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Co-firing – A strategy for bioenergy in Poland?

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ABSTRACT

Biomass provides the largest reduction of carbon dioxide (CO_2) emission when it replaces coal, which is the dominating fuel in heat and electricity production in Poland. One means of replacing coal with biomass is to co-fire biofuels in an existing coal-fired boiler. This paper presents an analysis of the strengths and weaknesses of co-firing biofuels in Poland with respect to technical, environmental, economical and strategic considerations. This analysis shows that co-firing is technically and economically the most realistic option for using biofuels in the large pulverized fuel (PF) boilers in Poland. However, from an environmental perspective, co-firing of biofuels in large combined heat and power (CHP) plants and power plants provides only a small reduction in sulphur dioxide (SO_2) emission per unit biofuel since these plants usually apply some form of desulphurization technology. In order to maximize the SO_2 emission reduction, biofuels should be used in district heating plants. However, co-fired combustion plants can handle disruptions in biofuel supply and are insensitive to moderate changes in fuel prices, which makes them suitable utilizers of biofuels from perennial energy crops. Co-firing could therefore play an important role in stimulating perennial crop production.

Keywords: co-firing, bioenergy, biofuels and Poland

1. Introduction

Renewable energy sources (RES) are gaining an increasingly important role in the EU in reducing the emission of greenhouse gases. In Poland, which has been an EU member state since 2004, the policies on RES have for several years, largely been guided by those on the EU level. Important landmarks concerning RES in Poland include the document "Development Strategy for the Renewable Energy Sector". This document, which was adopted by the Polish Parliament in 2000, calls for a 7.5% contribution from RES in primary energy supply by 2010 and a 14% contribution by 2020 [1]. For comparison, RES accounted for 4.6% in 2003 [2]. Much of the required increase is expected to be supplied by biomass, which has been identified as the most promising source of RES in Poland [3].

Biomass provides the largest reduction of carbon dioxide (CO_2) emission when it replaces hard coal and lignite (collectively referred to as *coal* in this paper), which are the most carbon-intensive fuels. In Poland, coal is the dominating fuel in heat and electricity production. Replacing coal by biomass usually also reduces the emission of sulphur dioxide (SO_2). SO_2 has negative effects on both public health and the environment. The environmental effects include acidification of soils and forests. In addition, SO_2 emissions cause corrosion of materials and buildings. The negative effects on health derive from sulphate aerosols, i.e. particulates that originate from gaseous SO_2 emissions.

One means of substituting biomass for coal is to co-fire biofuels in existing coal-fired boilers. Co-firing of biofuels has been demonstrated in numerous pilot and commercial plants in the USA and Europe. These projects show that co-firing of various types and proportions of biofuels is technically feasible in different types of boilers [4, 5]. Today, co-firing is a commercial, mature technology that is employed in many countries in Europe, including Poland. Most of these plants are large power plants that employ direct co-firing[1] [6].

Studies on co-firing in Poland have been carried out by Berggren and Ljunggren [7], who modelled the potential electricity production from co-firing of biofuels in Poland for 2010, and Nilsson et al. [8], who analyzed the potential of expanding the use of bioenergy in Poland, suggesting co-firing as a possible strategy.

This paper presents an analysis of the strengths and weaknesses of co-firing biofuels in Poland. For this purpose, an analytical framework, consisting of four perspectives: the technical, environmental, economical and strategic, was applied to the problem. The approach was mainly qualitative, but in terms of the economic and environmental perspectives, also quantitative. It is hoped that the results will contribute to the scientific basis for decisions regarding future use of biomass in Poland.

2. Heat and electricity production in Poland

Coal is the dominating fuel in heat and electricity production in Poland. In 2003 the consumption of hard coal and lignite corresponded to 2050 PJ and 530 PJ, respectively [2]. Table 1 lists the current use of hard coal and lignite broken down into five applications, distinguished by the production mix, thermal capacity of the plant boiler and economic sector (residential, energy or

[1]This paper concerns *direct co-firing*, which means co-firing of at least two fuels in the same boiler. Other modes of co-firing include *indirect co-firing*, in which the solid fuel is gasified and subsequently combusted together with a gaseous fuel and *parallel co-firing*, in which the fuels are burnt in separate boilers, but the steam produced is fed to the same turbines.

industrial). It can be seen that hard coal is used in all types of applications, while the use of lignite is restricted to large combined heat and power (CHP) plants and power plants. Biomass accounted for 170 PJ of the energy used in 2003 [9].

In 2003 electricity production in Poland amounted to 151 TWh, of which hard coal accounted for 63% and lignite for 35%. The remaining 2% was based on RES, most of which was hydropower [2]. In 2004 biomass-based electricity production amounted to 770 GWh [9]. This electricity was produced in seven industrial CHP plants and 15 public power and CHP plants. Five of the industrial CHP plants were located at forest industries and relied on biofuels only, while the other 17 plants co-fired biofuels and coal [10].

