Market Compatible Integration of Renewable Electricity Generation – Potential and Economics of Biomass/Biogas-CHP Units

A. Ortner

***Abstract*--High shares of variable renewable energy generation (v-RES) increasingly challenge the operation of Europeans power systems. One promising option to balance fluctuations of v-RES is to utilize the potential generation flexibility of biomass-/biogas combined heat and power generation units (CHP). In this respect it is necessary to enable these technologies to participate in intraday control energy markets. Based on historical data of 2010 this paper analyses the potential revenues of two biomass CHP-units in the German secondary control energy market and the cost sensitivity of various relevant parameters which are affected by the altered operation of the units. It concludes with potential support cost savings compared to the present support scheme via feed-in-tariffs (FIT).**

***Index Terms*--RES-electricity generation, biomass/ biogas- CHP, market value, financial support instruments, regulating power, Austria, Germany**

I. Introduction

IN recent years, renewable energy electricity generation (RES-E) has become an important cornerstone in the electricity generation portfolio in many European countries. In order to further significantly increase RES-E shares, the development of market-compatible grid and market integration mechanisms of RES-E generation apart from inflexible financial support instruments is necessary to (i) fully exploit the operational benefits of the different RES-E generation technologies for the electricity system and (ii) to reduce market intervention and “subsidies” in the segment of RES-E integration.

In terms of market-compatible renewable technology integration, the future potential of biomass/biogas combined heat and power production (CHP) is one of the most undervalued renewable technologies so far. More precisely, at present inflexible financial support schemes (e.g. fixed feed-in tariffs) and insufficient market design (especially tendering procedures and rules for regulating power) exclude biomass/biogas-CHP units to exploit its full market potential and to significantly contribute to balance the online electricity system with high shares of variable RES-E (v-RES) generation like wind and PV.

Currently in most European countries CHP producers have no clear incentive to participate in competitive energy markets [3]. For instance, due to the guarantee to receive a certain fixed feed-in tariff CHP-units in Austria are almost exclusively operated in base-load and do not make use of their capability to adjust the output on short notice [10]. Also the prequalification criteria in control energy markets are not designed to foster the integration of CHP units. For example, the minimum bid size of 5MW excludes a significant number of small-scale CHP units from the Austrian control energy market [14]. In this respect it has to be checked to what extent whether such plants should be obliged to submit a combined offer via a so called “virtual plant”, or the participation conditions should be adapted. The questions arise concern on the one hand the field of topics on how control energy markets have to be amended in order to foster the participation of decentralised CHP units and on the other hand which measurements are needed to allow CHP units to utilize their full flexibility and to offer both positive as well as negative control energy.

At this time not much practical experience on the flexible operation of CHP units has been made so far. One distinguished example for the successful integration of high shares of v-RES is Denmark, where comprehensive experience with the operation of decentralised (mainly gas-fired) CHP-units in the different electricity market segments, most notably in the intraday regulating power market exists [5]. First approaches identified additional components (hot water boiler, heat pumps, electrical heating, upgraded control systems, etc.) that have to be in place to fully enable CHP units to participate in the positive as well as negative control energy market while fulfilling their obligations related to the supply of heat.

In terms of the design of future support policy it needs to be reflected on various measurements to incentivise the participation in the control energy market (e.g. investment subsidies for heat storages). For instance, in Austria as well as in Germany the rules and procedures in the renewable segment are currently subject to fundamental changes (e.g. EEG2012 in Germany is comprehensively discussed a present, [1], [2]; similar in Austria, [4]) – has to be amended to fully exploit the market-driven potential of biomass/biogas-CHP technologies, most notably to enable the contribute in the intraday control power market.

As a first step this paper analyses the potential revenues of two representative biomass CHP-units in the Austrian secondary control energy market and the cost sensitivity of various relevant parameters, which are affected by the altered operation of the units. It concludes with potential support savings compared to the case compared to the present support scheme via feed-in-tariffs (FITs).

II. DATA

The market prices from 2010 serve as a base for the calculation of the economics. Hourly spot market data from EEX[1] are applied to calculate the potential profit under the assumption of an exclusive participation in the German spot market. Fig. 1 illustrates the price duration curve as well as the histogram and the corresponding expected probability density function of the spot prices. It can be shown that the prices of 2010 are well reproduced via applying a normal distribution with an average of 44.81 €/MWh and a standard deviation of 13.64 €/MWh. For the purpose of further research the probability distribution functions of several years should be used to produce stochastic spot market values. However, within this paper it is assumed that the spot market prices of 2010 are perfectly known in advance.

