Decentralised CHP in a competitive market

Danish energy policy has succeeded in stabilising primary energy supply during a period of 30 years of economic growth. A high priority given to combined heat and power (CHP) production has been one of the important elements in achieving this success.

In order to promote and encourage the use of decentralised CHP plants, many countries have introduced schemes holding various favourable market incentives for selling electricity in the past. Meanwhile, so far very little attention has been given to the fact that such rules and regulations play a major role in defining optimal performance for the CHP plants when optimising the income from selling electricity. Consequently, such conditions also influence the design of new CHP plants.

It is shown in this article that the ability of a CHP plant to earn money at the liberalised spot market and balancing markets (an aftermarket for spot trading of electricity in Sweden and Finland) very much depends on the initial design of the CHP plant. The article emphasizes that any intermediate favourable market conditions for selling electricity should promote the design of CHP plants in a way that will allow these to be able to survive in a future liberalised and competitive market.

Decentralised CHP plants: an important part of energy supply

Combined heat and power production (CHP) is a very efficient way of transforming fuels into energy services. Compared to the conventional approach of producing heat and power in separate plants, CHP plants offer the potential of decreasing fuel consumption by 20-30% when produc-

(see figure 1). Today, more than 50% of the electricity is produced on CHP plants, and half of it is coming from decentralised CHP plants.

CHP is also essential for the implementation of European climate change response objectives, and the various technologies are intended for further expansion in the near future. The EU strategy is to double the electricity production from CHP from 9% in 1994 to 18% in 2010. Other important EU goals are that by 2010, 22.1% of the total EU electricity consumption in 2010 should be coming from renewable energy sources (RES), and CO2 emissions should be reduced in accordance with the Kyoto agreement. Generation from decentralised CHP plants plays an important part in achieving all three objectives.

The introduction of liberalised electricity markets is also important to the European Communities. Consequently, the promo-

Figure 1. More than 400 DH and CHP plants cover the country of Denmark and the most dominant type by far is the decentralised CHP plant.
tion of decentralised generation in Europe as well as in most other parts of the world is now to be seen in the context of selling electricity on competitive electricity markets.

Market conditions influence performance and design

In Denmark, the market conditions for CHP plants changed fundamentally in the beginning of the 90's and are now again in the process of being revised fundamentally. Due to the long tradition of CHP in Denmark, most CHP plant operators have many years of experience in identifying optimal performance and optimal investment design under different conditions. Software applications are used by the majority of Danish CHP plant operators and their consultants to illustrate how optimal performance and investment design can be identified and how they change from one market condition to another.

The following four different market conditions have been identified from the historical and the expected future development in Denmark.

Market condition 1: Introduction stage (fixed sales prices)
Market condition 2: Market adaptation stage (triple tariff according to demand variations)
Market condition 3: Market introduction (sale on spot markets)
Market condition 4: Full market introduction (sale on balancing markets)
Market condition 1: Introduction stage (fixed sales prices)

The implementation of decentralised CHP in Denmark started with only a few plants. The experience obtained with these plants and the solution of the technical problems in the initial stage helped gain confidence in this new technology and made the technology known to other local energy companies.

The produced electricity was sold on a contract with a fixed price and a grant subsidy. This meant that the price did not vary and was a unit tariff. In this very beginning, designing optimal CHP investments was fairly simple. The Danish consultancy companies typically used heat duration curve calculations, as shown in figure 2.

Market condition 2: Market adaptation stage (triple tariff according to demand variations)

Ten years ago, the adaptation to market conditions started. The CHP plants left the unit tariff to follow a triple tariff price structure based on a theoretical market price curve, reflecting that the price for electricity is higher when electricity demands are high in the morning and the late afternoon. Electricity is sold according to the triple tariff (an example is shown in table 1), where the price varies in accordance with typical variations in the demand. The variation is known in advance and does not change if, for example, the demand changes.