District heating is common in Eastern Europe. In Poland roughly 52% of households are connected to district heating grids [11]. The major part of the district heat is produced in public and industrial CHP plants, and the rest in district heating plants. In 2003 hard coal and lignite accounted for 86% and 2%, respectively, of the heat production [2]. The remaining production was based on natural gas, oil and biofuels. In rural areas and small towns, the heat is mainly produced in detached-house boilers, stoves or local boiler rooms that supply heat to a small number of houses or buildings. In 2003 hard coal and firewood accounted for 45% and 17%, respectively, of small-scale heat production [2].

In 2003, industry sector consumed the equivalent of about 470 PJ of hard coal for the production of process heat [2]. Industry's consumption of hard coal for the production of district heat and electricity is included in the categories of small- and medium-scale CHP production (applications 2 and 3 in Table 1).

The grate boiler is common in local boiler rooms, district heating plants and small-scale CHP plants. In medium-sized CHP and power plants, pulverized fuel (PF) boilers dominate in terms of installed capacity. There are also 11 circulating fluidized bed (CFB) boilers with capacities ranging from 130 to 650 MW_{th} [12].

The heavy reliance on coal in heat and electricity production has made these sectors large emitters of CO_2 and SO_2. Four out of the ten largest point sources of SO_2 in the EU25 are Polish power plants [13]. Polish SO_2 emissions have, however, decreased considerably over the past 20 years, from about 4300 ktonnes per year in the mid-80s to 1375 ktonnes in 2003, of which 722 ktonne originated from public power and CHP plants, 303 ktonnes from industrial CHP plants and 256 ktonnes from district heating and small-scale heating plants [9]. The initial SO_2 emission reduction may be ascribed to the declining electricity production, increased electric efficiencies at power plants and the shift to coal with lower sulphur content [14]. During the past ten years or so the emissions of SO_2 have, despite the increasing electricity production, continued to decrease as a result of the gradual installation of flue gas desulphurization (FGD) at power plants.

Table 1: The Polish use of hard coal and lignite for heat and electricity production in 2003 (adapted from [2] and from Chalmers Power Plant Database, which includes power plants with a capacity above 1 MW_e built before 2000 [12]).

Application	Boiler capacity (MW_{th})	Hard coal (PJ)	Lignite (PJ)
1 Small-scale heat[1]	0-50	257	3.0
2 District heat[2] & small-scale CHP[3]	<100	290	0
3 Medium/large-scale CHP[3] & power[4]	100-500	508	78.5
4 Large-scale power[4]	>500	523	446
5 Industrial process heat[5]	1-500	470	0
Total		2048	528

[1]Heat production in detached-house boilers and stoves and in local boiler rooms. Local boiler rooms supply heat e.g. to a small neighbourhood, a school or a hospital. The boilers may be as large as 50 MW_{th}, but this is very rare.
[2]Production of district heat in heating plants (126 PJ), heat-only boilers at CHP and power plants (21 PJ) and in non-public heat plant transformation (6.7 PJ).
[3]Production of electricity and district heat in public or industrial CHP plants.
[4]Production of electricity in power plants.
[5]Production of process heat used in industry. The heat is produced either in a heat boiler or a CHP plant.

3. Technical considerations

3.1 Fuel flexibility

The fuel flexibility of a combustion plants depends to a great extent on the boiler technology, but also on the plant's ability to store and pre-process different fuels. From a technical perspective, all boilers can be converted from coal to biofuels. The cost of doing so, however, varies greatly depending on boiler technology and the size and age of the plant. Grate and CFB boilers can combust a relatively wide range of fuels in terms of particle size, composition and moisture content. After minor modifications, these types of boilers can usually accommodate complete or near-complete conversion to biofuels. PF boilers, on the other hand, which dominate in Poland in terms of installed capacity, are relatively inflexible unless major retrofitting is undertaken.

There are several reasons why co-firing is the most realistic option for introducing biofuels in large coal-fired PF and CFB boilers in Poland. Firstly, complete fuel conversion would require a biofuel supply from a large area surrounding the plant, posing a logistic challenge. Secondly, the lower energy density and higher moisture content of biofuels compared with coal makes biofuels more complicated to store and handle. The lower heating value of biofuels is about half that of hard coal and the density is about one fifth. Consequently, co-firing with 10% biofuel (on energy basis) requires roughly similar inputs of biofuels and hard coal in terms of volume. As a result, the maximum boiler capacity and electricity production may decrease, in particular if the proportion of biofuels exceeds 10% on energy basis. The drop in boiler capacity is generally more negative for large power plants than heating plants. During the next 10 years the demand for district heat, for example, is projected to decrease moderately, while the electricity consumption is expected to continue to grow [3]. Thirdly, PF boilers require a fuel with small particle size and low moisture content. These requirements on fuel quality can be met either by purchasing refined fuels, such as wood pellets and sawdust, or by purchasing biofuels such as wood chips that can be internally pre-processed (dried, milled). Fourthly, complete conversion to biofuels may cause operational problems in the boiler, which can be avoided by co-firing the biofuels with coal (see Section 3.2).