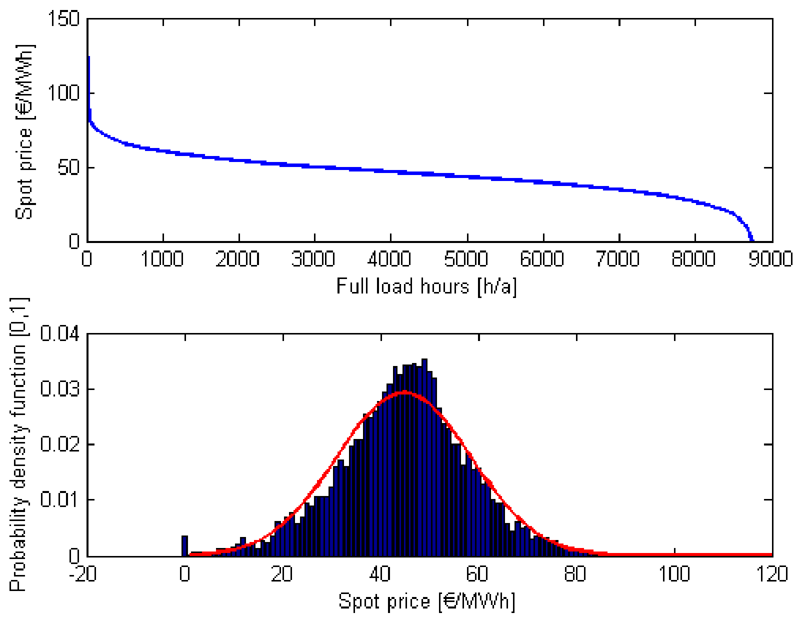

Fig. 1. Annual spot market price duration curve and corresponding histogram with expected probability density function in 2010

Fig. 2 and Fig. 3 depict the time-resolved number of calls in the Austrian secondary and tertiary control energy market respectively in the years 2006 till 2010. By the time being no data has been collected for the tertiary control energy market of Germany. However, due to the fact that the control energy markets in Austria and Germany show similar characteristics the data from Austria serves as a proxy for the decision which control energy market are most profitable for CHP-units.

[1] http://www.eex.com

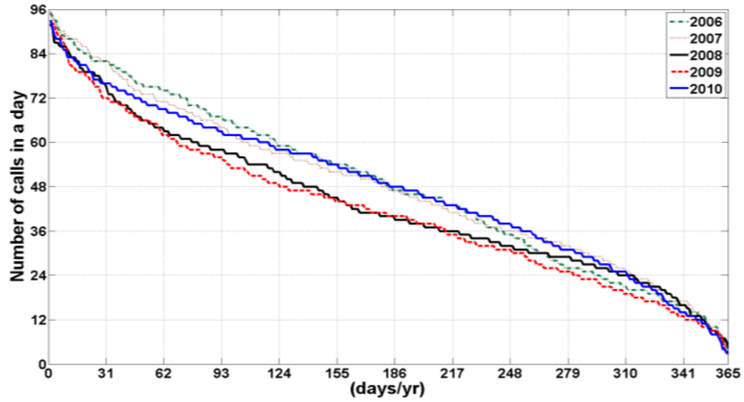

Fig. 2. Calls in the Austrian secondary (positive) control energy market for the years 2006 to 2010 [12]

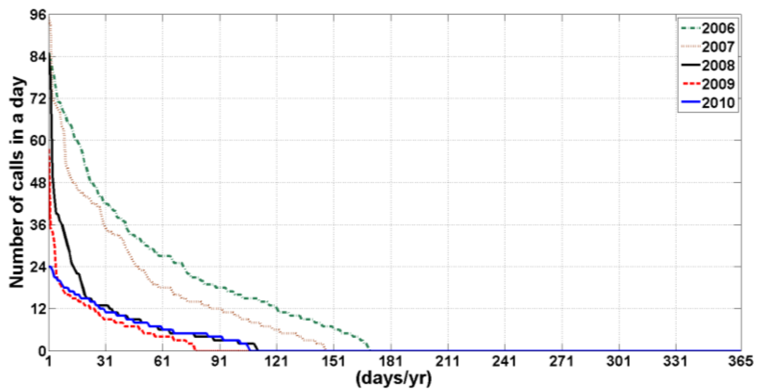

Fig. 3. Calls in the Austrian tertiary (positive) control energy market for the years 2006 to 2010 [12]

It can be seen that the number of calls in the tertiary market are significantly lower than the ones in the secondary market. Calculations show that although there is a higher price level in general the potential revenues in the tertiary sector are lower than in the secondary market due to the lower probability of dispatch (PoD) [12]. From this viewpoint a participation in the secondary market seems more profitable and for that reason the following analysis will focus on the secondary control energy market.

