in the Scandinavian day-ahead market. This "loss" is converted to a factor times a piecewise linear function. The factor is unique for each distributed DE plant but the index function (see Figure 4) is identical for all distributed DE plants and dependent on the monthly average price in the day-ahead market (spot price).

As Figure 4 shows, in month with a monthly average price in the Day-ahead market above 56 EUR/MWh$_e$ the DE plant receives no capacity payment, which is to say that with high day-ahead prices in a month, this DE plant would not have earned more on the triple tariff. At the other end of the register, at a monthly average spot market price less than 18 EUR/MWh$_e$, capacity payments are maximised.

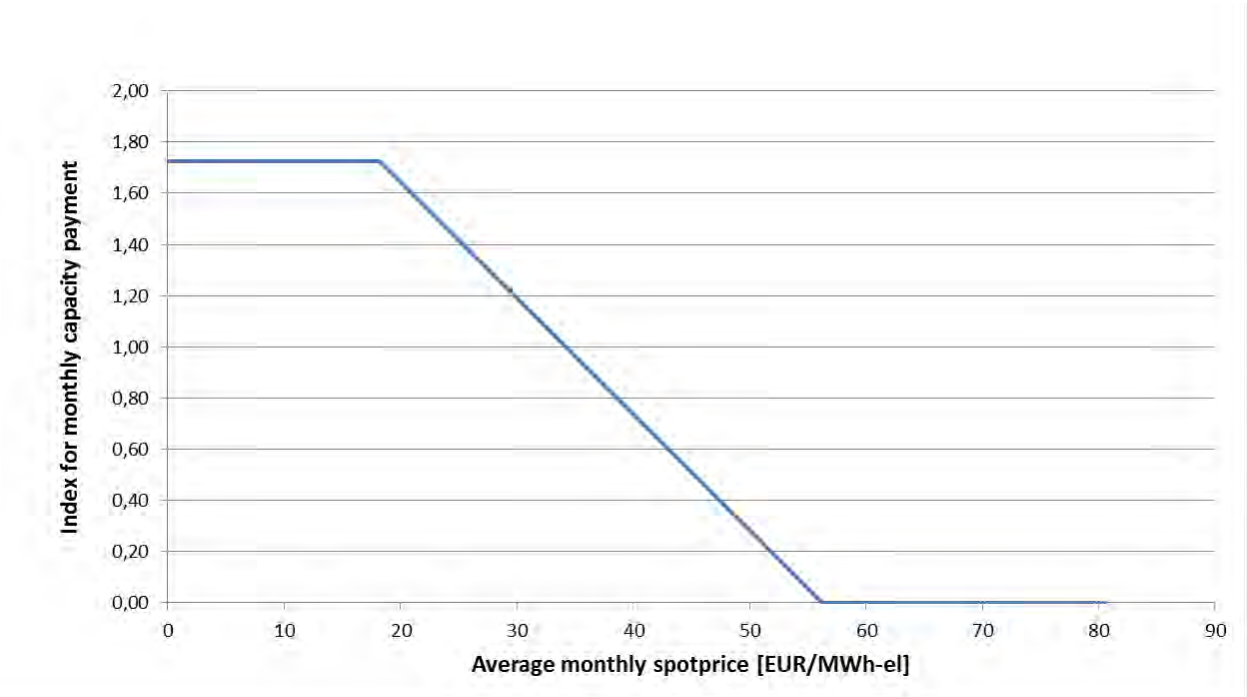

Figure 4: Index function to be used for calculating monthly capacity payment to DE plants.

1.3.3 Phase 3: CHP primarily delivers needed electrical capacity in few hours

In Figure 5 is shown the yearly electricity productions at distributed DE plants in Denmark. In 2014 CHPs at distributed DE plants produced only 6% of the Danish consumption [32], down to the same amount as the secondary producers, even if the secondary producers were only equipped with one third of the electrical capacity of the CHPs at distributed DE plants, as seen in Figure 2. The central power plants produced 39%, half of it being in condensing mode and half of it being in extraction mode with heat delivered to the big cities. Wind power produced 39% of the Danish consumption and 8% was imported. It is thus to be noticed that the decrease in CHP at distributed DE plants happens even if there are still central power plants producing in condensing mode, which seems in contradiction to Phase 1 operation, where the CHPs' task is to displace fossil fuelled condensing mode power plants by producing as much electricity as the heat demand allows.

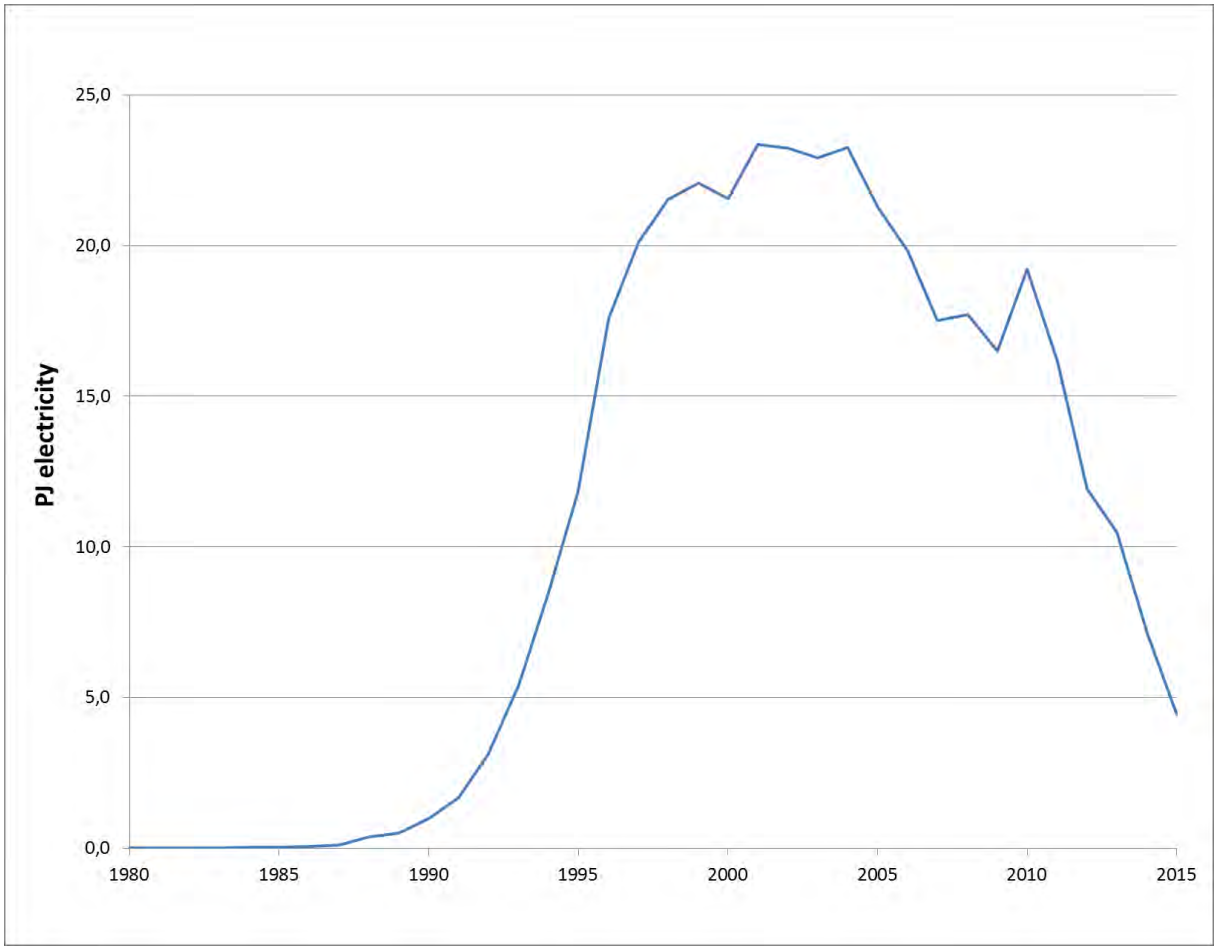

Figure 5: Yearly electricity productions at CHP at distributed DE plants, according to data from [32]*. Year 2015 has been derived from hourly data from the Danish TSO* [35]*.*

That there is a Phase 3 where CHP primarily delivers needed electrical capacity only in few hours, relates closely to the fact that the continued development of wind power and PV may reduce prices in the Scandinavian day-ahead market making CHP operation progressively less feasible. In a 100% renewable energy system, however there will still be hours where the fluctuating productions from RES are not able to cover inflexible electricity demands. So, an electrical capacity beside the capacity in wind turbines and PV is needed. This obvious consequence of developing wind power is also described in the Danish Transmission System Operator´s plans for 100% renewable energy in Denmark, which states that today's cogenerated 90 PJ of heat will in 2035 have gone down to 40 PJ and in 2050 have gone down to 5 PJ [36]. As shown in Figure 5, yearly electricity production at DE CHP has dropped dramatically in the last years, so the few hours of operation of CHPs at distributed DE plants make it difficult for these to survive, and if a new capacity payment is not decided, it is expected that the distributed CHP capacity will be reduced [37].

1.4 Needed optimization of daily operation of DE plants with large TES

Traditionally, the main task of the DE plants is to provide heating and cooling to cities. However, equipped with a combination of CHPs, HPs and TES, these flexible DE plants may furthermore have

an important role in integrating intermittent power production [38]. The very different tasks of DE plants in the transition to a RES-based system call for these to be equipped with both large production and TES capacity [39]. A large CHP capacity is needed to supplement intermittent RES production at times of low RES production. Likewise, a large HP capacity is needed in the integration of intermittent RES production by primarily consuming electricity and producing heat during periods with high intermittent RES production - often with low prices during these periods [40]. The needed large TES capacity is closely related to the large CHP and HP capacity enabling these to detach productions from momentary thermal demands [39].

The operation of DE plants will often be market-based to efficiently participate in the integration of the intermittent RES production. This calls for the operators of these plants to determine and dispatch a daily operation schedule of the production units, that is to say that they must decide when to start and stop each production unit and decide at which load, they should be operated. This is denoted Unit Commitment (UC), and UC methods are different approaches to determining this operation.

In this thesis the UC methods are proposed divided into two significantly different groups; the analytic UC methods and the solver-based UC methods, even if some UC methods may have properties that places them in-between or outside these two main groups.

The solver-based UC methods are based on the minimization of an objective function – typically for DE plants the Net Production Cost (NPC) in an optimizing period of, say, 7 days. The NPC is the cost of covering heating and cooling demands factoring in a possible sale of electricity in these days. The minimization is subject to constraints, e.g. that there is no overflow in the TES, and is made by randomly choosing a UC for which the NPC is calculated. Then this UC will be iterated towards improved NPC while meeting constraints.

The analytic UC methods typically dispatch the daily operation according to priorities calculated for each time step and for each production unit in the optimizing period.
Thus, the first step to determine these priorities could be to calculate what the NPC of each production unit is in each time step, e.g. showing that CHPs produce cheaper heat in hours with high Day-ahead prices and HPs produce cheaper heat in hours with low Day-ahead prices.
Based on these calculated priorities typically organized in a priority list, an analytic UC method makes a UC for the optimizing period fulfilling the constraints, and subsequently calculates the NPC of the whole optimizing period this UC leads to.

In many cases a solver-based UC method is able to give a precise estimation of how close the found NPC is to an optimal NPC. However, as a starting point an analytical UC method does not reveal this. Zheng et al. [41] pointed out that there has been a revolution in the energy system UC research with the mixed integer programming (MIP), standing out from the early solution and modelling approaches, amongst others priority list methods, which in this report is considered one of the analytic methods. Zheng et al. [42] reviewed 30 papers, showing the large effort over the last decades in developing efficient methods capable of solving the energy system UC problem in real cases or at least for obtaining good solutions in reasonable computational times. Abujarad et al. [43] pointed out that the complexities in balancing electrical loads with generation have introduced new

challenges in regards to UC. They conclude that the significance of the UC priority list methods relies on committing generation units based on the order of increasing operating cost, such that the least cost units are first selected until the load is satisfied and they conclude that the methods converge very fast but is usually far from the optimal UC. The authors further stress that the advantage of employing Mixed Integer Linear Programming (MILP) to solve the UC problem is that the MILP solver returns a feasible solution and the optimality level is known. The disadvantage of this method is that it often takes a long time to run and the calculation time grows exponentially with increasing problem size.

In recent years research has been somewhat but not entirely focused on balancing electrical loads using solver UC methods. For instance, Senjyu et al. [44] developed a new UC method, adapting an extended priority list, consisting of two steps. During the first step the new method rapidly obtains a UC solution disregarding operational constraints. During the second step the UC solution is modified using problem-specific heuristics to fulfil operational constraints. The method, however was for electricity systems only.

In some cases, research has also included the balancing of heating demands. Ommen et al. [45] presented an energy system dispatch model for both electricity and heat production of Eastern Denmark. They examined a system where HPs contribute significantly in balancing both electricity and heat production with their individual demands. Also, Mohsen et al. [46] proposed an optimal scheduling of CHP units of a distribution network with both electric and heat storage systems.

The above-mentioned UC research concentrated mainly on system-based balancing of electrical loads made by steam-based generators where ramping effects and maintaining system reliability are significant constraints when finding the least production cost. They are therefore concluding that analytic methods like the UC priority list methods are not useful. This conclusion could be true when optimizing the energy system across all actors in the energy system.

However, by introducing market-based operation of the energy system, the actors are divided into numerous companies that optimize their UC by optimizing their own biddings on the electricity markets. Market-based operation means here the DE plants perform UC according to changing electricity prices – as opposed to e.g. performing UC according to non-market prices like fixed feed-in-tariffs or according to heat demand. In the Nordic day-ahead market, for instance, market-based operation means that each DE plant at 12 o'clock each day has to bid into the Day-ahead market for each of the 24 hours tomorrow, both concerning selling electricity from the CHPs and buying electricity to the HPs. This bidding is made without any concern about the system balancing but with due concern to the TES contents at the DE plant. Similarly, DE plants may operate in the balancing market, which is operated with a shorter time lead.

The TSOs, responsible for the market-based system balancing of electrical loads, will often split the balancing tasks into three balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves [47]. These balancing markets together with the two whole-sale markets (Day-ahead market and Intraday market) comprise the five markets that DE plants can choose between – with variation across different countries.

As mentioned earlier, when developing further intermittent RES production there will be little room for inflexible steam-based generators on these markets, and the TSOs will maintain system reliability by other means, e.g. by installing synchronous condensers [48]. Also, flexible gas-based units will be needed. DE plants are often characterized by having fast units that can start and stop within typically 15 minutes, making it less important to include ramping effects when calculating UC.

Typically, these production units will be operated on/off which is enabled by the large TES. The focus of a DE plant is to cover heating and cooling demands, whereas electricity supply has less importance, thus often being neglected when planning UC. The market-based operation of DE plants will often be reduced to the participation in one or two of the electricity markets. That simplifies the UC problem and brings analytical UC methods back as potentially attractive methods for calculating UC of the DE plants.

However, this has not yet been seen in research. In this literature review is only found solver-based methods for calculating UC at DE plants. Mohsen et al. [46], Rooijers et al. [49], Wang et al. [50] and Lahdelma et al. [51] made UCs for optimal day ahead scheduling of CHP using MILP. Thorin [52] et al. succeeded in obtaining UC for CHP using both MILP and Lagrangian relaxation obtaining solutions within reasonable times by a suitable division of the whole optimization period into overlapping sub-periods. Anand et al. [53] considered dual-mode CHPs and found that in this case evolutionary programming was the best method to solve the UC problem. Basu et al [54] in a similar way used genetic algorithms for the UC problem, Takada et al. [55] used Particle Swarm Optimization, Song et al. [56] used an Improved Ant Colony Search algorithm. Gopalakrishnan et al. [57] used a Branch and Bound Optimization method for economic optimization of combined cycle district heating systems. Abdolmohammadi et al. [58] used an algorithm based on Benders decomposition to solve the economic dispatch of CHP. Rong et al. [59] used Sequential Quadratic Programming to solve multi-site CHP UC planning problem. Sudhakaran et al. [60] integrated genetic algorithms and tabu search for economic dispatch of CHP, and found that it reduces the computation time and improves the quality of the solution. Basu et al. [61] used a Colony Optimization algorithm to solve the CHP UC problem and showed that this algorithm is able to provide a better solution at a lesser computational effort compared to Particle Swarm Optimization, Genetic algorithm and Evolutionary programming techniques. Vasebi et al. [62] studied a multiple CHP system and found that a Harmony Search algorithm performs well. Powell et al. [63] studied a polygeneration distributed energy system with CHP, district heating, district cooling, and chilled water thermal energy storage, and have found that a Dynamic Programming algorithm performs well.

Pavičević et al. [64] described simplifications with a purpose of reducing computation time that in most of the studied scenarios exceeds 45 min. Wang et al. [65] studied improved wind power integration by a short-term dispatch CHP model, and shown that after necessary linearization processes, the CHP UC problem can be solved efficiently and analytically by MILP. Romanchenko et al. [66] investigated the characteristics of interaction between district heating (DH) systems and the electricity system, induced by present and future electricity price, and developed a MILP model to make optimal operating strategies for DH systems. Lahdelma at al. [51] used a Power Simplex algorithm to study the CHP UC problem.

Carpaneto et al. [67] studied optimal integration of solar energy in a district heating network and by making appropriate linearization and piecewise linear functions succeeded in using a MILP to the UC problem. Bachmaier et al. [68,69] studied spatial distribution of thermal energy storages in urban areas connected to DH and used the techno-economical optimization tool "KomMod" to solve the UC.

1.5 Needed support schemes promoting necessary flexibility at DE plants

The optimal extent of flexible CHPs, HPs and TES at DE plants in a certain country must be determined in national or regional analyses, or it may even be a political decision. Subsequently, a support scheme should, at the lowest cost of support, promote this amount. Often the present and most likely the future electricity prices do not create sufficient feasibility for the CHPs, HPs and TES to be installed. Therefore, support schemes are required to provide the required capacity.

In several reports EU has dealt with the challenge of designing and reforming energy sector support schemes [70–72] and pointed out that support should be limited to what is necessary and the support schemes should be flexible and respond to decreasing production costs [70]. Furthermore, support schemes should be phased out as technologies mature [70], and unannounced or retroactive changes should be avoided as they undermine investor confidence and prevent future investments [70].

On the basis of its analysis of support schemes, the EU Commission recommends, that Feed-in tariff schemes are phased out and that support instruments are used that expose energy producers and consumers to market price signals such as Premium schemes [72]. However, Dressler [73] has pointed out that Premium schemes may enhance market power, favour conventional electricity production and may even hamper the increase in production from RES.

From a policy side, the EU Commission states that support is intended to cover the gap between costs and revenues, for which reason adequate revenue projections must be made beforehand, but also states that these projections of the needed level of support can be difficult to make ex-ante, since the support may interact with, for instance, electricity prices in a complicated manner [72]. Thus, an ideal method for assessing DE support schemes should be able to show and to quantify if the level of support of the chosen support scheme can be expected to lead to the appropriate amount of production and storage capacity at DE plants and at what support cost.

Two of the most widely used support scheme types are the Feed-in premium types and the Feed-in tariff types. The focus in this thesis has been on these two support scheme, which are introduced and reviewed in the next two sections.

1.5.1 The Premium support scheme

In its basic form, the Premium support scheme adds a premium to the wholesale electricity price in each hour. This simple support scheme has gained ground in recent years and is used as main support instrument in Denmark, the Netherlands, Spain, Czech Republic, Estonia and Slovenia [74],

and premiums are usually guaranteed for a longer period, e.g. 10 up to 20 years. In this way the scheme provides long-term certainty when receiving financial support, which is considered to lower investment risks considerably. Premiums are applied in the case of support of biogas amongst other by Denmark, Italy and Slovenia. In Germany, the biogas plants with capacity larger than 750 kW_e are only offered premiums. In Slovenia, a market-premium scheme has been introduced for operators above 500 kW_e [75]. Schallenberg et al. [76] argue that Premium schemes can help create a more harmonized electricity market, effectively removing the difference between renewable and conventional electricity production.

Haas et al. [77] argue that, in principle, a mechanism based on a fixed premium/environmental bonus reflecting the external costs of conventional power generation can establish fair trade, fair competition and a level playing field in a competitive electricity market between RES and conventional power sources. They mention that from a market development perspective, the advantage of such a scheme is that it allows renewables to penetrate the market quickly if their production costs drop below the electricity-price-plus-premium. Therefore, if the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows renewables to compete with conventional sources without the need for entering "artificial" quotas. Mezősi et al. [78] have in their cost-efficiency benchmarking of European renewable electricity support schemes found that the premium support schemes in Denmark are the most cost effective ones.

The EU has dealt extensively with support in more reports [70–72] and recommends using the Premium scheme as it exposes the DE plant to the hourly market prices. Furthermore, in EU´s Guidelines on State aid for environmental protection [79] it is required that Member States convert the existing administratively determined Feed-in Tariff or Feed-in Premium schemes to competitively determined Feed-in Premiums or Green Certificate support schemes for new RES-E installations from 2017.

However, it is noticeable that Schallenberg et al. [76] have found that a premium scheme can occasionally lead to overcompensation. This is based on studying the Spanish system. Similarly, Gawela et al. [80], studying system integration of renewable energy through premium schemes on the German market, found a risk of overcompensating producers and find that it is questionable if a premium scheme is gradually leading plant operators towards the market.

1.5.2 The Feed-in tariff

In most countries Feed-in tariffs are amongst the preferred choices of support schemes [19]. They are designed in different ways, but in this thesis the Triple tariff has been chosen to be analysed in depth.

Much research has been published studying the effect of Triple tariff support schemes. Østergaard [81] analysed the geographical distribution of electricity generation and concluded that the Triple tariff influenced the local CHP plants to be operated according to a certain fixed diurnal variation. Soltero [82] mentions the Danish Triple tariff when considering the potential of natural gas district heating cogeneration in Spain as a tool for decarbonisation of the economy. Fragaki et al. [83], studying the sizing of gas engine and TES for CHP plants in the United Kingdom, mention that the

situation there resembles the Triple tariff electricity sales prices of the Danish system. Sovacool [84] mentions that the Danish Triple tariff made CHP operators being paid for their provision of peak power thus improving significantly the feasibility of investments in CHPs. Toke et al. [85] investigated whether the Danish Triple tariff could assist the implementation of CHP in the United Kingdom, arguing that this could help meeting its long-term objective of absorbing high levels of fluctuating RES.

Some articles describe simulation of energy systems based on the Danish Triple tariff without investigating the Triple tariff in depth. Lund [86] and Lund and Münster [87] studied large-scale integration of wind power into different energy systems using a reference scenario where the CHP plants produced according to the Triple tariff. Taljan et al. [88] studied the sizing of biomass-fired Organic Rankine Cycle CHP investigating the plant size being optimized against the Triple tariff. Gebremedhin [89] mentions the Triple tariff when looking into externality costs in energy system models. Heinz and Henkel [90] considered the Triple tariff in connection with a fuel cell population in the energy system. Dominković et al. [91] considered the application of feed-in tariffs in Croatia, and argued that feed-in tariff for pit TES will be of significance for the economic feasibility of investment. Østergaard [20] describes the capability in EnergyPLAN [92] to simulate the operation of national energy systems, where CHP plants are operated according to a fixed Triple tariff system. Schroeder et al. [93] mention that a Triple tariff system increased CHP´s integration into electricity markets. Hernández [94] studied photovoltaic in grid-connected buildings, investigated single, double and Triple tariff systems in Spain.

1.6 Estimated yearly investment in production capacity at German DE plants

The need for energy system simulation tools to analyse the investment in and operation of energy production units and energy stores at DE plants in a certain country is closely related to the amount of these to be installed. In this section the yearly investment in production capacity at DE plants in Germany is estimated.

The heating sector in Germany plays a key role in delivering the energy transition (Energiewende). With a demand for heating of 1500 TWh it accounted for more than 50% of final energy consumption in Germany in 2013, and total heat generation costs in Germany was in 2014 €118 billion [95].

The accounting firm PwC estimates that it will hardly be feasible to reduce German carbon emissions by between 80% and 95% of 1990 level by 2050, if the German decarbonisation strategy currently pursued in the heating sector is not adjusted [95].

The market share of district heating of Germany’s residential heat sector is 13.8%, equal to the average market share of district heating in the rest of EU. Total heat supply in the EU was 11.8 EJ (3278 TWh) in 2010, where district heating supplying EU's buildings is today 13% [11].

While the market share leaves room for further growth, Germany still remains the biggest market for district heating and cooling in the EU in terms of absolute figures. District heating production capacity is 51379 MW_{th} at 1372 district heating plants, and 10 mio. citizens are served by district energy [96].

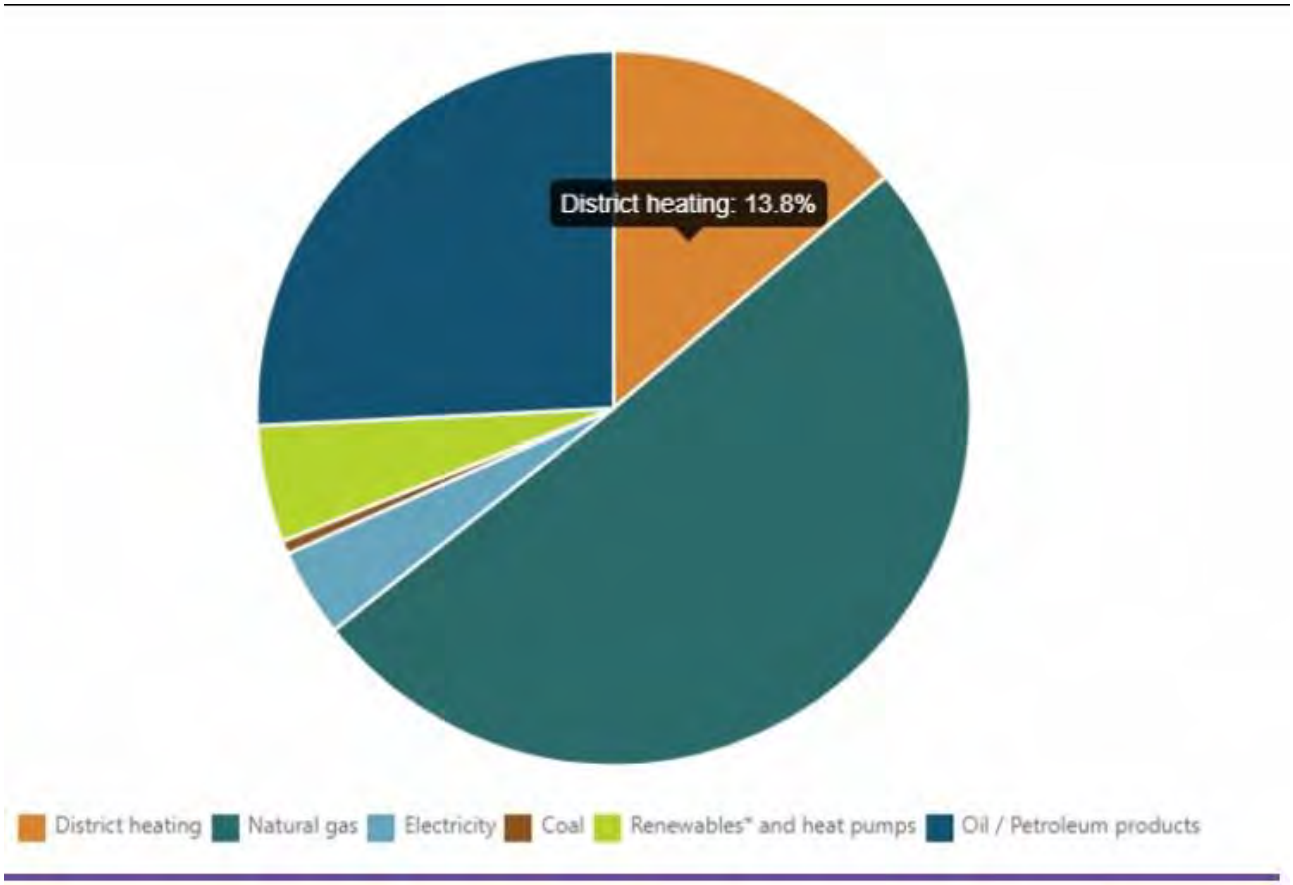

Figure 6: Composition of the origin for heat supply to residential and service sector buildings in Germany [96].

District energy in Germany has to be seen in the perspective of the German political goals [97]:

- 40 - 45 % share of renewables to be reached in electricity consumption by 2025
- In 2022 the remaining nuclear power plants are to be shut down
- 40 % of greenhouse gas emissions are to be reduced by 2020 (from 1990 levels)

In this estimation made in this section it is assumed that the results shown in Section 1.1 are applicable for Germany, concerning that a 30-40% reduction of the existing heat demand is socio-economic feasible, that approximately 50% of the remainder should be covered by DE and that this development of DE will reduce heating and cooling costs with approximately 15%. It is therefore assumed likely that Germany will decide to promote this development of DE. With these assumptions and an assumed typical investment in CHP and HP capacity of 0.7 mio. EUR/MW_{th}, Table 1 shows an estimated total yearly investment in new production capacity at DE plants in Germany of 6050 MW_{th} and a yearly investment cost of more than 4 billion EUR per year.

Present amount of heat demand in Germany	1500	TWh-heat
Present heat demand, after reduction with 35% through better efficiency	975	TWh-heat

Half of this to be served in the future by district energy	**488**	**TWh-heat**
Present heat demand (13,8%) served by district energy (DE)	207	TWh-heat
Present DE production capacity	51379	MW_{th}
Life time of DE production capacity	20	years
Investment cost in DE production capacity	0.7	mio. EUR/MW_{th}
Yearly investments in new production capacity at existing DE plants	2569	MW_{th}
	1.80	**billion EUR per year**
Yearly investments in new production capacity at new DE plants	3481	MW_{th}
	2.44	**billion EUR per year**
Total yearly investments in new production capacity at DE plants	6050	MW_{th}
	4.24	**billion EUR per year**

Table 1: Estimated total yearly investments in new production capacity at DE plants in Germany.

1.7 Scope and research questions for this thesis

A wide range of tools for DE plants are needed, among other tools ranging from supervisory control and data acquisition tools (SCADA) for controlling the instantaneous operation of the production units and the operation of the grids (e.g. the heating and cooling grids) to tools for handling financial accounting and cash flow at the DE plants.

However, this dissertation concerns the development of next generation energy system tools for simulating DE plants. The scope for this development has been delimited to those tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes (as dealt with in [39] and [98]).
- Daily or short-term planning of operation, also when this operation will be determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

Thus, the focus is on heating, cooling and electricity demands in more buildings supplied from a DE plant, typically equipped with energy stores, as heating, cooling, fuel or electricity stores. The operation is often market-based and optimized across different energy types, which each may be subject to restricted grid capacities between the DE plants and the buildings. The focus in the development is on optimizing plant and grid operation. However, optimization across plant, grids and buildings have in some detail been dealt [23].

The main research question is:
Is it possible to develop a tool which is able to analyse and compare sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions are formulated:

Sub question 1: *How can the optimization of market based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

In this PhD study the specification of the requirements for next generation energy system tools for simulating DE plants has primarily been made considering the conditions in Germany, Denmark and UK. These three countries have been compared on key figures in Table 2. The conditions in these three countries are similar, only when it comes to Area per capita Denmark has nearly the double area (7368 m^2), which in some cases will make it easier to establish e.g. large place requiring solar collectors and thermal stores. For comparison, area per capita is 58,462 m^2 in Norway, 41,616 m^2 in Sweden, 55,455 m^2 in Finland and 28,251 m^2 in the US [99].

Key figures	**Germany**	**Denmark**	**UK**
Population (million)	82.70	5.70	65.60
Total Final Consumption per capita (MWh/cap)	34.94	27.16	21.92
Electricity consumption per capita (MWh/cap)	6.92	5.81	4.99
Emissions per capita (tCO_2/cap)	8.93	5.63	5.99
Gross Domestic Product per capita (1000 EUR/cap)	36.36	38.18	32.68
Area per capita (m^2)	4220	7368	3689

Table 2: Comparison of key figures for selected countries [99]*. Data are from 2015.*

1.8 Thesis structure

This introduction describes the societal benefits of District Energy, the needed flexibility of DE plants, the changing roles of CHP at DE plants when developing renewable energy, the needed optimization of daily operation of DE plants with large TES, the needed support schemes promoting necessary flexibility at DE plants, the estimated yearly investment in production capacity at DE plants as well as the scope and research questions for this dissertation.
Section 2 defines the methodology used.

The next three sections deal with the three research sub questions in turn. Section 3 deals with how to mathematically solve the optimization of market based daily operation of DE plants with large TES. Section 4 deals with how to analyse coordinated investment in production and storage capacity at DE plants. Section 5 deals with how to analyse support schemes promoting necessary flexibility at DE plants. These sections are mainly based on two published and one under revision article each.

Section 6 discusses the need for further research in next generation generalized energy system simulation tools for district energy, and Section 7 concludes on the question if it is possible to develop one generalized tool which is able to analyse very different alternatives for DE plants providing heating and cooling.

2. Methodology

When choosing the methodology used in this PhD project, it is to be kept in mind that it deals with the development of next generation energy system tools for simulating DE plant, delimited to those tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation will be determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

In this section is described the methodology used to work with this development.

2.1 Literature review

The framework for the work is made through a comprehensive literature review in Section 1.
The review has started with a historical review, with the ambition of identifying a sufficiently broad range of aspects of the tasks mentioned above.
The literature review has been divided into five sections:

- Societal benefits of District Energy
- Needed flexibility of DE plants
- Optimization of daily operation of DE plants
- Support schemes promoting necessary flexibility at DE plants
- Estimated yearly investment in production capacity at DE plants

The author has 18 papers and articles at www.scopus.com, being main author of three papers and coauthor of the remainder. These papers and articles are all relevant for the topic of this PhD project. Most of them has been published before this PhD study and the work with these pre study publications have been inspired to keywords in each of the sections. The keywords have been used for search in ScienceDirect, Scopus, Google Scholar and Google.

Furthermore, a more systematic approach has been used to identify aspects contained in the research subject, used for identifying relevant search words, being used for block searching in the databases:

- Compendex
- Scopus
- Proquest

2.2 Case studies

In the PhD study has been developed a method for analysing coordinated investments in production and storage capacity at DE plants and developed a method for comparing the effect of support schemes at DE plants. At its best when using or verifying the methods in a certain country, all existing and expected future DE plants in this country should be analysed. This is outside the

scope of this PhD study to do such a comprehensive analysis. Therefore, this PhD study has been limited to complex natural gas fired generic DE plant cases.

When choosing these DE plant cases, Flyvbjerg´s work on the methods for making Case-Study Research [100] has been taken into account, as mentioned in Table 3.

Flyvbjerg´s emphasis on misunderstandings About Case-Study Research	**Flyvbjerg´s understandings About Case-Study Research**
One cannot generalize on the basis of an individual case; therefore, the case study cannot contribute to scientific development.	*One can often generalize on the basis of a single case, and the case study may be central to scientific development via generalization as supplement or alternative to other methods. But formal generalization is overvalued as a source of scientific development, whereas "the force of example" is underestimated.*
The case study is most useful for generating hypotheses; that is, in the first stage of a total research process, whereas other methods are more suitable for hypotheses testing and theory building.	*The case study is useful for both generating and testing of hypotheses but is not limited to these research activities alone.*
The case study contains a bias toward verification, that is, a tendency to confirm the researcher's preconceived notions.	*The case study contains no greater bias toward verification of the researcher's preconceived notions than other methods of inquiry. On the contrary, experience indicates that the case study contains a greater bias toward falsification of preconceived notions than toward verification.*

Table 3: Flyvbjerg´s work on the methods for making Case-Study Research [100]

Furthermore, Flyvbjerg mention that strategic choice of case may greatly add to the generalizability of a case study. In this PhD study it has been tried to comply with a strategic choice, when choosing the cases, by taking into account how DE plants is likely to be equipped with large CHPs, HPs and TES in a renewable energy system.

Furthermore, the reproducible research paradigm has been pursued in this study, so that even if it is complex plants considered, the description of these are sought to be so generic described, that it allows readers reproducing with minimal effort the results obtained. Therefore,
it has been assumed that partial load performance of production units is strictly linear. As mentioned by Ommen et al. [45] this simplified assumption will lead to a minor error when dealing with operation of a real plant, but is not considered to be a substantial problem when the generic DE plant is equipped with large TES.

2.3 Simple energy balance method

Throughout the analysis in this study only simple energy balance calculations have been made for the considered DE plants. A broader analysis of the DE plants would include hydraulic calculations, as well as flow and temperature modelling. Energy balance is an obvious starting point when the

ambition is the development of a generalized tool, which is able to analyse very different alternatives for DE plants providing heating and cooling. There has to be energy balance in every time step of a chosen optimizing period. However, it is to be kept in mind that no hydraulic constraints have been included and energy stores has been assumed to be split into two well defined temperature zones.

2.4 DE plants participating only in the Day-ahead electricity markets

In the comparison of unit commitment methods at DE plants, development of a method for analysing coordinated investments in production and storage capacity at DE plants and development of a method for comparing the effect of support schemes at DE plants, only participation in the Day-ahead electricity markets have been assumed.

However, in the future DE plants are assumed to participate across more of both existing and future electricity markets. A more elaborated analysis of the value of large production and storage capacity requires simulations across more markets, which is rather tedious, because it has to take into account the organization of these markets, when it comes to e.g. gate closures and price settlements. The need for further research in DE plants participating across more markets is described in section 6.1. The complexity of simulating DE plants participating across more markets is illustrated Figure 7, illustrating the organization of the electricity markets in West Denmark, having three balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves and two whole-sale markets (Day-ahead market and Intraday market).

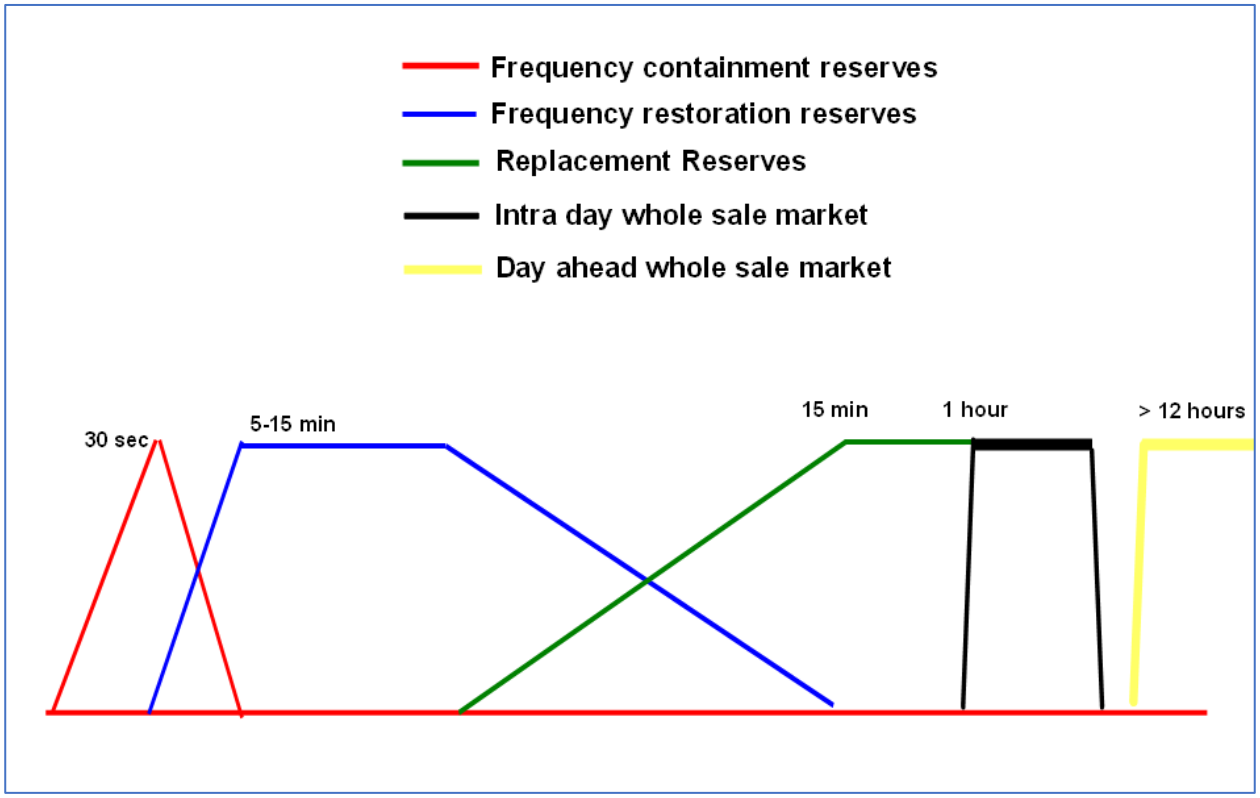

Figure 7: ACER´s [47] general framework for the organization of thee electricity markets as implemented in West Denmark.

2.5 Tools used in the analysis and methods

The tools used are energyPRO, VBA-coding in Excel, Phyton and Gurobi Solver.

2.5.1 The energy system analysis tool energyPRO

It is chosen to use energyPRO [34] in the developed method for analysing coordinated investments in production and storage capacity at DE plants and the developed method for comparing the effect of support schemes at DE plants. The reason for this choice is described in detail in [39], and summarized below.

In energyPRO the time step may be 1 hour or less allowing a calculation of the hourly cash flow. It allows the use of indexes describing e.g. the development of demands for heating and cooling and the development in prices over the years, which implies that the operation of the production units between the years may change e.g. due to changed economic conditions.

energyPRO is based on analytical programming based on pre-defined methods for finding optimal operation – either through marginal production costs of units or through user-defined priorities. This analytical method is described more thoroughly by Østergaard et al. [23]. An important reason for using energyPRO, is it is widely used by consultants to analyse investments in DE plants [101]. That brings the method for assessing support schemes close to how investment decisions are made. Furthermore, energyPRO is widely used for research, e.g. Sorknæs et al. have applied energyPRO to

study the treatment of uncertainties in the daily operation of combined heat and power plants [102]. Østergaard et al. used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [23] and to assess the economy of such systems [103]. Fragaki et al. applied energyPRO to study the economic sizing of a gas engine and a thermal store for CHP plants in the UK [104,105]. Streckienė et al. studied the feasibility of CHP-plants with thermal stores in the German Day-ahead market [106] and Østergaard studied heat and biogas stores' impacts on RES integration [107].

2.5.2 VBA-coding in Excel

VBA in Excel is an object-oriented application, that give full flexibility in analysing energy systems. In this study it has been used in the developed method for analysing coordinated investments in production and storage capacity at DE plants and the developed method for comparing the effect of support schemes at DE plants. An example of the VBA-coding made in the developed methods are shown in Annex I.

2.5.3 Python

Python is a programming language at the same level as VBA-coding in Excel. The reason for using it in this PhD study is primarily that is makes it easy to formulate object functions and constraints necessary for calling solvers. It has been used for comparing unit commitment methods at DE plants. The developed code is shown in Annex II, calling the solver Gurobi Optimizer.

2.5.4 Gurobi Optimizer

The Gurobi Optimizer is a commercial state-of-the-art math programming solver able to handle major problem types [108] and has in this PhD study been used as one of the methods used to calculate unit commitment at DE plants. It allows to solve among other MILP problems, defined by linear object functions and defined by constraints, as described in detail in [109]. The starting point for this solver is linear programming, that is able to be solved mathematically. However, it is a commercial solver, and it is not revealed in the documentation [108], how the linearity is converted to integer constraints.

2.6 Supporting input

The methods developed in this thesis have benefitted from and build upon the methods met in more of the completed PhD courses, as exemplified below. Moreover, a stay at EMD and dialogue with students have made important input to this PhD study.

2.6.1 Electricity Market and Power System Optimization

In this PhD course we were, amongst other things trained in UC problems, formulating these UCs with proper objective functions and constraints using solvers in GAMS (General Algebraic

Modelling System) [110] for solving the UCs. Professor Andres Ramos [111] from Comillas Pontifical University in Spain, delivered the main training.

2.6.2 Optimization Strategies and Energy Management Systems

This PhD course recognised and formulated different optimization problems in planning, operation and control of energy systems, and how to solve them using existing software and solvers such as MATLAB, GAMS, and Excel. Several illustrative examples and optimization problems were made, ranging from the classical optimization problems to the recent Mixed integer nonlinear programming (MINLP) models proposed for the optimization of integrated energy systems (such as residential AC/DC microgrids), including heuristics and meta-heuristics methods. Professor Moises Graells (Technical University of Catalonia) and Associate Professor Eleonora Riva Sanseverino (University of Palermo) completed major parts of this course.

2.6.3 Scientific Computing Using Python

Besides training in scientific computing using python, this PhD course introduced the reproducible research paradigm that has been pursued in this thesis. As mentioned in the course, all too often, articles do not describe all the details of an algorithm and thus prohibit people from reproducing with minimal effort the results obtained. Both the reproducibility of data and algorithms was discussed. The effort required to make research reproducible is compensated by a higher visibility and impact of the results, by convincing readers that the result is correct.

Associate Professor Thomas Arildsen from Aalborg University´s PhD Consult handled the teaching. Furthermore, he assisted in setting up the MILP problem in this thesis in Gurobi Optimizer interfaced by Python.

2.6.4 Photovoltaic Power Systems

In this PhD course Associate Professor Derso Sera and Associate Professor Tamas Kerekes from Aalborg University educated us in the methods for modelling PVs, being further elaborated on in Section 6.

2.6.5 Storage Systems based on Li-ion Batteries

In this PhD course, Dr. Daniel Stroe and Dr. Erik Schaltz from the Department of Energy Technology, Aalborg University, Aalborg, educated us in this PhD course in methods of performance testing and modelling, ageing, performance degradation and lifetime estimation of batteries, as further elaborated on in Section 6.

2.6.6 DE plants consultancy

Through my stay these three years at the Energy Systems Department at the company EMD International A/S, I have met a wealth of DE plants being analysed as part of consultancy tasks and project work.

2.6.7 Fruitful discussions with students

Being responsible together with Poul Alberg Østergaard for the Energy System Analysis course offered by The Sustainable Energy Planning Research Group, Department of Planning, Aalborg University, I handled the teaching concerning optimal operation of CHP and tri-generation plants and energy storage in energy systems, as well as the teaching of how to make a sustainable energy system analysis in the modelling language Visual Basic for Application (VBA). The students' wealth of very different examples was certainly a challenging inspiration to the work in this thesis concerning having only one tool being able to analyse very different alternatives for DE plants.

3. Comparison of unit commitment methods at DE plants

In the literature review has been demonstrated that a common conclusion hitherto has been that UC based on analytic methods is not useful. However, the market-based operation of DE plants often being reduced to participation in one or two of the electricity markets, simplifies the UC and brings analytic UC methods back as potentially attractive methods for DE plants. This is demonstrated in this section by making a complex generic DE plant yet so simplified that a MILP method is able to deliver optimal UCs. An advanced analytic UC method for district energy plants is proposed and the comparison of the UCs made by this method with the optimal UCs shows that the method delivers fully adequate UCS needed for daily operation planning, yearly budgeting and long-term investment analysis for this DE plant. The novelty in this comparison is thus that it brings analytic UC methods back as potential attractive methods to be used at DE plants.

The description in this section is based on the appended article II: *Analytic versus solver-based calculated daily operations of district energy plants*, which is in the second review round at the time of writing (December 31st 2018). Much of the text in this chapter is copied verbatim from this manuscript, while many of the more general aspects in the paper are left out here.

Technical and financial data of the complex generic DE plant being used for the comparison is shown in Table 4.

CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fuel input	13.65	MW
Electrical power	6.00	MW
Heat power	6.67	MW
Variable operation costs	5.40	EUR/MWh_e
Start costs of CHP´s	30	EUR/start
HPs		
COP	3.5	
Electrical consumption	1.91	MW
Heat power	6.67	MW
Variable operation costs	2.00	EUR/MWh_{heat}
Start costs of HP´s	10	EUR/start
Gas boilers		
Heat efficiency	103.0%	
Heat power	15.00	MW
Fuel input	14.56	MW
Variable operation costs	1.10	EUR/MWh_{heat}
TES	59.24	MWh_{heat}

Table 4: Technical and financial data on CHP, HP, TES and existing boilers (2016-prices) used in the test of the UC methods, based on typical values from [112].

The DE-plant participates in the Day-ahead market and as shown in Figure 8 only the CHPs and HPs have access to store heat in the TES. The capacities of the units are shown in Figure 8.

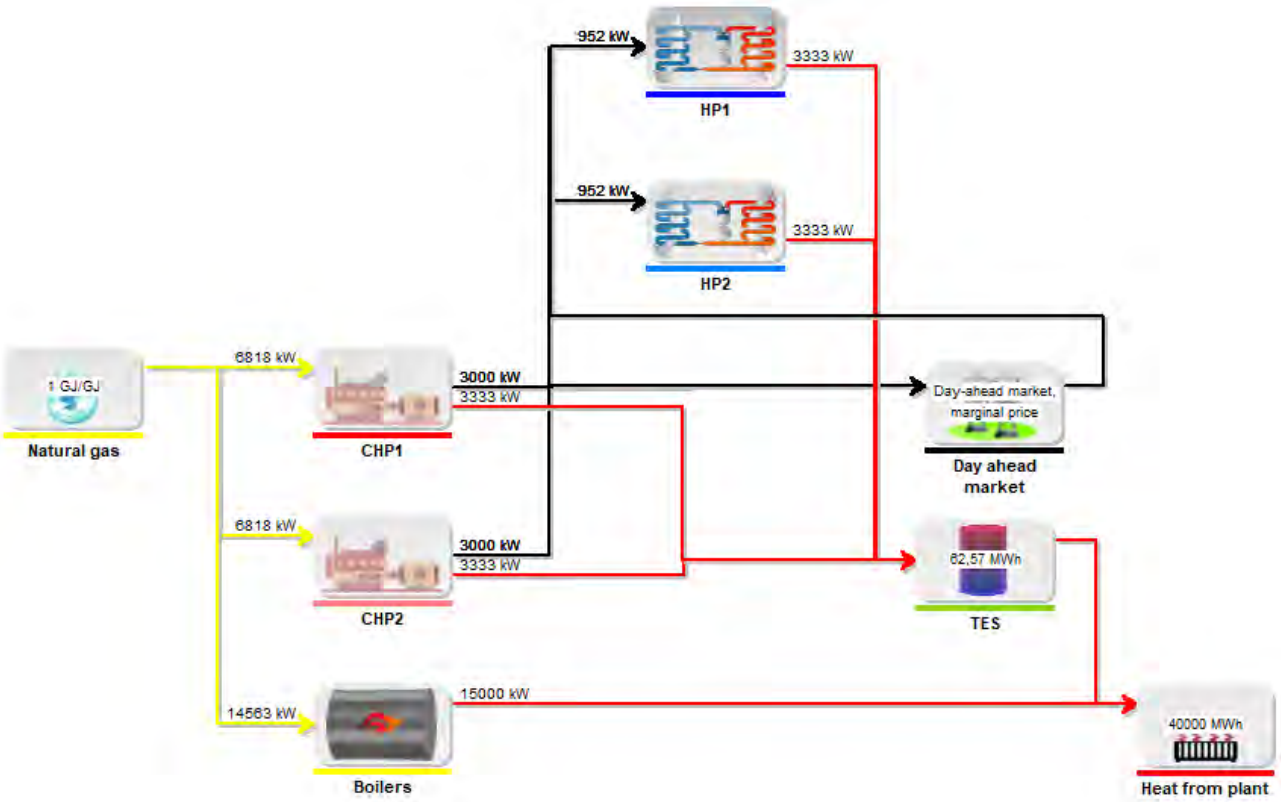

Figure 8: The generic DE plant case consisting of CHP, HP, boilers and TES units.

3.1 The UC methods to be compared

Loads to be satisfied at DE plants are primarily heat- and cooling loads, hence the focus is on heating and cooling production costs. As the CHPs and HPs are assumed to be traded on the Day-ahead market, these production costs will change from hour to hour. The two analytic UC methods and the solver UC method to be compared are described in this section.

3.1.1 The advanced analytic UC method

The description of the advanced analytic UC method in this section is delimited to a description on how to solve the UC at heat-only DE plants as the plant described Figure 8, but the method may be generalised to more complex DE plants.
The first step is for each production unit in each time step in the optimization period, to attribute a priority number reflecting the operating cost of 1 MWh_{heat}. The priority number for e.g. a CHP is the cost of producing 1 MWh_{heat} reduced with the value of the associated produced electricity in that time step, referred to as the Net Heat Production Cost (NHPC). In this case it is assumed that the produced electricity is sold on the Day-ahead market and that the time step is 1 hour, thus the

priority number for e.g. a CHP in a certain hour depends on the price on the electricity Day-ahead market (the spot price). Similarly, the NHPC of the HP depends on the electricity spot price.
The Technical and financial data given in Table 4 result in the priority numbers shown in Figure 9 as a function of the hourly electricity Day-ahead market price. The figure indicates that for all electricity spot prices the NHPC for the CHPs and HPs are lower than the NHPC of the boilers, which are independent of the spot price. Furthermore, it is seen that up to approximately a spot price of 40 EUR/MWh$_e$, the NHPC of the HPs is lower than these of the CHPs.
An ordered priority list (PL) is made of these priority numbers, with the lowest priority numbers firstly stated on the list and where each of these priority numbers links to a certain hour and production unit. Thus, if a plant has five production units as in this case and the simulation is hourly made over a one-year period, the PL contains 5*8760 priority numbers.

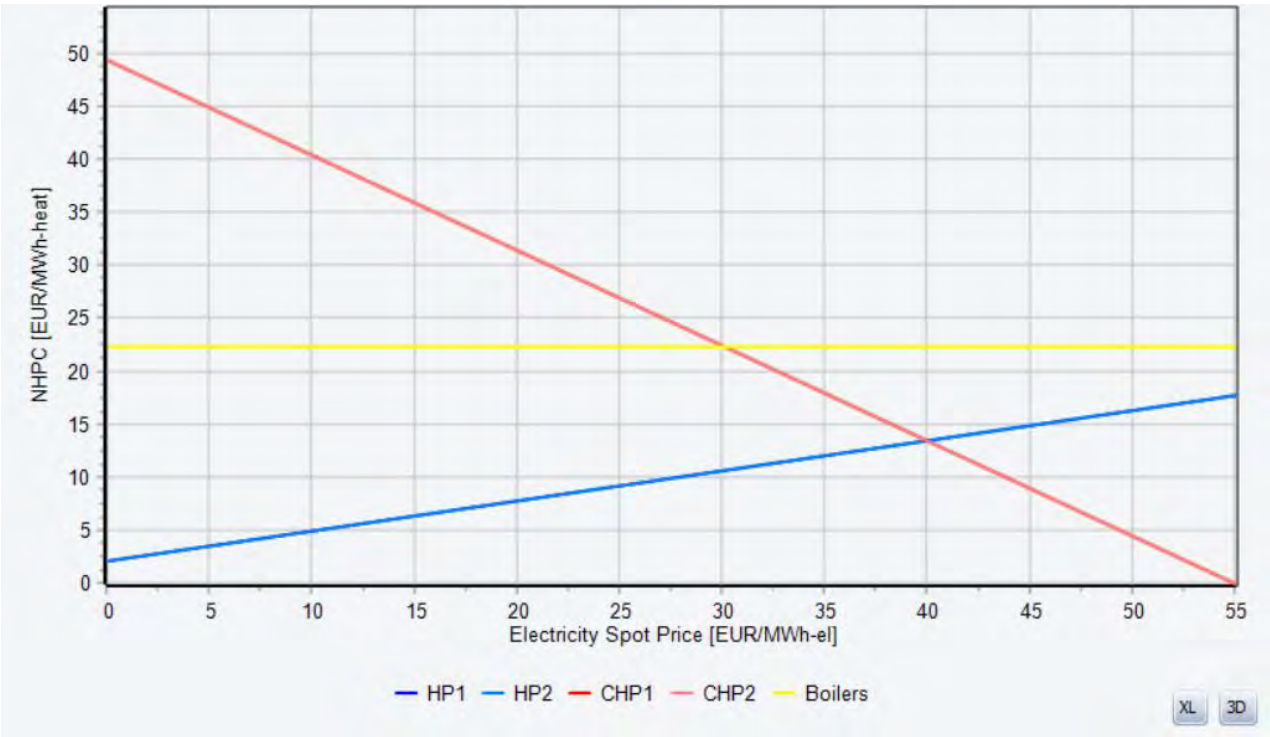

Figure 9: Specific NHPC of the production units as described in this section, as function of the electricity spot price on the Day-ahead market. Starting costs are not included.

Each production unit at a DE plant typically has associated starting costs and may e.g. have constraints regarding minimum operation period duration. It could e.g. be a minimum of 3 hours of continuous operation of CHPs, which is relevant when making block bids on the Day-ahead market. Similarly, minimum stop periods could be a constraint. The minimum operation periods have been included when creating an additional list of start blocks in parallel to the PL.
Each start block contains hours which is at least equal to the minimum length of an operation period. To each start block is associated a priority number which is calculated as the average NHPC of the production unit in the hours in the start block, and to the average NHPC is added the starting cost of the production unit divided by the amount of heat produced by the production unit in the start block. Thus, if a project has 5 production units and the simulation is hourly during a one-year period and the minimum length of operation periods for all production units is 3 hours,

there will be at least 5*(8760-2) different 3-hour start blocks. It is possible to also include larger start blocks e.g. 4-hour start blocks or 6-hour start blocks, which will significantly increase the number of start blocks if not only increasing the calculation time but also increasing the optimality of the UC solution. These start blocks are ordered in a Start Block List (SBL) with the start blocks with the lowest priority first.

After having created the PL and SBL, the UC starts taking the first start block in the SBL and try if it is possible to commit this when considering the restrictions in the energy stores and transmission lines. If it is not possible to commit this start block, the next start block is tried to be committed. This continues until a start block is committed.

When a start block is committed, the priority number of the next start block in the SBL is registered. Then the PL is checked up to the priority number of the next start block to see if some of the priority numbers are linked to an hour which may expand the committed start block. Before an expansion of an already planned production period is accepted, it must be carefully checked to ensure that it does not disturb already planned future productions. This is checked in an iterative way, by chronological checking from the hour of expansion if this new production in that hour together with the already planned future productions still fulfils the restrictions in the energy stores and transmission lines. When these expansions of operating periods are exhausted from the PL, the next start block in the SBL is tried committed. This continues until a start block in the SBL is successfully committed. Then again, the PL is checked for possible expansion of all already planned operations.