There are two basic options for co-firing of biofuels in PF boilers, one that entails a low to moderate investment cost and high fuel cost, and the other that entails a high investment cost and a lower fuel cost. The first option, which involves minor to moderate retrofitting of the plant, requires biofuels with a relatively low moisture content and small particle size in order to guarantee ignition and complete burnout. When co-firing up to 5% refined biofuels such as wood pellets it is technically feasible to mix the fuels before pulverization, thus avoiding investments in a separate mill and feeding system for the biofuels. When co-firing a higher proportion of biofuels (5-10%) or biofuels of somewhat higher moisture content and larger particle size, it is preferable to install a separate mill and feeding system for the biofuel in order to avoid operational problems [15].

The second option for co-firing involves major retrofitting of the PF boiler through the installation of a vibrating grate or CFB boiler at the bottom of the PF boiler. These modifications increase fuel flexibility, thus enabling the use of biofuels with high moisture content and large particle size.

3.2 Fuel compatibility

Depending on the source of biomass, the introduction of biofuels in a coal-fired boiler may cause operational problems in the boiler due to the higher content of alkali metals and chlorine compounds. These elements reduce the ash melting temperature, causing ash deposition problems, such as slagging, fouling and sintering, and corrosion. These elements are particularly abundant in herbaceous biomass such as straw. Combustion of straw is therefore associated with an increased risk of corrosion [16] and sintering in FB boilers [17]. Corrosion is particularly a problem when the straw is fired at high temperatures, causing so-called high-temperature corrosion, which primarily affects the super-heaters [16]. In order to avoid these problems, straw should be used in grate-fired boilers or co-fired unless the boiler was designed for straw. Co-firing of biofuels entails a lower risk of corrosion and ash deposition problems than utilizing biofuels alone. This effect is due to both the dilution of the biofuels and to the sulphur in the coal, which binds to the alkali metals [18].

Straw has considerably lower energy content per unit volume than wood chips. Straw should therefore be used relatively close to where it is harvested which makes it more suitable in small- and medium-sized combustion plants.

3.3 Selective catalytic reduction

According to several studies, for example Baxter [4] and Nussbaumer [19], co-firing increases the deactivation rate of selective catalytic reduction (SCR) catalysts, which are used to reduce the emission of nitrogen oxides (NO_x). The deactivation rate depends on the proportion and source of the biofuels, and the type and location of the catalyst in the boiler [20]. Experience from utilizing SCR catalysts in a number of Swedish biofuel-fired CHP plants indicates that washing of the catalyst is an effective method of reactivating it [21].

At the moment there are no Polish power plants equipped with SCR catalysts. Such equipment will, however, become necessary for power plants with boilers larger than 500 MW_{th} by 2016, when new stricter emission limit values (ELVs) for NO_x come into force [22]. At present, many combustion plants in Poland use primary NO_x abatement technologies such as staged combustion, exhaust gas recirculation and low-NO_x burners. The application of these primary technologies, sometimes several in combination, will continue to ensure compliance with ELVs for boilers with a thermal capacity of less than 500 MW_{th}.

4. Environmental considerations

The substitution of biomass for coal provides a large reduction in CO_2 emission since coal, which is the most carbon-intensive fuel, is replaced. This substitution also has the potential to reduce the emission of a number of air pollutants, in particular SO_2 which this discussion focuses on. The emissions of NO_x and particles are not discussed since combustion technology has a large impact on their formation than what the fuel has (assuming solid fuels). Biomass ash recycling and energy efficiency are also briefly discussed.

4.1 Sulphur dioxide emissions

The substitution of biomass for coal usually reduces the SO_2 emissions substantially because of the lower content of sulphur in biofuels[2] than in coal[3]. Direct co-firing reduces the SO_2 emissions further than what would be expected from the replacement of coal only. This is due to the increased binding of sulphur in the ash by alkali components in biofuels [19, 23, 24 and 25]. The reduction in SO_2 emission per unit biofuel varies between different combustion plants depending on the coal quality and the presence and efficiency of desulphurization technology. Whether desulphurization is applied or not depends to a great extent on the ELV for SO_2 that is applied to the combustion plant.

[2] The sulphur content is about 0.05-0.15 wt% in biofuels, where the lower value is typical for wood and the higher for straw.
[3] The sulphur content is on average 0.8 wt% for Polish hard coal and lignite.