Quarterly data for requested regulating power in the German control energy market during 2010 have been taken from the transparency platforms of the transmission system operators (TSOs) in Germany [15][16][17][18]. The duration curve of the requested control energy for both the positive and the negative control energy market are depicted in Fig. 4. One should notice that in 2010 a significant amount of positive control energy has been requested. Therefore the potential revenues might be overestimated as the share of positive and negative control energy could be significantly different, especially in the light of the integration of high shares of v-RES one can assume that the need for negative control energy will increase.

Furthermore, it is assumed that the control area balance is zero at any point in time. That means that the request of positive and negative control energy are mutually exclusive and implies that simultaneous bidding in positive and negative control energy markets is theoretically possible.

A further assumption is that the profit calculation within this paper abstracts from different markets products concerning the time period of delivery.

Tab. 1 and Tab. 2 show the average, minimum and maximum levels of energy and power prices both for negative as well as positive control energy in 2010. Reference [8] includes a concise summary of the occurred prices and additional statistical calculations for the period of May to December 2010.

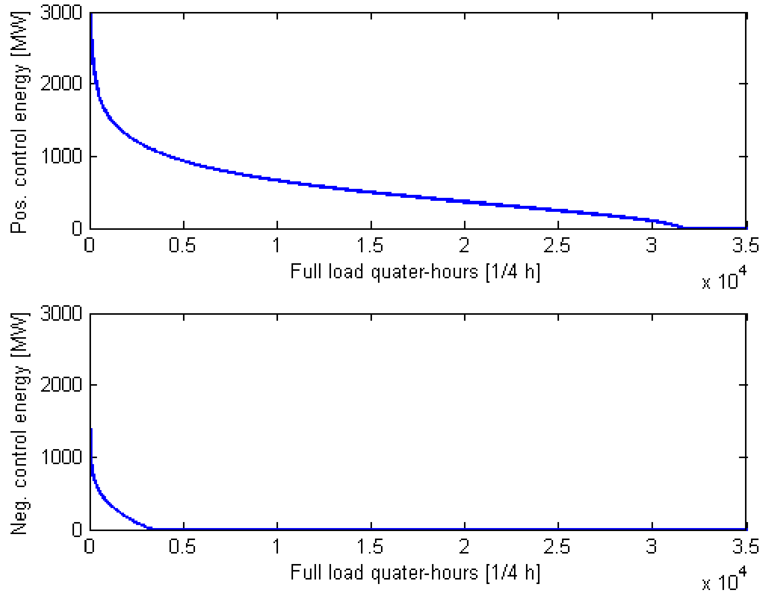

Fig. 4. Quarterly load duration curves of the German control energy market in 2010.

Tab. 1. High time auction data for positive control energy in Germany in 2010

Energy price	*Unit*	*Value*
Average	[€/MWh]	139.98
Median	[€/MWh]	119.00
Maximum	[€/MWh]	345.00
Minimum	[€/MWh]	61.00
Power price	*Unit*	*Value*
Average	[€/MW/month]	3671.64
Median	[€/MW/month]	3712.56
Maximum	[€/MW/month]	5695.32
Minimum	[€/MW/month]	2250.60

Tab. 2. High time auction data for negative control energy in Germany in 2010

Energy price	*Unit*	*Value*
Average	[€/MWh]	21.80
Median	[€/MWh]	12.00
Maximum	[€/MWh]	160.00
Minimum	[€/MWh]	-24.00
Power price	*Unit*	*Value*
Average	[€/MW/month]	6216.12
Median	[€/MW/month]	6997.32
Maximum	[€/MW/month]	20218.2
Minimum	[€/MW/month]	312.48

Since December 2006 the tendering of control energy are handled commonly by all German TSOs via the internet platform *regelleistung.net* [13]. The balancing areas of the individual TSOs have been connected and the started the so called *Netzregelverbund (NRV).* Since the beginning, additional countries have joined the NRV. Fig. 5 shows the resulting merit-order curves of the tendering of control energy in the NRV in 2010.

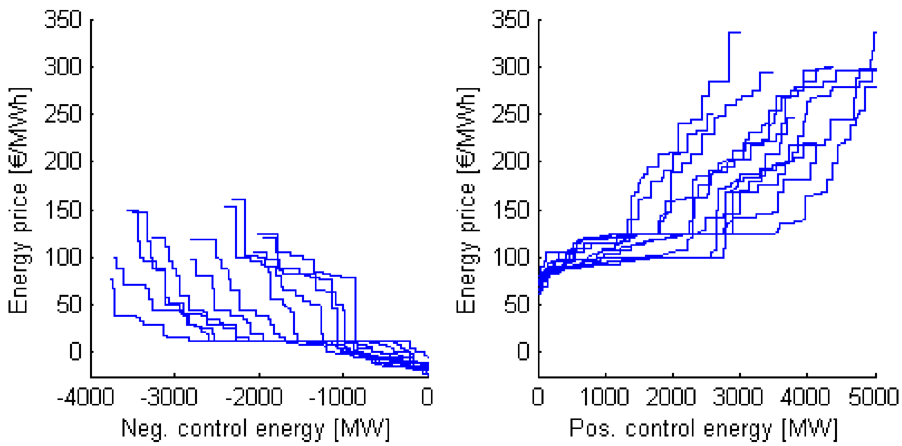

Fig. 5. Monthly merit-order curves of control energy prices in Germany in 2010.

