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**Institute for Future Energy Consumer Needs and Behavior (FCN)**

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# Economics of Biomass Co-firing in New Hard Coal Power Plants in Germany

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## Abstract

Biomass cofiring in coal power plants (with shares of typically 5-20%$_{th}$) is an interesting option to mitigate $CO_2$ emissions, since the additional costs are relatively minor and a secondary benefit is provided by the increased fuel flexibility. Worldwide, about 150 cofiring plants are in operation. In Germany, the potential for biomass cofiring in coal plants is about 28 TWh$_{el}$ per annum, assuming a 10% replacement of coal combustion by biomass. In this paper, we study the economic potential of biomass cofiring in hard coal power plants in Germany. To this end, we identify suitable biomass input fuels, investment and operating costs, and profitability of cofiring investments. In a sensitivity analysis, we check for the robustness of the results gained, and in a Monte Carlo simulation (MCS) uncertainties are explicitly taken into account. We find that both regional and international biomass supplies are relevant, and that the cost effectiveness of cofiring is strongly affected by prices for biomass, coal and $CO_2$ permits, while investment and operating costs only have a modest influence. According to our calculations, power generation costs attributable to biomass combustion for a plant put into operation in 2020 are between 70-75 € MWh$_{el}^{-1}$, while the average costs of biomass fuel from various sources and markets are calculated to be around 4.1 € GJ$^{-1}$.

*Keywords:* Co-combustion, Hard coal, $CO_2$ mitigation, Fuel flexibility, Monte Carlo simulation

## 1. Introduction

While coal is globally still very important for power generation it is also very $CO_2$-intensive. Biomass cofiring in coal power plants, with shares of typically 5-20%$_{th}$, depending on the technology involved and the type of biomass used, is an in many cases cost-effective option to substitute biomass for coal in electricity production, and thus to mitigate $CO_2$ emissions [1]. Another benefit of cofiring is the increased fuel flexibility. In Europe, cost-effectiveness has been enhanced further by the introduction of the EU emissions trading scheme (EU ETS) [2].

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Whereas typical conversion efficiencies of biomass-fired power plants are around 25%, average conversion efficiencies of conventional (sub-critical pulverized) coal-fired power plants are about 36% in OECD countries (state-of-the-art plants: ca. 46%). Hence biomass cofiring is an interesting way to convert biomass into electricity with high conversion efficiency. Worldwide, about 150 cofiring plants are in operation. In Germany, the potential for biomass cofiring in coal plants is about 28 $TWh_{el}$ per year, assuming a 10% replacement of coal combustion by biomass (in 2008, some 280 $TWh_{el}$ of electricity were produced from coal, cf. [3]). Economic studies are still quite rare (e.g. [2] investigates the economic potential for the EU-27, [4] studies the effects of biomass cofiring subsidies on the heat and electricity markets and [5] the impact of different operating and logistic schemes on the economic viability of biomass cofiring, and [6] reductions in fuel side costs).

In Europe, biomass cofiring is much more widespread than elsewhere in the world. About two thirds of all cofiring plants are located in Europe alone [7,p.10]. Especially in Northern Europe, Germany and Austria the technology is present, since large amounts of relatively low-cost biomass are available and because bioenergy is popular. In *Germany*, for example, the situation is as follows. In 2007 there were some 30 cofiring plants, of which thirteen were permanently operated with mixed fuels [7,pp.176-178]. The most frequently used fuel is sewage sludge, which is utilized in 50% of all plants. Sewage sludge can be co-fired up to $3\%_{th}$ without significant plant modifications. This is attractive, because sewage sludge is a resource that is available all year round and has negative costs [8]. Further fuel materials are waste wood, straw and organic residues. Important barriers in Germany are the limited security of biomass supply (lack of suppliers, seasonality etc.), high requirements regarding the operating licence for waste cofiring plants and the increased competition in liberalized power markets after deregulation, which has led to a less investor-friendly climate due to the additional risks involved in cofiring. Moreover, the feed-in tariffs stipulated in the German Renewable Energies Act (EEG) do not apply to biomass cofiring, in contrast to other technologies using renewables. Hence a plant that is fired 100% by biomass receives higher tariffs and can thus also pay higher prices for the biomass. Reviewing also the situation in other European countries (cf. [7]), it becomes evident that biomass use for cofiring is either enabled by favorable availability of biomass resources or by promotion policies. For Germany, hence, political support is necessary to push this technology, e.g. the EU ETS.

In the remainder of this paper, we study the economic potential of biomass cofiring in hard coal power plants in Germany, with a particular focus on the power plants owned by the energy provider E.ON. In section 2 we identify fuels suitable for biomass cofiring, and important influencing factors determining their contribution to overall investment and operating costs. Section 3 contains the analysis of the cost-effectiveness of biomass cofiring, and profitability calculations for cofiring investments, a sensitivity analysis for checking the robustness of the results gained, and a MCS for taking uncertainties explicitly into account. Section 4 concludes.

## 2. Biofuel cost analysis

Biofuel input costs vary significantly by the type of biomass and its origin. Whereas obtaining certain biomass types locally (e.g. straw, energy crops) can be favorable in some cases, international supply with refined biomasses (namely pellets) traded over long distances lends itself to applications with a high fuel input demand. Transportation costs and plant location (inland, coastal region) can become decisive factors. In this section, the determinants of fuel supply are further expounded. These considerations form the basis for the price scenario definition and profitability analysis provided in section 3. Fuel supply costs for selected plants in Germany and regional fuel supply are investigated in section 2.1, whereas the fuel prices for international trade are quantified in section 2.2. The combined results yield a qualitative synthesis over the fuel prices for different types of biomass.

### *2.1. Fuel supply costs in case of regional supply*

International trade of biomass enables the use of biomass resources also from other regions. Electrabel, for instance, has found that international pellet suppliers can provide less costly pellets for their power plants than local suppliers [9,p.725]. Fig. 1 shows the span of prices for different types of biomass. It becomes evident that the costs calculated for Germany in various studies (e.g. “Leitstudie Bioenergie”, cf. [10]; “RENEW”, cf. [11]) (A, B) are mostly higher than current market prices. In contrast, in the study of [12] (C) the costs are below the market prices.

### *2.2. Fuel supply cost in case of European/international supply*

Biomass is increasingly traded internationally. Often biomass from overseas is less costly than regional biomass, due to economies of scale in production and transport, e.g. in South America. Since economies of scale in ship transport are not very distance-dependent, the production cost differences are the main relevant factor. These are in Western Europe markedly higher compared to countries with lower land and labor costs. For intra-European trade the situation is different. As production is more expensive than in Latin America, and since transport has to be effected by railway or via often long detours on waterways, cost reductions due to scale effects are often minor (Fig. 2).

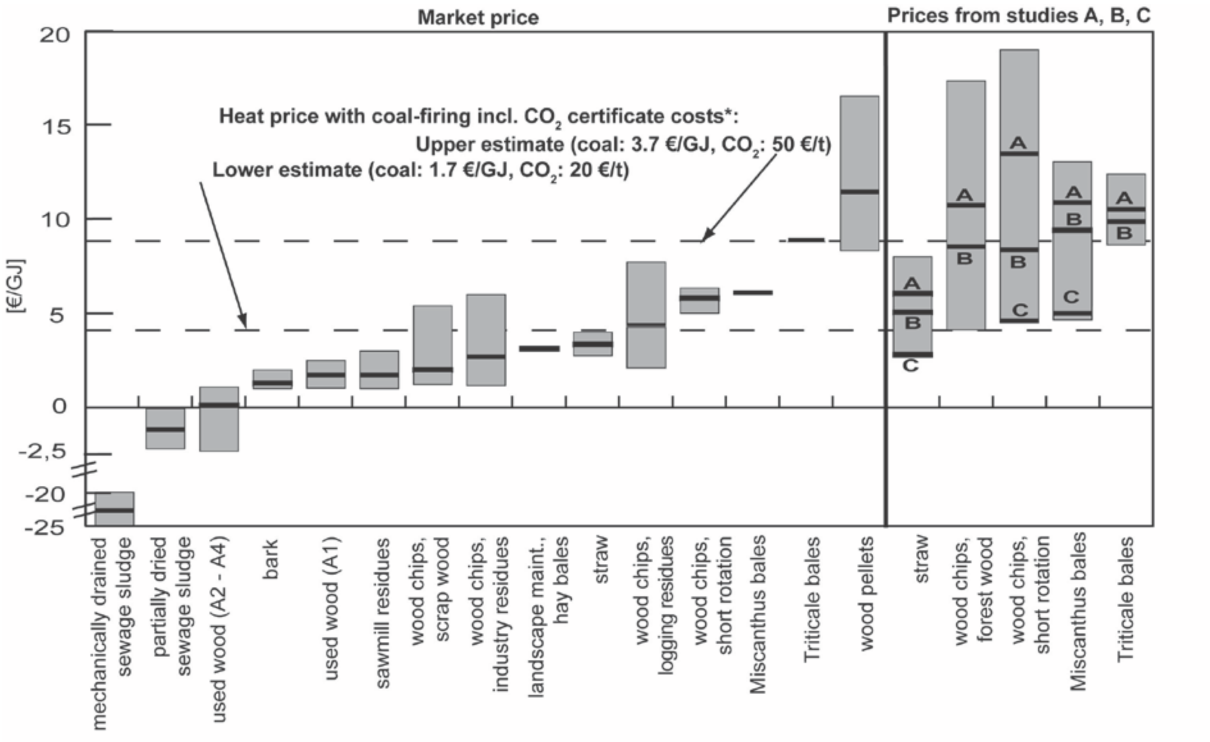


**Fig. 1. Fuel supply cost at plant located in Germany**

*Data sources:* [10,pp.208-225] (A), [11,pp.68-69] (B), [12,p.238] (C); [13,pp.103-104], [14,p.35], [15,pp.54, 86ff.], [16,pp.41-43], [17,p.3], [18,p.5], [19], [20,p.21], [21,p.273], [22,p.868], [23,p.379], [24,p.108], [25,p.292], own calculations. * For details see appendix A.1.

