Project Design Document
For Erupt-3

Ajka Biomass Project, Hungary

20 JULY 2003

PREPARED BY
EVOLUTION MARKETS LLC

IN COLLABORATION WITH
MAKK, THE HUNGARIAN ENVIRONMENTAL ECONOMICS CENTRE

Evolution Markets LLC

Evolution Markets LLC is the largest emissions and OTC coal brokerage firm in the world. Formed in 2000, the company structures transactions in the environmental credit, renewable energy, weather derivative, and over the counter (OTC) coal markets. Evolution Markets personnel are pioneers in energy and environmental markets having facilitated the first trades in SO_2 allowances, NOx allowances, ERCs in several states, greenhouse gas emissions, weather derivatives, and OTC coal trades. The company specializes in carbon finance; for example: the greenhouse gas brokerage and advisory team has closed some of the most important domestic and international GHG transactions, including the first trade of AAUs under the Kyoto Protocol's international emissions trading program. Evolution Markets also transacted the first brokered trade of emission allowances under the upcoming GHG emission trading scheme in the European Union. Through a joint venture with Starsupply Petroleum, Evolution Markets has created Evolution Carbon International to provide expert brokerage services to the international coal trading market.

MAKK, the Hungarian Center for Environmental Economics

MAKK is an applied research institution, which conducts research in the field of environmental economics. The institution started its work in 1998 on the basis of a 4-year long project of the Harvard Institute for International Development, which supported the activities of the Hungarian Ministry of Finance and the Ministry of Environment. The members of the institution are young economists dedicated to the idea that by showing regard for environmental and social processes it is possible to implement a system of economic instruments, which help maintain and improve the quality of our natural assets and resources.

MAKK's main research topics are the analysis of the effect of different environmental policies (primarily emission trading and eco-taxes - emission taxes, energy taxes, and product charges) at the macro-, sector-, and household-level. Other important fields of MAKK's research activity include analyzing and designing energy policies and conducting monetary valuation of environmental goods and services.

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1 PROJECT INFORMATION

1.1 Project Characteristics

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1.3 Project Abstract

Due to a more competitive economic environment and stringent environmental regulations, possibilities for coal-based electricity generation are shrinking and this type of electricity generation will likely become unfeasible for Bakony Power Plant Plc in the second half of the decade. To overcome this challenge and avoid a full shut down, the proposed project aims to convert two of the five boilers from coal to biomass. An independent corporation will be established for the biomass-based electricity production, which plans to produce a minimum of 190.4 GWh/year of net electricity. The biomass will mainly consist of wood from forestry management as well as wood waste. While this is a tested and feasible technology elsewhere, the value of greenhouse gas credits are needed to secure the financial structure of the project as well as to offset most of the project risks. The biomass project risks mainly relate to the price developments in the biomass fuel market and regulatory uncertainties about long-term government support for preferential renewable energy feed-in tariffs. Several forestry management and wood processing companies in the region would supply around 2.4 PJ or 240,000 tons of biomass input. There are also plans for energy plantations in the region to further increase the availability of biomass fuel. Conservative calculations of the greenhouse gas reductions result in a total of 453,000 tons of CO_2equivalent for the period of 2008-2012.

Project location: Ajka, Gyártelep, Hungary

Construction starting date: September 2003
Construction finishing date: January 2004
Project starting date: January 2004

1.4 Background and Justification

1.4.1 BACKGROUND AND HISTORY OF PROJECT

The Ajka Power Plant, one of the two power plants of Bakony Power Plc, is located near Ajka, a small town of 30 000 inhabitants at the feet of Bakony Mountains in Mid-West Hungary. The Ajka plant has been producing heat and electricity for decades, burning brown coal mined in the region. The first blocks of the power plant were installed in 1943; the second phase of investment was completed in 1961. The first significant renovation took place in the middle of the 1980's, when boilers were equipped with electrostatic dust-separators. The boilers were equipped with the currently applied hybrid-fluid (HF) technology in the early 90's, which led to a reduction in the emissions of harmful substances, especially SO_2. Due to the decrease in the demand for heat, seven of the coal-fuelled boilers of Ajka I were decommissioned. Recently a boiler of Ajka II was also withdrawn from production leaving five boilers – four HF boilers and one pulverized coal– in operation. The Ajka plant is equipped with five turbines, out of which three are extraction turbines for heat and electricity production. The remaining two are condensation turbines, producing only electricity.

The remaining technical lifetime of the current technology is approximately 10-15 years. However, the overall technology can be regarded as outdated as the efficiency of the plant is relatively low both in terms of energy conversion and unit cost of output. Thus Bakony Power, having an aging technology and experiencing a steep reduction in the heating value of the local Ajka coal, faces serious difficulties with its Ajka plant in an electricity market that is becoming liberalized and competitive. The long-term power purchasing agreement (PPA) of the plant with MVM, the public wholesaler, expired at the end of 2000. In the past, revenues from the electricity sales have been used to compensate for financial losses from the heat production (mainly due to low heat tariffs). The uncertain medium to long-term electricity sales outlook poses a problem for Bakony. To respond to this challenge, the plant has been considering a conversion of two of the five boilers from coal to 100% biomass combustion. The steam from these boilers will drive a condensation turbine to generate electricity only. Electricity generated from renewables (RES-E) enjoys priority access to the grid with preferential feed in tariffs. By reducing the share of coal and exposition to the competitive market, the plant has an opportunity to continue operating. Plans have been drawn up; preparatory assessments and experimental firing have been carried out and are currently underway; and permitting processes have started and are expected to be completed by September 2003. Potential biomass suppliers were contacted, and sixteen sent offers on prices with sufficient volumes. The project assessment of the proposed biomass conversion shows that the project is technically and logistically feasible. Organisational and ownership restructuring for the Ajka Plant to facilitate the project is also being considered. Bakony Power intends to create a separate legal entity, a special project company, for the operation of the biomass project.

The current Ajka plant also produces heat. The largest clients are a large alumina factory at Ajka and the municipal district heating company. The existence of the heat market has helped the plant maintain some electricity production despite the expiry of the electricity PPA. This was made possible by the preferential feed in tariffs that regulation provides for electricity generated jointly with heat (combined heat and power, CHP). Another factor of survival so far has been the support, in the form of mandatory take over at regulated tariffs, for selling electricity generated from selected domestic coalmines. Such support, however, is expected to end in 2004.

The biomass boilers will drive the condensational turbines and, thus, serve for electricity generation only. Therefore, the plant will need to involve additional and efficient production capacities if it wishes to keep its heat markets in the long term. Such capacities could replace the current coal-based CHP production. Several options, ranging from a small gas engine to a large scale (100 MW) gas combined cycle plant (gas CCP), have been considered. The options reflect different projections of the development of demand and prices for the heat and electricity production. A larger scale solution would also make it possible to maintain the optimal scale electricity production at the Ajka plant. Electricity production, besides mining and the alumina production, are the main economic activities in Ajka.

1.4.2 INTERVENTION

Bakony Power, faced with energy market liberalization and stricter environmental standards, has been seeking ways to continue operation of the Ajka facility. Since coal from the local coalmine at Ajka is dropping in quality, it is envisaged the plant will soon no longer meet the minimal technical heat value requirements. Also, the mines (Balinka mine, Lencsehegy) that have supplied the plant are close to depletion or on the verge of shut down due to economic reasons. Therefore, Bakony is considering substituting fuel with higher heat content while at the same time meeting sulphur dioxide emission requirements.

Low quality or expensive (due to transportation costs) coal, low conversion efficiency, more stringent environmental regulations, high operating costs, and market liberalization put pressure on the owners to adapt or prepare for a shutdown. Currently the plant produces around 200-300 GWh electricity annually, which is roughly only half the production level of the late 90's. During that time, Bakony was able to sell electricity to the public wholesaler under a long term PPA. This PPA provided for electricity sales volumes at cost recovering prices without uncertainties. The Ajka plant also produces 2.5 PJ/year heat, mainly for an Alumina Plant (2.0 PJ/year) nearby and the district heating company of the municipality of Ajka (0.5 PJ/year). A part of this heat (1.2 PJ/a) is generated in combination with electricity production (combined heat and power, CHP). Condensation turbines generate the majority of the electricity. It should be noted that current and envisioned market prices do not allow economically viable operation of the coal based condensational electricity generation part of the plant. In 2003, the feed in tariff decree continues to provide an opportunity to sell some condensational electricity at prices much higher than the market price, but such regulatory intervention is expected to cease from 2004. Electricity from the Ajka Plant generated with heat to supply district heating is likely to continue to enjoy some support, but only for a limited time.

A few strategic options have been considered which would enable the operation of the power plant in a manner that fulfils the environmental requirements of the Hungary government and the EU. At the same time, these options enable the plant to keep its position on the local heat market as well as maintain its current share or reestablish former positions in the electricity market. In the long term a gas combined cycle unit (hereinafter a gas combined cycle plant, or gas CCP) would both satisfy the demand for heat and produce electricity. However, at current electricity market prices and considering the uncertainty of the long-term heat demand from the alumina factory, the investment would not be an economically sound decision. If electricity prices increase, as expected later this decade, there are two major plans that are being considered, depending also on the related heat market circumstances: a 100 MW gas-fired combined cycle (CCP) based CHP producing annually 2.2 PJ heat, and 650 GWh electricity, or a smaller, 30-40 MW gas CCP producing 1 PJ heat and cc. 260 GWh electricity. Should the Alumina factory stop production completely, leaving only a small municipal heat market, the installation of a smaller gas engine to produce the needed municipal heat would be considered. These strategic options will be discussed in more detail in section 5.

Notwithstanding the need for a strategic solution, the owners and the management think that the proposed biomass project could extend operations at Ajka. This project could help to overcome current difficulties, and, once they are overcome, usefully supplement the plant's strategic choice and provide some diversification for Bakony's investors. The Ajka JI biomass proposal envisions the production of electricity only, heat production would be solved by other means. The project would use around 240,000 tons of biomass annually and using an average lower heating value of the biomass of 10 MJ/kg[1],the annual heat input would be around 2.4 PJ/year. The biomass is expected to be mainly (around 50-60%) wood from forestry management. This wood will consist of – according to the current state of supply offers- turkey oak (44%), beech (30%), oak (25%) and some trees with soft foliage (1%, mainly aspen). Also old wood leftover from wood processing and wrapping materials (pallets), mainly consisting of pine wood, will be collected and used. The HF boilers would supply one or two condensational turbines with 30 MW nominal capacity. The combustion of biomass would produce electricity at a net efficiency rate of 25.7%, supplying electricity to the transmission network of around 190.4 GWh annually. The output value is calculated using lower heating values of the biomass fuel and also includes firing of 267 TJ natural gas supplementary to the firing of 2400 TJ biomass. Thus, of the 190.4 GWh 171 GWh would be renewable energy based electricity, and 19 GWh would be generated from gas, utilizing the 10% allowance that the renewable energy feed-in tariff decree provides. The efficiency figure is higher than that of coal-based condensation electricity production of recent years. It will be achieved via the conversion of the boilers, the retrofit of the turbine (see section 1.4.6.) and the reduction in internal electricity consumption in the biomass project compared to coal firing. The reduction in internal electricity consumption is due to smaller energy needs (i) to pump lower volumes of ash slurry to the disposal grounds (more detailed information see section 6.2.1. and 11.5.4), (ii) for wood chopping compared to coal grinding.

A viable solution is sought for the utilisation of the condensational turbines, which will likely stand idle even from 2004. This can be achieved only with an environmentally sound, technologically and financially feasible technology. Biomass combustion is environmentally and technologically sound, but runs some risks financially – even with the current renewable tariff support scheme in place. The investment can become financially attractive through carbon financing. The revenues from the sale of emission reductions can, for example, be used to secure the biomass input, reduce the influence of potential biomass price fluctuations, and reduce the impact of the regulatory uncertainty of long-term government support for renewable energy (see section 5 for more information).

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[1] Assuming a conservative 40% average moisture content of the biomass fuel mix. At the time of delivery of the biomass to the project site, prices and amounts will be calculated to a 30% moisture content. However, to conservatively reflect potential biomass amounts transported, a higher moisture content of 40% has been assumed, resulting in lower biomass heating values of 10 MJ/kg as compared to 12 MJ/kg biomass for an average biomass moisture content of 30%.

1.4.3 GOALS

On the basis of the short assessment above and based on the challenges the Ajka plant faces, the following section will summarize the goals that the biomass JI project should achieve. The goals of the project can be divided in two groups according to whether goals of the project owner or the policy maker[2] are considered. While the plant sets goals that ultimately serve the interests of the owners of Bakony, the policy maker seeks to serve the interests of the whole society[3].

Goals of the project owner related to the biomass project proposal

- keep at least part of the plant in operation; and thereby
- keep a market presence for, and abridge difficulties of, the transition period until a strategic solution is decided upon and implemented (afterwards the biomass plant is supplemental to the strategic solution, and provides diversification to investors relative to a situation when they only invested in the strategic solution);
- find a solution, which is both economically and environmentally[4] sustainable;
- promote internal innovation and harvest the efficiency gains of it;
- save jobs for a considerable number of employees; and
- develop goodwill (in non-business language: valued "fame") and good public relations with the population in the closer and wider region (e.g. due to positive external employment effects and by demonstrating environmental improvements).

Goals of the policy maker to which the project contributes

Environmental:

- reduce average environmental load intensity of electricity and heat production;
- improve local and regional environmental quality;
- achieve these goals by involving innovative policy instruments (e.g. JI);
- raise climate-related awareness of the public; and
- foster international relations and cooperation in climate policy.

Energy policy:

- reduce average energy intensity of electricity and heat production (energy efficiency improvement in the economy);
- increase the share of renewables[5]; and
- reduce energy import dependency[6].

Economic:

- draw foreign capital in the country;
- mitigate current account deficit (using domestic fuel);
- promote technological development and innovation; and
- create jobs in the countryside, especially if enhanced forestry activity and energy plantations are realized.

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[2] The policy makers naturally have not expressed any goals explicitly and specifically to this particular project. They set their goals via legislation, resolutions, standards etc, or as derived from these when interpreted in permitting and support scheme procedures.

[3] Including but not restricting to the plant and the region. The goals of policy makers are often expressed in or translated to macro level objectives and targets.

[4] Including, but not restricted to meeting environmental regulations.

5 It is especially important as many experts claim the 3.6% renewable electricity (RES-E) target by 2010 is unattainable. Also see section 4.

6 The biomass plant is expected to displace some other plants' generation (coal use at Ajka Plant is lkely to be ceased anyway, see section on strategic options in section 5) from the grid. Apart from RWE Matra (a lignite plant), such plants from the second half of the decade will mostly be gas and oil-based plants. Natural gas import dependency is a major concern of energy policy makers.

Political:

- reduce the need and pressure for subsidising loss making electricity generation and coal mining.

1.4.4 PURPOSE

The purpose of the project has been amply discussed in the previous sections. The reason for carrying out the investment is that the current technology is inefficient and becoming obsolete. Faced with the liberalization of the electricity market, a shutdown of parts or the whole of the plant have become likely if no technological change is implemented. The biomass fuel switch could help to abridge a difficult transition period with a not yet transparent electricity market until the mid- and long-term strategic solution for the plant is decided upon and implemented. Afterwards the biomass project would play a supplemental role as a diversifying item in the owners' portfolio. The implementation would enable the plant to reduce the likelihood of further losing its share on the electricity market.