The data for the CHP-units observed in this paper were taken from a techno-economic study [6] conducted within the IEA Bioenergy Agreement Task 32 project and are related to two realised CHP-projects in Denmark and Austria.

The Danish CHP-unit (CHP1) consists of a steam turbine process and has an electric capacity of 4.4 MW_{el}. It is mainly operated in a heat-controlled mode and is connected to a district heating network. Due to additional components like a peak load system and a hot water boiler the plant can balance variations in heat demand while keeping the CHP-output constant. For this reason it is able to achieve approximately 5,500 full load hours. The relevant technical data of CHP1 are shown in Tab. 3. The second CHP-unit (CHP2) is located in Austria and utilizes an Organic Rankine Cycle (ORC) process. Similarly as CHP1 it is operated in heat-controlled mode and reaches about 5,500 electric full-load hours. The produced heat is fed into a city heat network. Additional components are a heat recovery unit and a peaking boiler to balance the heat demand fluctuations. The corresponding data are shown in Tab. 4.

Tab. 3. Technical parameters of CHP1

Parameter	*Unit*	*Value*
Electric capacity CHP (nominal conditions)	[kW_{el}]	4,700
Useful heat capacity CHP (nominal conditions)	[kW_{th}]	14,000
Full load operating hours CHP	[h/a]	5,500
Annual electric efficiency	[%]	22
Annual total efficiency	[%]	92
Electrical flow index	[-]	0.34

Tab. 4. Technical parameters of CHP2

Parameter	*Unit*	*Value*
Electric capacity CHP (nominal conditions)	[kW_{el}]	1,100
Useful heat capacity CHP (nominal conditions)	[kW_{th}]	4,969
Full load operating hours CHP	[h/a]	5,500
Annual electric efficiency	[%]	14.5
Annual total efficiency	[%]	88
Electrical flow index	[-]	0.2

The economic calculations of the CHP generation units have been performed on the basis of the guideline VDI 2067 accordingly to the calculations in [6]. The guideline dictates to divide the different types of costs in the categories capital costs, consumption costs, operation costs and other costs. Additionally, in case of combined heat and power production processes, the costs for electricity and heat generation have to be declared separately. The investment costs related to heat generation comprise all costs accruing to meet a given heat demand. The additional investment costs needed to upgrade the plant to a CHP-unit form together the electrical investment costs. Tab. 5 and Tab. 6 show the corresponding electrical cost calculations of CHP1 and CHP2.

Tab. 5. Cost structure of CHP1 [6]

Parameter	*Unit*	*Value*
Capital costs	[€]	12,770,000
Capital costs	[€/a]	1,621,802
Specific capital costs	**[€/kWh$_{el}$]**	**0.063**
Consumption costs	[€]	5,915,995
Consumption costs	[€/a]	751,337
Specific consumption costs	**[€/kWh$_{el}$]**	**0.029**
Operation costs	[€]	1,984,670
Operation costs	[€/a]	252,055
Specific operation costs	**[€/kWh$_{el}$]**	**0.010**
Other costs	[€]	1,070,858
Other costs	[€/a]	136,000
Specific other costs	**[€/kWh$_{el}$]**	**0.005**
Total electricity generation costs	[€/a]	2,761,194
Specific total generation costs	**[€/kWh$_{el}$]**	**0.1068**

Tab. 6. Cost structure of CHP2 [6]

Parameter	*Unit*	*Value*
Capital costs	[€]	2,973,998
Capital costs	[€/a]	404,071
Specific capital costs	**[€/kWh$_{el}$]**	**0.073**
Consumption costs	[€]	1,241,301
Consumption costs	[€/a]	168,653
Specific consumption costs	**[€/kWh$_{el}$]**	**0.031**
Operation costs	[€]	618,233
Operation costs	[€/a]	83,998
Specific operation costs	**[€/kWh$_{el}$]**	**0.015**
Other costs	[€]	218,889
Other costs	[€/a]	29,740
Specific other costs	**[€/kWh$_{el}$]**	**0.005**
Total electricity generation costs	[€/a]	686,462
Specific total generation costs	**[€/kWh$_{el}$]**	0.1248

The specific generation costs

$$c_{TOT} = \sum_j \frac{\alpha_j \cdot I_j}{C \cdot T} + \frac{p_{prim}}{\eta} \qquad (1)$$