*Note:* The bold black horizontal bars indicate the weighted average over the various prices.

Due to their favorable transport characteristics wood pellets are particularly well-suited for international trade. Their costs are sometimes at 5 € $GJ^{-1}$, and thus less expensive than pellets produced in Germany. Figure 3 shows the total supply costs of wood pellets for a representative onshore power plant location compared to an inland location (approx. 800 km off the sea port) and supply from different regions. The onshore location benefits from the easy access to shipping routes, so that heat prices from wood pellet use are similar to those from using coal. In contrast, the higher shipping costs compared to coal for the inland location lead to somewhat less favorable conditions when pellets are provided by an international supplier.

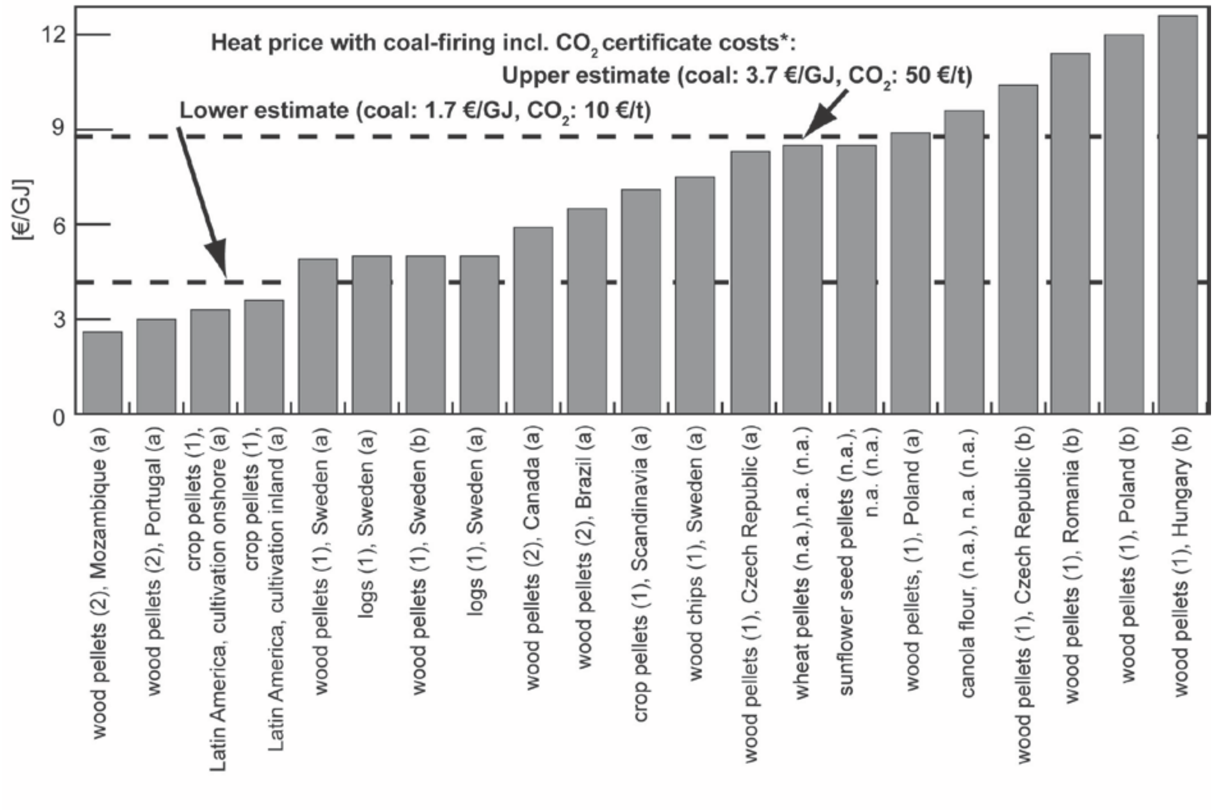


**Fig. 2. Cost/prices of internationally traded biomass at plant (1) and at destination harbor (2) (both in Germany) by ship (a) or rail (b)**

*Data sources:* [26,pp.127-128], [27,p.12], [9,p.724], [28,p.54], [29,p.44], own illustration. [a] *Note:* For details see Appendix A.

A comparison between international and regional supply shows the strong dependency of the fuel supply costs by type of biomass and origin due to their different energy density and transport characteristics. Straw and energy crops are best procured from regional suppliers. For long distances transport costs rise markedly and render this unattractive. Fresh wood chips are, due to the high moisture contents, also unfavorable if transported over long distances. Log wood can be transported over medium distances (e.g. from Sweden) at prices comparable to those of pellets. For longer distances, however, pellets are superior.

Figure 4 provides a qualitative overview of the cost development for various types of biomass over the amount of input fuel demanded. The rise for forest residues, straw and energy crops is mainly due to higher transport distances. A further influence has the rising marginal cost for harvesting large amounts. Increasing scarcity and competition with alternative uses are the reasons for rising prices of industry residues.

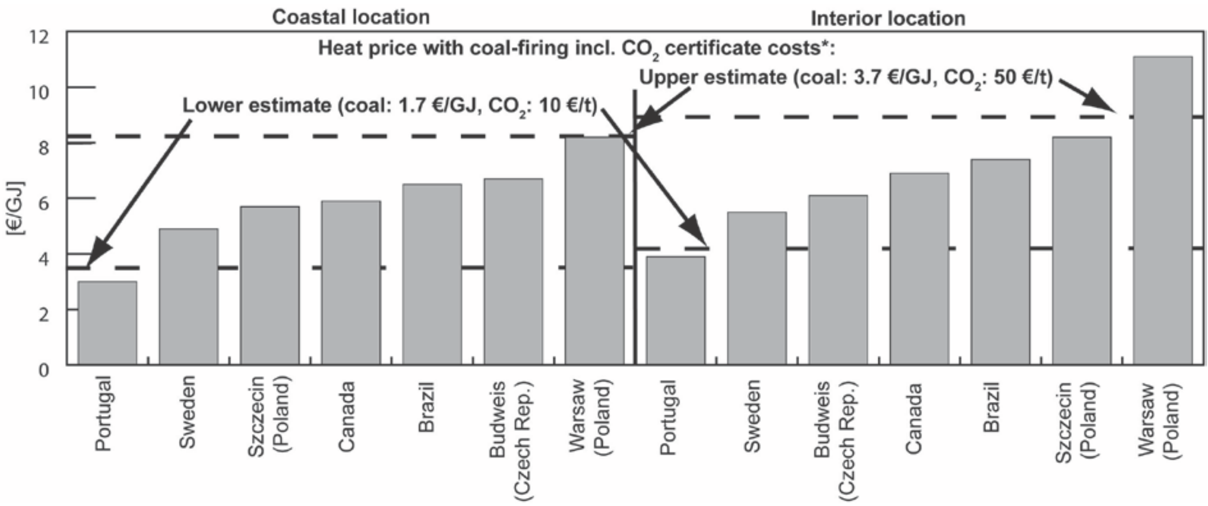


**Fig. 3. Biomass cost for internationally purchased wood pellets at representative power plant locations**

*Data sources:* [30,p.79], [9,p.724], [27,p.12], [29,p.44], [8], own calculations. [a] *Note:* for details see Appendix A.

