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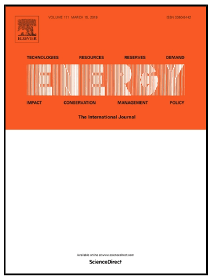

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Analytic versus solver-based calculated daily operations of district energy plants

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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.

Contents

Keywords

- District Energy
- Unit commitment
- Market-based operation
- Smart energy systems
- Daily operation planning
- Yearly budgeting and investment analysis

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 - 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 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 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 minutes, 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 Figure 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.

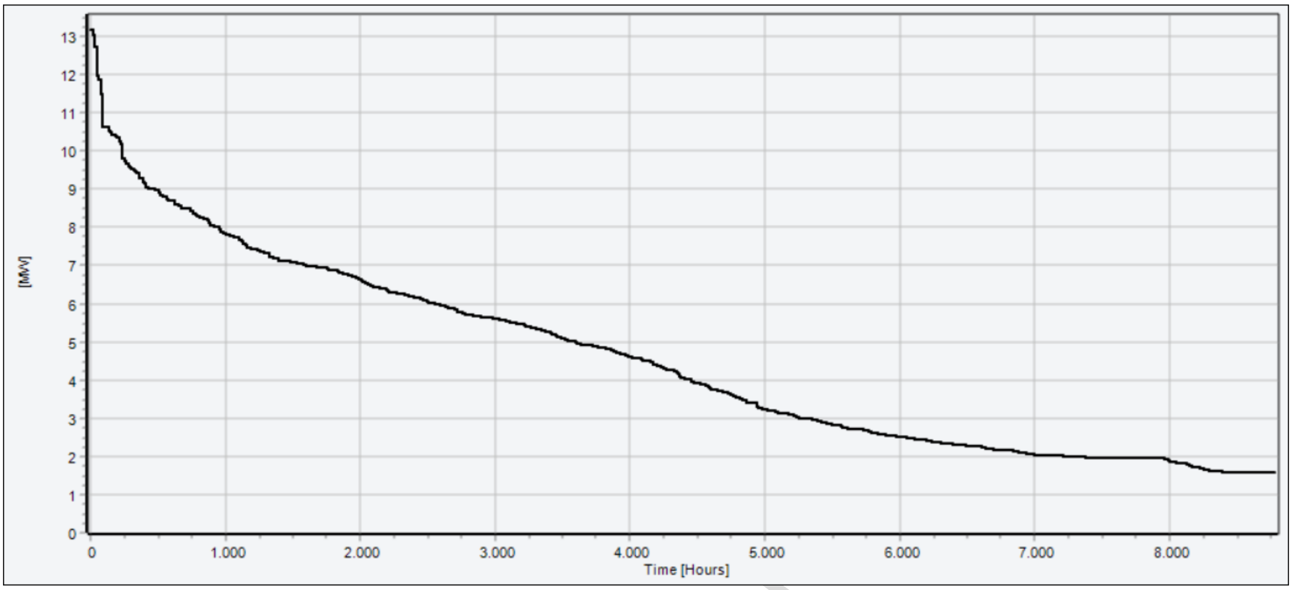

Figure 1: Heat duration curve for the hourly delivered heat from the DE plant.

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 Figure 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 hours. No temporal storage loss is included, and the TES temperatures reflect forward and return temperatures in the DH grid.

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 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 [40]**.**

As shown in Figure 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 the Figure 2.