I_j … Investment costs of component j [€]
C … Nominal plant capacity [kW]
T … Full-load hours [h/a]
p_{prim} … Price of primary fuel [€/kWh]
η … Annual efficiency [%],

whereas

$$\alpha_j = \frac{(1+i)^{n_j} \cdot i}{(1+i)^{n_j} - 1} \qquad (2)$$

i … Interest rate
n_j … Depreciation time of component j,

is the capital recovery factor CRF, have been derived for heat as well as electric generation costs by splitting the investment costs into heat and electricity related shares according to [6]. The investment costs of the certain components are summed up by taking into account their different depreciation time. In case of the electric components the depreciation time has been assumed to be 10 years for each component, which are intended to reflect the duration of financial support[2].

The costs calculated in Tab. 5 and Tab. 6 are a result of the base load operation of the plants and assume for both units a discount rate of 6% [6]. The actual specific generation costs are a function of the full-load hours and therefore sensitive to the operation pattern of the CHP.

III. Methodology

In this paper the focus is on the analysis of the necessary support which is needed to cover the generation costs of the CHP units by comparing the resulting revenues and costs of a participation in the spot market as well as the secondary control energy market.

A. Market Revenues

The base load operation serves as a benchmark to analyse the actual necessary support of the CHP units. The difference between the earned revenue from the sport market and the generation costs are defined to be the *base support*. In case of a Feed-in tariff (FIT) as support scheme of the CHP-unit the base support reflects the actual financial support needed to cover the generation costs.

The revenues on the spot market are calculated on an hourly basis by

$$R_{Spot} = \sum_h p^h_{Spot} \cdot C \qquad (3)$$

p … Spot market price at hour h [€/MWh]
C … Nominal capacity [MW].

Therein it is assumed that the plant does have an availability of 100% and participates 8760 hours with its nominal capacity in the spot market.

In the case of the control energy market it is assumed that the plant offers positive as well as negative control energy simultaneously. This is feasible because positive and negative control energy are mutually exclusive and the plant can offer its full available capacity in both market segments due to the fact that an increase of output in one segment equates to an decrease of output in the other segment and vice versa. Furthermore it is assumed that each plant does have a minimal load of 30% from its nominal output. An operation below that limit is not possible due to technical and process restrictions. The offered amount of energy in the control market is determined by the ability of the plant to change its output and the condition that the plant has to be operated above its minimal load limit. For both plants it is assumed that they can change their output by 20% per minute [11]. Based on this assumption and the prequalification requirement of the secondary market that each actor has to provide its offered power within five minutes this restriction does not limit the potential power which can be offered by the CHP units. As a result the only barrier for the capacity to be offered is the minimal load limit. However, the maximum capacity to be offered by the CHP unit is calculated through

$$C_{Sec} = 0.7 \cdot \Delta C \cdot 5\min \cdot C \qquad (4)$$

[2] At present in Austria CHP-units are granted a financial support over a period of 15 years and in Germany this period is 10 years [9][10]. Therefore an assumption of 10 years can be seen as conservative.

ΔC … Ability to adjust output [%/min]
C … Nominal capacity [MW].

The remaining capacity is assumed to be sold on the spot market.

One further aspect concerning the potential revenue on the control market is the level of the power and the energy price. In Germany the award procedure for control energy is carried out via the procedure stated in [13]. It foresees a ranking of the incoming bids per power price. Bidders with the lowest power price who fall into the tendered amount of control energy and fulfil the technical requirements are accepted to participate in the market. Each bidder receives the power price he offered (pay-as-bid procedure). The actual order of request of control energy is fixed by building the merit-order of the energy prices. The participants are called in increasing order accordingly to their offered price. Each participant receives the price of the marginal unit (marginal pricing). Given the fact that each bidder chooses the power and the energy price for its offer, the award procedure implies two expectations:

First, the higher the power price, the lower the probability that an offer will be accepted by the party issuing the invitation to bid. Second, the higher the energy price, the lower the probability that a certain offer will be requested. This probability is determined through the merit-order price curve and the actual need for control energy.

To adequately map the dependency of the success of the bidding from the power price a Bayesian approach were chosen as applied in [19]. The distribution of the maximum power prices of the years 2009, 2010 and 2011 were collected and their distributions were estimated. By building the cumulative distribution function the probability of dispatch are calculated via (1-cdf (power price)). It is assumed that the participation of the single CHP-units does have no influence on the merit-order and there is no strategically bidding of the remaining market participants.

The maximum power prices and the corresponding distribution functions are shown in Fig. 6.