1.4.5 RESULTS

The project is expected to have several results:

- Renewable electricity production: The fuel switch project from coal to biomass would provide 30 MW capacity producing 171 GWh pure renewable electricity and 19 GWh natural gas based electricity (altogether 190.4 GWh) annually. This project would use around 240,000 tons of biomass annually with an annual heat input of around 2.4 PJ. The boilers would drive a condensation turbine, which would thus produce more electricity now than the current coal-based condensational output.
- Effect on employment: the combustion of biomass would mean that some 100 jobs could be kept at the Ajka plant. Compared with the likely shutdown of the coal plant, this is a positive result, despite the fact that the combustion of coal provides many more jobs currently than is expected from the biomass project. Additional employment is expected through biomass production and transportation, especially if Bakony manages to realize its plans on energy plantations.
- Effect on the environment: The project is expected to achieve a beneficial effect both on the local and on the global environment. Regarding the local environment, there will be a 70 to 98% decrease of SO_2 emissions depending on the type of biomass combusted, as well as over 90% decrease in the quantity of slurry (combustion ash with water) produced. It will also benefit the environment globally, resulting in 399,200 tons of CO_2 emission reductions until the end of 2007 and 453,000 tons of CO_2equivalent for the period of 2008-2012.[7]

1.4.6 ACTIVITIES

The core of the investment project is essentially the conversion of two coal HF boilers, boilers XI and XII, enabling them to fire biomass on the fluidized bed. Broadly speaking, the project consists of a biomass fuel handling system and a combustion waste (ash, dust, slurry) treatment system. It also includes the rehabilitation of the condensation turbine V, which will slightly increase the efficiency of the turbine. A logistical system for purchasing, transporting, storing, and treating the biomass fuel will need to be established. Modifications will be carried out at the fuel conveying system and at the air and flue gas system of the boilers. The physical separation of the biomass boilers from the remaining coal boilers by dividing the steam pipeline system is being considered, but not yet decided upon.

[7] GHG emission reduction between 2008 and 2012 cannot be attributed specifically to this project if our starting point or "global baseline" is that Kyoto targets will be kept by all parties. This is because the emission reductions will probably be offset somewhere else, for example in the Netherlands, if she decides to purchase and keep the ERUs generated by this project. In other words, the project helps to achieve the global Kyoto target, but nothing beyond.

Specifically, the following modifications must be made:

Modification of the logistical system:

- Unloading shipment and feeding it into the chopping-machine: electrical, pillar type slewing crane, 3 pcs, rubber wheeled logger.
- Temporary storage of wood that cannot be fed into the chopping machine on arrival, and delivery of the wood from the temporary storage location to the chopping machine: rubber wheeled frontloader and logger (1-1 pcs., Diesel engine driven).
- Feeding equipment: belt-conveyor, metal detector with own conveyor-belt, waste separator.
- Chopping-machine: electricity-driven blade chopper for cutting blockwood with maximum 60 cm diameter, with a capacity of 375-450 m^3 woodchip per hour.
- Wood-chip forwarding to storage place: electricity-driven rubber-belt conveyors.
- Wood-chip storage: covered steel structure storage facility with 50 x 20 m floor-space and 12 m height, loaded by discharge conveyor.
- Delivery to the boilers: the fuel material can be directly delivered from the conveyor-belt system between the chopping-machine and the storage location to the existing feeding system. From the covered storage location the wood-chip can be delivered to the boilers through the existing chute.

Modifications in the firing technology:

- The four garners (two belonging to each boiler) will be modified according to the required angle of repose for wood-chip, and feeder-scraper equipment will be built in to secure continuous and controlled discharge of wood-chip to the boiler. The last section of the chain-scraper will be modified, in order to avoid jamming and carrying back due to the wedging in.
- The physical parameters of the biomass and its lower ignition temperature compared with that of coal do not allow drying with recirculated flue gas, therefore the flue gas recirculating duct will be closed on the boiler side.
- In order to avoid jamming, the cross section of the ducts leaving the mill and the “burners” must be modified.
- The modification of the fluidised bed structure is underway. The particle distribution of the fluidised bed material has to be modified and a material with a higher melting point has to be chosen.
- The air supply of the fluidised bed will be modified, since the bed temperature will be higher than under current operation.
- New air inlets are needed in order to burn the gases from the fluidised bed without producing nitrogen-oxide, then the gases are cooled with extensive excess air injection.

Decrease of solid particle emissions:

- The existing electrostatic dust separator must be overhauled, and an additional dust removing equipment (bag house) might be needed, in order to keep the solid particle emission below emission limits.

Handling of the residues from combustion:

- The classification of the separated dust.
- Construction of a deposition site according to the ash quality, preparation for the utilisation (the ash as a potential potassium fertilizer).

Rehabilitation of the turbine (currently under way):

- The turbine has been completely dismantled.
- The rotating, low and high pressure parts have been sent to Alstom for review and calibration.
- Purchase of new blades.
- Construction of new steam inlets, which are better able to lead the steam directly to the blades.
- All the sealants have been replaced.

2 GHG SOURCES AND SINKS AND PROJECT BOUNDARIES

2.1 *Direct on-site emissions*

- Emissions from combustion: . Emissions will be zero from biomass combustion[8]. The emissions from natural gas combustion will be accounted for.
- Ignition fuel: the ignition fuel used currently at the plant is natural gas. The fuel used will remain unchanged when the boilers are converted to biomass combustion. The quantity of ignition fuel used is expected to decrease and will be less than 1% of the complementary natural gas combustion.
- Emissions from vehicles used to transport the biomass within the area of the plant.
- Preparation of the biomass fuel and other technological processes: emissions from the machinery used for preparation of biomass fuel within the area of the plant. Only the front loader is fuelled by diesel oil, other equipment (e.g. for chopping the fuel wood, and conveyor belts) are electricity powered. These are taken into consideration with the difference between gross and net electricity production. The electricity used is produced on site from biomass, therefore the emissions related to the on-site electricity consuming equipment are included in the emissions mentioned above.
- Emissions related to the installation of the new equipment and reconstruction at the plant: these emissions are expected to be insignificant and will not be calculated in detail. As the project is a conversion of an existing plant, no heavy construction work will be done. The construction emissions will relate to some welding and metal cutting activity on the site.
- Methane emissions from biomass fuel storage: these emissions will be calculated and monitored, and will be included in the project emissions.

2.2 *Direct off-site emissions*

- Production of fuel: fuel used by the company producing the fuel wood: logging, collection of wood, chopping and dragging to the point where it is loaded onto trucks.
- Transport of fuel: the transport of fuel is estimated from the point of loading onto trucks. The emissions were estimated based on transport distance, fuel consumption and unit emission factors from an acknowledged Hungarian engineer (Tihamér Tajthy). The average figure used for transport distances is a conservative estimation for the potential biomass supplying region around the plant of max. 150 km radius. A high estimation of 100 km for the average biomass transport distance was taken. Transport distances and related emissions will be monitored through a uniform reporting format.
- Wood waste: decreased methane emissions from the anaerobic decomposition of wood waste left at other sites in the absence of the biomass project.
- Boiler and turbine conversion/reconstruction work requires transportation of, at most, 50 tons of equipment and sand to the site, which are a few truckloads only. These emissions will be negligible compared to other project emissions and will therefore not be listed.
- Emissions related to the production and transport of natural gas: these emissions are outside the project boundary and are therefore not calculated.

[8] The CH_4 and N_20 emissions from the combustion of biomass will very likely be lower than the CH_4 and N_20 emissions from the combustion of fossil fuels in the baseline.

2.3 Indirect on-site emissions

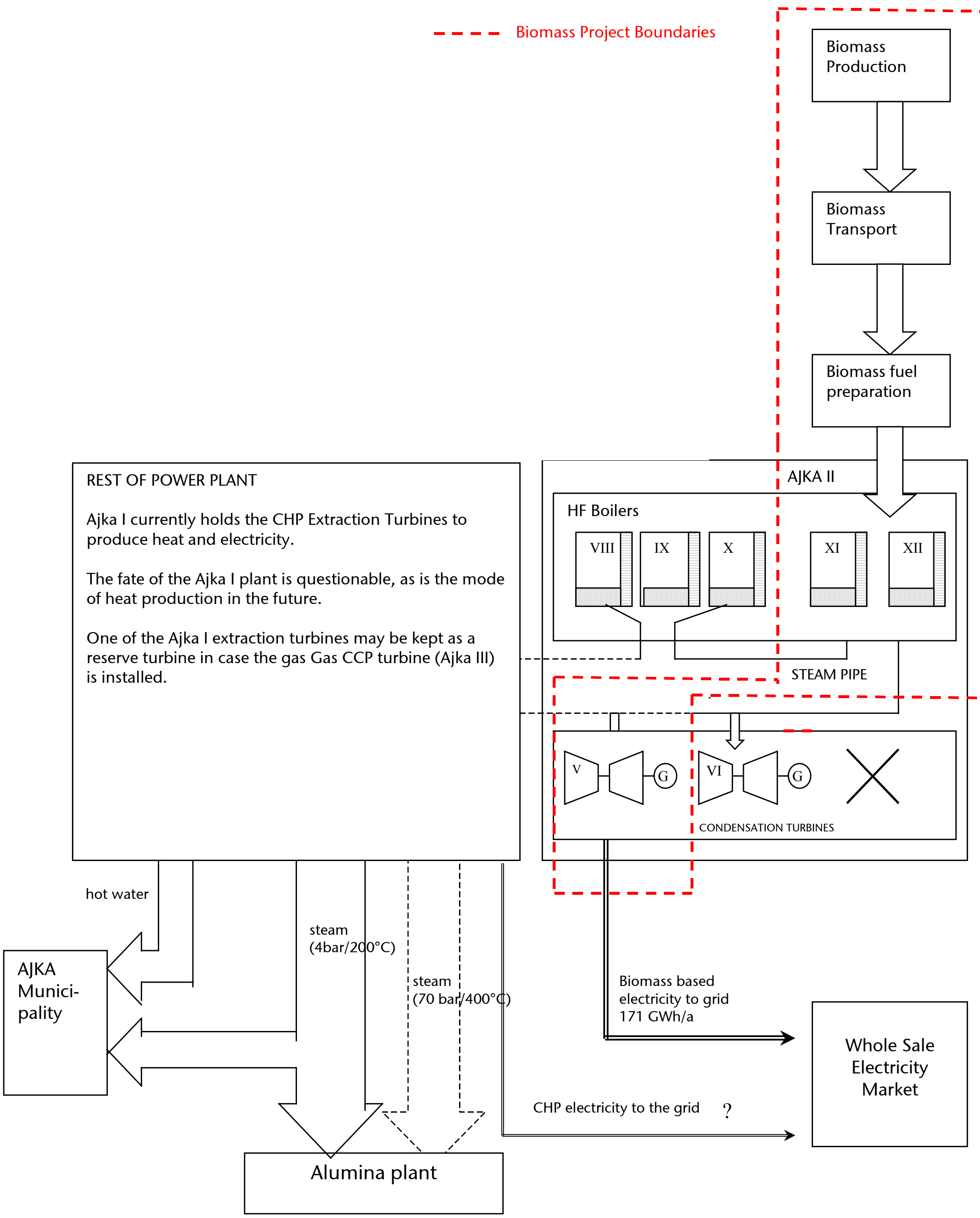
- There are no indirect on-site emissions

2.4 Indirect off-site emissions

- Effects on demand for electricity: since the electricity output of the biomass plant has lower than 1% share of the domestic market, it is assumed that the cost of production at the plant will not, in itself, influence electricity demand. Thus there is no shift in demand for electricity that can be attributed to the project.
- The demand for fuel by the plant may affect the regional fuel wood market. The price of fuel wood may be driven up to some extent. This might cause substitution for other fuels for households that are not yet connected to the gas network (these are quite few), or an increase in the collection of wood waste and remnants at the area of logging, either by the local residents in need of fuel wood, or by the companies supplying fuel wood to the power plant. In the long term, an increase in price of wood may induce an increase in supply in the form of enhanced forestry activity and energy plantations. These effects are expected to be less significant for GHG emissions, difficult to estimate, and difficult to monitor. However the monitoring plan addresses this issue.

2.5 Flow Chart of the Biomass Project

Figure 1 Flow chart of the biomass project



The direct on-site activities (ignition and preparation of fuel) were included within the project boundary as these are under the influence of the Ajka plant. The direct off-site emissions associated with the production (logging, collection) and transport of the biomass fuel were included because the plant is a large client of fuel wood on the local market and may have a significant impact on fuel use of the companies which produce and supply the wood for the plant. We excluded the potential future gas CCP from the project boundary, since the decision on the two plants is independent and they would operate separately and independently from the biomass project. This also holds if some coal-based production is maintained instead of a gas CCP (also refer to the section on strategic options and baseline scenario selection for more information). The fossil plants feeding electricity into the national grid have not been included, as the project owner has no *direct* influence on them; however one should keep in mind that it is their production, and consequently their emissions, that the electricity generation of the proposed biomass project would displace.

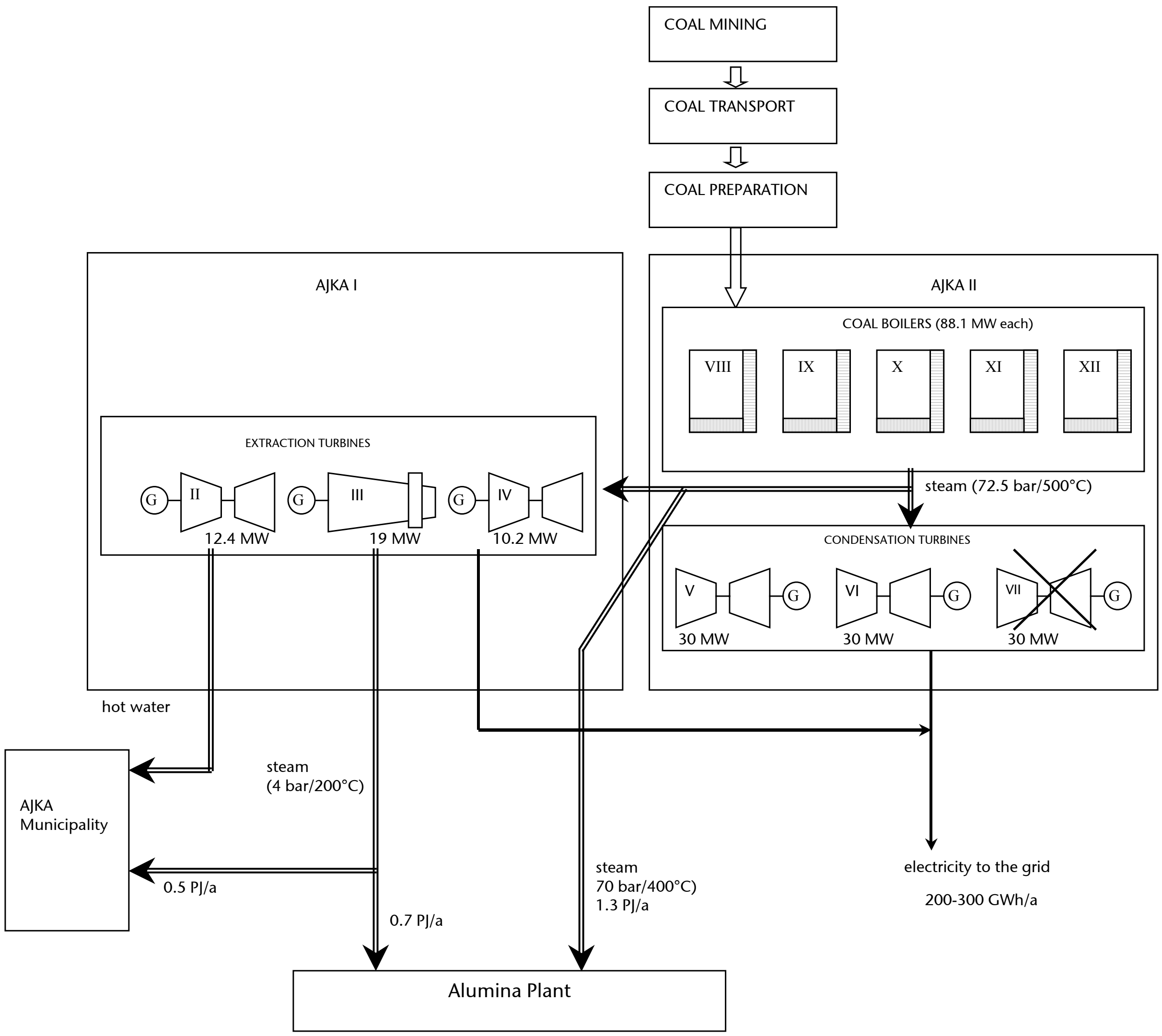
The heat production and related CHP electricity production at Ajka have been excluded from the boundaries of the biomass project. The main reasons are the fact that the biomass project will be an independent legal entity, separate from the rest of Bakony Power's operations although entirely owned by Bakony Power, and because the heat and related CHP electricity production at Ajka has no effect on the output of the biomass project and vice-versa.