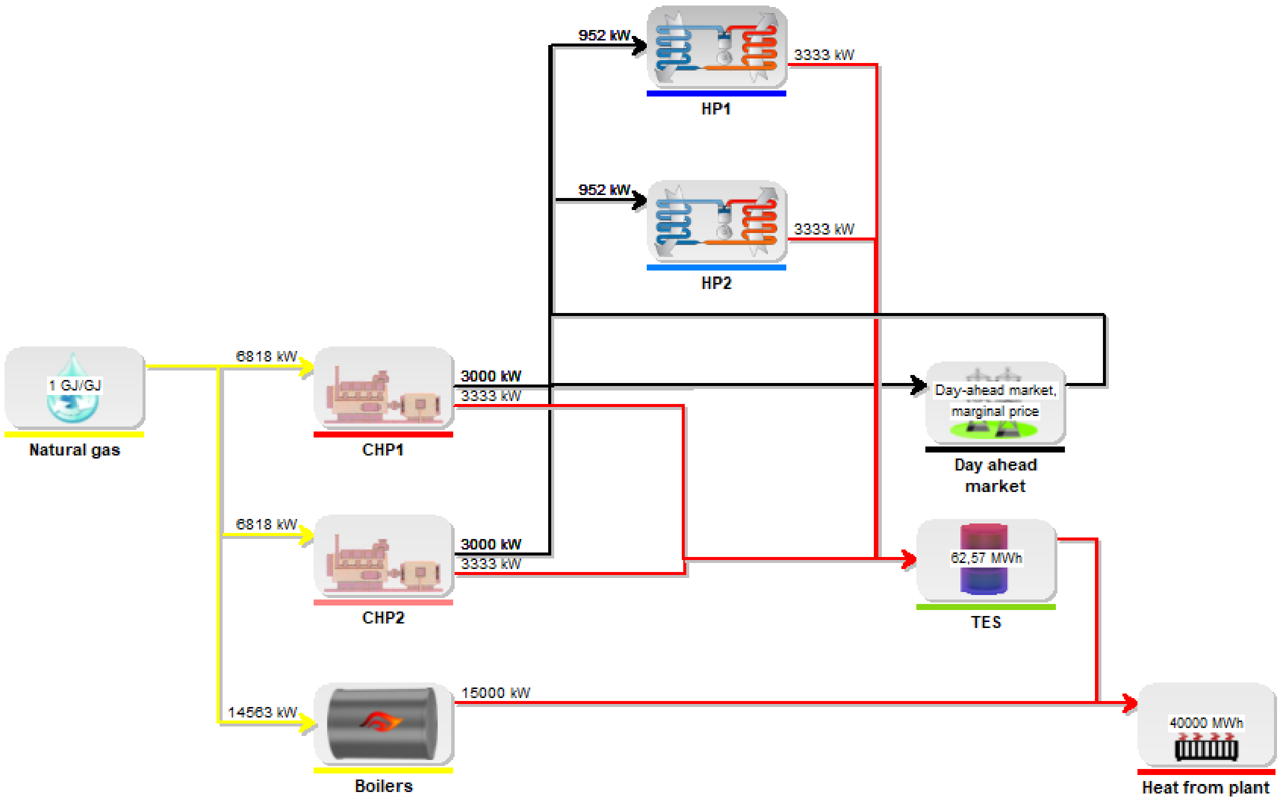

Figure 2: The generic DE plant case consisting of CHP, HP, boilers and TES units.

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 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 Section 2 result in the priority numbers shown in Figure 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 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 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.

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 in Section 2 is shown in Figure 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 Figure 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%.

Figure 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.

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 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.

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:

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

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 Figure 2 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.

4. Tools for testing UC methods

The energy system analysis tool energyPRO [42] is used to calculate the UC made by the advanced analytic UC method and the simple analytic UC method. This is a generalized 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).

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 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.

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 Figure 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 Figure 5 showing the optimal UC during the same 7 days as shown in Figure 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.

