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

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***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 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 support needed in the case of direct marketing in the spot market.**

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

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

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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 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 of direct marketing in the spot market.

II. DATA

The market prices from 2010 serve as a base for the calculation of the economics. Hourly spot market data from EXAA[1] are applied to calculate the potential profit under the assumption of an exclusive participation in the Austrian spot market. Quarterly data for requested regulating power in the Austrian control energy market during 2010 have been taken from [14]. At this time the control energy markets in Austria were not open for competition and the necessary control energy were exclusively supplied by Austrian Power Grid AG (APG). Therefore, there are no data for power and energy prices available. Thus the prices of the German secondary control energy market serves as a proxy for the values underlying the sensitivity analysis.

Fig. 1 and Fig. 2 shows the time-resolved number of calls in the Austrian secondary and tertiary control energy market respectively in the years 2006 till 2010.

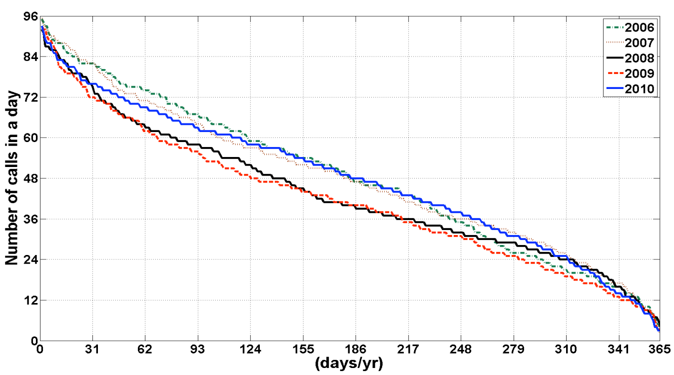

Fig. 1. Calls in the Austrian secondary (positive) control energy market for the years 2006 to 2010 [12]

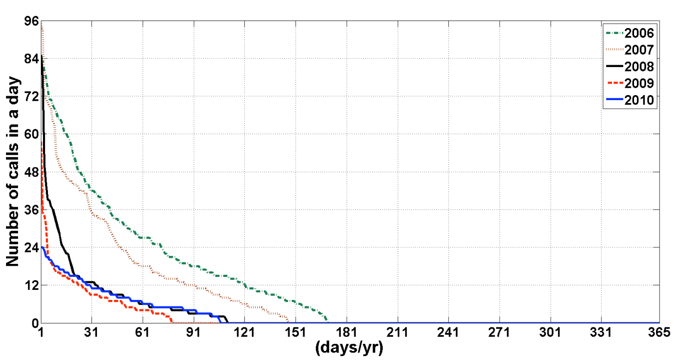

Fig. 2. Calls in the Austrian tertiary (positive) control energy market for the years 2006 to 2010 [12]

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). From this viewpoint a participation in the secondary market seems more profitable and for this reason the following analysis will focus on the secondary market.

Reference [8] includes a concise summary of the occurred prices and additional statistical calculations. 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 at high time for the period 1.5.2010 to 31.12.2010.

Tab. 1. High time auction data for positive control energy in Germany from May to December 2010 [8]

Energy price	*Unit*	*Value*
Average	[€/MWh]	125.30
Median	[€/MWh]	100.00
Maximum	[€/MWh]	335.00
Minimum	[€/MWh]	71.80
Power price	*Unit*	*Value*
Average	[€/MW]	3257.41
Median	[€/MW]	3308
Maximum	[€/MW]	3984
Minimum	[€/MW]	2250

Tab. 2. High time auction data for negative control energy in Germany from May to December 2010 [8]

Energy price	*Unit*	*Value*
Average	[€/MWh]	5.50
Median	[€/MWh]	5.00
Maximum	[€/MWh]	100.00
Minimum	[€/MWh]	-29.10
Power price	*Unit*	*Value*
Average	[€/MW]	831.33
Median	[€/MW]	849
Maximum	[€/MW]	1387
Minimum	[€/MW]	463

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.

[1] http://www.exaa.at

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 CHP1 a discount rate of 4.6% and for CHP2 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 spot market 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

$$R_{Spot} = \sum_h p^h_{Spot} \cdot C \cdot 8760 \qquad (3)$$

[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.