The principles behind the Danish price system were decided by the Danish Parliament. The basic idea is that the system operators are obliged to buy electricity from CHP plants of more than 6 kW electricity fuelled by natural gas, biomass or waste. The price should be equivalent to the costs of producing and transporting electricity on alternative units. The production costs are defined as the long-term marginal costs of producing electricity on a combined cycle power station fuelled by natural gas. Such costs include fuel, operation and maintenance costs and investment costs. The transportation costs include saved grid losses and saved investment costs in transmission capacities due to the decentralised locations of small CHP plants. The law defines in detail how to calculate the sales prices. The investment costs are adjusted by the net price index and the fuel costs are adjusted according to the development in international fuel prices. The other parameters influencing the operation of the CHP plant revenues within the law. At present, this principle results in an average electricity price of approximately 40 Euro/MWh.

Over the last ten years, the decentralised CHP plants in Denmark have got a lot of experience in optimising their electricity production against the triple tariff. Therefore, the CHP plants have a long-term experience in optimising when to switch the CHP units on and off and when to replace production in order to optimise their profit. The CHP owners have a long-term experience in designing their plants. The triple tariff structure resulted in decentralised CHP plants in Denmark investing in an over-capacity of the CHP units combined with thermal storage capacity. This design approach means that the plants can increase their performance in the highest paid periods, thereby optimising their revenues. More advanced software tools are needed when analysing and optimising the operation of CHP plants in market condition 2 as shown in figure 3.

Market condition 3: Market introduction (sale on spot market)

This year, the decentralised CHP plants in Denmark are leaving the triple tariff and will start to sell electricity at fluctuating market prices in the Scandinavian spot market (Nord Pool), which is organised as a day-ahead spot market, in which prices vary from hour to hour depending on variations in demand, water supply for hydro power and fluctuations in wind power. The implementation of liberalised electricity prices based on market conditions is the primary reason why the Danish system operators have financed several new development projects in which methods and tools for bidding at the spot market and the regulating power market are being developed. EMD International has received funding from system operators for developing methods that offer the answer to the following question, and more:

How does a CHP plant make optimal bidding at the spot market if, at the same time, it is going to optimise its earning at the regulating power market, taking into account limitations in heat demand and thermal storage?

Table 1. The triple tariff electricity sales price setting of the Danish TSO, Eltra.

<table>
<thead>
<tr>
<th>Type</th>
<th>Hours</th>
<th>Days of the week</th>
<th>Month</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak load</td>
<td>8:00-12:00</td>
<td>Monday-Friday</td>
<td>January-December</td>
<td>72 Euro/MWh</td>
</tr>
<tr>
<td></td>
<td>17:00-19:00</td>
<td>Monday-Friday</td>
<td>October-March</td>
<td></td>
</tr>
<tr>
<td>High load</td>
<td>6:00-21:00</td>
<td>Monday-Friday</td>
<td>January-December</td>
<td>56 Euro/MWh</td>
</tr>
<tr>
<td></td>
<td>(except from peak load)</td>
<td>Monday-Friday</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low load</td>
<td>The rest</td>
<td>Monday-Sunday</td>
<td>January-December</td>
<td>24 Euro/MWh</td>
</tr>
</tbody>
</table>

Some of the developed methods are described in the following:

An initial step is to determine how many days are considered as planning periods, when using the methods for optimal bidding at the spot market.

Using a period of only one day ahead is for most CHP plants too short an optimisation period. The risk would be to plan overproduction for tomorrow, filling the heat accumulator and thereby lose higher paid productions in the following days.

In our test cases we decided to look at a period of 7 days ahead. By using such a long planning period, it will be possible not to lose any production of electricity in the highest paid hours in the following days.

The first step in bidding at the spot market is to calculate the net heat production cost. This involves the cost of producing 1 MWh heat at each production unit at the plant. To do this, it is necessary to fill out the sheet shown in figure 2 for each production unit. It makes it easier to have these sheets in an Excel spreadsheet as the net heat production cost will depend on the value of the electricity sale. Depending on the actual efficiency, a typical CHP unit will normally produce 0.8 MWh of electricity when it is producing 1 MWh of heat. The value of the electricity will vary each day on the basis according to the actual spot market prices.

Based on the net heat production cost sheets it is now possible to determine an intersection price for the electricity spot price where the CHP units and the boilers at the energy plant will produce heat at the same price. At a spot price lower than the intersection price, the boilers will produce the cheapest heat, while at a spot price higher than the intersection price, heat from the CHP units will be cheapest.