Another section discussing future strategic options for the Ajka plant demonstrates the independence of the biomass project from the heat operations at Ajka. This detailed discussion can be found in section 5.1.

3 DESCRIPTION OF THE CURRENT DELIVERY SYSTEM

3.1 Description of the current electricity and heat delivery system at Ajka

Figure 2 Flow chart of the current delivery system



Ajka II contains all five of the currently operational boilers. These are boilers with a nominal capacity of 88.1 MW each. Boiler number VIII is fuelled by pulverized coal, boilers IX, X, XI, and XII are hybrid fluid boilers. All boilers are GANZ-DANUBIUS (MHD), 100 t/h heat capacity, coal-fired boilers, producing 72.5 bar, 500 °C steam. Ignition fuel is needed for heating the fluid beds to the appropriate temperature, and in case of low level of utilization, for sustaining fuel combustion. The ignition fuel used is natural gas, the amount needed for firing coal is approximately 100 000 m^3/yr.

The boilers supply the extraction turbines in Ajka I with steam. The three extraction turbines at Ajka I, turbines II, III, IV, have a capacity of 12.4, 19, and 10.2 MW respectively. Turbine III operates most of the time, the other two turbines are for back up. The turbines produce 4 bar/200 °C steam.

These extraction turbines produce both heat and electricity. The Ajka Alumina plant is partly supplied with steam (4 bar/200 °C) from the extraction turbines (0.7 PJ/a), but it also receives raw steam directly from the boilers (70 bar/400 °C, 1.3 PJ/a). In total, the power plant provides the alumina plant with 2 PJ/a heat, while 0.5 PJ/a of district heat and hot water is provided for the municipal district heating company of Ajka (7,000 households and some institutions, with a total of 10,500 household equivalent).

Three 30 MW capacity condensation turbines for the production of electricity are located at Ajka II: turbines V, VI, and VII. Of these, turbine V operates most of the time, turbine VI is for back up, turbine VII is not used. The current (inverse) efficiency of the electricity production from the condensation turbine is 15,300 kJ/kWh[9], which represents the heat content of the fuel input per sold electricity. Turbine V is in the process of being reconstructed to improve the efficiency, and according to Bakony's management, the expected new inverse efficiency will be around 14,000 kJ/kWh sold electricity, resulting in an efficiency of 25.7%. The efficiency calculation uses the lower heating values of the biomass fuel.

The generators of the turbines at Ajka I produce 10.5 kV electricity, which is delivered to the main distribution network through two 25 MVA transformers. The turbines at Ajka II operate with three 40 MVA block transformers.

The total built-in electricity production capacity of the plant is 131.6 MW (with the cessation of the operation of turbine VII now is only 101.6 MW). The potential electricity production is 500-600 GWh/a (actual production in recent years has only been 250-300 GWh). The annual heat production is around 2.5 PJ. The following table shows that the capacity of the plant is quite under utilized despite being not fully exposed yet to the competitive market.

Table 1 Capacity data of Ajka Power Plant

		1999	2000	2001	2002
Built-in electricity production capacity	MW	131,6	101,6	101,6	101,6
Available capacity	MW	81,5	67,7	68,9	66,5
Actually used capacity	MW	70	31,6	44,4	47,6
Built-in steam production capacity (5 boilers)	t/h	500	500	500	500

The following table lists the net efficiency (excluding self consumption; output *sold* per input energy) data of Ajka power generation during the past years. One can see that these efficiencies are low relative to what is achievable even by recent coal technologies. Efficiencies of new coal-based electricity production plants are in the range of 31-32%.

Table 2 Efficiency data of electricity and CHP production at Ajka Power Plant

	1999	2000	2001	2002
Efficiency of condensational electricity generation (%)	24,4	23,2	22,9	24,5
Combined efficiency of combined heat and power generation (%)	83,5	82,5	84,2	88,7

[9] This efficiency factor represents the heat value of the fuel input to the total electricity sold (which is the gross electricity produced minus self consumption and internal consumption)

Bakony receives its coal supplies from its own coalmines, which are being depleted both in terms of quantity and fuel quality. The Ajka plant currently uses coal from the Ajka, Balinka and Lencsehegy mines, with the majority of the coal coming from the Ajka mine. Coal from all these mines has very low energy content and is marked by high sulphur and ash content. The Ajka coal, in particular, exhibits a very low energy content with a heat value half of that of the other two coal mines (6517 kJ/kg versus 11116 kJ/kg and 11886 kJ/kg for the other two mines). The coal from the mines is sorted, and prepared for firing (dried and ground) at the plant.

3.2 Variations in electricity production

Annual production of the Ajka plant in recent years is shown in the following table. It indicates larger fluctuations in output than what the drop out of turbine VII would justify. This is due to the cessation of the PPA and fewer possibilities to sell electricity at supported prices.

Table 3 Annual production of the Ajka plant

Electricity (GWh/year)	1999	2000	2001	2002
Including self consumption	590	261	293	359
Net production	481	191	221	279

The seasonal variation in the electricity generation of the CHP turbines is quite large, and correlates with heat demand, which is the driving factor, while electricity production by the condensation turbines is relatively stable. The monthly figures showing CHP and condensation-produced electricity supplied to the grid are presented in the table below, with actual figures until June 2003, and a prognosis for the second half of the year.

Table 4 Electricity production at the Ajka plant in 2003

	Combined with heat (MWh)	**Condensational (MWh)**	**Total (MWh)**
January	8 165	12 679	20 844
February	7 212	11 696	18 908
March	7 777	10 292	18 069
April	5 953	9 405	15 358
May	3 275	14 036	17 311
June *	2 866	12 771	15 639
July *	2 700	?	?
August *	2 700	?	?
September *	3 710	?	?
October *	7 730	?	?
November *	8 900	?	?
December *	9 220	?	?
Total	70 208	≈128 000	≈198 000

* Prognosis

As the above tables illustrate, the combined electricity production figures show a large variation, with the highest figures in the winter months, when heat production is also higher, and lower figures for the summer months.

The daily production of electricity also follows the heat production pattern. If there is a drop in the demand for heat, then there is a corresponding drop in the steam led to the extraction turbines. The steam is then led to the condensation turbines for electricity production, while the combustion in the boilers is adjusted to the change in demand for steam. It takes approximately half an hour for the boilers to follow the change in heat demand.

The condensation turbines (mostly this means only turbine V) are operated at a low capacity level, so that they can receive any additional steam from the extraction turbines with the decrease in heat production. Of the extraction turbines, turbine III with a capacity of 19 MW operates most of the time. The other two extraction turbines are used for back up.

3.3 Variations in heat production

Table 5 Annual production of recent years

	1999	2000	2001	2002
Heat output (TJ)	2 471	2 628	2 716	2 453

Heat is produced by the extraction turbines (4 bar steam), as well as directly from the boilers (70 bar steam). The table above indicates a quite stable annual heat production, which reflects a stable heat demand due to the large weight of the alumina plant in heat consumption. Weather conditions affect district heat demand, but the weight of municipal consumption is much smaller.

The daily quantity of heat production in the form of steam and hot water for the alumina plant and the Ajka municipal district heating company also shows variation.

The quantity of 70 bar steam produced for the alumina plant is quite stable, around 140 GJ/h all day and all year round, with one daily short sharp fall in the summer months lasting around 2-3 hours.

The quantity of municipal hot water produced is lowest during the summer months, reaching almost zero levels during certain hours of the day, with a morning and evening peak of around 30 GJ/h for workdays. The winter months show the same pattern, with a low of around 130 GJ/h and a high of 180 GJ/h for workdays.

The 4 bar heat (produced for both the municipality and the alumina plant) shows less daily variation, and remains at around 60 GJ/h in the summer, and 90 GJ/h in the winter months during the entire day.

3.4 The electricity delivery system on the national level

So far, the plant-level delivery system has been reviewed. In this section we also describe the Hungarian electricity (national delivery) system.

Large plants using a variety of fuels dominate electricity generation in Hungary. These plants connect to the transmission network through electricity transported at a high voltage level (120 kV or higher) to the distribution network (120 kV or lower) and then to final consumers. There is less emphasis on distributed generation, but its impact is growing, especially with the spread of CHP and RES-E production. Figure 3 below provides a graphical illustration of the current grid-based electricity delivery system. The red dotted line indicates a system boundary relevant from aspect of the proposed Ajka JI project.

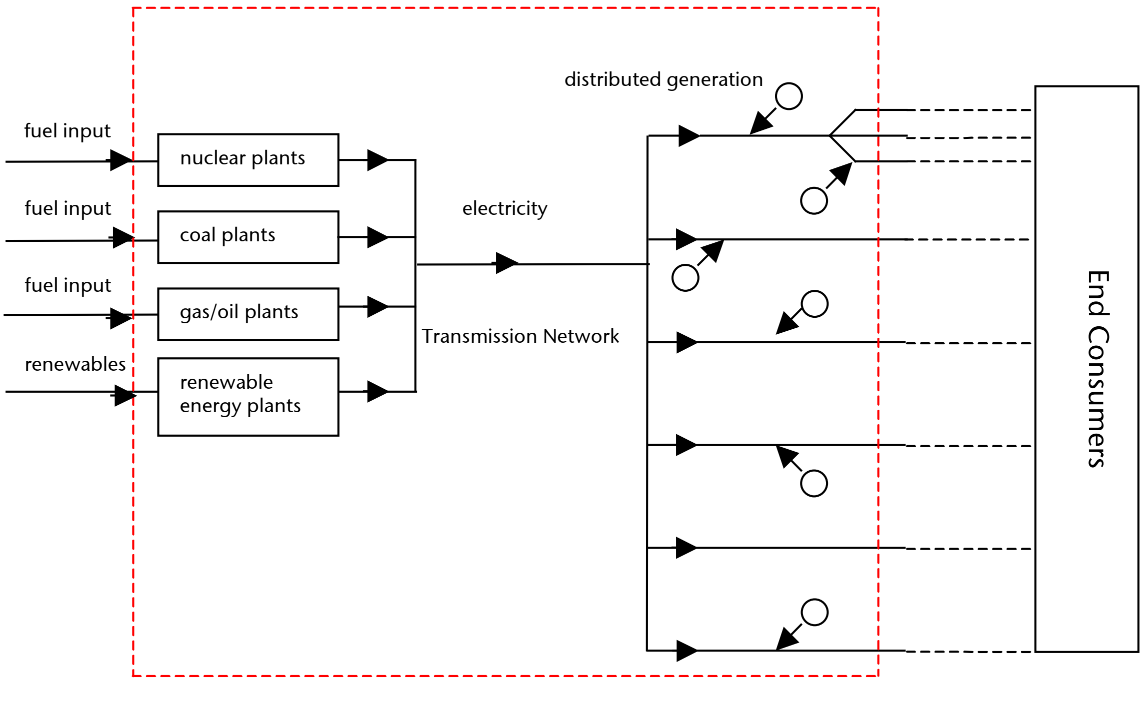


Figure 3 Structure of the electricity grid

The following table reviews macro level electricity volumes.

Table 6 Volume of Hungarian electricity production and foreign trade (TWh)

Year	Gross electricity production	Net electricity production[10]	Import	Export	Net import	Overall network loss
2000	35.191	32.444	6.197	2.757	3.440	4.733
2001	36.417	33.701	6.946	3.775	3.171	4.676

Source: Electricity Statistical Yearbook 2001

Although imported electricity amounts to nearly 10% of total electricity consumption, currently there is a domestic excess of generation capacities. Imports – apart from some peak demands and emergencies – usually occur because, on average, imported electricity is cheaper than domestic production. However, MVM, the state-owned wholesaler and transmission network operator (TNO), had the exclusive right to import until the beginning of the partial liberalization, i.e. January 1, 2003. On the other hand, the actual export/import volumes of electricity traded annually show a smaller amount than capacity would allow. Domestic power plants engage in long-term PPA contracts with MVM (which also owns power plants). Thus, it is expected that after widening the market access by increasing the number of authorized consumers as well as lifting their 50% import limit, the share of imports will rise. This expectation is supported by the fact that during the first cross border capacity auction new entrant traders had already bid for a significant share of import capacities, especially for import from Slovakia. Export is mainly aimed at Croatia, where fluctuating hydro capacities often result in good prices for transit or even for expensively produced Hungarian electricity.

In order to put the current and proposed Ajka plant capacities into context, domestic generation capacities are detailed in the following table.

[10] Gross electricity production minus self consumption of power plants.

Table 7 Characteristic Capacity data of the Hungarian Electricity System (MW)

(MW)	1990	1995	1998	1999	2000	2001
Installed capacity	7 177	7 288	7 602	7 845	7 855	8 365
Available capacity	7 065	6 982	7 424	7 667	7 601	8 059
Usable capacity	5 376	5 610	6 313	6 603	6 725	7 138
Actually usable capacity	5 286	5 468	6 033	6 236	6 349	6 663
Peak-power station load	3 635	4 383	4 614	4 640	4 425	4 566
Import-export balance	1 751	415	144	188	465	476
Peak load (annual weekday)	5 386	4 798	4 758	4 828	4 890	5 042
Maximum peak load	6 534	5 731	5 817	5 801	5 742	5 965

Source: Electricity Statistical Yearbook 2001

The table shows that there is significant excess generation capacity (around 8000 MW available capacity and 6700 MW actually usable capacity versus 4600 MW peak power station load), but until 2010 some additional 300-400 MW are expected to be needed. This is partly due to the shut down of most of the coal-fired plants and partly to the annual increase in electricity demand by 2%. According to the draft capacity need outlook, a study being prepared by the system operator MAVIR, new coal capacities are only expected in the second decade of the century. There are some lignite fields with cheap open mining possibilities in Hungary. These projects are expected to support large capacity coal plants by the end of the decade. However, the viability of these plans is in question due to strong resistance of the affected population.

The Sale of Electricity

- *Production and sales to the wholesaler:*

  Long-term bilateral contracts (power purchasing agreements, PPAs) between large generators and MVM, now the wholesale trader, continue to dominate electricity sales. Some 90% of the available capacity is reserved by MVM. The PPAs were concluded in the second half of the '90s, mostly to support privatisation. The contracts have two main pillars: (i) an annual capacity reservation fee and (ii) a fixed amount of electricity guaranteed to be purchased on that capacity. The contracts either referred to the regulated maximized prices listed annually, or contained special price formulas. Despite the end of price regulation of generation as of January 2004, producer prices live on due to inertia (or the explicit price formulae set in the contracts). MVM can (and actually unsuccessfully did) initiate renegotiation of PPAs. The company can also can sell or auction reserved capacities, if it becomes redundant along with increasing number of eligible consumers stepping out of the regulated market. Until the end of 2002 import rights were exclusively held by MVM. As of January 2003 import rights of free cross border capacities are auctioned. Import capacities are scarce. Although they have had a downward pressure on domestic prices, cheap imports cannot oust out the majority of domestic generation. Some 10% of available generation capacities are not reserved, and generators can sell electricity produced on them freely on the market.

- *The regulated wholesale and retail market:*

  The public wholesaler (MVM) purchases electricity as described above, then sells it on at the regulated wholesale price to regulated retail suppliers (distribution companies). These companies, in turn sell it on at another – higher – regulated price to captive consumers.

- *Free market:*

  So far the electricity market is based on bilateral contracts between producers, traders and eligible consumers (those with consumption above 6.5 GWh/yr for the first stage of market opening). Partial opening only recently took place, with only 5-10% of consumers[11] leaving or having left the regulated market, though 30% would be eligible.

- *Electricity exchange:*

  The electricity exchange is currently being organized. Such a small exchange does not seem viable on its own because of economies of scale. Therefore regional mergers are logical and expected in the mid-term.

- *Obligatory purchase at feed in tariffs:*

  CHP and RES-E have priority access to the grid and have to be taken over by MVM or the regional regulated retail supplier at a fixed feed in tariff. MVM or the supplier is compensated by the system operator for the premium it has to pay over the regulated wholesale price due to the feed in tariff. The source of the compensation is a component in the general system operation fee eventually paid by every consumer. Since 2003 the formerly uniform feed in tariffs have been differentiated between RES-E and CHP (lower for the latter), and within the CHP category, too, according to the size of plants.