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 never requested at the same time and the plant can offer its full 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

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

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 Austria the award procedure for control energy is carried out by Austrian Power Grid (APG) [14]. 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. However, there are no empirical data on energy and power prices, as well as the relation between energy prices and probability of dispatch so far since the Austrian market for control energy have just been established by January 2012. As a consequence of that the data presented in Tab. 1 and Tab. 2 from the German control energy market is used to serve as a proxy. In order to incorporate the probability of dispatch a linear relationship with the energy price has been taken for granted. To deal with the uncertainty regarding this relationship the sensitivity analysis are performed for two linear curves which differ in the value of probability for the maximum energy price. These values are assumed to be 5% and 25% at the maximum energy price and should reflect extreme cases. The two curves are shown in Fig. 3 on the example of the positive energy price in Germany during High Time[3].

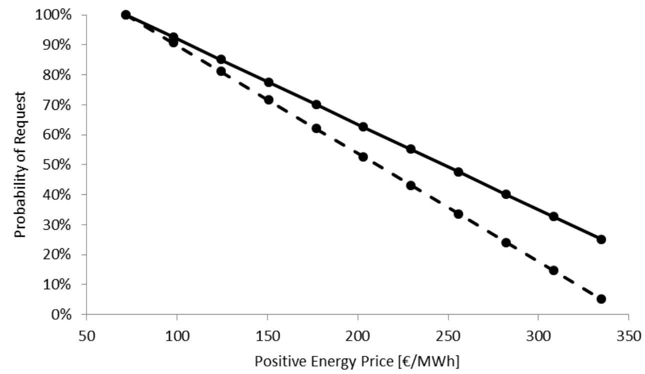

Fig. 3. Assumed probability curve on the example of the positive energy price in Germany at High Time (HT)

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

$$R_{Sec} = \sum_i pL_i \cdot C_{Sec} + pE_i \cdot Q_{Sec,i} \cdot \Omega(pE_i) + \sum_j pL_j \cdot C_{Sec} + pE_j \cdot Q_{Sec,j} \cdot \Omega(pE_j) \qquad (5)$$

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

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

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 a 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

[3] The products in the German control energy market are available for two time periods. High Time (HT) is defined as the period between 8:00am and 8:00pm and Low Time (NT) between 8:00pm and 8:00am as well as weekends.

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. 4 depicts the implemented part-load scaling factors for CHP1 and CHP2.

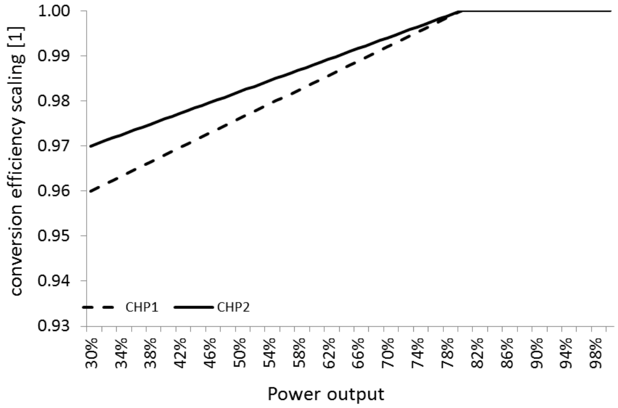

Fig. 4. Assumed conversion efficiency scaling factor for the two CHP-units

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 a marketing 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 corresponding base support. To eliminate scaling effects the values are depicted as percentages of Euros per MW. The independent parameters are shown in absolute values.

The results are presented in a group of parameters concerning the revenue side and a group of parameters related to the cost side. The revenue side comprises the parameters probability of dispatch, positive and negative power price and positive energy price by taking into account two different probability curves. The cost side show results of the influence of the part-load efficiency, the depreciation time, the operation and maintenance (O&M) costs as well as the overall investment costs.

The reference values for the following comparison are the necessary base support of the two CHP-units derived by subtracting their generation costs in base-load operation from their potential profit in the sport market. An average spot market price of 44.81 €/MWh and generation costs of 73.54 €/MWh for CHP1 and 71.25 €/MWh for CHP2 leads to a necessary base support of 251,639 €/MW and 231,529 €/MW respectively. In the following graphs the resulting necessary support is presented in relation to those reference values. The first set of parameters to be observed is related to the revenue side.