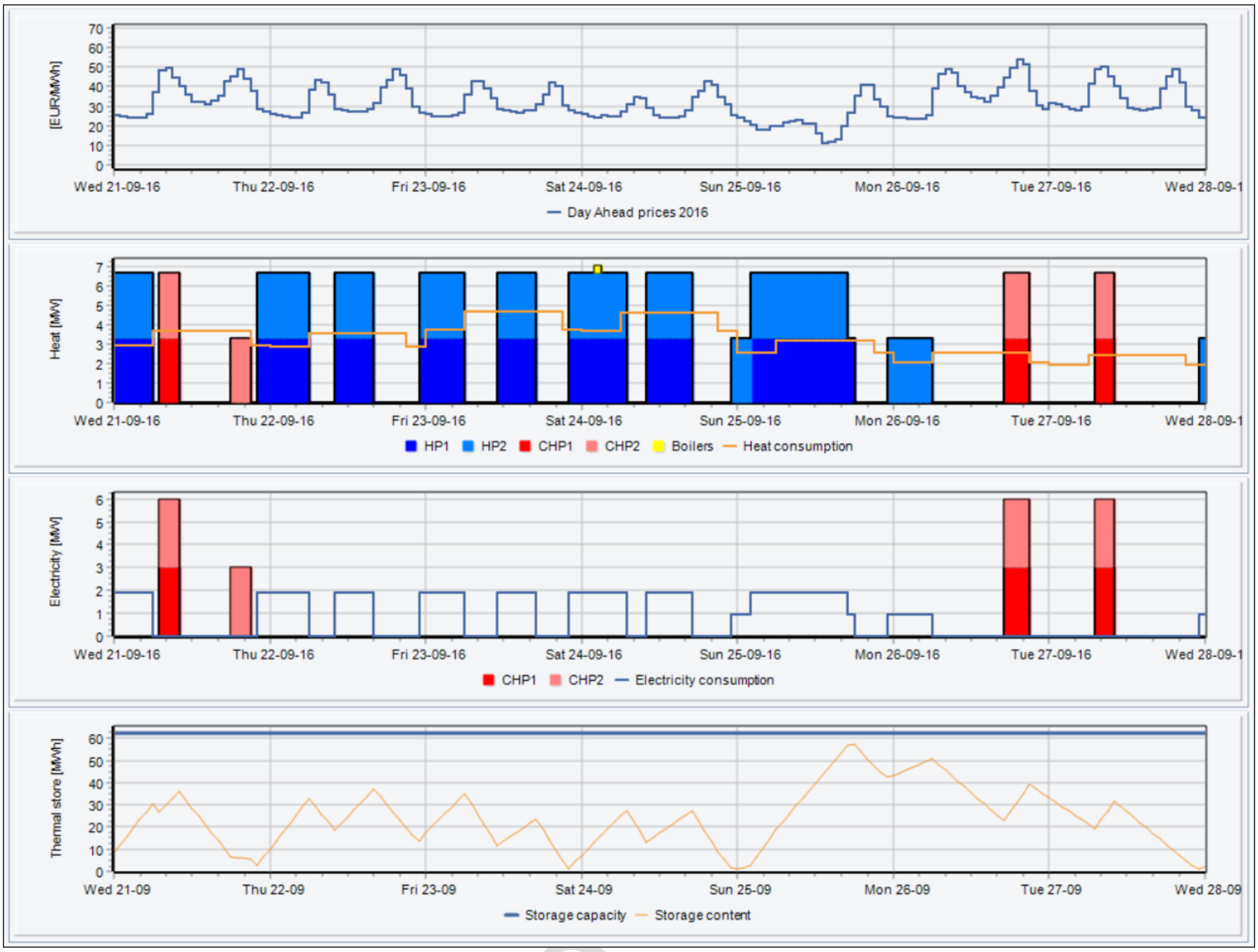

Figure 5: The optimal UC at the DE plant as described in Section 2 for 7 days in September using the solver-based UC method.

The next step in the test is to calculate the NHPC using the simple analytic UC method as described in Section 3.2. Looking at the specific NHPCs in Figure 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.

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 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.

Figure 6 shows the UC calculated with the simple analytic UC method for the same 7 days as in Figure 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.