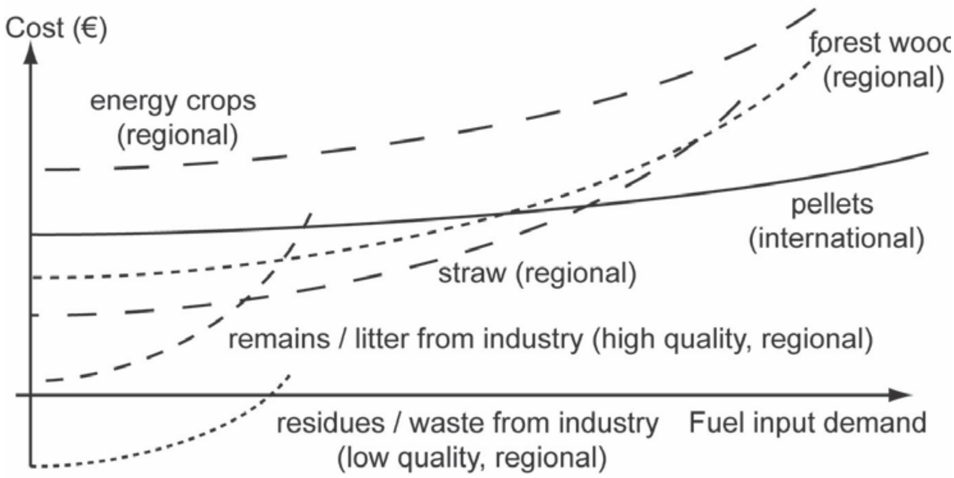


**Fig. 4. Cost curves for different kinds of biomass (stylized)**

## 3. Profitability analysis

### 3.1 Approach for the economic evaluation of cofiring

#### *3.1.1. Wood fuel price assumptions*

Due to the wide heterogeneity and volatility of biomass fuel prices, the cost of biomass supply for cofiring is difficult to estimate. In our study, we have considered three different wood fuel price scenarios (cf. Table 1):

- *Reference scenario (S1).* S1 is determined by the expected average market prices, which is calculated for wood utilization at a ratio of 10:1 (technical potential for wood residues:

industrial residues). Assuming an average price of 4.19 € $GJ^{-1}$ for forest residues and 1.36 € $GJ^{-1}$ for industrial residues (Fig. 1), we get a weighted price of 3.9 € $GJ^{-1}$. For pellets we assume that due to the relative price advantage, these are mainly taken from international sources, and that a large consumer is able to search the market for low-cost pellets and special conditions (e.g. free delivery) as it was done for the power plant in Maasvlakte (cf. [31]). Since least-cost pellets at 3 € $GJ^{-1}$ can be expected to be exhausted soon, and because at high prices of around 8.5 € $GJ^{-1}$ biomass cofiring is economically not feasible, we assume a lower value of 5 € $GJ^{-1}$. The high demand for straw and sewage sludge as well as the prices from theoretical calculations lead to an assumption of 3.4 € $GJ^{-1}$ (straw) and -20 € $GJ^{-1}$ (sewage sludge).

- *High price scenario (S2).* Prices are assumed to be 8.5 €/GJ for wood and 5.0 €/GJ for straw, based on theoretical calculations for Germany [10,pp.208-222;11,pp.68-69], which is a significant rise of market prices compared to today, thus helping to cover production cost. Wood pellet costs are assumed at 8.5 € $GJ^{-1}$. We further assume that demand for wood fuels increases, so that easily available resources are exhausted soon, while for sewage sludge increased demand leads to a price of 0 € $GJ^{-1}$.
- *Low price scenario (S3).* In S3 it is assumed that wood residues are available at 2.3 € $GJ^{-1}$, as most of it is waste wood, a value in line with [22,p.868]. Pellets are assumed to be available at 3.6 € $GJ^{-1}$ (taken together, this is what current purchase prices at Maasvlakte are, incl. a transport mark-up for an inland plant location)[31]. Straw prices at 2.8 € $GJ^{-1}$ are in line with the assumptions in [12,p.238;22,p.868], while for sewage sludge we assume current costs of -25 € $GJ^{-1}$.

**Table 1. Biomass price scenarios S1 to S3**

| Biomass price [€/GJ] | S1 (Reference) | S2 (High price) | S3 (Low price) |
|---|---|---|---|
| Wood | 3.9 | 8.5 | 2.3 |
| Wood pellets | 5.0 | 8.5 | 3.6 |
| Straw | 3.4 | 5.0 | 2.8 |
| Sewage sludge | -20.0 | 0.0 | -25.0 |

### *3.1.2. Technical assumptions*

In our study, concerning the technical implementation of biomass cofiring, we consider three different variants (cf. [32,p.3]):

*(i) Direct co-combustion.* Coal and biomass are either conveyed to the boiler via the same or separated conveyors, but in any case burnt jointly.

*(ii) Indirect co-combustion.* Biomass is gasified separately and product gas burnt in the boiler jointly with coal.

*(iii) Parallel co-combustion.* Combustion, heat transfer and flue gas cleaning are all separate. Energetically, however, they are connected to the same steam cycle.

While all three variants exist in reality, direct cofiring is the most common alternative [33], and with a biomass share of $10\%_{th}$ in overall capacity it has by far the lowest investment costs and highest conversion efficiency. For a power plant with 600 $MW_{el}$, an efficiency of 40% and 6000 full-load hours p.a., the specific cost and efficiencies (in brackets) are as follows: 40 € $kW_{el}^{-1}$ (39.5%), compared to 455 € $kW_{el}^{-1}$ (38%) for gasification, 935 € $kW_{el}^{-1}$ (36%) for pyrolysis and 940 € $kW_{el}^{-1}$ (38.5%) for parallel cofiring (cf. [7,pp.216-217]. Moreover, many experts see it as superior, as it is not limited by limited availability of the gasifier or additional boiler. The less common implementation of indirect or parallel cofiring has been mainly due to the lack of experience with cofiring at the time of installation and testing of the technology (only two plants worldwide are currently operated as parallel cofiring plants, cf. [33]).

We also performed a review of the technical implications of biomass cofiring, showing that most problems can be solved by plant modifications. Main restrictions arise with respect to the biomass fractions that can be grinded jointly with the coal, a problem which can be easily solved by separate grinding. The blowing into the furnace chamber should be in the form of a coal-biomass mix. Limitations to the usable biomass fractions arise from slagging and fouling, and from corrosion and deactivation of the $DeNO_x$ catalyst. Due to such problems, indicators have been developed that allow for the calculation of maximum shares [31,pp.23,62;34,pp.376-377;7,pp.25,221;35]. The suitability of the indicators depends on the plant concerned and has to be determined by tests. They are used to determine possible cofiring shares of exemplary biomasses. The results are summarized in Table 2. Note that limit values are indicative only. In general, it is noticeable that, when using biomass compositions, single types can have a positive influence overall.

In the economic calculations that follow, the fuel mixes Z1-Z3 reported in Table 3 are used. These mixes are realistic with respect to supply, since pellets have to be purchased internationally anyhow, whereas for wood and straw the assumed supply radius is 31 and 24 kilometers. For the technical calculations, these shares also turned out to be realistic, and comply with practical experience [36].

Z1 is composed of a variety of fuels. It offers great flexibility, as in case of supply shortages or technical problems one can switch from one kind of biomass to another. The storage facilities can also be used for other fuels, facilitating fuel switching (e.g. from straw to energy crops). Z2 and Z3 are based on Z1. In Z2 primarily high-quality biomass (wood chips, wood pellets) are used, whereas in Z3 only low-cost biomass is used.

**Table 2. Maximum possible shares for various types of biomass for cofiring**

| Type or combinations of biomass fuel | Cofiring share[a] [$\%_{th}$] | [Vol.-%] | Remarks |
|---|---|---|---|
| Green wood | 47 | 73 | Due to high moisture content limited to 15$\%_{th}$ |
| Straw | 3.4 | 4.9 | |
| Wood pellets | 21 | 27.2 | Realistic, since in Maasvlakte 37 volume-% have already been achieved |
| Miscanthus | 4 | 5.4 | |
| Willow | 18 | 23 | |
| Mechanically dehydrated sewage sludge | 0.4 | 9 | Due to positive experience limited to 0.17$\%_{th}$ |
| Green wood / Mech. dehydrated sewage sludge | 10 / 0.17 | 24.7 / 3.34 | Upper limit for sewage sludge due to positive experience so far set to 0.17$\%_{th}$, moisture content in green wood high as well, therefore 10$\%_{th}$ limitation imposed |
| Straw / Mech. dehydrated sewage sludge | 2.8 / 0.17 | 3.9 / 3.96 | Upper limit for sewage sludge due to positive experience so far set to 0.17$\%_{th}$ |
| Green wood / Straw | 24 / 1.7 | 49 / 1.65 | Shares of green wood and straw set to 50% of their maximum values |
| Green wood / Straw / Mech. dehydrated sewage sludge | 10 / 2.2 / 0.17 | 24.5 / 2.56 / 3.31 | Share of sewage sludge as for pairings, green wood limited to 10$\%_{th}$ due to high moisture contents |
| Wood pellets / Straw / Sewage sludge | 12 / 2.2 / 0.17 | 15.2 / 2.3 / 3.8 | Share of sewage sludge as for pairings, share of straw as for combinations with green wood |

[a] *Note:* The formulas used in the model can be found in [31,p.62].

**Table 3. Fuel mixes for the economic assessment**

| [$\%_{th}$] | Coal | Wood | Wood pellets | Straw | Sewage sludge, mechanically dehydrated |
|---|---|---|---|---|---|
| Coal-only | 100.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Z1 | 88.47% | 5.00% | 5.00% | 1.40% | 0.13% |
| Z2 | 89.87% | 5.00% | 5.00% | 0.00% | 0.13% |
| Z3 | 98.47% | 0.00% | 0.00% | 1.40% | 0.13% |

### *3.1.3. Investment costs*

For our calculations we used a newly built 800 $MW_{el}$ power plant at an inland location with hard coal dust firing. In 2006, specific investment costs for such plants were on average about 1120 € $kW_{el}^{-1}$ [37,p.153]. In the following years, due to high prices for steel, energy and labor they rose markedly and are expected to be 1700 € $kW_{el}^{-1}$ for future projects [37,p.152]. The projection is based on the investment cost developments over the last years.