A. *Probability of dispatch*

Figure Fig. 5 shows the influence of the probability of dispatch on the necessary support. It is assumed that the power price as well as the energy price is set to the median values in Tab. 1 and Tab. 2. Since the median values separating the higher half prices from the lower ones, it is assured by choosing those price levels to be in the middle of all submitted bids. The curves are normalised to their nominal power, therefore the slope of the curves are aligned to each other. The parallel shift is mainly caused by their differing specific cost structure and a variational amount of requested energy.

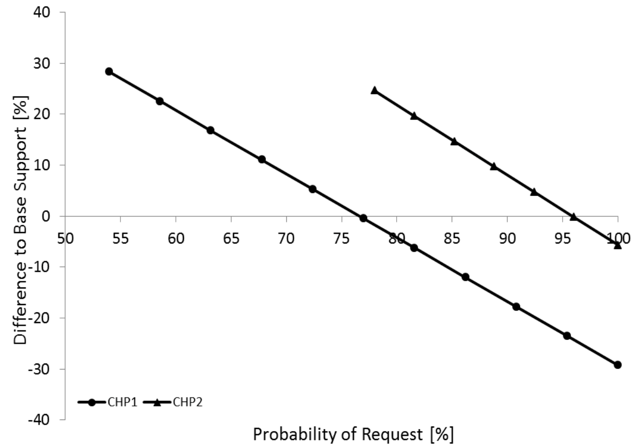

Fig. 5. Probability of dispatch

It can be seen that CHP1 needs to reach a probability of dispatch of 77% and CHP2 of 97% to require equal support in comparison to the base support. A lower probability of dispatch would lead to a situation where the necessary support increases compared to the base support. Basically, the probability of dispatch is a function of the offered energy price and the actual control energy requirements. Thus no sound statement on this result can be made. However, it can be assumed that CHP2 would hardly achieve a probability of dispatch of 97% with median values. From this viewpoint it can be argued that if median prices are offered in the control energy market it is still highly questionable if the necessary support level can be decreased. Therefore, a further analysis on the influence of different price offers has been carried out.

B. *Power Price*

The power price is paid for the provision of reserve power and thus is related to the offered capacity. Typically the power prices for positive and negative reserve capacity differs significantly. One explanation is that power prices reflect the opportunity costs of the bidder. These costs are higher in the case of positive control energy, because the bidders have to allocate a certain amount of capacity which cannot be sold in the sport market and thus causes higher opportunity costs.

Fig. 6 and Fig. 7 show based on median values of power and energy price and the probabilities of request of 77% (CHP1) and 97% (CHP2) a variation of the positive and negative power price between its minimum and maximum values depicted in Tab. 1 and Tab. 2. It can be inferred that due to a greater price span the positive power price does have a slightly greater effect on the support level.

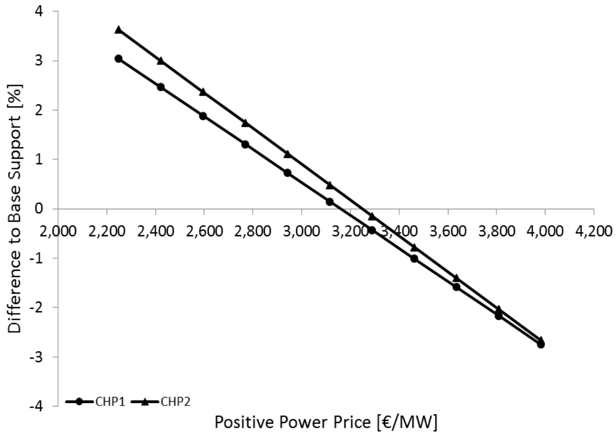

Fig. 6. Positive power price variation at the median value of the energy price and probabilities of request of 77% for CHP1 and 97% of CHP2

However, the effect on the support difference is less significant in both cases in general and just amounts for a view per cent. It should be emphasised that the assumption that both CHP units achieve at the same price levels such a different probability of dispatch is practically indefensible. The reason why it is presented in that form is to print the curves adjusted by means of their different cost structure. The remaining divergence between the curves gets smaller at higher levels of the power price and illustrates the effect of their variational requested energy throughout the year. This convergence is caused by the fact that the actual requested energy at higher power prices gets less significant in the overall revenue in relative terms.