Table 8 Feed in tariffs for RES-E in 2003

	HUF/kWh	EUR/kWh
Peak period	24	0.092
Off peak period	15	0.058
Weighted average	**17.41**	**0.067**

These tariffs were announced at the end of December 2002. The tariff system will not be altered for eight years, but it will be annually adjusted with some price index, unless the introduction of the tradable green certificate (TGC) system replaces it. The chance of such replacement creates a regulatory risk, because even if the percentage target of a TGC system is high, one hardly knows in advance what the equilibrium TGC price will be. Moreover, the fluctuating nature (volatility) of TGC prices creates additional (market) risks. On the other hand, the current magnitude of feed in tariffs seems insufficient to achieve the ambitious renewable goals (see the section on energy policy in section 4).

[11] In terms of consumption volume.

4 KEY FACTORS INFLUENCING THE BASELINE AND THE PROJECT

The following section provides a short description of the key factors that influence the baseline and the project. Their specific effects are analyzed in section 5.

4.1 Legal factors

4.1.1 Environmental legislation

The most important pieces of legislation are the *Large Combustion Plant Directive 2001/80/EC* and its transposition into national law, which took place recently by *Decree 10/2003 (June 11, 2003) of the Minister of Environment and Water Management* (MEWM)). These affect both coal-based and biomass-based electricity generation.

Stricter emission limits will apply for particulates, NO_x, and SO_2. Of these pollutants, it is the NO_x emissions, which require special attention, and additional experiments and adjustments in the biomass combustion process. For NO_x, the emission limit value was reduced from 650 to 300 mg/m^3 in the case of biomass.

This transposition decree affects the coal-based production. Ajka Plant will be required to adhere to either a strict SO_2 emission limit value (1695 mg/m^3 till the end of 2004 and 200 mg/m^3 from 2005) *or*, a 75 % desulphurisation ratio (which replaces the current requirement of 60%) as of January 1, 2005. For the new emission limit values, which apply to the Ajka Plant for various pollutants please see the environmental analysis section 11.

The beneficial environmental effects of the project, such as the decrease in CO_2 and SO_2 emissions, as well as the decrease in waste and slurry and thus the load on the soil and waters is expected to encourage the acceptability of the project.

4.1.2 EU wide GHG Trading System and its effect on electricity prices

The introduction of the EU GHG emission trading as of January 2005 can improve – but may also further impair – financial results of the current coal based plant, depending on how allocation will take place. Although allocation is not expected to be tight for Hungarian plants, emission trading on average is expected to raise the costs of fossil fuel plants in the EU and consequently the price of competitive electricity. Low carbon intensive plants and plants with a loose cap will become more competitive. However, the magnitude of electricity price increase is likely to be around 20-30%, which is probably not enough for Ajka to save its coal-based production.

GHG trading could intuitively affect biomass production by raising the competitive electricity price. However, as long as the feed in tariff prevails, biomass production does not compete with other producers and neither benefits from an increase in competitive price. It might – but not necessarily - change with the introduction of the tradable green certificate system (TGC) system. It can be shown that on a liquid and competitive TGC market the premium offered by TGC prices would decrease with the introduction of a GHG trading system, thus carbon pricing of dirty electricity may not put renewables in a better position on the competitive market.

4.1.3 EU Waste Management Legislation

The EU waste management legislation has already been transposed into national law and further restrictions and requirements are not expected due to EU accession. Both the current technology and the proposed project can satisfy the requirement of EU and Hungarian waste legislation (see the environmental analysis section).

4.1.4 Forestry Law

Forest management activities are controlled by the 1996/LIV law on Forests and the protection of Forests (Forestry Law). The implementation of the Forestry Law is regulated by the *29/1997 (IV. 30.) decree of the Minister of Agriculture*. The Hungarian Forestry Law requires that all managers of forests prepare an annual forest management plan subject to approval by the Forestry Authorities. The ten-year management plan has to be based on the ten-year forest district plan prepared by the Ministry. Thus, permission has to be given for every felling, and there is an obligation on all managers of forests to carry out reforestation within a certain time frame. The forest management activity also has to be consistent with the designation of the forest (e.g. nature protection, recreation), determined by the Ministry of Agriculture, and other relevant authorities. Not only logging, but also the collection of dead wood is considered a beneficial use of the forest, which has to be practiced in such a way so as not to damage or endanger the surface and subsurface waters, soil, and forest ecosystem, or the reforestation of the area. The National Forest Strategy and Programme are currently under preparation, which also deals with energy forests. The implementation of the programme may encourage investment into energy plantations, but there is still much uncertainty in this regard.

4.2 Economic factors

4.2.1 Electricity and heat market and related prices

The electricity market is characterised with excess capacities and the still limited competitive segment of the market is depressed with short run marginal cost pricing. These low prices reflect both domestic and foreign excess capacities. Imported electricity is cheap despite seemingly scarce import cross border capacities. Despite the liberalisation process, long term - higher than competitively priced - PPAs with the public wholesaler still prevail. The wholesaler cannot terminate simply and cheaply these contracts despite ongoing efforts to facilitate the termination of such contracts.

Such circumstances provide a very uncertain environment for investors in new capacity or in the rehabilitation of existing power capacities. However, by the end of the decade new capacities will be needed and scarcity will dive up the price making it possible to invest in both power plants and cross border capacities.

The PPA system cannot continue to provide shelter for the Ajka Plant. Its PPA expired in 2000, and it cannot be renewed due to high costs of production at the plant. The products of the plant are heat and electricity, which considered more than two products from an economic point of view due to special features of regulation. Furthermore, each of these products is priced differently. These products are:

1. Condensational electricity (electricity only)
   With the expiration of the PPA, former volumes of condensational electricity cannot be sold. In fact, the plant could not sell any amount at costs reflecting market prices due to the costs being very high. With such high costs, the plant cannot enter the competitive segment of the electricity market. Sale of the remaining amount is only possible due to political support, which provides transition time to keep the plant alive and thus facilitate heat supply for the municipality.

This support is tied to district heating. The condensational turbines are run so that they can serve as an adjustment channel by swallowing surplus heat in case heat demand recedes. Such quick adjustment is necessary until the boilers are modified to accommodate lower steam needs. The price for such district heat-related condensational electricity (so called “forced condensation”) is set very high for the Ajka Plant this year, but it may not be granted for coming years. The volume has to be negotiated with the wholesaler. The condensational electricity production at Ajka is larger than CHP based electricity production.

2. Electricity jointly produced with district heating
Electricity jointly produced with district heating enjoys a preferential regulated tariff. Apart from small-scale (capacity lower than 6 MW) generation, only CHP with district heating utilization receives a higher feed in tariff. However CHPs larger than 50 MW are only granted a mandatory take over (and no premium feed in tariff) if its heat goes for district heating. Since the Ajka Plant is a large plant with capacity over 50 MW output, its feed in tariff is being annually reduced, putting Ajka in a situation faced by most ordinary large combustion plans.

3. Electricity jointly produced with non-district heating
Ajka Plant provides the Alumina plant with 4 bar and 70 bar heat. The four bar heat is generated in a CHP mode along with electricity just as in the case of 2/. This electricity fraction enjoys no feed in tariff and according to the 56/2002 decree and has to be sold on the competitive market. Currently, the competitive prices are far too low, cross-subsidising electricity from heat price might only be possible on a limited scale and for a limited time in the future.

4. Low pressure (4 bar) heat from CHP (a/for district heating, b/for non-district heating (for the Alumina Plant)
This product is derived from the heat of the aforementioned (2. and 3) electricity generation.

    a/, Cooperation is likely to be renewed with the Municipality of Ajka, The municipality signed a statement of intent to continue purchasing heat from the Ajka Plant. If the city purchases district heat, the municipality is authorised by legislation to set the price. However, the price is subject to negotiations and must be based on cost recovery principles. The price cannot be raised too much without the risk that the municipal supplier company risking will lose clients and heat sales. Heat demand determines CHP electricity output, and this segment of the heat market is very valuable for the plant due to feed in support of related electricity.

    b/ The price of the non-district heat is determined by negotiated contracts with the Alumina Plant. The future demand for heat largely depends on the developments in the aluminium and in the alumina market, which at present are oversupplied. So far, the Alumina Plant exhibited a stable demand, and a long-term (10 years) contract for supplying heat to the Alumina plant has been signed. The uncertainty of the alumina output is reflected by a 2-year notice clause in the contract. Bakony does not run a loss on the 4 bar heat production.

5. High pressure (70 bar) heat (heat only)
The 70 bar heat production is currently produced at a loss. Until recently, the government regulated the price of heat to the Alumina factory. These tariffs were not set on a cost recovery basis. In order for Bakony to operate profitably, the 70 bar heat tariffs would have to be increased by 35%. In order to keep this heat market, Bakony struck an agreement with the Alumina factory to raise the tariffs each year to keep pace with inflation – plus an increment in order to achieve a cost recovery level over the timeframe of several years.

The markets and products above are likely to change due to the liberalization process. Developments on these markets affect both current coal based production and the strategic options the firm envisions. This will be discussed in more detail in section 5.

4.2.2 Biomass market

Bakony Power assessed the regional biomass market through several studies, and it also requested bids from biomass suppliers. The main conclusion is that under present circumstances it is possible to contract for delivery of approximately 200 kt/year of biomass at acceptable prices. The majority of biomass would come directly from logging (forestry management). The rest is wood waste from the wood industry. After energy plantations are established in the region, supply could reach 300 kt/year. Some experts, however, suggest that the large additional demand created by the entrance of Bakony into the market will drive prices up abruptly, narrowing the affordable quantity of biomass. While the management of Bakony Power is certain that it will be able to purchase 200 kt of biomass each year, there is definitely a risk of rising biomass prices, which could in turn lead to lower amounts of purchased biomass input. In this situation, energy plantations can have a vital role in securing a stable supply.

4.2.3 Energy plantations

There are two main types of energy plantations: grass/reed and forests. At present neither of them are widespread in Hungary. A number of experimental plantations exist or are being developed, and there is growing interest both from landowners and potential buyers of energy production. Despite the present lack of energy plantations, they will likely go through a boom in the coming years, for a number of reasons:

- There is growing demand for biomass, due in large part to conversion of coal-fired power plants to biomass combustion. In addition to Bakony Power, three large power plants combusting biomass will go online in 2004, and a number of smaller plants are likely to switch to biomass in the coming years. Constant demand will encourage farmers to invest in energy plantations.
- The technology for energy plantations has been continuously developed both abroad and in Hungary (e.g. "Szarvasi grass" for energy production), and pilot projects are proving to be successful. The Ministry of Agriculture and Regional Development intends to support additional pilot projects from its 2004 budget, with the aim of launching at least 500 hectares of energy plantations next year, yielding annual biomass of 6-8 kt. The initial success of such projects will be a key factor in persuading farmers to switch part of their land to energy plantations.
- There are already many agricultural fields in Hungary that have been taken out of agricultural production, and after EU accession additional land will be withdrawn from agricultural cultivation. A logical use of set-aside land is afforestation and energy plantations. The EU agricultural support scheme, starting in 2004 in Hungary, will offer favourable conditions to set aside land, providing subsidies to farmers that set aside up to 10% of their land for non-traditional purposes, such as energy plantations. The subsidy is expected to be 42,000 HUF/hectare in 2004, growing to about 80,000 HUF/hectare by 2008. Initial calculations show that energy plantations will be profitable even without the subsidies. At the same time, initial investments costs are relatively high in comparison with subsequent operating costs, therefore financial support can be an important factor in getting plantations underway through reduction of initial capital need and entrepreneurial risk.

4.3 Political factors

Renewable Energy Support Policies

Liberalization of the electricity market is a cornerstone of the Hungarian energy policy (as the Electricity Act of 2001 has provided for), with other main objectives being the increase of energy efficiency and the promotion of renewable energy sources. The 1107/1999 (X.8) Government Decree sets the target of 50 PJ/a for renewable primary energy consumption, as compared to the current 30 PJ/a. Considering that Hungarian total primary energy consumption is approximately 1000 PJ/a, the target set by the government decree does not even amount to half the 12% target set by the Community for primary energy consumption contained in the White Paper on Renewable Energy Sources.

This means that more efficient and effective instruments are needed for the promotion of renewables, and this is even more apparent when comparing Hungarian RES-E production of less than 1% with the Community target of 22% for 2010 contained in the 2001/77/EC Directive. By 2010 the current RES-E production (circa 0.5%-0.8%) in Hungary will have to be increased substantially, to 3.6% as result of negotiations with the Commission. Officials at MAVIR claim this is an overly ambitious target (Strobl, 2003). They deem a 2% target attainable. As current renewable support policies are not likely to be sufficient to achieve the 3.6% target, either the feed in tariff (see section 3) should be raised or an ambitious TGC system should be introduced.

The new tariff system is planned to last until 2010– with annual adjustment according to the forward looking price index of the National Bank– unless the introduction of the TGC system replaces it. The government has the discretion, but not the obligation, to introduce the TGC system after due evaluation of international experiences and national circumstances. This mandate is in place despite the fact that a recent lower level decree sets the feed in rules for eight years ahead. The chance of such replacement creates a regulatory risk.

Biomass, which is the largest renewable energy source in Hungary, is widely regarded as a desirable renewable energy source for the nation. Further exploitation of renewable energy resources, also reduces import dependency that, due to inefficient coal based electricity generation and limited domestic natural gas production, is expected to further increase. Biomass projects are also welcomed by policy makers because they can help alleviate the decline of some poor, rural regions by preventing population migration, providing local job opportunities, and managing the local landscape.

4.4 Socio-demographic

No major socio-demographic trends, events or factor can be identified that will affect either the project or the baseline.

The closing of the coalmines in the area, which will result in an increase of unemployment is inevitable, and is not linked to the project. The number of people to be employed for combusting biomass will be around 100, a decrease from the number of people employed for coal combustion currently, which is around 260. Some of these employees will stay on after the implementation of the biomass project, because coal will be used by the plant for a few more years in other blocks. Later on, with the potential installation of the gas CHP, employment will also be created, but the net effect on employment is expected to be negative. There is also currently an additional 40 managerial staff at the plant. This number may also decrease.

It should be emphasized, again, that unemployment due to closure of coal fired blocks is inevitable, and it is independent of the introduction of biomass combustion, which, in fact, will have a positive overall impact on employment compared to the closure of coal fired blocks. Additional employment may also be created by the increased demand for biomass, e.g. energy plantations will likely be established as a result of the increase in demand due to the project.

5 IDENTIFICATION OF THE MOST LIKELY BASELINE AND THE ASSOCIATED GHG EMISSIONS

5.1 Assessment of Strategic Options for the Ajka Plant

In the process of selecting the most likely baseline scenario, a number of strategic options for the Ajka plant (without the proposed JI project) were identified and their feasibility was assessed. It should be stressed that these strategic options *are not* the baseline scenarios; a distinction has to be made between the terms “strategic options” and “baseline scenarios”. The latter term is used as usual in the Kyoto context, while “strategic option” is a wider category including for example elements that will or might be implemented to produce heat and electricity, whether or not the JI project goes ahead.

The identification of these strategic options is important in order to obtain insight into directions the plant might pursue to deliver heat and electricity because *a priori* one cannot decide whether some choices of the plant are absolutely independent of the proposed biomass project. In other words, whether some options or some elements of the options are within the JI project boundary or not. Once the characteristics of each strategic option are assessed, the consequences of each option for determining potential baseline scenarios for the biomass project will be analyzed. The strategic options identified are listed in the following table. The reasons for the time intervals in the table headings are as follows:

1. From January 2005, stricter EU environmental regulations will apply to the Ajka plant (basically the implementation of the new LCP directive 80/2001/EC, the transposition of which has just taken place recently by Decree 10/2003 (July 11, 2003) of MEWM, also see the section on legal factors). This date is indicated to help to put the developments into context.
2. 2008 is an important year as it marks the start of the crediting period.