For biomass cofiring, compared to pure coal-firing, additional equipment for fuel processing, storage and transport is needed (for details see [38]). The calculated investment costs for the individual biomass installations are summarized in Table 4. Considering the biomass power shares, the additional specific investment costs of cofiring are calculated with these data at 131.5 € $kW_{el\_bio}^{-1}$ for Z1, at 134.5 € $kW_{el\_bio}^{-1}$ for Z2, and at 480.4 € $kW_{el\_bio}^{-1}$ for Z3.

Finally, at the decommissioning stage, additional costs occur which are assumed to be 1% of the investment cost.

**Table 4. Investment cost of biomass cofiring (year 2009)**

| Investment cost [in 1000 €] | Z1 | Z2 | Z3 | Remarks / Sources |
|---|---|---|---|---|
| *General equipment:* | | | | |
| Biomass unloader | 1500 | 1500 | | [36] |
| Conveyor belt | 700 | 400 | 300 | [36] |
| Pneumatic conveyor | 500 | 350 | 200 | [36] |
| *Wood chips (5%$_{th}$)* | | | | |
| Caterpillar | 150 | 150 | | [39] |
| Storage hall (building) | 1040 | 1040 | | 65 €/m³ [40,p.196], 15,700 m³ for wood chis and 100 m² for mills and transport |
| Storage hall (technical equipment) | 160 | 160 | | 10 €/m³ [40,p.196], 15,700 m³ for wood chips and 100 m² for mills and transport |
| Mill | 1700 | 1700 | | [41] |
| *Wood pellets (5%$_{th}$)* | | | | |
| Silo incl. discharge | 1000 | 1000 | | [42] |
| *Straw processing (1.4%$_{th}$)* | | | | |
| Indoor crane | 50 | | 50 | [43,p.2], own calculations |
| Storage hall (building) | 244 | | 244 | 40 €/m³) [40,p.196], 5800 m³ for straw bales and 70 m² for mills and transport |
| Storage hall (technical equipment) | 61 | | 61 | 10 €/m³ [40,p.196], 5800 m³ for straw bales and 70 m² for mills and transport |
| Direct comminution | 425 | | 425 | [44] |
| *Mech. dehydrated sewage sludge (0.13%$_{th}$)* | | | | |
| Entire line (bunker, conveyor, burner) | 4670 | 4670 | 4670 | (1) |
| Total | 12,200 | 10,970 | 5950 | |

*Note:* (1) Annual consumption at 0.13%$_{th}$: 58,500 GJ/a → 58,000 t/a → 4.67 million €/a; linear up-scaling from: 27,000 t/a → 3.5 million €; 40,500 t/a → 4 million €/a; 54,000 t/a → 4.5 million €/a

*Data source*: [20,pp.56,78].

### *3.1.4. Operating costs*

Operating and maintenance (O&M) costs are composed of fixed and variable costs, and amount to 36.21 € $kW_{el}^{-1}$ (or 2.26 € $MWh_{el}^{-1}$) for a pure coal-fired power plant in 2009 [37,p.151]. Costs of maintenance, staff, fees and insurance premiums are included in the fixed costs. Changes in variable costs arise due to additional costs for maintenance and fuel, minus revenues from ash and gypsum sales. In total, cofiring rises mainly the costs of labor, $DeNO_x$ catalyst and cleaning of the power plant [36]. The cleaning costs increase due to the higher dust loading, and are mostly independent of the amount of co-fired biomass. Additional personnel is required for the biomass-specific operations and management tasks [36]. Except for the workers needed for the fuel feed, labor costs are mostly independent of the level of biomass consumption. The deactivation of the $DeNO_x$ catalyst is strongly influenced by the type of biomass and the corresponding share of cofiring. For wood chips and wood pellets the contents of most catalytic pollutants (alkali-, alkaline earth oxide, sulphur, phosphor, arsenic) are low in contrast to straw and sewage sludge (contents are sometimes several magnitudes higher than those of coal). Therefore, a faster deactivation is likely. For pure coal-firing, according to [45], the share of the maintenance cost of the $DeNO_x$ catalyst is about 2% of the fixed operating costs. Further, it is known that in the power plant Maasflakte, for the cofiring of wood chips and wood pellets, dried paper sludge and other biomasses (total share of approx. 10%) the maintenance costs of the $DeNO_x$ catalyst is about 150% higher than in the case of pure coal combustion [36]. We assume that the biomass used in this plant causes the same damage to the catalyst as fuel composition Z1. Assuming further that the high amount of wood chips and pellets ($10\%_{th}$) has the same negative impact on the boiler as those from the low amounts of straw ($1.4\%_{th}$) and as the sewage sludge ($0.13\%_{th}$), the additional costs can be split at 50% on each of the three fractions. For the fuel compositions Z1, Z2, and Z3 cost increases of 150%, 100% and 100% result. For all other operating cost shares, a rise proportional to the rise in the investment costs is assumed. The costs of cofiring are calculated as depicted in Table 5. The cost escalation over time is determined by the inflation rate.

### *3.1.5. Fuel costs and $CO_2$ permit prices*

Fuel costs are determined by the fuel supply costs of coal and biomass at the plant gate. We assume an average coal price of 1.87 € $GJ^{-1}$ (reference year 2009). The biomass prices used are based on Table 1. The average $CO_2$ permit price is 30.6 € $t_{CO2}^{-1}$ (reference year 2009). Note that in January 2012, permit prices were down at some 7.5 € $t_{CO2}^{-1}$, which is much lower than the $CO_2$ mitigation costs for cofiring of 25-30 € $t_{CO2}^{-1}$ (depending on the fuel mix) found by applying Eq. (1) below. Since certificates are only required for the share of emissions attributable to coal use, $CO_2$ emission factors are lower and amount to 0.6607 $t_{CO2}$ $MWh_{el}^{-1}$ (Z1), 0.6711 $t_{CO2}$ $MWh_{el}^{-1}$ (Z2) and 0.7353 $t_{CO2}$ $MWh_{el}^{-1}$ (Z3), compared to 0.7467 $t_{CO2}$ $MWh_{el}^{-1}$ for pure coal combustion.

**Table 5. Operating costs of biomass cofiring**

| | Z1 | | Z2 | | Z3 | | Remarks / sources |
|---|---|---|---|---|---|---|---|
| **Fixed operating costs** | | | | | | | |
| Personnel | 5 persons[a] | €375,000 | 4 persons[b] | €300,000 | 4 persons[b] | €300,000 | 75,000 €/(person · a) |
| $DeNO_x$ catalyst | Increase by 150% | €869,040 | Increase by 100% | €579,360 | Increase by 100% | €579,360 | Catalyst ca. 2% of fixed op. cost, increase by cofiring by 150% [36], of which 50% wood chips & pellets, 50% straw, 50% sew. sludge |
| Plant cleaning cost [€] | | 100,000 | | 100,000 | | 100,000 | [36] |
| Other fixed cost [€] | | 214,367 | | 197,940 | | 101,390 | 65% share of total fixed cost, increase proportional to investment cost [45] |
| Unitary fixed operating cost [€/$kW_{el}$] | | 1.948 | | 1.472 | | 1.351 | |
| **Variable operating cost** | | | | | | | |
| Variable cost [€/$MWh_{el}$] | | 0.025 | | 0.023 | | 0.012 | Operating resources are not much affected, esp. ash disposal at no cost / revenue [45]; increase proportional to investment cost |

*Notes:* [a] 3 workers (fuel-feed, on-site logistics, monitoring), 2 engineers (leadership, analysis, procurement); [b] 2 workers (fuel-feed, on-site logistics, monitoring), 2 engineers (leadership, analysis, procurement).

### *3.1.6. Revenues*

Revenues arise from the sale of electricity. The net present value (NPV) calculation is based on a (confidential) annual price duration curve, provided by E.ON Energy AG, used for the calculation of full-load hours in each year. The power plant is assumed to be used only if the variable costs are lower than the actual electricity price. From this, the average annual electricity offer price for the amount of electricity produced in this particular power plant results. For 7000 full-load hours this amounts to 40 € $MWh_{el}^{-1}$ (base year 2009) over the projection period 2020 (time for putting the power plant into operation) until 2030.

Further relevant parameters used for the profitability analysis are those reported in Table 6. For the inflation projection, the average annual inflation over the last 30 years is used, since the construction of a new power plant is a long-term investment ([46], own calculations).

**Table 6. General parameters for the economic assessment**

| | |
|---|---|
| Depreciation period | 20 a |
| Year of putting into operation | 2020 |
| Operating lifetime | 40 a |
| Deconstruction (demolition) cost | 1% of investment sum |
| Discount rate, before tax (nominal) | 10.0% |
| Discount rate, after tax (nominal) [a] | 12.0% |
| Inflation rate | 2.4% |

*Note:* [a] The calculated pre-tax interest rate (interest rate applied to pre-tax values, which is used for computation of the after tax value) is calculated from the internal after tax interest rate by including the tax share and the depreciation rate.