In Poland, SO_2 emissions are regulated for all stationary combustion plants with a thermal capacity above 1 MW [22]. This is in accordance with the EU Directive (2001/80/EC) on the limitation of emissions of certain pollutants into the air from large combustion plants [26]. The ELVs vary depending on the age, size and fuel of the plant. In general, the larger and the newer the plant, the stricter the ELV, which is reflected in the application of desulphurization measures in combustion plants. Desulphurization technology is gradually being installed in large CHP and power plants in Poland. In 2005, 50-60 power units, accounting for up to half of the installed power capacity in Poland, applied some form of desulphurization measure (estimate based on [12] and [27]). The use of desulphurization measures will continue to increase as old combustion plants are phased out and as emission regulation is strengthened. In January 2008 the ELVs that apply to old[4] coal-fired combustion plants will be reduced, which will force many medium-to-large-sized combustion plants to introduce some form of SO_2 abatement measure. FGD will be necessary for large combustion plants (boiler capacity>500 MW_{th})[5] and for certain medium-sized plants while others will be able to comply with the ELVs by co-firing with biofuel and/or by changing to low-sulphur coal. The ELVs for co-firing plants are calculated based on the proportion of each fuel. The ELVs for the combustion of biofuels are lower than those for coal, but rather generous considering the sulphur content in biofuels.

4.1.1 Quantification of SO_2 emissions

In order to illustrate how the SO_2 emission reduction differs between combustion plants, four combustion plants that are typical for Polish heat and/or electricity production are defined (Table 2). Based on the earlier discussions in this paper, complete fuel conversion is assumed in the grate boiler, and retrofitting for co-firing is assumed in the PF boilers and the CFB boiler. The large power plants and the CFB boiler are assumed to be equipped with wet scrubbers, a form of FGD, and limestone injection, respectively. The SO_2 emission factors are calculated for each combustion plant using the equation below [28]:

$$EF_{SO2} = 2 \cdot C_S \cdot (1-\alpha_S) \cdot \frac{1}{H_u} \cdot 10^6 \cdot (1-\eta_{\sec} \cdot \beta)$$

where

EF_{SO2} = emission factor for SO_2 (g/GJ)

C_s = sulphur content in fuel (kg/kg)

α_s = sulphur retention in ash

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[4]Plants that were taken into operation before 29th March 1990.

[5]For example, the ELVs on SO_2 for a hard-coal-fired combustion plant (>500 MW_{th}) will be reduced from the current value of 2350 to 400 mg/Nm^3 [22].

η_{sec} = reduction efficiency of desulphurization measure

H_u = lower heating value of fuel (MJ/kg)

β = availability of a desulphurization measure

4.1.2 The SO_2 emission reductions for different plants

The SO_2 emission reduction per unit biofuel that replaces coal varies considerably between the four defined combustion plants, ranging from 83 to 625 g SO_2 per GJ of biofuel (Table 2). The reduction in SO_2 is lowest in the large power plants that are equipped with FGD, and highest in district heating plant that lack desulphurization measures. Lignite contains more sulphur per unit energy than hard coal. Consequently, replacing lignite gives a larger reduction in SO_2 emission than replacing hard coal, although some of lignite's higher sulphur content is offset by its higher sulphur retention in ash.

Table 2: Technical details of the four defined combustion plants pertaining to three applications in Table 1. The SO_2 emission factors describe the emissions before and after substituting biofuels for coal. Note that the emission factors for SO_2 (EF_{SO2}) are given per GJ fuel (total) whereas the emission reduction is given per GJ biofuel. HC= hard coal, L=lignite and Bio=biofuel.

Application	Before substitution					After substitution				ΔSO_2
Boiler, capacity	Fuel	α_s [1]	η_{sec} [2]	β	EF_{SO2} g/GJ_{tot}	Fuel(s)	α_s [1]	η_{sec} [2]	EF_{SO2} g/GJ_{tot}	g/GJ_{bio}
District heat & small-scale CHP production										
1. Grate, 10 MW_{th}	HC	0.05	-	-	676	Bio 100%	0.05	-	51	625
Medium/large-scale CHP & power production										
2. CFB, 300 MW_{th}	HC	0.05	0.45	0.98	378	HC/Bio 20%	0.06	0.45	305	365
Large-scale power production										
3. PF 600 MW_{th}	HC	0.05	0.9	0.99	74	HC/Bio 5%	0.06	0.9	69	83
4. PF 600 MW_{th}	L	0.3	0.9	0.99	144	L/Bio 10%	0.36	0.9	119	251

1 g SO_2/GJ=2.86 mg/Nm^3 flue gas

The sulphur content in biofuels is assumed to be 0.05 wt% which is typical for wood chips [29]. The sulphur content is assumed to be 0.8 wt% for both hard coal and lignite. In 2000 the average sulphur contents were 0.90%, 0.82% and 0.75% in hard coal that was used in public power and CHP plants, local district heating plants and domestic boilers, respectively [30]. The Bełchatów power plant accounts for almost half of the lignite-fired power capacity in Poland. In the period 1999-2002 this plant used lignite with a sulphur content ranging from 0.66 to 0.83% [31].