Table 9 Strategic options for the future of the plant that were considered and chosen from:

	Until 2005	**Between 2005 and 2008**	**From 2008 onwards**	**Probability**
1.	Coal	Full shutdown	Full shutdown	Medium
2.	Coal	Coal	Full shutdown	Low
3.	Coal	Coal	Gas CCP realized around 2008 with larger or equal electricity production than current technology	Medium-High
4.	Coal	Coal	Gas CCP with smaller capacity and production than current technology; shutdown for the rest of the plant	Medium-High
5.	Coal	Coal	Partial coal – partial shut down (two boilers would be shut down. The other three would remain heated by coal, supply and drive the extraction – CHP - turbines)	Low
6.	Coal	Coal	Coal (a full coal baseline)	Low

*”coal” here means either domestic coal, that is a mixture of currently used Ajka coal, and an increasing proportion of coal from the Lencsehegy or Oroszlány mine, or a mixture of domestic coal and Polish low sulphur, high energy content coal.

Strategic Option 1: Full shutdown of the plant from 2005

Such a full shutdown could take place due to:

A/ Electricity production becomes uncompetitive as the market becomes liberalised. The long-term power purchase agreement of the Ajka plant expired on 31 December 2000, and there is no chance for the plant to conclude a new one due to high production costs. Due to policy and regulatory changes, it is likely that Bakony will have to forego the high guaranteed price that regulation provided for a negotiated amount (approx. 128 GWh/a) of condensational electricity ("forced" condensation, see the section on economic factors in section 4). Even for 2003, it was only secured in a second amendment of the feed in tariff decree (56/2002 MET, second amendment). So far Ajka has enjoyed some political support, allowing it to obtain a cost covering price for a limited amount of condensational electricity. In this option, however, we assumed that such support would cease within one or two years in accordance with political declarations and legislation (Electricity Act, 2002) on cost effectiveness and liberalization in the electricity sector.

B/ Tightening environmental standards, especially SO_2 and NOx emission regulations, creating a 75% desulphurisation requirement from 2005 (see section on legal factors in section 4). Although the plant occasionally achieves this higher rate (despite currently being subject to only a 60% prescription), the stabilization of the ratio above 75% would cause difficulties and add costs to production that is already too expensive. The uniquely high limestone content of Ajka coal in combination with the HF technology leads to this high desulphurisation rate. In the future, the share of Ajka coal must be reduced as its heat value has recently been decreasing dramatically. The lower limestone content of substitute coals would, in turn, require adding significant amount of limestone to the combustion process, which adds complexity to logistics and increases costs.

Instead of using some other high sulphur domestic coal, high heat and low sulphur Polish coal could be an alternative. But, excessive transport costs and costs associated with a potentially necessary boiler replacement (due to the higher heat value of Polish coal) make this alternative unlikely.

Heat delivery to the municipality of Ajka is not a limiting factor for a full shutdown in 2005 as a gas engine to service the 0.5PJ heat market can be planned, financed and installed within one year.

We assigned a medium probability to this option (early shut down without any continuation) because even though there are good chances for the complete shut down, Bakony's management seeks possibilities to continue operations in some other ways (see options 3 and 4 below).

Strategic Option 2: Full shutdown of the plant from 2008

Option 2 only differs from option 1 in that it allows coal-based production to continue beyond 2005 until 2008. Year 2008 is somewhat arbitrary; it could be 2007 or – though with a lower probability - 2009. The assumption behind this option is that the environmental difficulties mentioned above can be overcome, and political willingness remains strong enough to support some condensational production in order to delay layoffs. This would also continue to provide safe and cheap municipal heat supply (condensational turbines help to "swallow" fluctuating steam from CHP).

We assigned a low probability to this extended coal operation option due to market liberalization legislation, the declared political tendency to make the electricity system more cost effective, and a general move to stop subsidizing inefficient operations. However, declarations often differ from practice, as the ambiguous results have shown so far in subsidising electricity production and coal mining.

Strategic Option 3: Large Capacity Gas-Fired Combined Cycle Power Plant

In this option an approximately 100 MW gas combined cycle plant (CCP) unit would be built around 2008 in order to maintain large-scale electricity (cc 650 GWh/a) and heat production (cc. 2.2PJ/a) at Ajka. This unit would consist of a cc. 70 MW gas turbine and a connected new 30 MW steam turbine.

The gas CCP unit in this option would generate larger (or at least equal) electricity volume than the current technology can or could ever do.

The preparation for such a large CCP plant started a few years ago. Bakony is in the last phase of obtaining the general license from the Energy Office and is currently completing the public consultation process. Bakony has already received the environmental license for such a gas-fired CCP.

The further development of gas-fired CCP mainly depends on two factors:

1. The future of the alumina factory and the subsequent heat demand from the alumina factory, which in return depends on the regional and global market prices and demand for alumina. Bakony currently has a 10-year heat off-take agreement with the alumina factory, which includes a two-year notice period for the cancellation of the agreement. In order to invest in a large scale CCP, the Alumina factory has to be willing to extend the two-year notice period to give longer-term heat offtake security to Bakony.
2. Electricity prices on the liberalized market are high enough to recuperate the costs of a large-scale CCP investment.

The operation of a gas CCP would commence in 2008, at the earliest. This delay would be mainly caused by difficulties securing acceptable debt financing from banks (who would command higher interest rates in early market liberalization due to distorted electricity prices, or would require two years of historical data and forecasts on the development of electricity prices in the liberalized market in order to secure lower interest rates).

Under this 3rd strategic option, coal-based production would continue until 2008, though capacities would be underutilized similarly to option 2. However, under this option maintaining coal based production and continuing heat supply seems more probable than without the gas CCP intention. It is likely that the plant would bear some operational losses between 2005-2008 in order to keep the heat market for the gas CCP period. Also, the risks of an on-site solution for the alumina plant outweigh the use of efficient gas CCP from the Ajka Plant.

With the start of the gas CCP, boilers would be shut down or converted to gas and oil to serve as reserves. Although the licensing process has begun, there are still numerous time consuming preparatory measures to finalize, including permitting procedures, securing project financing, and construction work.

This option 3 is assigned a medium–high probability. Electricity prices on the competitive market should rise above the current low prices (which only reflects short run marginal cost) for the gas CCP to be realised. A price increase is inevitable as the annually 2 % increase in demand and the shut down of several plants will necessitate an additional 400 MW capacity towards the end of the decade. The resulting scarcity will drive up the price to long run marginal costs making investments possible, but building new cross border capacities to supply cheap imports will compete with new domestic plants. Price of foreign electricity, however, is also expected to rise as European excess capacities diminish. This process is partly affected by the gradual phase out of German nuclear plants as well as the prevention of vertically integrated German utilities from cross subsidizing electricity production[12]. On the other hand the local heat market - of which the plant enjoys a quasi-monopoly[13] – poses significant demand for the heat segment of the plant output. A related question is the stability of this heat demand, which we will discuss at option 4.

[12] These utilities keep electricity prices under long run marghinal costs and subsidize this from monopoly pricing of electricity distribution. They do so to raise the barrier to entry for new entrants in electricity production.

[13] For the households, it seems easy to detach from and substitute for district heating. However, for the alumina plant it would be costly and risky (no expertise, higher transaction costs than for Bakony etc) to switch to another solution such as self supply or third party investment. There is a threshold or tolerance heat price though, above which the alumina plant may opt for self heat supply and sell the jointly generated electricity on the competitive market.

Strategic Option 4: Small Capacity Gas-Fired Combined Cycle Power Plant

Under this option a 30-40 MW combined cycle gas plant unit would be built around 2008 in order to maintain some electricity and heat production at Ajka after shutting down the coal boilers. In this option the gas CCP would produce 1 PJ/year of heat instead of the 2.2 PJ/year of option 3. This option also assumes that oversupply on the alumina market will continue, putting downward pressure on prices. The alumina plant, therefore, would have to cut its production. Until 2008 coal based CHP and limited condensational production would continue, though capacities would be underutilized similar to options 2 and 3.

From 2008, this option can be characterized as gas CCP with smaller capacity and production than current technology (and consequently shutdown for the rest of the plant in terms of capacities).

This option is assigned a medium-high probability. Due to economies of scale, unit costs (re MW) of smaller gas CCP investments are expected to be higher than those of a 100 MW plant. This would necessitate an even more favorable electricity price development than option 3 assumes. Also there is a risk to build a low capacity gas CCP; if the alumina plant later still demands more heat, the capacity can only be augmented at higher than optimal unit cost. In this case a/ profit is not maximized compared with a one-off large-scale investment[14]; b/ it might be worthwhile for the alumina plant to switch to self-supply by building its own gas CCP of sufficient and efficient size.

On the other hand, there is a risk of idle and hence wasted capacities if the alumina plant builds the 100 MW plant. In this case, the alumina plant still will have to cut its production due to unfavorable developments on its market.

In order to compare the probability of option 3 and option 4, a more detailed analysis of the future developments of the alumina market (and more specifically, the market of the Ajka alumina plant) needs to be performed. Such an analysis is beyond the scope of this study and the strategic options 3 and 4 are considered to have similar probabilities.

Strategic Option 5: Partial Coal Firing with Partial Shut Down

Two boilers, one using pulverized coal and the other a HF bed boiler, would be shut down. The other boilers remain fired by coal, and drive the extraction – CHP – turbines so as to maintain some of the heat supply. The condensation turbines would be largely shut down. Thus the net cost of heat would be reduced somewhat by revenues from electricity sales (or the other way round; heat, however, has a special role as in sales of heat Bakony has bigger market and consequently bargaining power than in the case of electricity). Also, the plant can conclude long-term contracts both with the municipality and the alumina plant, while such contracts seem impossible for Bakony on the electricity market. Such heat supply contracts can be advantageous but can also lock the plant in a rut that may become undesirable should other circumstances change (for example an obligation to supply heat despite unfavorable price development of inputs or of the jointly produced electricity). With carefully prepared contracts, however, such risks can be mitigated.

This option was assigned a low probability. To be locked in a heat supply obligation despite loss-making is avoidable for the plant. Thus, if the economic and political environment takes shape as was discussed in previous options for coal based electricity, the plant would proceed with even a partial continuation of coal based CHP production.

Strategic Option 6: Continued Coal Based Production until 2012

This option has a relatively low probability due to expensive production costs; low and decreasing heat content and high sulphur value of the local coal; and obsolete, low efficiency generation

[14] However, time also has a role here. The later the increment needs to be installed, the more the higher unit cost of the increment is likely to be offset with the value of not building until there is an idle capacity surplus.

equipment. Also the regulatory, economic and political environment considerations of previous options apply.

Summary of the Strategic Options Assessment

Strategic options 3 and 4, namely the installation of a small or large scale gas-fired CCP in the second half of the decade for both heat and efficient electricity production, can be considered as the most likely medium- to long-term strategic directions of the Ajka plant. The biomass project does not influence the realization of the gas-fired CCP. Green electricity production at Ajka might be able to make the transition easier from coal based CHP to gas-fired CCP based CHP by keeping the plant in operation, keeping the work culture, and keeping the workforce. Nonetheless this is not a determining factor for realizing the gas-fired CCP. The only determining factors for the CCP are the positive development of the electricity prices in a liberalized market and the heat demand from the alumina factory. The plans to build a gas-fired CCP way before Bakony began to consider developing the biomass project (second half of the nineties for gas fired CCP versus fall 2002 for biomass). The gas-fired CCP is possible future option for the heat and related electricity production at Ajka with or without the biomass project.

Owners of Bakony Power may also choose a complete shut down of the coal plant. This option has a lower probability than options 3 and 4, but is overall quite a realistic option. Continuation with coal on any scale beyond 2008 will be difficult to justify in a verifiable manner and was therefore attributed a low probability.

The discussion above illustrates that the biomass plant and the heat production are independent from each other, which enables us to clearly set the boundaries of the biomass project. This insight into the future strategic options helps us to identify the baseline scenarios in the next section. The project boundaries of the biomass project are limited to the production of green electricity and include turbine V and the boilers XI and XII at the Ajka site. Separation of the biomass project from the heat production at Ajka is important when discussing the baseline scenarios in the following section. The potential future heat production at Ajka through a smaller or large gas-fired CCP based CHP (or even a small gas engine) can be seen as independent from the biomass project and therefore does not need to be discussed in the following section. Whatever the future holds for the heat and related electricity production (as most likely a future heat production solution will be CHP based) at Ajka, this electricity production will be fed independently into the grid, constituting part of the future electricity grid mix, and will not be affected by the independent of the proposed biomass project (and vice versa).

The arguments discussed above are summarized in an evaluation matrix below. The matrix lists the options and the key factors affecting these options. Cells show the significance of the given factor for the option considered. Blank cells indicate that the particular factor is neutral to the corresponding option. For comparison, we also included the proposed biomass project to see how the key factors of strategic options affect it. For the factors indicated for the biomass project, see section 4 and the section on additionality below in this chapter.

Table 10 Evaluation matrix of strategic options for the plant (• : low limiting factor, ••: medium limiting factor •••: strong limiting factor)

	Till 2005	2005-2008	2008-2012	Stricter environ-mental (i.e. SO2, NOx) standards	Energy market liberalization, competitive electricity production	Unstable electricity prices in liberalizing market	Heat demand from alumina factory	Heat demand from municipality	Availability and costs of low sulphur, higher energy content coal	Availability of biomass and biomass price uncertainty	Regulatory uncertainty for the continued support for RES-E feed in tariffs
1	Coal	Full shut down	Full shut down	•	•••		•	•	••		
2	Coal	Coal	Full shut down	•	•••		••	•	••		
3	Coal	Coal	Gas CCP, large capacity			•••	•••	•			
4	Coal	Coal	Gas CCP, smaller capacity			•••	••	•			
5	Coal	Coal	Shut down condens ation turbine		•••		••		••		
6	Coal	Coal	Coal	•	•••		••		•••		
	Biomass	Biomass	Biomass	•						•••	•••

5.2 Identification of possible baseline scenarios

In choosing a baseline scenario one should ask what would happen in the absence of the proposed project that the implementation of the project will prevent from happening. In other words, what state or direction of the world the project prevents by taking developments in another direction.

While discussing the baseline scenarios one has to consider service equivalence. Which means, describing scenarios, which in the absence of the proposed JI project, would have produced the same output as in the proposed JI project, namely annual 190.4 GWh of grid connected electricity production.

Different baseline scenarios that would describe what would have happened in the absence of the proposed biomass project are the following:

1. Continuation of the status quo:

The continuation of the status quo means that the 190.4 GWh condensational electricity production based on coal would continue for the coming 10 years.

2. Fuel switch from coal to gas:

The fuel switch from coal to gas fired condensational electricity production to produce 190.4 GWh/year.

3. Shutdown of the condensational electricity production:

The condensational electricity production using turbine V and HFB boilers XI and XII would be shutdown in the near future. The annual 190.4 GWh would be produced by other power plants that feed electricity into the grid.

5.3 Selection of the baseline scenario

The three possible baseline scenarios identified in the previous section will be discussed in this section based on the findings in the previous sub-chapter and the key factors identified in section 4.

1. **Continuation of the status quo**:

The continuation of the coal fired condensational electricity production is very unlikely due to economic factors, especially the competitive electricity pricing as Hungary moves towards a liberalized electricity market. This influence has been discussed in detail in previous sections 4.2.1 (point 1) and 5.1. strategic option 1.