## *3.2. Profitability calculations*

The economic viability analysis is based on full cost and the NPV. The full cost calculation only considers the cost aspects and comprises the investment shares, operating and fuel cost. $CO_2$ mitigation cost of cofiring can be derived from this. Profitability can only be assessed from the NPV, as it also takes into account the revenue side. Both types of analysis are only informative if cofiring is compared with pure coal combustion. Depending on the assumptions made about cost and price levels, and their development over time, negative NPVs for cofiring may result. Profit deterioration compared to pure coal-firing results if the difference between NPVs ($NPV_{\text{Cof}} - NPV_{\text{Coal}}$) is negative, irrespective of the absolute value of $NPV_{\text{Cof}}$.

### *3.2.1. Full cost calculation*

The full cost calculation is used primarily for a rough comparison of the alternatives and cost splitting. We assume 7000 full-load hours per year and separate the cost (in real values, base year 2009) into four components (investment, fixed and variable operating costs, fuel cost). As the putting into operation is set for 2020, construction starts in 2015, which is when the first payments occur; investment payments end in 2020, and operating expenditures occur from 2020 to 2059.

The calculation of the costs is illustrated in the following example. For each year the individual cost components attributable to the investment are calculated and their sum discounted to the year of putting into operation (reference year). Subsequently, the sum is cumulated over all years and multiplied with the annuity factor ($ANF$ = 9.64%; the annuity (or capital recovery) factor is calculated as follows: $ANF = [r\ (1+r)^T/((1+r)^T\text{-}1]$, $T$ = operation period, $r$ = (real) discount rate). This yields the average real costs for the investment in each year. The average investment cost per $MWh_{el}$ is calculated by dividing through the amount of electricity produced. Analogously, this calculation is made for the other three cost components. By summing up over all components (investment, fixed and variable operating costs, fuel cost) and addition of the cost for $CO_2$ permits we can then calculate the total power generation cost per $MWh_{el}$. The $CO_2$ certificate price is assumed at 30 € $t_{CO2}^{-1}$ , as this corresponds with our calculations as well as the average price of the forecast (both presented in [38] in detail).

The $CO_2$ mitigation cost ($MC_{CO2}$) results from the comparison between the power generation cost (i.e. without consideration of the $CO_2$ certificate price) $PGC_{\text{Cof}}$ and $PGC_{\text{Coal}}$, respectively, and the specific $CO_2$ emissions ($EF_{\mathrm{Cof}}$, $EF_{\mathrm{Coal}}$) of a cofiring plant with those of a pure coal-fired power plant, i.e.:

$$MC_{CO2} = (PGC_{\mathrm{Cof}} - PGC_{\mathrm{Coal}})/(EF_{\mathrm{Coal}} - EF_{\mathrm{Cof}}). \quad (1)$$

where the emission factor $EF$ is the amount of $CO_2$ attributed to the coal in $t_{CO2}$ per $MWh_{el}$. The splitting of the power generation costs is reported in Fig. 5. Investment costs account for almost 40% and thus the largest cost share. Due to the high cost of the entire power plant in comparison to the biomass processing facilities the latter only have a negligible impact on power generation costs (the same holds true for the operating costs of the biomass facilities). The fuel cost increase in Z1 and Z2 relative to 100% coal combustion is due to the relatively expensive wood chips and wood pellets. For fuel composition Z3, revenues from sewage sludge lead to lower fuel prices in comparison to coal. For Z1 and Z2 the biomass shares and the price span of the biomass mix are large, resulting in a large span of the full cost. The $CO_2$ mitigation cost in the reference scenario is 30 € $t_{CO2}^{-1}$ for fuel mixes Z1 and Z2, and for 25 € $t_{CO2}^{-1}$ for Z3 (see Table 7).

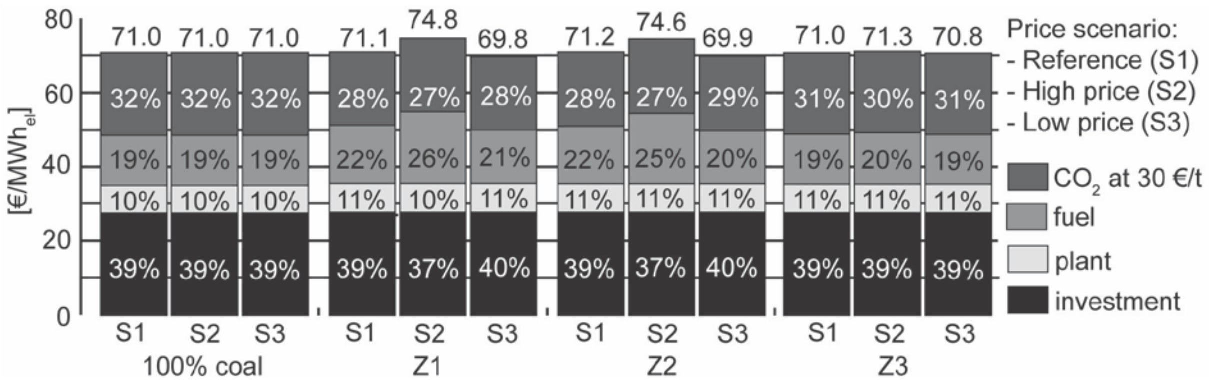


**Fig. 5. Full cost and decomposition for the four fuel mixes considered**

Overall, variant Z3 turns out to be superior regarding costs. In the longer run, a $CO_2$ certificate price of 30 € $tCO_2^{-1}$ can be considered as realistic. Under this assumption, the fuel mixes Z1 and Z2 are comparable from a cost perspective with pure coal combustion.

**Table 7. Results for the full cost calculation**

| [€/MWh$_{el}$] | Coal-only | Z1 | Z2 | Z3 |
|---|---|---|---|---|
| **Reference scenario** | | | | |
| Full cost | 71.01 | 71.14 | 71.17 | 70.96 |
| Change in full cost compared to coal-only | | 0.19% | 0.23% | -0.08% |
| $CO_2$ avoidance cost [€/t$_{CO2}$] | | 31.56 | 32.14 | 25.32 |
| Change in fuel cost compared to coal-only | | 15.96% | 14.55% | -0.26% |
| **High price scenario** | | | | |
| Full cost | 71.01 | 74.77 | 74.62 | 71.34 |
| Change in full cost compared to coal-only | | 5.30% | 5.08% | 0.47% |
| $CO_2$ avoidance cost [€/t$_{CO2}$] | | 73.69 | 77.73 | 59.21 |
| Change in fuel cost compared to coal-only | | 42.67% | 39.94% | 2.59% |
| **Low-price scenario** | | | | |
| Full cost | 71.01 | 69.82 | 69.92 | 70.84 |
| Change in full cost compared to coal-only | | -1.67% | -1.54% | -0.24% |
| $CO_2$ avoidance cost [€/t$_{CO2}$] | | 16.23 | 15.59 | 14.88 |
| Change in fuel cost compared to coal-only | | 6.24% | 5.33% | -1.14% |

### *3.2.2. NPV calculation*

In this section, we calculate the NPV from the marginal yield, investment cost, fixed operating costs, and taxes.

- *Marginal yield*. The marginal yield is determined as the difference between revenues from electricity sales and variable costs (fuel costs and variable operating costs). Fuel costs $c_f$ [€ MWh$^{-1}$] are calculated as:

$$c_f = \left( \left( p_{Coal} + EF_{CO2} \cdot p_{CO2} \right) \cdot x_{Coal} + \sum_{i}^{BiomassFuels} \left( p_{i,Bio} \cdot x_{i,Bio} \right) \right) \cdot \frac{3.6 \left[ GJ / MWh \right]}{\eta} \tag{2}$$

where $p_{i,Bio}$, $p_{Coal}$ is the price of biomass $i$ (e.g. wood) and coal [€ GJ$^{-1}$], respectively, $p_{CO2}$ the $CO_2$ certificate price [€ $t_{CO2}^{-1}$], $x_{i,Bio}$, $x_{Coal}$ the (co-)firing share of biomass $i$ and coal, respectively, $EF_{CO2}$ the emissions factor of coal combustion (0.094 $t_{CO2}$ GJ$^{-1}$), and $\eta$ the fuel conversion efficiency of electric power generation. Adding the variable operating costs yields the total variable production costs. The power plant is only operated at times when marginal production costs are lower than the electricity price. Hence we can determine full-load hours and electricity sales by the annual load duration curve of the power price. By subtracting the variable cost from the revenues we can compute the marginal yield.

- *Investment and fixed costs*. Investment outlays occur during construction, i.e. before putting the plant into operation, while decommissioning costs arise at the end of the lifetime. In contrast, fixed operating costs occur during the operation, and are computed by multiplying the specific costs with the power capacity of 800 $MW_{el}$.
- *Taxes*. The basis for the tax calculation is the EBIT (earnings before interest and taxes), computed by subtracting the fixed operating costs and the depreciation from the marginal yield. The tax rate applied to the EBIT is 30%.