If the expansion of operation periods results in a distance between two operation periods equal to the length of a start block, the start block fitting into the gap between these two operation periods, will have its priority number recalculated improving the priority number, because if successfully committed it will remove a starting cost, as the two operation periods have become one coherent operation period. The start block will be moved up in the SBL.

This UC continues until the end of the SBL, but the steps go faster and faster because the next start block on the list might be deemed illegal and skipped as it is either overlapping or too close to already planned operation periods or in conflict with minimum stop periods.

An example of the advanced priority list UC for the DE plant described is shown in Figure 10 for 7 days in September. The upper panel shows the electricity price in the Day-ahead market. The heat and electricity production and consumption are shown in the next two panels. The bottom panel shows the contents in the TES.

It is seen that the CHPs are mainly producing during hours with high spot prices and the HPs are mainly producing during hours with low spot prices. The boilers are not producing, which is in good compliance with the NHPCs shown in Figure 9, where the cost of producing heat in boilers is the most expensive one for all spot prices.

The starting point for comparing the quality of UCs is their NHPCs for the chosen optimization period, thus the UC with the lowest NHPC is considered the best. The reason for not choosing the operation income of the optimization period when comparing UCs is that e.g. the revenues from the sale of heat is the same for all UCs as long as the heat demand is covered. An example of the UC for an optimization period, where the UC is calculated using the advanced analytic UC method is shown in Figure 10, and the associated NHPC is shown in Table 5.

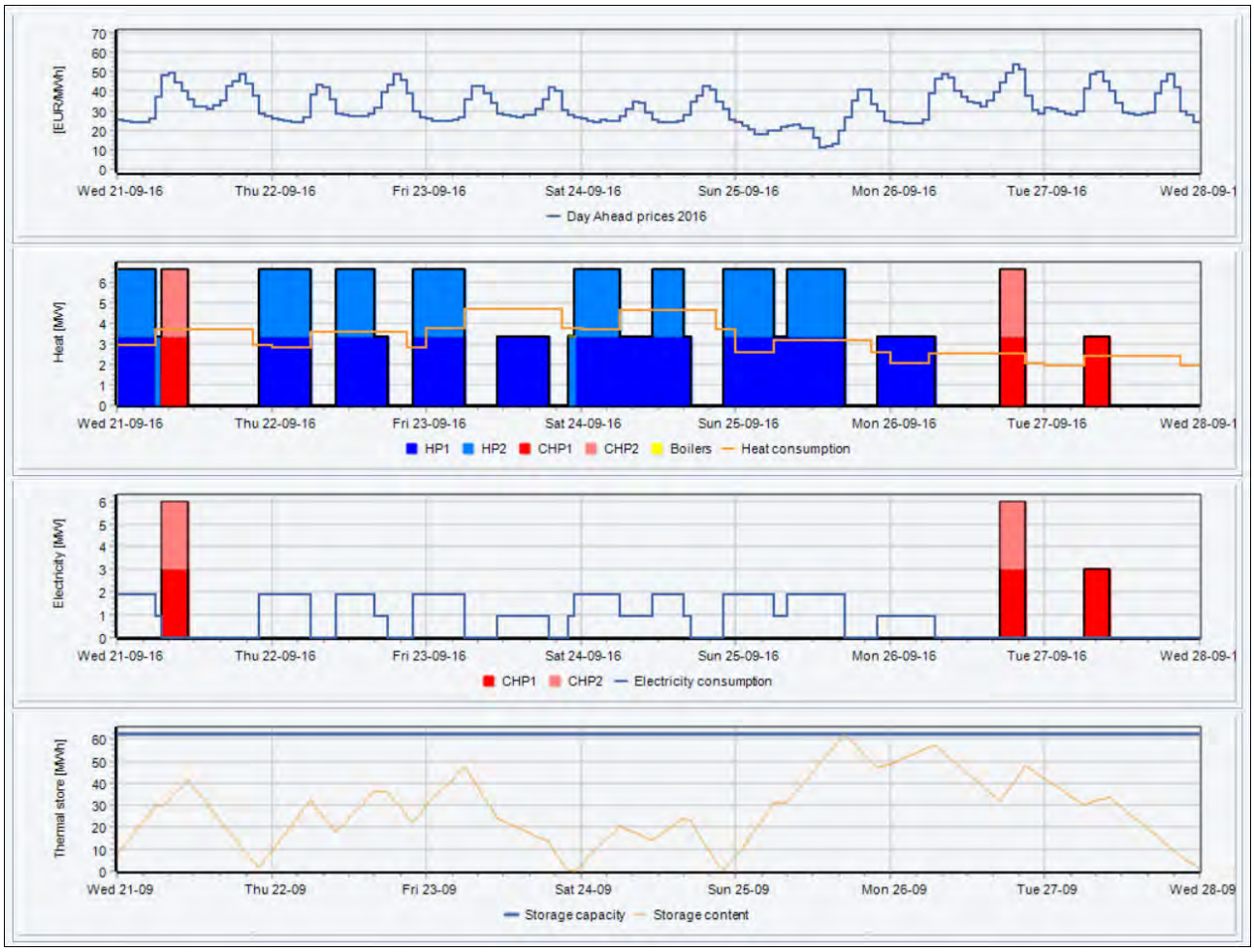

Figure 10: An example of the UC at the DE plant during 7 days in September calculated using the advanced analytic UC method.

Net Heat Production Cost from 01-09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	282.7	MWh_e				6 941	
Purchase of electricity HP2	212.3	MWh_e				5 137	
Variable operation costs of HP1	989.9	MWh_{heat}	at	2.0	=	1 980	
Variable operation costs of HP2	743.3	MWh_{heat}	at	2.0	=	1 487	
Fuel costs	752.1	GJ	at	5.6	=	4 212	
CO2 quotas	42.6	ton CO_2	at	8.0	=	341	
Variable operation costs of CHP1	69.0	MWh_e	at	5.4	=	373	
Variable operation costs of CHP2	21.0	MWh_e	at	5.4	=	113	
Variable operation costs of boilers	4.5	MWh_{heat}	at	1.1	=	5	
Start costs of CHP1	6	starts	at	30.0	=	180	
Start costs of CHP2	2	starts	at	30.0	=	60	
Start costs of HP1	33	starts	at	10.0	=	330	
Start costs of HP2	27	starts	at	10.0	=	270	
Total Operating Expenditures							**21 428**
Revenues							
Sale of electricity CHP1	69.0	MWh_e				3 234	
Sale of electricity CHP2	21.0	MWh_e				1 026	
Total Revenues							**4 260**
Net Heat Production Cost							**17 168**

Table 5: The NHPC at the DE plant during the first 28 days in September calculated using the advanced UC priority list method.

3.1.2 The simple analytic UC method

As mentioned by Abujarad et al. [43] the basics of UC priority list methods are to commit generation units based on the order of increasing operating cost, such that the least cost units are firstly selected until the load is satisfied. In the simple UC priority list method, it is chosen that the production units are ranked, and the highest ranked production unit is tried to be committed to the entire optimizing period respecting the limited size of the TES. The next highest ranked production unit is then tried, on top of the first one, to be committed to the entire optimizing period, continuing this way to add production units until the heat demand is covered

3.1.3 The MILP solver UC method delivering the optimal UC solutions

The MILP method is a formulation of the UC with start-up and shut-down constraints, described by Gentile et al. [113]. Decision variables are established for each of the five production units and the TES. The two CHPs and the two HPs are each binary as no partial load operation is allowed. For

the boiler and TES, the decision variables are continuous with upper bounds equal to the maximum capacity.

The objective function to be minimized is the NHPC for the optimizing period. An example of the calculation of the NHPC is shown in Table 5, and is calculated as:

$$NHPC = \sum PurchaceOfElectricity + \text{VariableOperationCosts} + \text{FuelCosts} + \text{CO2Quotas} + \text{Startcosts} - \text{SaleOfElectricity}$$

The technical and economic conditions for the calculation of the NHPC is given above.

There are included the following constraints.

To each of CHP1, CHP2, HP1 and HP2 is connected three decision variables ensuring that the minimum length of operation periods and stop periods are equal to three hours, as shown for CHP1:

CHP1[i]	Unit commitment Boolean {0;1} being true for CHP1 in operation in this time step
CHP1start[i]	Boolean {0;1} true for CHP1 in operation in this time step and not in operation in the time step before.
CHP1stop[i]	Boolean {0;1} true for CHP1 not in operation in this time step and in operation in the time step before.

Constraint 1: General connection between unit Booleans.

$$CHP1[i] - CHP1[i-1] = CHP1start[i] - CHP1stop[i]$$

Constraint 2: Minimum length of operation periods - here three hours.

$$3 \cdot CHP1start[i] \leq CHP1[i] + CHP1[i+1] + CHP1[i+2]$$

Constraint 3: Minimum length of stop periods – here three hours.

$$CHP1stop[i] + CHP1stop[i+1] \leq 1 - CHP1[i+2]$$

The use of the TES meets the heat balance constraint.

Storage[i]+3.333*(CHP1[i]+CHP2[i]+HP1[i]+HP2[i]) + Boilers[i] – HeatFromPlant[i]=Storage[i+1]

Storage is the content in the TES in the beginning of each time step measured in MWh. The other symbols refer to the symbols used in Figure 8 and are measured in MW. The chosen time step is 1 hour, and it is not necessary to multiply the other symbols with the time step.

3.2 Result of the tests

The focus in this thesis is the development of UC methods needed for daily operation planning, yearly budgeting and long-term investment analysis of DE plants. When planning the daily operation for today or tomorrow, also operation during the next days has to be taken into account, as these plants are often equipped with large TES. Thus, using the storage capacity today decreases the possibility to store heat the subsequent days even if production conditions (prices) are better at that given time, therefore a needed optimizing period could be a 7-day period. When making yearly budgeting and long-term investment analysis the total optimizing period may be from one year to e.g. 20 years. Considering the size of the TES, it may be justifiable to split the long optimizing period into monthly optimizing periods. Another optimizing period could therefore be a 4-week period (28 days). These two periods are chosen in the comparison of the UC methods.

3.2.1 Comparison the UC methods on the first 28 days of September

In Table 6 the NHPC during the first 28 days in September is calculated to EUR 17,008 using the MILP solver UC method. As mentioned earlier this is the optimal NHPC, which is possible as the generic DE plant is complex but yet so simplified that a MILP method can deliver optimal UCs. The NHPC of EUR 17,168 for the same period using the advanced analytic UC method is shown in Table 5. It shows that the NHPC when using the advanced analytic UC method is approximately 1% worse than the optimal NHPC (Table 6).

Net Heat Production Cost (NHPC) from 01-09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	238.0	MWh_e				5 681	
Purchase of electricity HP2	253.2	MWh_e				6 071	
Variable operation costs of HP1	833.3	MWh_{heat}	at	2.0	=	1 667	
Variable operation costs of HP2	886.6	MWh_{heat}	at	2.0	=	1 773	
Fuel costs	863.2	GJ	at	5.6	=	4 834	
CO2 quotas	48.9	ton CO_2	at	8.0	=	391	
Variable operation costs of CHP1	42.0	MWh_e	at	5.4	=	227	
Variable operation costs of CHP2	63.0	MWh_e	at	5.4	=	340	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	4	starts	at	30.0	=	120	
Start costs of CHP2	6	starts	at	30.0	=	180	
Start costs of HP1	32	starts	at	10.0	=	320	
Start costs of HP2	36	starts	at	10.0	=	360	
Total Operating Expenditures							**21 965**
Revenues							
Sale of electricity CHP1	42.0	MWh_e				2 007	
Sale of electricity CHP2	63.0	MWh_e				2 949	
Total Revenues							**4 957**
Net Heat Production Cost							**17 008**

Table 6: The NHPC at the DE plant during the first 28 days in September calculated by means of the MILP solver UC method.

Furthermore, noticeably is that the CHP production in the optimal solution results in, if using MILP, a significantly higher production than the CHP production calculated when using the advanced UC priority list method shown in Table 5. The reason for this deviation of the CHP production, even if the NHPCs are practically the same, is to be understood looking at the specific NHPC as shown in Figure 9. At a spot price of approximately 40 EUR/MWh_e the cost of producing 1 MWh_{heat} at CHPs and HPs is the same. Shifting the production from HP to CHP in hours with spot prices around 40 EUR/MWh_e does not change NHPC significantly. That is also shown in Figure 11 showing the optimal UC during the same 7 days as shown in Figure 10. E.g. both CHPs are started 27th of September in the optimal UC but only one CHP is started in the UC calculated using the advanced analytic UC method.

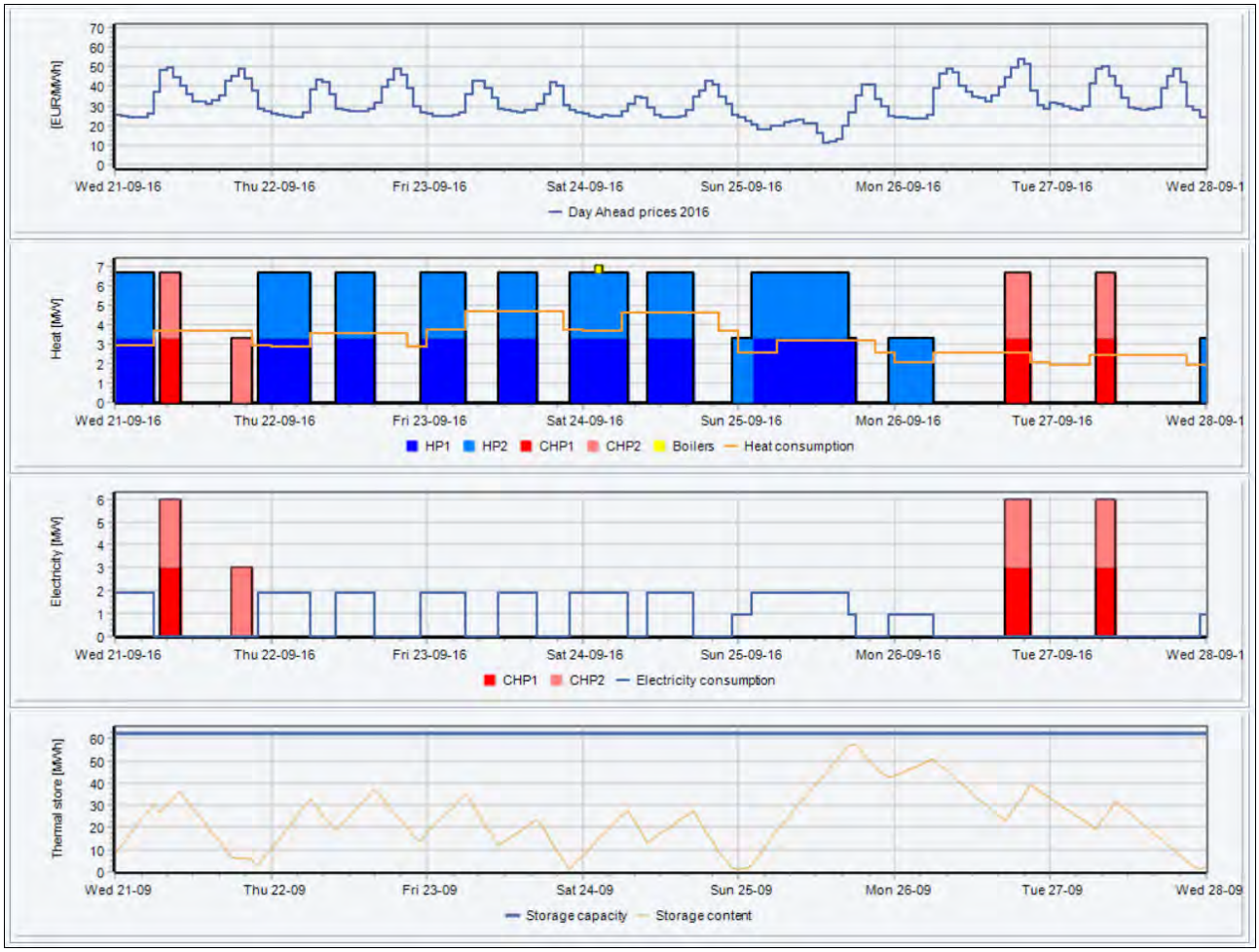

Figure 11: The optimal UC at the DE plant for 7 days in September using the solver-based UC method.

The next step in the test is to calculate the NHPC using the simple analytic UC method as described in Section 3.1.2. Looking at the specific NHPCs in Figure 9 it is obvious that boilers should have the lowest priority, but it depends on the spot price level during the 28-day period whether the CHPs or the HPs should have the highest priority.

With the CHPs having the highest priority, the simple analytic UC method gives a NHPC of EUR 40,118, whereas using the HPs having the highest priority, the NHPC is EUR 19,887. Therefore, comparison will be made using HPs with the highest priority in the simple analytic UC method. The NHPC calculated for the 28-day period with the simple analytic UC method is shown in Table 7. It shows that the high priority HP1 produces close to all the needed heat and the number of starts is extremely low.

Net Heat Production Cost from 01-09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	524.6	MWh_e				16 138	
Purchase of electricity HP2	0.0	MWh_e				0	
Variable operation costs of HP1	1836.5	MWh_{heat}	at	2.0	=	3 673	
Variable operation costs of HP2	0.0	MWh_{heat}	at	2.0	=	0	
Fuel costs	4.1	GJ	at	5.6	=	23	
CO2 quotas	0.2	ton CO_2	at	8.0	=	2	
Variable operation costs of CHP1	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of CHP2	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	0	starts	at	30.0	=	0	
Start costs of CHP2	0	starts	at	30.0	=	0	
Start costs of HP1	5	starts	at	10.0	=	50	
Start costs of HP2	0	starts	at	10.0	=	0	
Total Operating Expenditures							**19 887**
Revenues							
Sale of electricity CHP1	0.0	MWh_e				0	
Sale of electricity CHP2	0.0	MWh_e				0	
Total Revenues							**0**
Net Heat Production Cost							**19 887**

Table 7: The NHPC at the DE plant during the first 28 days in September calculated using the simple analytic UC method.

Figure 12 shows the UC calculated with the simple analytic UC method for the same 7 days as in Figure 11 during the 28-day period. The large TES makes it possible to have few starts of HP1 - even if it is not allowed to operate with partial load.

Figure 12: The UC at the DE plant during 7 days in September using the simple analytic UC method.

In Table 8 is compared the three different UC methods. It is seen that the UC calculated with the advanced analytic UC method gives a NHPC which is less than 1% worse than the optimal NHPC calculated by the MILP solver UC method. On the other hand, the UC made by the simple analytic UC method is approximately 17% worse. Furthermore, the sale of electricity is 16% larger and the purchase of electricity is 3% smaller in the optimal UC compared to the UC calculated by the advanced analytic UC method.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 008**	**17 169**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	116.7	100.0	0
HPs [MWh_{heat}]	1 719.8	1 733.2	1 836.5
Boilers [MWh_{heat}]	1.2	4.5	1.2
Number of starts of CHPs	10	8	0
Number of starts of HPs	68	60	5
Purchase of electricity [EUR]	11 751	12 078	16 138
Sale of electricity [EUR]	4 957	4 260	0

Table 8: Comparing the UCs at the DE plant during the first 28 days in September using three different UC methods.

3.2.2 Comparison the UC methods on the first 7 days of September

The same test of the three UC methods, as described in the previous section, is conducted during the first 7 days of September. The short optimizing period is more relevant when making daily operation planning. In Table 9 is shown a comparison parallel to the comparison in Table 8. Similar results are seen when using the UC calculated with the advanced analytic UC method resulting in a NHPC 0.8% worse than the NHPC using the optimal UC, whereas the UC using the simple analytic UC method is approximate 15% worse.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4 214**	**4 248**	**4 853**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	440.0
Boilers [MWh_{heat}]	0.0	2.0	2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	2
Purchase of electricity [EUR]	2 912	2 974	3 909
Sale of electricity [EUR]	1 070	936	0

Table 9: Comparing the UCs at the DE plant during the first 7 days in September calculated using three different UC methods.

3.2.3 Testing with minimum operation and stop periods

A further test has been made, in which an extra constraint has been introduced. The minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours. The results of this test are shown in Table 10 and Table 11, where similar results are seen as in the 28 days calculations, that the advanced analytic UC method results in a NHPC 0.8% worse than the optimal NHPC, whereas the UC when using the simple analytic UC method is approximately 15% worse.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4 214**	**4 248**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	1 836.5
Boilers [MWh_{heat}]	0.0	2.0	1.2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	5
Purchase of electricity [EUR]	2 912	2 974	16 138
Sale of electricity [EUR]	1 069	936	0

Table 10: Comparing the UCs at the DE plant during the first 7 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

It is to be noticed that these extra constraints only reduce NHPC of the optimal UC. The fact that the NHPC is not changed in the advanced UC is amongst others due to the number of production periods are lower with the advanced UC than with the optimal UC.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 039**	**17 169**	**20 169**
Heat production:			
CHPs [MWh_{heat}]	113.3	100.0	0
HPs [MWh_{heat}]	1719 .8	1733 .2	1 833 .1
Boilers [MWh_{heat}]	4 .5	4 .5	4 .5
Number of starts of CHPs	9	8	0
Number of starts of HPs	67	60	6
Purchase of electricity [EUR]	11 756	12 078	16 342
Sale of electricity [EUR]	4 799	4 260	0

Table 11: Comparing the UCs at the DE plant during the first 28 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

In this section is demonstrated that the NHPC of the presented advanced analytic UC method is with-in 1% of the NHPC of the optimal UC at a generic complex DE plant. It is chosen to simplify the plant, in order for a MILP method to be able to deliver the optimal UC for optimizing periods of respectively 7 days and 28 days. These two periods are typical needed optimizing periods when planning daily operation or making yearly budgeting and long-term investment analysis at DE plants.

4. A method for analysing coordinated investments in production and storage capacity

Investments in large production capacity compared to the instantaneous heat demand at a DE plant needs new methods to be analysed, simply because the feasibility of an investment will be closely dependent on a simultaneous investment in a large TES. The large TES enables e.g. that a large CHP capacity can be fully used producing electricity in hours with high prices in the Day-ahead market, while the surplus heat production is stored in the TES until needed later. Similarly, the large TES enables e.g. that a large HP capacity can be fully used producing heat in hours with low prices in the Day-ahead market, while the surplus heat production is stored in the TES until needed later.

As part of this thesis work a method for analysing coordinated investments in production and storage capacity has been developed.

The description in this section is based on the appended article I. *A method for assessing support schemes promoting flexibility at district energy plants* and the submitted manuscript III. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system.* Much of the text in this chapter is copied verbatim from these articles, while many of the more general aspects in the papers are left out here.

The developed investment method consists of an Excel spreadsheet that through Visual Basic for Application (VBA) coding iteratively calls an energy system analysis tool, which for each size of CHPs, HPs and TES, calculates an optimized operation of the production units in a user-given time horizon (planning period). Calculated cash flows are returned to the spreadsheet for each combination, allowing the Net Present Value (NPV) to be calculated. Through iteration, the optimal size of CHPs, HPs and energy stores are thus identified by optimizing the Net Present Value (NPV).

4.1 Choosing an appropriate energy system analysis tool

The energy system analysis tool used in the investment analysis must be able to calculate an optimized operation of user-given production units in each hour of the planning period. This temporal resolution is required by amongst others hourly market prices. The planning period considered is typically 20 years.

Secondly, the tool must be able to assess the business economic consequences for the plant owner. Thirdly, it is a requirement for a tool to be used, that it allows calls from e.g. a spreadsheet, where DE plant design characteristics may be changed.

Sameti and Fariborz have made a comprehensive review of optimization approaches and tools to be used [114]. They conclude that while Mixed Integer Linear Programming (MILP) is the most widely used approach for optimization of DE systems, most models suffer from very long computational time when large networks are considered. Allegrini et al. [115] concludes in their

review of tools for simulation of DE systems that there are still many important challenges to be overcome if simulation tools are to provide the benefits on the urban level that they have delivered at the building scale. Olsthoorn et al. focus on storage techniques and renewable energy sources when comparing different tools and methods for modelling district energy plants [116]. Lyden et al. [117] makes a modelling tool selection process for planning of community scale energy systems including storage and demand side management. They conclude that COMPOSE, DER-CAM, energyPRO, EnergyPLAN, MERIT and MARKAL/TIMES are the six tools that meets all essential capabilities. Further to be mentioned is TRNSYS [118] meeting the above mentioned requirements. It is amongst these tools chosen to select energyPRO [34]. In energyPRO the time step may be 1 hour or less thus allowing a calculation of the hourly cash flow. It uses indexes for describing e.g. the development of demands for heating and cooling and the development in prices over the years, which implies that the operation of the production units between the years may change e.g. due to changed economic conditions.

energyPRO is based on analytical programming based on pre-defined methods for finding optimal operation – either through marginal production costs of units or through user-defined priorities. Productions are placed over one-year time horizons based on full foresight of e.g. spot market prices. As a starting point, energyPRO creates a matrix formed by the number of production units times the number of time steps (e.g. 1 h) in the planning period. Each of the cells in this matrix contains a calculated priority number indicating in which order productions are prioritised in the planning period. The priority number for e.g. a CHP in a certain time step could be the cost of producing 1 MWh heat reduced with the value of the associated produced electricity. Thus, if a project has three production units and the simulation is hourly made using one-hour time steps over a one-year period, the matrix would contain 3*8760 priority numbers. energyPRO assigns these hourly productions in a non-chronological way, starting with the production unit in the time step, that has the lowest priority number (highest priority) in the matrix taking into account the restrictions in the energy stores and transmission lines. After having tested if this production is possible, energyPRO continues to the production unit in the time step with the second lowest priority number in the matrix and tests whether this production is possible. This non-chronological way of assigning production has the consequence that each new production before being accepted has to be carefully checked to ensure that it does not disturb already planned productions.
The analyses in this paper are based on a perfect prognosis for electricity market prices when calculating the priority numbers in the matrix. energyPRO thus has perfect foresight and can optimise against known future electricity prices. This analytical method is described more thoroughly by Østergaard et al. [23].

Furthermore, an important reason for using energyPRO, is it is widely used by consultants to analyse investments in DE plants [101]. That brings the method for assessing support schemes close to how investment decisions are made. Furthermore, energyPRO is widely used for research, e.g. Sorknæs et al. have applied energyPRO to study the treatment of uncertainties in the daily operation of combined heat and power plants [102]. Østergaard et al. used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [23] and to assess the economy of such systems [103]. Fragaki et al. applied energyPRO to study the economic sizing of a gas engine and a thermal store for CHP plants in the UK [104,105]. Streckienė et al. studied the feasibility of

CHP-plants with thermal stores in the German Day-ahead market [106] and Østergaard studied heat and biogas stores' impacts on RES integration [107].

4.2 Choosing the optimal investment

There are different economic criteria used for choosing an optimal investment, amongst others Simple Pay Back time, Internal Rate of Return, NPV, or a combination of more criteria. Here is used the NPV of the additional cash flow at the plant in each month in the planning period, caused by the investment in new units.
As an example, when considering investment in CHPs and TES at a boiler-based DE plant, the payments relating to these additional units include amongst others:

- sale of electricity,
- support paid through the chosen support scheme,
- extra purchase of fuel, because a CHP uses more fuel than boilers to produce the same amount of heat,
- extra use of CO_2 quotas,
- fixed and variable costs of the CHPs,
- reduced variable costs of the boiler and
- the investments in the components.

An optimal solution found by optimizing the NPV may result in identifying too large CHPs and TES compared to what in fact will be established. Smaller sizes may be chosen to save investment cost, but the identified sizes still indicate what CHPs and TES will be established.
For a certain DE plant and a certain level of support the optimal size of the new production units and TES are determined in a two-dimensional matrix-calculation as illustrated in Table 12. Here a CHP capacity of 4.4 MW_e and a TES capacity of 480 m^3 is identified as the combination with the highest NPV. The path to this optimum goes through iterative calls of energyPRO starting with zero CHP and zero TES. First, the size of CHP is increased until the NPV starts to decrease. Keeping this CPH size fixed, the TES is increased until NPV starts to decrease. Then again, the size of the CHP is increased keeping the size of the TES fixed. This procedure continues, until no improved NPV is found.

At a capacity of 3.8 MW_e, the optimization procedure will start increasing the TES until a size of 420 m^3 is reached. Then CHP capacity is increased while keeping the size of the TES fixed. The size of the CHPs then ends at 4.4 MW_e. Then again, the size of the TES is increased keeping the size of the CHPs fixed, which ends the optimization at a CHP capacity of 4.4 MW_e and a TES of 480 m^3 since no further NPV improvement is possible.

In the method, it is possible to choose the precision of the found optimal solution, e.g. by choosing the size of steps when increasing the sizes of the new production units and TES, and it is possible to choose a minimum improvement in NPV for accepting an increase in the sizes of the components.

Total CHP capacity [MW_e]	TES [m^3]									
	0	**60**	**120**	**180**	**240**	**300**	**360**	**420**	**480**	**540**
3.00	2.515	2.585	2.627	2.651	2.662	2.665	2.663	2.659	2.654	2.648
3.20	2.563	2.642	2.692	2.722	2.738	2.744	2.744	2.742	2.739	2.735
3.40	2.598	2.686	2.742	2.777	2.797	2.805	2.807	2.806	2.803	2.800
3.60	2.623	2.715	2.775	2.815	2.838	2.849	2.853	2.853	2.851	2.848
3.80	2.632	2.727	2.794	2.838	2.865	2.878	2.884	2.885	2.884	2.882
4.00	2.627	2.727	2.797	2.846	2.878	2.895	2.902	2.905	2.905	2.903
4.20	2.605	2.713	2.790	2.845	2.883	2.903	2.913	2.917	2.918	2.917
4.40	2.570	2.687	2.772	2.834	2.876	2.902	2.915	2.922	2.924	2.924
4.60	2.522	2.648	2.742	2.809	2.857	2.887	2.904	2.913	2.916	2.917
4.80	2.461	2.596	2.698	2.772	2.823	2.857	2.877	2.888	2.893	2.896

Table 12: An example of the path to an optimal solution, shown in a section of a decision matrix of Net Present Values in Mio. EUR of investment in CHP and TES at a DE plant.

Using this heuristic to find an optimum offers a much faster calculation, compared to calculating all possible combinations of CHP´s and TES capacities. Shown in Figure 13 is an example of the investment analysis method being used in the appended article III. Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system [98].

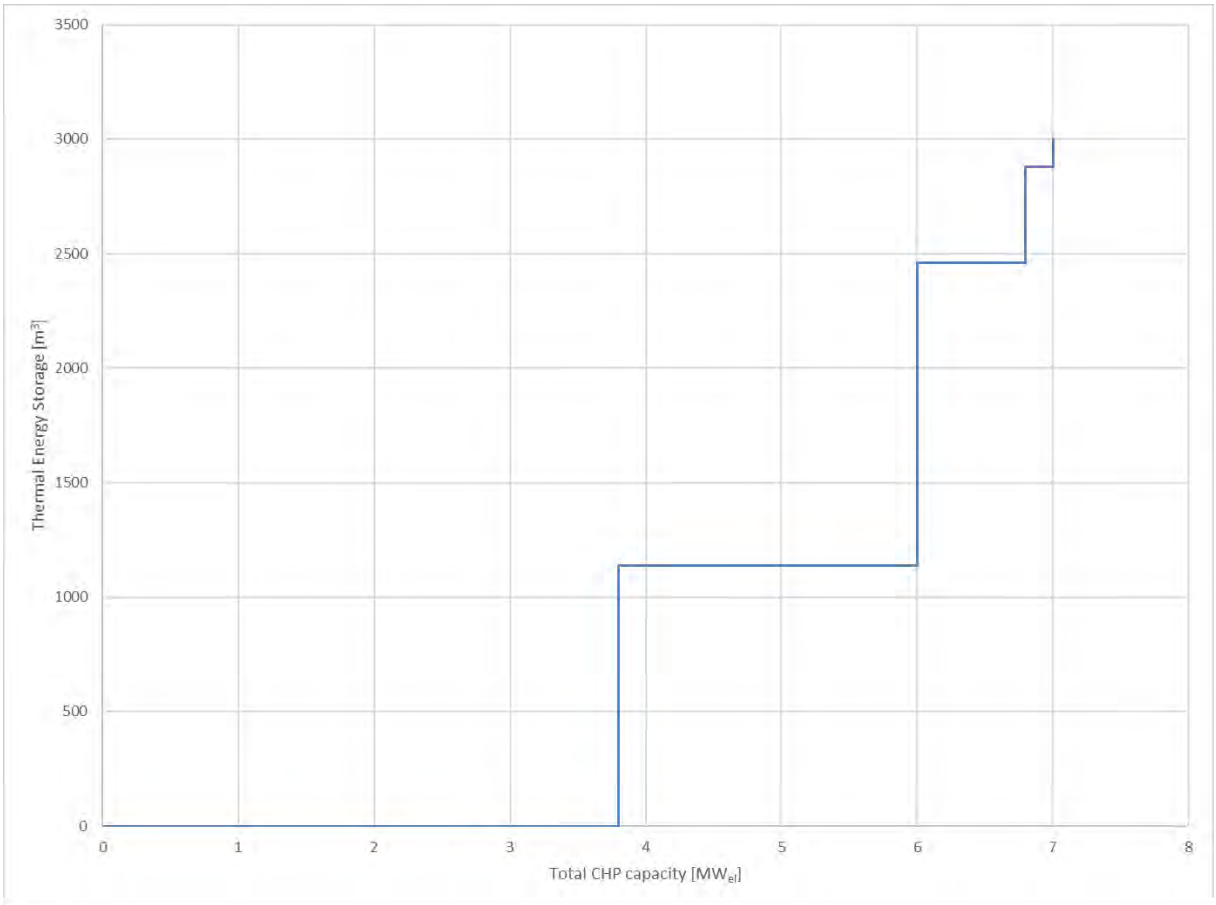

Figure 13: For a certain DE plant the optimal size of the CHPs and TES are determined in a two-dimensional matrix-calculation. In this figure is shown the path to the optimal NPV of the size of the CHPs and TES at the Triple tariff, as described in [98].

5. A method for comparing the effect of support schemes at DE plants

DE plants have a role to play but will often require support to fulfil this. For financial reasons, this should be minimised while supporting adequate quantities. In this section is presented a method for comparing support schemes promoting CHPs, HPs and TES at DE plants.

The description in this section is based on the appended article I. *A method for assessing support schemes promoting flexibility at district energy plants* and the submitted manuscript III. *Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system.* Much of the text in this chapter is copied verbatim from these articles, while many of the more general aspects in the papers are left out here.

Different schemes have been applied in different places at different times for supporting DE CHPs, amongst others Feed-in premiums, Feed-in tariffs, Quota obligations, Tax exemptions, Tenders and Investment aids. Each of these support scheme types can be designed differently and even combined with the aim of meeting the requirements for the support schemes.

Two of the most widely used support scheme types are the Feed-in premium types and the Feed-in tariff types, made as a triple tariff. These are introduced and reviewed in the next two sections. Hereafter in the following sections an example of the use of the method by comparing these two.

5.1 The Premium support scheme

The premium is paid on top of hourly wholesale electricity prices and is made as a flat-rate price supplement paid to CHPs for each produced MWh_e, independent of which hour the electricity is produced. There is not assumed any cap on the premium paid, that is to say that even if the wholesale electricity price in a certain is high, the DE plant will still receive the premium.

5.2 The Triple tariff support scheme

The procedure of determining the Triple tariff includes both a procedure for determining the time periods and the prices of the Peak, High and Low tariff. The procedure is similar to the used procedure in the Danish Triple tariff as described in the Danish legislation [33], and includes a procedure for calculating the savings at central power plants and the saved grid losses and grid investments. The procedure assumes a strict Phase 1 situation, where the DE CHPs is assumed to displace fossil fuelled condensing mode power plants.

5.2.1 The three load periods

When used in a certain country the first step in the procedure is to decide the periods of the Peak, High and Low tariff, which is made by analysing the demand for electricity and grouping it into three load situations with a weekly cycle, eventually being split into winter and summer load situations. The periods used in the analysis reported in this article are the ones used in Denmark in 2015; these are shown in Table 13. The tariffs paid for electricity delivered from local CHP plants is equal within each of the tariff periods but dependent on the voltage level at which the CHP production is delivered.

	Low tariff periods	High tariff periods in working days	Peak tariff periods in working days
Winter (October-March)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 17.00 19.00 – 21.00	08.00 – 12.00 17.00 – 19.00
Summer (April-September)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 21.00	08.00 – 12.00

Table 13: The separation of the year into low, high and peak tariff periods as applied in the Danish Triple tariff in 2015 [33].

5.2.2 The procedure for calculating savings at central power plants

The total saved costs at central power plants, SC_i, for each reduced production of 1 MWh_e depends if the reduced production takes place in Low, High or Peak tariff periods and illustrated in Equation (2), where the index i designates the tariff period.

$$SC_i = \frac{GP*3.6}{\eta} + V_{Plant} + \frac{(YC_{plant}*I_{plant}+YF_{Plant})*D_i}{FLH_i} \quad (1)$$

The saved cost is split into saved fuel, variable operation and maintenance cost, investment cost and fixed operation and maintenance cost. Saved fuel and variable operation and maintenance cost is straightforward related to reduced amount of produced electricity, but how a reduction in produced electricity translates into reductions in investment costs and reductions in fixed operation and maintenance cost is of a more probabilistic nature. In this Triple tariff procedure is applied a method where a part of the reduced need for investment and reduced fixed operation and maintenance cost is assigned to reduced produced electricity in Peak and High tariff periods respectively, but no part is assigned to Low tariff periods.

In equation (1) η is the net electrical efficiency at central power plants, GP the natural gas price is in EUR/GJ and the V_{Plant} variable operation and maintenance cost is in EUR/MWh_e, YC_{plant} is the yearly capital cost factor of investment, I_{plant} is the investment cost in EUR/MW_e, YF_{Plant} is the yearly fixed operation and maintenance cost in EUR/MW_e, D_i are distribution keys between Low, High and Peak tariff periods for investment and yearly fixed costs and FLH_i is full load hours of electricity demand calculated for each of the Low, High or Peak tariff periods as the electricity demand in the period divided by the peak demand for electricity of the year.
The yearly capital cost factor - YC_{plant} - is calculated as an annuity (Equation (2)) dependent on the discount rate (r) and the life-time of the investment (L). The yearly capital cost factor thus determines the share of an investment that is attributed to each year of operation.

$$YC = \frac{r}{1-(1+r)^{-L}} \quad (2)$$

5.2.3 The procedure for calculating saved grid losses and grid investments

Delivering electricity to the 60 kV-grid is assumed to replace an amount of electricity to be delivered from the central power plants. However, delivering one unit of electricity in the 60 kV-grid replaces more than one unit from the central power plant as grid losses in the 150 and 400 kV grids are avoided. Also, as grid losses increase with the transmission system load, the value of delivery of electricity to the 60 kV-grid is higher, the higher the load situation is. Furthermore, delivering electricity in the 60 kV-grid is assumed to reduce the need for investments in the 150 kV-grid, and again, this reduced investment is larger at higher load situations, using the same arguments that led to equation (1). Thus, the compensation for electricity delivered in the 60 kV-grid, $P@60_i$, depends on the fact if the production happens in Low, High or Peak tariff periods and is given by equation (3). $NL150_i$ is the load and tariff period-dependent net Loss percentage in the combined 150 & 400 kV-grid, YC_{grid} is the yearly capital cost factor of investment in electrical grids and I_{150} is investment cost in the 150 kV-grid in EUR/MW_e.

$$P@60_i = SC_i/(1 - NL150_i) + YC_{grid} * I_{150} * D_i/FLH_i \quad (3)$$

Similar conditions apply when delivering electricity to the 10 kV-grid or to the 0.4 kV-grid. Thus, the paid compensations of electricity delivered to the 10 kV-grid, $P@10_i$, and to the 0.4 kV-grid, $P@0.4_i$, are given by Equations (4) and (5).

$$P@10_i = P@60_i/(1 - NL60_i) + YC_{grid} * I_{60} * D_i/FLH_i \quad (4)$$

$$P@0.4_i = P@10_i/(1 - NL10_i) + YC_{grid} * I_{10} * D_i/FLH_i \quad (5)$$

Here $NL60_i$ and $NL10_i$ are the net Loss percentages in the 60 and 10 kV-grids respectively, and I_{60} and I_{10} are investment cost in the 60 and 10 kV-grids respectively in EUR/MW_e.

Finally, supplying electricity to the 0.4 kV-grid directly at the site of consumption furthermore is assumed to reduce grid losses and reduce the need for investment in the 0.4 kV grid. Thus, the compensation to be paid for electricity delivered to the consumer, $P@consumer_i$, is given by Equation (6)

$$P@consumer_i = P@0.4_i/(1 - NL0.4_i) + YC_{grid} * I_{0.4} * D_i/FLH_i, \quad (6)$$

where $NL0.4_i$ is the net Loss percentage in the 0.4 kV-grid and I_{150} is investment cost in the 0.4 kV-grid in EUR/MW_e.

Notice that the procedure for calculating paid prices is cumulative – i.e. supplying at 0.4 kV also provides saving in 10, 60, 150 and 400 kV grids so therefore the rationality of the equations is that prices at higher voltage levels always influence prices at lower voltage levels.

5.2.4 The data used to calculate the Triple tariff prices

The Triple tariff prices are calculated with the power plant and grid data shown in Table 14, and the tariff-period dependent data shown in Table 15. The shown data are equal to the data used in the

Danish Triple tariff at the end of 2015. The used power plant net electrical efficiency used is high but comparable to the efficiency expected in 2020 by Danish Energy Agency [112].

Power plant net electrical efficiency	η	58%	
Power plant, Variable operation and maintenance cost	V_{Plant}	2.54	EUR/MWh$_e$
Power plant, Yearly fixed operation and maintenance cost	YF_{Plant}	13,597	EUR/MW$_e$
Real discount rate	r	3%	
Investment cost in power plant	I_{plant}	0.905	MEUR/MW$_e$
Life time of power plant	L_{plant}	25	years
Yearly capital cost factor of investment in power plant	YC_{plant}	0.05743	
Investment cost in the 150 kV-grid	I_{150}	0.286	MEUR/MW$_e$
Investment cost in the 60 kV-grid	I_{60}	0.095	MEUR/MW$_e$
Investment cost in the 10 kV-grid	I_{10}	0.054	MEUR/MW$_e$
Investment cost in the 0.4 kV-grid	$I_{0.4}$	0.054	MEUR/MW$_e$
Life time of electrical grids	L_{grid}	25	years
Yearly capital cost factor of investment in electrical grids	YC_{grid}	0.05743	

Table 14: The power plant and grid data not depending on the tariff periods, used for calculating the Triple tariff.

		Low tariff	High tariff	Peak tariff
Hours per year	H_i	5010	2498	1252
Full load hours of electricity demand	FLH_i	2475	1728	1097
Distribution keys for investment and yearly fixed costs	D_i	0	0.5	0.5
Net Loss percentage in the 150 + 400 kV-grid	$NL150_i$	2.8%	4.2%	4.7%
Net Loss percentage in the 60 kV-grid	$NL60_i$	2.1%	3.2%	3.6%
Net Loss percentage in 10 kV-grid	$NL10_i$	1.4%	2.7%	3.5%
Net Loss percentage in 0.4 kV-grid	$NL0.4_i$	2.8%	5.1%	6.8%

Table 15: The power plant and grid data depending on the tariff periods, used for calculating the Triple tariff.

5.3 The DE plant case

The DE plant case is similar to the case used in [39] and shortly recapitulated in this section. The yearly heat delivered to the district heating grid is 40 GWh of which grid loss and domestic hot water represent 40% and are assumed to be constant and thus also weather independent.
The remaining 60% is the space heating and assumed linearly dependent on ambient temperature. It is assumed that space heating is only required in days with an average temperature below 15 °C. A diurnal variation is assumed, with the delivered heat demand approximately 20% lower during the nocturnal hours compared to hours during daytime, which is based on empirical evidence from Danish DH systems [119]. The resulting heat demand requires an average delivered heat from the plant of 4.6 MW, with a maximum heat delivered from the plant of 11.6 MW and a minimum of 1.6 MW.

As the reference situation for analysing an investment in CHPs and TES, an existing DE plant is assumed to produce the heat on existing heat-only boilers. These boilers are assumed to have an efficiency of 97.1% and variable operation costs of 1.10 EUR/MWh$_{heat}$, which in the reference situation with the assumed economic conditions described in this section gives a yearly heat production cost of 0.938 M EUR.

Investment and operation costs are assumed to be strictly proportional to the sizes of the CHPs – thus it is not important in how many units the CHPs are split into. However, it is chosen to split the CHP capacity between two CHP units, as shown in Figure 8, which is in good accordance with how DE plants are designed, as exemplified at online presentations at [119]. Splitting the CHP capacity in more units also reduces the need to include partial load operation characteristics.

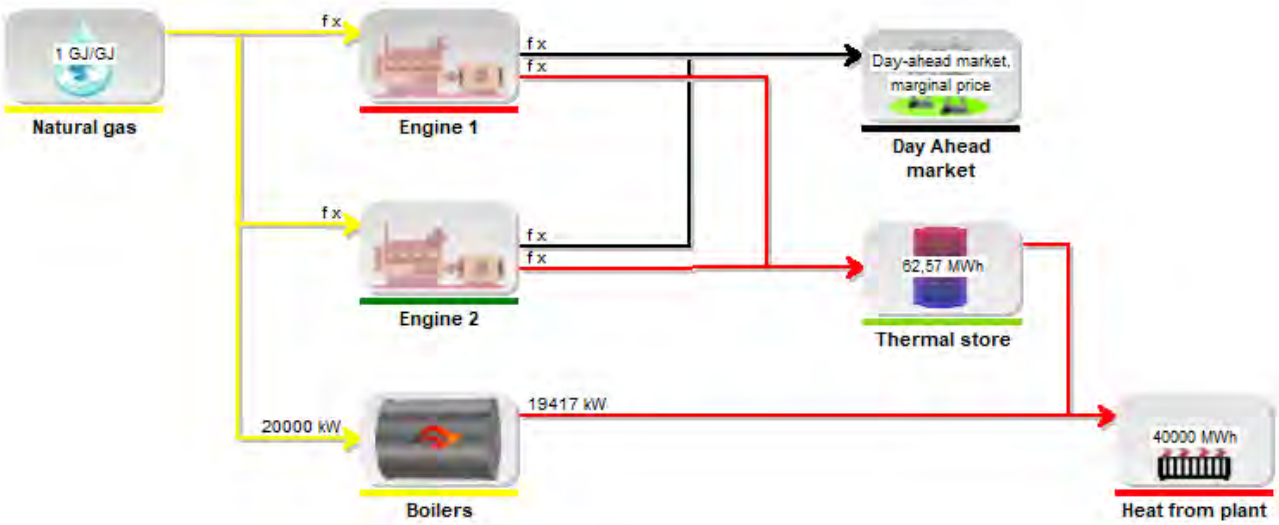

Figure 14: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - 2 CHPs and a TES.

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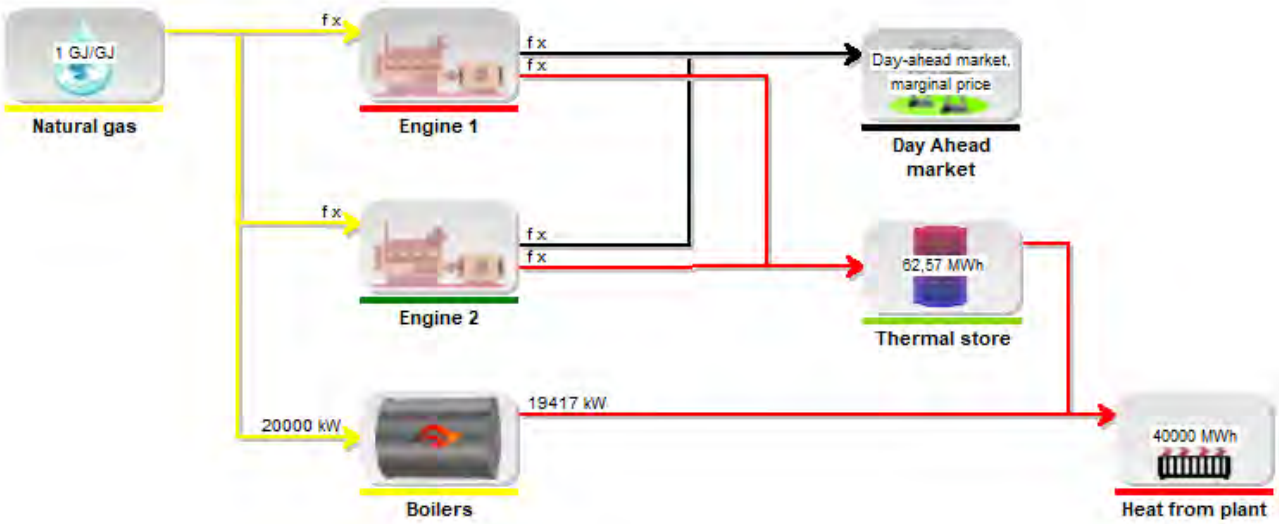

Figure 15: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - 2 CHPs and a TES.

5.4 Technical and economic assumptions

In this comparison, efficiencies are chosen to be kept constant over time and with no size-dependency. A similar simplification has been made regarding investment and operation costs which are being modelled proportionally to the sizes of both the CHPs and TES. An overview of technical and economic data used in the comparison is shown in Table 16. The data correspond to the data used in [39].

Gas price	5.60	EUR/GJ
CO_2 quota price	8.00	EUR/tonne
Existing boilers		
Heat efficiency	97.1%	
Variable operation costs	1.00	EUR/MWh_{heat}
CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fixed operation costs	10000	EUR/MW_e/year
Variable operation costs	5.4	EUR/MWh_e
Investment in CHPs	650000	EUR/MW_e
Non-availability periods per year	16	days
Investment in installation	350000	EUR/MW_e
Thermal storage		
Investment in thermal storage	200	EUR/m^3

Table 16: Technical and economic characteristics (2016-prices) used in the comparison of the two support schemes based on [112]

The cost for society when providing a support scheme is in this analysis set equally to the NPV of the paid support in the planning period of 20 years. The support is calculated for each hour during the planning period and is subsequently summed in an NPV calculation to determine the total support in the planning period.

For the Premium scheme, the cost of the support in a certain hour is calculated simply as the premium multiplied by the electricity produced on the CHPs in that hour.
For the Triple tariff, the support in a certain hour is calculated as the tariff in that hour minus the Day-ahead price in that hour. This difference is then multiplied with the electricity produced on the CHPs in that hour. This interpretation of support is consistent with the way a Triple tariff is often administered. Being paid a Triple tariff often includes that either the transmission system operator or a trader (balancing responsible party) is responsible for selling the produced electricity at the Day-ahead market, thus it is only the discrepancy between the Triple tariff and the Day-ahead price in that hour, that makes up the support, often to be paid by the consumers through a grid tariff. That is also to imply, that if in a certain hour the price in the Day-ahead market is higher than the Triple tariff, the support will be negative in that hour.

In this comparison the Day-ahead prices for all years in the planning period are set as the hourly prices in West Denmark in 2016.

5.5 Results of the comparison of the two support schemes

This section introduces a two-step procedure for comparing support schemes and applies to the case with the given support schemes.

The first step in comparing the two support schemes is to calculate the business economic optimal CHP and TES with the Triple tariff. The result of this calculation is shown in Figure 13 showing an optimal total CHP capacity of 7 MW_e and a TES size of 3000 m^3.
The next step is to determine the support level of the Premium scheme, that results in the same optimal CHP capacity of 7 MW_e. This way of finding the support level of the Premium scheme, that gives the same CHP capacity of 7 MW_e is shown in Figure 16. The support level is found to be 66.67 EUR/MWh_e.

It is illustrated in the figure that a Premium scheme support less than 10 EUR/MWh_e causes no CHP capacity to be installed and from a level of support around 25 EUR/MWh_e the growth in electrical CHP capacity becomes smaller as operation is restricted by a limited heat demand at the DE-plant. The slightly irregular shape of the graph is due to the fact that when identifying the optimal NPV the step value for electrical capacity is set equal to 0.2 MW_e and the step value for TES size is set equal to 60 m^3. These step sizes are chosen to reduce calculation time without compromising the conclusions based on the calculation.

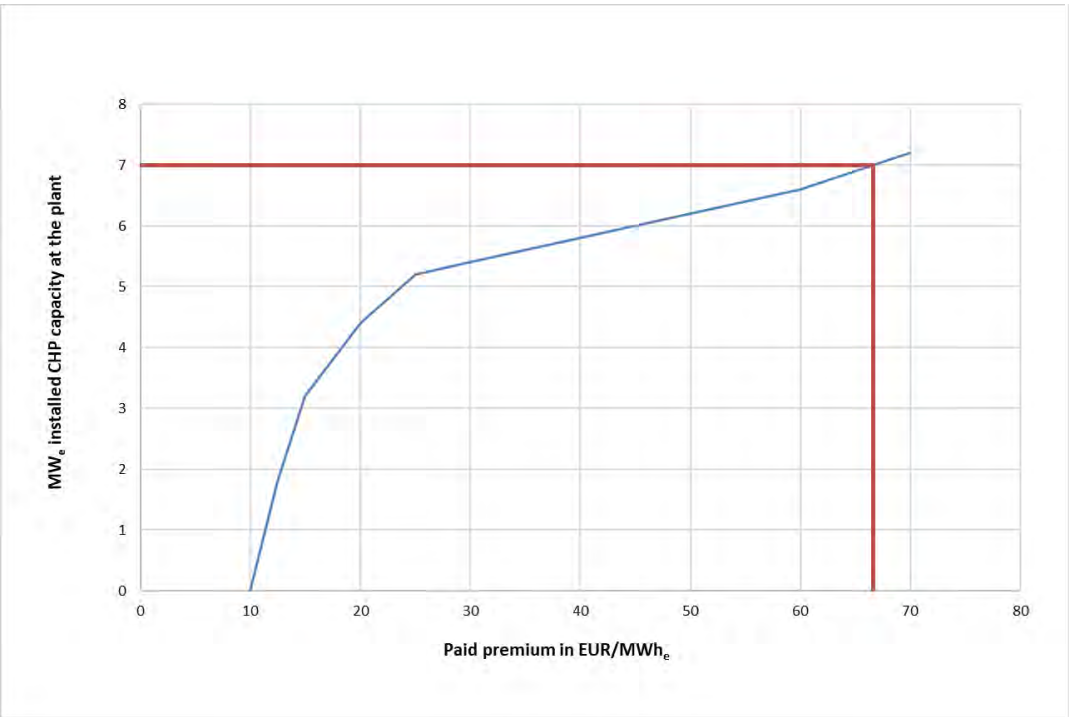

Figure 16: Determining the paid premium giving the total CHP capacity of 7 MW_e being equal to 66.67 EUR/MWh_e.

The results are shown in Table 17. It is seen that at this total CHP capacity of 7 MW_e the belonging TES capacity is the double when using the Triple tariff than when using the Premium scheme, which also implies a total investment in CHP and TES capacity that is slightly bigger when using the Triple tariff than when using the Premium scheme. The net present value in a 20-year period (NPV_{20}) of the changed cash flow caused by the investment in the CHPs and TES is around 22 M EUR bigger when using the Premium scheme. This is also reflected in the extra NPV_{20} of support to the plant when using the Premium scheme compared to the Triple Tariff Scheme.

This is the most thought-provoking result; that the societal cost is nearly three times bigger for providing a certain CHP capacity when using the Premium scheme than when using the Triple tariff.

	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and store [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity produc-tion [MWh_e]
Triple tariff	7.00	3000	7.60	3.59	12.92	34440
Premium scheme (66.67 EUR/MWh_e)	7.00	1520	7.30	25.48	34.05	34345

Table 17: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW_e.

6. Discussion

The work done in this PhD study has made the first steps towards the development of next generation generalized energy system simulation tools for district energy, being able to analyse very different alternatives for DE plants providing heating and cooling. In this section is discussed questions that have to be further researched when developing these tools.

6.1 DE plants participating across more of the electricity markets

The developed tools shall be able to simulate DE plants participating across more of both the existing and future electricity markets, to make a proper analysis of the value of large production and storage capacity. This requires flexible tools to be able to do such simulations, because the organization of these markets, when it comes to e.g. gate closures and price settlements may be very different.

As seen in West Denmark, the electricity markets may be split into five markets. The Agency for the Cooperation of Energy Regulators (ACER), an EU agency, is working on creating common balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves [48]. These balancing markets, as indicated in Figure 17, will together with the two whole-sale markets (Day-ahead market and Intraday market), be the five markets that DE plants often can choose between for potential participation – with variation across different countries.

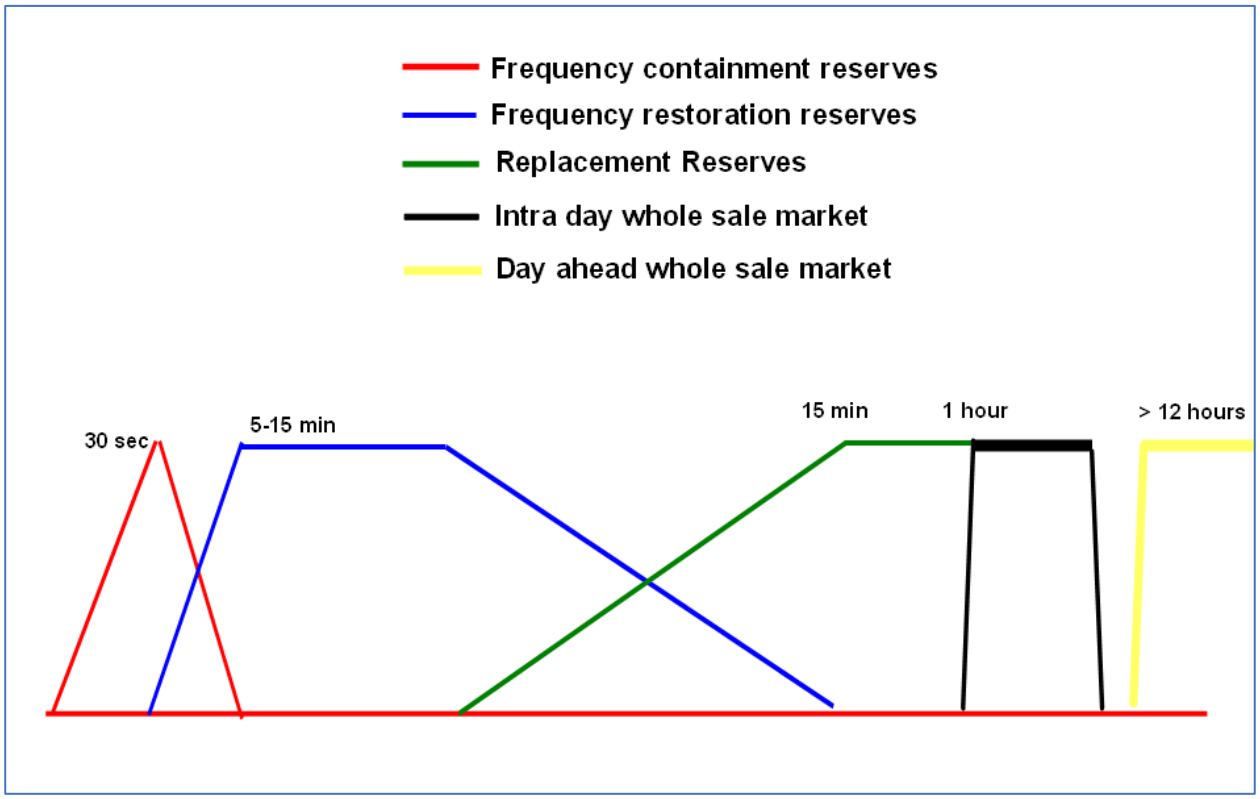

Figure 17: ACER´s [47] general framework for the organization of thee electricity markets.