Based on data on Polish coal consumption the lower heating value was assumed to be 22.5 MJ/kg for hard coal and 8.5 MJ/kg for lignite [2].

[1]The sulphur retention in ash was set to 0.05 for all hard-coal-fired combustion plants (plant 1-3) and 0.3 for the lignite-fired combustion plant. These are rough approximations based on data for combustion of hard coal and lignite in PF boilers (dry bottom boiler) from [28]. Because of the absorption of sulphur by alkali compounds in the biofuels, the sulphur retention in ash was assumed to be 20% higher when co-firing the fuels compared with firing them separately.

[2]The wet scrubbers and limestone injection reduce the SO_2 emissions by 90% and 45%, respectively.

4.2 Biomass ash recycling

Co-firing prevents recirculation of the biomass ash to forest and agricultural land due to the mixture of biomass and coal ash. When biomass residues are extracted from forest and agricultural land, nutrients and minerals are also removed. In order to avoid the depletion of minerals and nutrients in the soil, biomass ash should be recycled to land from which biomass residues have been extracted [32, 33, 34]. Ash from coal, on the other hand, should not be spread in the environment due to its content of trace metals which, apart from being toxic, do not emanate from the biosphere. Today, biomass ash is landfilled in Poland. Biomass ash is only recycled on a small scale in a few countries such as Sweden, Finland, Denmark and Austria [35]. Nevertheless, the lost opportunity of biomass ash recycling is a weakness of co-firing in the longer term.

4.3 Energy efficiency

Solid biofuels may have a high water content, sometimes up to 60%. When using biofuels with high water content, the overall energy efficiency of the combustion plant can be improved by the use of flue gas condensation (FGC). FGC increases heat production by recovering the energy that is used for vaporizing the water content in the fuels in the combustion process. Hence, FGC only serves a purpose in CHP and district heating plants or in power plants that need heat for drying the biofuel.

5. Economic considerations

Conversion from coal to biofuels and retrofitting for co-firing incur a capital cost and increase the costs of fuel and of operation and maintenance (O&M) of the plant. Substituting biofuels for coal may, however, also increase income and decrease costs for the energy company as a result of various policy instruments.

5.1 Additional costs

In the literature on co-firing, the economics and the low risk are often pointed out as the strengths of this concept compared with other RES electricity projects. Retrofitting of a combustion plant generally incurs a lower capital cost than other RES projects [36], although it should be noted that these projects are not fully comparable since retrofitting for co-firing does not change the capacity whereas the other projects increase the total system capacity. The capital cost for retrofitting of a coal-fired combustion plant ranges between €40 and €160/kW$_e$ (\$50-200/kW$_e$[6]) [36], while the corresponding cost for a new biofuel-fired combustion plant is €1280-2000/kW$_e$ (biofuel capacity) (\$1600-2500/kW$_e$[6]) [37].

The cost of converting to biomass or retrofitting for co-firing depends on the boiler technology, age (remaining lifetime), size and location of the plant and on the source and proportion of biofuels. For PF boilers, co-firing with less than

[6] These estimates of the capital cost were made in the late 1990s. The values have not been adjusted for inflation. It was assumed that €0.8=\$1.0.

5% biofuels can be achieved at a relatively low capital cost, about €40-80/kW$_e$ ($50-100/kW$_e$,), assuming the fuels are mixed at the fuel pile and fed together into the boiler [36]. This concept, however, requires the use of relatively expensive biofuels such as sawdust and wood pellets. The capital cost of retrofitting a PF boiler, including the installation of a separate mill and a feeding system for the biofuels, was estimated to be €140-160/kW$_e$ ($175-200/kW$_e$) by Hughes [36] and to €180/kW$_e$ by Berggren and Ljunggren [7]. The capital cost of retrofitting a grate and CFB boiler was estimated to about €60/kW$_e$ [7].

In order to compare the economics of using biofuels in different coal-fired combustion plants, some rough calculations were made for the four combustion plants defined in Table 2. Wood chips (unrefined biofuels) are assumed for three of the combustion plants and wood pellets (refined biofuels) for the other. The price ranges of wood chips and pellets are assumed to be €3.0-4.5/GJ and €4.5-6/GJ, respectively. The price of coal was set to €2.0/GJ.