2. Fuel switch from coal to gas:

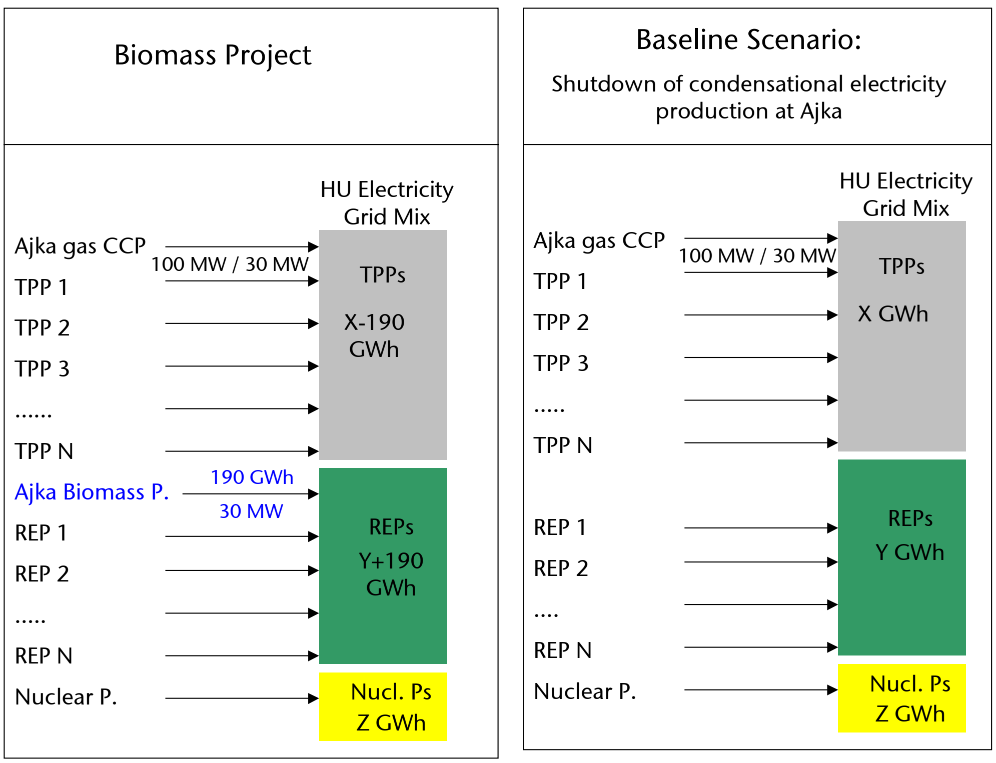
A fuel switch from coal to gas in the current HFB boilers and condensational turbine is technically not feasible at reasonable cost. In order to produce 190.4 GWh based on gas, an new system with a capacity of some 30 MW would have to be installed. Recent installations of such small to medium electrical capacities around Hungary are all CHP based in order to take advantage of the higher CHP feed in tariffs and efficiency gains of joint production. As the heat market in and around Ajka is expected to be covered by the gas CCP that might be installed in Ajka, an additional 30 MW gas fired plant would have no heat offtakers and the investment would be difficult to justify economically. On the other hand, should the realization of the gas CCP not take place, the conversion of the HF boilers to gas and conversion of the condensational turbine to an extraction turbine is not an efficient way to produce both heat and electricity. At foreseeable gas and electricity prices, an electricity only production would not be efficient and sustainable. Therefore, this scenario can be ruled out.

3. **Shutdown of the condensational electricity production**:

As discussed above, the continuation of the 190.4 GWh condensational electricity production based on coal or gas is not an economically viable scenario for Bakony. Therefore, the shutdown of the boilers XI, XII and turbine V and cessation of condensational electricity production is the most likely scenario in the absence of the biomass project[15].

In the event of a shut down of the condensational electricity production at Ajka, the 190.4 GWh/year that will be produced in the biomass project, would have to be generated by the other power plants that feed electricity into the grid over the coming 10 years. Due to the takeoff obligation, the renewable energy produced in the biomass project will be dispatched right after the nuclear electricity and therefore very likely would very likely displace fossil fuel based electricity generation[16].

The scenario with the biomass project and the scenario in the absence of the biomass project (shutdown of current condensational electricity capacity) can be illustrated as follows:



Result of the baseline selection:

On the basis of the above three scenarios, the baseline scenario number 3 is selected as the baseline. This entails the calculation of emissions from those plants whose electricity generation will be displaced. The method that is going to be applied is based on the grid emission factors for Hungary as stated in the ERUPT guidelines.

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[15] Especially because the condensation electricity production at Ajka does not at all influence the realization of the longer term strategic options for the heat production at Ajka.
[16] According to information received in an interview with the Hungarian Energy Office

The selection of scenario 3 is robust, as it is far more likely than any of the other two baseline scenarios. It is also conservative, as it yields lower baseline emissions than the continuation with coal scenario, which comes second in probability. The conversion of the HF boilers to gas has a close to zero probability due to its inefficient operation.

5.4 How Joint Implementation can overcome Biomass Project Risks (Additionality Considerations)

The environmental additionality of this project in relation to what would have otherwise occurred in the absence of the project, has been discussed in length in the previous sections. This section will briefly describe how the proceeds from the sale of the emission reductions can help to overcome some of the main risks of the biomass project, like the biomass fuel supply risk, regulatory risk and aging equipment, which can lead to higher costs (especially higher financing costs of the biomass project). The revenues from Joint Implementation can help overcome some of these project implementation barriers and contribute to the long-term success and reinforcement of the additionality of this project.

5.4.1 Biomass Fuel Supply Risks

Uncertainty of the long-term availability of biomass supply

One of the main reasons for the higher financial costs of biomass based electricity production is the actual and perceived risk of unproven fuel supply[17].

The availability of sufficient amounts of biomass at attractive prices is a main factor in the uncertainty of biomass based electricity production. Long-term agreements for the supply of predefined quantities of biomass at predefined prices are rare. Furthermore, as significant amounts of biomass are needed for electricity production, increased competition with other existing markets for biomass, like the firewood market or plywood manufacturing, could result in biomass fuel price increases, which are often difficult to predict.

Long-term certainty of biomass fuel prices, as well as sufficient amounts of biomass quantities for electricity production, are therefore main prerequisites to attract equity investors and debt providers.

How Bakony intends to mitigate the fuel supply risk:

- Biomass fuel risk diversification. Bakony intends to sign biomass supply agreements with numerous biomass suppliers.

- Development of new markets for energy plantations. A biomass offtake agreement is a condition to get subsidies from the Ministry of Agriculture to sponsor initial investments in energy plantation demonstration project. The new biomass company will be the purchaser of the biomass from the first energy plantation demonstration project and thus paves the way for the introduction of energy crops and forests in Northwestern Hungary. More details on energy plantations are provided on the section on biomass market in section 4.

How revenues from sale of emission reductions can help to overcome the fuel supply risk:

- Securing revenues from emission reductions, the plant can better compete for wood, whose price is expected to rise due to a large client (the biomass plant) entering the market.

[17] (http://europa.eu.int/comm/energy_transport/atlas/html/bioerisk.html).

- Cash from the forward sale of emission reductions can be used to invest in energy plantations in order to kick-start and foster the development of an energy crop market. As mentioned in previous sections, the Ministry of Energy has supports the first demonstration project for energy plantations with grants. The farmers are, however, reluctant to set aside land for these plantations as they fear that the one-time investment from the Ministry is not enough to make the energy plantation a profitable business. Farmers prefer to see longer term investors and a clear demand for the produced energy crops.

  Both conditions can be achieved in this project using the environmental benefits that will result from the biomass-based electricity. Use of biomass by the Ajka biomass electricity plant will create long term demand while forward sale of emission reduction units will raise funds to finance longer-term investments in energy crops in the region.

  In order to realise a long-term investment in energy crops and to boost the biomass market, a significant portion of the revenues from the sale of emission reductions needs to be available upfront and the project might need to monetize early emission reductions generated before 2008. These early emission reductions can be monetized through the allocation of Assigned Amount Units (AAUs) by the government to this project. AAUs will be able to further attract early investments into biomass plantations and thus ensure the availability of fuel supply and the success of the biomass project during 2008-2012.

5.4.2 Regulatory Risks

Long term Availability of Subsidized Feed-in Tariffs

Most decision makers consider that the greatest risk lies is the uncertainty of future energy politics. The risk that taxes and fees will change before the investment has been paid off keeps them from investing. (http://europa.eu.int/comm/energy_transport/atlas/html/bioerisk.html).

According to Hungarian law, the renewable energy feed-in tariff will expire in December 2010. This represents an uncertain long-term revenue stream from the sale of green electricity for renewable energy project developers. Especially for the years 2011 and 2012, which are Kyoto compliance years, it is important that renewable energy projects are working at maximum capacity in order to help the Hungarian government meet its emission reduction targets as well as fulfill its obligation of reaching a certain percentage of renewable energy production by 2010. The Electricity Act of 2001 also allows for earlier introduction of the tradable green certificates (TGC) system if international experience is positive. Should it take place, the uncertain level and volatility of TGC prices create additional risk.

How revenues from sale of emission reductions can help to overcome this risk:

- The allocation of AAUs and ERUs can be considered as a form of additional government support to ensure the long-term success of renewable energy projects. By using international environmental markets, the government can extend its support for renewable energy projects without having to use direct public funds, which can be freed up for other government investment priorities.
- AAUs or advanced payment for ERUs could further help to develop the biomass markets in early years to ensure a greater availability of biomass in the Kyoto compliance years and thus greater reduction of greenhouse gas emissions during these years.

5.4.3 Aging equipment and related risks of higher maintenance costs

Bakony intends to use the existing equipment because the fluidized bed boilers still have a remaining life of 15 years and the condensation turbine is well maintained and can operate for another 15 years. However, as the equipment is aging, sufficient cash needs to be available for regular maintenance works, repairs as well as unforeseeable technological upgrades.

Banks normally require lenders to set aside cash in a maintenance account to ensure that sufficient funds are readily available for such works. Generally, these maintenance accounts are initially created through stand-by equity made available by the equity investors. This stand-by equity has an opportunity costs for the equity investors.

How revenues from sale of emission reductions can help to overcome this risk:

The proceeds from the sale of emission reductions can be used to fill the maintenance account. Reduced need for stand-by equity will increase the overall internal rate of return of the project and thus make the project more financially attractive.

5.5 Variation of key factors to demonstrate robustness and likeliness of the selected baseline

Since the selected baseline emission *calculation method* is robust (and has by far the highest probability of the three baseline scenarios) and is not affected by the most likely 4 strategic options and the key factors that affect these options, the baseline emissions are only affected by the variables of the algorithm. Since the ERUPT grid emission factors are taken fixed, the only variable is the electricity output that the project generates between 2008 and 2012. This output is mainly affected by renewable support policies, which basically translates to actual and expected renewable electricity prices, availability of biomass, and not independently of this - cost of production. The remaining factor for biomass, the NO_x problem, can be overcome. The rest of the examined factors only affect the choice of the strategic options, but not the biomass project.

In the long run, the output depends on the boiler input and turbine output capacity, the net energy conversion efficiency, the utilisation level of the capacities, and the amount of biomass input and its specific heat value. Of these the capacities, the conversion efficiency and to a lesser extent the heat value of biomass can be taken as fixed[18]. The output mainly depends on the amount of input.

The expected reasonable RES-E prices do not affect the capacity size of this biomass project; they only provide yes or no type signals (go ahead or not go ahead with the investment with the planned capacity). Once the project is implemented, investment cost becomes a fixed cost, and cost of production will only depend on short run variable costs. This is almost 100% determined by the price of biomass, therefore when the owner is deciding on the output level, and is comparing short run marginal cost with the output price, he can do so by comparing biomass prices with the feed in tariff or other actual RES-E prices[19] in place. This means a higher output price (i.e. stronger renewable support) makes it possible to involve larger amount (and more expensive types) of biomass and increase output. Thus, the key factor for output, and therefore for baseline emissions, was shown to be the amount of biomass input. Therefore, when determining the baseline emissions, the starting point was the selection of feasible biomass input scenarios.

5.6 Sensitivity Analysis and effect on GHG emissions

5.6.1 Sensitivity of baseline emissions

Baseline emissions depend on the amount of electricity sold and the average grid emission factors during the crediting lifetime of the project.

The grid emission factors are supplied by the Operational Guidelines for Project Design Documents of Joint Implementation Projects, published by the Ministry of Economic Affairs of the Netherlands, and

[18] But see the sensitivity analysis in next section.
[19] For example, the sum of the TGC price and the competitive price, if there is a tradable green certificate system in place.

as such, they are exogenous from the perspective of the project. The next table shows the emission factors for electricity generating projects.

Table 11 Hungarian grid CO_2 emission factors of ERUPT

Year	Baseline electricity grid CO_2 emission factors (tCO_2/GWh)
2004	658
2005	648
2006	637
2006	626
2008 crediting year	616
2009 crediting year	605
2010 crediting year	594
2011 crediting year	584
2012 crediting year	573

The amount of electricity that is sold depends on the following factors:

- Quantity of combusted biomass,
- Quantity of combusted natural gas,
- Energy content of the biomass, and
- Efficiency factor of electricity production (a concise measure which transforms energy input into electricity that is sold, taking into account self-consumption as well).

Production figures for baseline calculation are 240 kt/year of biomass, an efficiency factor of 25.7%, and energy content of 10 MJ/kg of biomass, resulting in 190.4 GWh/year of electricity output. The heating value of the biomass is taken on a lower heating value basis.

Sensitivity analysis:

- The quantity of biomass is proportional to electricity production, a one percent increase in the quantity of biomass will, *ceteris paribus*, results in a one percent increase in electricity production.
- The maximum natural gas input is proportional to biomass input, since Hungarian regulations allow that up to 10% of the electricity purchased at RES-E feed-in tariff is produced from fossil sources. If the biomass input changes, the natural gas input might also change, likely contributing to the same percentage change of electricity production.
- A one percent improvement/deterioration in the efficiency of electricity production will result in one percent change in the quantity of sold electricity[20], showing a linear proportionality between the efficiency factor and the quantity of sold electricity.
- An increase in the energy content of biomass will result in more electricity sold. However, there is not an exact linear proportionality between the energy content of biomass and the electricity sold. This is due to the fact that the quantity of generated electricity will change proportionately with the energy content of biomass, while self-consumption will not change (or only very moderately), implicitly modifying the net efficiency value.

Of the above factors, the efficiency of electricity production is not likely to be significantly altered. The energy content of the biomass is expected to be higher than the conservatively estimated 10 MJ/kg used in the present calculations. The quantity of combusted biomass, however, can vary, and it is expected to fall between 240 and 360 kt/year. A conservative figure of 240 kt/year will be used as the basis of emission reduction calculations. The following table reviews the amount of electricity generated under different combinations of biomass heat content and biomass input. In each case it is assumed that exactly 90% of the energy input is derived from biomass, and 10% from natural gas.

[20] Please note that a one percent improvement in the efficiency factor (e.g. from 25.7% to 25.957%) is not equivalent to a one percentage point change of efficiency (e.g. from 25.7% to 26.7%)

Table 12 Amount of electricity generated with different biomass heat content and inputs

	Biomass input (kton/year)		
Heat content of biomass (MJ/kg)	**240***	300	360
	Electricity output (GWh/year)		
8	152.3	190.4	228.4
9	171.3	214.2	257.0
10*	**190.4***	238.0	285.6
11	209.4	261.8	314.1
12	228.4	285.6	342.7

*The reference values.

5.6.2 Sensitivity of Project Emissions

The following changes in project emissions take place as the quantity of combusted biomass (and along with it quantity of natural gas) increases:

On-site emissions:

- Emissions from combustion increases proportionally (from a low value).
- Emissions from ignition fuel will not change, unless extremely low or extremely high quantities of biomass are combusted, which can influence the operating pattern of the boilers, resulting in lower or higher number of ignitions than presently used 10 ignitions/year. However, such extreme situations are unlikely and associated changes in emissions are minor.
- Emissions from equipment for on-site transport of biomass are proportional to the quantity of biomass that is combusted.
- Emissions from preparation of fuel are already included in combustion related emissions as it is related to self-consumption (or internal consumption) of electricity generated in the biomass project.

Off-site emissions:

- Emissions from logging, chopping and dragging are proportional to combusted wood, which arrives directly from the forests and makes up about 50-60% of all combusted biomass. Emissions from cultivation of energy plantations are expected to be somewhat higher than emissions related to logging.
- Emissions from transport of biomass will increase with growing quantities of combusted biomass. There is uncertainty as to whether marginal emissions will grow or not, but there is some probability that supplementary biomass is transported from locations further away, as nearby sources are exhausted.
- Methane emissions from decomposition of wood waste will fall back as the quantity of combusted biomass increases.
- Emissions due to variations in the local fuel pattern are not likely to change very much.

A change in unit heat content of biomass (if mass of biomass adjusts to offset this) will not alter the response characteristics of any of the above emissions.