The complexity of simulating DE plants participating across these markets is shown online at [119] for both the current and historic operation of the West Danish electricity system as well as examples of the current and historic operation of five West Danish DE plants.

As an example, Figure 17 shows the operation of the West Danish electricity system 8th of August. The bottom dark blue area shows the aggregated production of the wind turbines, the yellow shows the production of the PV, the lighter dark blue areas shows the power production at the distributed DE plants and at the top the power production at the central power plants. It is seen that the wind turbines in many hours produce around 10 times more power than the distributed DE plants and the central power plants. The green line shows the prices in the West Danish Day-ahead market, and the blue line (upward regulation) and yellow line (downward regulation) show activation prices in the West Danish Replacement Reserves market (Regulating power market).

What makes 8th of August noteworthy is the high upward regulation prices from 9-11 o´clock, which showed prices around 2000 DKK/MWh$_e$. Furthermore, what makes 8th of August noteworthy was that it seems that wind turbines from 17-20 o´clock won downward regulation, but as there is not shown yellow prices in these hours, it was probably not in the Replacement Reserves market but probably in the Special regulation market [120], which is a special market operated by the TSO to avoid bottle necks in the grid.

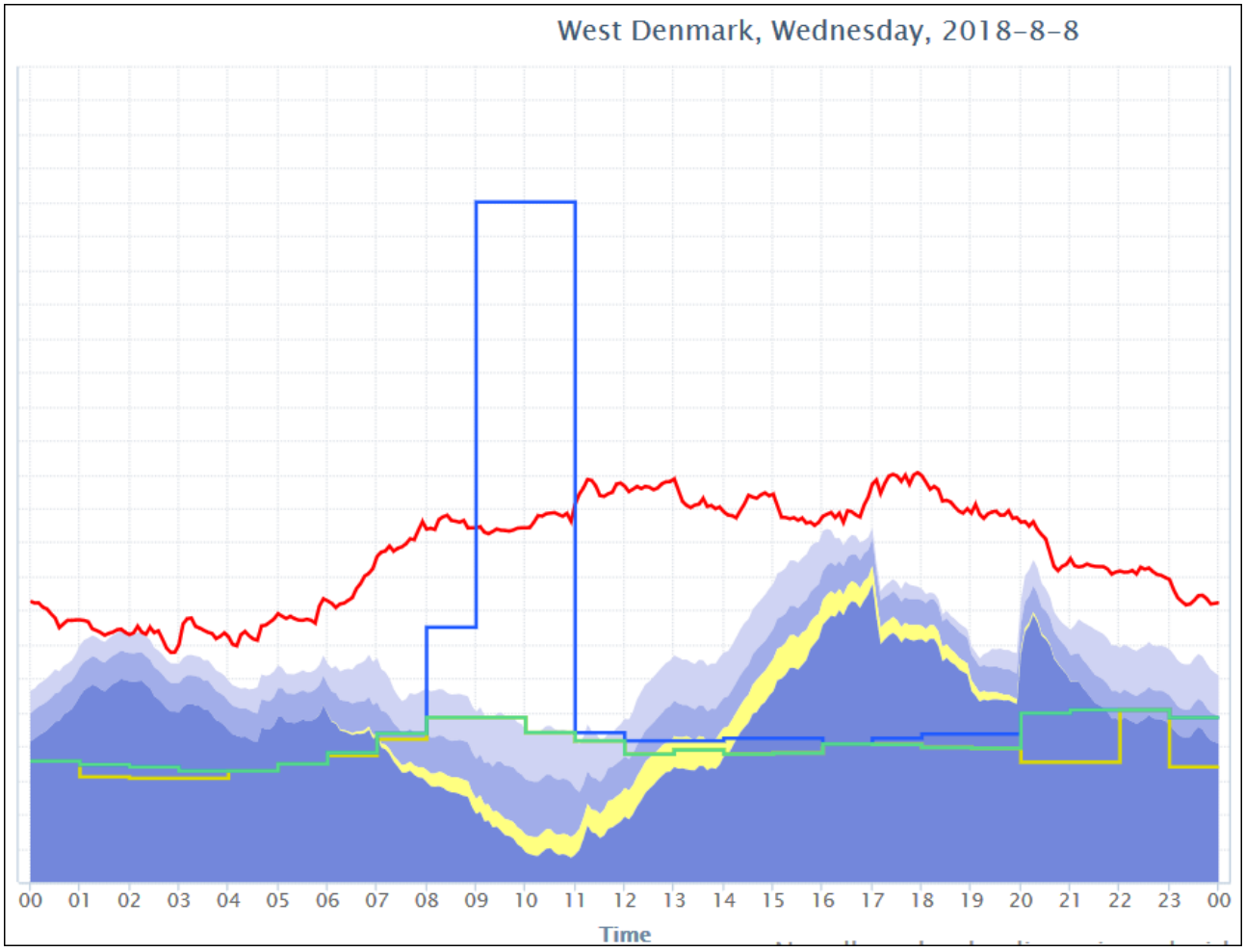

Figure 18: The operation of the West Danish electricity system 8th of August 2018 [119]

It is interesting to observe how the DE plants operated that day. In Figure 19 is shown the operation of Skagen DE plant. It is seen that two of the CHPs were activated (in total 9.4 MW_e and 14.4 MW_{heat}) from 9 to 11 o´clock in the well-paid hours for upward regulation in the Regulating power market. Similarly the electrical boiler was activated from 17 to 20 o´clock winning downward regulation (in total 10 MW_e). This day both the CHPs and the electrical boiler created valuable earnings, that simulation tools have to be able to reproduce.

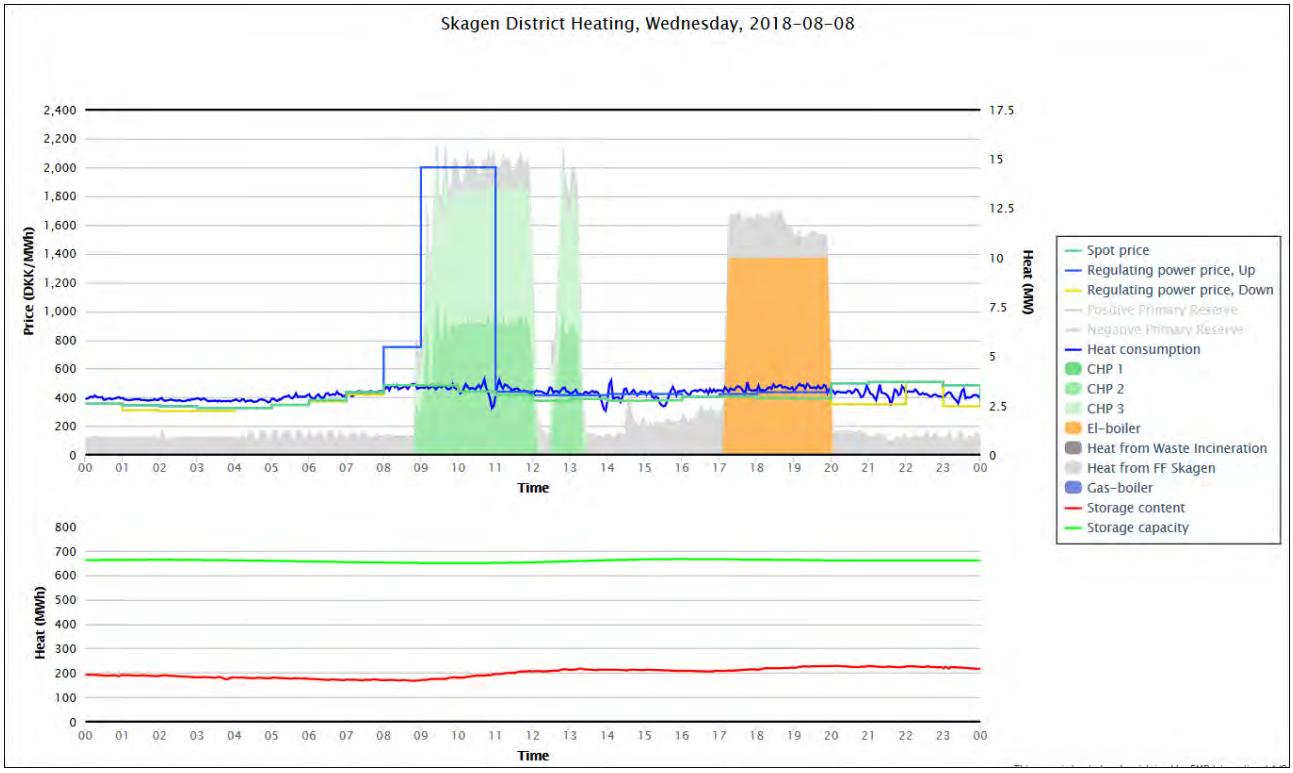

Figure 19: The operation of Skagen DE plant 8th of August 2018 [119]

What makes 8th of August demonstrate is that future research is needed to allow a proper simulation of DE plants participating across more of the electricity markets, when looking into the operation of some of the other DE plants shown online at [119].

As seen in Figure 20 the two CHPs at Hvide Sande were not activated from 9 to 11 (in total 7.4 MW_e and 9.8 MW_{heat}), and as seen in Figure 21 the CHP at Ringkøbing was not activated from 9 to 11 o´clock (in total 8.8 MW_e and 10.3 MW_{heat}).
When it comes to winning down ward regulation from 17 to 20 o´clock only Hvide Sande was activated (in total 6 MW_e and 6 MW_{heat}), but not Ringkøbing (in total 12 MW_e and 12 MW_{heat}).

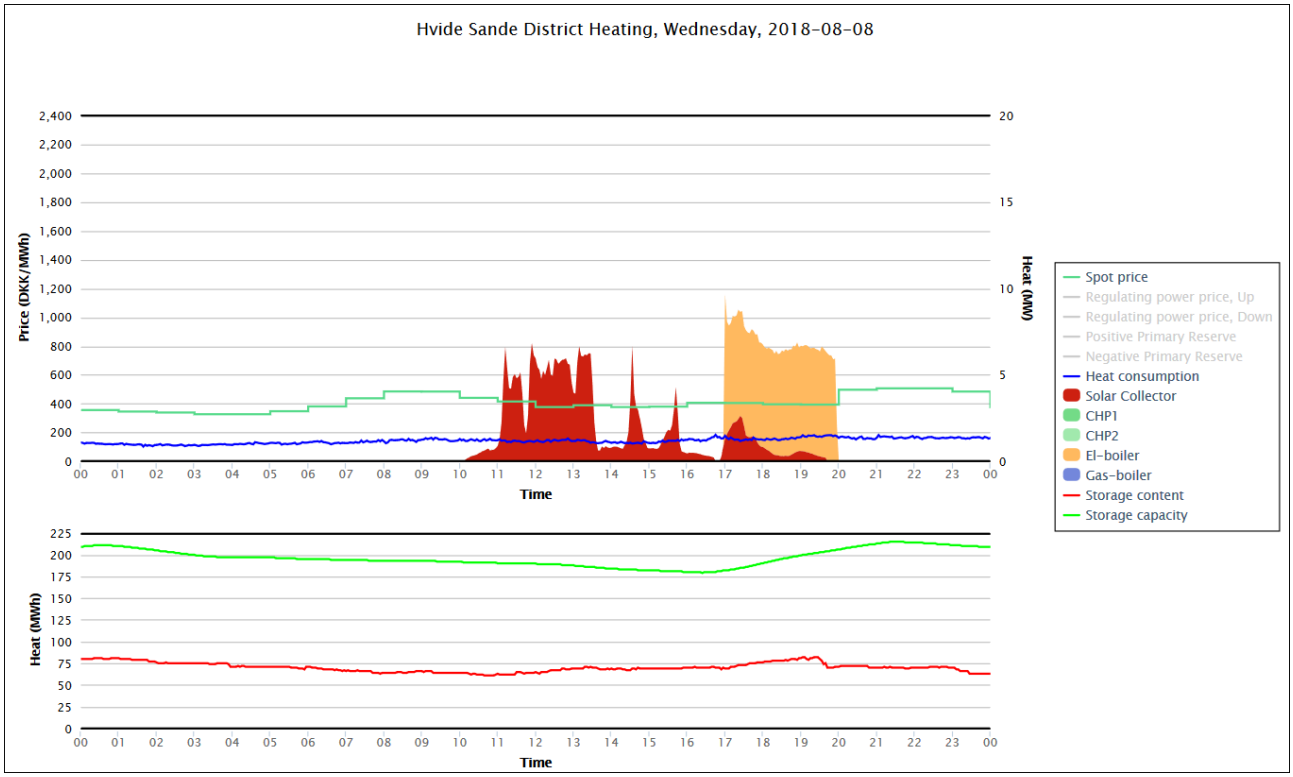

Figure 20: The operation of Hvide Sande DE plant 8th of August 2018 [119]

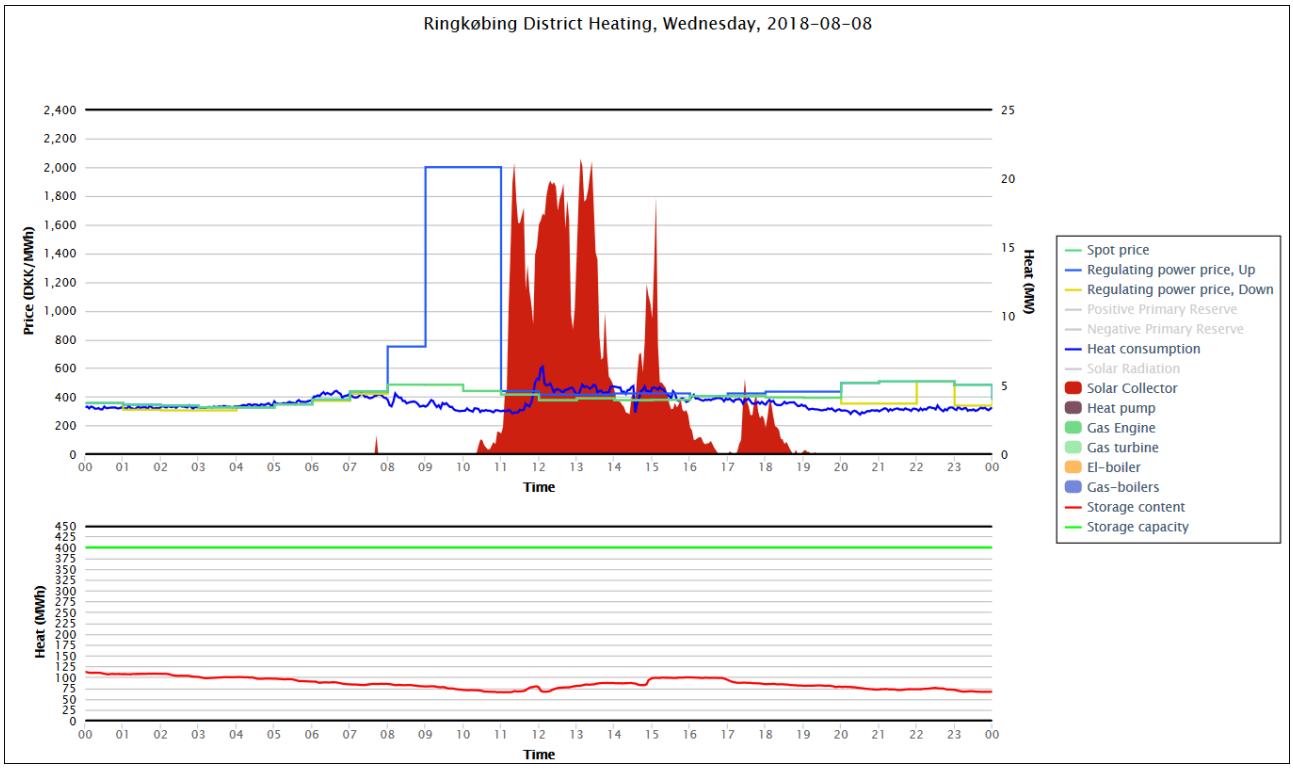

Figure 21: The operation of Ringkøbing DE plant 8th of August 2018 [119]

Another example showing that future research is needed to allow a proper simulation of DE plants participating across more of the electricity markets is seen at Skagen DE plant 16th of December 2018. From 2-6 o´clock the TSO needed downward regulation and the prices in the Regulating power market became negative, making it very attractive for DE plants to win downward regulation. But only the boiler won downward regulation from 2-6 o´clock. It has to be investigated why the CHPs did not stop in these hours.

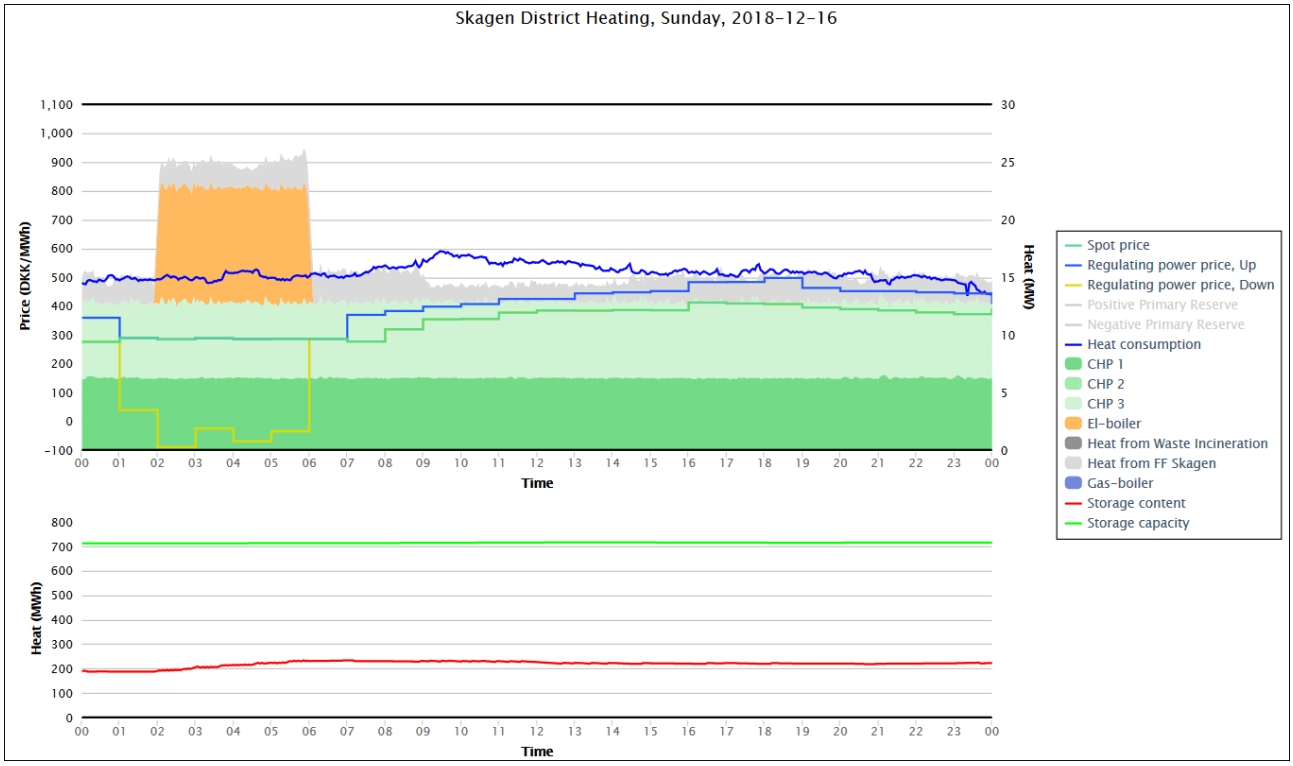

Figure 22: The operation of Skagen DE plant 16th of December 2018 [119]

6.2 More research in complex production units are needed

Development of next generation generalized energy system simulation tools for district energy needs to use sufficiently simplified models for each of the production units at the DE plant, yet using so detailed model for each of the production units that the calculated operations are robust for deciding new investments and daily operation.

Robust models for HPs at DE plants are needed, but e.g. when the heat source is ambient temperature, they might become complicated as illustrated in Figure 23 and Figure 24. As is seen the heat production at the HP are very fluctuating. The manager at Ringkøbing DE plant [121] has informed that it is due to that the heat exchanger has regularly to be defrosted when ambient temperatures are low.

Figure 23: The ambient air heat source for the HP at Ringkøbing DE plant [119].

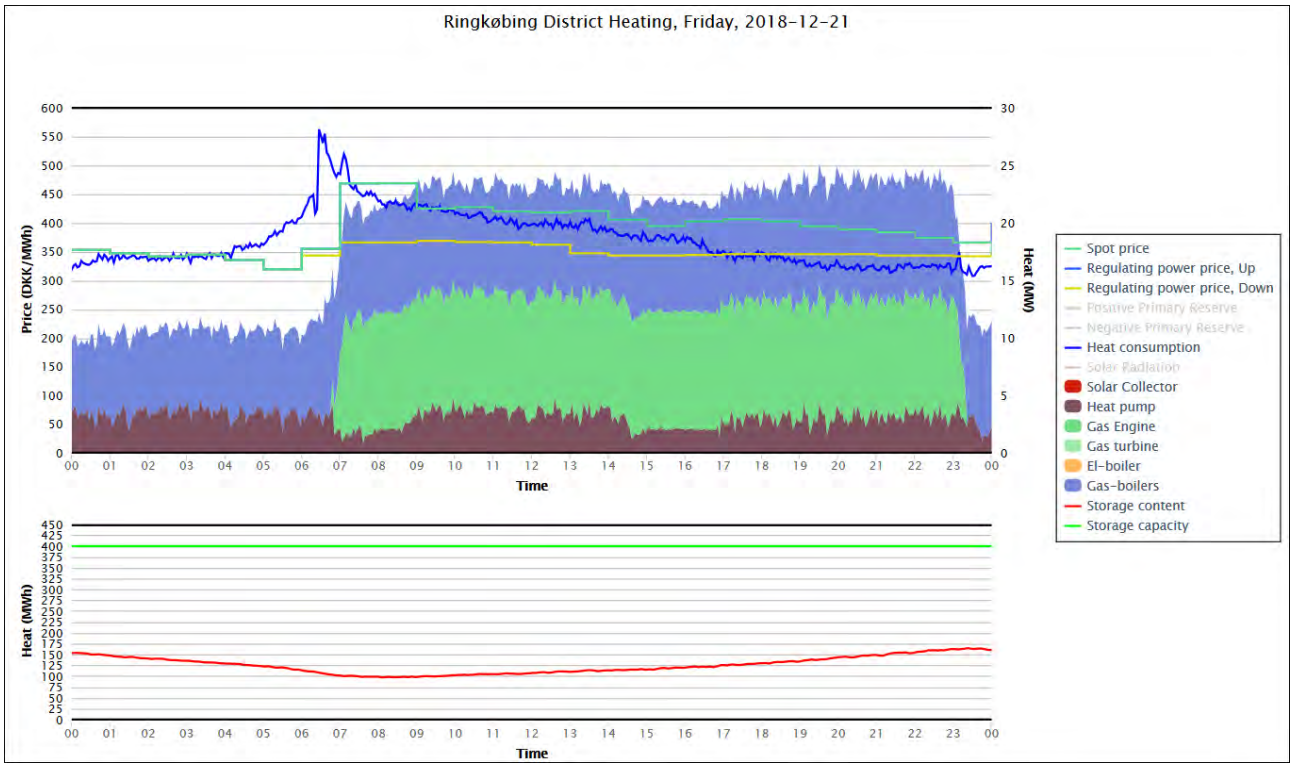

Figure 24: The operation of Ringkøbing DE plant 21th of December 2018 [119]

6.3 More research in unit commitment methods at DE plants are needed

The next steps in the research of the UCs for DE plants could be to making use of and combining the best of analytic and solver-based UC methods, and to compare these methods against the real UCs seen at DE plants. Examples of further research in UC is given in this section.

6.3.1 CHP operated in both condensing mode and extraction mode

Apparently, the UC of a CHP being able to be operated in both condensing mode and extraction mode is not easily made with the advanced analytic UC method presented in Section 3.1.1, because the needed priority numbers become multi-dimensional. In Figure 25 this is illustrated by a two-dimensional model to describe the multitude of operation modes possible, which is illustrated as a feasible operating region of such a CHP plant (operation modes allowed inside the polygon area).

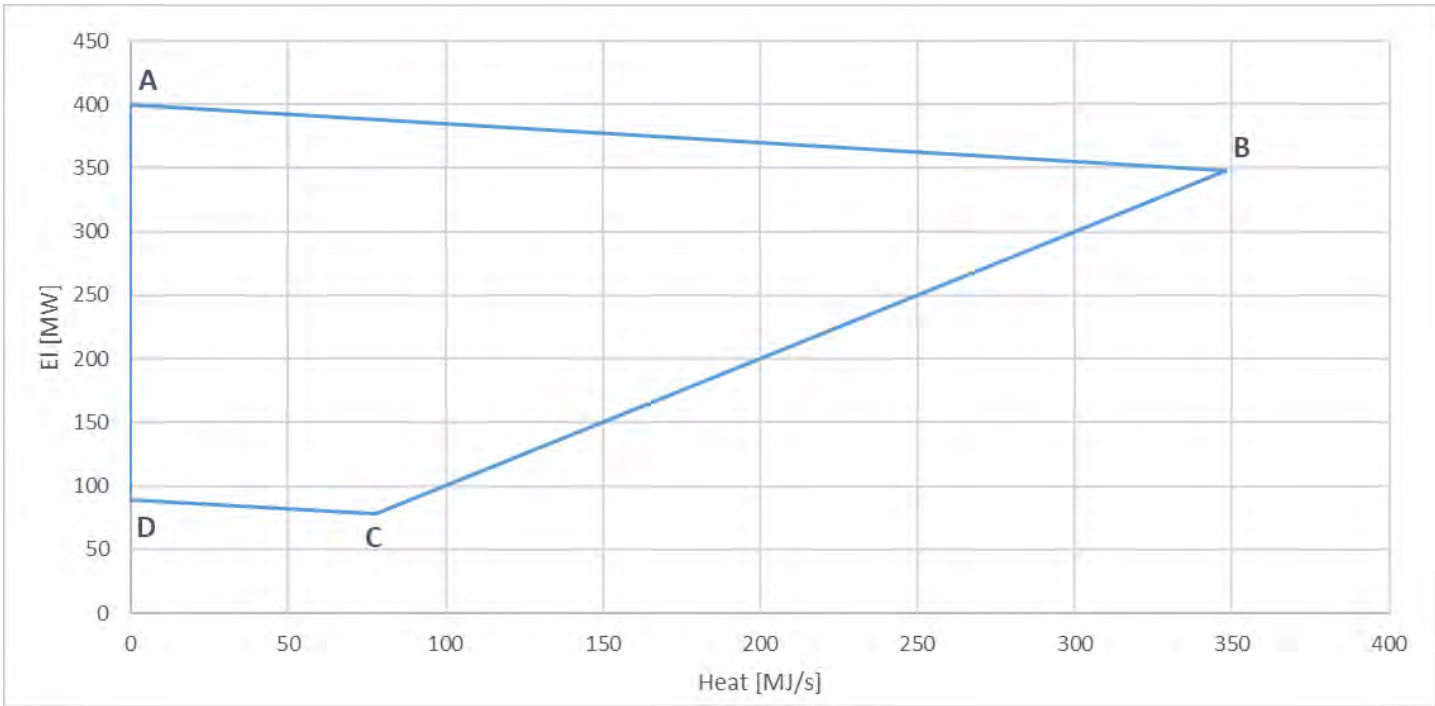

Figure 25: A CHP being able to be operated in both condensing mode and extraction mode inside the polygon area.

However, it is expected to be possible to simplify the modelling of this CHP, without compromising a sufficiently precise energy system analysis. This is done by assuming that all operation happens on the edge of the polygon and that the CHP is modelled as four separate ECUs operated in subsequent operation modes, as shown in Table 18 and in Figure 26.

Operation modes of extraction plant	Fuel consumption [MJ/s]	Heat production [MJ/s]	El. production [MW]	El. Efficiency [%]	Total efficiency [%]
[A] Full Condensing Mode	888,9	0,0	400,0	45,0%	45,0%
[B] Full Backpressure Mode	888,9	348,0	347,8	39,1%	78,3%
[C] Min Backpressure Mode C	198,9	78,0	77,8	39,1%	78,3%
[D] Min Condensing Mode	198,9	0,0	89,5	45,0%	45,0%
Modelled as separate subsequent operation modes					
Min Condensing Mode zero to D	198,9	0,0	89,5	45,0%	45,0%
Min Backpressure Mode D to C	0,0	78,0	-11,7		
Full Backpressure Mode C to B	690,0	270,0	270,0	39,1%	78,3%
Full Condensing Mode D to A	690,0	0,0	322,2	46,7%	46,7%

Table 18: CHP modelled as 4 separate ECUs operated in subsequent operation modes.

Notice that in fact "Min Backpressure Mode D to C" is producing negative electricity and is as such modelled as a heat pump.

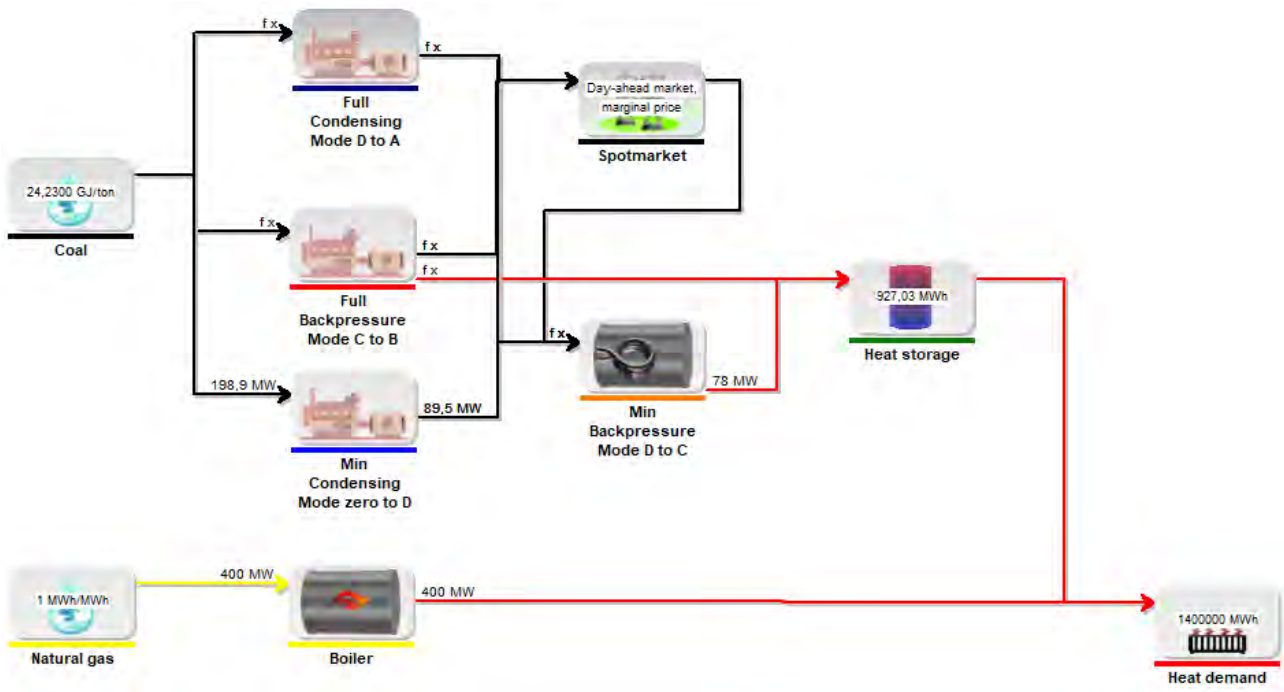

Figure 26: An energy plant equipped with a CHP modelled as four separate ECUs operated in subsequent operation modes and equipped with a gas boiler.

The operation strategy of a usual gas engine CHP is about coproducing heat and electricity in hours with high spot prices. That is not the case with a CHP being able to be operated in both condensing mode and extraction mode. On the contrary it shall in hours with high spot prices stop coproducing heat and electricity and instead produce electricity in condensing mode to allow for the highest electricity production possible.
Assuming an economy of the plant in Figure 26 being described simple by a cost of coal of 600 DKK/ton and an operation and maintenance cost of the CHP of 30 DKK/ton of coal (heat value in

coal of 24.23 GJ/ton) and a production cost on the gas boiler of 500 DKK/MWh$_{heat}$, gives a NHPC as function of spot prices shown in Figure 27 for the separate operation modes.

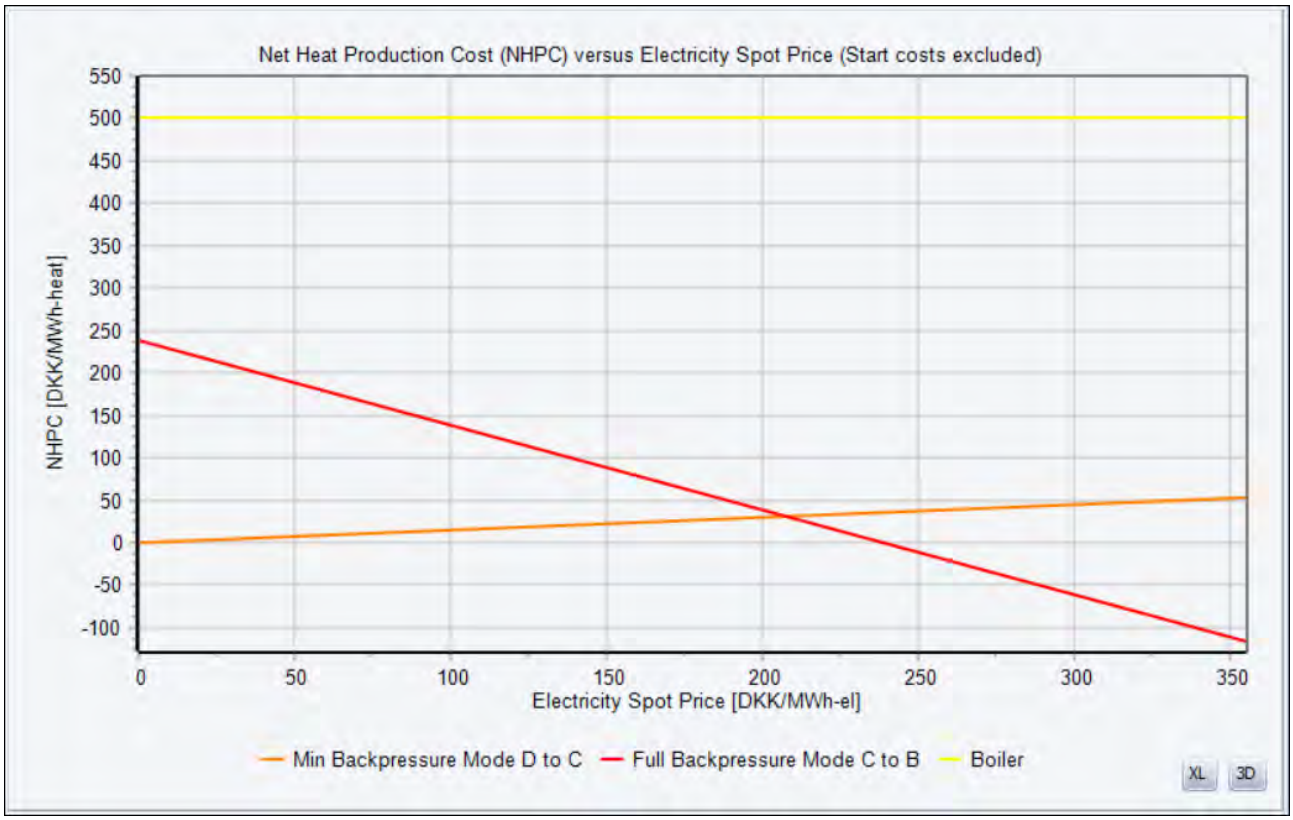

Figure 27: The NHPC of the operation modes shown in Table 18 and showing the NHPC of the gas boiler.

When including in an analytic method that other operation modes are only allowed if "Min Condensing Mode zero to D" is in operation and that operating "Full Backpressure Mode C to B" is only allowed if "Min Backpressure Mode D to C" is operating. This allows that at high spot prices it has low priority to coproduce heat and electricity and primarily produce electricity in condensing mode, simply because the "Min Backpressure Mode D to C" being modelled as a heat pump will have low priority operating at high spot prices, and since "Full Backpressure Mode C to B" is only allowed operating if "Min Backpressure Mode D to C" is operating, this constraint will reduce priority of combined heat and power production on the CHP at high spot prices. An example of such an operation of the CHP described in this section is shown in Figure 28. The upper graph shows the spot prices, the next two graphs show heat and electricity productions, and the bottom graph shows content in the thermal store. It is seen that e.g. at 25th of September 2019, when the spot prices are high, combined heat and power production stops and the CHP is operated in condensing mode, and the thermal store is emptied.

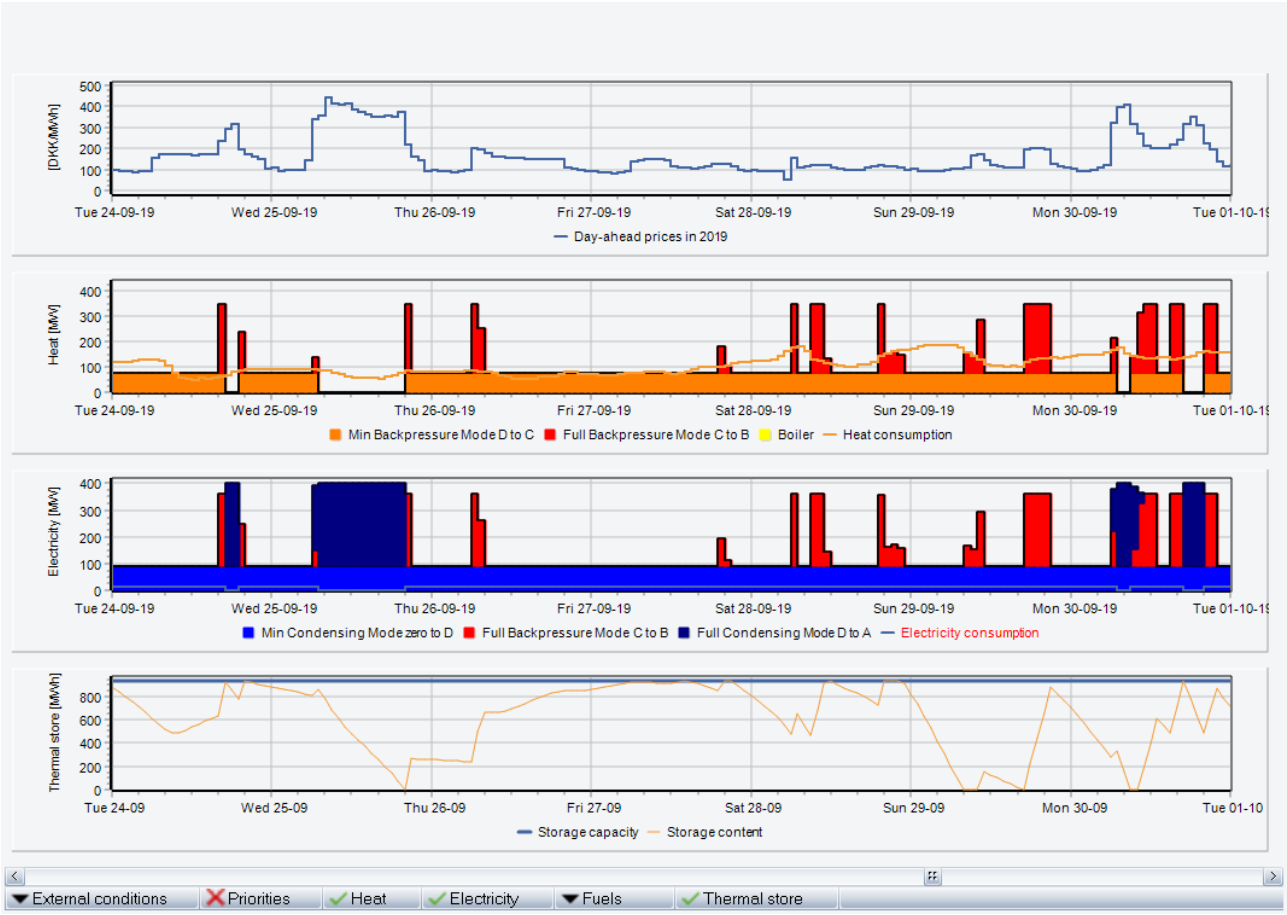

Figure 28: An example of the operation of the CHP described in this section, modelled as 4 separate ECU´s operated in subsequent operation modes.

Using such an analytical method for optimizing UC described in gives the operation in each hour of 2019 shown in Figure 29 (orange points).

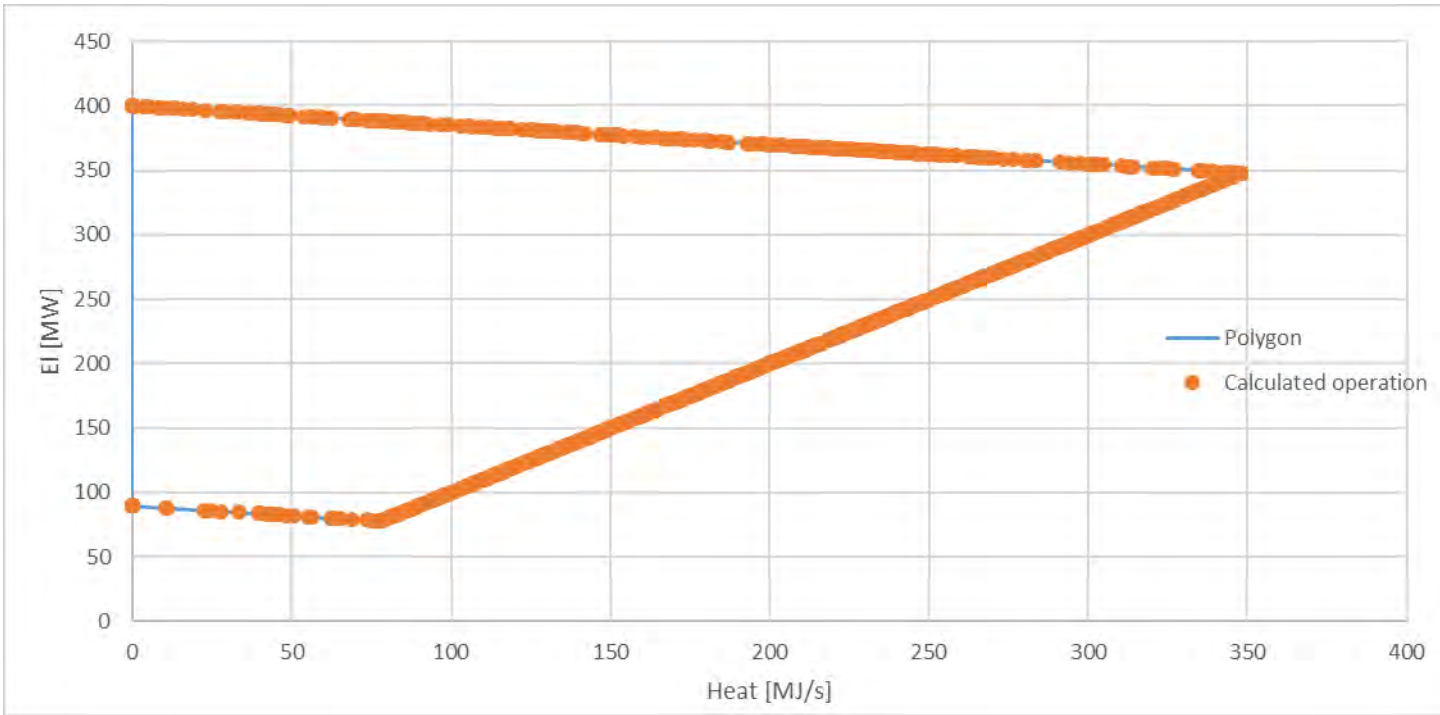

Figure 29: The operation of the CHP in each hour of the 2019, using the analytical UC method described in this section.

Further research might compare analytic and solver-based UC methods for operating such CHPs.

6.3.2 Serial coupled central and booster heat pumps

In the paper *Booster heat pumps and central heat pumps in district heating* [23][1] is shown another example of ECUs that as generalized input/output units can convert energy types to other energy types. The booster heat pump is an example of such an ECU. It converts the energy type "low temperature district heat" together with the energy type "electricity" to the energy type "hot water". Heat source for the central heat pump is ambient temperature. Through functional expressions the load curve for the central heat pump will differ from hour to hour depending on ambient temperature as well as flow and return temperature in the district heating grid. Similarly, through functional expressions the load curve for the booster heat pumps will depend on hot water temperature to be delivered as well as flow and return temperature in the district heating grid. The functional expressions are given in [23].

[1] The PhD candidate's contribution to this article was the model development and implementation in energyPRO. The remainder including application and analyses were done by the first author.

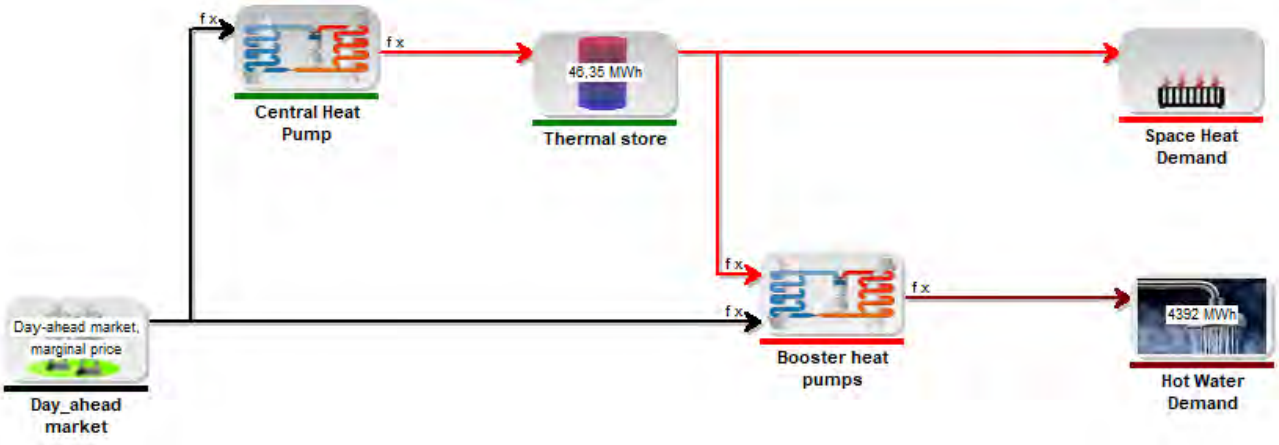

Figure 30: A diagram showing a central heat pump delivering low temperature district heating to cover space heat in each building, as well as being heat source for a booster heat pump producing hot water in each building.

The electricity consumed by the central heat pump is assumed to be purchased in the Day-ahead market, and the district heating is assumed to be able to be stored in a large thermal store. An example of the operation of the central heat pump and the use of the thermal store is shown for a week in Figure 31. The upper graphs show the hourly prices in the Day-ahead market. The next two graphs show the heat production and the electricity consumption of the central heat pump. The bottom graph shows the content in the thermal store. It is seen that e.g. June 27th the spot prices are high; thus, the central heat pump is not operated.

Figure 31: An example in a week of the operation of the central heat pump of the DE plant shown in Figure 30.[2]

[2] The PhD candidate's contribution to this article was the model development and implementation in energyPRO. The remainder including application and analyses were done by the first author

6.3.3 Absorption chiller in a trigeneration plant

The operation of an absorption chiller is another challenging example of UCs at DE plants, because the energy input to one production unit (heat is needed for the absorption chiller) is to be produced by other production unit. Apparently, this UC is not easily made with an analytic UC method, because the needed priority numbers again become multi-dimensional. An example of such a DE plant illustrated in Figure 32. The absorption chiller consumes the energy type heat and produces the energy type cooling to cover a cooling demand. But covering the cooling demand is in competition with any of the electric chillers. Either (or both) an analytical method or a solver method may be used to determine the optimal UC of the absorption chiller and the electric chiller, as well as the UC of the two CHPs and the boiler, taking into account that the produced heat can be stored in a thermal store before covering both the heat demand and the heat consumed by the absorption chiller. Furthermore, it has to be taken into account that electricity produced by the CHPs may be sold in a Day-ahead market at hourly prices and that the consumption of the electric chiller has to be purchased in the Day-ahead market.

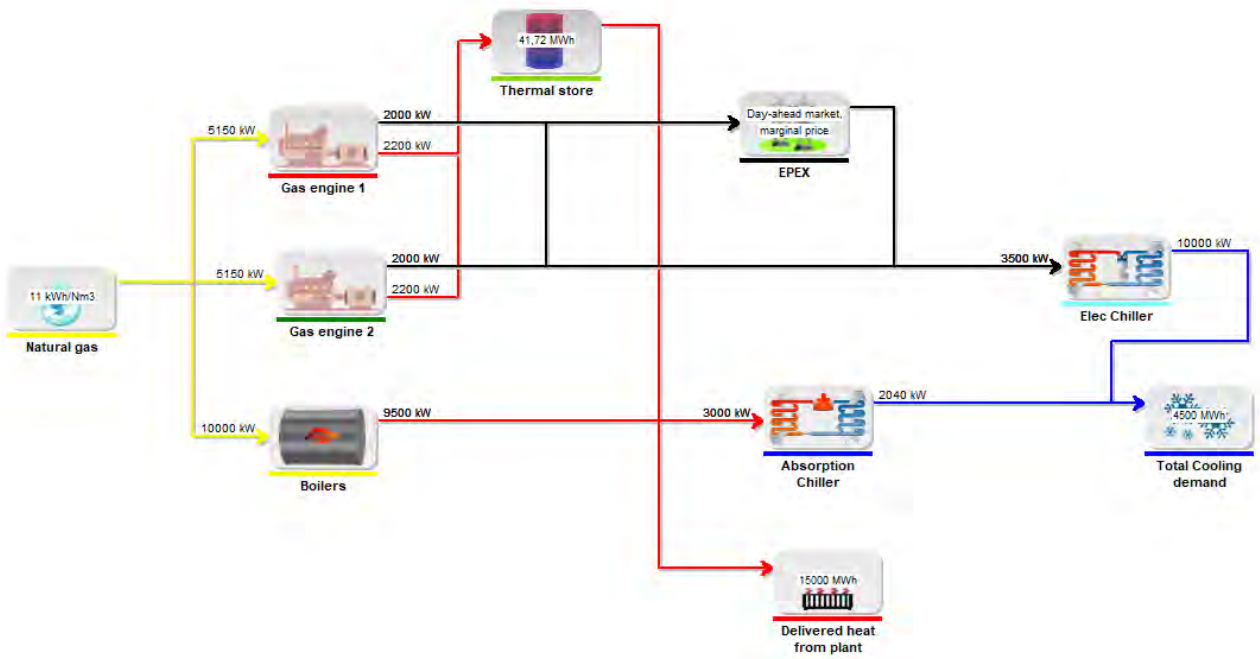

Figure 32: Absorption chiller in a trigeneration plant

Below is described an idea making use of an analytic UC methods, allowing the dispatch of the production units according to priority numbers.
The first step is to attribute priority numbers to the CHPs and boilers, which could be the hourly NHPCs. An example of these NHPCs are shown in Figure 33. It is seen that at a spot price of around 38 EUR/MWh$_e$ the NHPC of the CHPs and the boiler is the same around 24 EUR/MWh$_{heat}$.

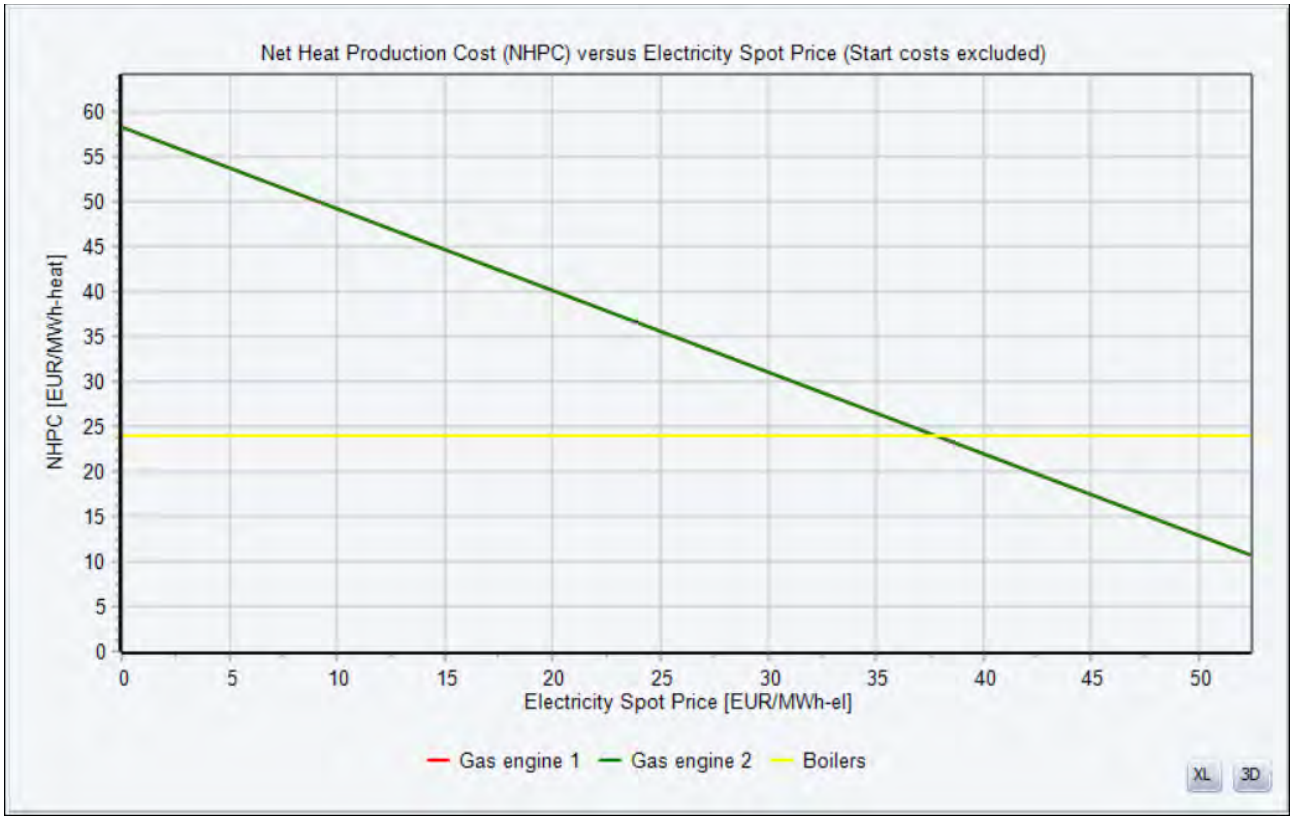

Figure 33: NHPCs of the heat producing units of the DE plant shown in Figure 32.

The next step is to attribute priority numbers to the absorption chiller and the electric chiller, which could be the hourly Net Cooling Production Cost (NCPC). This is straightforward to do for the electric chiller and its NCPC is shown in Figure 34. However, when coming to the absorption chiller its ability to produce cheap cooling depends on if it receives cheap heat from the heat producing units, thus it becomes a two-dimensional problem, where there has to be an absorption chiller NCPC-graph for each heat producing unit. It is seen in the graph that the absorption chiller produces cheaper cooling than the electric chiller, if the spot prices are above 38 EUR/MWh$_e$ and if the heat is coming from the CHPs. It is to be kept in mind that the heat consumed in a certain time step of the absorption chiller is not necessarily produced in that time step but may be produced earlier and stored in the thermal store.