Based on data in the studies by Hughes [36] and Berggren and Ljunggren [7], the rough assumption was made that the capital costs associated with these fuel conversions are €24/kW$_{th}$ (biofuels) for the grate and CFB boilers, €30/kW$_{th}$ for the PF boiler burning wood pellets and €72/kW$_{th}$ for the PF boiler burning wood chips. The wood chips have to be pre-processed before they are fed to the PF boiler, unless a grate is installed at the bottom of the boiler. Pre-processing increases the capital cost and is assumed to reduce the net electricity production by 10%. The other assumptions are presented in the notes to Table 3.

Given these assumptions, the additional costs associated with converting from coal to biofuels or retrofitting for co-firing are dominated by the additional fuel cost (biofuels are more expensive than coal). The capital cost contributes to the additional cost to a smaller extent and the increased cost for O&M is almost negligible. The additional costs presented in Table 3 correspond to costs of €12-52/tonne CO_2 avoided, assuming the net CO_2 emissions zero for biofuels.

Table 3: Additional costs per unit of biofuel for different coal-fired combustion plants that are converted to biofuels or retrofitted for co-firing. u, p and r denote unrefined, pre-processed and refined biofuels, respectively.

Boiler, capacity, % biofuel	Bio-capacity (MW$_{th}$/MW$_e$)	Biofuels (€/GJ$_{bio}$)	Additional costs (€/GJ$_{bio}$)			
			Capital[b]	Fuel	O&M[c]	Total
Grate, 10 MW$_{th}$, 100% (u)	10/0	3.0-4.5	0.14	1.0-2.5	0.0035	1.1-3.1
CFB, 300 MW$_{th}$, 20% (u)	60/15	3.0-4.5	0.14	1.0-2.5	0.0035	1.1-3.1
PF, 600 MW$_{th}$, 5% (r)	30/12	4.5-6.0	0.12	2.5-4.0	0.0031	2.6-4.9
PF, 600 MW$_{th}$, 10% (p)	60/24	3.6-5.1[a]	0.29	1.6-3.1	0.0065	1.9-3.4

[a]The biofuel cost includes €0.6/GJ$_{bio}$ for pre-processing.

[b]The capital costs are annualised over 15 years using an interest rate of 6%, which results in an annuity rate of 0.103. The power plants are assumed to operate for 7000 hours per year and the district heating and CHP plants for 5000 hours per year, taking the seasonal heat demand into account.

[c]The cost of O&M was assumed to increase by a fixed amount equal to 2% of the capital cost plus a variable cost of €0.7/TJ of biofuel.

5.2 Additional income and reduced tax costs

In spite of the higher production costs, converting to biofuels or retrofitting for co-firing can be viable for an energy company due to various policy instruments that increase incomes and reduce taxes.

In 2000 a Quota Obligation Ordinance[7] promoting electricity from RES was introduced in Poland, replacing a system of feed-in tariffs. The Ordinance obliges electricity distributors to provide a minimum proportion of electricity from RES [38]. For 2006, the quota is 3.7%, which will gradually be increased to 9.0% in 2010. In October 2005 the Ordinance was supplemented with a scheme for trading Guarantees of Origin (GOs), to which all producers of electricity from RES are eligible.

For energy companies, the trade in GOs provides a strong economic incentive for using biofuels in power production (Table 4). Electricity from RES is sold at a fixed price that equals the average market price for electricity for the previous year, i.e. about €35/MWh (PLN134/MWh[8]) in 2005 [39]. In addition to the sale of electricity, income is also generated from the sale of GOs. About 90% of the GOs are traded bilaterally at an approximate price of €25/MWh and 10% is traded on the spot market at a price of about €50/MWh [40].

Electricity distributors can fulfil their quota of electricity from RES either by purchasing and submitting the minimum amount of GOs to the Energy Regulatory Office or by depositing a buy-out payment of about €62/MWh [39, 41]. The buy-out payment enables fulfilment of the quota obligation when there is a shortage of GOs on the market and it prevents sharp price increases. In the case of non-compliance, the electricity distributor has to pay a penalty, which equals 1.3 times the buy-out price. Future compliance with the Ordinance is therefore expected. Electricity from RES is also promoted by exemption from the excise tax of €5.2/MWh, which is levied on electricity production [42]. This tax reduction, however, provides a weaker incentive for biomass-based electricity production than the trade of GOs (Table 4).

Another policy instrument that promotes bioenergy in Poland is the EU emission trading scheme for greenhouse gases [43]. The scheme applies to boilers with a rated thermal input of 20 MW or more and concerns 1166 installations in Poland [44]. These plants are allocated a certain amount of emission allowances (EAs), which can be traded. For the first trading period, 2005-2007, the scheme only covers CO_2. The price of EAs has varied since their introduction between €10 and €30/tonne CO_2 [45]. At a price of €16/tonne CO_2, the substitution of biofuels for coal provides a value of about €1.5/GJ of biofuel (Table 4).