5.7 *Baseline GHG Emissions*

5.7.1 On-site emissions

None (due to the grid emissions baseline scenario).

5.7.2 Off-site emissions

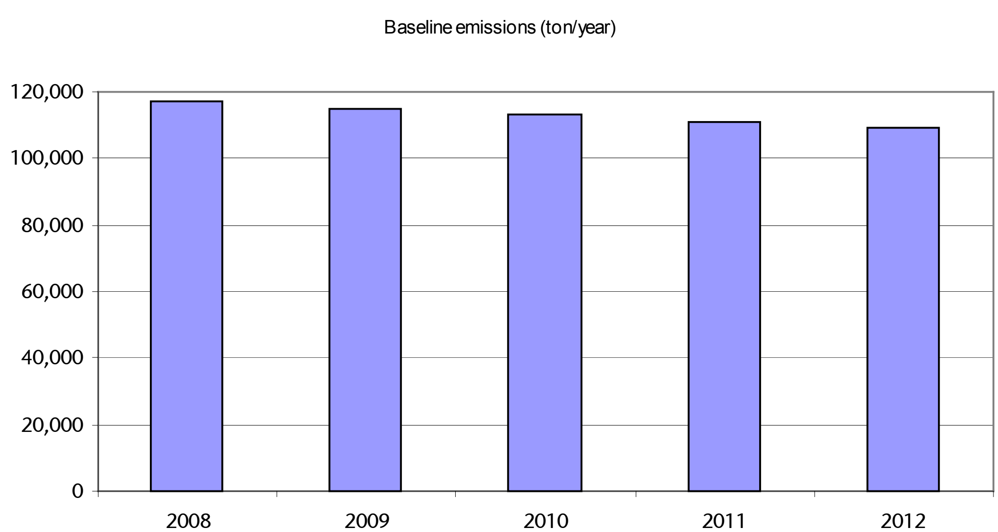
Only off-site emissions will take place, in accordance with the grid emissions factors. The baseline electricity grid CO_2 emission factors for JI projects generating electricity, as listed in table B1 of the Senter Guidelines for JI Projects – Vol. 2A: Baseline Studies, Monitoring, Reporting, have been used for the calculation of the off-site GHG emissions. These emission factors only include CO_2 emissions from the power plants that feed electricity in to the grid. According to Senter, N_2O and CH_4 emissions of the future grid based electricity production has not been calculated due to the difficulty to gather relevant and accurate information on CH_4 and N_2O emissions form the different fossil fuel based grid electricity production.

Baseline electricity generation, based on fuel input of 2.4 PJ/year (240 kt/year) of biomass and 0.267 PJ/year of natural gas, is 190.4 GWh/year. The corresponding baseline emissions depend on the annual grid CO_2 emission factors and are depicted in the next table. Total baseline emissions for the five-year crediting period are 565,800 tons of CO_2.

Table 13 Baseline CO_2 emissions of the project

Year	Baseline CO_2 emissions (tCO_2/year)
2004	125,264
2005	123,360
2006	121,266
2007	119,172
2008 (crediting year)	117,268
2009 (crediting year)	115,174
2010 (crediting year)	113,080
2011 (crediting year)	111,176
2012 (crediting year)	109,082
2008-2012 (total crediting period)	565,780

Figure 4 Baseline emissions during the crediting lifetime of the project (t/year)



The total baseline CO_2 emission for 300 kt/year of biomass combustion for a period of the five crediting years would be 707.2 kt/year, while the respective value for 360 kt/year of biomass is 848.7 kt of CO_2.

The baseline scenario will very likely generate CH_4 emissions from the storage of 200,000 tons of biomass. The biomass from the forestry management companies will either be left rotting in the forest or if it is sold as firewood, it will very likely be stored for a while by the purchasers of firewood before it will be burnt. The wood from forestry management companies consists – according to the state of the biomass offers at the beginning of July 2003- of turkey oak (44%), beech (30%), oak (25%), trees with soft foliage (1% mainly aspen). The old wood, which is mainly waste and from wood processing and packaging (especially pallets made out of pine wood) would very likely be put into landfills (many of them illegal) or burnt after some storage time, while it would also generate CH_4 emissions. How long the old and waste wood would remain in the landfills is unclear. Often poor people collect wood from such illegal landfills and use it as firewood. The CH_4 emissions from the storage of the biomass in the absence of the biomass project are difficult to quantify due to uncertain storage times and storage conditions. It can however be assumed that the 200,000 tons of biomass will be stored at least as long and probably under worse conditions than in the biomass project and would therefore result in higher CH_4 emissions than the biomass project. Due to the uncertainty surrounding the storage of the biomass in the baseline and the missing data, these emissions have not been included in the baseline emission calculation.

5.7.3 Total baseline emissions (sum of on-site and off-site emissions)

Total baseline emissions are 565,780 tons of CO_2.

6 ESTIMATION OF PROJECT EMISSIONS

6.1 Description of the factors used for estimation of project emissions

This section describes the factors that are used for the estimation of project emissions. It includes information on the output of the project and specifies activity levels for all years from the start of the project until the end of the crediting time.

The project will generate electricity primarily from biomass and to a small extent from natural gas. The net generated electricity will be sold to the grid. Based on formerly received[21] and continuing supply offers, the management is confident in securing at least 2.4 PJ/year biomass input, which requires 240 kt/year of biomass. This amount is derived from the 10 MJ/kg heating value of biomass with 40% moisture content. The actual moisture content is expected to be lower as fresh cut mixred types of drier wood waste will be used in addition to logs. According to the Forest Utilisation Department of Western Hungarian University (formerly called Forestry and Wood Processing University) at Sopron, freshly cut oak and beech has a moisture content of cc. 44%. Those supply offers received so far which gave moisture content has a wide scatter from 25% to 50%, mostly between 30-40%. The management will conclude contracts that is based on prices and quantities converted to 30% moisture content, and which – apart from emergency - preclude delivery of fresh cut without a drying time straight to the plant. The referred 44% moisture content will decrease by the time of delivery and if the lower moisture content of supply offers are considered, one can be confident that 40% is a conservative estimation of the weighted average. Moreover standardised measurements at Ajka of heat values from 32 samples of varying moisture content (9-59%) and wood waste type always yielded heat values higher than the formula provided by an independent consultant (around 10% higher on average). It means that if instead of 10 MJ/kg the wood with 40% moisture content actually has 11 MJ/kg heat value on average, then instead of 240 kt annually 218 kt is sufficient to provide 2.4 PJ biomass.

As described in detail in Section 5 on baseline emissions, combustion of 240 kt/year of biomass and 0.267 PJ/year of natural gas will produce 190.4 GWh/year of net electricity. The corresponding net electricity generation from the combustion of 300 kt/year and 360 kt/year of biomass (and the allowed supplementary natural gas) are 238.0 GWh/year and 285.6 GWh/year, respectively.

Bakony Power intends to dedicate two blocks for 90% biomass and 10% natural gas combustion, each block comprising a fluidized bed boiler with a capacity of 88 MWth. If the supply of biomass at any of the boilers is not adequate for operation at full capacity, the power plant will, subject to technical limitations, schedule electricity generation for output during peak hours. At this time, there is a higher premium in the feed-in tariff. However, the general intention is to run the electricity production at 123 hours of off-peak and 45 hours of peak time per week.

The most important factor determining the electricity output is the availability of biomass at attractive prices. A recent survey of the biomass market indicated that there is adequate supply of 240 kt/year of biomass within a suitable distance. About 50-60% of this quantity consists of wood logs from forestry management, while the rest is wood waste from the wood processing industry. The average supplier intends to deliver about 15 kt/year of biomass, thus there is a diversified supply of biomass and Bakony Power is not dependent on any particular supplier.

In addition to the 240 kt/year of biomass whose supply is considered to be certain, there is approximately 60% probability for securing another 60 kt/year of biomass from regional suppliers within an 80-100 km radius of the plant. Furthermore, Bakony Power intends to contract nearby farmers to grow energy crops and energy forests on at least 3,000 hectares of land, supplying at the minimum another 60 kt/year of biomass for the power plant. Initial negotiations with farmers and

[21] 297 kt until the end of June, 2003. Actually it is at least 50 kt more, since less preferred, but usable sunflower and corn stems were not included.

landowners are promising, and again, there is a 60% probability there will be a realization of 60 kt/year of biomass from this source.

Based on the above discussion, the expected value of annually combusted biomass is 312 kt[22], with a minimum value of 240 kt/year and a maximum value of 360 kt/year. Computations of project emissions and credits for each of the crediting years within the present proposal will, nonetheless, be based on a lower value of 240 kt/y – as Bakony Power wants to minimize the chance of non-delivery of credits. In case biomass combustion should increase above 240 kt/year, Senter will have the option of purchasing additionally generated credits.

The entire steam generation, steam transportation and turbine operation are constantly monitored electronically and supervised so that even the smallest abnormalities (increased vibration, steam loss) can be quickly detected and solved during operation.

It is not feasible to provide an actual 95% confidence interval for the activity level, but probabilities for milestone activity levels are supplied in the previous section.

6.2 Calculation of the direct project emissions

6.2.1 Direct on-site emissions

Direct on-site emissions result from the following activities:

- Combustion of biomass.
- Combustion of natural gas including its use as ignition fuel[23].
- Methane emissions from the on-site storage of biomass.
- On-site transportation of biomass.

Emissions of CO_2 from combustion of biomass do not need to be considered since the released carbon has previously been captured by the combusted biomass. In fact, additional carbon is sequestered in the soil. Therefore there is a negative overall carbon balance in the atmosphere due to the implementation of the project. Emissions of CO_2 from combustion of natural gas amount to 15,055 tons annually, of which 95 tons are attributed to the ignition fuel.

Methane (CH_4) and nitrous oxide (N_2O) emissions from combustion of both fuel types have been calculated. Using the CH_4 and N_2O emission factors recommended by the IPCC and listed below, these emissions result in 4,488 tones CO_2e/year for biomass and 259 tons/year for natural gas, of which 2 tons CO_2e/year are associated with the use of natural gas for ignition purposes.

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[22] There is 0.6*0.6=0.36 probability that both sources of 60 kt/year biomass will be realized. The probability for realizing only one of the two sources of 60 kt/year is 2*0.6*(1-0.6)=0.48. And lastly, the probability that neither source will be available is (1-0.6)*(1-0.6)=0.16. The expected value of additional biomass availability is therefore 0.36*120kt/y+0.48*56kt/y+0.16*0kt/y=72 kt/y. This amount needs to be added to the 240 kt/y quantity of certainly available biomass, and the resulting sum is 312 kt/y as the expected amount of biomass.

[23] For purposes of GHG emission calculations ten ignitions per year have been assumed, which is probably an overestimation of the ignition needs, as the technical staff of Bakony expects 3 ignitions per year. Ten ignitions annually would result in a consumption of 50,000 m3 of natural gas with an energy content of 1.7 TJ.

Table 14 CH_4 and N_2O emission factors of different fuels

Pollutant	Unit of emission	Emission		
		Biomass	Coal	Natural gas
CH_4	T/PJ	30	3.5	1. 715
N_2O	T/PJ	4	14*	3
Total GWP	T/PJ	1 870	4414	966

Source of information: IPCC reports, CORINAIR database, Hungarian national communications to the UNFCCC
** Factor of 1.4 according to IPCC, but Hungary uses a factor of 14 in its UNFCCC national communications due to local technical conditions.*

The methane emissions from the storage of biomass on site results in 2,536 tones CO_2e emissions, assuming the total handling of 240,000 t of biomass per year and assuming a biomass moisture content of 40%. Less than 20% of the biomass fuel delivered to the plant is expected to be already chopped. The chopped material goes straight to the feeding containers from where it is almost immediately fed into the boilers. The rest of the biomass will be chopped at the plant as needed. The capacity of the biomass chips container is four days during normal business mode. Conservatively, and to consider the need for safe supply of biomass, it was assumed that *all* of the biomass material goes through one *week* of storage before being fed into the boilers.

The reserve stock will be stored for most of the time in barns, which are currently used to store the coal, to protect the biomass from getting wet. Bakony expects the summer stock to be around two weeks and the winter stock to be around one month. Conservatively, it is assumed that the barns will store almost one month of stock all year round, i.e. one-twelfth of the annual biomass supply will be stored for one year. It is also assumed that the reserve stock turns over once a year.

Little specific information is available on CH_4 emission factors from the short time storage of biomass. Yearly methane emission factors for the newly dumped biomass of 0.0125 [m3 CH_4/kg dry biomass][24] have been used to calculate the CH_4 emissions. As no weekly emission factors are available and despite knowing that the decomposition of biomass is not linear, it has been assumed that 0.00024 m3 CH_4/kg dry biomass are emitted per week for newly stored biomass. Based on the above assumptions and average moisture contents of 40% for the delivered biomass, this results in 184,600 m3 CH_4/year[25] and 2,536 tones CO_2e/year. It should be stressed that these emissions figures are probably over-estimated of actual emissions from storage[26], and during the crediting period they will be adjusted after monitoring.

[24] WorldBank PCF Plus Research, Methane and Nitrous Oxide Emissions from Biomass Waste Stockpiles –Final Report, P.49, prepared by BTG Biomass Technology Group
[25] Methane specific weight default factor: 0.654 kg/m3
[26] Another factor supporting the notion of overestimated emissions is that part of the biomass input will be of wood logs, the CH4 emissions of which are lower than the factors used in our calculations.

The chopping installations for biomass and transportation of the ash slurry via pipes to the deposit site are powered by electricity generated by the biomass electricity plant itself. It is worth noticing that this electricity is included in the self-consumption. The amount of self consumed electricity is expected to be slightly less than 10% of the gross produced electricity, which is comparable to the domestic average of fossil fuel based plants. Related emissions of CO_2, CH_4 and N_2O are already included in the combustion related emissions above.

On-site transportation of biomass is presumed to take place with two types of vehicles. The first one consumes about 20 liters of gasoline per hour and operates for 3,180 hours per year. The annual consumption of the second one (trucks between the reserve site and the feeding site) has been calculated as 964 liters of gasoline. The total fuel used is 64,564 53,000 liter/year, resulting in GHG emissions of 180 tons of CO_2equivalent/year.

6.2.2 Direct off-site emissions

Direct off-site emissions consist of two components:

- Emissions related to logging, dragging and chopping of the biomass.
- Transport emissions of the biomass.

According to interviews conducted with forest managers, approximately four liters of gasoline per ton of wood is used for logging, dragging, chopping and uploading of wood at the site of logging, before the wood is transported. As 75% of the biomass comes directly from the forests, emissions from the use of the logging equipment apply to this amount of biomass input, while the rest of the input, mainly wood waste, is considered to be emission free. Total emissions for logging of 180 kt/year of biomass are 2,009 tons of CO_2equivalent.

Biomass from energy plantations and energy forests is not part of the first 240 kt/year of biomass combustion. If, however, additional biomass from plantations is purchased and fired, then GHG emissions related to the cultivation of biomass plantations will need to be considered. These unit emissions are different from the above emissions of logging, dragging and chopping. The literature references and experience with the energy use and related emissions of energy plantations is much more limited than that of forests. Preliminary calculations show, however, that between 7 and 14 liters of gasoline are needed to harvest one ton of biomass from plantations, making this source of biomass more GHG intensive than wood from the forest.

It is conservatively assumed that biomass will be transported from an average distance of 100 km. 90% of the biomass input will be transported with trucks; the rest will arrive by train. The average truck is assumed to have a load capacity of 10 tons, and consumes 25.6 liters of gasoline when loaded, and 20.5 liters of gasoline when free of load. Trucks are supposed to be fully loaded on the way to the power plant, and empty on the way back. Based on several pieces of literature, unit emissions of freight train transportation (GWP/ton km) have been conservatively estimated at 40% of unit emissions of truck transportation. Total transport emissions of 240 kt/y of biomass were computed to result in 2,902 t CO2equivalent/year.

6.3 Calculation of indirect project emission effects (leakage)

6.3.1 Indirect on-site emissions

There are no indirect on-site emissions resulting from the project.