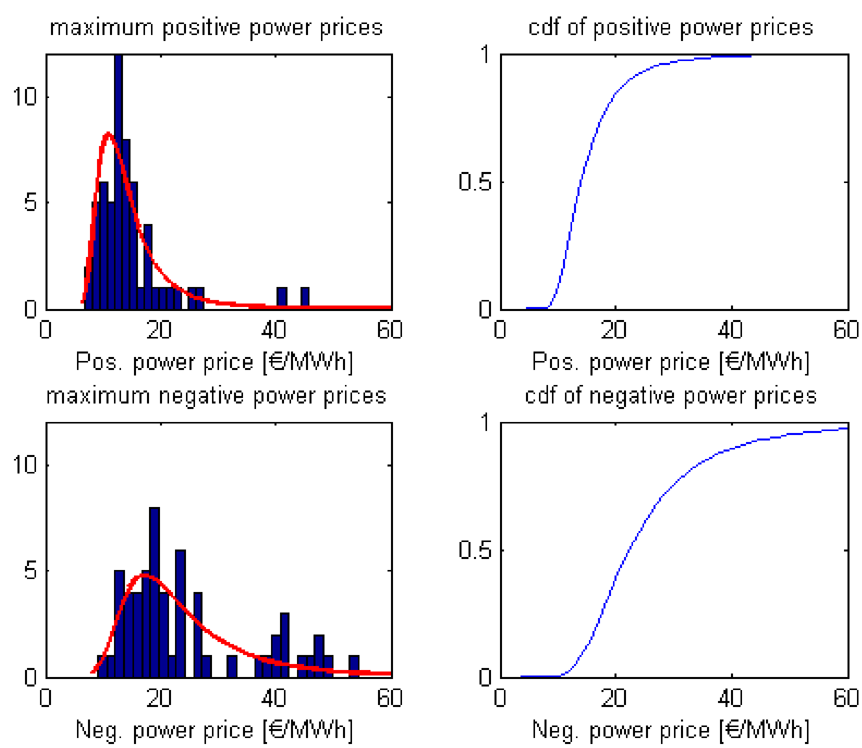

Fig. 6. Maximum power prices of the years 2009, 2010 and 2011 in the German secondary control energy market

Finally, the potential revenue in the control energy market are derived through

$$R_{Sec} = \sum_i \left(pL_i \cdot C_{Sec} + pE_i \cdot Q_{Sec,i} \right) \cdot (1 - cdf(pL_i)) + \sum_j \left(pL_j \cdot C_{Sec} + pE_j \cdot Q_{Sec,i} \right) \cdot (1 - cdf(pL_j)) \qquad (5)$$

i … Time index of the positive control energy market
j … Time index of the negative control energy market
pL … Power price
pE … Energy price
Q_{Sec} … Actual requested control energy
Ω … Probability function

whereas

$$Q_{Sec} \le C_{Sec} \qquad (6).$$

Those revenues are maximises via an yearly optimization subject to the positive and negative power prices as well as the share of power which should be marketed in the control energy market.

B. Generation Costs

The results of the dynamic economic calculation of the CHP units are their specific electricity and heat generation costs subject to the assumed depreciation time, discount rate and their actual energy output. As a consequence, its generation costs strongly depend on its full-load hours in the different markets. A further aspect to note is that generally plants do have decreasing conversion efficiency in part-load operation. This behaviour affects the generation costs as well because if plants are operated flexible they are operated in part-load for a significant amount of time.

Measurements on the part-load behaviour of CHP2 show a linear trend and a decrease of the conversion efficiency of about 3% at a power output of 30% [7]. Also the part-load efficiency of CHP1 is assumed to decrease by 4% at a power output of 30%. Furthermore, the measurements show an approximately constant development of the conversion efficiency down to 80% of the power output. Fig. 7 depicts the implemented part-load scaling factors for CHP1 and CHP2.

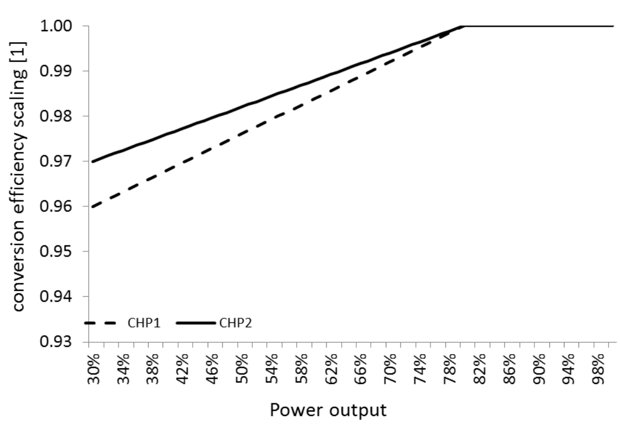

Fig. 7. Assumed conversion efficiency scaling factor for the two CHP-units

IV. RESULTS

This section summarises the main results of the sensitivity analysis performed with different relevant parameters to get insights into the economics of CHP-units under the assumption of base load operation, direct marketing in the spot market as well as in the secondary control energy market based on the data prescribed in the former section. Each result is presented through its relative difference to the necessary base support in the case of base load operation.