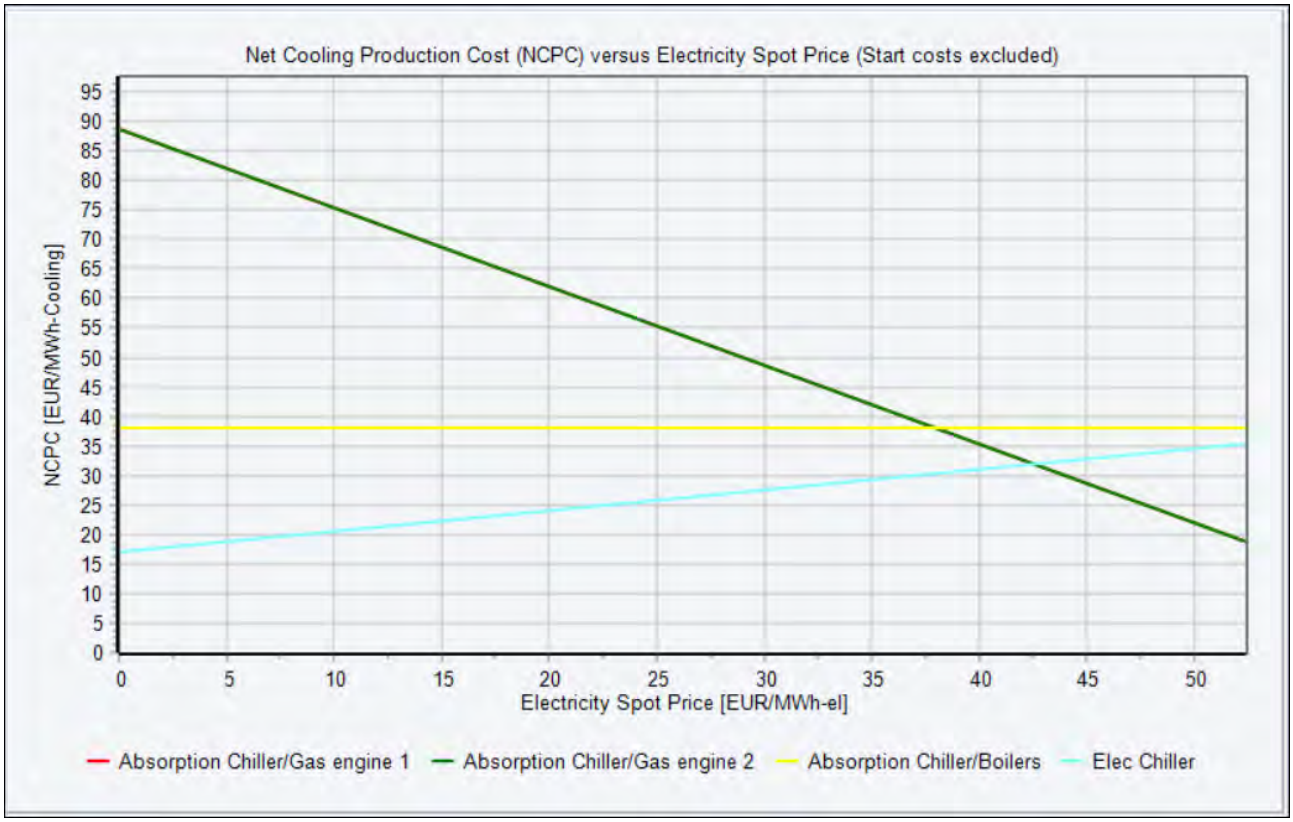

Figure 34: NCPCs of the cooling producing units of the DE plant shown in Figure 32.

The optimal UC of the DE plant shown in Figure 32, found by an analytical method and based on these precalculated NHCPs and NCPCs, could be made in the following way. The first step is to cover the heat demand using NHPCs as priority numbers. Nest step could be to cover the cooling demand by noticing in each time step the NCPC of the electrical chiller. This creates the highest NCPC allowed in that time step, because the electric chiller is able to produce cooling at that price. This NCPC in that time step then is the highest allowed NCPC, which then for the absorption chiller can be converted to the highest allowed price for heat in that time step. The analytical method is then to make the absorption chiller ask for heat from the three heat producing units if they in some time step before are able to produce heat at a lower price than this highest allowed price for heat, eventually may the heat be stored in the thermal store before being used by the absorption chiller in that time step. This analytical method gives the UC shown in Figure 35. The upper graphs show the hourly prices in the Day-ahead market. The next two graphs show the heat and the electricity productions and consumptions. The bottom graph shows the content in the thermal store. It is seen that e.g. 15th of July the absorption chiller is operating introducing a large heat consumption when operating.

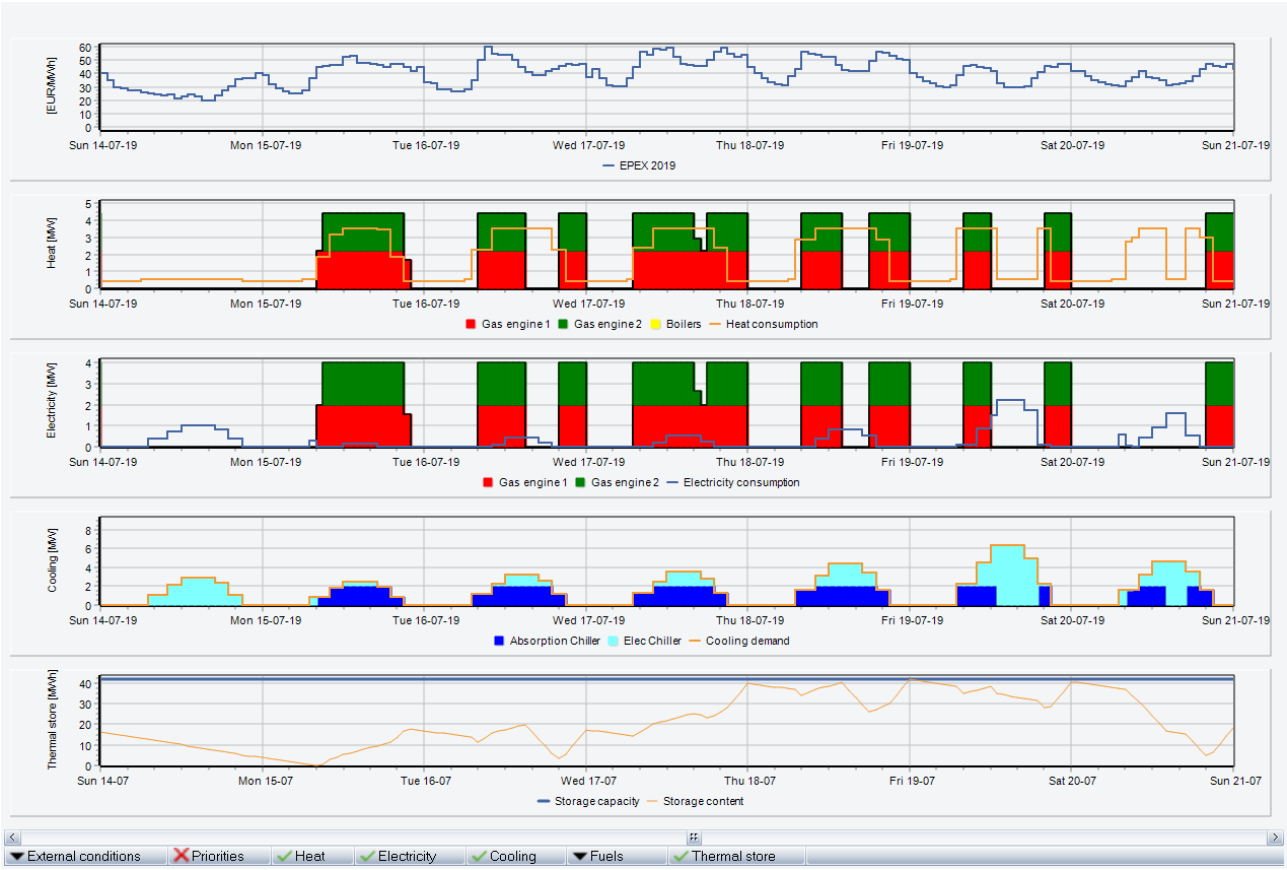

Figure 35: An example of UC at the DE plant shown in Figure 32.

6.3.4 Batteries in private wire operation

One important and challenging next steps in the research of the UCs for DE plants, making use of and combining the best of analytic and solver-based UC methods, is private wire operation, where e.g. a large electrical grid tariff is avoided when electricity demand is covered by own production units.

Analytic UC methods could still be involved in meeting this UC challenge. This is illustrated in Figure 36 showing a diagram for a battery in a private wire operation. The battery is modelled as a fuel (chemical energy), where a charger can produce this fuel consuming electricity and a discharger can consume this fuel and produce electricity. Because there is a PV in the private wire, the priority of the charger depends on if it consumes electricity from the PV or it consumes electricity from import (paying taxes and grid tariff of this import). This is simply modelled by splitting the charger into two units, that together must consume less than the capacity of the charger. The *Charge from production*-unit (the auto production at site) is only allowed to charge with a power equal to the instantaneous PV production minus the electricity demand. In the same way the discharger is split into two units.

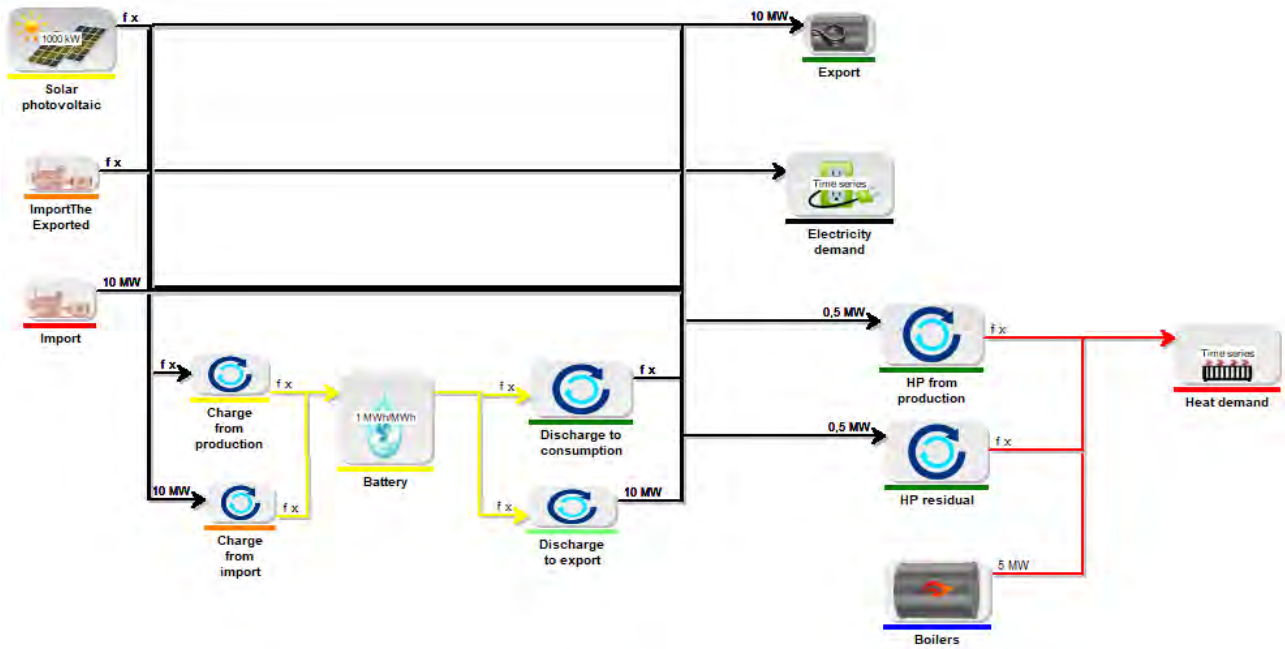

Figure 36: Batteries in private wire operation

6.4 More research in the value of a generalized tool is needed

As described in Section 1.7, the main research question of this thesis concerns the development of generalized tools, which is able to analyse very different alternatives for DE plants providing heating and cooling.

It is outside the scope of this PhD to study and quantify the value of developing these tools. This PhD study is restricted to the company perspective of DE plant, but it is assumed that awareness of radical technological different alternatives, made quantified available in one tool, are valuable for amongst other managers of DE plants and their consultants. A further research into this assumed value could draw parallels to the societal Choice Awareness theory [122]. In general, the Choice Awareness theory states that existing organizations and institutions, according to their own perceptions of the world and to maintain their existing positions, will influence public opinion and the solution choices available. Further, the theory states that society as a whole can benefit from promoting awareness of technical, and potentially more feasible, alternatives to those suggested by existing organisations.

7. Conclusion

Flexible DE plants have an important role in the transition to a renewable energy system, as they may become major actors in integrating wind and solar power, when amongst others equipped with CHPs and heat pumps producing both heating and cooling.
This integration of the DE plants with the rest of the energy system will often be based on biddings in electricity and fuel markets and affected by availability of fluctuating energy sources and large energy stores, as well as being based on complex subsidy schemes and energy taxes. This calls for new generalized tools which are able to analyse very different alternatives for DE plants providing heating and cooling.

The research made in this PhD study concerns the development of the next generation generalized energy system simulation tools for designing and operating DE plants.

The research has been delimited to tools needed for the following tasks in DE plants:

- Investment analysis for comparing very different alternatives for complex future DE plants operating in complex energy markets subject to complex support schemes and energy taxes.
- Daily or short-term planning of operation, also when this operation is determined from biddings in the electricity and fuel markets and affected by availability of fluctuating energy sources, large energy stores and restricted capacities in the heating, cooling and electrical grids.

The main research question is:
Is it possible to develop a generalized tool which is able to analyse and compare sufficiently detailed very different alternatives for DE plants providing heating and cooling?

For such a tool to be appropriate for practitioners, it has to offer an acceptable time setting up models, an acceptable calculation time and it should use a calculation method understandable by the managers of the DE plants.

To make this research question operational as well as to delimit it, three sub questions are formulated:

Sub question 1: *How can the optimization of market based daily operation of DE plants with large TES be solved?*

Sub question 2: *How can a coordinated investment in production and storage capacity at DE plants be analysed?*

Sub question 3: *How can the effect of support schemes promoting necessary flexibility at DE plants be analysed?*

For establishing the research's novelty and scope a literature review has been presented, showing that there is major societal benefits of DE, flexibility of DE plants is needed, CHP at DE plants when developing renewable energy meets changing roles, daily operation of DE plants with large energy stores needs optimization, support schemes promoting necessary flexibility at DE plants is needed and it is made probable that large investments in production capacity at DE plants has to be made,

justifying the large effort to be made to develop next generation generalized energy system simulation tools for designing and operating DE plants.

To answer the main research question and the three sub questions, complex generic DE plants have been designed. Still, the reproducible research paradigm has been pursued in this thesis, so that even if it is complex plants considered, the description of these and the methods presented are sought to be so detailed described, that it allows readers reproducing with minimal effort the results obtained.

To give an answer to Sub question 1, two significantly different UC methods is presented, which show that the optimization of market-based daily operation of these generic DE plants with large TES are able to be solved in a sufficient detail and fast. The one UC method is based on Mixed Integer Linear Programming. The other UC method presented is an advanced analytic method based on priority numbers detailed for each production unit in each time step. The novelty in the answer to Sub question 1 is thus that it brings analytic UC methods back as potential attractive methods to be used at DE plants for daily operation planning, yearly budgeting and long-term investment analysis.

Investments in large production capacity compared to the instantaneous heat demand at a DE plant needs new methods to be analysed, simply because the feasibility of an investment will be closely dependent on a simultaneous investment in a large TES. To give an answer to Sub question 2, a method for analysing coordinated investments in production and storage capacity is presented. It is demonstrated that the presented method returns reliable results, when dealing with the complex generic DE plants being suggested and when using the presented UC methods.

Often support schemes are required to fulfil the role DE plants have to play when developing renewable energy. To give an answer to Sub question 3, a method for comparing support schemes promoting CHPs, HPs and TES at DE plants has been presented. The methods are used to compare two support schemes, one of a Feed-in premium type and one of a Feed-in tariff type. The effect of these two support schemes are tested on the complex generic DE plants, while using the method for analysing coordinated investments in production and storage capacity. It is shown that the societal cost for providing a certain production capacity, measured as the support in the planning period, is around three time larger when using the Feed-in premium type as when using the Feed-in tariff type.

However, in the discussion in Section 6, DE plants are presented that differ significantly from the generic DE plants studied in this PhD study, amongst others CHP operated in both condensing mode and extraction mode, serial coupled central and booster heat pumps, absorption chillers in trigeneration plants and batteries in private wire operation. Furthermore, in the discussion is elaborated on the challenge of optimizing DE plants participating across more of the electricity markets, by showing examples of real plant operations. These specific DE plants and examples from real plant operations presented should be further researched in the future for the pursuit of developing next generation generalized energy system simulation tools for designing and operating DE plants.

8. References

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Appendix I: A method for assessing support schemes promoting flexibility at district energy plants

```
Option Explicit
Const MaxNumberOfYears = 50
Dim Buffer() As Byte
Dim PathToDirectory As String
Dim Inputfile As String
Dim Outputfile As String
Dim ElectricalCapacity As Double
Dim StoreSize As Double
Dim Support As Double
Dim datafile As Variant
Dim SupportAsString As String
Dim StoreSizeAsString As String
Dim ScalingfactorAsString As String



Sub Calculate()
 Dim Lifetime As Integer
 Dim YearsWithSupport As Integer
 Dim x, y As Integer
 Dim Iteration As Integer
 Dim NoOfImprovingSteps As Integer
 Dim ImprovedOI(1 To MaxNumberOfYears) As Double
 Dim NPVinvest As Double
 Dim NPVsupport As Double
 Dim energyPRO_exe As String
 Dim CallText As Variant
 Dim CalculationStarttime As Variant
 Dim Start_energyPRO As Variant
 Dim OIbefore As Double
 Dim YearlyPaidSupport As Double
 Dim DiscountRate As Double
 Dim FixedSpecificOperatingCost As Double
 Dim CHPSpecificInvestmentCost As Double
 Dim StoreSpecificInvestmentCost As Double
 Dim StepEC As Double
 Dim StepST As Double
 Dim Epsilon As Double
 Dim PreviousNPVinvest As Double
 Dim PreviousYearlyPaidSupport As Double
 Dim OIafterWithSupport As Double
 Dim OIafterWithoutSupport As Double

 energyPRO_exe = [energyPRO]
 PathToDirectory = ActiveWorkbook.Path
 Inputfile = PathToDirectory + "\inputfile.xml"
 Outputfile = PathToDirectory + "\OperationIncome.txt"
 CallText = energyPRO_exe + " /XMLMod " + Chr(34) + Inputfile + Chr(34)
 Dim energyPRO_call_no As Integer
 Sheets("Main").Cells(16, 2) = ""
 CalculationStarttime = Now

 ' Calculate operation income of plant before investment in CHP and store
 Support = 0
 StoreSize = 0
 ElectricalCapacity = 0
 Create_Inputfile
 Start_energyPRO = Shell(CallText, 1)
 Wait_until_energyPRO_has_returned_result
 Write_Outputfile_to_Imports_sheet
 OIbefore = [OperationIncome]
 NPVinvest = 0
 YearlyPaidSupport = 0

 DiscountRate = Sheets("Main").Cells(5, 2)
 FixedSpecificOperatingCost = Sheets("Main").Cells(6, 2)
 CHPSpecificInvestmentCost = Sheets("Main").Cells(7, 2) * 1000000
 StoreSpecificInvestmentCost = Sheets("Main").Cells(8, 2)
 Lifetime = Sheets("Main").Cells(9, 2)
 YearsWithSupport = Sheets("Main").Cells(9, 5)

 StepEC = Sheets("Main").Cells(11, 2)
 StepST = Sheets("Main").Cells(12, 2)
 Epsilon = Sheets("Main").Cells(13, 2)
 energyPRO_call_no = 0
```

```
For x = 1 To [Runs] ' Calculate the different support levels

 For Iteration = 1 To 10

 NoOfImprovingSteps = 0

 Do 'Increase ElectricalCapacity until NPV gets less
  PreviousNPVinvest = NPVinvest
  PreviousYearlyPaidSupport = YearlyPaidSupport

  'Operation income and paid support in first years with support
  Support = Sheets("Main").Cells(18 + x, 1)
  ElectricalCapacity = ElectricalCapacity + StepEC
  Create_Inputfile
  Start_energyPRO = Shell(CallText, 1)
  Wait_until_energyPRO_has_returned_result
  Write_Outputfile_to_Imports_sheet
  OIafterWithSupport = [OperationIncome]
  YearlyPaidSupport = [PaidSupport]
  For y = 1 To YearsWithSupport
   ImprovedOI(y) = OIafterWithSupport - OIbefore - FixedSpecificOperatingCost * ElectricalCapacity
  Next y

  'Operation income in years withOUT premium
  If YearsWithSupport < Lifetime Then
   Support = 0
   Create_Inputfile
   Start_energyPRO = Shell(CallText, 1)
   Wait_until_energyPRO_has_returned_result
   Write_Outputfile_to_Imports_sheet
   OIafterWithoutSupport = [OperationIncome]
   For y = YearsWithSupport + 1 To Lifetime
    ImprovedOI(y) = OIafterWithoutSupport - OIbefore - FixedSpecificOperatingCost * ElectricalCapa
city
   Next y
  End If

 ' Calculate NPV of Improved Operation Income
  NPVinvest = 0
  For y = 1 To Lifetime
   NPVinvest = NPVinvest + ImprovedOI(y) / ((1 + DiscountRate) ^ y)
  Next y
  NPVinvest = NPVinvest - CHPSpecificInvestmentCost * ElectricalCapacity
  NPVinvest = NPVinvest - StoreSpecificInvestmentCost * StoreSize
  If NPVinvest > PreviousNPVinvest + Epsilon Then
   NoOfImprovingSteps = NoOfImprovingSteps + 1
  End If
 'Test report for intermidiate calculation
  energyPRO_call_no = energyPRO_call_no + 1
  Sheets("Main").Cells(32 + energyPRO_call_no, 1) = Sheets("Main").Cells(18 + x, 1)
  Sheets("Main").Cells(32 + energyPRO_call_no, 2) = ElectricalCapacity
  Sheets("Main").Cells(32 + energyPRO_call_no, 3) = StoreSize
  Sheets("Main").Cells(32 + energyPRO_call_no, 4) = NPVinvest / 1000000
  Sheets("Main").Cells(32 + energyPRO_call_no, 5) = OIafterWithSupport
  Sheets("Main").Cells(32 + energyPRO_call_no, 6) = Iteration
  Sheets("Main").Cells(32 + energyPRO_call_no, 7) = NoOfImprovingSteps
  Sheets("Main").Cells(32, 1) = Sheets("Main").Cells(18 + x, 1)
  Sheets("Main").Cells(32, 2) = ElectricalCapacity
  Sheets("Main").Cells(32, 3) = StoreSize
  Sheets("Main").Cells(32, 4) = NPVinvest / 1000000
  Sheets("Main").Cells(32, 5) = OIafterWithSupport
  Sheets("Main").Cells(32, 6) = Iteration
  Sheets("Main").Cells(32, 7) = NoOfImprovingSteps


 Loop Until NPVinvest <= PreviousNPVinvest + Epsilon
 ElectricalCapacity = ElectricalCapacity - StepEC
 NPVinvest = PreviousNPVinvest
 YearlyPaidSupport = PreviousYearlyPaidSupport

 Do 'Increase StoreSize in steps until NPV gets less
  PreviousNPVinvest = NPVinvest
  PreviousYearlyPaidSupport = YearlyPaidSupport

  'Operation income and paid premium in first years with premium
  Support = Sheets("Main").Cells(18 + x, 1)
  StoreSize = StoreSize + StepST
```

```
   Create_Inputfile
   Start_energyPRO = Shell(CallText, 1)
   Wait_until_energyPRO_has_returned_result
   Write_Outputfile_to_Imports_sheet
   OIafterWithSupport = [OperationIncome]
   YearlyPaidSupport = [PaidSupport]
   For y = 1 To YearsWithSupport
    ImprovedOI(y) = OIafterWithSupport - OIbefore - FixedSpecificOperatingCost * ElectricalCapacity
   Next y

  'Operation income in years withOUT support
   If YearsWithSupport < Lifetime Then
    Support = 0
    Create_Inputfile
    Start_energyPRO = Shell(CallText, 1)
    Wait_until_energyPRO_has_returned_result
    Write_Outputfile_to_Imports_sheet
    OIafterWithoutSupport = [OperationIncome]
    For y = YearsWithSupport + 1 To Lifetime
     ImprovedOI(y) = OIafterWithoutSupport - OIbefore - FixedSpecificOperatingCost * ElectricalCapa
city
    Next y
   End If

   ' Calculate NPV of Improved Operation Income
   NPVinvest = 0
   For y = 1 To Lifetime
    NPVinvest = NPVinvest + ImprovedOI(y) / ((1 + DiscountRate) ^ y)
   Next y
   NPVinvest = NPVinvest - CHPSpecificInvestmentCost * ElectricalCapacity
   NPVinvest = NPVinvest - StoreSpecificInvestmentCost * StoreSize
   If NPVinvest > PreviousNPVinvest + Epsilon Then
    NoOfImprovingSteps = NoOfImprovingSteps + 1
   End If
   'Test report for intermidiate calculation
   energyPRO_call_no = energyPRO_call_no + 1
   Sheets("Main").Cells(32 + energyPRO_call_no, 1) = Sheets("Main").Cells(18 + x, 1)
   Sheets("Main").Cells(32 + energyPRO_call_no, 2) = ElectricalCapacity
   Sheets("Main").Cells(32 + energyPRO_call_no, 3) = StoreSize
   Sheets("Main").Cells(32 + energyPRO_call_no, 4) = NPVinvest / 1000000
   Sheets("Main").Cells(32 + energyPRO_call_no, 5) = OIafterWithSupport
   Sheets("Main").Cells(32 + energyPRO_call_no, 6) = Iteration
   Sheets("Main").Cells(32 + energyPRO_call_no, 7) = NoOfImprovingSteps
   Sheets("Main").Cells(32, 1) = Sheets("Main").Cells(18 + x, 1)
   Sheets("Main").Cells(32, 2) = ElectricalCapacity
   Sheets("Main").Cells(32, 3) = StoreSize
   Sheets("Main").Cells(32, 4) = NPVinvest / 1000000
   Sheets("Main").Cells(32, 5) = OIafterWithSupport
   Sheets("Main").Cells(32, 6) = Iteration
   Sheets("Main").Cells(32, 7) = NoOfImprovingSteps

  Loop Until NPVinvest <= PreviousNPVinvest + Epsilon
  StoreSize = StoreSize - StepST
  NPVinvest = PreviousNPVinvest
  YearlyPaidSupport = PreviousYearlyPaidSupport

  If NoOfImprovingSteps = 0 Then
   Exit For
  End If

  Next Iteration

  'Calculation of NPV of paid support
  NPVsupport = 0
  For y = 1 To YearsWithSupport
   NPVsupport = NPVsupport + YearlyPaidSupport / ((1 + DiscountRate) ^ y)
  Next y

  Sheets("Main").Cells(18 + x, 2) = ElectricalCapacity
  Sheets("Main").Cells(18 + x, 3) = StoreSize
  Sheets("Main").Cells(18 + x, 4) = NPVinvest / 1000000
  Sheets("Main").Cells(18 + x, 5) = NPVsupport / 1000000

 Next x 'Next support level to be calculated

 Sheets("Main").Cells(16, 2) = Now - CalculationStarttime
```

```
End Sub

Sub Wait_until_energyPRO_has_returned_result()
 Do
  Application.Wait (Now + TimeValue("0:00:01"))
 Loop Until Dir(Outputfile) <> ""
End Sub

Sub WriteToFile(text)
  Buffer = Format(text) + Chr(10)
  Put #1, , Buffer
End Sub

Sub Create_Inputfile()
  If Dir(Inputfile) <> "" Then Kill Inputfile
  Open Inputfile For Binary As #1
  WriteToFile [Enc]
  WriteToFile "<XMLtoEnergyPRO>"
  HeadData
  InputData
  OutputData
  WriteToFile "</XMLtoEnergyPRO>"
  Close #1
  Application.DefaultWebOptions.Encoding = msoEncodingUTF8
End Sub

Sub HeadData()
  WriteToFile "<Head>"
  datafile = "<energyPRODataFile>" + PathToDirectory + "\"
  datafile = datafile + [ProjectFile] + "</energyPRODataFile>"
  WriteToFile datafile
  WriteToFile "<Version>1</Version>"
  WriteToFile "</Head>"
End Sub

Sub InputData()
  WriteToFile "<InputDataElements>"
  WriteToFile "<InputDataElement>"
  WriteToFile "<BaseID>TimeSeriesFunctionData</BaseID>"
  WriteToFile "<DataElementName>FuncFormular</DataElementName>"
  WriteToFile "<DataName>Support paid to plant</DataName>"
  SupportAsString = Format(Support)
  WriteToFile "<DataElementValue>" + SupportAsString + "</DataElementValue>"
  WriteToFile "</InputDataElement>"
  WriteToFile "<InputDataElement>"
  WriteToFile "<BaseID>TimeSeriesFunctionData</BaseID>"
  WriteToFile "<DataElementName>FuncFormular</DataElementName>"
  WriteToFile "<DataName>Scaling factor</DataName>"
  ScalingfactorAsString = Format(ElectricalCapacity / 5)
  WriteToFile "<DataElementValue>" + ScalingfactorAsString + "</DataElementValue>"
  WriteToFile "</InputDataElement>"
  WriteToFile "<InputDataElement>"
  WriteToFile "<BaseID>StorageData</BaseID>"
  WriteToFile "<DataElementName>StorageVolume</DataElementName>"
  WriteToFile "<DataName>Thermal store</DataName>"
  StoreSizeAsString = Format(StoreSize)
  WriteToFile "<DataElementValue>" + StoreSizeAsString + "</DataElementValue>"
  WriteToFile "</InputDataElement>"
  WriteToFile "</InputDataElements>"
End Sub

Sub OutputData()
  WriteToFile "<OutputDataElements>"
  WriteToFile "<OutputDataElement>"
  WriteToFile "<ReportBaseID>OperationIncome</ReportBaseID>"
  WriteToFile "<ReportDelimiter>;</ReportDelimiter>"
  WriteToFile "<ReportFileName>" + Outputfile + "</ReportFileName>"
  WriteToFile "<ReportFileType>csv</ReportFileType>"
  WriteToFile "</OutputDataElement>"
  WriteToFile "</OutputDataElements>"
End Sub

Sub Write_Outputfile_to_Imports_sheet()
 Dim y As Integer
 Dim textline As String
 Dim Data As Variant
 Dim s As Integer
```

```
 Open Outputfile For Input As #1
  y = 1
  Do While Not EOF(1)
   Line Input #1, textline
   Data = Split(textline, ";")
   For s = 0 To UBound(Data)
    Data(s) = Replace(Format(Data(s)), ",", ".")
    Sheets("Imports").Cells(y, s + 1) = Data(s)
   Next s
   y = y + 1
   Loop
  Close #1
  Kill Outputfile
End Sub
```

Annex II: Python call of Gurobi in analytic versus solver calculated operations

```
import sys, os
from gurobipy import *

def mycallback(model, where):
  if where == GRB.Callback.MIP:
    time = model.cbGet(GRB.Callback.RUNTIME)
    best = model.cbGet(GRB.Callback.MIP_OBJBST)
    if time > 10 and best < GRB.INFINITY:
      model.terminate()

timeSteps = 4*7*24 # 28 days

spotPrices = []
with open('spotPrices.csv', 'r') as spotPricesFile:
    spotPrices = [float(x) for x in spotPricesFile.readlines()]
heatDemand = []
with open('HeatDemand.csv', 'r') as heatDemandFile:
    heatDemand = [float(x) for x in heatDemandFile.readlines()]

# Technical and economic conditions
gasPrices = [5.6 * 3.6]*len(spotPrices)
CHPh =3.333 # chp heat capacity in MW
CHPe =3 # chp electrical capacity in MW
CHPf =6.818 # chp fuel capacity in MW
HPh =3.333 # hp heat capacity in MW
HPe =0.952 # hp electrical capacity in MW
Boilerh = 15 # boiler heat capacity in MW
Boilerf = 14.563 # boiler fuel capacity in MW
TEScap = 59.24 # TES capacity in MWh
CHPoandm = 5.4 # chp operation and maintenance cost in EUR/MWh electricity
HPoandm = 2 # hp operation and maintenance cost in EUR/MWh heat
Boileroandm = 1.1 # boiler operation and maintenance cost in EUR/MWh heat
CHPstartcost = 30 # start cost of CHP in EUR/start
HPstartcost = 10 # start cost of HP in EUR/start

CO2price = 8 # CO2 quota price in EUR/tonne

m = Model("test1")
chp1      = m.addVars(timeSteps, lb=0.0, ub= 1.0, vtype=GRB.BINARY, name="CHP1")
chp2      = m.addVars(timeSteps, vtype=GRB.BINARY, name="CHP2")
hp1       = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP1")
hp2       = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP2")
boiler    = m.addVars(timeSteps, lb=0.0, ub= 1.0, vtype=GRB.CONTINUOUS, name="Boiler")
storage   = m.addVars(timeSteps + 1, lb=0.0, vtype=GRB.CONTINUOUS, name="Primo Storage")
chp1start = m.addVars(timeSteps, vtype=GRB.BINARY, name="CHP1start")
chp1stop  = m.addVars(timeSteps, vtype=GRB.BINARY, name="CHP1stop")
chp2start = m.addVars(timeSteps, vtype=GRB.BINARY, name="CHP2start")
chp2stop  = m.addVars(timeSteps, vtype=GRB.BINARY, name="CHP2stop")
hp1start = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP1start")
hp1stop  = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP1stop")
hp2start = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP2start")
hp2stop  = m.addVars(timeSteps, vtype=GRB.BINARY, name="HP2stop")
```

```python
# Build optimisation problem
m.addConstr(storage[0] == 0, 'initial_storage')
objectiveFunction = 0
for i in range(timeSteps):
  # Heat constraints
  constraint = storage[i]+CHPh*(chp1[i]+chp2[i]+hp1[i]+hp2[i])+Boilerh*boiler[i]-heatDemand[i]==storage[i+1]
  m.addConstr(constraint, 'heat_{:d}'.format(i))
  constraint = storage[i] <= TEScap
  m.addConstr(constraint, 'Max store_{:d}'.format(i))
  if i>0:
    constraint = chp1[i] - chp1[i - 1] == chp1start[i] - chp1stop[i]
  else:
    constraint = chp1[i] == chp1start[i]- chp1stop[i]
  m.addConstr(constraint, 'Changed operation mode_{:d}'.format(i))
  if i>0:
    constraint = chp2[i] - chp2[i - 1] == chp2start[i] - chp2stop[i]
  else:
    constraint = chp2[i] == chp2start[i]- chp2stop[i]
  m.addConstr(constraint, 'Changed operation mode_{:d}'.format(i))
  if i>0:
    constraint = hp1[i] - hp1[i - 1] == hp1start[i] - hp1stop[i]
  else:
    constraint = hp1[i] == hp1start[i]- hp1stop[i]
  m.addConstr(constraint, 'Changed operation mode_{:d}'.format(i))
  if i>0:
    constraint = hp2[i] - hp2[i - 1] == hp2start[i] - hp2stop[i]
  else:
    constraint = hp2[i] == hp2start[i]- hp2stop[i]
  m.addConstr(constraint, 'Changed operation mode_{:d}'.format(i))

  if i < timeSteps - 2:
    #Minimun 3 hours operation time
    constraint = 3 * chp1start[i] <= chp1[i] + chp1[i + 1] + chp1[i + 2]
    m.addConstr(constraint, 'Min CHP1 operation_{:d}'.format(i))
    constraint = 3 * chp2start[i] <= chp2[i] + chp2[i + 1] + chp2[i + 2]
    m.addConstr(constraint, 'Min CHP2 operation_{:d}'.format(i))
    constraint = 3 * hp1start[i] <= hp1[i] + hp1[i + 1] + hp1[i + 2]
    m.addConstr(constraint, 'Min HP1 operation_{:d}'.format(i))
    constraint = 3 * hp2start[i] <= hp2[i] + hp2[i + 1] + hp2[i + 2]
    m.addConstr(constraint, 'Min HP2 operation_{:d}'.format(i))
    #Minimun 3 hours stop time
    constraint = chp1stop[i] + chp1stop[i + 1] <= 1 - chp1[i + 2]
    m.addConstr(constraint, 'Min CHP1 stop_{:d}'.format(i))
    constraint = chp2stop[i] + chp2stop[i + 1] <= 1 - chp2[i + 2]
    m.addConstr(constraint, 'Min CHP2 stop_{:d}'.format(i))
    constraint = hp1stop[i] + hp1stop[i + 1] <= 1 - hp1[i + 2]
    m.addConstr(constraint, 'Min HP1 stop_{:d}'.format(i))
    constraint = hp2stop[i] + hp2stop[i + 1] <= 1 - hp2[i + 2]
    m.addConstr(constraint, 'Min HP2 stop_{:d}'.format(i))
```

```
  # Objective function
  # --- Sale of electricity
  objectiveFunction += CHPe * spotPrices[i] * (chp1[i] + chp2[i])
  # --- Purchase of electricity
  objectiveFunction -= HPe*spotPrices[i] * (hp1[i] + hp2[i])
  # --- Variable O and M of HPs
  objectiveFunction -= HPoandm * HPh * (hp1[i] + hp2[i])
  # --- Fuel costs
  objectiveFunction -= CHPf * gasPrices[i] * (chp1[i] + chp2[i]) + Boilerf * gasPrices[i] * boiler[i]
  # --- CO2 quotas
  objectiveFunction -= CHPf*3.6*56.69/1000*CO2price*(chp1[i] + chp2[i]) + Boilerf*3.6*56.69/1000*CO2price*boiler[i]
  # --- Variable O and M of CHPs
  objectiveFunction -= CHPe * CHPoandm * (chp1[i] + chp2[i])
  # --- Variable O and M of boilers
  objectiveFunction -= Boilerh * Boileroandm * boiler[i]
  # --- Start costs of CHPs
  objectiveFunction -= CHPstartcost * (chp1start[i] + chp2start[i])
  # --- Start costs of HPs
  objectiveFunction -= HPstartcost * (hp1start[i] + hp2start[i])

m.setObjective(objectiveFunction, GRB.MAXIMIZE)
#m.optimize()
m.optimize(mycallback)
with open("output.txt", "w") as f:
  for v in m.getVars():
    f.write('{:s}; {:g}\n'.format(v.varName, v.x))
  f.write("Spot prices\n")
  for i in range(timeSteps):
    f.write('A{:g}\n'.format(spotPrices[i]))
  f.write("Heat demand\n")
  for i in range(timeSteps):
    f.write('A{:g}\n'.format(heatDemand[i]))
```

Appendix I: A method for assessing support schemes promoting flexibility at district energy plants

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A method for assessing support schemes promoting flexibility at district energy plants

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HIGHLIGHTS

- District energy plants may become major actors in integrating wind and solar power.
- Often electricity prices do not create sufficient feasibility for needed investments.
- Support should be minimized while ensuring adequate installed capacity at plants.
- Method for determine the production and store capacities support schemes will promote.
- The method used shows a premium scheme promotes more flexibility than a FIT scheme.

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Combined heat and cooling
Heat pump
Trigeneration
Thermal energy store

ABSTRACT

Flexible District Energy plants providing heating and cooling to cities have an important role in the transition to a renewable energy system. They may become major actors in integrating wind and solar power, when equipped with a combination of combined heat and power units, heat consuming absorption chillers, heat pumps producing both heating and cooling and large thermal energy stores.

However, often electricity prices do not create sufficient feasibility for these to be installed thus calling for support schemes. The societal resources dedicated to support should be minimised while ensuring the establishment of an adequate amount and right ratio between these units. This paper presents a method for determining the capacities different support schemes will promote as a function of dedicated resources. The method is used in a comparison of two support schemes promoting combined heat and power; a premium on top of hourly wholesale electricity prices and a fixed Feed in Tariff. The comparison shows that the premium scheme requires a little less total support than the Feed In Tariff scheme for promoting a given amount of electrical capacity, but promotes a five-times larger thermal energy store capacity, thereby promoting substantially increased flexibility for integrating intermittent power production.

1. Introduction

Climate change has been on the global political and environmental agenda since the 2015 Paris agreement [1] established a common target to limit global warming to well below 2 °C. Most countries are therefore seeking ways to reduce greenhouse gas emissions [2].

The European Union (EU) has set a target of 40% reduction in CO_2-emissions by 2030, compared with 1990 [3]. In order to achieve this target, certain actions are planned, amongst others a revision of the EU Emissions Trading System after 2020 [4] and binding emission targets for all the EU member states for the sectors outside the ETS until 2030 [5]. Regardless of the ways for the reduction, enhanced deployment of renewable energy sources (RES) is one of the main elements; sources that to a high degree are of an intermittent nature.

Concurrently with the transition of the energy system, the United Nations (UN) World Urbanization Prospect [6] has described an ongoing urbanization worldwide. Today more people live in urban areas than in rural areas, and the Prospect projects that by 2050, 66% of the world's population will be urban. This impact both which RES to use and how to use these for covering demands. Appropriate technologies for covering heating and cooling demands depend for instance on the demand density in the cities, where the high densities favour the District Energy (DE) systems.

The UN Environment Programme [7] states that half of the energy

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Nomenclature

Flexible units units that may advance or defer production or consumption through access to thermal storage. Includes Combined Heat and Power (CHP) units, Heat Pumps (HP) and electric chillers

Premium scheme support scheme, with a fixed price supplement on top of hourly wholesale electricity prices

FIT scheme in this paper, a Feed In Tariff scheme is a support scheme, where the electricity producers get a fixed price in all hours

used in buildings today is heating and cooling and that most of this comes from fossil fuels. It further states that DE is a tried-and-tested answer to a more sustainable coverage of urban heating and cooling demands, however current DE development is limited [8].

The research project Heat Roadmap Europe [9] concluded that a 30–40% reduction of the existing heat demand in Europe is socio-economic feasible, and approximately 50% of the remainder should be covered by DE. As an indicative figure, the project finds that when the heat density is above 120 TJ/km^2, DE is socio-economic the cheapest way of covering the heat demand. A thermal atlas [10] made in the Heat Roadmap Europe shows e.g. that parts of all major cities in Germany and the United Kingdom have higher heat densities than this threshold. DE plants providing heating and cooling to cities should thus have a significant role in the emission reduction and transition to a renewable energy system.

Providing heating and cooling to multiple buildings, DE systems can use far larger sources of heating and cooling than can be connected to just one building [7]. The sources include waste heat from industry or power stations [11]; large solar thermal [12]; heat from groundwater and sewage systems [13], free cooling from lakes, rivers or seas [14] and geothermal energy [15].

The role of DE plants changes with the renewable energy exploitation. Before a country has developed a comprehensive amount of intermittent renewable energy production, DE plants primarily displace fossil fuel-based condensing mode power plants, heat production on individual and communal boilers [16] and cooling from electric chillers. This is accomplished though cogeneration of heat and power (CHP) and trigeneration units that are producing as much electricity as the heat and cooling consumption allows.

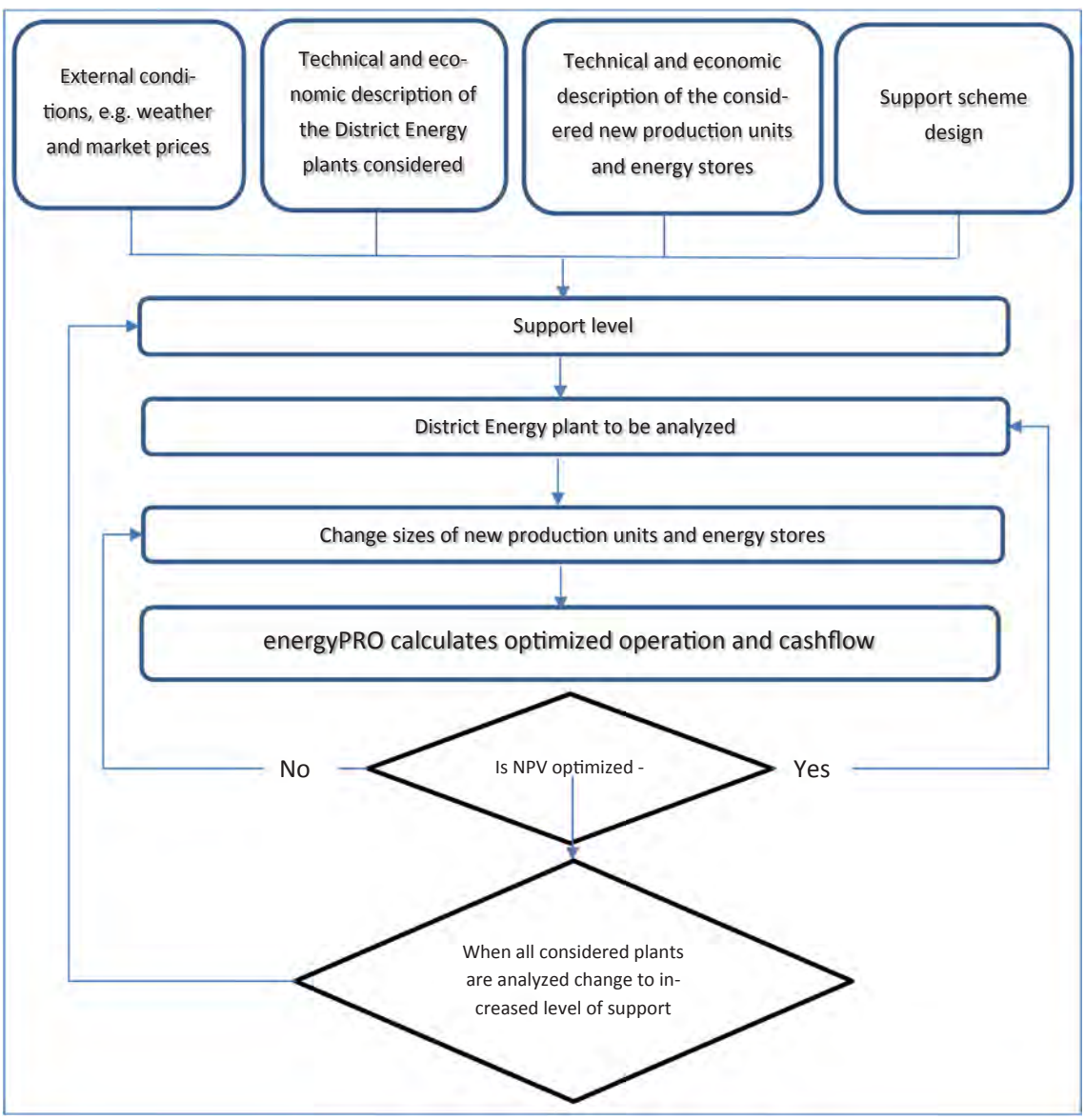

Fig. 1. Flowsheet for quantifying the costs of support schemes.

When a high level of intermittent production is reached, this production almost covers the electricity demand, leaving only few hours for CHP and trigeneration. Instead, the DE plants have a major task of producing heat and cooling efficiently through HPs and to participate in the integration of intermittent production providing power when intermittent production does not suffice [17].

These very different tasks of DE plants in the transition to a RES-based system call for these to be equipped with large CHP and HP capacity as well as large TES [18]. The large CHP capacity is needed both when the task is to displace condensing mode power and when the task is to supplement intermittent production. The large HP capacity is primarily needed in the integration of intermittent productions by primarily consuming electricity and producing heat in periods with high intermittent production; periods typically with low prices [19]. The large TES capacity is closely related to the large CHP and HP capacity enabling these to detach momentary thermal demands from productions.

However, often the present and most likely the future electricity prices do not create sufficient feasibility for the CHPs, HPs and TES to be installed. Therefore, support schemes are required to provide the required capacity.

EU has in several reports dealt with the challenge of designing and reforming energy sector support schemes [20–22] and pointed out, that support should be limited to what is necessary and the support schemes should be flexible and respond to decreasing production costs [20]. Furthermore, support schemes should be phased out as technologies mature [20], and unannounced or retroactive changes should be avoided as they undermine investor confidence and prevent future investments [20].

On the basis of its analysis of support schemes, the EU Commission recommends, that FIT schemes are phased out and that support instruments are used that expose energy producers and consumers to market price signals such as Premium schemes [22]. However, Dressler [23] has pointed out that Premium schemes may enhance market power, favours conventional electricity production and may even hamper the increase in production from RES.

From a policy side, the EU Commission states that support is intended to cover the gap between costs and revenues, therefore adequate revenue projections must be made beforehand, but also states that these projections of the needed level of support can be difficult to make ex-ante, since the support may interact for example with electricity prices in a complicated manner [22]. Thus an ideal method for assessing DE support schemes should be able to show and to quantify if the level of support of the chosen support scheme can be expected to lead to the appropriate amount of production and storage capacity at DE plants and at what support cost.

The optimal extent of flexible CHPs, HPs and TES at DE plants in a certain country must be determined in national or regional analyses or it may even be a political decision. Subsequently, a support scheme should, at the lowest cost of support, promote this amount. This is the focus in this paper.

1.1. Scope and structure of the article

DE plants have a role to play but require support to fulfil this. For financial reasons, this should be minimised while supporting adequate quantities. This paper presents a method for assessing support schemes promoting CHPs, HPs and TES at DE plants. As an example, the method is used to compare two support schemes promoting CHP; a Premium scheme, where a fixed price supplement is paid on top of hourly wholesale electricity prices, and a FIT scheme, where the producer through price hedging is secured the same total fixed price in all hours for all electricity produced.

The original and innovative contribution in this paper is that the method allows a quantitative comparison of how different support schemes influence the capacity and design of flexible DE plants and thus their ability to integrate intermittent power production. The paper thus bridges the gap between research, development and implementation, by creating this quantified documentation. A literature review has not revealed any similar work on support schemes.

Section 2 describes the methodology focusing on the simulation model and the developed environment for testing support schemes. The support scheme cases are described in Section 3. The results of the test together with sensitivity analyses are presented in Section 4. The validity of the results together with limitations are addressed in Section 5, and finally Section 6 presents the conclusions.

2. The method

The support scheme assessment method consists of an Excel spreadsheet that through Visual Basic for Application (VBA) coding iteratively calls energyPRO [24]. For each DE plant, support scheme design, size of CHPs, HPs and TES, it calculates an optimized operation of the production units in a user-given time horizon (planning period). Calculated cash flows are returned to the spreadsheet for each combination, allowing the Net Present Value (NPV) to be calculated. Through iteration, the optimal size of CHPs, HPs and energy stores for each DE plant and for each support scheme design are thus identified by optimizing the NPV. The stepwise approach is shown in Fig. 1.

The individual parts are detailed in the following sections.

2.1. Choosing an appropriate energy system analysis tool

The energy system analysis tool used in the assessment of support schemes must be able to calculate an optimized operation of user-given production units in each hour of the planning period. This temporal resolution is required by amongst others hourly market prices. The planning period considered is typically 20 years.

Secondly, the tool must be able to assess the business economic consequences for the plant owner.

Thirdly, it is a requirement for a tool to be used, that it allows calls from e.g. a spreadsheet, where DE plant design characteristics may be changed.

Sameti and Fariborz have made a comprehensive review of optimization approaches and tools to be used [25]. They conclude that while Mixed Integer Linear Programming (MILP) is the most widely used approach for optimization of DE systems, most models suffer from very long computational time when large networks are considered. Allegrini et al. [26] concludes in their review of tools for simulation of DE systems that there are still many important challenges to be overcome if simulation tools are to provide the benefits on the urban level that they have delivered at the building scale. Olsthoorn et al. focus on storage techniques and renewable energy sources when comparing different tools and methods for modelling district energy plants [27]. Lyden et al. [28] makes a modelling tool selection process for planning of community scale energy systems including storage and demand side management. They conclude that COMPOSE, DER-CAM, energyPRO, EnergyPLAN, MERIT and MARKAL/TIMES are the six tools that meets all essential capabilities. Further to be mentioned is TRNSYS [29] meeting the above mentioned requirements.

It is amongst these tools chosen to select energyPRO [24]. In energyPRO the time step may be 1 h or less thus allowing a calculation of the hourly cash flow. It uses indexes for describing e.g. the development of demands for heating and cooling and the development in prices over the years, which implies that the operation of the production units between the years may change e.g. due to changed economic conditions.energyPRO is based on analytical programming based on predefined methods for finding optimal operation – either through marginal production costs of units or through user-defined priorities. Productions are placed over one-year time horizons based on full foresight of e.g. spot market prices. As a starting point, energyPRO creates a matrix formed by the number of production units times the number of

time steps (e.g. 1 h) in the planning period. Each of the cells in this matrix contains a calculated priority number indicating in which order productions are prioritised in the planning period. The priority number for e.g. a CHP in a certain time step could be the cost of producing 1 MWh heat reduced with the value of the associated produced electricity. Thus, if a project has three production units and the simulation is hourly made using one-hour time steps over a one-year period, the matrix would contain $3 * 8760$ priority numbers. energyPRO assigns these hourly productions in a non-chronological way, starting with the production unit in the time step, that has the lowest priority number (highest priority) in the matrix taking into account the restrictions in the energy stores and transmission lines. After having tested if this production is possible, energyPRO continues to the production unit in the time step with the second lowest priority number in the matrix and tests whether this production is possible. This non-chronological way of assigning production has the consequence that each new production before being accepted has to be carefully checked to ensure that it does not disturb already planned productions.

The analyses in this paper are based on a perfect prognosis for electricity market prices when calculating the priority numbers in the matrix. energyPRO thus has perfect foresight and can optimise against known future electricity prices. This analytical method is described more thoroughly by Østergaard et al. [30].

Furthermore, an important reason for using energyPRO, is it is widely used by consultants to analyse investments in DE plants [31]. That brings the method for assessing support schemes close to how investment decisions are made. Furthermore, energyPRO is widely used for research, e.g. Sorknæs et al. have applied energyPRO to study the treatment of uncertainties in the daily operation of combined heat and power plants [32]. Østergaard et al. used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [30] and to assess the economy of such systems [33]. Fragaki et al. applied energyPRO to study the economic sizing of a gas engine and a thermal store for CHP plants in the UK [34,35]. Streckienė et al. studied the feasibility of CHP-plants with thermal stores in the German Day-ahead market [36] and Østergaard studied heat and biogas stores' impacts on RES integration [37].

2.2. External conditions

Relevant external conditions include ambient temperatures due to the impact on the space heating demand and on gas turbine electrical output. Hourly electricity and gas prices are essential for deciding in which hours the production units shall produce. Furthermore, indexes for the development of prices are essential external for long term analyses. Depending on the concrete DE plants, even more external conditions might be applicable, e.g. solar radiation and wind velocity.

2.3. DE plants considered

To assess how a certain support scheme design will create incentives for DE plant design in a given country, optimally all DE plants should be analysed. This would require a major amount of data about the DE plant stock. As an example, Denmark has a total of 415 DH grids [38], of which 16 are supplied by central power plants and 130 are mainly small-scale systems served by boilers. The remainder are mainly small and medium sized CHPs. The Danish Energy Agency holds most information about these DH grids, thus in principle making it possible to include all Danish DE plants. Another more limited approach is to group existing and new DE plants into typical types of plants, allowing only one analysis to be made for each of the groups.

In this paper we focus on a typical case as described in Section 3.

2.4. Assumptions about the new production units and energy stores

The technical and economic assumptions about the new potential energy units must include efficiencies and costs. For each support level, different combinations of unit sizes are calculated. In the present version, investment costs have to be continuous functions of the sizes. With discontinuous functions, the risk is that a local optimum will be found. If more specific investment costs are not available, assumptions given in Danish Energy Agency's catalogue of technologies [39] may be used. However, the investment costs given there are proportional functions of size without economy of scale effects.

2.5. The calculation of the support schemes

The support given to each DE plant through a support scheme is calculated for each hour in the planning period and these are subsequently summed in a NPV calculation to determine the total societal support. For a support scheme, where e.g. a premium is paid on top of the market price for electricity production from CHPs, the cost of the support in a certain hour is calculated simply as the premium multiplied by the hourly production. Similarly, for a Feed In Tariff the cost of the support in a certain hour is calculated as the Feed In Tariff minus the market price in that hour multiplied by the hourly production. This interpretation of support is consistent with the way a Feed In Tariff is often administered. Being paid a Feed In Tariff often includes that either the transmission system operator or a balancing responsible party sells the produced electricity at the Day Ahead market. The support is only the difference between the Feed In Tariff and the market price in that hour. This difference is often paid by the consumers through a grid tariff. That is also to imply, that if in a certain hour the price in the Day Ahead market is higher than the Feed In Tariff, the cost of the support in this hour is negative.

Table 1
An example of the path to an optimal solution, shown in a section of a decision matrix of Net Present Values in Mio. EUR of investment in CHP and TES at a DE plant.

Total CHP capacity [MW_e]	TES [m^3]									
	0	**60**	**120**	**180**	**240**	**300**	**360**	**420**	**480**	**540**
3.00	2.515	2.585	2.627	2.651	2.662	2.665	2.663	2.659	2.654	2.648
3.20	2.563	2.642	2.692	2.722	2.738	2.744	2.744	2.742	2.739	2.735
3.40	2.598	2.686	2.742	2.777	2.797	2.805	2.807	2.806	2.803	2.800
3.60	2.623	2.715	2.775	2.815	2.838	2.849	2.853	2.853	2.851	2.848
3.80	2.632	2.727	2.794	2.838	2.865	2.878	2.884	2.885	2.884	2.882
4.00	2.627	2.727	2.797	2.846	2.878	2.895	2.902	2.905	2.905	2.903
4.20	2.605	2.713	2.790	2.845	2.883	2.903	2.913	2.917	2.918	2.917
4.40	2.570	2.687	2.772	2.834	2.876	2.902	2.915	2.922	2.924	2.924
4.60	2.522	2.648	2.742	2.809	2.857	2.887	2.904	2.913	2.916	2.917
4.80	2.461	2.596	2.698	2.772	2.823	2.857	2.877	2.888	2.893	2.896

2.6. Choosing the optimal investment

There are different economic criteria used for choosing an optimal investment, amongst others Simple Pay Back time, Internal Rate of Return, NPV, or a combination of more criteria. Here is used the NPV of the additional cash flow at the plant in each month in the planning period, caused by the investment in new units.

As an example, when considering investment in CHPs and TES at a boiler-based DE plant, the payments relating to these additional units include amongst others

- sale of electricity,
- support paid through the chosen support scheme,
- extra purchase of fuel, because a CHP uses more fuel than boilers to produce the same amount of heat,
- extra use of CO_2 quotas,
- fixed and variable costs of the CHPs,
- reduced variable costs of the boiler and
- the investments in the components.

An optimal solution found by optimizing the NPV may result in identifying too large CHPs and TES compared to what in fact will be established. Smaller sizes may be chosen to save investment cost, but the identified sizes still indicate what CHPs and TES will be established.

For a certain DE plant and a certain level of support the optimal size of the new production units and TES are determined in a two-dimensional matrix-calculation as illustrated in Table 1. Here a CHP capacity of 4.4 MW_e and a TES capacity of 480 m^3 is identified as the combination with the highest NPV. The path to this optimum goes through iterative calls of energyPRO starting with zero CHP and zero TES. First, the size of CHP is increased until the NPV starts to decrease. Keeping this CPH size fixed, the TES is increased until NPV starts to decrease. Then again, the size of the CHP is increased keeping the size of the TES fixed. This procedure continues, until no improved NPV is found.