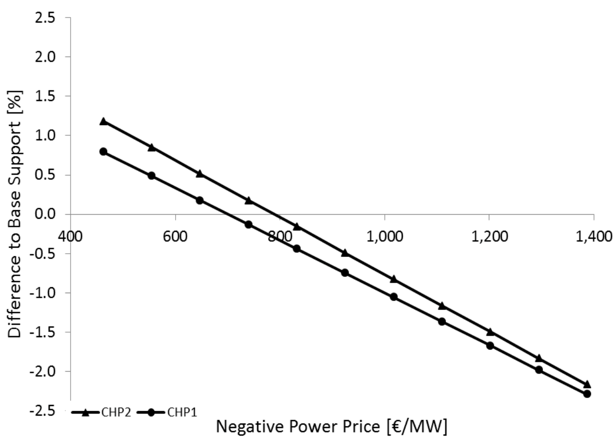

Fig. 7. Negative power price variation at the median value of the energy price and probabilities of request of 77% for CHP1 and 97% of CHP2

C. Energy Price

The energy prices in an ideal market should reflect the marginal prices of delivering control energy. Consequently, based on the merit-order of the spot market the energy price for positive control energy are higher and for negative control energy are lower than the corresponding spot market price. Participants in the negative control energy market can profit from low energy prices if they are able to store their produced energy in some way in contrast to a delivery to the market which equals a purchase of cheaper energy. In case of CHP-units the surplus electrical energy can be converted to heat and be stored in heat storage systems. Assuming that at a later point in time the heat is sold at a price which is high enough to cover the conversion costs additional revenue can be gained. Due to the fact that revenues from produced heat are not considered within this paper the influence of lower energy prices on the overall revenue cannot be represented adequately and therefore the negative energy market segment are not subject of the following analysis.

With regard to the sensitivity of the resulting support in the light of increasing positive energy prices we have to consider the dependence of the energy price from the probability of dispatch (cf. Fig. 5). Fig. 8 illustrates the relationship by assuming a probability of dispatch of 25% at the maximum energy price of 335€/MWh. In addition Fig. 9 depicts the relationship under the assumption of 5% request probability at the maximum energy price. Again it is assumed that the power prices are fixed to the median value in Tab. 1 and Tab. 2.

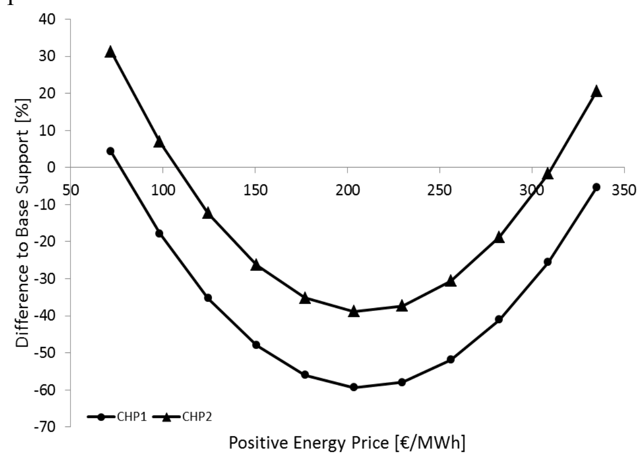

Fig. 8. Positive energy price variation with 25% request probability at highest energy price