For the assumptions made the NPV is about €-1000 million both for cofiring ($NPV_{\mathrm{Cof}}$) and pure coal combustion ($NPV_{\mathrm{Coal}}$). This highly negative value is mainly due to the very low electricity price (on average ca. 40 € $MWh_{el}^{-1}$) and the high discount rate (10%) assumed. However, for assessing the relative merit of the cofiring investment, a comparison between the two technologies in terms of NPV differences ($NPV_{\mathrm{Cof}} - NPV_{\mathrm{Coal}}$) is more useful since the subtraction of $NPV_{\mathrm{Coal}}$ brings all cases onto the same basis. The absolute NPVs ($NPV_{\mathrm{Cof}}$, $NPV_{\mathrm{Coal}}$) can be used for assessing the magnitude of the NPV difference.

**Table 8. NPV differences of the cofiring variants, by price scenario (reference year 2009)**

| $NPV_{\mathrm{Cof}}$ - $NPV_{\mathrm{Coal}}$ [million €] | Reference scenario | High price scenario[a] | Low price scenario |
|---|---|---|---|
| Z1 | 9.84 | -16.43 | 83.76 |
| Z2 | 4.96 | -13.38 | 77.26 |
| Z3 | 8.05 | -10.58 | 17.53 |

[a] *Note:* Losses limited by the PV of the investment and fixed operating costs.

In the reference scenario all biomass-coal mixes are preferred, as they yield positive NPV differences ($NPV_{\mathrm{Cof}} - NPV_{\mathrm{Coal}}$) (Table 8). The difference is largest for Z1, followed by Z3. In the low price scenario, the high biomass shares in Z1 and Z2 lead to highly positive values. The profits from cofiring of mix Z3 versus pure coal combustion are approximately 80% lower due to the lower biomass share.

Generally speaking, due to the lack of availability of low-cost biomass a switch to pure coal combustion is possible. If, in the least favorable case, cofiring after putting into operation of the power plant is not economically viable due to high prices, cofiring will lead to additional expenditures in comparison to pure coal combustion that arise from the higher investment and the fixed operating costs and consequently will not be applied. Note that, in reality, it can be assumed that not all additional fixed operating costs of cofiring occur, since e.g. the deactivation of the $DeNO_x$ catalyst will become less frequently necessary. In every other case cofiring is applied, because power can be produced cost-effectively by cofiring. The present value (PV) of the investment and fixed operating costs for cofiring thus is a lower bound of the NPV difference. This bound is limited to the losses that may result in the cofiring in comparison to pure coal combustion through high biomass prices. Note that also in the high price scenario in variants Z1 and Z2 higher losses are possible than in Z3. The relation of the profits for low prices compared to the losses in case of high prices is for Z1 and Z2 about 5.5, whereas for Z3 it is only two. Comparing the NPV differences with the NPV of pure coal combustion, $NPV_{\mathrm{coal}}$ = €-1082 million, it is striking that the differences are one to two magnitudes smaller than for the absolute NPV. Hence cofiring has only minor consequences on the profitability of the power plant.

*3.2.3. Sensitivity analysis*

In this section we check the robustness of the NPV results by varying the input parameter values by 10%. Since the decision in favor of or against cofiring is based on the NPV difference, rather than on the absolute NPV of the cofiring option, also the sensitivity is referred to this difference. This means that we consider the difference:

$$\left(NPV_{\mathrm{Cof}} - NPV_{\mathrm{Coal}}\right)_{\pm 10\%} - \left(NPV_{\mathrm{Cof}} - NPV_{\mathrm{Coal}}\right)_{\mathrm{BC}}. \tag{3}$$

where the subscript BC refers to the base case, i.e. with NPVs based on original assumptions. A negative change implies a reduction in the cost-effectiveness of cofiring vis-à-vis 100% coal-firing. Figure 6 shows the horizontal line above which the NPV of cofiring is higher than that of pure coal-firing ($NPV_{\mathrm{Cof}} > NPV_{\mathrm{Coal}}$). Fuel mix Z1 is chosen to illustrate the sensitivity analysis (Fig. 6). As can be seen, changes in the biomass prices have the strongest impact on the NPV difference. A more detailed discussion of the results can be found in [38].

Due to the significant effect of biomass, $CO_2$ certificate, coal and electricity prices and the conversion efficiency and inflation on the NPV difference, we assess its influence in a Monte Carlo simulation next.

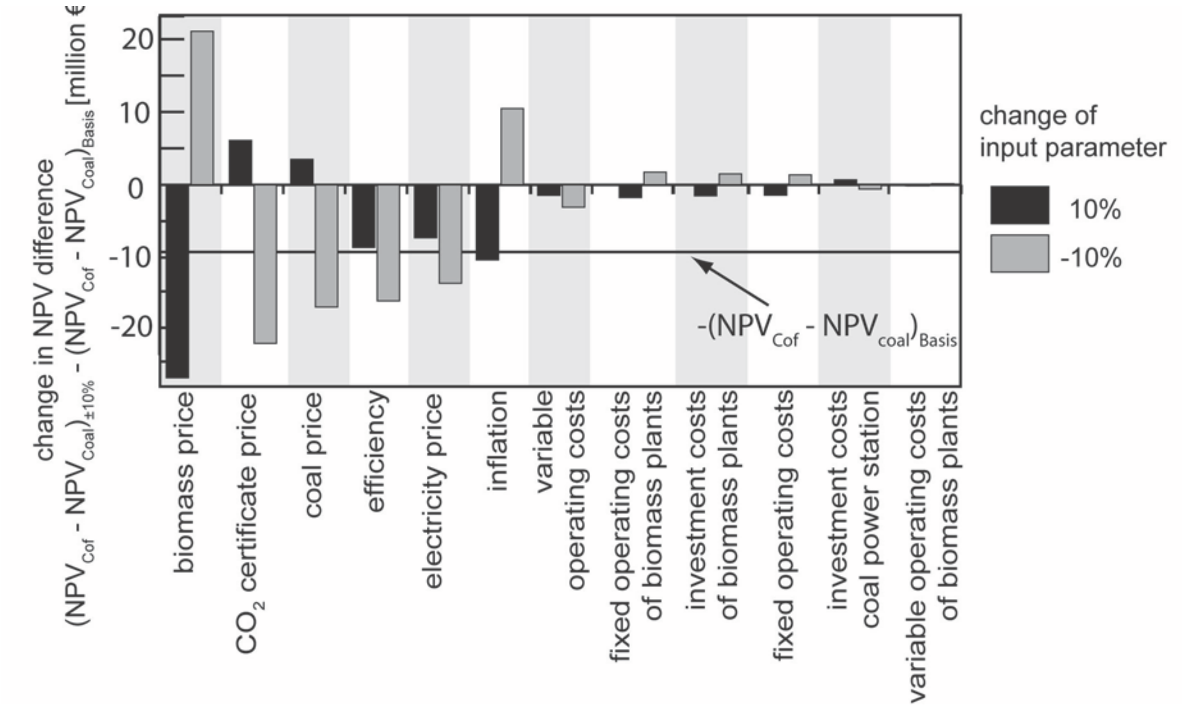


**Fig. 6. Results from the sensitivity analysis**

*3.2.4. Monte Carlo simulation*

With the help of Monte Carlo simulation (MCS) the uncertainty in the NPV calculation can be scrutinized. The values of those input factors found to be particularly influential in the sensitivity analysis are changed one by one, and the NPV newly computed. By applying a probability function on the input factors as well as frequent repetition, this change and the NPV calculation results in a NPV probability distribution. The latter is a major advantage of this method in comparison to others.

The choice of the probability distributions of the input factors is crucial for the informative value of the simulation results, since they determine the probability distribution of the NPV. The particularly relevant parameters are taken from the sensitivity analysis for fuel mix scenario Z1: prices of biomass (wood, pellets, straw, sewage sludge), coal price, $CO_2$ certificate price, electricity price, inflation, and efficiency. Since in the MCS the electricity price is not determined by a forecast, but assigned by a probability distribution, the full-load hours cannot be determined via the annual electricity price duration curve. Instead, they are also represented by a probability distribution.

In the literature, it is often assumed that prices of commodities can be approximated by a log-normal distribution (e.g. [47,p.9]). Such a distribution has the advantage that a lower bound exists (e.g. prices cannot turn negative) and in the existence of a relatively small expected value. Thirdly, there is an asymptotic decrease of the probability in case of rising values (i.e. prices will only take large values with a very small probability). The probability distributions for all parameters are chosen such that they best fit the historical data or theoretical considerations (see [38] for a detailed discussion of probability distributions). Table 9 summarizes the parameterization adopted.