At a capacity of 3.8 MW_e, the optimization procedure will start increasing the TES until a size of 420 m^3 is reached. Then CHP capacity is increased while keeping the size of the TES fixed. The size of the CHPs then ends at 4.4 MW_e. Then again, the size of the TES is increased keeping the size of the CHPs fixed, which ends the optimization at a CHP capacity of 4.4 MW_e and a TES of 480 m^3 since no further NPV improvement is possible.

In the method, it is possible to choose the precision of the found optimal solution, e.g. by choosing the size of steps when increasing the sizes of the new production units and TES, and it is possible to choose a minimum improvement in NPV for accepting an increase in the sizes of the components.

Using this heuristic to find an optimum offers a much faster calculation, compared to calculating all possible combinations of CHP's and TES capacities.

2.7. Outputs

The output from the test of support schemes show for each DE plant the economically optimal investment in new production units and TES as a function of the level of support of the support scheme and as a function of the NPV of the paid support.

3. Test of the two support schemes

This section describes the external conditions, the technical and economic assumptions about the CHPs and TES, as well as the DE plant case used in the test of the two support schemes.

3.1. External conditions

The planning period is set to 20 years from 2017 to 2026, and the real discount rate used in the NPV-calculations is set to 3%, equal to a nominal discount rate of around 4–5%, being a realistic bank interest rate for financing the investments. All prices are given in 2016 levels.

For the wholesale electricity prices are used the prices in the Scandinavian Day-ahead market. This market is organized as a marginal price market [40], where each producer in a certain hour gets the same price for the produced electricity equal to the most expensive bid accepted in that hour [41]. In this analysis the Day-ahead prices for all years in the planning period are set equal to the hourly prices in West Denmark in 2016 [42]. This gives an average price of 26.7 EUR/MWh_e, with a minimum price of −53.6 EUR/MWh_e and a maximum price of 105.0 EUR/MWh_e. Using hourly prices for only one year is a simple choice. A more elaborate approach may include an analysis of the year-to-year trend and make projections of any trend in the hourly variations.

The ambient temperature chosen are Danish numbers with a yearly mean temperature of 8.1 °C, a daily mean temperature on the coldest day of −9.0 °C and on the warmest day of 22.2 °C.

The average natural gas price at the Gaspoint Nordic [43] market was in 2016 around 13 EUR/$MWh_{higher\ value}$, equal to around 4.0 EUR/$GJ_{lower\ calorific\ value}$. In this paper when not being mentioned explicitly otherwise, fuel prices and efficiencies refer to the lower calorific value of the fuels. The gas distribution tariff was around 1.2 EUR/GJ and the transmission tariff was around 0.4 EUR/GJ in 2016, adding up to a natural gas price used in all years equal to 5.6 EUR/GJ for both CHPs and boilers. No taxes are applicable in this context.

A CO_2 quota price of 8 EUR/tonne is used in all years. This is in parallel with an estimation made by Danish Energy Agency [44] for 2016.

3.2. CHP and TES characteristics

In the analyses, efficiencies are constant over time and size independent. Similarly, CPH and TES investment and operation costs are modelled strictly proportional to the size, shown in Table 2.

TES options are split into four technologies; sensible stores, which use the heat capacity of the storage material, latent stores, which make use of the storage material's latent heat during a phase change, sorption stores, which use the heat of ad- or absorption of a pair of materials and chemical stores. The market is dominated by sensible storage vessels due to the qualities, the cost, the simplicity and the versatility of water as a storage medium [39] and is used in this analysis.

The temperature at the top of the TES is assumed to be 90 °C and at the bottom 50 °C, and 10% of the TES is assumed not to be utilized due to stratification layer and placement of nozzles. No storage loss is included. The TES temperatures reflect forward and return temperatures in the DH grid.

Table 2
Technical and economic CHP, TES and existing boilers characteristics (2016-prices) used in this test. Based on [39].

CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fixed operation costs	10,000	EUR/MW_e/year
Variable operation costs	5.40	EUR/MWh_e
Investment in CHPs	650,000	EUR/MW_e
Investment in installation	350,000	EUR/MW_e
Thermal storage		
Investment in thermal storage	200	EUR/m^3
Existing boilers		
Heat efficiency	97.1%	
Variable operation costs	1.10	EUR/MWh_{heat}

3.3. The DE plant case

This test considers only one generic type of DE plants which produces only electricity and heat and thus no cooling.

The yearly amount of heat delivered to the DH grid is 40,000 MWh_{heat}, equivalent to an urban district of 1 km^2 with a heat density of around 120 TJ/km^2 or around 2000 single family houses. 40% of the delivered heat is assumed independent of weather, half of it being grid loss and half of it being consumption for the preparation of domestic hot water (DHW). The rest – representing the demand for space heating – is assumed linearly dependent on ambient temperature. This represents the conditions at a typical Danish DH company [45], where the heat delivered at consumers is composed of a 25% share for DHW and a 75% share for space heating. Only the aggregate heat delivered to the DH grid is used in the model.

The load is considered as an external condition, thus no demand side response (DSR) is included.

An off-set temperature for space heating of 15 °C is chosen so space heating demands only incur in days with an average temperature below 15 °C. The heat demand is assumed to be lower in night hours compared to day hours, around 20% lower in night hours. This is based on empirical evidence from Danish DH systems.

The resulting heat demand requires an average delivered heat from the DE plant of 4.6 MW, a maximum of 11.6 MW and a minimum of 1.6 MW. The hourly delivered heat from plant is shown in Fig. 2 as a heat duration curve.

From the duration curve one can see that the delivered heat is around 5 times larger in winter than in summer, and that the peak delivered heat above 10 MW only happens in few hours of the year.

As the reference situation for analysing the investment in CHPs and TES, the DE plant is assumed to produce the heat on existing heat only boilers, which in the reference situation with the assumed economic conditions gives a heat production cost of 0.938 Mio. EUR per year. Since the investment and operation costs is assumed to be strictly proportional to the sizes of the CHPs it is not important in how many units the CHPs is split. It is chosen to split the CHP capacity on two CHP units, as shown in Fig. 3, which is in good accordance with how CHP at DE plants are designed, as exemplified at online presentations at [46].

4. Results

This section presents the results of the two support schemes analysed.

4.1 Promotion of CHP capacity

The total electrical capacity of the CHPs as function of the paid Premium and FIT is shown in Fig. 4. The obvious outcome is that an identical paid Premium and FIT gives a higher CHP capacity with the Premium scheme than with the FIT scheme. This is primarily because in addition to the premium paid in the Premium scheme is also paid the price in the Day-ahead market. Additionally, it is seen that above a certain level of support the growth in CHP capacity becomes smaller; the system saturate.

Fig. 5 shows the optimal installed CHP capacity as function of the NPV of the paid support over 20 years for the two support schemes. This figure shows more clearly that the cost for society of having a certain CHP capacity at the considered DE plant is nearly the same, whether the Premium scheme or the FIT scheme is used, though slightly smaller with the Premium scheme. This is because with the Premium scheme, it becomes more feasible to invest in TES which allows the plant to seek to place the electricity productions in hours with the highest electricity price. This is not the case when using the FIT scheme, in which case the plant is paid the same price in all hours thus providing no incentive to place the electricity productions in hours with the highest electricity price, thereby making the needed support in the FIT scheme higher.

4.2. Promotion of TES

The largest difference between the Premium scheme and the FIT scheme, however, is that the Premium scheme promotes around five-time larger TES to be installed than the FIT scheme, as seen in Fig. 6.

It is seen in the figure that at a NPV of paid support around 3 Mio. EUR there is no investment in TES. This may be understood by observing Fig. 5, showing that a NPV of paid support around 3 Mio. EUR makes an investment in the CHP around 2 MW_e. This size, however, is approximately equal to the base load of the heat demand, as seen in Fig. 2. Similarly, a NPV of paid support around 30 Mio. EUR makes an investment in the CHP around 7 MW_e, which is a large CHP capacity

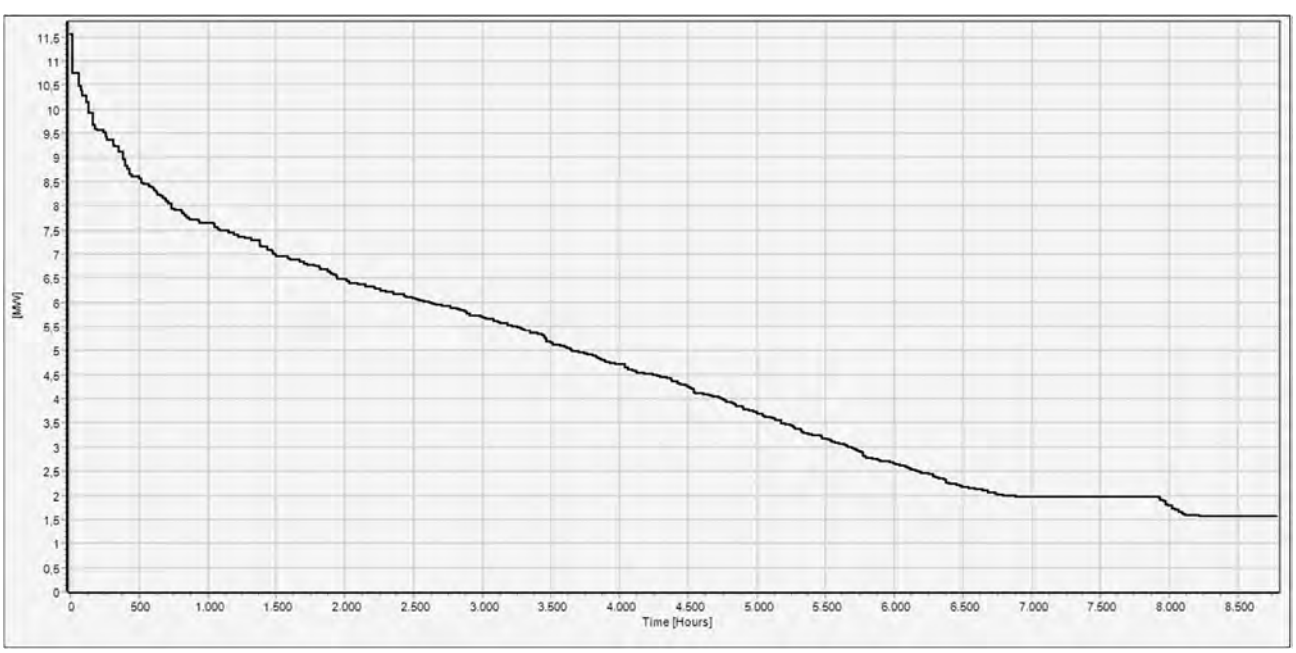

Fig. 2. Heat duration curve for the hourly delivered heat from the DE plant.

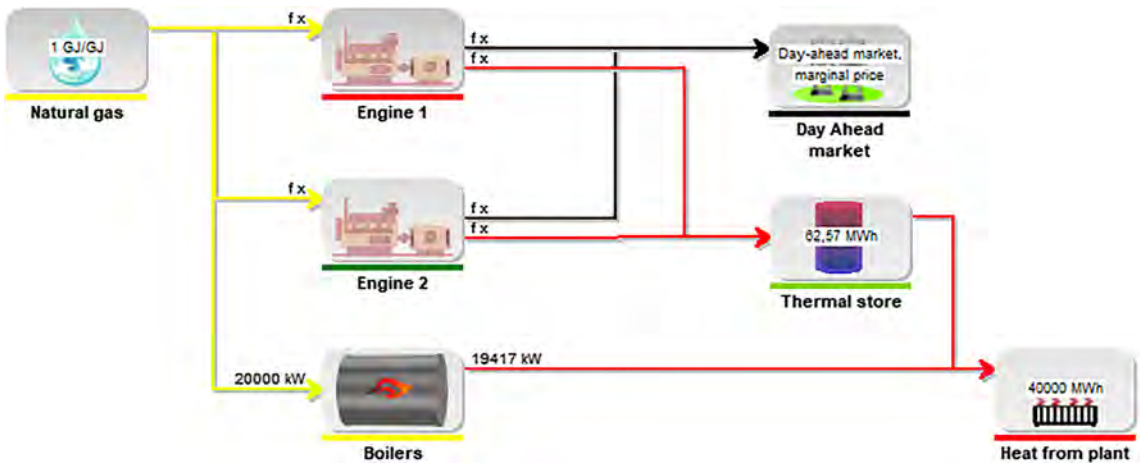

Fig. 3. The generic DE plant case consisting of existing boilers and new CPH and TES units. System chart from energyPRO.

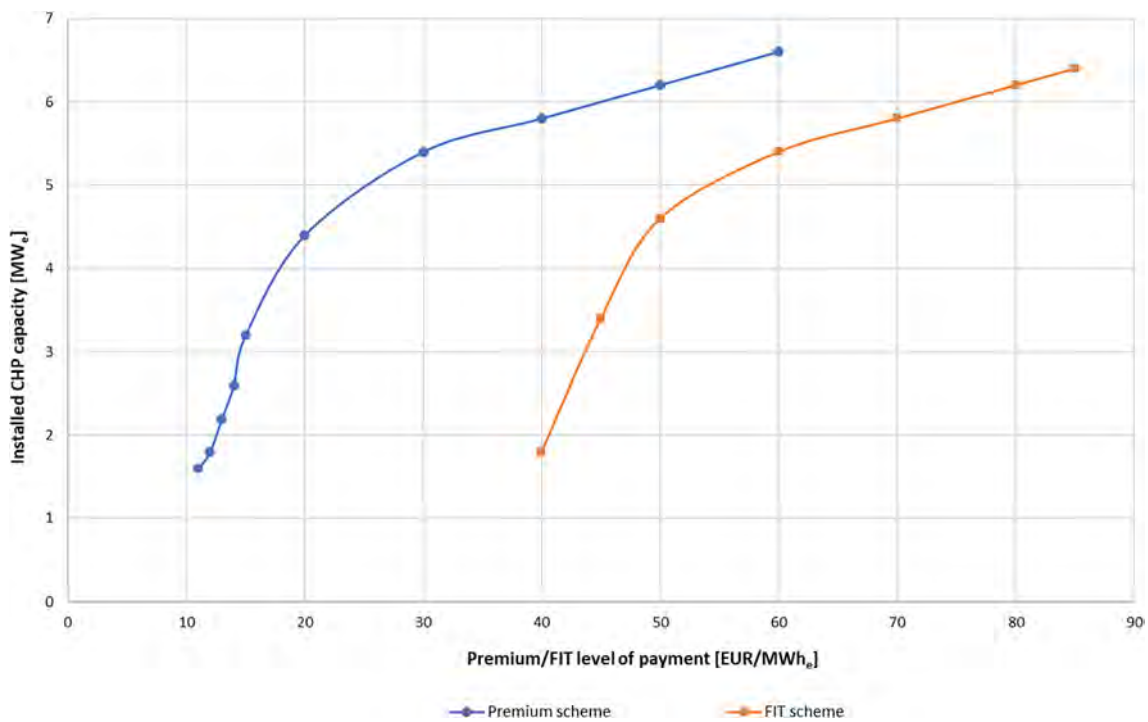

Fig. 4. The optimal CHP capacity at the considered DE plant as a function of paid Premium and paid FIT. It is seen that if the DE plant is paid a premium of 30 EUR/MWh_e the optimal CHP capacity will be around 5.5 MW_e. Similarly, if paid a FIT of 60 EUR/MWh_e the optimal CHP capacity will be around the same size.

compared to the heat demand therefore requiring a large TES when paid the Premium scheme.

4.3. A sensitivity analysis of the Premium scheme

In the analyses so far, the Premium scheme has constituted a fixed premium in all 20 years, however the design can me more complex. In hours with negative market prices for instance, a fixed supplement could create a positive and wrong incentive for production. One minor change could thus be that the premium was not to be paid in hours with negative prices in the Day-ahead market. A major change could be that the premium is reduced by e.g. 40% in the last 10 years.

As a sensitivity analysis, this section present results of an analysis of a design of the Premium scheme, where the premium is only paid in the first 10 years. One consequence of this will often be that the daily operation of the CHPs changes significantly after 10 years, because in more hours they will no longer be competitive in producing heat compared to the heat-only boiler.

Fig. 7 shows the optimal installed CHP and TES capacity at the considered DE plant as function of the level of the support in the Premium scheme, either paid in 20 years or in the first 10 years. It is seen, that when the support is only paid in the first 10 years, a higher level of support is needed to have the same installed CHP and TES capacities.

However, as seen in Fig. 8, the installed CHP capacity at the considered DE plant as function of NPV of the paid support, is practically the same, whether the support is paid in 20 years or only paid in the first 10 years. The same applies for the TES size, but the support paid in 20 years results systematically in a little higher TES size.

4.4. Sensitivity analyses at fixed NPV of support

Further sensitivity analyses are provided in Table 3. The total CPH and TES capacities are shown at a NPV of the paid support equal to 10 Mio. EUR. The table show that the conclusion that a premium support

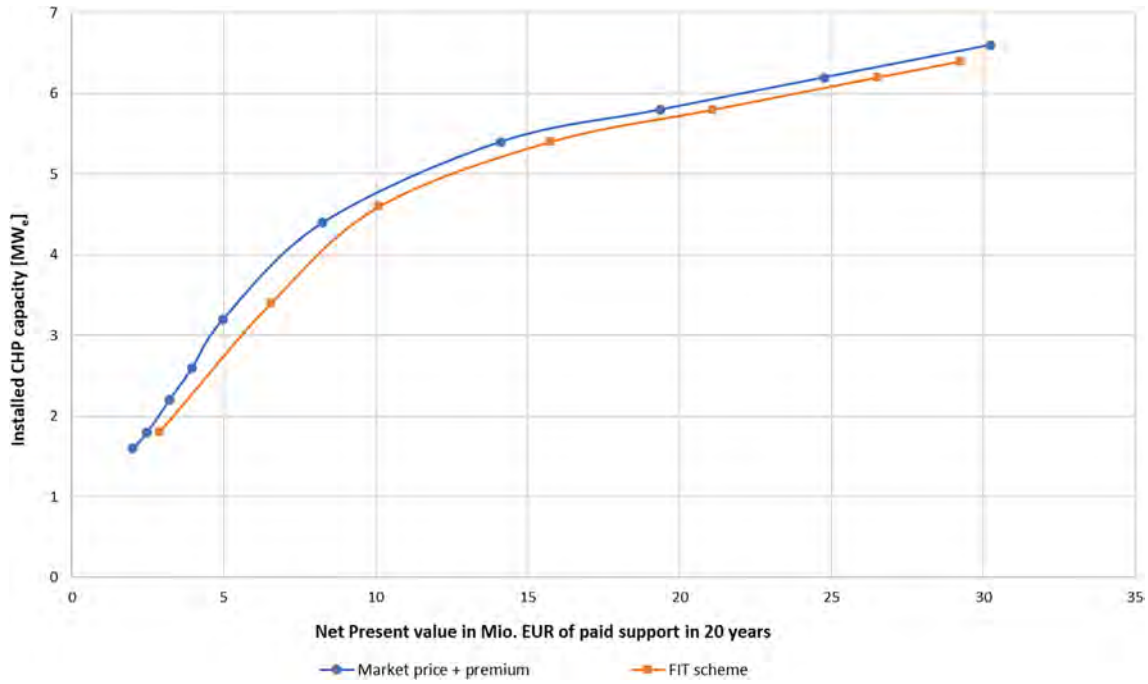

Fig. 5. Optimal installed CHP capacity at the considered DE plant as function of the NPV of the paid support over 20 years for with the Premium scheme and the FIT scheme.

scheme promotes a little more electrical capacity and promotes a five-times larger thermal energy store capacity to be installed is not sensitive to changes in conditions.

5. Discussion

In this section is discussed the reason for that the Premium scheme promotes larger TES to be installed compared to the FIT scheme, for that diminishing marginal utility of support is found and for that an investment support scheme would provide CHP capacity cheaper. Furthermore, using the method for assessing support schemes in real applications is discussed.

5.1. CHP operation with FIT and Premium scheme

To appreciate the results shown in Section 4 it is to be noticed that the simulated daily operation of the CHPs is very different, if the considered DE plant is subject to a Premium scheme or a FIT scheme. In Fig. 9 is shown an example of the simulated operation for a week in June with a Premium scheme. The total size of the CHPs of 5 MW_e corresponds to a premium of 25 EUR/MWh, as seen in Fig. 4.The upper panel shows the Day-ahead prices, the next two the heat and electricity production and finally at the lower panel TES contents.

As is typically seen, the Day-ahead prices are higher in the morning and late afternoon causing the two CHP units to have two starts most of

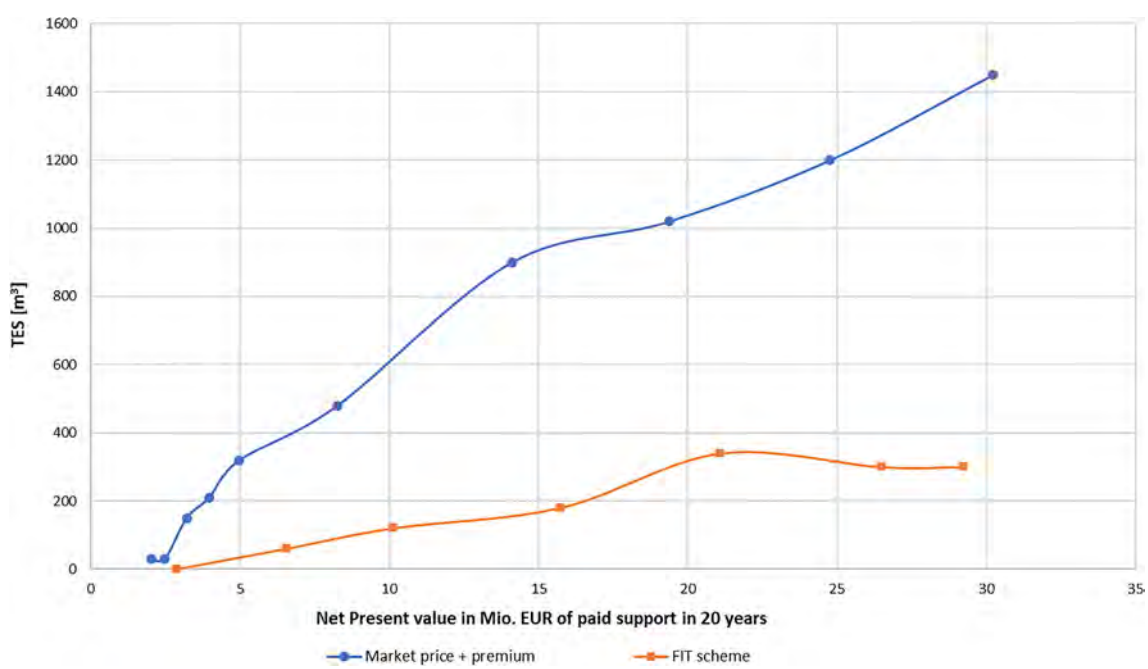

Fig. 6. Optimal installed TES as function of NPV of paid support in 20 years for the Premium scheme and the FIT scheme.

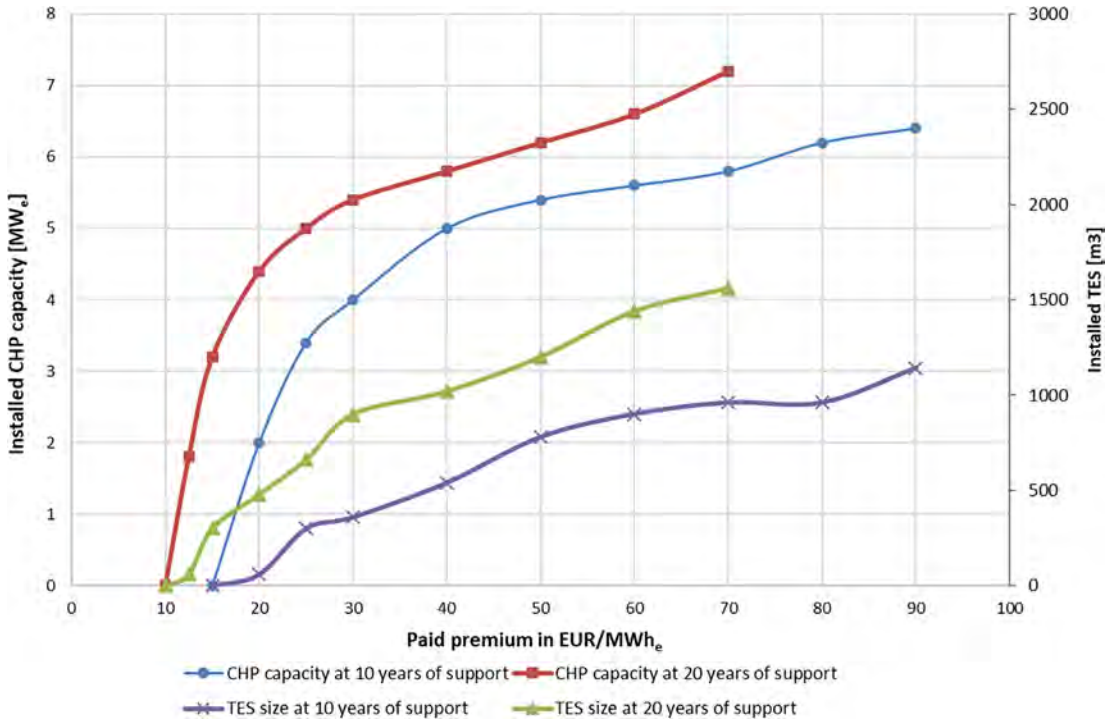

Fig. 7. Optimal installed CHP and TES capacity as function of the level of the support in the Premium scheme, either paid in 20 years or only paid in the first 10 years.

the days of this week. When both CHP units are operated they produce around the double of the heat demand and the excess heat is stored in the TES. When both CHP units are stopped the heat delivered to the DH grid is delivered from the TES. It is further to be noticed, that due to the lower prices Sunday and Monday the TES is more extensively emptied these days.

The simulated operation of the same DE plant in the same week, but subject to the FIT scheme is shown in Fig. 10. The difference to be noticed is that with the FIT scheme only one CHP unit is operated, and it is operated continuously, while the other CHP unit is not operated at all, compared to that with the Premium scheme both CHPs are operated in multiple operation periods. The immediate implications of this are clearly, that with the FIT scheme the CHPs adapt in each hour to the immediate heat demands, because there are no incentives to start both CHPs if one CHP can cover the heat demand. With the Premium scheme and by using the TES, the CHPs adapt flexibly to the immediate

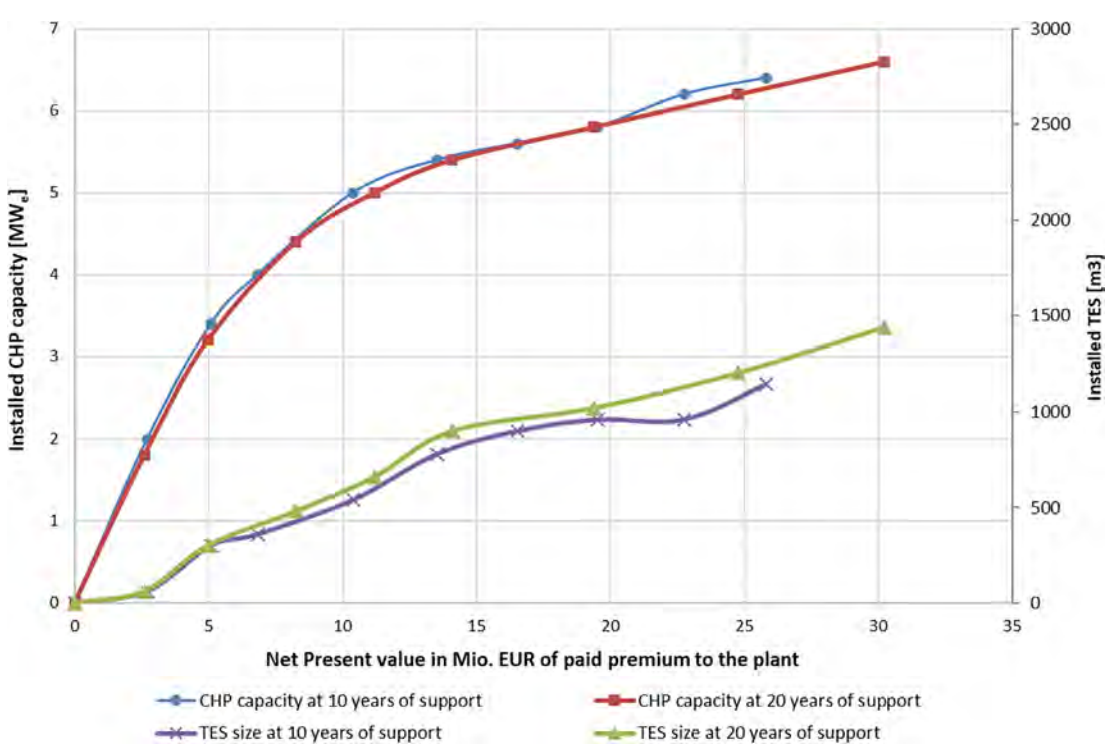

Fig. 8. Optimal installed CHP and TES capacity as function of NPV of the paid support in the Premium scheme, either paid in 20 years or only paid in the first 10 years.

Table 3
A sensitivity analyses of the main case described in Section 3. The CHP TES capacities are shown at a NPV of the paid support equal to 10 Mio. EUR. Each of the 6 * 2 different scenarios shown need around one hundred 20-year calculations to be made. The computing of each scenario takes around ¾ of an hour on a 2.3 GHz computer, thus the table shows the results of 9 h of computing.

Sensitivity analysis	FIT support scheme		Premium support scheme	
	CHP [MW_e]	TES [m^3]	CHP [MW_e]	TES [m^3]
Main case	**4.56**	**118**	**4.70**	**605**
Only 10 years of support	4.52	103	4.91	527
Gas price increased by 20%	3.89	84	4.15	499
Investment costs increased by 20%	4.00	80	4.26	485
Spot price increased by 20%	4.83	128	5.27	894
Discount rate increased from 3% to 5%	4.37	117	4.74	574

demands as indicated by the signal from electricity prices. The NPV of paid support in the FIT scheme will be increased when more of the electricity production is placed in hours with low Day-ahead prices, which more often will happen, because there are no incentives to avoid producing electricity in hours with low Day-ahead prices.

5.2. Diminishing utility of support

It is shown in Fig. 5 that with the technical and economic assumptions about the considered DE plant, an NPV of 20 years of support around 5 Mio. EUR gives a CHP capacity around 3 MW_e, and a NPV of support around 30 Mio. EUR gives around 6 MW_e. Thus, a six times larger support only provides the double CHP capacity. This diminishing marginal utility of support is caused by that the finite heat demand connected to the DE plant.

5.3. High support compared to the needed support for only providing electrical capacity

Another finding is that the NPV of the support promoting CHP and TES is high compared to needed support for only providing electrical capacity. As shown in Fig. 5, a NPV of support around 11.2 Mio. EUR gives a CHP capacity around 5 MW_e. With the used economic assumptions, it would only have been around half had the support been made as an investment support instead of a production dependent Premium scheme. With a CHP investment cost of 1 Mio. EUR/MW_e and fixed operation cost of CHPs of 10,000 EUR/MW_e/year, in a 20-year perspective this gives a NPV of 5.7 Mio. EUR for the cost of the same CHP capacity of 5 MW_e. The reason for still considering a Premium scheme compared to an investment support scheme is that an investment support scheme would reduce the amount of electricity produced on the CHPs. As an example, with a support of 25 EUR/MWh_e in the Premium scheme, the DE plant will be equipped with CHP capacity of 5 MW_e and 660 m^3 TES and will produce 30.1 GWh_e annually. If the support is given as investment support instead, the CHP will be competitive compared to heat-only boilers in fewer hours, which will reduce the yearly electricity production with 55% down to 16.5 GWh_e.

Especially before a country has developed a comprehensive amount of intermittent RES production, where the role of DE plants is primarily through CHP to displace fossil fuel-based condensing mode power

Fig. 9. An energyPRO simulation of the operation in a week in June with a Premium scheme. The upper panel shows the assumed day-ahead electricity prices; the next two the commitment of heat and electricity producing units and the lower the TES content.

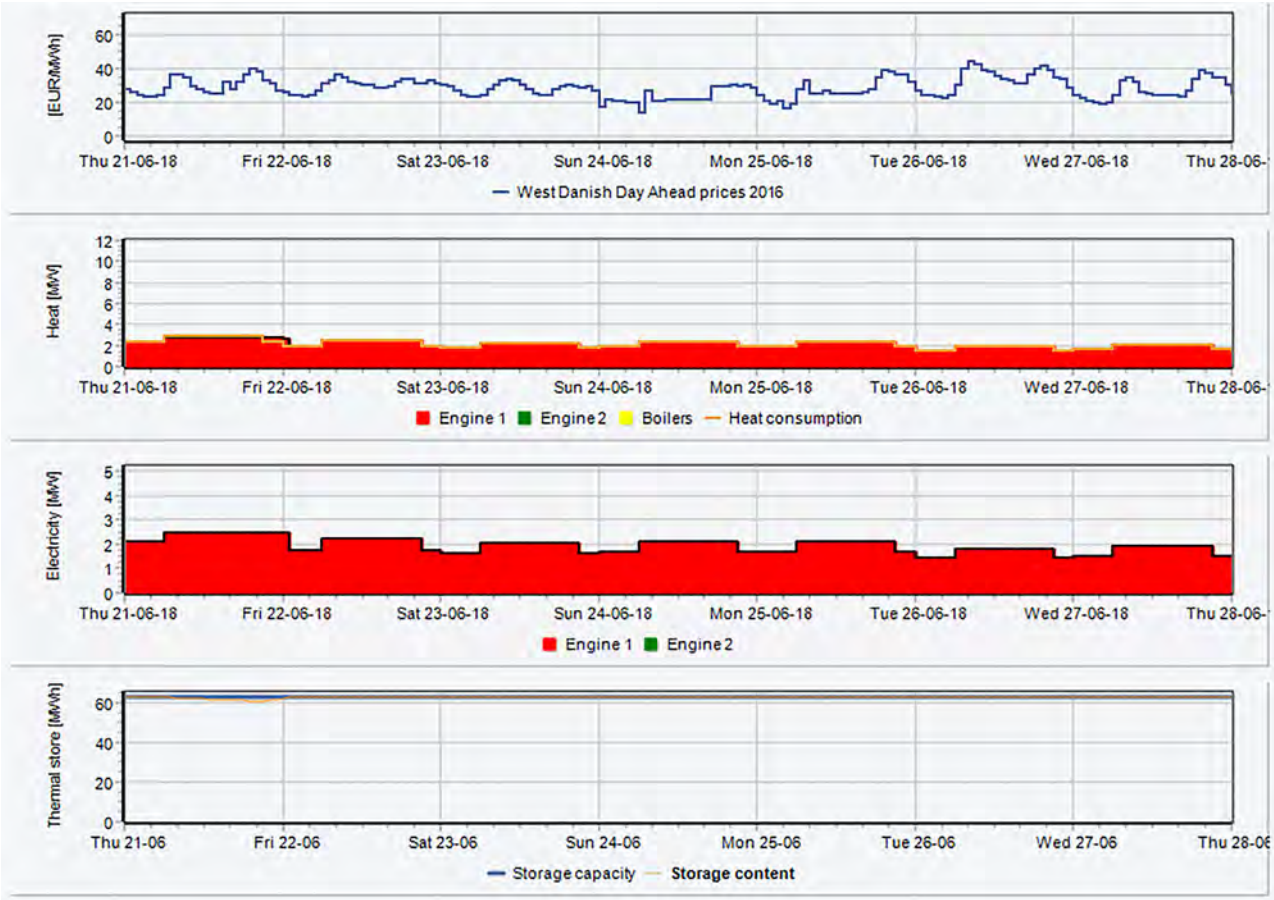

Fig. 10. An energyPRO simulation of the operation in the same plant and period as in Fig. 9 but subjected to the FIT scheme.

plants, this reduction may not be acceptable.

5.4. Using the method for assessing support schemes in real applications

As mentioned, support must be minimised while ensuring proper incentives for adequate investments in CHPs, HPs and TES at DE plants. This method for assessing support schemes shows that for the same NPV of support the design of a DE plant depends significantly on the design of the support scheme. This calls for clear steps for designing the needed support schemes:

1. Making national energy plans for reaching cost effective the national energy goals.
2. Based on these plans determine the right amount and ratio between CHPs, HPs and TES at DE plants.
3. Design cost-minimising a support scheme that promotes these investments.

This method for assessing support schemes makes it manageable to make Step 3. The first two steps are not easy to complete, but necessary for making a proper design of the support scheme. Chittum et al. [47] have made a comprehensive analysis of needed actions for completing the first two steps, pointing to the importance of long-term stable energy policy, political consensus, awareness of local heat planning and for cities to have needed tools for spatial economic impact analysis.

6. Conclusion

DE plants providing heating and cooling to cities have an important role to play in the transition to a RES-based system. In each country the needed extent of flexible CHPs, HPs and TES at DE plants must be determined in national or regional analysis, however, often electricity prices do not create feasibility for sufficient capacity of these to be installed at the DE plants, therefore, support schemes are required.

This paper proposes a method for assessing support schemes, where the focus is that the support schemes besides promoting the right amount of production capacity at the lowest cost of support, furthermore must promote the right ratio between production capacity and TES capacity.

The method is used to test a Premium scheme and a FIT scheme, and the analyses show that the Premium scheme requires a little less total support compared to a FIT scheme for promoting a certain amount of CHP capacity, but promotes a five-times larger TES to be installed. The Premium scheme thus promotes increased flexibility for integrating intermittent RES power production.

Furthermore, the paper has addressed that before a country has developed a comprehensive amount of intermittent RES production, production dependent support schemes is advisable to increase displacement of production at fossil fuel-based condensing mode power plants. When a high level of intermittent RES has been reached, this production covers electricity demand in most hours, leaving only few hours for CHP production. Investment support schemes may be considered at this stage as they require less support.

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Appendix II: Analytic versus solver-based calculated daily operations of district energy plants

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Analytic versus solver-based calculated daily operations of district energy plants

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ABSTRACT

Flexible District Energy plants providing heating and cooling to cities represent an important part of future smart renewable energy systems. Equipped with large combined heat and power units, heat pumps and thermal energy storage they have the possibility to provide flexibility – but an optimized unit commitment is required. A common conclusion has been that unit commitment based on analytic methods is not useful. However, the market-based operation of District Energy plants often being reduced to participation in one or two electricity markets, simplifies the unit commitment problem and brings analytic unit commitment methods back as potentially attractive methods for District Energy plants. This is demonstrated in this paper by establishing a complex generic District Energy plant which is yet so simplified that a solver-based Mixed Integer Linear Programming method is able to deliver optimal unit commitments. An advanced analytic unit commitment method for district energy plants is proposed and the comparison of the unit commitments made by this method with the optimal solver-based unit commitments shows that the method delivers operation income within 1% of the optimal operation income, which is fully adequate for daily operation planning, yearly budgeting and long-term investment analysis for this generic District Energy plant.

1. Introduction

Limiting climate change has been discussed more than a century and has particularly been on the global political agenda since the 2015 Paris agreement [1]. Enhanced deployment of intermittent renewable energy sources (RES), such as wind power and photo voltaic (PV), is one of the main elements for the reduction of greenhouse gas emissions.

One obvious consequence of deployment of RES, however, has been observed in e.g. Denmark, where today an extensive amount of electricity produced by intermittent RES reduces the prices on the Day-ahead market as the power is bid into the market at their near-zero marginal costs. This significantly reduces the operation hours and the profitability of other power plants [2,3], mainly combined heat and power units (CHP) in Denmark.

The Danish Energy Agency estimates in 2025 electricity production from wind power and PV in Germany and Scandinavia will amount to 25% of the total electricity production of the area [2], which will even further affect electricity prices and operation hours and profitability of the other plants negatively. This development is included in the Danish Transmission System Operator's (TSO) plans for 100% renewable energy supply [4], which states that today's cogenerated 90 PJ of heat at CHPs in Denmark will be reduced to 40 PJ in 2035 and to 5 PJ in 2050.

The main task of the District Energy (DE) plants has traditionally been focused on providing heating and cooling to cities. However, equipped with a combination of CHP, heat consuming absorption chillers, heat pumps (HP) producing both heating and cooling and thermal energy stores (TES) these flexible DE plants may furthermore have an important role in integrating intermittent power production [5].

The very different tasks of DE plants in the transition to a RES-based system call for these to be equipped with both large production and TES capacity [6]. A large CHP capacity is needed to supplement intermittent RES production at times of low RES production. Likewise, a large HP capacity is needed in the integration of intermittent RES production by consuming electricity and producing heat during periods with high intermittent RES production -

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often during periods with low prices [7]. The needed large TES capacity is closely related to the large CHP and HP capacity enabling these to detach productions from momentary thermal demands [6].

The operation of DE plants will often be market-based to efficiently participate in the integration of the intermittent RES production. This calls for the operators of these plants to determine and dispatch a daily operation schedule of the production units, that is to say that they must decide when to start and stop each production unit and decide at which load, they should be operated. This is what is denoted Unit Commitment (UC), and UC methods being different approaches to determining this operation.

The UC methods are in this paper proposed divided into two significantly different groups; the analytic UC methods and the solver-based UC methods, even if some UC methods may have properties that places them in-between or outside these two main groups. The solver-based UC methods are based on the minimization of an objective function – typically for DE plants the Net Production Cost (NPC) in an optimizing period of say 7 days. The NPC is the cost of covering heating and cooling demands factoring in a possible sale of electricity in these days. The minimization is subject to constraints, e.g. that there is no overflow in the TES, and is made by randomly choosing a UC, for which the NPC is calculated. Then this UC for the optimizing period will be iterated towards improved NPC while meeting constraints.

The analytic UC methods typically dispatch the daily operation according to priorities calculated for each time step and for each production unit in the optimizing period. The first step to determine these priorities could be to calculate what the NPC of each production unit is in each time step, e.g. showing that CHPs produce cheaper heat in hours with high Day-ahead prices and HPs produce cheaper heat in hours with low Day-ahead prices. In the order of these calculated priorities typically organized in a non-chronological priority list, an analytic UC method tries to commit the production units in each time step taking into account the constraints, and subsequently calculates the NPC of the optimizing period this UC leads to. In many cases a solver-based UC method is able to give a precise estimation of how close the found NPC is to an optimal NPC in the optimizing period. However, as a starting point an analytical UC method does not reveal this.

1.1. Litterature review

Zheng et al. [8] pointed out that there has been a revolution in the energy system UC research and real life practice with the mixed integer programming (MIP), standing out from the early solution and modeling approaches, amongst others priority list methods, which in this report is considered one of the analytic methods. Zheng et al. [9] reviewed 30 papers, showing the large effort over the last decades in developing efficient methods capable of solving the energy system UC problem in real cases or at least for obtaining good solutions in reasonable computational times.

Abujarad et al. [10] pointed out that the complexities in balancing electrical loads with generation have introduced new challenges in regards to UC. They conclude that the significance of UC priority list methods relies on committing generating units based on the order of increasing operating cost, such that the least cost units are first selected until the load is satisfied and conclude that the method converge very fast but is usually far from the optimal UC. The authors further stress that the advantage of employing Mixed Integer Linear Programming (MILP) to solve the UC problem is that the MILP solver returns a feasible solution and the optimality level is known. The disadvantage of this method is that it often takes a long time to run and the calculation time grows exponentially with increasing problem size.

Research has in recent years been somewhat but not entirely focused on balancing electrical loads using solver UC methods. Senjyu et al. [11] developed a new UC method, adapting an extended priority list, consisting of two steps. During the first step the method rapidly obtains a UC solution disregarding operational constraints. During the second step the UC solution is modified using problem-specific heuristics to fulfill operational constraints.

Furthermore, research has in some cases also included the balancing of heating demands. Ommen et al. [12] presented an energy system dispatch model for both electricity and heat production of Eastern Denmark. They examined a system, where HPs contribute significantly in balancing both electricity and heat production with their individual demands. Also Mohsen et al. [13] proposed an optimal scheduling of CHP units of a distribution network with both electric and heat storage systems.

The above-mentioned UC research has mainly been concentrated on system-based balancing of electrical loads made by steam-based generators, where ramping effects and maintaining system reliability are significant constraints when finding the least production cost. They are therefore concluding that analytic methods like the UC priority list methods are not useful. This conclusion could be true when optimizing the energy system across all actors in the energy system.

But introducing market-based operation of the energy system, the actors are divided into numerous companies that optimize their UC by optimizing their own biddings on the electricity markets. Thus, market-based operation means the DE plants perform UC according to changing electricity prices – as opposed to e.g. performing UC according to non-market prices like fixed feed-in-tariffs or according to heat demand.

In the Nordic spot market, for instance, market-based operation means that each DE plant at 12 o'clock each day has to bid into the Day-ahead market for each of the 24 h tomorrow, both concerning selling electricity from the CHPs and buying electricity to the HPs. This bidding is made without any concern about the system balancing but with due concern to the TES contents at the DE plant. Similarly, DE plants may make biddings in the balancing market, which is operated with a shorter time lead.

The TSOs, responsible for the market based system balancing of electrical loads, will often split the balancing tasks into three balancing markets namely Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves [14]. These balancing markets will together with the two whole-sale markets (Day-ahead market and Intraday market), be the five markets that DE plants can choose between – with variation across different countries.

As mentioned earlier when developing further intermittent RES production there will be little room for inflexible steam-based generators on these markets and the TSOs will maintain system reliability by other means, e.g. installing synchronous condensers [15]. Also, flexible gas-based units will be needed. DE plants are characterized by having fast units, that can start and stop within typically 15 min, making it less important to include ramping effects when calculating UC. These production units will typically be operated on/off which is enabled by the large TES.

The focus of a DE plant is to cover heating and cooling demands, whereas electricity supply has less importance, thus often neglected when planning UC. The market-based operation of DE plants will often be reduced to the participation in one or two on the electricity markets. That simplifies the UC problem and brings analytical UC methods back as potentially attractive methods for calculating UC of the DE plants, however this has not yet been seen in research, which in this literature review for methods for calculating UC at DE plants only show solver-based methods.

Mohsen et al. [13], Rooijers et al. [16], Wang et al. [17] and

Lahdelma et al. [18] made UCs for optimal day ahead scheduling of CHP using MILP. Thorin [19] et al. succeeded obtaining UC for CHP using both MILP and Lagrangian relaxation obtaining solutions within reasonable times by a suitable division of the whole optimization period into overlapping sub-periods. Anand et al. [20] considered dual-mode CHPs and found that in this case evolutionary programming was the best to solve the UC problem.

Basu et al. [21] have in a similar way used genetic algorithms for the UC problem, Takada et al. [22] used Particle Swarm Optimization, and Song et al. [23] used an Improved Ant Colony Search algorithm. Gopalakrishnan et al. [24] used a Branch and Bound Optimization method for economic optimization of combined cycle district heating systems. Abdolmohammadi et al. [25] used an algorithm based on Benders decomposition to solve the economic dispatch of CHP. Rong et al. [26] used Sequential Quadratic Programming to solve multi-site CHP UC planning problem.

Sudhakaran et al. [27] integrated genetic algorithms and tabu search for economic dispatch of CHP, and found that it reduce the computation time and improve the quality of the solution. Basu et al. [28] used a Colony Optimization algorithm to solve the CHP UC problem, and shown that this algorithm is able to provide a better solution at a lesser computational effort compared to Particle Swarm Optimization, Genetic algorithm and Evolutionary programing techniques. Vasebi et al. [29] studied a multiple CHP system and found that a Harmony Search algorithm perform well. Powell et al. [30] studied a polygeneration distributed energy system with CHP, district heating, district cooling, and chilled water thermal energy storage, and have found that a Dynamic Programming algorithm performs well.

Pavičević et al. [31] described simplifications with a purpose of reduction of computation time that in most of the studied scenarios exceeds 45 min. Wang et al. [32] studied improved wind power integration by a short-term dispatch CHP model, and showed that after necessary linearization processes, the CHP UC problem can be solved efficiently by MILP. Romanchenko et al. [33] investigated the characteristics of interaction between district heating (DH) systems and the electricity system, induced by present and future electricity price, and developed a MILP model to make optimal operating strategies for DH systems. Lahdelma at al [18]. used a Power Simplex algorithm to study the CHP UC problem. Carpaneto et al. [34] studied optimal integration of solar energy in a district heating network and by making appropriate linearization and piecewise linear functions succeeded using a MILP to the UC problem. Bachmaier et al. [35,36] studied spatial distribution of thermal energy storages in urban areas connected to DH and used the techno-economical optimization tool “KomMod” to solve the UC.

1.2. Novelty, scope and structure of the article

The novelty in this paper is that it brings analytic UC methods back as potential attractive methods to be used at DE plants. This is demonstrated by applying both a simple and an advanced analytic UC method and a solver-based UC method to a generic DE plant. The comparison demonstrates that it is correct - as described in literature - that simple analytic UC methods do not match solver-based UC methods, but the advanced analytic method presented in Section 3.1 often does. In the literature review it is made probable that no single UC method will be able to solve all UC problems at DE plants, therefore, an option is to make use of and combine the best of analytic and solver-based UC methods. This combination will even improve the dialogue with operators of DE plants, who have extensive experience in the complexity, non-linearities and constraints of the daily operation of the DE plants. It will often be difficult to explain to operators of DE plants why a certain UC has emerged from a solver-based UC method. In contrast, it is easier to understand the UC emerging from an analytic UC method.

The scope of this paper is thus to bring research in analytic UC methods back as an option, when scheduling UC at DE plants. Research in UC has, in recent years, mainly concerned system-based balancing of electrical loads made by steam-based generators, where the analytic UC priority list method has proved not easy to use. When developing intermittent RES production there will be little room for inflexible steam-based generators and the market-based operation of DE plants change significantly the requirements of planning UCs at these plants.

This section has, through a literature review, quoted research for showing that both analytical UC methods and solver UC methods have advantages. In Section 2 is described the generic DE plant used for testing the UC methods. The simple and advanced analytical UC method and the solver UC method are described in Section 3. The test benches used for the testing and comparing these three UC methods are described in Section 4. The results of the tests are shown in Section 5 and discussed in Section 6. Finally, conclusions are drawn in Section 7.

2. Considering the generic DE test plant

This section describes a complex generic DE plant, yet also so simplified that a MILP solver-based UC method can deliver optimal UCs. This is enabled assuming that partial load performance of production units is strictly linear. As mentioned by Ommen et al. [12] this simplified assumption will lead to a minor error when dealing with operation of a real plant, but is not considered to be a substantial problem when only using this generic DE plant for comparing UC methods. The plant is used to test two analytic UC methods against a MILP solver UC method described in Section 3. The DE plant is made as a generic DE plant situated in the north of Germany.

Sections 2.1 and 2.2 describe the external conditions including electricity market data, temperature data for heat demand. Section 2.3 describes the plant with case parameters including unit sizes and efficiencies. All prices are stated in year 2016 levels.

2.1. External conditions

German Day-ahead whole sale electricity prices for 2016 [37] are used. The average price this year was 28.98 EUR/MWh$_e$, with a minimum price of −130.09 EUR/MWh$_e$ and a maximum price of 104.96 EUR/MWh$_e$. This market is organized as a marginal price market, where each producer in a certain hour gets the same price for the produced electricity equal to the most expensive bid accepted in that hour. Each consumer in a certain hour must pay the same price for the consumed electricity as paid to the producers. The hourly heat demand is based on the ambient temperature. The temperature of Berlin in 2016 had a yearly mean temperature of 9.1 °C, a temperature on the coldest day −15.0 °C and on the warmest day 22.2 °C.

In 2016 the average natural gas price on the gas markets was approximately 4.0 EUR/GJ [38]. In this paper, when not mentioned explicitly otherwise, fuel prices and efficiencies refer to the lower calorific value of the fuels. The gas distribution tariff was approximately 1.2 EUR/GJ and the transmission tariff was approximately 0.4 EUR/GJ in 2016, adding up to a natural gas price of 5.6 EUR/GJ for both CHPs and boilers. No taxes are included in the comparison, but a CO_2 quota price of 8 EUR/tonne is used. This is close to an estimation made by the Danish Energy Agency [39] for 2016. The CO_2 emission is set to 56.69 kg/GJ-fuel.

2.2. DE plant loads served

The DE plant loads served are similar as used in the analysis of DE plant support schemes made by Andersen & Østergaard [6], thus it is assumed that only a heat demand and no cooling demand is connected to the DE plant, where the yearly amount of heat delivered to the DH grid is 40,000 MWh_{heat}, of which 40% of the delivered heat is weather independent. The rest is assumed to be space heating, being linear dependent on ambient temperature with an off-set temperature for space heating of 15 °C so space heating demands will only be present in days with an average temperature below 15 °C.

The heat demand is assumed to be approximately 20% lower during night hours compared with day hours. The delivered heat from the DE plant is shown in Fig. 1, from where it is seen that maximum delivered heat from plant is slightly above 13 MW and minimum slightly above of 1.5 MW. The duration curve shows that the delivered heat is almost six times larger during winter than during summer, and the peak delivered heat above 10 MW only happens few hours during the year.

2.3. CHP, HP, boilers and TES at the DE plant

The technical and financial data used for CHP, HP, TES and boilers are shown in Table 1. The data are typical data provided by the Danish Energy Agency [40]. To make the test of the UC method more challenging, the CHP and HP capacities are divided into two units as shown in Fig. 2.

The CHP and HP heat capacities are chosen to be equal and the CHPs would be able to deliver 93% of the yearly delivered heat representing large CHP capacity, similar for the HPs. They are assumed only to be operated full load on/off.

In the analyses the efficiencies are assumed constant over time, thus not being dependent on e.g. operating hours. The effect of efficiencies being assumed constant at the generic test plant over the simulation horizon is not considered to be significant. When comparing UC methods, changing efficiencies will have parallel impacts on the different methods. The analyses could have been made with time-varying efficiencies, however this would have clouded the numerical results for the UC methods. In this work it has been assumed that it is justifiable to split the UCs in a 20-year period into monthly optimizations. When going through all months of the 20-year period it will thus not be a problem to change the efficiencies from month to month.

The starting costs are estimated and not necessarily realistic.

The market for TES is dominated by sensible storage vessels [40] and this is also used in these analyses. The size of the TES is set to 1500 m^3. Temperature at the top of the TES is assumed to be 90 °C and at the bottom 50 °C, and 10% of the TES is assumed not to be utilized due to stratification layer and placement of nozzles, in total representing a maximum energy content of 59.24 MWh_{heat}, equal to an energy amount produced full load of both CHP's in around 9 h. No temporal storage loss is included, and the TES temperatures reflect forward and return temperatures in the DH grid.

As shown in Fig. 2 the DE-plant participates in the Day-ahead market, and only the CHPs and HPs have access to store heat in the TES. The capacities of the units are shown in Fig. 2.

3. The UC methods to be compared.

Loads to be satisfied at DE plants are primarily heat- and cooling loads, hence the focus is on heating and cooling production costs. As the CHPs and HPs are assumed to be traded on the Day-ahead market, these production costs will change from hour to hour. The two analytic UC methods and the solver UC method to be compared are described in this section.

3.1. The advanced analytic UC method

The description of the advanced analytic UC method in this section is delimited to a description on how to solve the UC at heat-only DE plants as the plant described in Section 2, but the method may be generalised to more complex DE plants. The first step for each production unit is, in each time step in the optimization period, to attribute a priority number reflecting the operating cost of 1 MWh_{heat}. The priority number for e.g. a CHP is the cost of producing 1 MWh_{heat} reduced with the value of the associated produced electricity in that time step, referred to as the Net heat Production Cost (NHPC). In this case it is assumed that the produced electricity is sold on the Day-ahead market and that the time step is 1 h, thus the priority number for e.g. a CHP in a certain hour depends on the price on the electricity Day-ahead market (the spot price). Similarly, the NHPC of the HP depends on the electricity spot price.

The Technical and financial data given in Section 2 result in the priority numbers shown in Fig. 3 as a function of the hourly electricity spot market price. The figure indicates that for all electricity spot prices the NHPC for the CHPs and HPs are lower than the NHPC

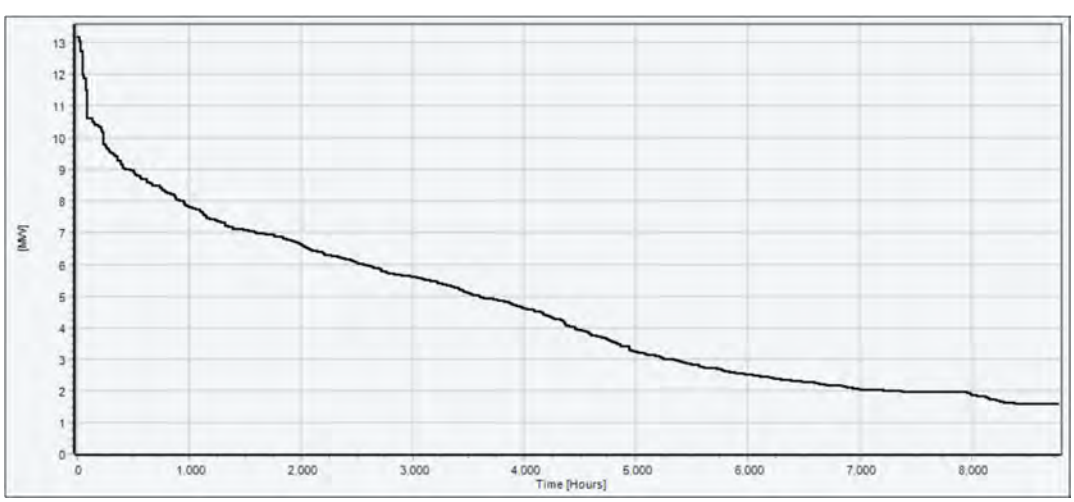

Fig. 1. Heat duration curve for the hourly delivered heat from the DE plant.

Table 1
Technical and financial data on CHP, HP, TES and existing boilers (2016-prices) used in the test of the UC methods, based on typical values from Ref. [40].

CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fuel input	13.65	MW
Electrical power	6.00	MW
Heat power	6.67	MW
Variable operation costs	5.40	EUR/MWh$_e$
Start costs of CHP's	30	EUR/start
HPs		
COP	3.5	
Electrical consumption	1.91	MW
Heat power	6.67	MW
Variable operation costs	2.00	EUR/MWh$_{heat}$
Start costs of HP's	10	EUR/start
Gas boilers		
Heat efficiency	103.0%	
Heat power	15.00	MW
Fuel input	14.56	MW
Variable operation costs	1.10	EUR/MWh$_{heat}$
TES	59.24	MWh$_{heat}$

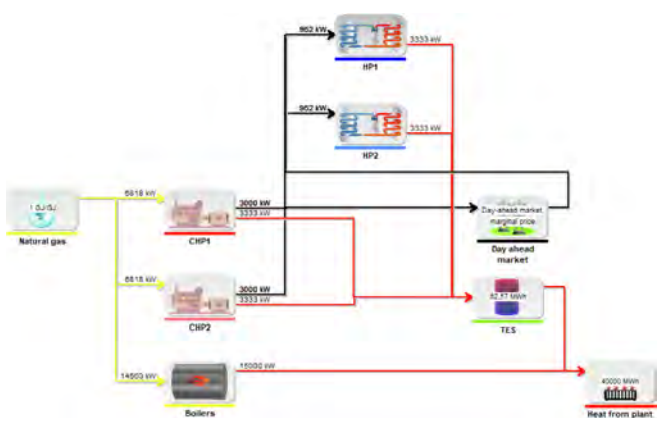

Fig. 2. The generic DE plant case consisting of CHP, HP, boilers and TES units.

of the boilers, which are independent of the spot price. Furthermore, it is seen that up to approximately a spot price of 40 EUR/MWh$_e$, the NHPC of the HPs is lower than these of the CHPs.

An ordered priority list (PL) is made of these priority numbers, with the lowest priority numbers firstly stated on the list and where each of these priority numbers links to a certain hour and production unit. Thus, if a plant has five production units as in this case and the simulation is hourly made over a one-year period, the PL contains 5*8760 priority numbers.

Each production unit at a DE plant typically has associated starting costs and may e.g. have constraints regarding minimum operation period duration. It could e.g. be a minimum of 3 h of continuous operation of CHPs, which is relevant when making block bids on the Day-ahead market. Similarly, minimum stop periods could be a constraint. The minimum operation periods have been included when creating an additional list of start blocks in parallel to the PL.

Each start block contains hours which is at least equal to the minimum length of an operation period. To each start block is associated a priority number which is calculated as the average NHPC of the production unit in the hours in the start block, and to the average NHPC is added the starting cost of the production unit divided by the amount of heat produced by the production unit in the start block. Thus, if a project has 5 production units and the simulation is hourly during a one-year period and the minimum length of operation periods for all production units is 3 h, there will be at least 5*(8760-2) different 3-h start blocks. It is possible to also

Fig. 3. Specific NHPC of the production units as described in Section 2, as function of the electricity spot price on the Day-ahead market. Starting costs are not included.

include larger start blocks e.g. 4-hour start blocks or 6-h start blocks, which will significantly increase the number of start blocks if not only increasing the calculation time but also increasing the optimality of the UC solution. These start blocks are ordered in a start block list (SBL) with the start blocks with the lowest priority first.

After having created the PL and SBL, the UC starts taking the first start block in the SBL and try if it is possible to commit this when considering the restrictions in the energy stores and transmission lines. If it is not possible to commit this start block, the next start block is tried to be committed. This continues until a start block is committed. When a start block is committed, the priority number of the next start block in the SBL is registered. Then the PL is checked up to the priority number of the next start block to see if some of the priority numbers are linked to an hour which may expand the committed start block. Before an expansion of an already planned production period is accepted, it must be carefully checked to ensure that it does not disturb already planned future productions. This is checked in an iterative way, by chronological checking from the hour of expansion if this new production in that hour together with the already planned future productions still fulfils the restrictions in the energy stores and transmission lines. When these expansions of operating periods are exhausted from the PL, the next start block in the SBL is tried committed. This continues until a start block in the SBL is successfully committed. Then again, the PL is checked for possible expansion of all already planned operations.

If the expansion of operation periods results in a distance between two operation periods equal to the length of a start block, the start block fitting into the gap between these two operation periods, will have its priority number recalculated improving the priority number, because if successfully committed it will remove a starting cost, as the two operation periods have become one coherent operation period. The start block will be moved up in the SBL.

This UC continues until the end of the SBL, but the steps go faster and faster because the next start block on the list might be deemed illegal and skipped as it is either overlapping or too close to already planned operation periods or in conflict with minimum stop periods.

An example of the advanced priority list UC for the DE plant described in Section 2 is shown in Fig. 4 for 7 days in September. The upper panel shows the electricity price in the Day-ahead market. The heat and electricity production and consumption are shown in the next two panels. The bottom panel shows the contents in the TES. It is seen that the CHPs are mainly producing during hours with high spot prices and the HPs are mainly producing during hours with low spot prices. The boilers are not producing, which is in good compliance with the NHPCs shown in Fig. 3, where the cost of producing heat in boilers is the most expensive one for all spot prices.

The starting point for comparing the quality of UCs is their NHPCs for the chosen optimization period, thus the UC with the lowest NHPC is considered the best. The reason for not choosing the operation income of the optimization period when comparing UCs is that e.g. the revenues from the sale of heat is the same for all UCs as long as the heat demand is covered. An example of the NHPC for an optimization period, where the UC is calculated using the advanced analytic UC method is shown in Table 2. The first 28 days in September, the operating hours of the two HPs are very different, as well as the operating hours of the two CHPs. Splitting CHP and HP capacity into two units resemble a unit being able to part load down to 50%.

3.2. The simple analytic UC method

As mentioned by Abujarad et al. [10] the basics of UC priority list methods are to commit generation units based on the order of increasing operating cost, such that the least cost units are firstly selected until the load is satisfied. In the simple UC priority list method, it is chosen that the production units are ranked, and the highest ranked production unit is tried to be committed to the entire optimizing period respecting the limited size of the TES. The next highest ranked production unit is then tried, on top of the first one, to be committed to the entire optimizing period, continuing this way to add production units until the heat demand is covered.

3.3. The MILP solver UC method delivering the optimal UC solutions

The MILP method is a formulation of the UC with start-up and shut-down constraints, described by Gentile et al. [41]. Decision variables are established for each of the five production units and the TES. The two CHPs and the two HPs are each binary as no partial load operation is allowed. For the boiler and TES, the decision variables are continuous with upper bounds equal to the maximum capacity.

The objective function to be minimized is the NHPC for the optimizing period. An example of the calculation of the NHPC is shown in Table 2, and is calculated as:

$$\begin{aligned} NHPC = \sum & Purchace\ of\ Electricity + \text{Variable Operation Costs} \\ & + \text{Fuel Costs} + \text{CO2 Quotas} + \text{Start costs} \\ & - \text{Sale of Electricity} \end{aligned}$$

The technical and economic conditions for the calculation of the NHPC is given in Section 2.

There are included the following constraints.

To each of CHP1, CHP2, HP1 and HP2 is connected three decision variables ensuring that the minimum length of operation periods and stop periods are equal to three hours, as shown for CHP1:

CHP1[i] Unit commitment Boolean {0; 1} being true for CHP1 in operation in this time step.

CHP1start[i] Boolean {0; 1} true for CHP1 in operation in this time step and not in operation in the time step before.

CHP1stop[i] Boolean {0; 1} true for CHP1 not in operation in this time step and in operation in the time step before.

Constraint 1: General connection between unit Booleans.

$$CHP1[i] - CHP1[i-1] = CHP1start[i] - CHP1stop[i]$$

Constraint 2: Minimum length of operation periods - here three hours.

$$3 \cdot CHP1start[i] \leq CHP1[i] + CHP1[i+1] + CHP1[i+2]$$

Constraint 3: Minimum length of stop periods – here three hours.

$$CHP1stop[i] + CHP1stop[i+1] \leq 1 - CHP1[i+2]$$

The use of the TES meets the heat balance constraint.

Storage[i]+3.333*(CHP1[i]+CHP2[i]+HP1[i]+HP2[i]) + Boilers [i] – HeatFromPlant[i] = Storage[i+1].

Storage is the content in the TES in the beginning of each time step measured in MWh. The other symbols refer to the symbols used in Fig. 2 and are measured in MW. The chosen time step is 1 h, and it is not necessary to multiply the other symbols with the time step.

4. Tools for testing UC methods

The energy system analysis tool energyPRO [42] is used to

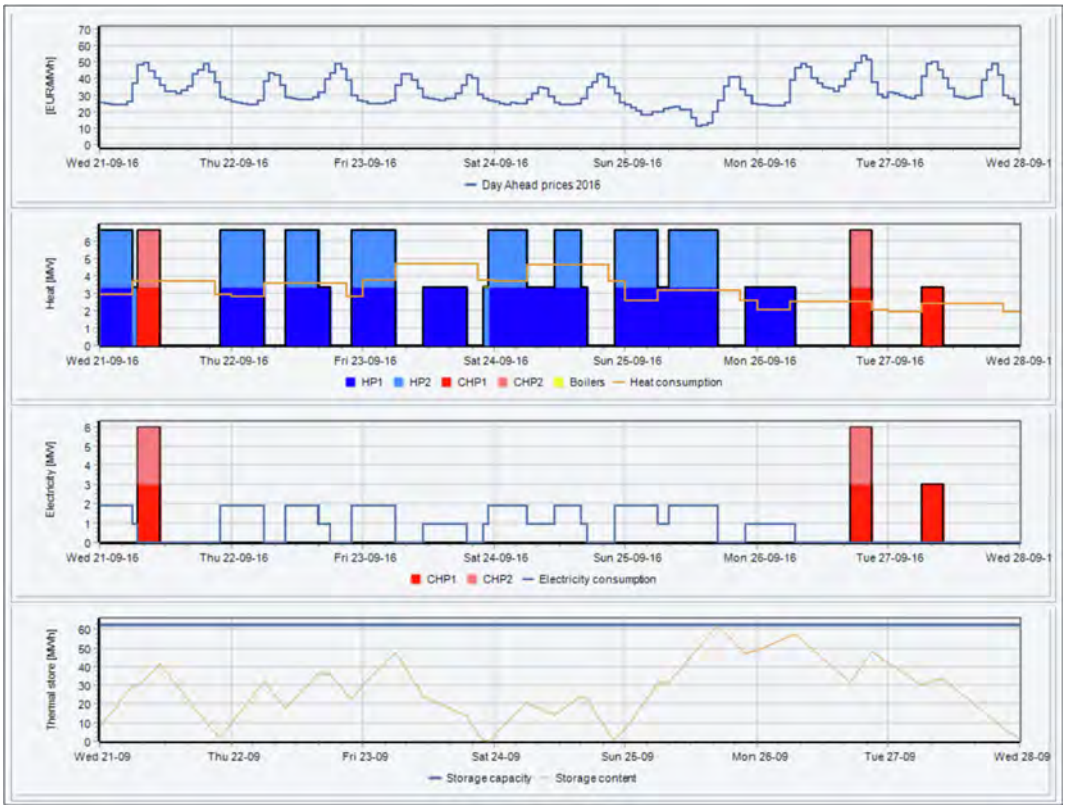

Fig. 4. An example of the UC at the DE plant as described in Section 2 during 7 days in September calculated using the advanced analytic UC method.

Table 2
The NHPC at the DE plant as described in Section 2 during the first 28 days in September calculated using the advanced UC priority list method.

Net Heat Production Cost from 01 to 09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	282.7	MWh_e				6941	
Purchase of electricity HP2	212.3	MWh_e				5137	
Variable operation costs of HP1	989.9	MWh_{heat}	at	2.0	=	1980	
Variable operation costs of HP2	743.3	MWh_{heat}	at	2.0	=	1487	
Fuel costs	752.1	GJ	at	5.6	=	4212	
CO2 quotas	42.6	ton CO_2	at	8.0	=	341	
Variable operation costs of CHP1	69.0	MWh_e	at	5.4	=	373	
Variable operation costs of CHP2	21.0	MWh_e	at	5.4	=	113	
Variable operation costs of boilers	4.5	MWh_{heat}	at	1.1	=	5	
Start costs of CHP1	6	starts	at	30.0	=	180	
Start costs of CHP2	2	starts	at	30.0	=	60	
Start costs of HP1	33	starts	at	10.0	=	330	
Start costs of HP2	27	starts	at	10.0	=	270	
Total Operating Expenditures							**21 428**
Revenues							
Sale of electricity CHP1	69.0	MWh_e				3234	
Sale of electricity CHP2	21.0	MWh_e				1026	
Total Revenues							**4260**
Net Heat Production Cost							**17 168**

calculate the UC made by the advanced analytic UC method and the simple analytic UC method. This is a generalised tool for simulating amongst others market-based operation of DE plants. More operation strategies may be tested in energyPRO, some of these being user defined, and energyPRO allows to test both the advanced and the simple analytic UC method as described in this paper.

Examples of operation strategies being modelled in energyPRO includes Andersen et al. [6] that modelled market-based operation of CHPs, Kontu et al. [43] that simulated market-based operation of heat pumps in district heating systems and Østergaard & Andersen [44] that simulated the operation of booster heat pumps and central heat pumps in district heating systems.

Sorknæs et al. [45] applied energyPRO to model the German secondary control reserve market, Sneum and Sandberg [46] used energyPRO to model flexible district heating and Trømborg et al. [47] applied the model to analyse the effects of different electricity price scenarios on the operation of TES. The MILP solver UC method is calculated with the Gurobi Optimizer [48] used with an interface

made in Python v3.6.

5. Result of the tests

The focus in this paper is the development of UC methods needed for daily operation planning, yearly budgeting and long-term investment analysis of DE plants. When planning the daily operation, also operation during the next days has to be taken into account, as these plants are often equipped with large TES. Thus, using the storage capacity today decreases the possibility to store heat the subsequent days even if production conditions (prices) are better at that given time, therefore a needed optimizing period could be a 7-day period. When making yearly budgeting and long-term investment analysis the total optimizing period may be from one year to e.g. 20 years. Considering the size of the TES, it may be justifiable to split the long optimizing period into monthly optimizing periods. Another optimizing period could therefore be a 4-week period (28 days). These two periods are chosen in the comparison of the UC methods.

5.1. Comparison the UC methods on the first 28 days of September

In Table 3 the NHPC during the first 28 days in September is calculated to EUR 17,008 using the MILP solver UC method. As mentioned earlier this is the optimal NHPC, which is possible as the generic DE plant is complex but yet so simplified that a MILP method can deliver optimal UCs. The NHPC of EUR 17,168 for the same period using the advanced analytic UC method is shown in Table 2. It shows that the NHPC when using the advanced analytic UC method (Table 2) is approximately 1% worse than the optimal NHPC (Table 3).

Furthermore, noticeably is that the CHP production in the optimal solution results in, if using MILP, a significantly higher production than the CHP production calculated when using the advanced UC priority list method shown in Table 2. The reason for this deviation of the CHP production, even if the NHPCs are practically the same, is to be understood looking at the specific NHPC as shown in Fig. 3. At a spot price of approximately 40 EUR/MWh_e the cost of producing 1 MWh_{heat} at CHPs and HPs is the same. Shifting the production from HP to CHP in hours with spot prices around 40 EUR/MWh_e does not change NHPC significantly. That is also shown in Fig. 5 showing the optimal UC during the same 7 days as shown in Fig. 4. E.g. both CHPs are started 27th of September in the optimal UC but only one CHP is started in the UC calculated using the advanced analytic UC method.

The next step in the test is to calculate the NHPC using the simple analytic UC method as described in Section 3.2. Looking at the specific NHPCs in Fig. 3 it is obvious that boilers should have the lowest priority, but it depends on the spot price level during the 28-day period whether the CHPs or the HPs should have the highest priority. With the CHPs having the highest priority, the simple analytic UC method gives a NHPC of EUR 40,118, whereas using the HPs having the highest priority, the NHPC is EUR 19,887. Therefore, comparison will be made using HPs with the highest priority in the simple analytic UC method. The NHPC calculated for the 28-day period with the simple analytic UC method is shown in Table 4. It shows that the high priority HP1 produces close to all the needed heat and the number of starts is extremely low.

Fig. 6 shows the UC calculated with the simple analytic UC method for the same 7 days as in Fig. 4 during the 28-day period. The large TES makes it possible to have few starts of HP1 - even if it is not allowed to operate with partial load.

In Table 5 is compared the three different UC methods. Again, it is seen that the UC calculated with the advanced analytic UC method gives a NHPC which is less than 1% worse than the optimal NHPC calculated by the MILP solver UC method. On the other hand, the UC made by the simple analytic UC method is approximately 17% worse. Furthermore, the sale of electricity is 16% larger and the purchase of electricity is 3% smaller in the optimal UC compared to the UC calculated by the advanced analytic UC method.

5.2. Comparison the UC methods on the first 7 days of September

The same test of the three UC methods, as described in the previous section, is conducted during the first 7 days of September. The short optimizing period is more relevant when making daily operation planning. In Table 6 is shown a comparison parallel to the comparison in Table 5.

Similar results are seen when using the UC calculated with the advanced analytic UC method resulting in a NHPC 0.8% worse than the NHPC using the optimal UC, whereas the UC using the simple analytic UC method is approximate 15% worse.

Table 3
The NHPC at the DE plant as described in Section 2 during the first 28 days in September calculated by means of the MILP solver UC method.

Net Heat Production Cost (NHPC) from 01 to 09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	238.0	MWh_e				5681	
Purchase of electricity HP2	253.2	MWh_e				6071	
Variable operation costs of HP1	833.3	MWh_{heat}	at	2.0	=	1667	
Variable operation costs of HP2	886.6	MWh_{heat}	at	2.0	=	1773	
Fuel costs	863.2	GJ	at	5.6	=	4834	
CO2 quotas	48.9	ton CO_2	at	8.0	=	391	
Variable operation costs of CHP1	42.0	MWh_e	at	5.4	=	227	
Variable operation costs of CHP2	63.0	MWh_e	at	5.4	=	340	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	4	starts	at	30.0	=	120	
Start costs of CHP2	6	starts	at	30.0	=	180	
Start costs of HP1	32	starts	at	10.0	=	320	
Start costs of HP2	36	starts	at	10.0	=	360	
Total Operating Expenditures							**21 965**
Revenues							
Sale of electricity CHP1	42.0	MWh_e				2007	
Sale of electricity CHP2	63.0	MWh_e				2949	
Total Revenues							**4957**
Net Heat Production Cost							**17 008**

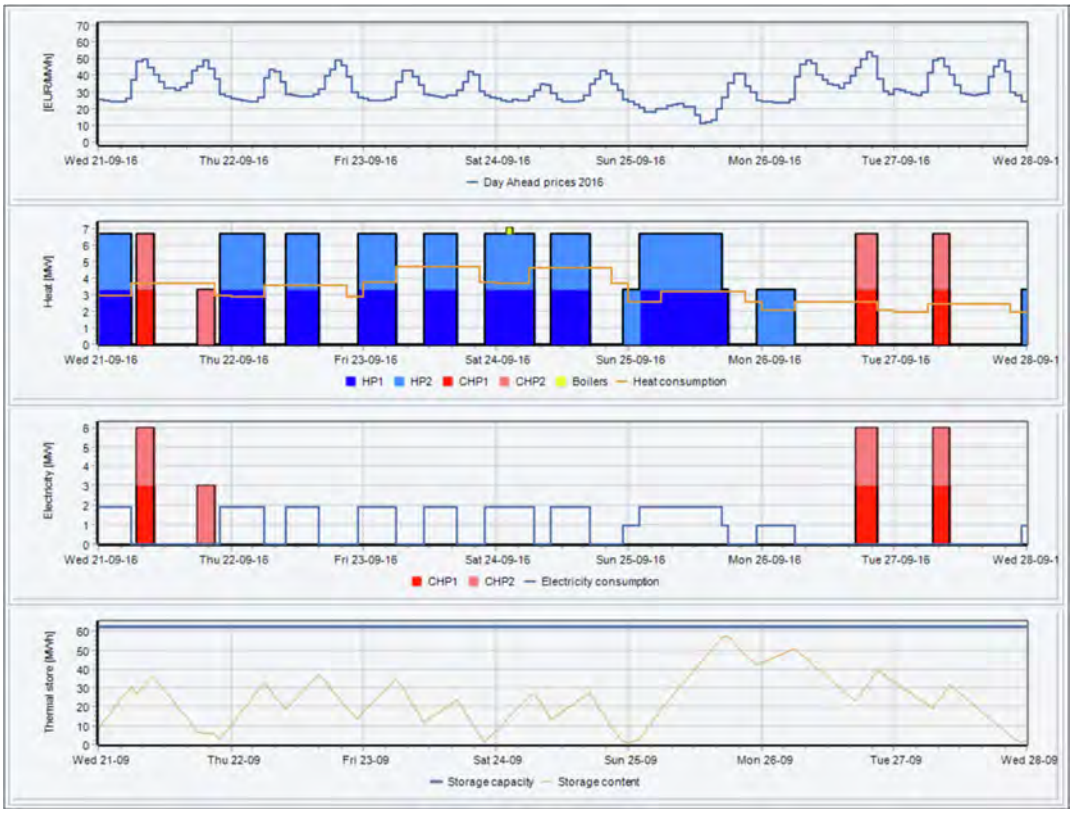

Fig. 5. The optimal UC at the DE plant as described in Section 2 for 7 days in September using the solver-based UC method.

Table 4
The NHPC at the DE plant as described in Section 2 during the first 28 days in September calculated using the simple analytic UC method.

Net Heat Production Cost from 01 to 09-2016 00:00 to 29-09-2016 00:00							
(All amounts in EUR)							
Operating Expenditures							
Purchase of electricity HP1	524.6	MWh_e				16 138	
Purchase of electricity HP2	0.0	MWh_e				0	
Variable operation costs of HP1	1836.5	MWh_{heat}	at	2.0	=	3673	
Variable operation costs of HP2	0.0	MWh_{heat}	at	2.0	=	0	
Fuel costs	4.1	GJ	at	5.6	=	23	
CO2 quotas	0.2	ton CO_2	at	8.0	=	2	
Variable operation costs of CHP1	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of CHP2	0.0	MWh_e	at	5.4	=	0	
Variable operation costs of boilers	1.2	MWh_{heat}	at	1.1	=	1	
Start costs of CHP1	0	starts	at	30.0	=	0	
Start costs of CHP2	0	starts	at	30.0	=	0	
Start costs of HP1	5	starts	at	10.0	=	50	
Start costs of HP2	0	starts	at	10.0	=	0	
Total Operating Expenditures							**19 887**
Revenues							
Sale of electricity CHP1	0.0	MWh_e				0	
Sale of electricity CHP2	0.0	MWh_e				0	
Total Revenues							**0**
Net Heat Production Cost							**19 887**

5.3. Testing with minimum operation and stop periods

A further test has been made, in which an extra constraint has been introduced. The minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours. The results of this test are shown in Tables 7 and 8, where similar results are seen as in the 28 days calculations, that the advanced analytic UC method results in a NHPC 0.8% worse than the optimal NHPC, whereas the UC when using the simple analytic UC method is approximately 15% worse.

It is to be noticed that these extra constraints only reduce NHPC of the optimal UC. The fact that the NHPC is not changed in the advanced UC is amongst others due to the number of production periods are lower with the advanced UC than with the optimal UC.

6. Discussion

This paper demonstrates that the NHPC of the presented

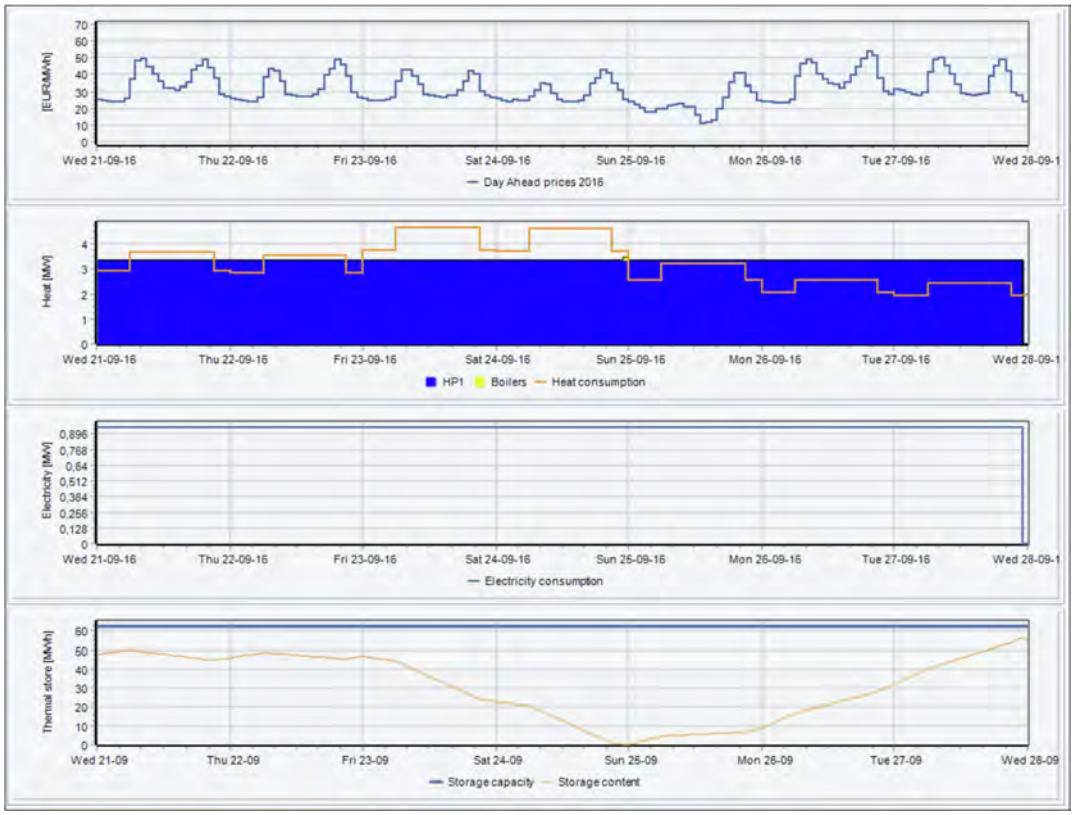

Fig. 6. The UC at the DE plant as described in Section 2 during 7 days in September using the simple analytic UC method.

Table 5
Comparing the UCs at the DE plant as described in Section 2 during the first 28 days in September using three different UC methods.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 008**	**17 169**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	116.7	100.0	0
HPs [MWh_{heat}]	1719.8	1733.2	1836.5
Boilers [MWh_{heat}]	1.2	4.5	1.2
Number of starts of CHPs	10	8	0
Number of starts of HPs	68	60	5
Purchase of electricity [EUR]	11 751	12 078	16 138
Sale of electricity [EUR]	4957	4260	0

Table 6
Comparing the UCs at the DE plant as described in Section 2 during the first 7 days in September calculated using three different UC methods.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4214**	**4248**	**4853**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	440.0
Boilers [MWh_{heat}]	0.0	2.0	2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	2
Purchase of electricity [EUR]	2912	2974	3909
Sale of electricity [EUR]	1070	936	0

advanced analytic UC method is within 1% of the NHPC of the optimal UC at a generic complex DE plant. It is chosen to simplify the plant, in order for a MILP method to be able to deliver for comparison reasons the optimal UC for optimizing periods of

Table 7
Comparing the UCs at the DE plant as described in Section 2 during the first 7 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**4214**	**4248**	**19 887**
Heat production:			
CHPs [MWh_{heat}]	26.7	23.3	0
HPs [MWh_{heat}]	416.6	416.6	1836.5
Boilers [MWh_{heat}]	0.0	2.0	1.2
Number of starts of CHPs	1	1	0
Number of starts of HPs	19	15	5
Purchase of electricity [EUR]	2912	2974	16 138
Sale of electricity [EUR]	1069	936	0

Table 8
Comparing the UCs at the DE plant as described in Section 2 during the first 28 days in September calculated using three different UC methods, with the extra constraint that minimum length of operation periods and minimum length of stop periods for HPs and CHP are set to three hours.

	Optimal UC	Advanced UC	Simple UC
Net Heat Production Cost [EUR]	**17 039**	**17 169**	**20 169**
Heat production:			
CHPs [MWh_{heat}]	113.3	100.0	0
HPs [MWh_{heat}]	1719 .8	1733 .2	1833 .1
Boilers [MWh_{heat}]	4 .5	4 .5	4 .5
Number of starts of CHPs	9	8	0
Number of starts of HPs	67	60	6
Purchase of electricity [EUR]	11 756	12 078	16 342
Sale of electricity [EUR]	4799	4260	0

respectively 7 days and 28 days. These two periods are typical needed optimizing periods when planning daily operation or making yearly budgeting and long-term investment analysis at DE plants.

This close NHPC of the advanced analytic UC method compared to the optimal UC, brings analytic UC methods back as potentially attractive methods for calculating DE plants' UC for more reasons.

The main reason is due to the implemented market-based operation of the energy system, where the actors are divided into numerous companies that optimize their UC by optimizing their own biddings on the electricity markets and that the market-based operation of DE plants will often be reduced to one or two of these electricity markets.

A further reason that simplifies the UC problem at DE plants, is that they are characterized by having fast units, that can start and stop within typically 15 min. This makes it less important to include ramping effects when calculating UC. Assisted by the large TES, these production units will furthermore typically be operated on/off. This is due to that e.g. the CHPs are developed to have their highest electrical efficiency at full load [49]. Simulating partial and minimum load on CHPs and HPs require changes to be made to the advanced analytic UC method and the solver UC method described in Section 3. Partial load allows a better optimization of the participation in the Day-ahead market, but at lower efficiency. Thus, the NPC will be changed slightly by allowing partial load, but it is not expected that the difference between the NPCs calculated by the two UC methods will change significantly for the DE plant considered.

As highlighted in the literature review in Section 1, it is not expected that only one UC method will be able to solve sufficiently precise and fast all UC problems at DE plants. Therefore, an option is to make use of and combine the best of analytic and solver-based UC methods. The optimal NPC of a UC at an actual DE plant are expected often to be more than 1% off the optimal NPC of the UC of a simplified model of this DE plant, simply because assumed linearities do not exist at real DE plants. E.g. the temperatures in a TES are not perfectly stratified in a cold and a hot water zone but are more or less mixed through the TES. This may have the consequence that a CHP has to operate in partial load when mixed hot and cold water from the TES reaches the CHP or that the thermal efficiency of CHPs and boilers are reduced when mixed hot and cold water is sent to the heat exchangers. Also, the coefficient of performance of the HPs does not depend linearly on the temperatures of the heat sources and of the delivered heat. Missing linearity can have the consequence that MILP is not able to solve a UC, contrary to analytic UC methods that will always deliver a solution and often deliver it fast, but the optimality level is less known.

Even if linearity is not present many mathematical solvers will be able to deliver a solution for a UC, but this will often be very time-consuming as shown by Mohsen et al. [13]. Furthermore, one common characteristic is that it will often be difficult to explain why a certain UC has emerged from a solver UC method. Analytic UC methods has the opposite approach. Determining a logical prioritised UC of each production unit in each time step, it will calculate a UC for the whole optimization period. This logic will often take its starting point in a dialogue with operators of DE plants, which have extensive experience in the complexity of daily operation of the DE plants. A simple example of this is that an operator is often aware of the priorities of each production unit as shown in Fig. 3, where CHPs produce cheap heat at high Day-ahead prices and HPs produce cheap heat at low Day-ahead prices, therefore making these hourly NPCs a natural starting point for analytic UC methods being used for planning plant operation.

A consequence of not having access to a sufficiently precise and fast calculated UC may be that biddings in the electricity markets are not optimized. As an example, at 12 o'clock each day, Danish DE plants have to bid into the Day-ahead market for each of the 24 h the following day, both concerning selling electricity from the CHPs and buying electricity to the HPs. This must be done with due concern about the contents in the TES at the DE plant. These bids will amongst others be based on prognosis for Day-ahead prices and required heat deliveries from the plant. A suboptimal UC may either result in bid being given for the wrong hours or that the bidding prices are not reflecting the true value of winning the bids.

The UC methods used in national analyses has in a similar way been divided into different types of UC. Besides solver UC methods, has also been used analytic UC methods as e.g. performed in EnergyPLAN [50,51], simulating the operation of national energy systems on an hourly basis.

7. Conclusion

Flexible District Energy plants with large combined heat and power units, heat pumps and thermal energy storage providing heating and cooling to cities represent an important part of a renewable energy system, but an optimized unit commitment is required. The market-based operation of these plants means that they can sub-optimize their own production independently of the rest of the energy system, which has simplified the unit commitment at these plants.

Three different unit commitment methods have been compared; a unit commitment calculated with mixed integer linear programming, a unit commitment calculated with an advanced analytic unit commitment method, where the priorities are made as function of the Day-ahead prices, and a simple analytic unit commitment method, where the priorities are independent of the hourly Day-ahead prices.

It is shown in this paper that the advanced analytic unit commitment method delivers results within 1% of the optimal operation. As an example, the optimal Net Heat Production Cost in the first 28 days in September of the chosen generic energy plant is 17 008 EUR, and when using the advanced analytic unit commitment method, it is 17 169 EUR, which is less than 1% of the optimal unit commitment. This makes analytic unit commitment methods potential attractive methods.

Furthermore, it is suggested that a valuable dialogue with operators of District Energy plants will be achieved, if research in unit commitment at District Energy plants focuses on both analytical as well as solver methods. The next steps in the research of the UCs for DE plants could be to making use of and combining the best of analytic and solver-based UC methods, and to compare these methods against the real UCs seen at DE plants, which will create a valuable exchange of experience with the daily operators of the plants.

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Appendix III: Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy

Support schemes for the radically changing role of District Energy CHPs through the transition to a renewable energy system

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Abstract

The role of Combined Heat and Power units connected to District Energy plants (DE CHP) changes radically in the transition to a renewable energy system, developing from displacing condensing mode power generation and boiler-based heat generation (Phase 1), via assisting in the integration of fluctuating renewables (Phase 2) to finally only providing reserve capacity (Phase 3).

Often the earnings on the electricity markets are not sufficient to promote the establishment of a desired amount of DE CHPs, therefore support schemes are needed. A methodological comparison is made of a Premium and a Triple tariff support scheme. The comparison shows that the societal cost during a 20-year period, is less than half when using the Triple tariff compared to using the Premium scheme for providing a certain CHP capacity. While this CHP capacity displaces the same amount of production from condensing mode power plants in Phase 1, the Triple tariff promotes larger thermal energy storage capacity compared to the Premium scheme, which is beneficial for DE CHP to fulfil their tasks in Phase 2 and 3. However, it is shown that in these later phases adaption of the support schemes is needed.

Contents

Keywords

Triple tariff
Premium support scheme
Combined Heat and Power
Thermal Energy Store

Highlights

- District Energy plants have major tasks in integrating wind and solar power
- Support is required for making the needed investments in District Energy plants
- A methodological comparison of a Premium and a Triple tariff support scheme
- Societal cost during a 20-year period is less than half when using the Triple tariff
- The Triple tariff promotes larger storage capacity than Premium scheme

1 Introduction

Climate change is on the global agenda and most countries are considering how to reduce the emission of greenhouse gasses – most notably CO_2 [1] of which the main proportion comes from energy consumption. In the European Union (EU), heating and cooling represent approximately half the final energy consumption and it is a larger end-use sector than transport and electricity [2]. Furthermore, with only 15% covered by Renewable Energy Sources (RES), this is a carbon-intensive sector. Worldwide, heating and cooling also require special attention as they represent half of the energy used in buildings and primarily produced from fossil fuels. The United Nations Environment Programme [3] emphasizes the importance of sustainable heating and cooling solutions – not least from a climate change mitigation perspective.

The research project Heat Roadmap Europe [4] has found that it is socio-economically feasible through energy savings to reduce the heat demand in Europe with 30-40%. The remaining heat demand, it will be socio-economically feasible to cover a large share of this with district energy (DE) instead of individual heating. Especially in cities with high heat densities it becomes feasible to establish systems that provide heating and cooling to more buildings [3]. The reasons are amongst others that it enables the exploitation of waste heat from power plants and industry [5]; that a significant economy of scale-effect makes solar collectors at DE plants much cheaper to build compared to solar collectors at each building [6]; that heat pumps (HP) gets access to a broader range of heat sources, e.g. heat from sewage systems [7] and sea water [8,9] and that for many cities it will be possible to exploit geothermal energy [10]. In future energy systems with transportation fuels being produced from wind power and PV, DE systems will be able to make use of the inevitable losses [11]. Similarly, more cooling sources become available, e.g. free cooling from lakes, rivers or oceans [12].

However, in the transition to a renewable energy system, the role of CHP at DE plants changes radically between three phases in the transition. In Phase 1 the DE CHP's task is to displace fossil fuelled condensing mode power plants as well as displacing production on individual and communal boilers, thus producing as much electricity as the heat demand allows. In Phase 2, where wind power and photo voltaic (PV) cover a major part of the electricity demand, the DE CHPs participate market-based in the integration of these fluctuating productions and produce less electricity compared to Phase 1. In Phase 3, the DE CHPs are producing even less electricity and are instead providing needed electrical reserve capacity during the few hours, where wind power and PV do not produce enough to cover the electricity demand [13]. In Phase 2 and 3 DE plants will have the task of consuming electricity at HPs or electrical boilers during hours with surplus intermittent RES-based electricity production and only to produce electricity at CHP in hours with lack of intermittent RES-based electricity production [14]. To fulfil this role, DE plants have to be equipped with large CHP and HP capacity [15], and as a consequence of these large capacities they also have

to be equipped with large Thermal Energy Storage (TES), providing the DE plants with the needed flexibility to integrate the intermittent RES.

Often electricity prices do not create sufficient commercial feasibility in CHPs and TES to promote adequate amounts to be installed at DE plants. Therefore, support schemes are needed. Different schemes have been applied in different places at different times for supporting DE CHPs, amongst others Feed-in premiums, Feed-in tariffs, Quota obligations, Tax exemptions, Tenders and Investment aids. Each of these support scheme types can be designed differently and even combined with the aim of meeting the requirements for the support schemes.

Two of the most widely used support scheme types are the Feed-in premium types and the Feed-in tariff types. These are introduced and reviewed in the next two sections.

1.1 The Premium support scheme

In its basic form, the Premium support scheme adds a premium to the wholesale electricity price in each hour. This simple support scheme has gained ground over the last years and is used as main support instrument in Denmark, the Netherlands, Spain, Czech Republic, Estonia and Slovenia [16] and premiums are usually guaranteed for a longer period, e.g. 10 up to 20 years. In this way the scheme provides long-term certainty when receiving financial support, which is considered to lower investment risks considerably. Premiums are amongst other applied in the case of support of biogas by Denmark, Italy and Slovenia. In Germany the biogas plants with capacity larger than 750 kW_e are only offered premiums. In Slovenia, a market-premium scheme has been introduced for operators above 500 kW_e [17]. Schallenberg et al. [18] argues that Premium schemes can help creating a more harmonized electricity market, effectively removing the difference between renewable and conventional electricity production.

Haas et al. [19] argues that in principle, a mechanism based on a fixed premium/environmental bonus reflecting the external costs of conventional power generation can establish fair trade, fair competition and a level playing field in a competitive electricity market between RES and conventional power sources. They mention that from a market development perspective, the advantage of such a scheme is that it allows renewables to penetrate the market quickly if their production costs drop below the electricity-price-plus-premium. Therefore, if the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows renewables to compete with conventional sources without the need entering "artificial" quotas.

Mezősi et al. [20] has in its cost-efficiency benchmarking of European renewable electricity support schemes found that the premium support schemes in Denmark are the most cost effective ones.

The EU has dealt extensively with support in more reports [21–23], and recommends to use the Premium scheme as it exposes the DE plant to the hourly market prices. Furthermore, in EU´s Guidelines on State aid for environmental protection [24] it is required that Member States convert the

existing administratively determined Feed-in Tariff or Feed-in Premium schemes to competitively determined Feed-in Premiums or Green Certificate support schemes for new RES-E installations from 2017.

However it is noticeable that Schallenberg et al [18] has found that a premium scheme can occasionally lead to overcompensation. This is based on studying the Spanish system. Similarly, Gawela et al. [25], studying system integration of renewable energy through premium schemes on the German market, found a risk of overcompensating producers and find that it is questionable if a premium scheme is gradually leading plant operators towards the market.

Dressler [26] pointed out that Premium schemes may enhance market power, favours conventional electricity production and may even hamper the increase in production from RES.

1.2 The Feed-in tariff succeeded with Investment aid

In most countries Feed-in tariffs are amongst the preferred choices of support schemes [19]. They are designed in different ways, but in this article the Triple tariff has been chosen to be analysed. This was instrumental in the Danish introduction of DE CHP as shown in Figure 1 and was thus in force in the years where the Danish energy system became decentralized.

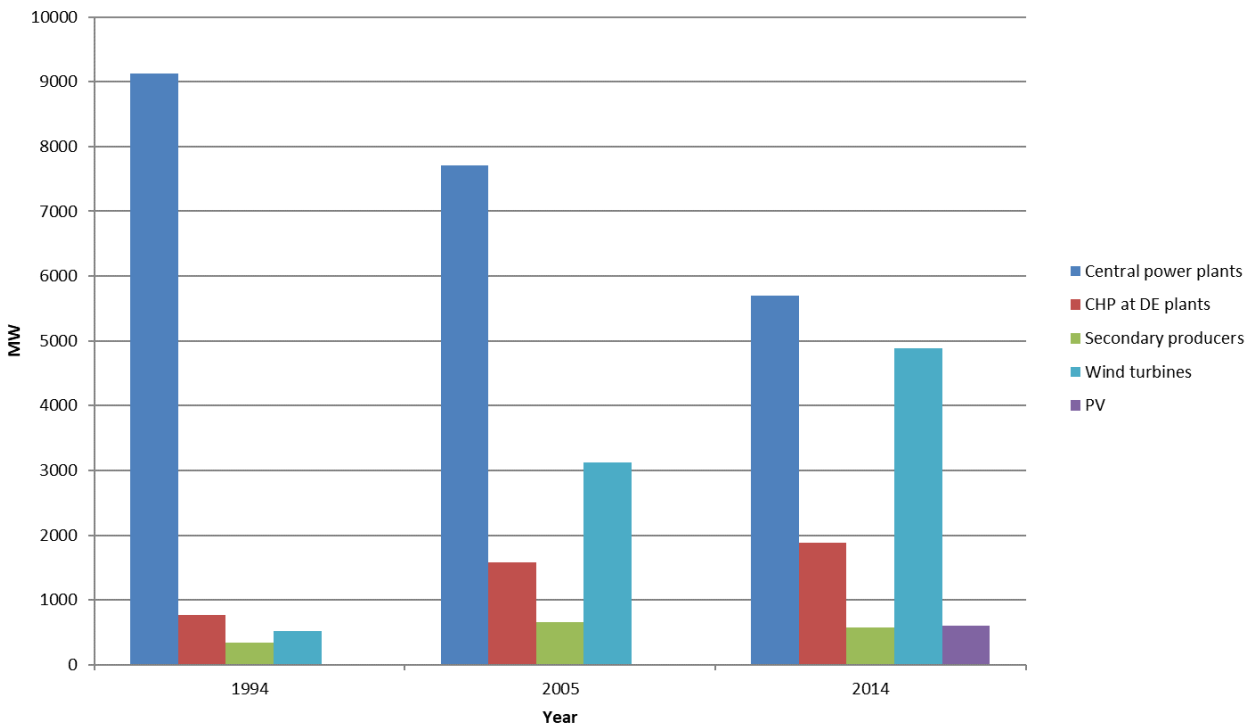

Figure 1: Electricity production capacity in Denmark in the last 20 years, according to data from [27]. The central power plants are situated at 16 sites. The secondary producers are industrial producers and waste incineration plants.

The Danish Energy Agency has illustrated how this development changed the Danish energy landscape – see Figure 2. From a few power plants in the beginning of the 1980s to thousands of power producing units today, where, besides the central power plants, 285 DE CHP plants, 380 industrial

and private CHP-plants and 5260 on-shore wind turbines shore and 515 off-shore wind turbines are in operation [28].

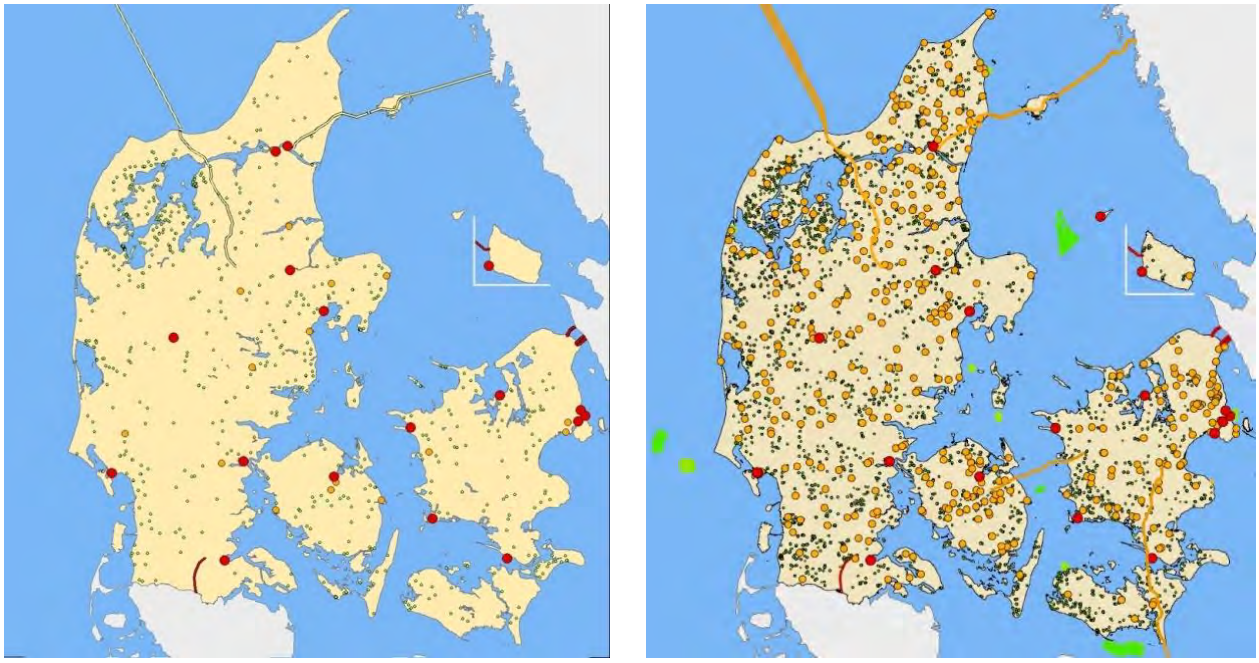

Figure 2: The electrical infrastructure in Denmark in 1985 (left) and 2013 (right). Red circles indicate central power plants, yellow circles DE CHPs and secondary producers above 500 kW. The green dots show wind turbines and green off-shore areas show off-shore wind farms [29].

More research has been published studying the effect of Triple tariff support schemes. Østergaard [30] analysed the geographical distribution of electricity generation and concluded that the Triple tariff influenced the local CHP plants to be operated according to a certain fixed diurnal variation. Soltero [31] mentions the Danish Triple tariff when considering the potential of natural gas district heating cogeneration in Spain as a tool for decarbonisation of the economy. Fragaki et al. [32], studying the sizing of gas engine and TES for CHP plants in the United Kingdom, mentions that the situation there resembles the Triple tariff electricity sales prices of the Danish system. Sovacool [33] mentions that the Danish Triple tariff made CHP operators being paid for their provision of peak power thus improving significantly the feasibility of investments in CHPs. Toke et al. [34] investigated whether the Danish Triple tariff could assist the implementation of CHP in the United Kingdom, arguing that this could help meeting its long-term objective of absorbing high levels of fluctuating RES.

Some articles describe simulation of energy systems based on the Danish Triple tariff without however investigating the Triple tariff in depth. Lund [35] and Lund and Münster [36] studied large-scale integration of wind power into different energy systems using a reference scenario where the CHP plants produced according to the Triple tariff. Taljan et al. [37] studied the sizing of biomass-fired Organic Rankine Cycle CHP investigating the plant size being optimized against the Triple tariff. Ge-

bremedhin [38] mention the Triple tariff when looking into externality costs in energy system models. Heinz and Henkel [39] considered the Triple tariff in connection with a fuel cell population in the energy system. Dominković et al. [40] considered the application of feed-in tariffs in Croatia, and argued that feed-in tariff for pit TES will be of significance for the economic feasibility of investment. Østergaard [41] describes the capability in EnergyPLAN [42] to simulate the operation of national energy systems, where CHP plants are operated according to a fixed Triple tariff system. Schroeder et al. [43] mention that a Triple tariff system increased CHP´s integration into electricity markets. Hernández [44] studied photovoltaic in grid-connected buildings, investigated single, double and Triple tariff systems in Spain.

1.3 Novelty, scope and structure of the article

A main requirement of a support schemes is that it induces technology deployment at the lowest possible costs for the society, however the literature review in Sections 1.1 and 1.2 revealed the on-going move towards Premium schemes in spite of some authors noticing potential excessive cost of this scheme. At the same time, empirical evidence shows how the triple tariff was instrumental in the introduction of DE CHP in Denmark. We have not encountered any quantitative comparisons of the societal costs of providing a certain technology deployment at different support schemes at DE plants. This is the aim of this article based on a quantitative comparison for a generic DE plant.

Analyses are made to compare a triple tariff scheme with peak, high and low load tariffs and a premium on top of hourly wholesale electricity prices.

Based on the comparison of these two support schemes a proposal is discussed for the design of support schemes for the radically changing role of CHPs through the transition to a renewable energy system.

Section 2 presents the detailed procedures of the Triple tariff and Premium support schemes, followed in Section 3 by the method for assessing the CHP capacity a support scheme promotes. Section 4 describes the DE plant case used in the analysis as well as the external conditions and the technical and economic assumptions about the CHPs and TES. Section 5 shows the results of the comparison of the two support schemes, and finally, discussions and conclusions are presented in Sections 6 and 7.

2 The analysed two support schemes in detail

In this section is described the two compared support schemes. In Section 2.1 is presented the premium support scheme and in section 2.2 is presented a systematic procedure of determining the Triple tariff.

2.1 The Premium support scheme

The premium is paid on top of hourly wholesale electricity prices and is made as a flat-rate price supplement paid to CHPs for each produced MWh_e, independent of which hour the electricity is produced. There is not assumed any cap on the premium paid, that is to say that even if the wholesale electricity price in a certain is high, the DE plant will still receive the premium.

2.2 The Triple tariff support scheme

The procedure of determining the Triple tariff includes both a procedure for determining the time periods and the prices of the Peak, High and Low tariff. The procedure is similar to the used procedure in the Danish Triple tariff as described in the Danish legislation [45], and includes a procedure for calculating the savings at central power plants and the saved grid losses and grid investments. The procedure assumes a strict Phase 1 situation, where the DE CHPs is assumed to displace fossil fuelled condensing mode power plants.

2.2.1 The three load periods

When used in a certain country the first step in the procedure is to decide the periods of the Peak, High and Low tariff, which is made by analysing the demand for electricity and grouping it into three load situations with a weekly cycle, eventually being split into winter and summer load situations. The periods used in the analysis reported in this article are the ones used in Denmark in 2015; these are shown in Table 1. The tariffs paid for electricity delivered from local CHP plants is equal within each of the tariff periods but dependent on the voltage level at which the CHP production is delivered.

	Low tariff periods	High tariff periods in working days	Peak tariff periods in working days
Winter (October-March)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 17.00 19.00 – 21.00	08.00 – 12.00 17.00 – 19.00
Summer (April-September)	21.00– 06.00 All holidays All weekends	06.00 – 08.00 12.00 – 21.00	08.00 – 12.00

Table 1: The separation of the year into low, high and peak tariff periods as applied in the Danish Triple tariff in 2015 [45].

2.2.2 The procedure for calculating savings at central power plants

The total saved costs at central power plants, SC_i, for each reduced production of 1 MWh_e depends if the reduced production takes place in Low, High or Peak tariff periods and illustrated in Equation (2), where the index i designates the tariff period.

$$SC_i = \frac{GP*3.6}{\eta} + V_{Plant} + \frac{(YC_{plant}*I_{plant}+YF_{Plant})*D_i}{FLH_i} \quad (1)$$

The saved cost is split into saved fuel, variable operation and maintenance cost, investment cost and fixed operation and maintenance cost. Saved fuel and variable operation and maintenance cost is straightforward related to reduced amount of produced electricity, but how a reduction in produced electricity translates into reductions in investment costs and reductions in fixed operation and maintenance cost is of a more probabilistic nature. In this Triple tariff procedure is applied a method where a part of the reduced need for investment and reduced fixed operation and maintenance cost is assigned to reduced produced electricity in Peak and High tariff periods respectively, but no part is assigned to Low tariff periods.

In equation (1) η is the net electrical efficiency at central power plants, GP the natural gas price is in EUR/GJ and the V_{Plant} variable operation and maintenance cost is in EUR/MWh_e, YC_{plant} is the yearly capital cost factor of investment, I_{plant} is the investment cost in EUR/MW_e, YF_{Plant} is the yearly fixed operation and maintenance cost in EUR/MW_e, D_i are distribution keys between Low, High and Peak tariff periods for investment and yearly fixed costs and FLH_i is full load hours of electricity demand calculated for each of the Low, High or Peak tariff periods as the electricity demand in the period divided by the peak demand for electricity of the year.

The yearly capital cost factor - YC_{plant} - is calculated as an annuity (Equation (2)) dependent on the discount rate (r) and the life-time of the investment (L). The yearly capital cost factor thus determines the share of an investment that is attributed to each year of operation.

$$YC = \frac{r}{1-(1+r)^{-L}} \quad (2)$$

2.2.3 The procedure for calculating saved grid losses and grid investments

Delivering electricity to the 60 kV-grid is assumed to replace an amount of electricity to be delivered from the central power plants. However, delivering one unit of electricity in the 60 kV-grid replaces more than one unit from the central power plant as grid losses in the 150 and 400 kV grids are avoided. Also, as grid losses increase with the transmission system load, the value of delivery of electricity to the 60 kV-grid is higher, the higher the load situation is. Furthermore, delivering electricity in the 60 kV-grid is assumed to reduce the need for investments in the 150 kV-grid, and again, this reduced investment is larger at higher load situations, using the same arguments that led to equation (1). Thus, the compensation for electricity delivered in the 60 kV-grid, $P@60_i$, depends on the fact if the production happens in Low, High or Peak tariff periods and is given by equation (3). $NL150_i$ is the load and tariff period-dependent net Loss percentage in the combined 150 & 400 kV-

grid, YC_{grid} is the yearly capital cost factor of investment in electrical grids and I_{150} is investment cost in the 150 kV-grid in EUR/MW_e.

$$P@60_i = SC_i/(1 - NL150_i) + YC_{grid} * I_{150} * D_i/FLH_i \quad (3)$$

Similar conditions apply when delivering electricity to the 10 kV-grid or to the 0.4 kV-grid. Thus, the paid compensations of electricity delivered to the 10 kV-grid, $P@10_i$, and to the 0.4 kV-grid, $P@0.4_i$, are given by Equations (4) and (5).

$$P@10_i = P@60_i/(1 - NL60_i) + YC_{grid} * I_{60} * D_i/FLH_i \quad (4)$$

$$P@0.4_i = P@10_i/(1 - NL10_i) + YC_{grid} * I_{10} * D_i/FLH_i \quad (5)$$

Here $NL60_i$ and $NL10_i$ are the net Loss percentages in the 60 and 10 kV-grids respectively, and I_{60} and I_{10} are investment cost in the 60 and 10 kV-grids respectively in EUR/MW_e.

Finally, supplying electricity to the 0.4 kV-grid directly at the site of consumption furthermore is assumed to reduce grid losses and reduce the need for investment in the 0.4 kV grid. Thus, the compensation to be paid for electricity delivered to the consumer, $P@consumer_i$, is given by Equation (6)

$$P@consumer_i = P@0.4_i/(1 - NL0.4_i) + YC_{grid} * I_{0.4} * D_i/FLH_i, \quad (6)$$

where $NL0.4_i$ is the net Loss percentage in the 0.4 kV-grid and I_{150} is investment cost in the 0.4 kV-grid in EUR/MW_e.

Notice that the procedure for calculating paid prices is cumulative – i.e. supplying at 0.4 kV also provides saving in 10, 60, 150 and 400 kV grids so therefore the rationality of the equations is that prices at higher voltage levels always influence prices at lower voltage levels.

2.2.4 The data used to calculate the Triple tariff prices

The Triple tariff prices are calculated with the power plant and grid data shown in Table 2, and the tariff-period dependent data shown in Table 3. The shown data are equal to the data used in the Danish Triple tariff at the end of 2015. The used power plant net electrical efficiency used is high but comparable to the efficiency expected in 2020 by Danish Energy Agency [46].

Power plant net electrical efficiency	η	58%	
Power plant, Variable operation and maintenance cost	V_{Plant}	2.54	EUR/MWh$_e$
Power plant, Yearly fixed operation and maintenance cost	YF_{Plant}	13,597	EUR/MW$_e$
Real discount rate	r	3%	
Investment cost in power plant	I_{plant}	0.905	MEUR/MW$_e$
Life time of power plant	L_{plant}	25	years
Yearly capital cost factor of investment in power plant	YC_{plant}	0.05743	
Investment cost in the 150 kV-grid	I_{150}	0.286	MEUR/MW$_e$
Investment cost in the 60 kV-grid	I_{60}	0.095	MEUR/MW$_e$
Investment cost in the 10 kV-grid	I_{10}	0.054	MEUR/MW$_e$
Investment cost in the 0.4 kV-grid	$I_{0.4}$	0.054	MEUR/MW$_e$
Life time of electrical grids	L_{grid}	25	years
Yearly capital cost factor of investment in electrical grids	YC_{grid}	0.05743	

Table 2: The power plant and grid data not depending on the tariff periods, used for calculating the Triple tariff.

		Low tariff	High tariff	Peak tariff
Hours per year	H_i	5010	2498	1252
Full load hours of electricity demand	FLH_i	2475	1728	1097
Distribution keys for investment and yearly fixed costs	D_i	0	0.5	0.5
Net Loss percentage in the 150 + 400 kV-grid	$NL150_i$	2.8%	4.2%	4.7%
Net Loss percentage in the 60 kV-grid	$NL60_i$	2.1%	3.2%	3.6%
Net Loss percentage in 10 kV-grid	$NL10_i$	1.4%	2.7%	3.5%
Net Loss percentage in 0.4 kV-grid	$NL0.4_i$	2.8%	5.1%	6.8%

Table 3: The power plant and grid data depending on the tariff periods, used for calculating the Triple tariff.