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[7]The Quota Obligation Ordinance is part of the Polish implementation of the RES Electricity Directive (2001/77/EC), based on which Poland has assumed the target of 7.5% electricity from RES by 2010. This national target was set in the Accession Treaty and it applies to the total electricity production, i.e. including both the sales and the electricity that is consumed internally by the power plant (Council of the European Union, 2003).

[8]The conversion rate used throughout this paper is €1=PLN4.

A comparison of the additional costs and incomes in Tables 3 and 4 shows that retrofitting for co-firing in large CHP and power plants is viable for an energy company. Due to the lack of incentives for heat production based on RES, conversion to biofuels in small district heating plants is, however, not viable despite the lower additional costs.

Table 4: Additional income from the sale of GOs (bilateral price to spot price) and of EAs, and the SO_2 and excise tax reduction for the four defined combustion plants.

Boiler, capacity, % biofuel	Bio-capacity (MW_{th}/MW_e)	Tax cost reduction (€/GJ_{bio})		Additional income (€/GJ_{bio})		
		SO_2	Excise	GOs[1]	EAs	Total
Grate, 10 MW_{th}, 100%	10/0	0.07	-	-	-	-
CFB, 300 MW_{th}, 20%	60/15	0.04	0.4	1.7-3.5	1.5	3.2-5.0
PF, 600 MW_{th}, 5%	30/12	0.01	0.5	2.4-4.9	1.5	3.9-6.4
PF, 600 MW_{th}, 10%	60/24	0.03	0.5	2.2-4.4	1.5	3.7-5.9

[1]The electric efficiency was assumed to be 25% in the CFB boiler and 35% in the PF boilers. In the PF boiler firing wood chips, 10% of the electricity production is consumed internally, thus reducing the net electricity efficiency to 31.5%.

In addition to the emission regulation on SO_2, there is a tax on SO_2 emissions in Poland. The SO_2 tax is imposed on heat and electricity producers with the exception of owners of small boilers (<5 MW_{th}) who pay a general environmental fee per tonne of fuel used depending on fuel characteristics. Households are exempt from this fee. However, due to the low tax rate, €0.10/kg SO_2, it provides a rather weak incentive for energy companies to reduce their SO_2 emissions [46].

5.3 Environmental costs

The emission of air pollutants from heat and electricity production leads to costs that are not always fully accounted for by producers or consumers. Policy instruments such as the trade of EAs and the tax on SO_2 emission, and possibly the trade of GOs, are means of internalizing these so-called external costs. External costs have been estimated for the emission of various air pollutants and of CO_2 in several projects, for example in the research project "Externalities of Energy" (ExternE) [47, 48]. The geographical scope of this project was the EU15 countries. Negative health effects dominate the external cost of air pollutants in the ExternE methodology. As a result, external costs are high in areas of high population density. Poland has about the same population density as Denmark (about 1.2 capita/ha), for which the external cost of SO_2 emissions was estimated to be €2990-4216/tonne SO_2 in ExternE. This range was used in the present work as the benchmark for Poland. It should be noted that estimates of external costs are associated with great uncertainties, especially those for CO_2.

The external cost of CO_2 emissions varies greatly between studies. ExternE presents a range of €3.8-139/tonne CO_2 [47, 48]. The IPCC Second Assessment

Report [49] presents a range of $1-34 per tonne CO_2. Other studies present higher estimates, e.g. Azar and Sterner [50] €71-161/tonne CO_2.

The environmental values of avoided CO_2 and SO_2 emissions were estimated for the fuel conversions in the four defined combustion plants. (Table 5). The calculations are based on external costs from ExternE [47, 48]. These calculations showed that the environmental value is greatest when substituting biofuel for coal in district heating plants due to the larger reduction in SO_2 emission per unit biofuel in this kind of plant (Table 5). Table 5 also shows to what degree environmental costs are internalized for the different combustion plants.

It should be noted that it is difficult to draw conclusions on health impacts since the analysis only includes the emissions of SO_2 and CO_2 and not those of e.g. primary particles. (Emissions of second particles were partly included in the external cost of SO_2 emissions). Exposure to fine particles has been pointed out to have important adverse effects on human health, especially to the lungs. The mechanism by which the particles harm the lungs is not well understood, but the adverse effect is suggested to be related to the size, composition and acidity of the particles [51].

Table 5: Environmental value of avoided emissions based on external costs from ExternE [47, 48] and related change in income for energy companies with current policy instruments.