**Table 9. Parameterization of the probability distribution functions of the variables used in the MCS**

| | Distribution function | Location | Mean | Standard dev. |
|---|---|---|---|---|
| Coal [€/GJ] | Log-normal | 1.65 | 2.36 | 0.75 |
| $CO_2$ certificate price [€/t] | " | 0 | 30 | 6.80 |
| Electricity [€/MWh] | " | 0 | 86.4 | 20.14 |
| Forest residue [€/GJ] | " | 0 | 4.22 | 1.75 |
| Wood residue [€/GJ] | Normal | - | 1.36 | 1.27 |
| Wood pellets [€/GJ] | Log-normal | 0 | 5.00 | 1.40 |
| Straw [€/GJ] | " | 0 | 3.40 | 0.61 |
| Sewage sludge [€/GJ] | " | -30.00 | -20.00 | 7.00 |
| Inflation rate [%/a] | " | -3.26 | 2.37 | 1.57 |
| Conversion efficiency [%] | Normal | - | 45% | 1% |
| Full-load hours p.a. | " | - | 7070 | 450 |

We ran 100,000 simulations. The lowest mean for the NPV occurs for pure coal combustion, followed by that for fuel mix scenario Z3 (Table 10). Z1 is the scenario with the highest NPV and thus likely to be the most profitable one. Although the absolute NPVs of this calculation (ca. €200 million) compared to the simple NPV calculation (approx. €-1,000 million) are markedly different (due to the changed assumptions regarding electricity prices and full-load hours) the results match well. This insensitiveness of the cost-effectiveness of cofiring with regard to the electricity price level is confirmed by another MCS, where the mean of the power prices is taken as the average real electricity price from the simple NPV calculation (57 € $MWh_{el}^{-1}$), while all distributions of the other input parameters are as before. As can be seen from the middle part of Table 10, the absolute NPVs are markedly lower than for the case of high future electricity prices. However, the NPV differences are hardly affected. The reason for this independence of the absolute level is the decoupling of the electricity prices from the annual operating hours. Relevant is the difference between production costs for the different fuel mix variants studied. The 0.5% range in Table 10 indicates the interval, in which the probability of occurrence of the NPV above and below the interval is smaller than 0.5%. We can see that in the scenarios "pure coal-firing" and Z3 NPVs of less than €-1000 million are possible at a probability of 0.5%, whereas in Scenarios Z1 and Z2 this lower bound is at €-930 million. Hence for the former higher losses are possible. At the same time, the upper bound – and thus the maximum expected profits – is the same in all scenarios (€1600 million).

**Table 10. Mean and standard deviation of NPV for the four fuel mix scenarios (reference year 2009)**

| Net present value | Coal-only | Z1 | Z2 | Z3 |
|---|---|---|---|---|
| *Electricity price (mean): 86 €/MWh$_{el}$* | | | | |
| Mean [million €] | 186 | 197 | 195 | 189 |
| Standard deviation [million €] | 538 | 529 | 530 | 536 |
| 0.5%-interval | [-1000, 1600] | [-930, 1600] | [-930, 1600] | [-1000, 1600] |
| *Electricity price (mean): 57 €/MWh$_{el}$* | | | | |
| Mean [million €] | -538 | -523 | -526 | -534 |
| Standard deviation [million €] | 580 | 567 | 569 | 587 |
| *NPV difference:* | | | | |
| Mean [million €] | - | 11 | 5 | 3 |
| Standard deviation [million €] | - | 25 | 22 | 4 |
| Probability for neg. NPV differences | - | 33% | 36% | 9% |

Next, we consider the NPV difference of the cofiring alternatives compared with the pure coal combustion ($NPV_{\text{Cof}}$ – $NPV_{\text{Coal}}$). A positive difference implies an economic superiority of cofiring. Figure 7 shows the probability distributions of the NPV differences for scenarios Z1, Z2 and Z3 after 100,000 simulation runs. From the area underneath the envelopes in a certain interval we can infer the probability of the NPV difference in this interval.

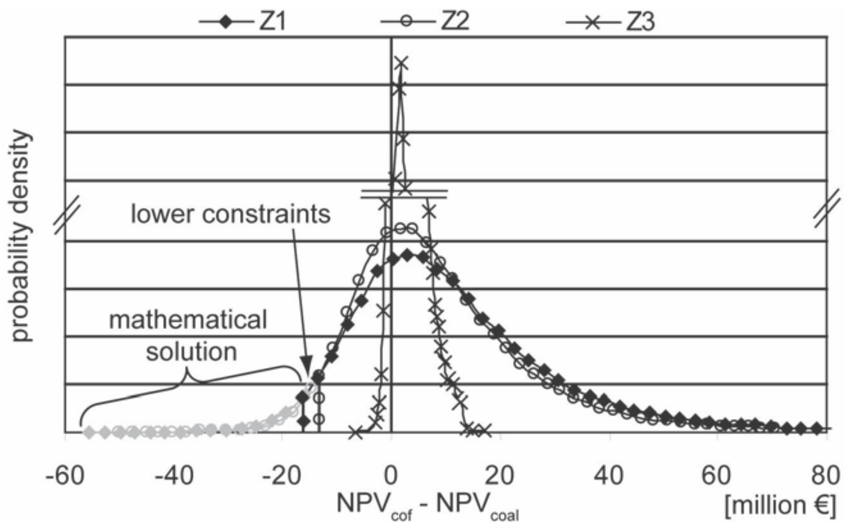


**Fig. 7. Distribution of difference $NPV_{\text{Cof}} – NPV_{\text{Coal}}$ for Scenarios Z1, Z2 and Z3 (reference year 2009)**

Regarding the limitation of the NPV difference against negative values there exists, just like for the simple NPV analysis, a lower constraint determined by the NPVs of the investment and fixed operating costs.

From the MCS a probability of more than 60% results for the higher NPVs that arise from all cofiring variants, as compared to the pure coal combustion. Specifically, fuel scenario Z1 could turn out to be markedly more or less profitable than pure coal combustion.

Scenario Z2 has, compared to Z1, a stronger trend to negative NPV differences and is, therefore, inferior. Thus, fuel composition Z3 is the preferred one by risk-averse investors.

It is important to note that the results are generally only valid if the assumed probability distributions for the input parameters are valid as well. In order to enhance this, we used presumptions that seemed both reasonable and plausible to us. Still, the correctness of the distributions assumed cannot be guaranteed. Also, we ignored correlations between the individual input parameters due to data limitations. Since total independence of all parameters is unlikely, the results ought to be interpreted against this background with some caution.

### *3.2.5. Conclusions from the economic analysis*

From the full cost calculation we learn that cofiring of biomass in the reference scenario leads to $CO_2$ mitigation costs of 30 € $t_{CO2}^{-1}$. Generally, we find for fuel composition Z3 the lowest $CO_2$ mitigation costs irrespective of the price scenario. The simple NPV analysis and the MCS have both shown that the occurrence probability of a higher NPV of the cofiring variants relative to pure coal combustion is more than 60%. Given the larger flexibility inherent in the fuel types used in Z1, risk mitigation can be realized in a way that is impossible with fuel mixes Z2 and Z3.

## 4. Conclusions

Investigations of 150 power plants worldwide have shown that biomass cofiring is technically feasible [7,p.10] and that at least $10\%_{th}$ of coal can be replaced by high-quality biomass. Hence, in Germany some 28 $TWh_{el}\ a^{-1}$ could be produced by biomass cofiring, implying a rise in the $CO_2$-neutral power generation by almost 25%. According to our calculations, power generation cost assigned to biomass range between 70-75 € $MWh_{el}^{-1}$ for a power plant to be put into operation in 2020. Compared to other renewable energy technologies this is in the lower cost range. In comparison to the power generation cost projections for other renewable energy sources for the year 2020, biomass ranks in the lower range (concentrated solar power: 110-115 € $MWh_{el}^{-1}$, photovoltaics: 67-200 € $MWh_{el}^{-1}$ , onshore wind: 66-68 € $MWh_{el}^{-1}$, offshore wind: 103-110 € $MWh_{el}^{-1}$; see [48,p.16]. Another advantage of biomass cofiring is the independence from external conditions, such as wind or solar irradiation, enabling its utilization to be adjusted to actual demand. In addition, the use of biomass raises the flexibility of fuel use and thus leads to a reduced dependence on (fossil) fuel markets.

Our analysis of the economic potentials and the supply costs shows that wood chips from forest residues from national and near European sources can be used. Supply costs are at approximately 4.1 € $GJ^{-1}$. Wood pellets, due to their relatively high energy density, can be bought from large international suppliers at a cost of approx. 5 € $GJ^{-1}$ and thus are often less expensive than regionally or locally available ones. For the case of straw, regional supply is most cost-effective at costs of about 3.6 € $GJ^{-1}$. Smaller potentials of low cost waste and by-products are also available, of which wood waste and wood residues (on average available at 1.4 € $GJ^{-1}$) and sewage sludge (available at -20 € $GJ^{-1}$) are the most interesting ones. In principle, the span of possible biomass prices is wide, mainly due to regionally diverse conditions and supply and demand fluctuations over time.

Technical boundaries for biomass shares in cofiring exist, resulting in upper limits for cofiring of wood at some $20\%_{th}$, for straw at $5\%_{th}$, and of sewage sludge at 4 volume-%. Flue gas emissions normally do not limit the share of biomass. The ash from pure coal combustion is used as an additive in cement production. For using ash from cofiring as well, an application for a special permit is required (in Germany).

For the assessment of the economic feasibility of cofiring we have made a comparison with pure coal combustion. For new power plants we have shown that biomass, coal and $CO_2$ certificate prices are the main influencing factors. For the reference scenario we find that cofiring is economically superior with a probability of more than 60% as compared to coal-only firing. $CO_2$ avoidance cost are at about 30 € $t_{CO2}^{-1}$, if a high quality biomass mix with a cofiring share of about $11\%_{th}$ is used. For low-cost biomass resources and a cofiring share of $1.1\%_{th}$ these are at about 25 € $t_{CO2}^{-1}$. In case biomass prices turn out to be too high for their economical use, the cofiring plant can switch to pure coal combustion. Thus the economic risk is limited to the investment and fixed operating costs of the cofiring plant components, amounting to some €10-20 million maximum.