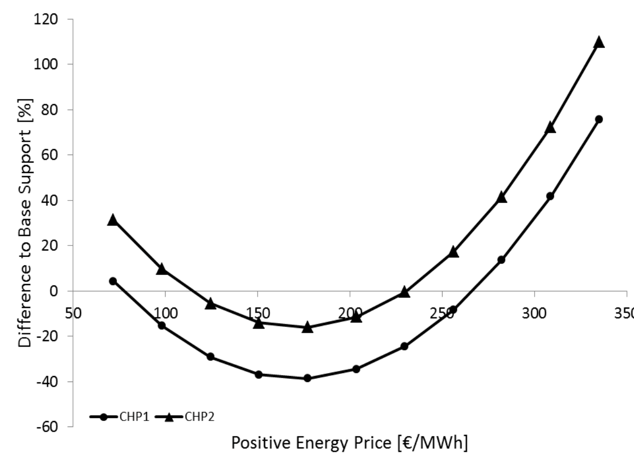

Fig. 9. Positive energy price variation with 5% request probability at highest energy price

Both graphs show a significant influence of the energy price level on the earned revenues from the control energy market. Even with a low probability of dispatch there are support savings between 20% and 40% possible, depending on the cost structure of the plant. A variation of the generation costs causes a parallel shift of the curve. According to the assumptions the maximum revenue can be achieved at 200€/MWh and corresponds to a probability of dispatch of 63%. In case of a steeper probability curve the point of maximum revenue from the control market shifts to the left at 177€/MWh and 62% probability of dispatch.

The previous analysis has focused on the relevant parameters concerning the revenue side of the support comparison. In the following sections a couple of relevant parameters according to the cost side are discussed.

D. Part-load Efficiency

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.

Based on the minimal-load efficiencies from Fig. 4 and the median values at the revenue side Fig. 10 illustrates the effect of decreasing part-load efficiency at minimal load. In the present case it can be seen that the part-load efficiency do not significantly influence the cost side. This mainly arises from the fact that in the present case the fuel prices (15 and 16 €/MWh) are comparatively low against the energy price levels.

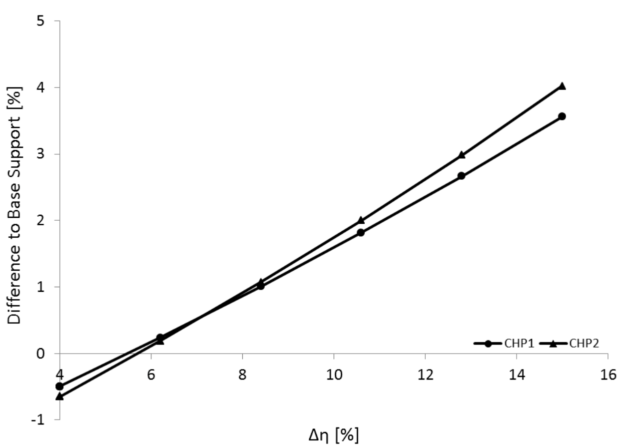

Fig. 10. Part-load efficiency variation Δη at minimal load and median market prices

E. Depreciation Time

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 components 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.

From the sensitivity analysis carried out on the influence of the depreciation time we can conclude that in the present case a support increase of approximately 15 – 20% per year depreciation time reduction have to be taken into account (s. Fig. 11).

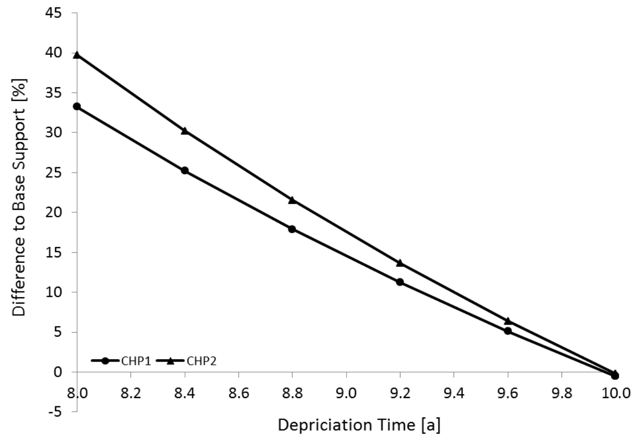

Fig. 11. Variation of the depreciation time at median market prices

F. Operations-/Maintenance Costs

Also of significance is the question how the O&M costs are influenced by the more sophisticated requirements of a flexible plant operation. Potential rises in the support level are shown in Fig. 12.