Boiler, capacity, % biofuels	Environmental value (€/GJ_{bio})		Change in income (€/GJ_{bio})		
	SO_2	CO_2	GOs	EAs	SO_2 tax red.
Grate, 10 MW_{th}, 100%	1.9-2.6	0.4-13.2	-	-	0.07
CFB, 300 MW_{th}, 20%	1.2-1.6	0.4-13.2	1.7-3.5	1.5	0.04
PF, 600 MW_{th}, 5%	0.2-0.3	0.4-13.2	2.4-4.9	1.5	0.01
PF, 600 MW_{th}, 10%	0.8-1.1	0.4-13.2	2.2-4.4	1.5	0.03

6. Strategic considerations

6.1 Security of fuel supply

The biofuel market in Poland is still at an early stage of development, which is associated with uncertainties regarding future prices and volumes available. For energy companies, co-firing of biofuels is a low-risk bioenergy strategy since disruptions of the biofuel supply have only a limited effect on the plant. Also, co-fired combustion plants that have signed contracts with biofuel suppliers are relatively insensitive to moderate changes in fuel prices since biofuels account for a minor part of the total fuel cost. Also, co-firing offers a means for energy companies to gradually build up contacts with biofuel suppliers and gain experience of biofuel combustion. From this point of view, co-firing of biofuels may facilitate the use of biofuels in stand-alone plants at a later point in time [52].

6.2 Stimulation of perennial crop production

Assessments of the potential biomass supply in Poland have shown that the greatest potential lies in perennial energy crops, such as willow. The long-term biomass potentials were estimated to be 650-1450[9] PJ/y for perennial energy crops, 150 PJ/y for straw and 55-65 PJ/y for forestry residues [8]. So far, agriculture has played a minor role in biomass supply. In the future, the agricultural sector must take on a much more important role if the targets on RES are to be met.

So far, there is little experience of commercial cultivation of perennial energy crops in Poland. Co-firing could play an important role in stimulating perennial energy crop production. In the start-up phase of perennial energy crop production, time will be needed for learning-by-doing and capacity building among farmers and actors in the logistic chains. This phase could be facilitated by promoting the use of biofuels from perennial energy crops in CHP and power plants. This strategy has been adopted in the United Kingdom. From 2009 and onwards an increasing proportion of the biofuels that are co-fired for electricity production in the UK must be based on energy crops in order for the plant to be eligible for Renewable Obligation Certificates. The required proportion of energy crops in the biofuel supply will start at 25% and be gradually increased to 75% by 2011 [53]. However, in order to prevent co-firing from completely dominating electricity production from RES, there is a restriction on its contribution in the supply of electricity from each supplier. At present, the cap on co-firing is 25% of the electricity from RES, which will gradually be decreased to 5% by 2011 [53]. Another way to promote the use of biofuels from perennial energy crops is, as suggested by Helby et al. [54], to grant a subsidy to combustion plants that offer long-term contracts to farmers for biofuel supply.

7. Discussion

Co-firing of biofuels in Poland has both strengths and weaknesses.

Technically, co-firing is the most realistic option for using biofuels in the large PF boilers in Poland due to their low fuel flexibility and the vast volume of biofuels that would need to be supplied in the case of complete fuel conversion. Also, co-firing enables biofuels rich in alkali metals and chlorine compounds to be used in coal-fired boilers while avoiding or controlling corrosion and ash deposition problems.

Environmentally, co-firing prevents recirculation of the biomass ash in forests and on agricultural land, which is a weakness in the longer term. At present the most important weakness associated with co-firing, as employed today in large CHP and power plants, is that it results in only a small reduction in SO_2

[9] The high-end estimate is based on the assumption that energy crops are grown on about 9 Mha (half of the Polish agricultural area) with a yield of 10 tonne/ha/y.

emission per unit biofuel. Biofuels provide a larger reduction in SO_2 emission when replacing coal in smaller combustion plants.

Economically, the additional cost per unit biofuel is smaller for complete fuel conversion in a grate boiler in a district heating plant than for retrofitting for co-firing in a PF boiler at a power plant. However, for energy companies, co-firing for electricity production is the most viable utilization of biofuels. Co-firing for electricity production not only increases costs but also income due to sales of GOs. The use of biofuels for heat production, on the other hand, only increases costs.

Strategically, co-firing could play an important role in stimulating perennial energy crop production, provided that the energy companies have an incentive to purchase biofuels from this biomass source rather than from other sources.

8. Conclusions

Co-firing, as it is employed today in large CHP and power plants, provides a smaller reduction in SO_2 emission than that which can be achieved if the biofuels are used in smaller combustion plants that do not have desulphurization technology. Thus, if the reduction of SO_2 emission has the same priority as that of CO_2, biofuels in Poland should be used to replace coal in small district heating plants rather than being co-fired in large power plants. However, if the priority is to ensure long-term reduction of CO_2 emissions, emphasis should be placed on developing biomass supply and logistics. This latter priority speaks for pursuing both co-firing of biofuels in large CHP and power plants and the use of biofuels in district heating plants. Co-firing could play an important role in stimulating perennial crop production, while biofuels from certain types, of biomass, such as straw, are more suitable for use in district heating plants. Current policies clearly favour co-firing for electricity production. In order to increase the use of biofuels in heat production, policies supporting this utilization of biofuels are necessary.

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