In order to be able to introduce cofiring in a power plant, the following steps are required. First, a detailed assessment of the regional and international markets is necessary, in order to identify the low-cost biomass supply potentials that can be secured. Second, in a technical examination, the possible biomass shares of a new fuel mix have to be determined. Also, if applicable and reasonable, necessary permissions for exceeding emission limits and for the utilization of the ashes from cofiring in the cement industry should be applied for.

Overall, our study has shown that biomass cofiring can be a technically and economically feasible alternative to $CO_2$-neutral power generation, and that the biomass fuel price risk is limited due to the possibility of reverting to pure coal combustion. Therefore, we recommend the above-described steps for the introduction of biomass cofiring, and on this basis the economic viability of specific cofiring projects can be evaluated.

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## Appendix A: Determination of the heat price for coal firing

The coal price free sea port was estimated in 2008 by the IEA for 2010 and 2015 at about 3.70 € $GJ^{-1}$ each, vis-a-vis 2.24 € $GJ^{-1}$ in 2007 (real 2007 prices; cf. [49, p.68]). Note that we converted the original figure of 120 US$ $t^{-1}$ using a factor of 1.16 US$ $€^{-1}$, which is the mean value since the introduction of the Euro [50], and an assumed heating value of hard coal (water contents: 5.1%) of 28.06 GJ $t^{-1}$. The 2007 estimate, in contrast, expected 1.70 € $GJ^{-1}$ (2010) and 1.80 € $GJ^{-1}$ (2015) (real 2006 prices; [49, p.64]). In our study, the forecasts of 2008 serve as an upper limit of expectations, as for the years following 2015 decreasing prices were expected [49, p.68] and because the estimates were influenced by the high energy prices in summer 2008. The 2007 predictions serve as lower limits, as they do not yet reflect the price increases in the following year. Following B. Nelson ([51, pp.11-12) almost 50% of the global anthropogenic $CO_2$ emissions in 2030 can be avoided by measures at cost of max. 40 € $t_{CO2}^{-1}$. This also comprises the bulk of emissions from power generation. As the plant operators will rather invest in mitigation measures than to buy the more expensive $CO_2$ certificates, on the other hand these investments are subject to risk and needing a certain lead time, in the following we assume the cost of the $CO_2$ certificates not to exceed 50 € $t_{CO2}^{-1}$. As the lower level estimate of the $CO_2$ certificate prices we assume 20 € $t_{CO2}^{-1}$. With this we can compute the heat prices for the assumption of high coal and $CO_2$ certificate prices as follows:

$$3.70\ €/GJ + \frac{50\ €/t_{CO2} \cdot 2.52\ t_{CO2}/t_{Coal}}{28.06\ t_{Coal}/GJ} = 8.2\ €/GJ\,. \tag{A.1}$$

For low coal and $CO_2$ certficate prices we obtain:

$$1.70\ €/GJ + \frac{20\ €/t_{CO2} \cdot 2.52\ t_{CO2}/t_{Coal}}{28.06\ t_{Coal}/GJ} = 3.5\ €/GJ\,. \tag{A.2}$$

Depending on the distance and access an amount of up to 0.6 € $GJ^{-1}$ has to be added for the supply of an inland location (assuming transport costs from Rotterdam to the power plant in Zolling (Bayern), which is considered as representative for a location with more intricate supply ([46], own calculations).

## Appendix B

**Table A.1. Input values and results from NPV and $CO_2$ avoidance cost calculations for cofiring retrofits**

| | A | B | C | D | E |
|---|---|---|---|---|---|
| **Z1** | | | | | |
| Firing shares [$\%_{th}$] | | | | | |
| Wood chips | 5.00% | 5.00% | 0.00% | 0.00% | 5.00% |
| Wood pellets | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Straw | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% |
| Sewage sludge | 0.13% | 0.13% | 0.13% | 0.13% | 0.13% |
| Investment cost [million €] | 9.6 | 9.6 | 5.8 | 5.8 | 8.8 |
| Unitary fixed operating cost [€/$kW_{el}$] | 38.0 | 37.9 | 38.4 | 38.5 | 38.3 |
| Unitary var. operating cost [€/$MWh_{el}$] | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| $NPV_{Z1}$ minus $NPV_{Coal}$ [million €], 2009 | | | | | |
| Reference scenario | 6 | 3 | -4 | -1 | -2 |
| High price scenario | -15 | -18 | -8 | -8 | -13 |
| Low price scenario | 41 | 49 | 6 | 5 | 27 |
| $CO_2$ avoidance cost [€/$t_{CO2}$] | | | | | |
| Reference scenario | 26 | 28 | 37 | 33 | 30 |
| High price scenario | 68 | 70 | 74 | 69 | 72 |
| Low price scenario | 12 | 12 | 23 | 22 | 14 |
| **Z3** | | | | | |
| Firing shares [$\%_{th}$] | | | | | |
| Wood chips | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Wood pellets | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Straw | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% |
| Sewage sludge | 0.13% | 0.13% | 0.13% | 0.13% | 0.13% |
| Investment cost [million €] | 4.5 | 4.6 | 3.6 | 3.6 | 3.8 |
| Unitary fixed operating cost [€/$kW_{el}$] | 37.3 | 37.3 | 37.8 | 37.9 | 37.5 |
| Unitary var. operating cost [€/$MWh_{el}$] | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| $NPV_{Z3}$ minus $NPV_{Coal}$ [million €], 2009 | | | | | |
| Reference scenario | 4 | 7 | 2 | 0 | 2 |
| High price scenario | -7 | -7 | -4 | -4 | -6 |
| Low price scenario | 7 | 11 | 4 | 2 | 5 |
| $CO_2$ avoidance cost [€/$t_{CO2}$] | | | | | |
| Reference scenario | 19 | 16 | 34 | 39 | 21 |
| High price scenario | 53 | 50 | 68 | 73 | 55 |
| Low price scenario | 9 | 5 | 23 | 29 | 10 |

*Note:* Unitary costs refer to total electric capacity and energy, respectively, and not only the share of biomass.

**Table A.2: Detailed account of the investment and operation costs for the co-firing retrofit of five power plants in Germany owned by E.ON**

| | A | B | C | D | E |
|---|---|---|---|---|---|
| Z1 | | | | | |
| Investment cost [1000 €] | | | | | |
| General | 2700 | 2700 | 1850 | 1850 | 2700 |
| Plant-specific (wood) | 1903 | 1904 | | | 3100 |
| Plant-specific (pellets) | 732 | 741 | 560 | 604 | 625 |
| Plant-specific (straw) | 776 | 842 | 361 | 369 | 1892 |
| Plant-specific (sewage sludge) | 3500 | 3500 | 3000 | 3000 | 496 |
| Sum | 6110 | 6187 | 2770 | 2823 | 8813 |
| Fixed operating costs | | | | | |
| DeNOx catalyst [1000 €/a] | 821 | 951 | 350 | 328 | 554 |
| Personnel [1000 €/a] | 300 | 300 | 225 | 225 | 300 |
| Cleaning [1000 €/a] | 100 | 100 | 100 | 100 | 100 |
| Other fixed costs [1000 €/a] | 133 | 134 | 80 | 81 | 122 |
| Spec. fixed costs [€/$kW_{el}$] | 38.0 | 37.9 | 38.4 | 38.5 | 38.3 |
| Variable operating costs | | | | | |
| Variable costs [1000 €/a] | 69.7 | 66.0 | 23.4 | 44.9 | 55.2 |
| Spec. var. costs [€/$MWh_{el}$] | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| | | | | | |
| Z3 | | | | | |
| Investment cost [1000 €] | | | | | |
| General | 250 | 250 | 250 | 250 | 250 |
| Plant-specific (wood) | 3500 | 3500 | 3000 | 3000 | 3100 |
| Plant-specific (pellets) | 0 | 0 | 0 | 0 | 0 |
| Plant-specific (Straw) | 0 | 0 | 0 | 0 | 0 |
| Plant-specific (sewage sludge) | 776 | 842 | 361 | 369 | 496 |
| Sum | 4526 | 4592 | 3611 | 3619 | 3846 |
| Fixed operating costs | | | | | |
| DeNOx catalyst [1000 €/a] | 548 | 634 | 250 | 234 | 369 |
| Personnel [1000 €/a] | 150 | 150 | 150 | 150 | 150 |
| Cleaning [1000 €/a] | 100 | 100 | 100 | 100 | 100 |
| Other fixed costs [1000 €/a] | 63 | 64 | 50 | 50 | 53 |
| Spec. fixed costs [€/$kW_{el}$] | 37.3 | 37.3 | 37.8 | 37.9 | 37.5 |
| Variable operating costs | | | | | |
| Variable costs [1000 €/a] | 32.8 | 31.3 | 14.6 | 27.9 | 24.1 |
| Spec. var. costs [€/$MWh_{el}$] | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |

*Notes:* Rounded figures. The specific operating costs refer to the total electrical power or energy, and not only to the biomass share.

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