The CHP/biogas intersection price is used to divide the coming days into three categories of hours (A, B and C. Figure 4 shows these three types of hours.

In the A-hours, the CHP units will produce the heat cheaper than the boilers. The first task when planning the coming production is therefore to make sure that as much as possible of the coming production will take place as CHP production in the A-hours.

Table 2. Sheet for calculating the net heat cost of producing 1 MWh heat for each production unit at the plant.
In the C-hours, the boilers will produce heat cheaper than the CHP units. During these hours it is therefore important that the operation of the CHP units is given a higher priority than the operation of the boilers.

When optimizing against the spot market prices compared to optimizing against the old triple tariff, the operation of the CHP units shall always be given higher priority than the boilers in the B-hours. If a heat demand still exists after the CHP units have been planned to produce in the A-hours, the CHP units should be planned to continue producing in the B-hours until the heat demand has been fulfilled. The reason for this can be explained as follows: Assuming that on the basis of the planning the CHP plant decides to make bids only in the A-hours, and it subsequently turns out that the actual market prices in the B-hours are better than the prognosis estimated and also above the CHP boiler intersection price, then the plant could have generated a higher income, if it had also put in bids in the B-hours where the heat demand was not fulfilled, instead of producing this amount of heat on boilers.

Based on the calculated planned productions, the CHP plant will now send bids to the spot market for electricity supply in each of the different hours next day at prices equal to minimum the calculated CHP boiler intersection price. It should be noticed that the hourly spot market price paid (market cross point price) is the same to all the producers who have won a contract, despite the fact that they have given different bids prices.

The new methods and tools developed for bidding at the spot market is being tested this year at selected CHP plants and will be available from EMD International as a new software tool in the near future.

Earning money at the spot market increases uncertainty and risk, and giving up the triple tariff will probably result in a situation where the present owners of the distributed CHP plants will not continue to invest in their plants themselves due to uncertainty and increased risk, but will instead form alliances or merge with large energy companies.

Market condition 4: Full market introduction (sale on balancing markets)

Within the next three years, the distributed CHP plants are expected to move further towards liberalisation by selling more advanced electricity products. These advanced products are the deliverance of the ancillary services:

- Primary reserves (automatic services)
- Regulating power (manual services)
- Upward regulating reserves (manual services)
- Downward regulating reserves (manual services)

These services take care of the balancing between production and consumption.

The system operators must have access to power plants to balance the deviation between scheduled and actual productions and consumptions. For this purpose, the system operators in the Nordic countries have established a market for trade in energy in the operational moment – the regulating power market.

In certain situations, the system operators cannot know in advance if sufficient resources are available in the regulating power market. This may be the case if there is a large deviation between scheduled and actual operation, e.g. outages of large power plants or a major fault on the transmission lines. As a result, the system operators must purchase regulating power reserves to be certain that sufficient regulating power is offered to the regulating power market every hour even in these situations.

This means that the system operators pay selected plants to hold back power from the spot market and instead offer this power at the regulating power market every hour. Other plants are welcome to do the same, which means that the selected plants are not guaranteed to win any regulating power contracts (see table 3).

At the moment, the decentralised CHP plants lack experience in offering these services. As part of the above-mentioned development projects, new tools for optimal bidding at the regulating power market as well as the regulating power reserves are being developed.

The minimum bidding price for regulating power and regulating power reserves are calculated as the “lost earning” at the spot market. The bidding price is established through a double calculation. Initially, an estimation of the expected future earning at the spot market is made. After this, the plant reserves some of the capacity for the regulating power market and with this restriction in mind again estimates the expected future earning at the spot market. The difference in the earnings constitutes the minimum offer at the regulating power market.

The expected price levels for regulating power reserves offer the Danish plants an annual profit of approx. 30,000 Euro for each MW that they offer to this reserve market. For many, this is expected to be attractive, as they have installed rather big electrical capacity and heat accumulators.

The described bidding methods for regulating power and regulating power reserves are presently being tested at several Danish co-generation plants.

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