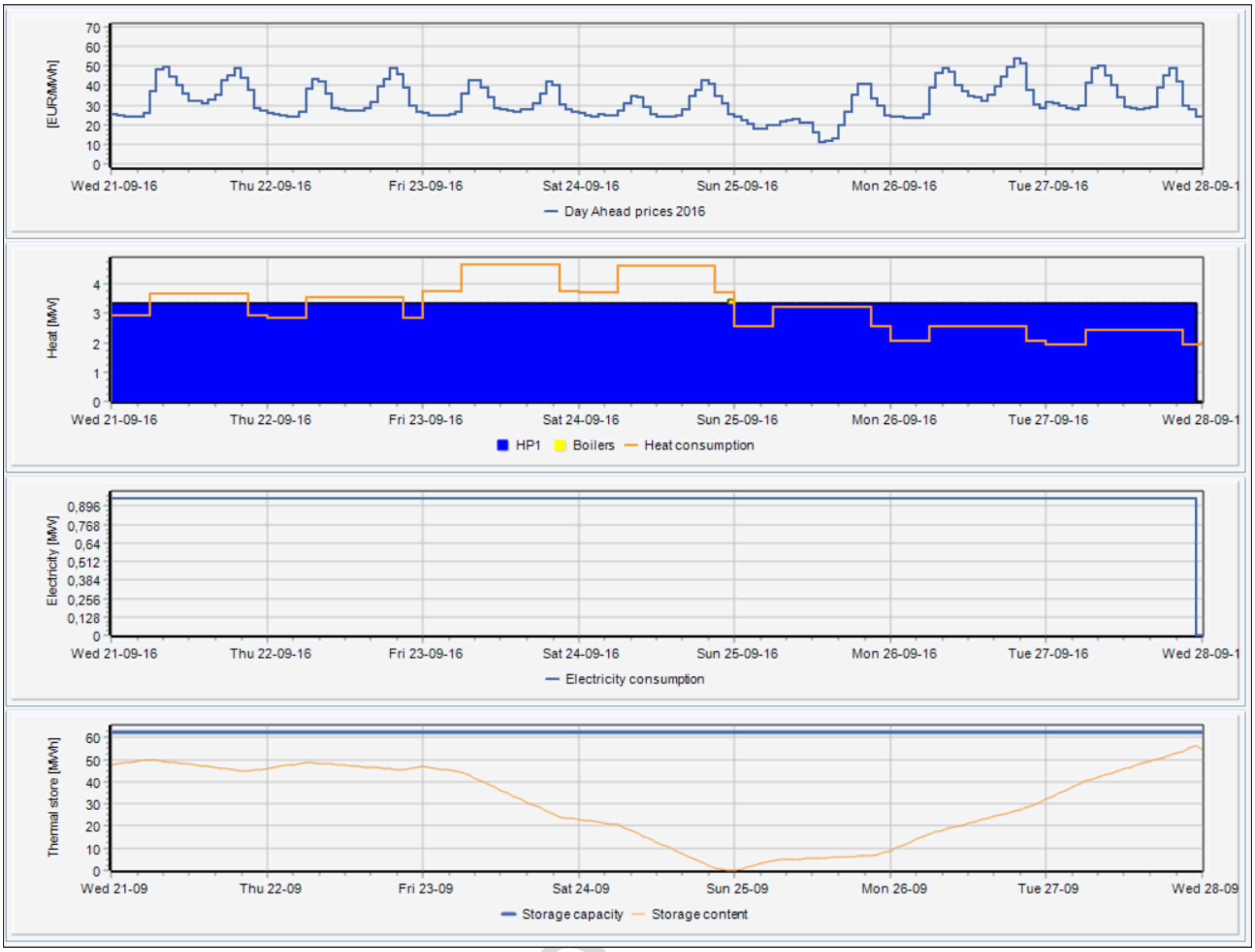

Figure 6: The UC at the DE plant as described in Section 2 during 7 days in September using the simple analytic UC method.

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.

	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 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.

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.

	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 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.

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 Table 7 and Table 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.

	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 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.

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 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.

6. Discussion

This paper demonstrates that the NHPC of the presented 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 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 minutes. 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 optimisation 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 Figure 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 hours 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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Highlights

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

Highlights:

- Flexible District Energy plants are an important part of smart energy systems.
- Research in unit commitment has until now nearly been delimited to solver methods.
- Three different unit commitment methods have been compared.
- An advanced analytic method delivers adequate unit commitments.
- Analytic methods for unit commitment are in cases superior.