Exemplarily, in Fig. 8 the modelling results of CHP unit 1 in December 2010 are summarised. The results from a direct marketing in the spot market are illustrated in the first column and a simultaneous bidding on the positive, negative and spot market are shown in column two and three of the figure. When comparing the market prices in the first row of the figure, we can conclude that the positive control energy market prices are throughout at the highest price levels, whereas in the negative control energy market rather negative prices occur for the most part of the period. The red lines mark the variable generation costs of the CHP-unit. The optimisation process requires that the plant only operates during times when the market prices exceed its variable costs.

As the market prices are just one side of the coin the realised profit is also dependent on how much energy is actually requested during the period of time. Therefore the second row shows the sorted sold market power on a quarter-hourly basis and therefore represents the sold energy in the certain markets. The black areas mark the sold energy in the spot market, whereas the blue shaded areas mark the sold energy in the control energy market. We can see from the first column that the plant is not operated throughout the whole month, because the spot market prices fall below the variable generation costs during some hours. In the case of the positive control energy market the maximum available capacity are marketed within the control energy market due to its higher price levels. One can see that the sold energy is not significantly lower than in the case of marketing in the spot market. Due to the frequent occurrence of negative prices in the negative control energy market just minimal energy are actually sold in this market. However, due to the payment received from the power prices even from the negative control energy market considerable revenue can be earned.

Finally, the last row depicts the actual relative composition of the profits earned from the spot market, the power and the energy price.

Tab. 7 summarises the annual results regarding the necessary annual support costs in order to cover the long run marginal costs of the CHP units. The results are compared to the *Base case (FIT)* which is modelled as a base load participation in the spot market. Based on that, further options like the direct marketing in the spot market *(direct)* and an optimised participation in the control energy market are presented, whereas the control energy options consequently incorporate potential cost boosters linked to the flexible operation of the plants.

A. *Investment costs increase (INV)*

All additional components and necessary upgrades required to adjust the plants to participate in the control energy market has to be taken into account with regard to additional investment costs. Upgrades of the control and feedback control systems as well as the installation of adequate heat storage capacity are already mentioned examples. It is assumed that the overall investment costs rise by 20%.

B. *Operations-/maintenance costs increase (O&M)*

Also of significance is the question how the O&M costs are influenced by the more sophisticated requirements of a flexible plant operation. As there exist not much experience on such plant operation potential rises still subject to uncertainty. It is assumed that annual O&M costs will rise by 50%.

C. *Life time reduction (LD)*

A further aspect to be considered is that a more flexible operation of CHP plants leads to a higher stress of its components and therefore their lifetime could be shortened. The assumed depreciation time for the electrical parts of 10 years in this paper can be perceived as conservative, thus the suggestion that the lifetime of the components could fall below 10 years should be further analysed. Within this evaluation a reduction of 1 year is assumed.

D. *Part-load efficiency reduction (EFF)*

One crucial aspect when operating power plants more flexible is their part-load behaviour. Since lower conversion efficiency leads to higher generation costs the part-load behaviour can play an important role in determining the ideal capacity to be offered in the control energy market. In the worst case, if a small deviation in the power output corresponds to a strong decrease of the conversion efficiency a flexible operation will not be preferable. It is assumed that the part-load efficiency decrease by 50%.