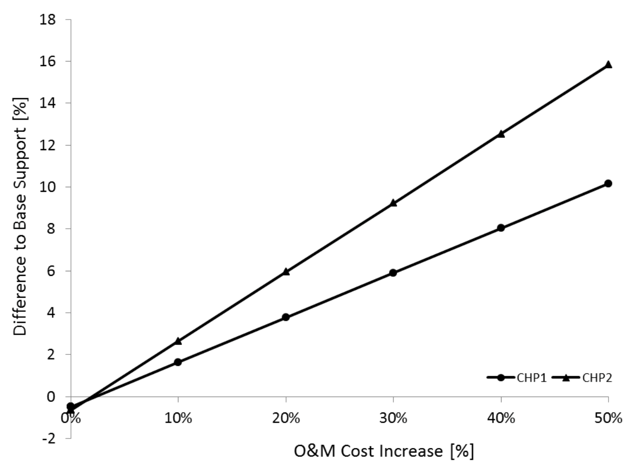

Fig. 12. Variation of the O&M costs at median market prices

G. Investment Costs

Finally 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.

Fig. 13 illustrates the order of magnitude of the support rises we have to count with if the investment costs increase.

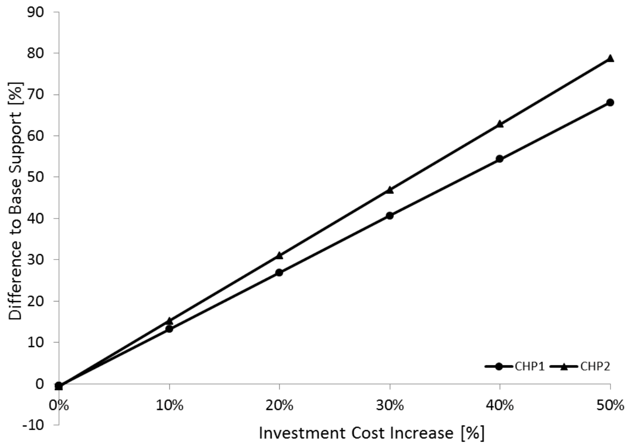

Fig. 13. Variation of investment costs at median market prices

V. Conclusions and Outlook

Having taken all the discussed aspects into account it can be concluded that a sound statement on potential support cost reductions of biomass CHP-units via a participation in the secondary control energy market cannot be made. Based on expectations regarding the achievable control market revenues, no final conclusion on the profitability could be drawn in the light of uncertain expectations on additional costs caused by upgrade requirements and altered operation. As a result, it is clear that further research on the exact order of magnitude of the relevant aspects have to be done. In any case, even a neutral balance will lead to enhanced market awareness on the part of the RES-E producers and therefore is a value itself.

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.

A further step is to analyse optimal bidding strategies of CHP-units in the context of uncertain future market conditions. Thus the approach presented in this paper has to be refined to a mathematical optimisation problem in order to tackle this issue adequately.

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.

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VII. Biographies

André Ortner is a research associate and PhD candidate at the Energy Economics Group at the Technical University of Vienna. He holds a degree in electrical engineering (power engineering and energy economics) from Vienna University of Technology and has studied at the Vienna University of Business Administration, Universidad Politécnica de Madrid and Universidad de Sevilla with coursework in business administration, innovation management and entrepreneurship. At the energy economics group he participates in several international research and consulting projects in the field of energy economics and energy system modelling. His research interests comprise the analysis of regulatory and technological framework conditions for the promotion of renewable energy technologies and the application of mathematical programming in energy models.

Rusbeh Rezania was born in Linz (Austria), on December 14, 1979. He holds his master in power engineering from the Vienna University of Technology.in November 2009. He analyzed in his master thesis the impact of various grid integration methods on the grid tariffs and economics of decentralized power plants. Since February 2009 he has been working as a junior researcher at Vienna University of Technology, Energy Economics Group (EEG). His major fields of research are micro CHP and integration of electric vehicles as well as storage systems into the energy system.

Hans Auer was born in Schmirn (Austria) on March 26, 1969. He is senior researcher at Vienna University of Technology, Institute of Energy Systems and Electrical Drives - Energy Economics Group (EEG). He joined EEG in 1995. Hans' main research interests are electricity market analyses in general and grid and market integration policies of DG/RES-E technologies in this context in particular.