The saved fuel costs at power plants are based on a gas price, GP, that is set equal to the average natural gas price at the Gaspoint Nordic [47] market in 2016, which was approximately 13 EUR/MWh$_{\text{higher calorific value}}$, equal to approximately 4.0 EUR/GJ$_{\text{lower calorific value}}$. Fuel prices and efficiencies refer to lower calorific value of the fuels. With a transmission tariff at 0.4 EUR/GJ results in a natural gas price at power plants of 4.4 EUR/GJ.

2.2.5 The resulting tariff prices in the Triple tariff

The resulting tariffs are shown in Table 4. The DE plant considered in this article is assumed to deliver electricity to the 10 kV-grid and therefore the used prices in the Triple tariff is equal to P@10.

EUR/MWh	Low tariff	High tariff	Peak tariff
Saved fuel costs at power plants	27.31	27.31	27.31
Saved variable operating costs at power plants	2.54	2.54	2.54
Saved fixed operating costs at power plants	0.00	3.93	6.20
Saved investment costs at power plants	0.00	15.04	23.69
Total saved at power plants	**29.85**	**48.82**	**59.74**
Saved grid loss in 150 + 400 kV grid	0.86	2.14	2.95
Saved grid expansion of 150 kV grid	0.00	4.75	7.49
To be paid for electricity delivered at the 60 kV-grid, P@60	**30.71**	**55.72**	**70.17**
Saved grid loss in 60 kV grid	0.66	1.84	2.62
Saved grid expansion of 60 kV grid	0.00	1.58	2.49
To be paid for electricity delivered at 10 kV-grid, P@10	**31.37**	**59.14**	**75.28**
Saved grid loss in 10 kV grid	0.45	1.64	2.73
Saved grid expansion of 10 kV grid	0.00	0.90	1.41
To be paid for electricity delivered to the 0.4 kV-grid, P@0.4	**31.81**	**61.67**	**79.42**
Saved grid loss in 0.4 kV grid	0.92	3.31	5.79
Saved grid expansion of 0.4 kV grid	0.00	0.90	1.41
To be paid for electricity delivered at the consumers, P@consumer	**32.73**	**65.89**	**86.63**

Table 4: Resulting tariffs in the Triple tariff.

3 Optimal investment assessment in CHP and TES

This section describes the method used for assessing the investment in CHPs and TES that a given support scheme stimulates. The development and test of this method has been described in more details in [48]. The method is based on the energyPRO simulation model [49] which is used to find the optimal operation based on a given system configuration and an external shell that determines optimal system configurations as described in the following sections.

3.1 The energy system simulation model energyPRO

energyPRO is a general energy system analysis tool typically used for simulating complex market-based energy systems like DE plants equipped with large TES. However, it has also been used to simulate market-based operation of other energy stores, e.g. market-based operation of pumped hydro in the EU project stoRE [50], and in the EU project NEMO [51] the operation of smart grids using the batteries in electrical cars as electricity storage.

energyPRO calculates an optimized operation of user-given production units in each hour of e.g. a 20-year planning period. It also allows iterative calls from e.g. a spreadsheet, where e.g. the capacity of CHPs and energy stores may be changed.

The time step used in the optimization can be 1 hour or less. It uses indexes for describing e.g. the development of demands for heating and cooling and the development in prices over the years. This implies that the operation strategy of the production units between the years may change e.g. due to changed economic conditions.

energyPRO is based on an advanced priority list method for finding the optimized operation of the production units under the conditions given by energy demands, energy costs, subsidy schemes and energy units. This method is described thoroughly by Østergaard & Andersen [52].

An important reason for using energyPRO in this analysis is that it is widely used by consultants to design DE plants with an economic optimal sizing of productions units and TES [53].

Furthermore, energyPRO is widely used for research, e.g. Østergaard and Andersen used energyPRO to optimize the sizing of booster heat pumps and central heat pumps in district heating [52]. Sorknæs et al. applied energyPRO to study the treatment of uncertainties in the daily operation of combined heat and power plants [54]. Fragaki et al. applied energyPRO to study economic sizing of DE plants in the UK [55,56]. Streckienė et al. studied the feasibility of CHPs equipped with large TES in the German Day-ahead market [57] and other work have studied heat and biogas stores' impacts on renewable energy integration [58].

3.2 The system configuration optimization method

The system configuration optimization method is based on a Net Present Value (NPV) calculation of the changed cash flows caused by new production units and TES. For instance, the changed cash flow when assessing an investment in CHPs and TES at a boiler-based DE plant, includes the unit

investments as well as the sale of electricity, support paid through the chosen support scheme, additional fuel purchase, because a CHP unit uses more fuel than boilers to produce the same amount of heat, extra use of CO_2 quotas and fixed and variable costs of the CHPs. Furthermore, the changed cash flow includes the reduced variable cost of the existing boilers, due to their lower production when implementing CHP.

The external shell used to make the iterative calls of energyPRO is an Excel spreadsheet that performs these calls through Visual Basic for Application (VBA) coding.

For a certain DE plant and a certain support scheme the optimal size of the CHPs and TES is determined in a two-dimensional matrix-calculation. In this method, the path in the matrix to the optimal NPV starts with zero CHP and zero TES. First, the size of CHP is increased until NPV becomes less in the matrix. Then keeping this size of the CHP fixed, the TES is increased until NPV decreases. Then again, the size of the CHP is increased keeping the size of the TES fixed. This procedure continues, until no improved NPV is found. The method is more detailed described in [48]. A simpler heuristic would be to calculate all combinations and find the lowest cost in the table, but the described heuristic is significantly faster due to the scenario reduction.

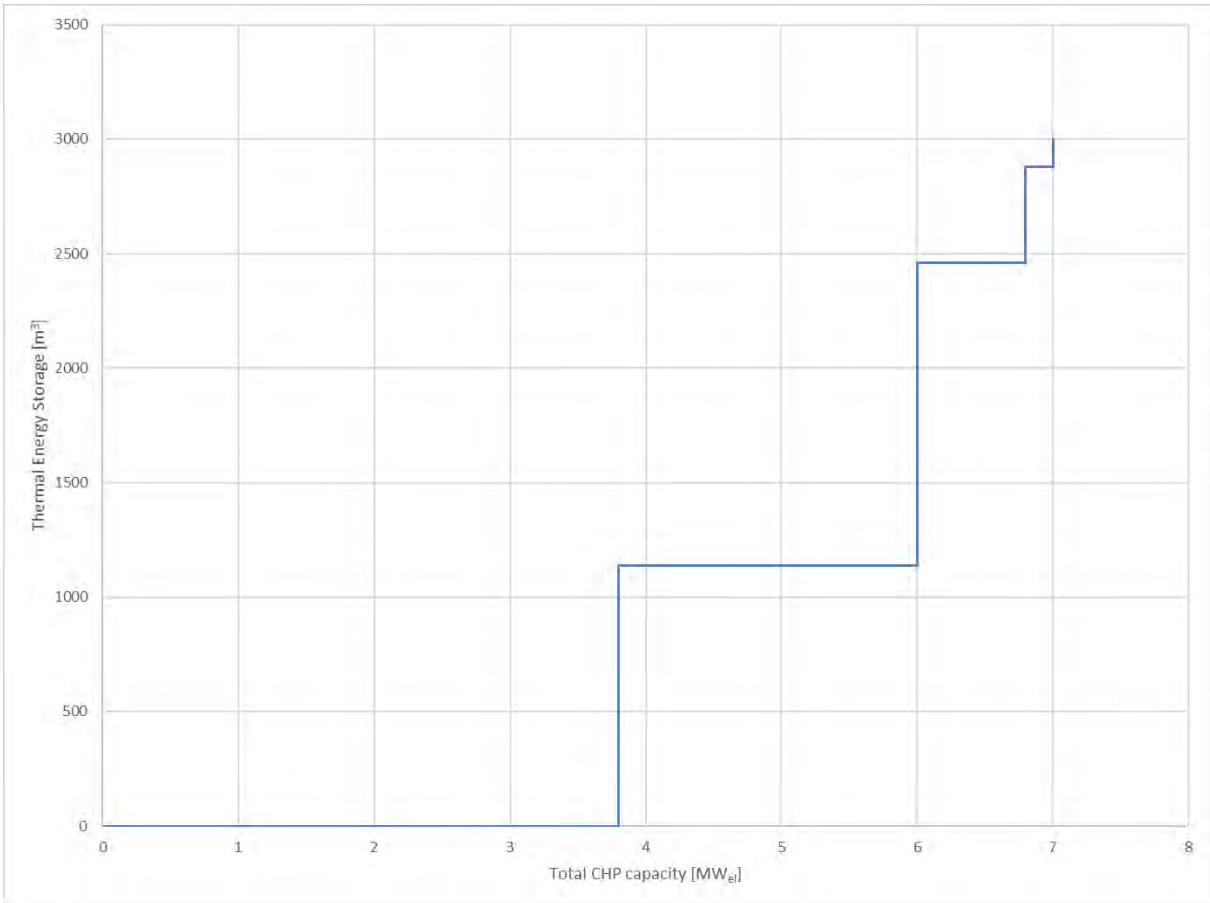

Figure 3: For a certain DE plant and a certain support scheme the optimal size of the CHPs and TES are determined in a two-dimensional matrix-calculation. In this figure is shown the path to the optimal NPV of the size of the CHPs and TES at the Triple tariff.

An optimal solution found when optimizing the NPV may result in different size of CHPs and TES compared to what in fact will be established, since other factors will often be included in the investment decision, but it still represents an important estimate of the sizes of the CHPs and TES that will be installed.

4 Technical and economic case characteristics

This section describes the DE plant case used in the comparison of the two support schemes, as well as the external conditions and the technical and economic assumptions about the CHPs and TES. The planning period is set to 20 years from 2017 to 2026, and the real discount rate is set to 3%, which is comparable to using a nominal discount rate of around 4-5%, reflecting the costs of a loan for financing the investments. All prices are listed in 2016 levels.

4.1 Wholesale electricity prices

Electricity prices from the Scandinavian Day-ahead market are used. This market is organized as a marginal price market [59], that is to say that each producer in a certain hour gets the same price for the produced electricity equal to the most expensive bid accepted in that hour [60]. To keep it simple, the Day-ahead prices for all years in the planning period are set to the hourly prices in West Denmark in 2016 [61], which gives an average price of 26.7 EUR/MWh_e, a minimum price of -53.6 EUR/MWh_e and a maximum price of 105.0 EUR/MWh_e.

4.2 Ambient temperatures

Ambient temperatures are used to model yearly variations of the heat demand. The analysis is based on a time series with a yearly mean temperature of 8.1 °C, a daily mean temperature during the coldest day of -9.0 °C and a daily mean temperature during the warmest day of 22.2 °C. The time series are discussed further in [48].

4.3 Natural gas price at the DE plant

In Section 2.2.4 is argued for and used a natural gas price at power plants of 4.4 EUR/GJ. It is assumed that the gas price at DE plants is found by just adding a distribution tariff around 1.2 EUR/GJ, so that the resulting gas price at DE plants is 5.6 EUR/GJ for both CHPs and boilers. No taxes are included, and the same gas price is used for all years in the analyses and no yearly variation is assumed.

4.4 CO_2 quota price

An estimation of the CO_2 quota price made by the Danish Energy Agency [62] for 2016 is approximately 8 EUR/tonne. This value is used in all the years in the analyses.

4.5 The DE plant case

The DE plant case is similar to the case used in [48] and shortly recapitulated in this section. The yearly heat delivered to the district heating grid is 40 GWh of which grid loss and domestic hot water represent 40% and are assumed to be constant and thus also weather independent.

The remaining 60% is the space heating and assumed linearly dependent on ambient temperature. It is assumed that space heating is only required in days with an average temperature below 15 °C. A diurnal variation is assumed, with the delivered heat demand approximately 20% lower during the noctural hours compared to hours during daytime, which is based on empirical evidence from Danish DH systems [63]. The resulting heat demand requires an average delivered heat from the plant of 4.6 MW, with a maximum heat delivered from the plant of 11.6 MW and a minimum of 1.6 MW.

As the reference situation for analysing an investment in CHPs and TES, an existing DE plant is assumed to produce the heat on existing heat-only boilers. These boilers are assumed to have an efficiency of 97.1% and variable operation costs of 1.10 EUR/MWh_{heat}, which in the reference situation with the assumed economic conditions described in this section gives a yearly heat production cost of 0.938 M EUR.

Investment and operation costs are assumed to be strictly proportional to the sizes of the CHPs – thus it is not important in how many units the CHPs are split into. However, it is chosen to split the CHP capacity between two CHP units, as shown in Figure 4, which is in good accordance with how DE plants are designed, as exemplified at online presentations at [63]. Splitting the CHP capacity in more units also reduces the need to include partial load operation characteristics.

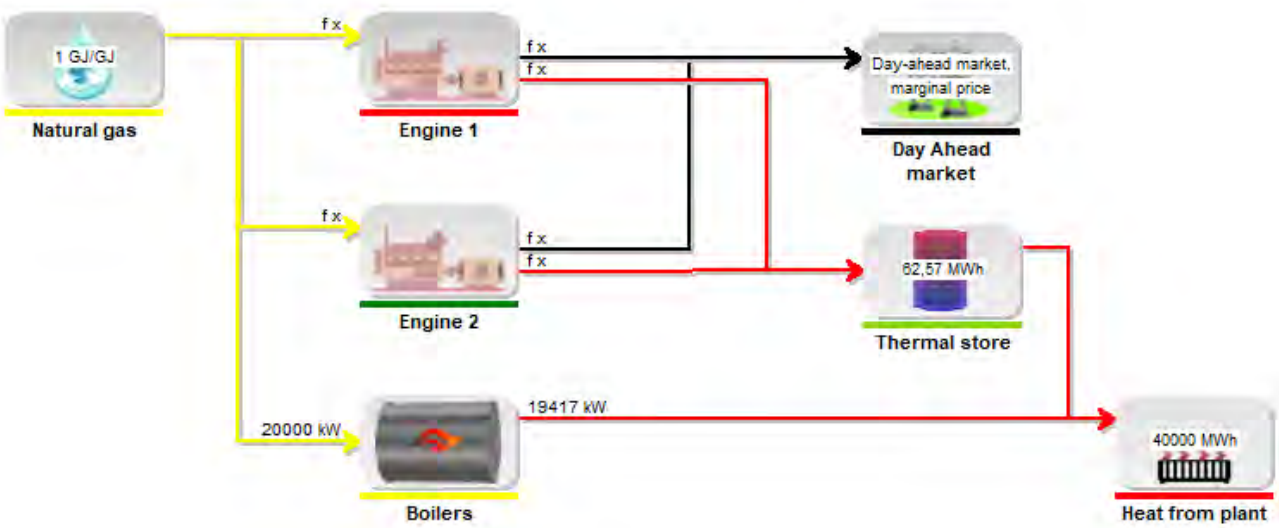

Figure 4: The generic DE plant used in the test of the two support schemes, consisting of existing boilers and the new units - 2 CHPs and a TES.

4.6 Technical and economic assumptions

In this comparison, efficiencies are chosen to be kept constant over time and with no size-dependency. A similar simplification has been made regarding investment and operation costs which are-being modelled proportionally to the sizes of both the CHPs and TES. An overview of technical and economic data used in the comparison is shown in Table 5. The data correspond to the data used in [48].

Gas price	5.60	EUR/GJ
CO_2 quota price	8.00	EUR/tonne
Existing boilers		
Heat efficiency	97.1%	
Variable operation costs	1.00	EUR/MWh_{heat}
CHPs		
Electrical efficiency	44.0%	
Heat efficiency	48.9%	
Total efficiency	92.9%	
Fixed operation costs	10000	EUR/MW_e/year
Variable operation costs	5.4	EUR/MWh_e
Investment in CHPs	650000	EUR/MW_e
Non-availability periods per year	16	days
Investment in installation	350000	EUR/MW_e
Thermal storage		
Investment in thermal storage	200	EUR/m^3

Table 5: Technical and economic characteristics (2016-prices) used in the comparison of the two support schemes based on [46]

The cost for society when providing a support scheme is in this analysis set equally to the NPV of the paid support in the planning period of 20 years. The support is calculated for each hour during the planning period and is subsequently summed in an NPV calculation to determine the total support in the planning period.

For the Premium scheme, the cost of the support in a certain hour is calculated simply as the premium multiplied by the electricity produced on the CHPs in that hour.

For the Triple tariff, the support in a certain hour is calculated as the tariff in that hour minus the Day-ahead price in that hour. This difference is then multiplied with the electricity produced on the CHPs in that hour. This interpretation of support is consistent with the way a Triple tariff is often administered. Being paid a Triple tariff often includes that either the transmission system operator or a trader (balancing responsible party) is responsible for selling the produced electricity at the Day-ahead market, thus it is only the discrepancy between the Triple tariff and the Day-ahead price in that hour, that makes up the support, often to be paid by the consumers through a grid tariff. That is also to imply, that if in a certain hour the price in the Day-ahead market is higher than the Triple tariff, the support will be negative in that hour.

5 Results of the comparison of the two support schemes

This section introduces a two-step procedure for comparing support schemes and applies to the case with the given support schemes. The first is at the current spot market price level in Section 5.1 using the price level in West Denmark in 2016. The price level in West Denmark has been higher both before and after 2016, therefore the comparison is also made at a higher price level in Section 5.2. As mentioned, the role of DE CHP changes radically in the transition to a renewable energy system, developing from displacing condensing mode power generation and boiler-based heat generation (Phase 1), via assisting in the integration of fluctuating renewables (Phase 2) to finally only providing reserve capacity (Phase 3). Therefore, a comparison of the effects of the support schemes in the transition to Phase 2 and 3 is presented in Section 5.3.

5.1 Comparison at current spot market prices

In this comparison the Day-ahead prices for all years in the planning period are set as the hourly prices in West Denmark in 2016, as described in Section 4.1.

The first step in comparing the two support schemes is to calculate the business economic optimal CHP and TES with the Triple tariff. The result of this calculation is shown in Figure 3 showing an optimal total CHP capacity of 7 MW_e and a TES size of 3000 m^3.

The next step is to determine the support level of the Premium scheme, that results in the same optimal CHP capacity of 7 MW_e. This is done by using the method shown in Section 3.2 at different levels of support. This way of finding the support level of the Premium scheme, that gives the same CHP capacity of 7 MW_e is shown in Figure 5. The support level is found to be 66.67 EUR/MWh_e.

It is illustrated in the figure that a Premium scheme support less than 10 EUR/MWh_e causes no CHP capacity to be installed and from a level of support around 25 EUR/MWh_e the growth in electrical CHP capacity becomes smaller as operation is restricted by a limited heat demand at the DE-plant. The slightly irregular shape of the graph is due to the fact that when identifying the optimal NPV the step value for electrical capacity is set equal to 0.2 MW_e and the step value for TES size is set equal to 60 m^3. These step sizes are chosen to reduce calculation time without compromising the conclusions based on the calculation.

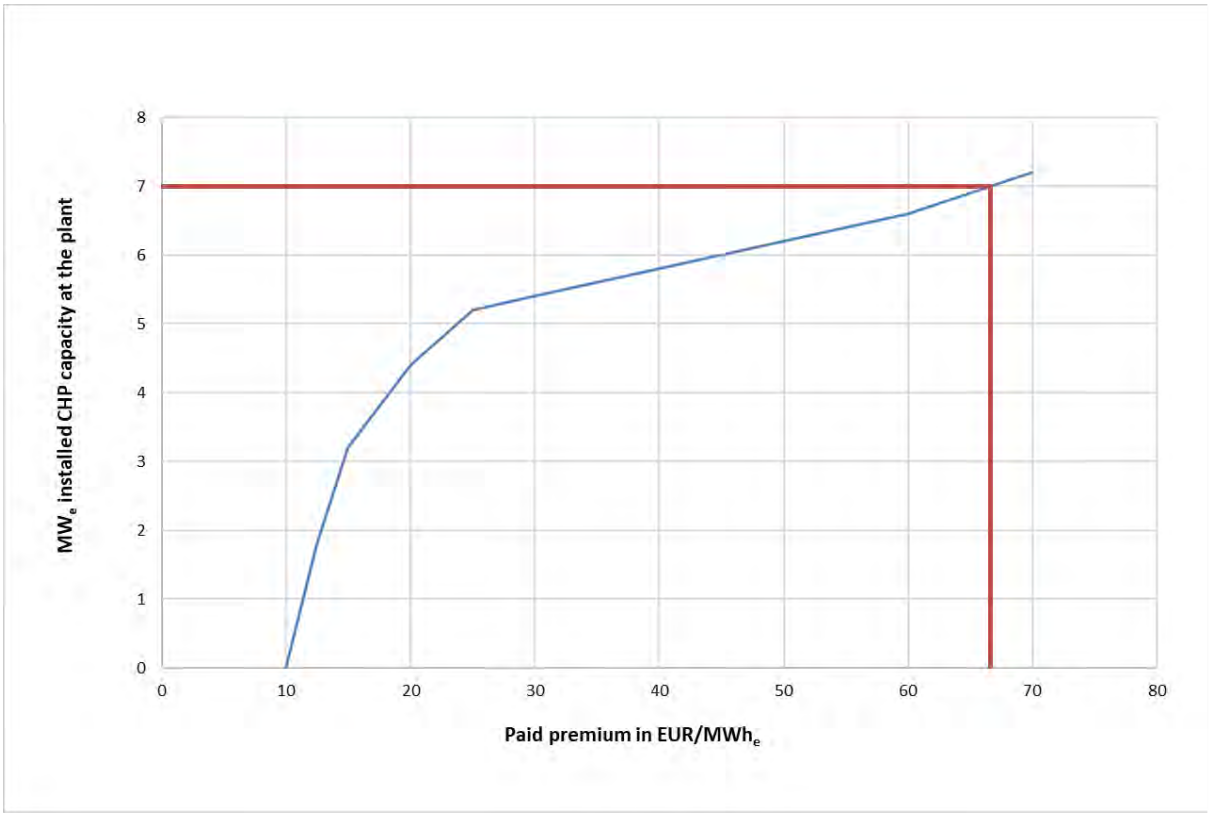

Figure 5: Determining the paid premium giving the total CHP capacity of 7 MW_e being equal to 66.67 EUR/MWh_e.

The results are shown in Table 6. It is seen that at this total CHP capacity of 7 MW_e the belonging TES capacity is the double when using the Triple tariff than when using the Premium scheme, which also implies a total investment in CHP and TES capacity that is slightly bigger when using the Triple tariff than when using the Premium scheme. The net present value in a 20-year period (NPV_{20}) of the changed cash flow (as described in Section 3.2) caused by the investment in the CHPs and TES is around 22 M EUR bigger when using the Premium scheme. This is also reflected in the extra NPV_{20} of support to the plant when using the Premium scheme compared to the Triple Tariff Scheme.

This is the most thought-provoking result; that the societal cost is nearly three times bigger for providing a certain CHP capacity when using the Premium scheme than when using the Triple tariff.

	CHP capacity [MW_e]	TES size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and store [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_e]
Triple tariff	7.00	3000	7.60	3.59	12.92	34440
Premium scheme (66.67 EUR/MWh_e)	7.00	1520	7.30	25.48	34.05	34345

Table 6: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MW_e.

5.2 Comparison made at scaled up Day-ahead prices

In this comparison the Day-ahead electricity prices are scaled up from the current spot market price level of 26.7 EUR/MWh_e to an average price of 36.7 EUR/MWh_e by multiplying the hourly prices with the factor 36.7/26.7. This brings up the Day-ahead price level half the way to the Triple tariff price level of 45.7 EUR/MWh_e. It would probably be unrealistic to consider a Day-ahead price level equal to the Triple tariff price level, because besides the investment and operation costs at central power plants, the Triple tariff also includes reduced energy losses and investments in transmission and distribution grids.

The methodology of the two steps are identical to the steps presented in section 5.2 as the only difference is the spot market prices. Thus, for the Triple tariff, there are no changes.

The next step is to determine the support level of the Premium scheme, that gives the same CHP capacity of 7 MW_e. In Figure 6 is seen that support level is found to be around 33 EUR/MWh_e.

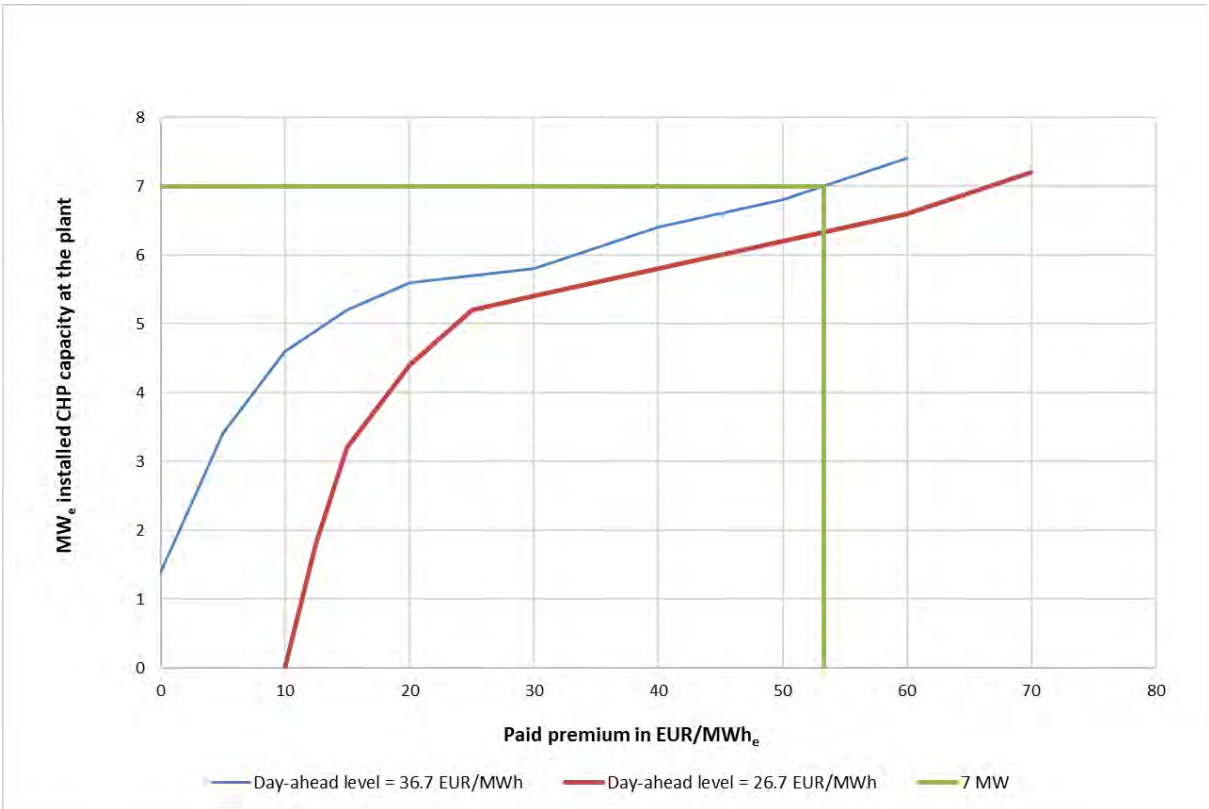

Figure 6: Determining the paid premium giving the same total CHP capacity of 7 MW_e being equal to 53.33 EUR/MWh_e when the Day-ahead level is 36.7 EUR/MWh_e.

The results are detailed in Table 7. It is seen that NPV_{20} of paid support is reduced for both support schemes compared to the values in Table 6, but the conclusion is robust to this increase in the Day-ahead level: The NPV_{20} of the support is three times bigger when using the Premium scheme than when using the Triple tariff.

	CHP capacity [MW_{el}]	Thermal store size [m^3]	Investment [M EUR]	NPV_{20} of extra cash flow caused by the investment in the CHPs and store [M EUR]	NPV_{20} of paid support [M EUR]	Yearly electricity production [MWh_{el}]
Triple tariff	7.00	3000	7.60	3.59	7.63	34440
Premium scheme (53.33 EUR/MWh_{el})	7.00	1900	7.38	24.11	27.21	34251

Table 7: Results of the comparison of the Triple tariff and the Premium scheme both resulting in a CHP capacity of 7 MWe, when the Day-ahead level is 36.7 EUR/MWh_e.

5.3 Effects of the support schemes in the transition to Phase 2 and 3

In Phase 2 with significant wind power and PV production, the DE CHPs must assist in the integration of these fluctuating productions. Framework condition must be designed to ensure that DE CHPs do not replace wind power and PV but only fossil fuel-based condensing mode power plants. The problem is illustrated in Figure 7, showing the simulated operation in a certain week of the DE plant when receiving the Premium scheme and equipped with the CHP and TES capacity shown in Table 6. The Day-ahead prices from 24th to 26th of December are negative, but due to a high level of the Premium scheme and due to a high heat demand, the CHPs continue to produce, with the risk that wind power will have to be curtailed. The same problem arises with the Triple tariff.

Figure 7: Operation of the DE plant on the Premium scheme and equipped with the CHP and TES shown in Table 6

When this problem happens often, the country is entering Phase 2, and it should be considered to discontinue the support. Figure 8 shows a simulation of the same DE plant, but now without any support. It is seen that the CHP has stopped in the three days, and when the TES is emptied, the gas boilers produce the needed heat.

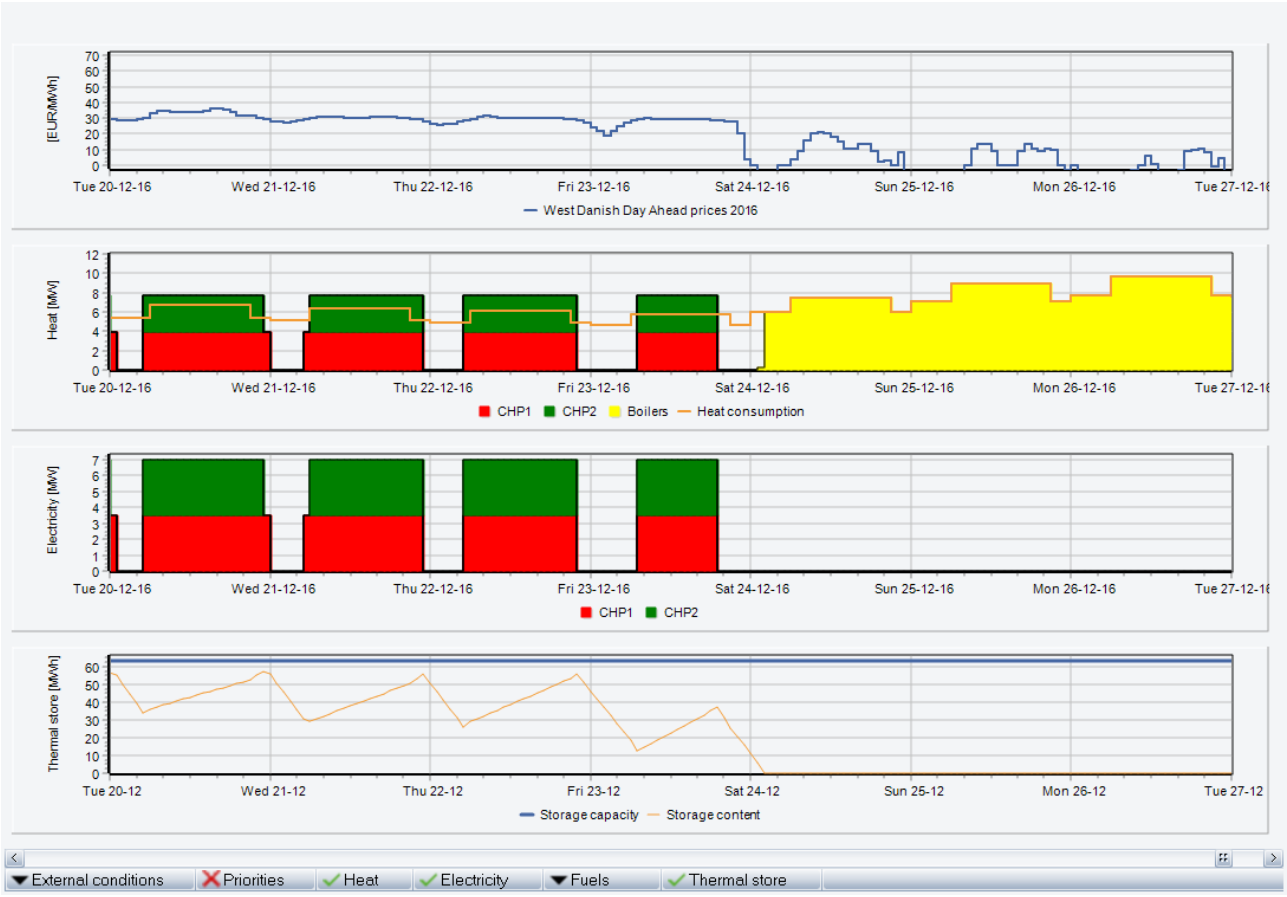

Figure 8: Operation without support scheme of the DE plant equipped with the CHP and TES shown in Table 6

However, ending a support scheme before time can compromise the investment made by the DE plant in the CHPs and TES. Therefore, a capacity payment should be considered to compensate the DE plant for the lost support in the last years of the planned support period if Phase 2 and 3 occurs before planned.

Table 8 shows the needed yearly payment to compensate the DE plant for lost support. It is to be noticed that in Table 6 it is shown that the NPV_{20} of paid support is around three times bigger when using the Premium scheme than when using the Triple tariff for providing a certain CHP capacity, amounting to 21 M EUR. Even if the DE plant is to be compensated in e.g. 5 years with 676,530 EUR per year, that would not change the conclusion that the societal cost – measured as the NPV_{20} of the support - is less than half when using the Triple tariff compared to using the Premium scheme for providing a certain CHP capacity.

Yearly Net Heat Production Cost [EUR]	**Triple tariff**	**Premium scheme**
With support	118,341	-1,336,075
Without support	794,871	799,676
Needed yearly payment for lost support	**676,530**	**2,135,751**

Table 8: Yearly Net Heat Production Cost of the DE plant with the CHP and TES shown in Table 6

6 Discussion

In Denmark, as shown in Figure 1, a Triple tariff scheme triggered the installation of around 2,000 MW_e of CHP capacity with large TES. The results of this research indicate that the societal cost of the support schemes promoting the same amount of CHP capacity in Denmark if having used a Premium scheme would have been more than 5,000 M EUR more expensive. This is based on the example from Table 6 where providing 7 MW_e is around 20 M EUR more expensive with a Premium than a Triple tariff support scheme.

It is beyond the scope of this paper to deal with other factors when making investment decisions than optimizing NPV, but it must be acknowledged that most DE plants are small and decision-making board members are not necessarily skilled within CHP and investment optimisation. For these members a Triple tariff will probably seem as a more secure condition for an investment decision, than a Premium scheme, simply because there is considerable uncertainty about the future price level in the Day-ahead market, compared to the Triple tariff prices that is well known.

Personal communication with the managers of three district energy plants - Lemvig Varmeværk [64], Skagen Varmeværk [65] and Ringkøbing Fjernvarmeværk [66] - confirms that the more certain investment conditions constituted by the Danish Triple tariff prices promoted their decisions regarding investments in large CHP and TES capacity.

In the introduction is mentioned more factors to be considered, when deciding which design of a support scheme to use. Apart from these factors and as detailed in [48] another important factor to keep in mind is that the role of CHP changes radically in the transition to a 100% RES system. When developing wind power and PV, the power plants and the CHPs have to produce less electricity, which has the consequence that they mainly participate in the integration of these intermittent RES-based productions. If in a country this development of wind power and PV goes fast compared to e.g. a needed 20-year period for making the CHP investment feasible, it should be considered in the end of the period to change the Triple tariff. A solution is to change it to a more dynamic Triple tariff, where the peak, high and low tariff periods are not only determined by the demand for electricity but are determined by the residual demand for electricity when having subtracted wind power and PV production. Or even in the end of the period change the Triple tariff to a capacity payment, which was in fact done in Denmark.

7 Conclusion

Combined heat and power units and large thermal energy stores at District Energy plants are important instruments to reduce both fossil fuel-based condensing mode power production and to integrate intermittent renewable energy productions. However, often electricity prices do not create sufficient business economic feasibility for these units to be installed, therefore, support schemes are required.

This article has shown that the design of a support scheme highly influences how much combined heat and power and thermal energy storage capacity that is installed. It shows that the societal cost of the support schemes promoting a certain amount of CHP capacity reducing the same amount of condensing mode power production, is a significant factor three times bigger when using a Premium scheme compared to using a Triple tariff.

However, it has furthermore been demonstrated, that when wind energy and PV has been developed, the support schemes have to be adapted allowing CHP units to participate more comprehensively in the integration of these intermittent productions.

Acknowledgements

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Appendix IV: Booster heat pumps and central heat pumps in district heating

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Booster heat pumps and central heat pumps in district heating

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HIGHLIGHTS

- Energy systems simulation of district heating systems based on heat pumps.
- Alternative with booster heat pumps for domestic hot water production.
- Hourly simulation over a year using energyPRO.
- Booster heat pumps enable lower district heating temperature and grid losses.
- Energy use and costs are lower with booster heat pumps than without and lower than with individual heat pumps or boilers.

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ABSTRACT

District heating (DH) enables the utilisation and distribution of heating from sources unfeasible for stand-alone applications and combined with cogeneration of heat and power (CHP), has been the cornerstone of Denmark's realisation of a steady national primary energy supply over the last four decades. However, progressively more energy-efficient houses and a steadily improving heat pump (HP) performance for individual dwellings is straining the competitive advantage of the CHP–DH combination as DH grid losses are growing in relative terms due to decreasing heating demands of buildings and relatively high DH supply temperatures.

A main driver for the DH water temperature is the requirements for domestic hot water (DHW) production. This article investigates two alternatives for DHW supply: (a) DH based on central HPs combined with a heat exchanger, and (b) a combination of DH based on central HPs and a small booster HP using DH water as low-temperature source for DHW production. The analyses are conducted using the energyPRO simulation model and are conducted with hourly varying factors; heating demands, DH grid losses, HP coefficient of performance (COP) and spot market prices in order to be able to analyse the relative performance of the two options and their performance over the year. Results are also compared to individual boilers and individual HPs.

The results indicate that applying booster HPs enables the DH system to operate at substantially lower temperature levels, improving the COP of central DH HPs while simultaneously lowering DH grid losses significantly. Thus, DH performance is increased significantly. Additionally, performance for the DH HP with booster combination is considerably better than individual boiler or HP solutions.

1. Introduction

Energy systems throughout the world are facing the challenge of supplying existing and coming energy needs in a sustainable way that does not add carbon to the atmosphere and thus enhance the greenhouse effect any further [1]. Not all countries have accepted the challenge yet, however some countries like Denmark have agreed on ambitious energy targets for the reduction of carbon dioxide emissions to the atmosphere. Denmark aims to have a carbon-neutral electricity and heating system by 2030 and a completely carbon neutral energy system by 2050 [2]. Such aims call for ambitious changes to the energy system. Municipal analyses of e.g. Aalborg [3] and Frederikshavn [4] in Denmark as well as national analyses [5,6] have already demonstrated potential pathways for Denmark, and while they differ slightly in terms of how much individual technologies are introduced, core elements include expansion with Renewable Energy Sources (RES) like wind, photo voltaics (PV), solar thermal, and geothermal energy, heating demands covered by DH and HPs, and a transportation sector based on electricity – either directly or through the production of synthetic fuels as discussed by Ridjan et al. [7] and Connolly et al. [8].

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Nomenclature

c	Heat capacity of water (kJ/(kg K))
C_{Loss}	DH pipe heat loss coefficient (kW/K)
DH_D	Total heat delivered to consumers from DH (kW)
DH_{Loss}	DH loss (kW)
$\dot{m}$	Total DH flow (kg/s)
T_A	Ambient air temperature (°C)
T_{DHW}	Domestic hot water temperature (°C)
T_{DHF}	Average temperature of forward DH pipe (°C)
T_{DHR}	Average temperature of return DH pipe (°C)
$T_{R,FH}$	Floor heating return temperature (°C)
T_{Ref}	The ambient air temperature above which space heating is turned off (°C)
T_{SAP}	DH supply temperature from plant (°C)
T_{SAC}	DH supply temperature at consumers (°C)
T_{RAP}	DH return temperature at plant (°C)
T_{RAC}	DH return temperature from consumers (°C)
T_{Soil}	Ambient soil temperature for DH pipes (°C)
$T_{S,FH}$	Floor heating supply temperature (°C)
TA_{In}	Absolute inlet temperature to HP evaporator or condenser (K)
TA_H	Logarithmic mean high absolute temperature (K)
TA_L	Logarithmic mean low absolute temperature (K)
TA_{out}	Absolute outlet temperature from HP evaporator or condenser (K)
$\Delta T_{HP,HE}$	Required heat exchanger temperature difference (K)
η_{HP}	HP efficiency (or COP)
η_L	Lorentz efficiency
η_S	HP system efficiency

Abbreviations

CHP	Cogeneration of heat and power
COP	Coefficient of performance
DH	District heating
DHW	Domestic hot water
PV	Photo voltaic
RES	Renewable energy sources
SHD	Space heating demand

1.1. Heating in Denmark

In a temperate climate like the Danish, heating plays an important role. Continuously stricter building code requirements over particularly the four post-1973 oil crisis decades have caused the heating demand to drop slightly in spite of an increasing heated area caused by growth in population and economy, combined with new family structures. In private Danish dwellings, heating demands were covered by 8.2% oil, 18.5% natural gas, 23.8% biomass and solar, 47.2% DH and 3% HP in 2013.[1] The two latter are also key factors in most energy scenarios for Denmark, while the fossil fuel boilers need to be replaced for obvious carbon dioxide reasons and biomass boilers due to the limited availability of biomass and a more important use for electricity supply and for transportation [10,11]. Biomass is still being proposed for DH in e.g. Greece [12] and being implemented in Norway [13], and as Zhang and Lucia [14] state, biomass "*share a high degree of technical compatibility with the technologies and knowledge of the [present coal-based DH] regime*", however in the long term, biomass must target demands where no easy alternatives exist.

1.2. District heating in Denmark

DH combined with CHP is one of the identifying characteristics of the Danish Energy system, and has been at the centre of energy planning and policy attention for decades [15,16], and as early as in 1987, Hvelplund [17] pointed at the very large potential benefits that might be realised in Denmark through the further combination of energy conservation and DH. At present, however, most Danish DH CHP plants are based on fossil fuels and have a strained economy – not least due to the tendency that increasing wind power production drives down spot market prices for electricity [18]. In the future, HPs could be an alternative source for DH production thus enabling DH production to effectively be shifted to wind or solar power while at the same time introducing flexible loads that can help integrate these fluctuating sources. Some of these benefits may also be harvested using individual HPs, however DH enables the utilisation of a variety of thermal energy sources, while the HP DH combination extends the scope of these to low-temperature resources. Lund and Persson [19] found that "*potential heat sources are present near almost all district heating areas and that sea water most likely will have to play a substantial role as a heat source in future energy systems in Denmark*", however tapping these sources require HPs. Additionally, with existing DH systems, the feasibility of utilising central DH HP systems in contrast to individual HPs is improved as the DH grid investment has been carried out prior. Even if DH is not switched to HPs, Sorknæs et al. [20] find potential for improving the general capability of existing small-scale CHP plants in integrating fluctuating RE production.

1.3. Heat pumps for district heating

Many analyses have been conducted of HPs in the Danish energy system. Mathiesen and Lund [21] conclude that "*Large-scale heat pumps prove to be especially promising as they efficiently reduce the production of excess electricity*". Connolly and Mathiesen [22] list the introduction of small and large-scale heat pumps as the second stage in a transition to RE supply after the introduction of DH. Østergaard [23] finds that compression HPs can play a role in the integration of wind power as they limit boiler-based DH production as well as electricity excess – though at the same time also tend to increase condensing-mode power generation. The same author investigates different optimisation criteria for assessing the optimal introduction of HPs in DH, finding that "*different optimisation criteria render different optimal designs*" [24]. Nevertheless these authors have mainly focused on the macro-scale, and often based on simplified analyses using fixed COP values and without detailed analyses of temporal variations in losses or demand-specific losses in the DH system.

1.4. Heat savings in district heating systems

Insulation standards are improving, thus heat savings are also being realised and the assessment of heat savings and system

[1] Based on data from [9]. Numbers should be seen as indicative as e.g. biomass use is estimated. Electricity may also be used for various purposes – including heating. Electric heating is limited in Denmark and is not included in the percentages listed. LPG and petrol is assumed used for other purposes than heating – and the heat pump contribution is based on an estimated COP of 3.

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impacts of these as well as the impacts on the feasibility of various individual and DH solutions have been investigated extensively. Möller and Nielsen [25] established a so-called *heat atlas* to investigate heat demands in Denmark to be able to assess the potential for DH expansion. Sperling and Möller [26] found that "*end-use energy savings and district heating expansion combined in the existing energy system improve the overall fuel efficiency of the system*", however Østergaard [27] points at the systems effects of realising heat savings in DH areas as it impacts the operation of ancillary service providing CHP plants – and thus the potential integration of non-ancillary service providing RES-based electricity production. Likewise, Thellufsen and Lund [28] stress the need for assessing the benefits of savings on an energy systems level. Lund et al. [29] conclude that "*A suitable least-cost heating strategy seems to be to invest in an approximately 50% decrease in net heat demands in new buildings and buildings that are being renovated anyway, while the implementation of heat savings in buildings that are not being renovated hardly pays*". Mosgaard and Maneschi [30] stress however the complexity of energy renovations and the circumstance that even economically favourable energy savings are not always carried out. All in all, this calls for integrated studies of optimal heating solutions – individual or DH combined with savings – in future high-RES energy systems, as performed in e.g. [31].

1.5. Booster heat pumps in district heating

Köfinger et al. [32] found that "*Booster for DHW preparation are possible solutions if the grid temperature is too low or DHW needs to be stored e.g. in larger buildings like Hotels*" and Zvingilaite et al. [33] analysed low-temperature DH systems in combination with small booster HPs with the purpose of supplying DHW in DH systems with forward DH temperatures below the required DHW temperature. In one typology, DH water was split in two streams; one passing the condenser and one passing the evaporator of a booster HP, thus creating 53 °C hot water from 40 °C DH water; sufficient to produce DHW at 45 °C with a reasonable heat exchanger temperature difference. Ommen et al. [34] present analyses of booster HPs in the actual DH system of Copenhagen, Denmark, using a mixed integer linear optimisation model with operation optimised against the electricity spot market. The work however is primarily based on CHP and how lowering DH forward temperatures benefit the operation of CHP units using temperature performance curves. Central DH-connected HPs are included to some extent, but not as a single or primary source of DH. The authors "*recommend the use of 65–70 °C as the optimal forward temperature for DH networks, since lower temperatures require high investment, among others DH booster HP units in each dwelling*". Likewise, Elmegaard et al. [35] investigate low-temperature DH systems combined with booster HPs using the DNA (Dynamic Network Analysis – see [36]) framework. These analyses are also based on the combination of CHP and DH and are furthermore based on yearly average consumption rates and not a high temporal resolution. The authors find that "*Conventional systems with higher temperatures in the network have a better utilisation than low temperature solutions, as the decrease in heat loss does not compensate the electricity demand to cover the energy consumption.*"

1.6. Low-temperature district heating

In general a low temperature is preferable due to lower DH grid losses, thus DH development has seen a decline in temperatures over the past century [37]. In addition, when turning to HPs, lowering DH forward temperatures improves the COP of HPs producing DH, thus the DH development towards lower temperature levels facilitates a switch to HPs.

1.7. Challenges for district heating in Denmark

A number of factors act as actual threats to the Danish DH CHP model. Fossil-based CHP has no long-term future in the Danish energy system given the political ambitions to switch to RES, thus DH will need to rely on other heat sources. Heat savings cause relative DH pipe losses to increase in magnitude, and on a short term basis, low electricity prices and high natural gas prices lower the profitability of CHP units to the extent that some swap to biomass boilers. This may push the balance between individual heating solutions including HPs and DH unless other DH production technologies may be employed. In general, in the future, a shift towards further electrification of the energy systems may be foreseen [38].

1.8. Scope and structure

In this article, we investigate the optimal use of HPs in the DH system within the long-term ambitions of a RES-based system with heating based on electricity. We investigate two different alternatives with central HPs and booster HPs:

(a) Central electric HPs supplying DH for space heating and DHW.
(b) Central electric HPs combined with small electric booster HPs utilising DH water as heat source.

The alternatives are analysed and compared with respect to energy efficiency and operational economic viability and based on hourly simulations of a year. As opposed to most of the work referred to before, the analyses are conducted with a high temporal resolution of HP COP and DH grid losses as well as with hourly time series of electricity prices for optimal market operation of the central HPs. The following sections present the methodology, the case, the results and finally the conclusions.

2. Methodology

This section presents the choice of simulation model, description of the chosen simulation model, and the thermal models of HPs and DH grids used in the simulations.

In short, the model consists of an industry-standard energy systems simulation model (energyPRO) and a number of algebraic models of system components implemented in energyPRO.

The algebraic models are constructed with the aim of finding the DH supply temperature at plant (T_{SAP}) as well as the DH return temperature at plant (T_{RAP}). These are both input factors in the HP COP calculation as well as parts of the DH grid loss calculation.

DH systems may be operated in different modes; constant flow and variable T_{SAP}, constant T_{SAP} and variable flow – or for that matter constant T_{SAP} and constant flow (and thus shunts) or combinations thereof. In this article, the supply temperature at customers (T_{SAC}) is determined by the required input temperature in the DHW heat exchanger in the case without a booster HP – and is thus fixed considering the fact the required temperature at the DHW heat exchanger is higher than the floor heating water temperature (see Sections 3.3 and 3.6). With a booster HP, the temperature is determined by floor heating requirements, which varies with the ambient temperature. DH production is controlled through T_{SAP} and flow.

2.1. Choice and description of energy systems simulation model

Several of the DH analyses referred to in Section 1 have been performed using the hourly energy systems simulation model EnergyPLAN. This model has been applied in nearly 100 journal

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articles [39], however it has some shortcomings with respect to the requirements for these analyses; COP for HP is a fixed value, the combination booster HPs and DH is not included and DH heat demands including grid losses are entirely exogenously given. For these analyses, a more disaggregated model is required which can handle COP values that vary with external conditions, booster HPs in combination with DH and DH grid losses that endogenously vary with external conditions and loads.

The model energyPRO is able to handle energy system analyses at a user-defined level of aggregation both temporally and in terms of units and is listed in [40] as one of the models able to analyse 100% RES systems. Hinojosa et al. [41] compare energyPRO to three other models made for CHP plant feasibility assessment (the models SEA/RENUE, CHP Sizer 2 and Ready Reckoner), and they conclude that energyPRO "*is a powerful and flexible application*", while also finding that "*a good understanding of the system and the program is fundamental*" [41].

The model has been applied in a number of analyses, ranging from national analyses of Hungary [42], via market analyses of conditions for CHPs [43] and sizing analyses of CHPs and storage [44] in the United Kingdom to analyses of particular technologies in energy systems such as storages [45] and compressed air energy storage (CAES) [46]. Allegrini et al. [47] compares energyPRO to a series of other model and labels it as having a detailed modelling of thermal grids, though Volkova et al. [48] opt to combine energyPRO with TERMIS, using the latter to simulate DH grids and energyPRO to model scenarios of energy conversion units. In [49], energyPRO is applied to analyse the role of a large-scale heat storage at an Estonian CHP station, while Streckiene et al. [50] perform a similar analysis under German conditions. Lund et al. [51] analyse the role of CHP in Lithuania and Sorknæs et al. [52] use energyPRO to analyse the daily operation of CHP plants operating under uncertainty under market conditions. Wang et al. [53] compare a linear programming optimisation model with energyPRO simulation of hybrid renewable energy systems for communities. Nielsen and Möller [54] employed energyPRO to assess the existence of net zero energy buildings (NZEB) in DH systems. Blarke [55] applied energyPRO as a reference while developing the COMPOSE model.

In energyPRO, in addition to being able to model systems at the required level of aggregation, it is also possible to model units with characteristics that are based on the momentary performance of other units or momentary values from user-defined input series. For instance, the COP of a HP may be modelled as being a function of a forward temperature from DH plant which in turn is a function of amongst others a required inlet temperature at dwellings, DH water flow and DH forward pipe losses to the ground. All units may thus be expressed in advanced algebraic terms referring to outputs from other units and time series.

EnergyPRO furthermore enables the user to model the performance of energy systems against an external electricity market – e.g. through dispatching power units or power consuming units optimally and using storage to furnish the required flexibility in detaching momentary demand and supply. This facility is used in these analyses.

A conventional method of calculating optimal energy productions for e.g. HPs would be to make a chronological hour-by-hour calculation, taking into account the contents in the thermal stores and the electricity market prices. Another method is to use a mathematical solver to minimize the yearly production costs of the heat pumps. The optimising method used by energyPRO differs from these two approaches; it is a strict analytical method being used for planning flexible district heating and cooling plants equipped with energy stores and transmission lines for heat and cooling.

As a starting point energyPRO creates a matrix formed by the number of production units times the number of time steps (e.g. 15 min or 1 h) in the planning period (e.g. 1 year). Each of the cells in this matrix contains a calculated priority number indicating in which order new productions shall be entered. The priority number for e.g. a HP in a certain time step could be the cost of producing 1 MWh_{heat}. Thus if a project has three production units and the simulation is made using one hour time steps over a one year period, the matrix would contain 3*8760 priority numbers. energyPRO enters new productions in a non-chronological way, starting with the production unit in the time step, that has the lowest priority number (highest priority) in the matrix taking into account the restrictions in the energy stores and transmission lines. After having tested if this production is possible, energyPRO continues to the production unit in the time step with the second lowest priority number in the matrix, and tries to enter this production. This non-chronological way of entering production has the consequence that each new production has to be carefully checked to ensure that it does not disturb already planned productions, before being accepted.

In the calculations reported in this paper is used a perfect prognosis for electricity market prices when calculating the priority numbers in the matrix; i.e. energyPRO has perfect foresight and is able to optimise against known future electricity prices. energyPRO also allows that a prognosis for electricity market prices is used for calculating the priority numbers and it furthermore allows gate closures to be included in the calculations. This, however, makes the calculations at least a factor 50 slower. It is expected that the conclusions made in this paper holds even if it is based on calculations with perfect foresight. This situation is not so different from actual operation where plant operators optimise short-term bidding strategies against spot market prognoses.

The optimisation procedures of energyPRO are further detailed in [56].

2.2. Simulation model of central DH HP

In the analyses, a simplified HP model is applied, where the efficiency is based on the theoretical Lorentz efficiency η_L and an empirically determined system efficiency η_S. The Lorentz efficiency is defined as

$$\eta_L = \frac{TA_H}{TA_H - TA_L}$$

where TA_L is the logarithmic mean low absolute temperature (for heat pumps, evaporator) and TA_H is the logarithmic mean high absolute temperature (for heat pumps, condenser) defined as

$$TA_L \text{ or } TA_H = \frac{TA_{in} - TA_{out}}{Ln\left(\frac{TA_{in}}{TA_{out}}\right)}$$

The expression is similar to the Carnot efficiency, except that "*the isothermal heat sources have been replaced by polytropic ones*" as Sofrata [57] expresses it. Finally, the total HP efficiency η_{HP} (or COP) is

$$\eta_{HP} = \eta_L * \eta_S$$

For the DH HP, any heat exchanger loss between HP working fluid and DH fluid is included in the system efficiency η_S.

2.3. Simulation model of booster HP

In general, the booster HP is modelled in the same way as the central DH HP, however an extra heat exchanger with storage is introduced. The secondary side of the booster HP is a closed-loop circuit heating up a heat storage which in turn through a heat exchanger heats cold water to the required DHW temperature at the moment of consumption. In terms of energy efficiency, direct utilisation of storage water would provide for a better HP COP as

well as avoid any heat exchanger temperature difference. However, storing DHW at use-temperature would improve living conditions for the undesired legionella bacteria, whereas the use of heat exchangers minimize the time DHW is warm as noted by Brand and Svendsen [58].

Thus, the booster HP is connected to DHW production through a heat exchanger (HE) with heat storage, introducing a temperature loss $\Delta T_{HP,HE}$ and the correlation

$$TA_{Out} = T_{DHW} + \Delta T_{HP,HE} + 273.15\ K$$

The DHW house installation with booster HP, storage and heat exchanger is shown in Fig. 1.

The return water from space heating (floor heating) is not utilised in the scheme for producing DHW in the present systems configuration.

2.4. Simulation model of DH grid

For the DH grid, a model is required which connects temperatures at the DH plant, temperatures at consumers and DH losses as shown in Fig. 2.

The total heat delivered from the DH grid (DH_D) depends on flow of DH water ($\dot{m}$), the heat capacity of water (C) and cooling at consumers, i.e.

$$DH_D = \dot{m} * c * (T_{SAC} - T_{RAC})$$

The DH flow may thus be expressed as

$$\dot{m} = \frac{DH_D}{c * (T_{SAC} - T_{RAC})}$$

The heat loss of the supply pipes is calculated as a simple mean temperature in the supply pipes times an average pipe heat loss coefficient (C_{Loss}). This heat loss is set equal to an average reduction in the supply temperature from the plant to the consumers:

$$\text{Forward pipe loss} = C_{Loss} * \left(\frac{T_{SAP} + T_{SAC}}{2} - T_{Soil}\right) = \dot{m} * c * (T_{SAP} - T_{SAC})$$

Thus, the ex-works supply temperature may be expressed as:

$$T_{SAP} = \frac{C_{Loss} * T_{Soil} - C_{Loss} * \frac{T_{SAC}}{2} - \dot{m} * c * T_{SAC}}{\frac{C_{Loss}}{2} - \dot{m} * c}$$

Similarly, the return temperature at the DH plant may be expressed as

$$T_{RAP} = \frac{C_{Loss} * T_{Soil} - C_{Loss} * \frac{T_{RAC}}{2} - \dot{m} * c * T_{RAC}}{\frac{C_{Loss}}{2} - \dot{m} * c}$$

2.5. Simulation model of floor heating

The buildings in the modelled system are adapted for low-temperature DH and are thus equipped with floor heating.