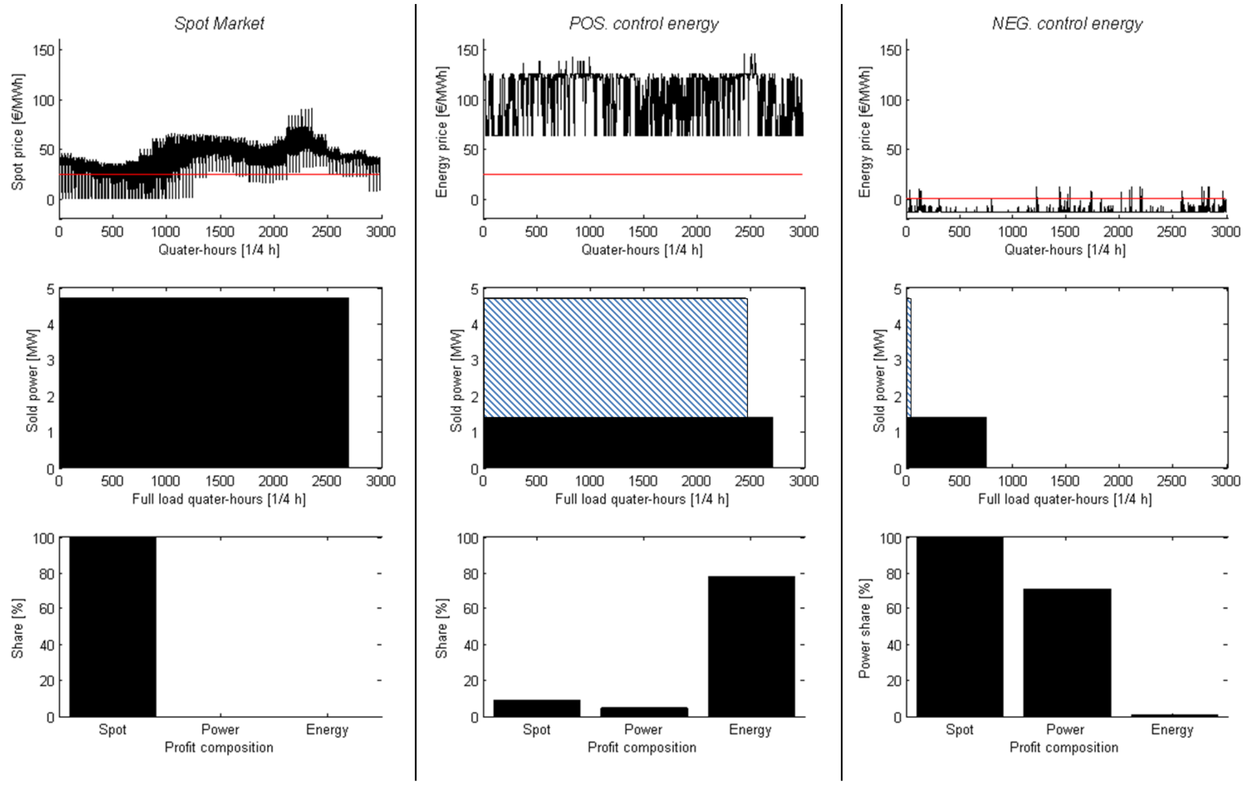

Fig. 8. Market prices, sorted power output duration curve and profit composition of three different energy markets in December 2010
Note: The power output duration curve uses a distinct color-code: Black – spot energy market / Blue shaded – control energy market

Tab. 7.. Overview on the results of potential support cost reductions under consideration of cost boosters

Plant	Unit	Spot market		Control market					
		FIT	Direct	Base	INV	O&M	LD	EFF	Total
CHP1	[€/a]	2,311,200	2,290,300	497,960	844,970	632,790	674,480	919,870	1,617,800
	Δ [%]	0	-0.9	-78.5	-63.4	-72.6	-70.8	-60.2	-30.0
CHP2	[€/a]	564,310	558,870	142,222	223,040	184,220	187,350	238,660	547,850
	Δ [%]	0	-1.0	-74.8	-60.5	-67.4	-66.8	-57.7	-2.9

The results show potential support cost reductions of approximately 1 to 75 per cent depending on the considered cost booster. The reduction also depends on the underlying cost structure of the unit and therefore differs between both units. To sum up, we can conclude that given the assumptions made even in the case of the simultaneous occurrence of all considered cost boosters a participation of CHP units in the control energy market would lead to a reduction in the necessary support costs.

V. CONCLUSIONS AND OUTLOOK

Having taken all the discussed aspects into account it can be concluded that cost reductions of biomass CHP-units via a participation in the secondary control energy market is possible. Although a final conclusion on the profitability could not be drawn in the light of uncertain expectations on additional costs caused by upgrade requirements and altered operation the sensitivity analysis show that the balance remains positive. In any case, even a neutral balance would lead to enhanced market awareness on the part of the RES-E producers and therefore is a value itself.

As a result, further research on the exact order of magnitude of the relevant aspects has to be done. It also has to be noticed that the preliminary results have to be interpreted with caution because first, the year 2010 has shown long periods of (highly paid) positive control energy and therefore the results are biased. Second, it was assumed that all the relevant information was known in advance. Further research should incorporate stochastic modelling of market prices and the adequate mapping of risk aversion of the bidders. Third, the feedback-effects of other market participants as a result to the own bidding behaviour as well as the long-term price effects were neglected within this evaluation. Furthermore, it is necessary to integrate the heat market into the analysis, as most CHP-units are obliged to satisfy a certain heat demand pattern, which adds an additional constraint to the operation of the plants. In this respect the incorporation of heat storages, heat pumps, or other components like peak power units have to be analysed in detail.

Finally, the analysis has to be embedded into a discussion on future adaptions of the organisation of control energy markets in order to integrate biomass/biogas-CHP units as current prequalification criteria and support schemes do not consider the special needs of such power plants and thus hamper their optimal operation.

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