The Space Heating Demand (SHD) is modelled as a linear function of the ambient air temperature (T_A) and a specific SHD-factor (SpecSHD) for temperatures below a reference temperature above which no heating is required:

$$SHD = SpecSHD * \max(T_{ref} - T_A; 0)$$

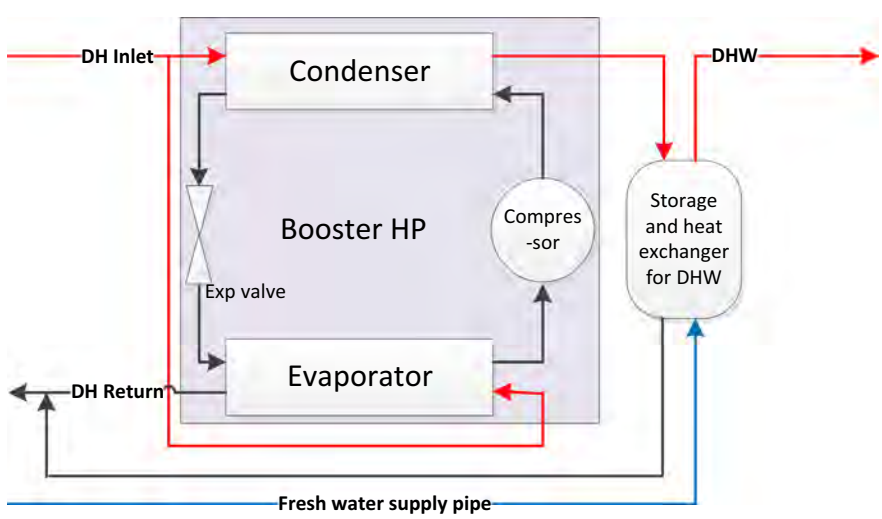

Fig. 1. DHW house installation with booster HP and storage/heat exchanger.

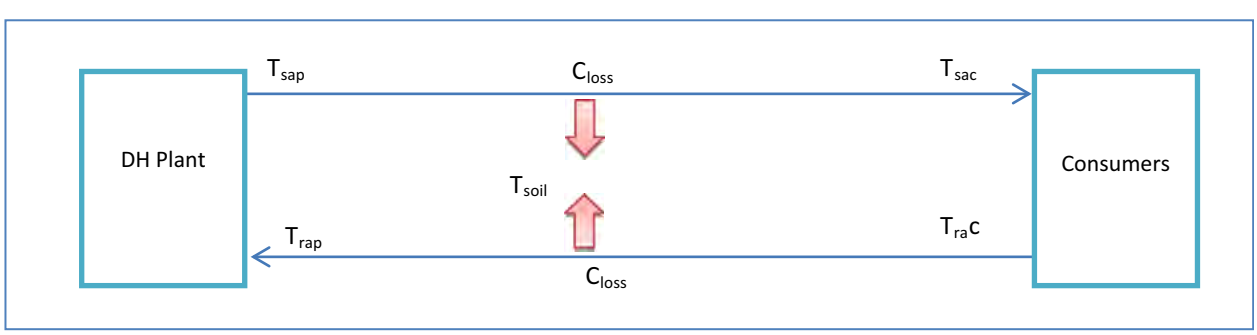

Fig. 2. Grid diagram and input parameters.

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The supply temperature for floor heating ($T_{S,FH}$) is assumed to be controlled as a linear function of the ambient temperature (T_A) based on two points; a lower reference floor heating supply temperature ($T_{S,FH,LR}$) at the lower reference ambient temperature ($T_{A,FH,LR}$) and similar an upper point ($T_{A,FH,UR}$, $T_{S,FH,UR}$). The two points may be determined empirically as in this article or theoretically. Altogether, the floor heating supply temperature reads

$$T_{S,FH} = \max\left(\frac{T_{S,FH,UR} - T_{S,FH,LR}}{T_{A,FH,UR} - T_{A,FH,LR}} * (T_A - T_{A,FH,LR}) + T_{S,FH,LR}; T_{S,FH,UR}\right)$$

If the DH supply temperature at consumers is higher than the required supply temperature for the floor heating, it is assumed that sufficient shunt is made.

The return temperature from floor heating ($T_{R,FH}$) is assumed to be controlled to the following temperature:

$$T_{R,FH} = \frac{T_{S,FH} + T_{S,FH,UR}}{2}$$

This is based on empirical experience from [59].

2.6. Limitations in hydrological modelling

In the analyses, the hydrological capacity of DH pipes is not considered. Thus, calculated DH pipe temperature levels may be lower than the required levels to transmit the required amounts of heat. In the modelling, the flow is a function of the temperature levels and is not restricted by maximum fluid velocities, concerns of laminar or turbulent flows or pumping power requirements. One way to overcome this is to compare flows to maximum permissible flows, however this is very DH-grid dependent. Another way is to set minimum T_{SAC} at different periods of the year, however for these analyses, neither are implemented as they mask the system response.

3. Case description and input parameters

The chosen case is a theoretical case, however representing a typical Danish DH system. This case has a DH plant production of 20,000 MWh annually corresponding to just below 900 typical Danish houses of each 18.1 MWh/year (numbers do not add up due to grid losses).

The plant is equipped with a HP with an electrical input of 0.5 MW. The potential output varies with the COP factor – in practice between 2.5 and 5 MW in the modelled system. In the modelling, partial load operation is allowed.

The plant is also equipped with a natural gas boiler for peak loads or if production costs using the central DH HP exceeds the costs of using the boiler. This 10 MW boiler has a production price of 65 €/MWh.

The plant is equipped with a DH storage of 1000 m^3 – corresponding to 46.35 MWh between temperature levels of 80 °C and 40 °C, or 60 °C and 20 °C in case of low-temperature DH. This corresponds to 20 h of average heat production of the DH plant based on the 20,000 MWh.

In the following, additional case and input parameters for the modelling are given.

3.1. Ambient DH pipe soil temperature (T_{Soil})

In Aalborg, Denmark, the soil temperature at a depth of 10 cm for 2015 varied between 1 and 20 °C [60], however DH pipes are placed at depths from approximately 1 m for branch pipes to individual dwellings up to a few metres for transmission lines. In Copenhagen, a new 3 m Ø DH tunnel with room for pipes and maintenance staff, is placed at a depth of 25 m. At such depths, the temperature is much more stable, and in general, one can assume an ambient soil temperature (T_{Soil}) of 8 °C in Denmark [61]. This temperature is used in the grid model.

3.2. Heat loss coefficient for DH pipes (C_{Loss})

The annual DH loss may be expressed as a function of the average forward temperature (T_{DHF}; average of supply at plant (T_{SAP}) and supply at consumer (T_{SAC})), the average return temperature (T_{DHR}; average of return at plant (T_{RAP}) and return from consumer (T_{RAC})), the soil temperature (T_{Soil}) and the DH pipe loss coefficient (C_{Loss}). This may be expressed as

$$DH_{Loss} = \sum_{hour=1}^{8760} \left(C_{Loss}(T_{DHF_{Hour}} - T_{Soil_{Hour}}) + C_{Loss}(T_{DHR_{Hour}} - T_{Soil_{Hour}})\right)$$

In Denmark, annual DH demands typically split 60%/20%/20% on Space Heating Demand, DHW and DH grid losses with an average supply temperature (T_{DHF}) of 80 °C and an average return temperature (T_{DHR}) of 40 °C. With T_{Soil} being fixed, and assuming fixed pipe temperatures, annual DH_{Loss} may be rewritten to

$$DH_{Loss} = 8760 * C_{Loss}\left(\left(\frac{T_{SAP} + T_{SAC} + T_{RAC} + T_{RAP}}{2}\right) - 2T_{Soil}\right)$$

For a plant with an annual production of 20 GW h, DH grid losses are approximately 4.0 GW h, and C_{Loss} may be determined to 4.40 kW/K. This factor is used in the grid model.

3.3. Floor heating temperature

The floor heating model is based on empirically found temperature levels. The upper point on the linear curve ($T_{A,FH,UR}$, $T_{S,FH,UR}$) is (15.5 °C, 23 °C) while the lower point ($T_{A,FH,LR}$, $T_{S,FH,LR}$) is (−12 °C, 35 °C). These are empirical numbers from [59]. At ambient temperatures above 15.5 °C, floor heating switches off.

3.4. System efficiency of HPs (η_S)

In these analyses, η_S is set at 50% in agreement with empirical experience referenced in a project on large HPs in DH systems [62] and communication with the researchers behind the project. For small booster HPs, η_S is set at 40% to reflect poorer performance for small-scale HPs.

3.5. Ambient air temperature (T_A)

The ambient air temperature follows a one year distribution profile at one day intervals – see Fig. 3. Minimum is −9.0 °C, maximum is 22.2 °C and the mean temperature is 8.1 °C. A total of 63 days have temperatures at or above the floor heating reference temperature (T_{Ref}). Using daily rather than e.g. hourly values accommodate for the large thermal mass in the buildings (see e.g. [63]). Using hourly values would have exhibited too high variations within the day.

The resulting heat demand for the dwellings is as depicted in Fig. 4, with a variation between 0.5 MW (corresponding to DHW supply only) and just below 5 MW on January 11th.

It should be noted, that in the summertime, floor heating is turned on and off a number of times. Thus at times, DHW alone causes DH demand and at other time space heating adds DH demand. This is detailed further in Section 4.2.

3.6. DHW temperature

Without concern for bacteria, the DHW temperature should be at a minimum of 40 °C for personal hygiene while for dishwashing, the temperature should be 45–55 °C [64]. For these analyses, the required DHW water temperature is set at the lower range of this

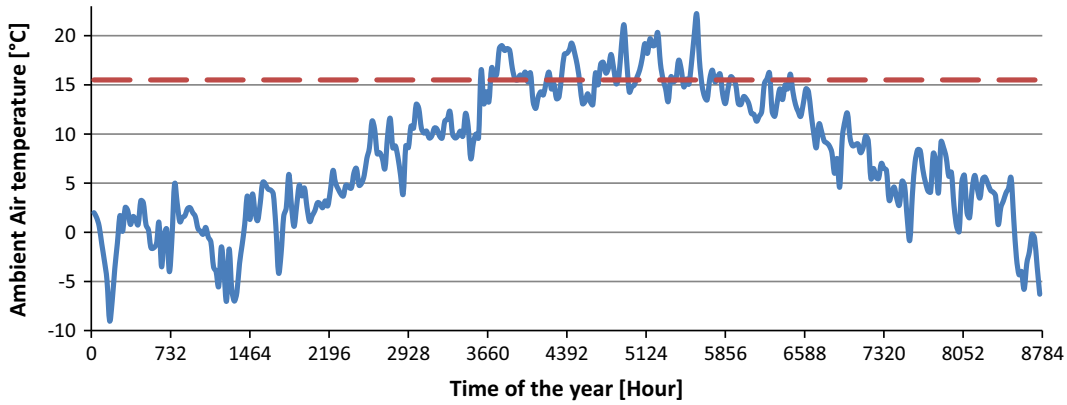

Fig. 3. Daily average ambient air temperature (T_A) over a one year period used in the energy systems analyses. The horizontal line indicates the temperature level above which heating is switched off. The 732 h step corresponds to an average month in a leap year.

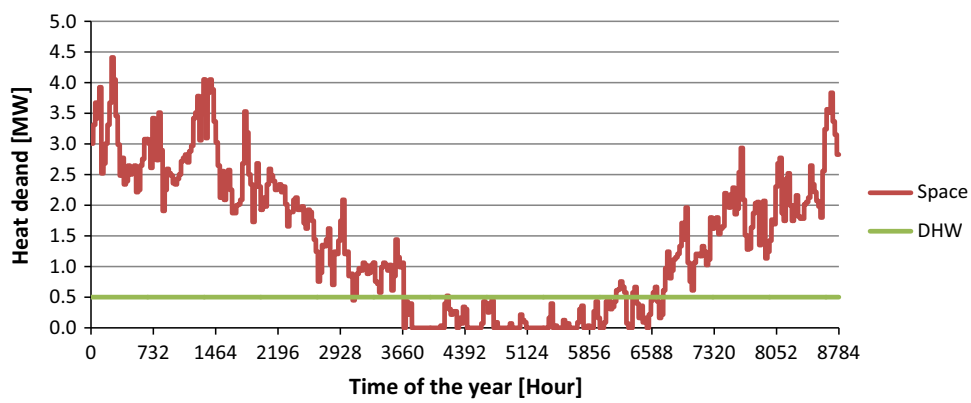

Fig. 4. Heat demand variation (not including DH grid losses).

at 45 °C. This also corresponds to the level applied by Zvingilaite et al. [33].

3.7. Heat exchanger temperature loss ($HT_{HP,HE}$)

Heat exchanger temperature losses are introduced between the internal circuit of the booster HP and the DHW system of the individual buildings. In these analyses, $\Delta T_{HP,HE}$ is set at 8 K. Thus, with a DHW temperature of 45 °C, the inlet temperature to the DHW heat exchanger must be 53 °C. This temperature is used regardless of whether a booster HP is used or not; i.e. in the case without a booster HP, T_{SAC} has to have at least this temperature.

3.8. Central DH HP heat source

In the analyses, a heat source temperature for the central HP is assumed fixed throughout the year at 10 °C. This is marginally above the ambient ground temperature for DH pipes and above the ambient air temperature during the colder season, thus it is based on an expected availability of a source of low-temperature heat higher than the ambient temperature. This could for instance be industrial excess heat.

3.9. Spot market operation and electricity costs

The DH plant is operated on the Nordic electricity day-ahead spot market under the constraints given by production system, demands and storage size and contents. Hourly spot market prices from the pricing area DK1 (=Western Denmark) for 2014 are used – see Fig. 5.

As shown in the duration curve in Fig. 5, most of the year, electricity spot market prices are between 20 and 40 €/MWh, however the full range is from approximately −60 to +160 €/MWh with an average of 30.7 €/MWh. The very high and very low prices are limited to very few hours though.

It is assumed that the operation of the modelled DH plant does not affect settling prices on the electricity market.

In addition to the markets costs, the appropriate levies are applied to the electricity costs. This is an electricity tax of 51 €/MWh, grid tariffs of 21 €/MWh, and PSO (Public Service Obligation) at 28 €/MWh.

The same costs are applied for both central and booster HP.

3.10. Operation and maintenance costs

Operation and maintenance costs for the both central and booster HPs are set at 1 €/$MWh_{electric}$. This will in practice amount to a negligible number for the booster HP, which is in line with expected levels from a potential manufacturer of these, Danfoss.

4. Energy systems analyses and results

In the following, main results from the simulations are presented with a focus on technical and economic performance.

4.1. Temperatures, grid losses and COP

The main determining factor for the DH forward temperature is the DHW productions, thus without a booster HP, forward temperatures from the DH plant by far exceed forward temperatures for

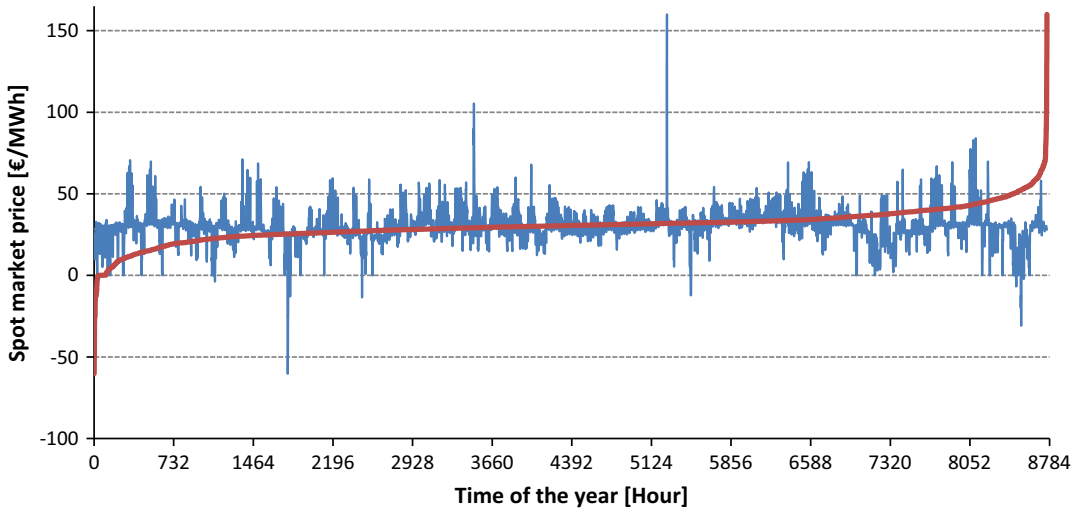

Fig. 5. Electricity spot market prices applied in the analyses; hourly plot and duration curve.

the same system with a booster HP. Without a booster HP, temperatures are in the 53–68 °C range as shown in Fig. 6. With a booster HP, the general level can be decreased to 23–34 °C as also shown in Fig. 6. In the case with a booster HP, the yearly non-weighed average is only 26.8 °C.

One important conclusion to be drawn from Fig. 6 is that for the system without a booster, DH temperatures have to be higher in summer than in winter to ensure a sufficiently high T_{SAC} to provide DHW at the required temperature level. In contrast, with a booster HP, T_{SAC} is at its yearly minimum during the summer.

With the very low DH supply temperatures, the central HP COP is high, with values up to 10 (see Fig. 7). Compared to other analyses where assumed DH HP COP values typically range from 3 to 4, this is very high, however it is the actual modelled COP including thermodynamic losses in the HP. Such high COP values can only be attainted through the combination of very low DH forward temperatures and reasonably good low-temperature heat resources. In the summer situation, the low temperature resource is even modestly assumed at 10 °C; using sea water for instance would give a low-temperature resource temperature of approximately 18–20 °C during the summer in Denmark and thus an even higher COP value. With low-temperature resource temperature and DH forward temperature approaching one another, the theoretical Lorentz efficiency η_L of the DH HP would approach infinity.

As expected, the COP value varies over the year with the lowest values during the coldest season (and with highest DH forward temperatures) and the highest values during the summer. The weighted average COP over the year is 8.1. For the system without a booster, the level is somewhat lower with an average yearly value of 5.0. During the summer, the value reaches 5.2 while in the winter it drops to 4.7. Thus, the variation is far less than for the system with a booster HP, and particularly during the summer, the difference is pronounced.

A second derived effect of the lower DH forward temperatures is reduced DH grid losses, as shown in Fig. 8, where the variation in DH grid losses are shown over the year.

Relative grid losses are by far the highest during summer, but due to the low DH forward temperature of the booster HP system, grid losses are 10 percentage points lower during summer with the booster HP compared to without. During winter, losses are also lower.

As stated in Section 3.2, the grid loss coefficient is calculated based on an annual loss of 20%. For these two systems, losses are 7.8% or 12.4% with and without booster HP. Losses are thus lower in both cases which is due to lower temperature levels, where the 20% was based on forward/return temperature of 80 °C/40 °C. For the case with the booster HP, the DH forward temperature is throughout the year lower than the 40 °C return temperature considered representative of present DH system operation.

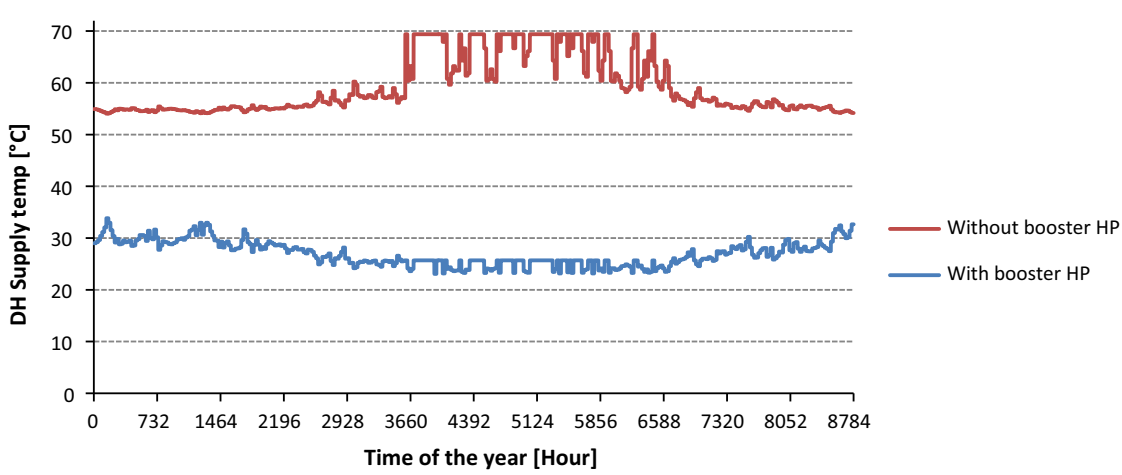

Fig. 6. DH supply temperature (T_{SAP}) with and without booster HP.

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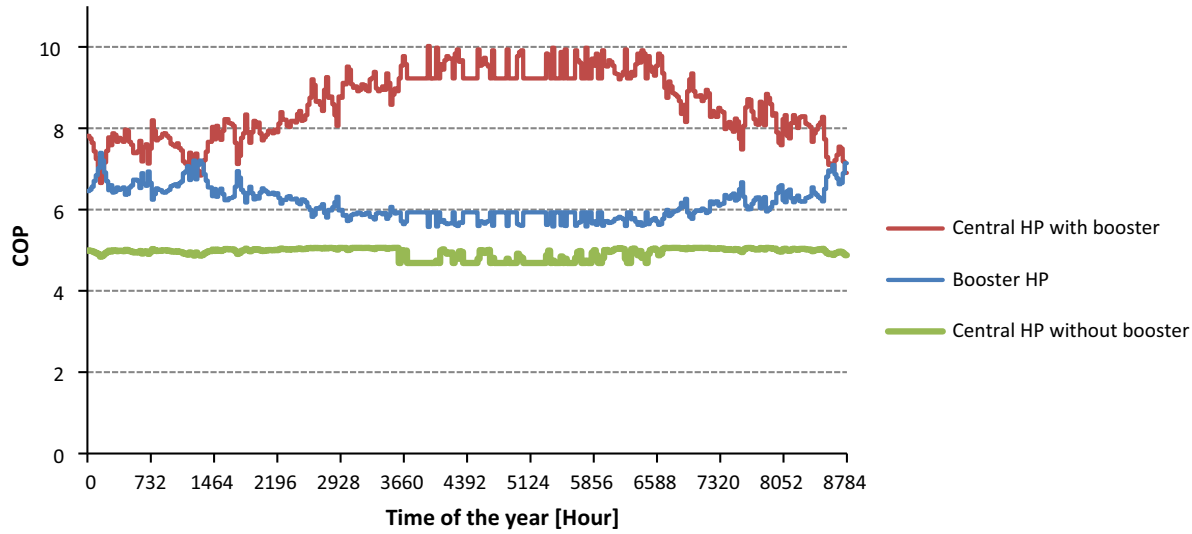

Fig. 7. HP COP variation over the year for central and booster HP.

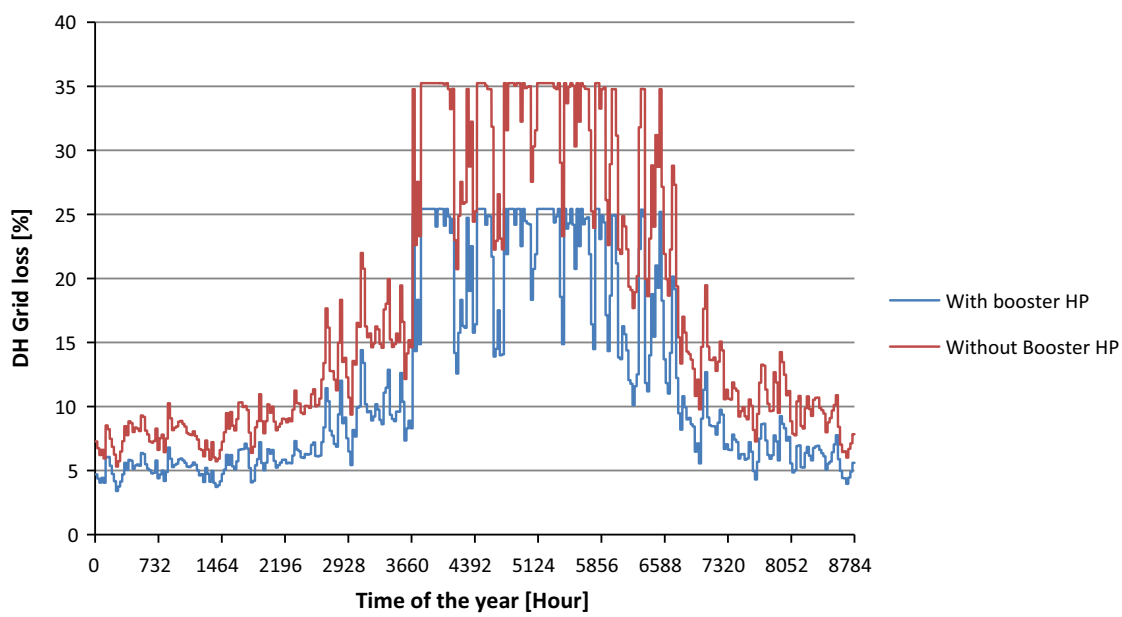

Fig. 8. Relative DH grid losses with and without booster HP.

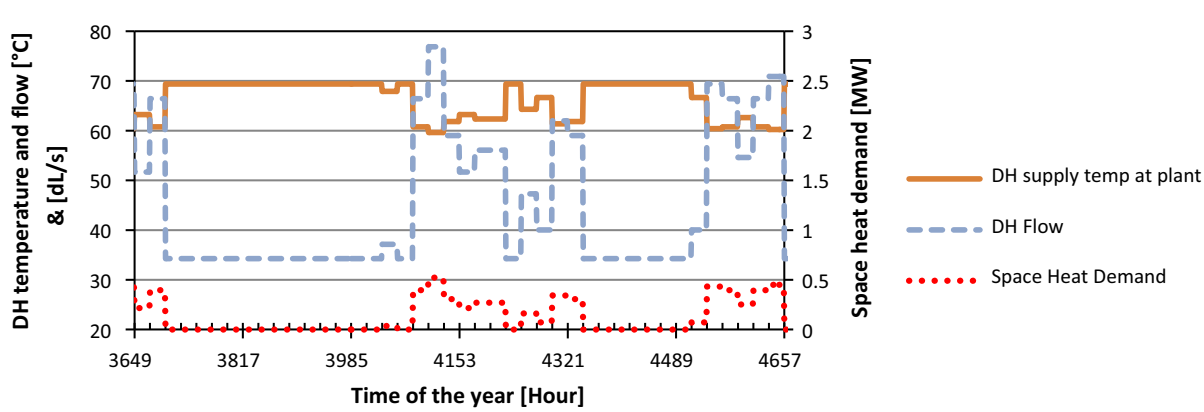

Fig. 9. DH temperature (T_{SAP}) and flow ($\dot{m}$) from DH plant as well as SHD at consumer for six summer weeks starting June 1st (hour 3649 of the year).

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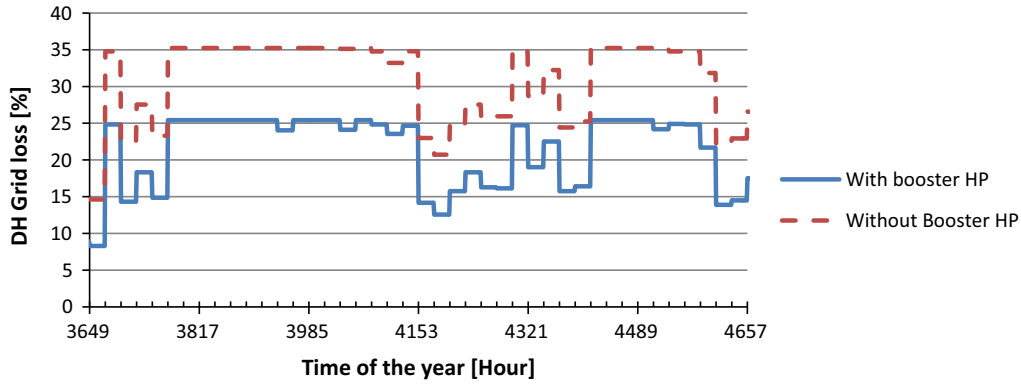

Fig. 10. DH grid loss for six summer weeks starting June 1st (hour 3649 of the year).

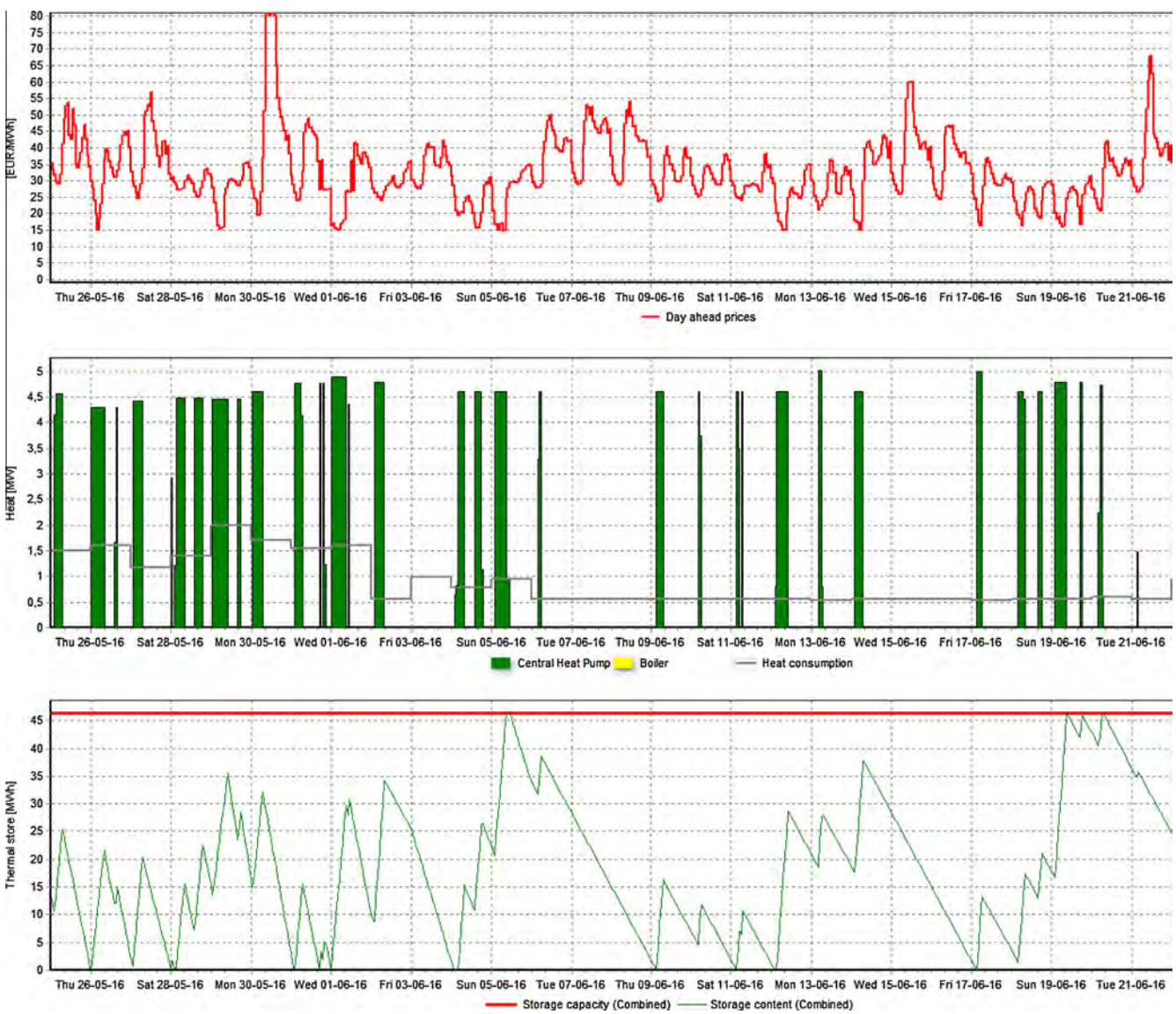

Fig. 11. Main hourly operation characteristics for four weeks in spring/summer. For system with booster HP. Screendump from energyPRO.

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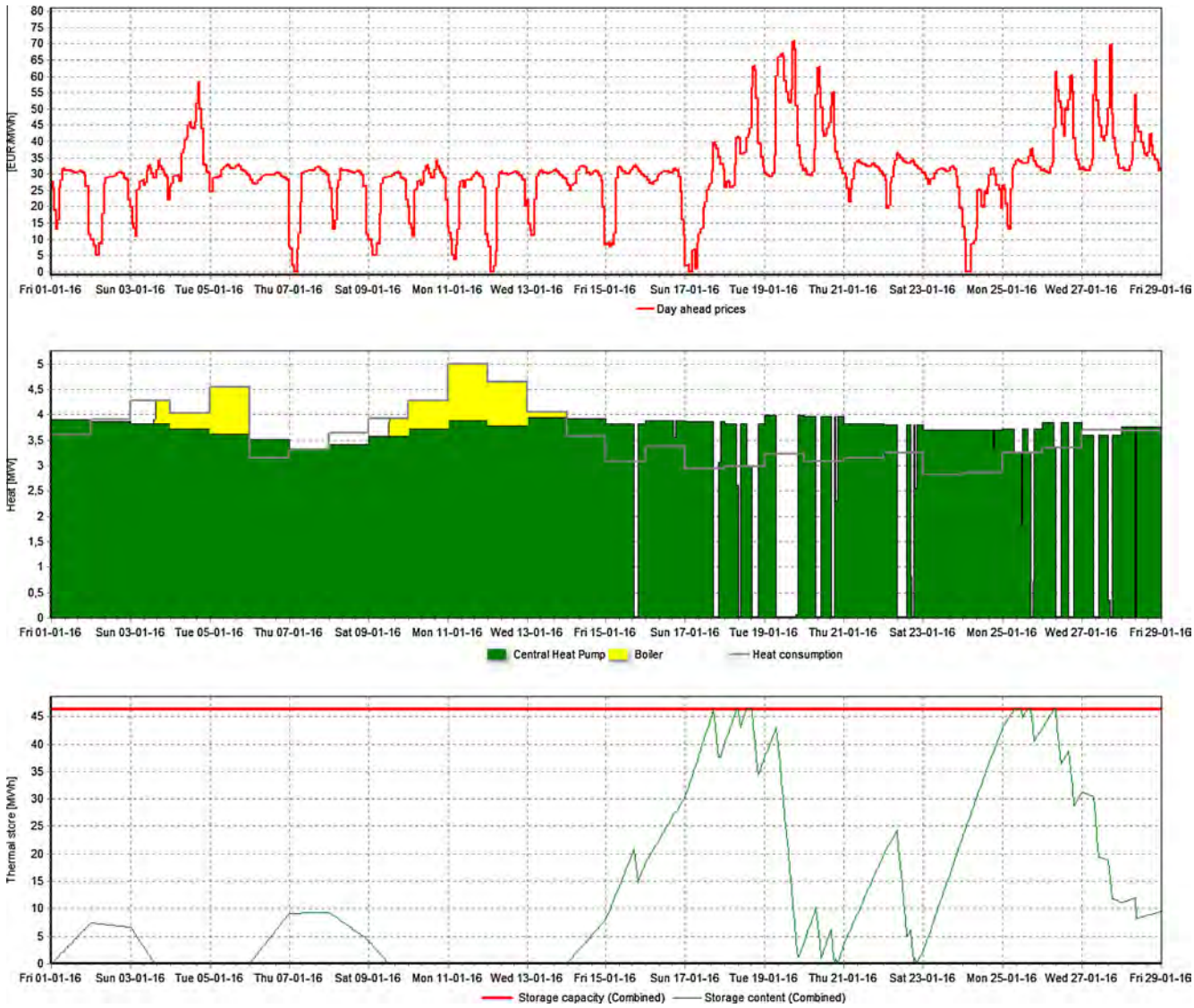

Fig. 12. Main hourly operation characteristics for four weeks in winter. For system with booster HP. Screendump from energyPRO.

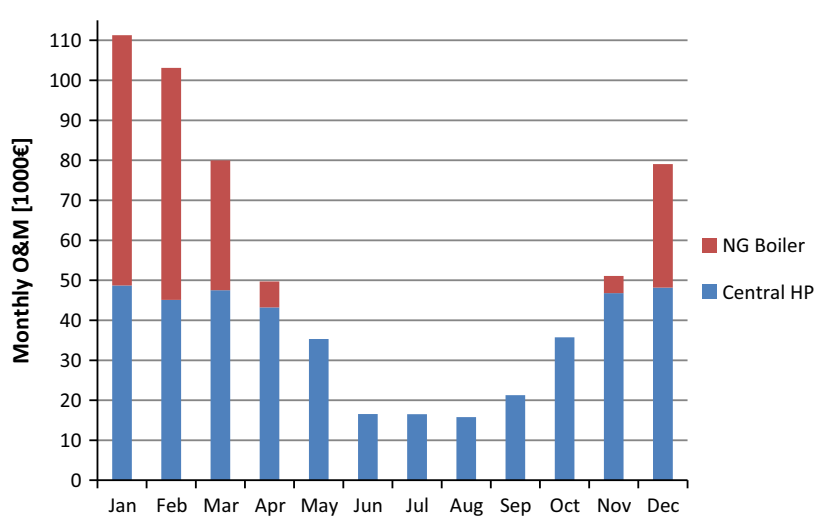

Fig. 13. Monthly heating costs for central DH HP without booster HP.

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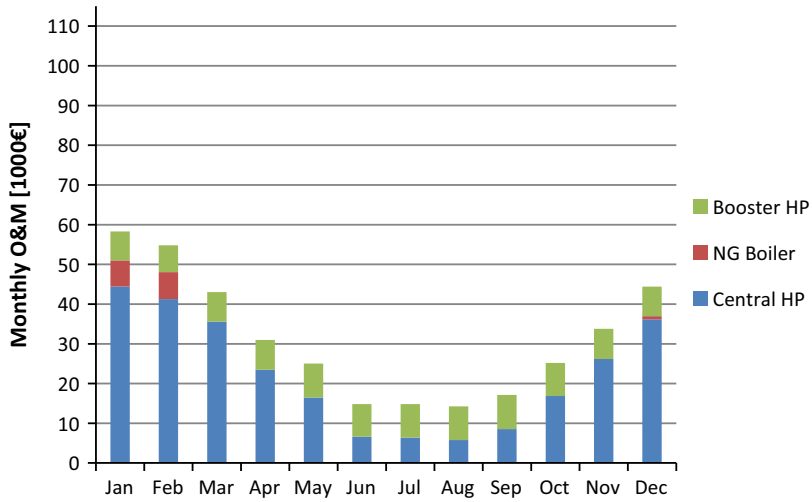

Fig. 14. Monthly heating cost for central DH HP and booster HP.

The yearly average losses can of course not be read from Fig. 8 as high-loss summer months enter the equation with a much lower weight than the low-loss winter months.

4.2. Summertime operation

During the summer, SHD is frequently zero as shown in Fig. 9. During these intervals, DHW demand is the only driver of flow and DH supply temperature at the DH plant. As soon as there is a SHD, DH flow increases while the DH supply temperature decreases here shown for system without booster HP.

The higher the SHD, the higher the flow and the lower the DH supply temperature as relative losses decrease at higher DH demands. Fig. 10 shows DH grid losses for the same six summer weeks as Fig. 9, and it is clear that the DH grid losses drop whenever there is a SHD and increase when there is only a DHW demand.

4.3. Operating expenditures

The systems are operated on the spot market, and Figs. 11 and 12 demonstrate how energyPRO seeks to optimise the usage of the storage to avoid high-price periods and locate demands in low-price periods to the extent possible. The figures show two four-week periods during the cold and the warm season respectively, and during the warm season, there is a clear pattern that high-price periods correspond to periods where the storage is being tapped and vice versa.

During the cold period, there is less flexibility; the central HP needs to operate much more and the modelled size of the HP leaves little or no unused capacity for supplying flexibility. In some instances, it is even required to operate the natural gas boiler. In these instances, this is not due to economic optimisation (but could be in other cases with very high electricity prices) but due to the circumstance that the central HP simply cannot supply enough heat. The drop in HP output from January 1 to January 7 is not due to partial load operation or high electricity prices, but simply due to a decrease in the Lorentz efficiency of the central HP caused by the temperature conditions of that period.

The operation of the booster HP is not shown; this unit is producing constantly to the storage for DHW production.

Operation expenditures are shown on a monthly basis in Figs. 13 and 14 distributed on costs of electricity for the two HP types and natural gas for the DH boiler. Here it is clear, that with today's price levels, the booster HP is preferable when investment costs are not considered. A large part of the cost for the non-booster system arises due to the natural gas demand. If the central HP capacity

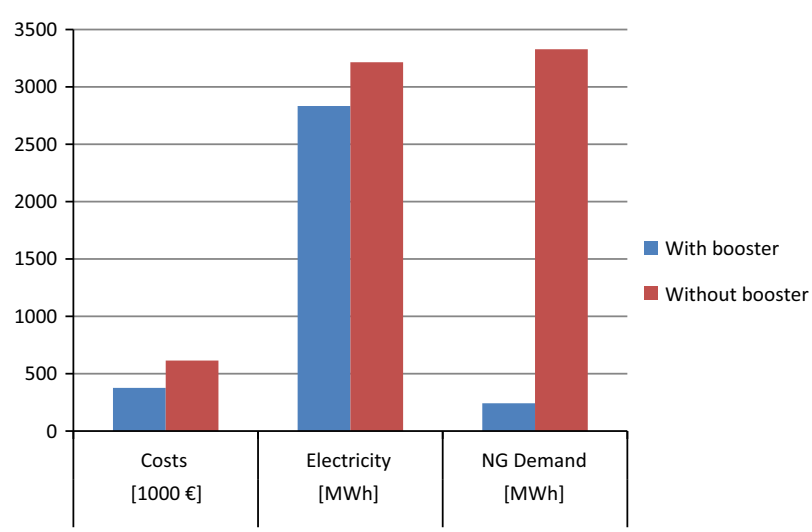

Fig. 15. Annual aggregate heating costs and energy demands with and without booster HP.

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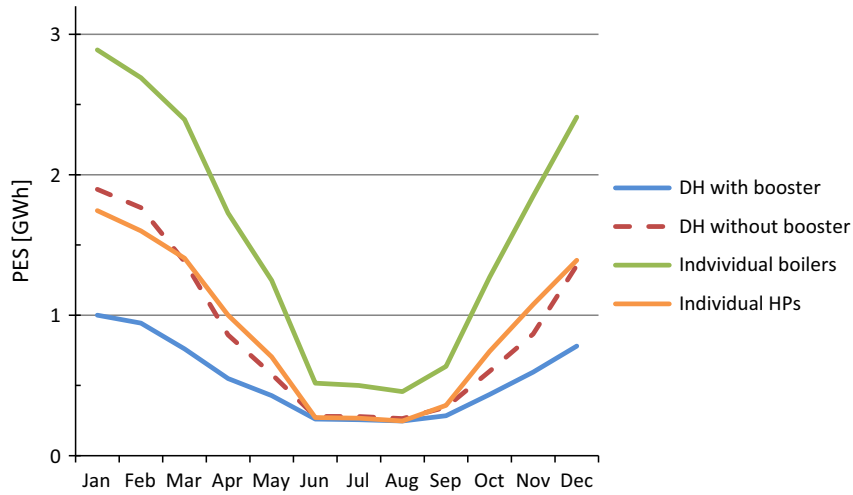

Fig. 16. Primary energy demand of heating alternatives.

is increased to be able to cover the entire demand, then operation expenditures would decrease to a maximum of 75,200 € per year.

Fig. 13 also shows in general how attractive the DH HP is compared to a natural gas boiler considering that for instance in January, the central HP delivers 1.84 GW h while the natural gas boiler only delivers approximately a third of the entire production at 0.96 GW h. Thus bar contributions in Figs. 13 and 14 should not be misinterpreted as relative production contributions from the three production technologies in question.

4.4. Annual aggregate results

On an annual basis, the system with booster HP has operation costs of 376,500 € while the non-booster system has costs of 615,400 €, and the difference primarily comes from the additional consumption of natural gas in the non-booster system as shown in Fig. 15.

If the natural gas demand for the non-booster system is removed by expanding the central HP unit, then annual costs end at approximately 500,000 €, thus still well above the level for the system with a booster HP.

4.5. Primary energy demand comparison

Finally, in order to compare the performance in terms of primary energy supply (PES), four alternatives are established.

(1) HP-based DH as described before with electricity for the HP supplied from a power plant with an efficiency of 45%. Combined with a natural gas boiler with an efficiency of 90%.
(2) HP-based DH combined with a booster HP for DHW as described before with electricity for the HPs supplied from a power plant with an efficiency of 45%. Combined with a natural gas boiler with an efficiency of 90%.
(3) Individual natural gas or oil boilers with an efficiency of 0.9.
(4) Individual HPs. In practise modelled as 1) without any DH grid losses; with a HP system efficiency (η_S) of 0.4 and a heat source temperature for the HP fixed throughout the year at 4 °C (as opposed to the 10 °C assumed for the central HP).

Fig. 16 shows the variation in monthly PES for the four alternatives. Individual boilers have the highest PES demand throughout the year as it is unable to compete against the COP of HPs. In January, PES demand is nearly three times higher for individual boilers than for DH HP with booster. Individual HPs are on par with DH HP without booster for most of the year and even lower for some months. Thus, DH HP cannot compete against individual HPs from a simple PES perspective under these circumstances. With a booster HP, PES demand is generally lower – except during the summer months where it is on par with the other options. In July, individual HPs have a PES of 0.27 GW h compared to DH with booster 0.26 GW h and 0.28 GW h without booster, thus individual HPs are marginally better than DH HP without booster and worse than DH HP with booster, though differences are smaller than the uncertainty in input parameters. For the remainder of the year, DH HP with booster is markedly preferable to the other heating options.

Sensitivity analyses have been made for other heat resources for the individual HPs; a source temperature of 10 °C corresponding to the assumed temperature level for the central DH HPs as well as a seasonally varying temperature developing linearly from 4 °C January 1st to 8 °C July 1st and back to 4 °C at the end of the year. At 10 °C, summer performance is better than for DH HP with booster with a PES in July and August of 0.22 GW h against 0.26 GW h for both months for DH HP with booster. This resource temperature is higher than what is generally attainable though – and any lower demand during the warmest summer months is by far outweighed by higher PES for individual HPs during the winter months.

In case the electricity is produced on either RES or in CHP mode, PES equivalents of electricity demands will either be less important (RES) or smaller in magnitude (CHP). For RES supply, the importance is linked to whether there is a limited availability as in the case of biomass and/or associated investment costs.

5. Conclusion and discussion

In this article, we have established an operable model detailing temperatures, losses and COP values in DH systems, the operation of which in turn can be simulated and optimised against a spot market. Using this model, we have investigated the effects of using low-temperature heating and DHW production systems; floor heating and booster HPs. This has been combined with detailed hourly analyses of the COP values for HPs and simulations using the energyPRO package to optimise the operation against the spot market.

Regardless of whether the booster HP is used or not, DH grid losses decrease significantly, but for the system with the booster HP, the required forward temperature from the DH plant is lowered so much that the COP increases to as much as 10 during the

warm season – where relative losses are also the highest. This of course reduces the significance of the high relative losses during the warm season.

Operation costs for the system with booster are 39% lower than for the system without a booster HP. This is primarily due to natural gas costs, but even if a natural gas boiler was avoided through a larger central DH HP, costs would still be higher due to higher temperature requirements at the consumer, due to higher grid losses and due to a lower COP of the central DH HP.

Comparing the performance of the DH HP booster system to e.g. individual HPs show that while individual HPs may be preferable during the summer, the relatively poorer performance of the DH HP booster system during the summer is by far compensated by a better performance during the rest of the year.

In the work, there are two important factors that have not been included. As stated, the analyses have not considered the flow requirements. The data has been calculated; however flows have not been constrained in the calculations as it would require a detailed description of the DH grid. Secondly, investment costs have not been considered as the booster HP technology is still in an early stage of development and no authoritative cost assessments are available.

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Appendix V: New roles of CHPs in the transition to a Renewable Energy System

SYSTEM INTEGRATION

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NEW ROLES OF CHPs IN THE TRANSITION TO **A RENEWABLE ENERGY SYSTEM**

District Heating and Cooling Plants (DHCP) will have both the opportunity to provide efficiency and flexibility through e.g. CHP, heat storages and heat pumps – while at the same time providing capacity when required. Fortunately, through investment decisions made a long time ago, Danish DHCP plants are already partially equipped for this role but to take on the role as capacity provider of the future, further incentives have to be established.

Combined heat and power (CHP) units at DHCP have an important, but changing, role to play in the transition to a renewable energy system. Their initial role is merely to displace fossil fuelled condensing mode power generation, however, the development in Denmark shows that this role changed to providing flexibility for accommodating fluctuating renewable energy sources instead. Also, in the future, the role will be to provide electrical capacity during the hours where fluctuating renewable energy sources are unavailable.

In the first phase, the aim is simply to cover the heat demand to the highest extent possible by DHCP CHP plants thus providing electricity where all coproduced heat is utilised. Generally, for each MWh of power thus replaced on a condensing mode power station by DHCP CHP, the same quantity of fuel is saved, often called the CHP benefit.

With an increasing penetration of fluctuating renewable energy sources – mainly wind, solar, and wave power – it becomes increasingly important that the DHCP CHPs act with more flexibility and assist in the integration of these. One of the consequences is a decrease in the power generation from DHCP CHP in the next phase.

As the energy systems progress towards fully renewable energy systems, based on fluctuating renewable energy sources, very little production is left on DHCP CHP and they have only to produce electricity in the relative few hours where fluctuating renewables are insufficient. At this stage, it is questionable whether there is any surviving condensing mode capacity, however multi-purpose DHCP CHPs may still present a business case, amongst others providing needed electrical capacity.

The changing role is important to keep in mind when designing DHCP plants – while at the same time keeping in mind that the ongoing electrification of society requires that heating and cooling production at DHCP stations primarily will be served by electrical heat pumps using e.g. surplus, low-grade heat from industry, sewage systems or seawater.

In Denmark, 16 central power plants providing district heating to big cities, 285 distributed CHPs providing heat for towns and villages and 380 industrial and private CHP plants proving heat for private and public DH grids have played an important role in providing an efficient energy system. The installed electrical capacity at the central power plants is 5,693 MW, 1,887 MW at the distributed CHP-plants and 574 MW at industrial and private CHP plants – however, they are currently threatened by decreasing spot market prices.

This article argues that distributed DHCP CHP - representing 23 % of the total electrical capacity in Denmark - is quickly moving to the capacity-providing phase – perhaps even too quickly!

As shown in figure 1, the electricity production at the distributed DHCP CHPs has been decreasing rapidly in recent years as a natural consequence of wind power developments. Wind power has come to cover a major part of the electricity demand, leaving less electricity to be produced by CHP. Until 2005 the Danish DHCP CHPs was paid under a fixed tariff system thus producing independent of wind production, but from year 2000 the wind turbines started to be curtailed from time to time - amplified by the situation that DHCP CHPs continued to produce because they were operating under the fixed tariff system. This also indicates the point in time where the energy system role of CHP changed from being a provider of electricity produced efficiently in cogeneration mode to being a provider of flexibility. As a consequence of the changed role, from 2005 to 2015, the fixed tariff system was phased out for progressively smaller DHCP CHP sizes, turning these over to be market-operated and most of these being traded on the Scandinavian day-ahead market.

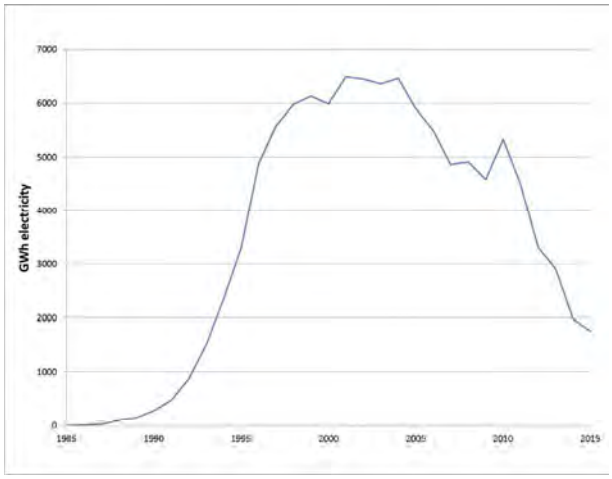

Figure 1: Annual electricity productions at distributed DHCP CHP in Denmark

An example of the flexible operations of Danish DHCP CHPs is shown in figure 2 and figure 3, showing respectively the aggregated electricity productions and consumptions in West Denmark together with day-ahead prices (Spot price) for the 6th December and 27th December 2016. The day-ahead prices rose at 7 o´clock on 6th December 2016 to the double compared to the prices in the night hours, which caused the DHCP CHPs (shown as local CHP units in the figures) to go from an electricity production of a little more than 300 MW to an electricity production of nearly three times bigger. Figure 3 shows a more extreme situation, where spot prices became negative until 7 o´clock on 27th December 2016 and the DHCP CHP production fell to approximately 100 MW. Comparing the two days (figure 2 and 3) shows a changed production from 100 MW to 900 MW, a flexibility in production of a factor 9.

An important question could be why the DHCP CHP production was not reduced down to 0 MW when the day-ahead prices were negative – or another way to ask, which DHCP CHP is willing to pay around 400 DKK/MWh for being allowed to enter electricity into the grid. The simple answer is that it is the Danish Transmission System Operator (TSO) that is willing to pay so. These remaining 100 MW are mainly biogas CHP-plants, to which the TSO pays a feed-in tariff (FIT) independent of the hour in the day. The TSO is balancing responsible party (BRP) for these FIT-productions and sells the electricity from these plants as price independent production in the day-ahead market. In figure 3 it is further seen that a part of the wind production was curtailed until 7 o´clock. The wind production is as well offered in the day-ahead market, and some of the wind turbines use a bidding price around 0 protecting them from having to pay for producing electricity in certain hours. In fact, it is seen in figure 3 that the economic curtailments changed both at 6 o´clock and 7 o´clock, showing that wind turbine uses different bidding prices. Why, then, did not all wind turbines stop in these hours? The reason is probably that some of the wind turbines are old wind turbines that are not able to be operated/stopped remotely.

Figure 2: Aggregated electricity productions and consumptions in West Denmark together with day-ahead prices (Spot price) 6th December 2016. These productions and market data are shown online at www.emd.dk.

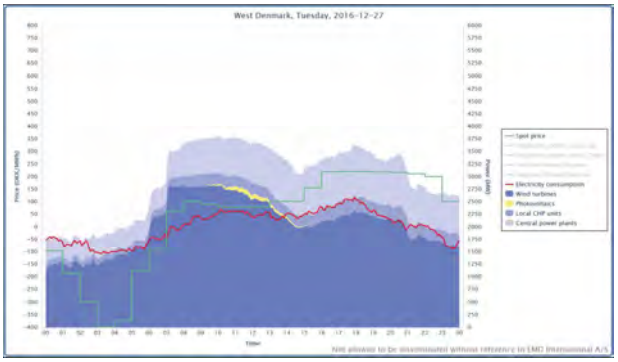

Figure 3: Aggregated electricity productions and consumptions in West Denmark together with day-ahead prices (Spot price) 27th December 2016. These productions and market data are shown online at www.emd.dk.

Wind power and PV with bidding prices around 0 lower the price in the day-ahead market, with negative consequences for CHP. Yearly average day-ahead prices in West Denmark 2011-2016 are shown in figure 4. By 2025, it is estimated that wind power and PV in Germany and Scandinavia will cover one quarter of the production there and thus depress power prices significantly with important consequences for DH and CHP. This side-effect of wind power development causes the Danish TSO to assess that 90 PJ of heat from CHP plants will be decimated to 5 PJ in 2050 when having 100% renewable energy.

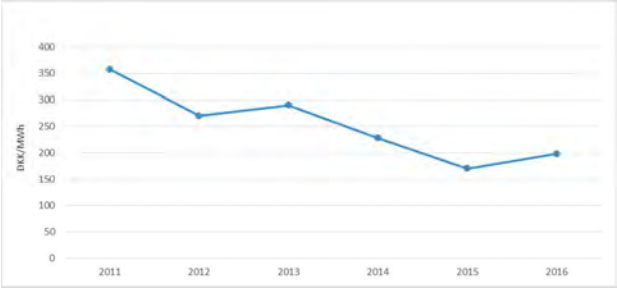

Figure 4: Annual average day-ahead prices in West Denmark 2011-2016

For DHCP CHP to participate in the integration of fluctuating renewable energy, the plants need large electrical capacity and large thermal stores. In a normal situation, wind production is only curtailed in hours with low spot prices and DHCP CHP only produces in hours with high spot prices, which thus makes sure that DHCP CHP do not create unnecessary curtailment of wind. The large capacity and large thermal stores allow DHCP CHPs in the hours with high spot prices to produce excess heat being stored in the thermal stores, this heat being delivered from the thermal stores in hours with low spot prices where the DHCP CHPs are not producing. The effect of this is illustrated in Figure 5.

Figure 5: Simulated operation against the Scandinavian day-ahead market in one week in the autumn of 2015 of a CHP-plant equipped with large electrical capacity and large thermal store. The simulation is made in the energy systems analysis tool energyPRO.

The fixed tariff initially applied for CHPs in Denmark was a triple-tariff with incentives for producing in certain periods of the day and week based on experience. This tariff made it attractive to equip CHPs with large electrical capacity and large thermal stores and in effect also prepared them for the role of providing flexibility. In general, all Danish DHCP CHPs are thus equipped with large thermal stores. As examples, Ringkøbing District Heating delivers app. 110,000 MWh heat to the district heating network and is equipped with a thermal store of 4,500 m3, Hvide Sande District Heating delivers app. 41,100 MWh heat to the district heating network and is equipped with a thermal store of 2,000 m3, and finally Sæby District Heating delivers app. 77,500 MWh heat to the district heating network and is equipped with a thermal store of 2,700 m3. The online operation of these plants are shown at www.emd.dk/energy-system-consultancy/online-presentations

One of the advantages of the triple tariff system was the financial certainty and incentives it established, causing CHP plants that were decided by and operated by non-specialists to be given a design that was also appropriate for flexibility provision. Also, rather than reflecting the short-term marginal costs of the electricity market, price levels in the triple tariff reflected the long-term marginal value of CHP production. Owners of CHP plants are, however, not sufficiently financially robust to sustain the transition to providing capacity only. A Danish capacity payment scheme expires in 2018, beyond which point in time their economic feasibility is stressed.

While CHPs may have a diminishing role to play in the future, DHCP DH still allows various heat sources to be exploited, and in effect, switching DHCPs to being electricity consumers. Being electricity consumers through e.g. heat pumps is a logical consequence of market price levels. What is infeasible for a producer will be beneficial for a consumer. However, as stated in the beginning, optimally, DHCP plants will have both the opportunity to provide efficiency and flexibility through e.g. CHP, heat storages and heat pumps – while at the same time providing capacity when required. Fortunately, through investment decisions made a long time ago, Danish DHCP plants are already partially equipped for this role but to take on the role as capacity provider of the future, further incentives have to be established.

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