6.3.2 Indirect off-site emissions

Indirect off-site emissions may result upstream of the project. The local firewood market may be affected by the project in such a way as to result in leakage, but the effect is probably low and difficult to predict. If the demand for firewood by the project proves significant enough to have an effect on the market, this could result in several outcomes:

- A slight increase in logging: currently the amount of logging is lower than what could be authorized. Therefore an increase in logging activity is possible.
- An increase in the amount of wood waste collected from logging sites: wood is only collected where this is economical. If there is an increase in demand for wood, driving up the price of fuel wood, it can become economical for companies to collect waste wood usually left at the site of logging.
- If the price of fuel wood increases locally, small village households, that are not yet connected to the gas pipe network (very few), may choose to use other fuels (especially coal), or they may choose to collect wood in the nearby forests that would otherwise not have been collected.
- An increase in demand for biomass may induce an increase in the plantation of energy crops and the establishment of tree plantations.

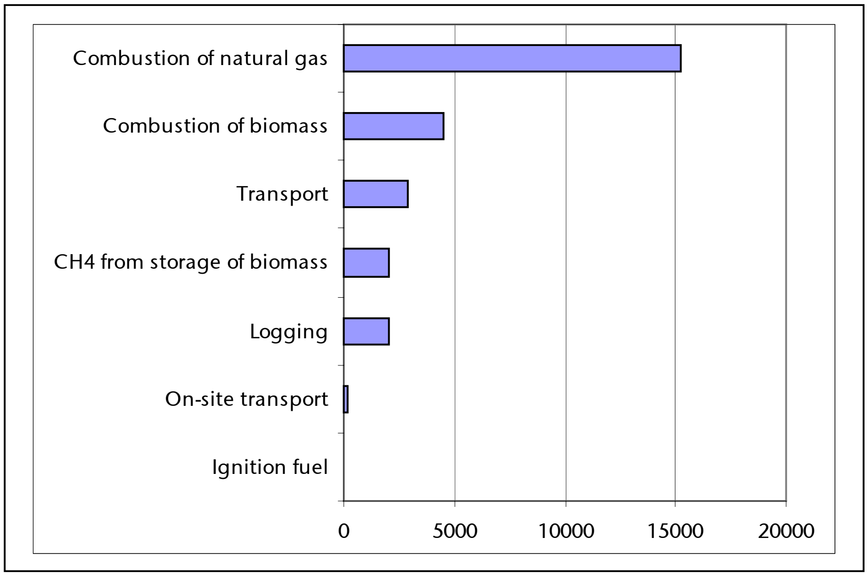
The effect of the project on the above activities is difficult to isolate, and it is not possible to predict the net effect of activities which result in an increase in CO_2 emissions (e.g. an increase in coal use by households) and activities resulting in a decrease in GHG emissions (the collection of waste wood. It is not even possible to predict whether the net effect will be significant. However, the monitoring of these activities is required and, as far as possible, addressed.

There are no downstream indirect effects expected from the project, since it will only produce electricity, which is sold on a national or regional market at a regulated feed-in tariff and represent lower than 1% of domestic comsumption. Therefore, the project will not have an effect on electricity prices or electricity consumption.

6.4 Calculation of total project emissions

Total project emissions amount to 27,429 t CO_2equivalent/year, in the following breakdown. In case of 300 kt/year and 360 kt/year biomass combustion, related project emissions would be approximately 34,300 and 41,100 tCO2e/year.

Project emissions (ton CO_2equivalent/year)



7 CREDITING TIME

Start date of the project:	December 2003 or January 2004
Lifetime of the project:	15 years
Crediting time of the project:	2008-2012

8 ESTIMATION OF EMISSION REDUCTIONS

As depicted by the next table, baseline emissions will decrease through the crediting time of the project due to decreasing grid emission factors, while project emissions will be constant. As a result, annual emission reductions will slightly decrease over the years. Total emission reductions are expected to be 453,453 tons of CO_2equivalent (CO_2e). Total emission reduction would be about 567 kt CO_2e and 680 kt CO_2e for combustion of 300 kt/year and 360 kt/year biomass respectively.

The emission reduction calculations do not include the CH_4 and N_2O emissions from the combustion of biomass from the project as well as the combustion of a mix of fossil fuels (natural gas, oil, coal) used for electricity production in the baseline scenario. Grid emission factors of other GHGs (CH_4 and N_2O) are not supplied by the ERUPT Guidelines, and they are not available within Hungarian statistics either. Nonetheless, there will annually be about 4.5 kt CO_2equivalent of N_2O and CH_4 emissions from generation of electricity at the proposed biomass plant, which needs to be compared to emissions of the same gases from displaced electricity generation sources. Displaced electricity generation will probably be either natural gas, oil or coal based. Coal is more N_2O and CH_4-intensive than biomass; biomass, however, emits more of these gases than natural gas. If biomass generation replaces a mix of 36% coal and 64% natural gas based generation, then the N_2O and CH_4 emissions of the displaced generation will be equal to that of biomass generation[27]. If the ratio of coal generation within the displaced mix is higher than 36%, then the biomass project will result in net savings of N_2O and CH_4 emissions. In 2002, coal use dominated natural gas in domestic electricity production. In the coming years some coal powered capacities are expected to finish operation, but towards the beginning of the next decade, new coal power plants are projected to open. It is very unlikely that for 2008-2012 coal use would fall below half of natural gas use[28]. Therefore it can be safely assumed that there will be net savings of non-CO_2 GHGs due to the realization of biomass production, thus these emissions were excluded from emission reduction calculations.

However CH_4 and N_20 emissions from the combustion of gasoline used for the transportation of the biomass to the Ajka site have been included in the emission reduction calculations.

The CH_4 emissions from the storage of the biomass in the chips container ("one week storage") have not been included in the emission reductions calculations. The reason is that the different kinds of storage conditions and different storage times of the biomass (the biomass will be sourced from more than 15 different sources) in the absence of the biomass project is impossible to accurately assess. However, it can be safely assumed that without the project average storage time would be more than the one-week storage time of the project. Also, the associated CH_4 emissions are relatively low in the project (475 t CO_2e/year)

CH_4 emissions of about 2,060 ton/year resulting from storage of the reserve biomass in the barns have, nonetheless, been included among project emissions, since in the absence of the project these emissions would probably only occur to a more limited extent.

Table 15 Emission reduction of the project during the crediting years

Year	2008	2009	2010	2011	2012	Total
Baseline emissions (ton CO_2e)	117 268	115 174	113 080	111 176	109 082	565 781
Project emissions (ton CO_2e)	22 466	22 466	22 466	22 466	22 466	112 328
Emission reductions (ton CO_2e)	94 803	92 709	90 614	88 711	86 617	453 453

[27] Calculations were carried out with the emission factors supplied in Section 6.2.1, and 14 MJ/kWh of power generating factors for biomass and coal, and 9 MJ/kWh of power generating factor for natural gas. In case replaced natural gas based generation were even more efficient, e.g. 7 MJ/kWh, then the ratio of coal in the replaced mix should be at least 41%. It is not likely, however, that the most efficient producers will be among the replaced ones, therefore a less efficient natural gas based generating factor, such as 9 MJ/kWh is reasonable to use.

[28] Which would imply 33.3% of coal and 66.7% of natural gas within their mix.

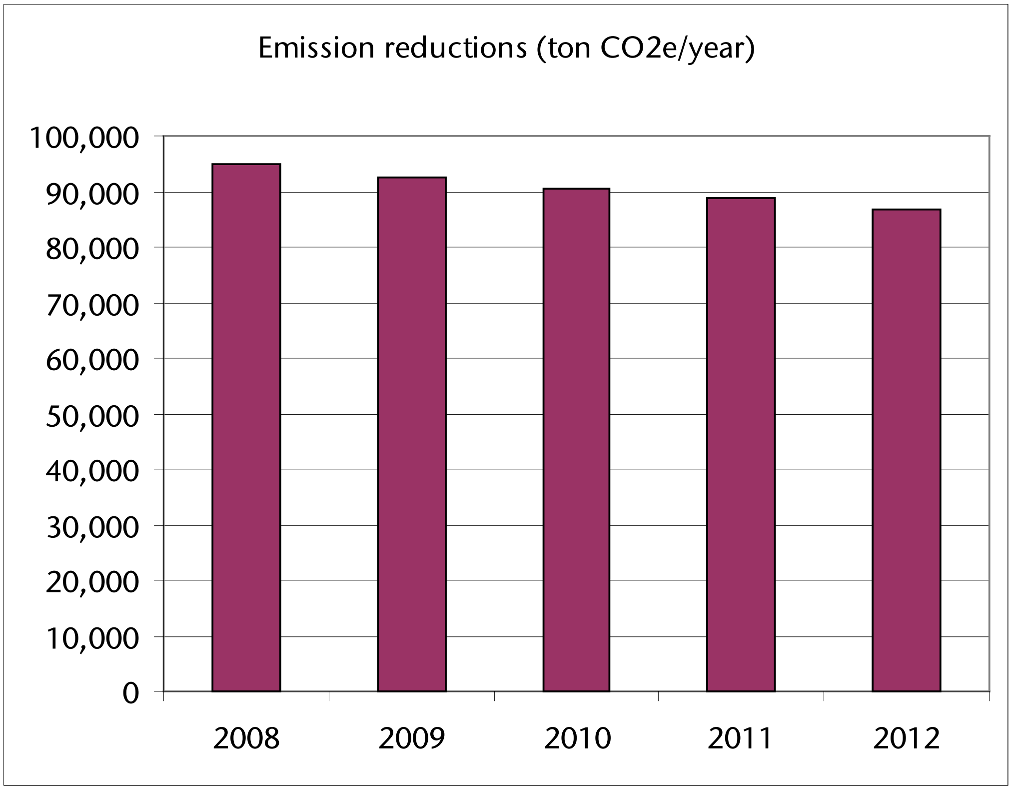


Figure 5 *Emission reductions (tCO_2e/year)*

9 MONITORING PLAN

9.1 *Level of activity*

Monitoring the level of activity (”renewable electricity output and fuel input”) is relevant both for determining the baseline GHG emissions using the grid baseline CO_2 emission factor, and, where necessary, for the indirect determination of project GHG emissions, i.e. the determination of project emissions, which are not based on emission measurements, but standardized emission factors and activity levels.

There are several possible scenarios for monitoring output of the Ajka biomass project. The output will either be measured directly or estimated indirectly based on fuel input and efficiency factors. The method of measurement will depend on the requirements of the Hungarian Energy Office (HEO), as well as whether it will be physically possible to separate the electricity output of biomass combustion from other electricity production at the plant. If supplemental natural gas is added to the biomass combustion (as is planned now), it is sufficient to measure “renewable” output even in the event of total separation, since the use of natural gas increases project GHG emissions.

Electricity generated from biomass cannot be measured directly as long as any of the coal boilers are still operating. The reason being that the steam produced by the coal boilers and the steam produced by the biomass boilers are delivered to a common pipe system, and then distributed to the different turbines. The operation of the coal boilers is unlikely in 2008, at the beginning of the crediting period, but the possibility cannot be entirely excluded. If the coal boilers are still operating, then in addition to monitoring the electricity output from turbine V, the steam output from the biomass boilers and turbine V’s efficiencies need to be monitored at regular intervals in order to clearly demonstrate that the entire electricity output of turbine V is generated using biomass.

There are also plans for total physical separation of the biomass plant from the coal-fired plant. In this case, the baseline emission estimation problem would be solved, and monitoring the volume of renewable electricity[29] becomes possible by measuring the electricity output of turbine V. Condensation turbine V, which produces the biomass-based electricity, is separately connected to the electricity grid. MVM, the electricity wholesaler and Hungarian transmission network operator can read the electricity production of this turbine. The amount of electricity fed into the grid is measured by equipment belonging to MVM, and certified by OMH (National Measurement Office). Measurements are made every 15 or 30 minutes.

Even if the physical separation of biomass based electricity production from other means of electricity production can be achieved, monitoring of the electricity output and the biomass input (volume and heating value) will be required by the Hungarian Energy Office (HEO). The HEO further specifies that the biomass input be verified by an independent third party. It is foreseen that the HEO will require that this verification will be done using invoices and biomass delivery records as well as internal laboratory results of the calorific value of the biomass fuel. Presentation of invoices and third party verification is required by the Energy Office in order to qualify for the renewable energy feed-in tariff. Supplemental monitoring measures are prescribed by MVM. Ajka will follow all the required monitoring and verification steps prescribed by the HEO and MVM in order to determine the level of activity of the project. The steps, which Ajka will have to take, have not yet been specified.

Account will also be taken of the fact that biomass stored for a long time on the site before the introduction into the boilers might result in degradation of the biomass heat value, therefore the duration and volume of on-site storage will be documented by Bakony. The CH_4 emissions generated during the storage of the biomass on site will be calculated using generic the emission data specified in the

[29] It counts renewable from accounting point of view even if up to 10% natural gas is used. In any case, the total electricity should be taken into account for the baseline that is subject to mandatory take over (and this way displaces other plants).

recent report from World Bank PCF Plus Research, Methane and Nitrous Oxide Emissions from Biomass Waste Stockpiles –Final Report, P.49, prepared by BTG Biomass Technology Group, but the method should be tailored to Bakony's needs.

Later on, if the installation of the CHP gas turbine replaces the production of the coal boilers, this situation will change, because the steam output will be physically separate.

Ajka will use its existing laboratory and trained staff, which currently carries out the testing of the coal specifications, to test the humidity and heat content of the biomass. . This will be necessary, even with physical separation of the biomass from other boilers, especially if supplementary gas is also burned. Measurements of the following biomass characteristics will be made:

- Measurement of the tonnage: Monitoring the number of trucks and trains, using the weighting bridge to weight each truck and railway. Internal monitoring protocols as well as official invoices and bills of delivery from suppliers will be used to demonstrate the tonnage of the biomass.
- Measurement of the humidity level of each shipment (which can consist of many trucks from one source): Internal laboratory results as well as invoices and bills of delivery will be used to monitor and verify the humidity of the biomass.
- Measurement of the heat content (or calorific value, MJ/kg) of the biomass: The heat content for wood does not significantly differ from one type of wood to another if the wood is dry. The tonnage and the humidity are the most relevant measurements. Information on the type of wood used will also be available from invoices, but since the heat content of deliveries of fuel wood to the plant will be measured, this will provide no additional information. Only occasional measurements of the heat content are required, and this will be carried out following the international standardised procedure. Internal laboratory results will be used to monitor the heat value of the delivered biomass. It is also in Ajka's own interest to closely monitor the quality of the biomass delivered, as Ajka will want to ascertain that it is receiving good quality fuel from its suppliers. Ajka already has equipment satisfying Hungarian Standards, used for measuring the heat content of solid fuels, which is currently used for measuring the heat content of coal.

Boiler and turbine efficiency is currently measured annually – before and after the annual overhaul of the equipment. Ajka will use existing efficiency determination processes to determine the efficiency of the biomass electricity production. Currently an indirect method is used for the measurement of the efficiency of the boilers, where energy loss is measured and subtracted from 100% efficiency to determine the efficiency of boilers and turbines. The efficiency measurements will be validated by an independent organization. If required by the HEO, the measurements will be carried out by such an organization instead of Bakony Power, using their own methodology.

According to Bakony Power, the current (inverse) efficiency of the electricity production from the condensation turbine is 15,300 kJ/kWh, which represents the heat content of the fuel input/electricity sold. Turbine V has been reconstructed to improve efficiency, and according to Ajka the expected new inverse efficiency will be around 14,000 KJ/kWh for sold (net) electricity. In addition to the reconstruction of the turbines, the reconstruction of the boilers, as well as a large decrease in its own consumption due to the decrease in slurry and the need to pump it to the slurry storage lakes will result in an increase in net efficiency. Efficiency also improves due to that wood fuel preparation is less energy demanding than coal preparation (grinding).

9.2 *Project Greenhouse Gas Emissions*

The following emission sources have to be accounted for:

- Direct
    - On-site:
        - CO_2 emissions from combustion: (i) zero for biomass, (ii) The emissions from the supplementary burning of natural gas will be calculated by monitoring the volume of gas used, and by using IPCC emission factors. The total volume of gas used is measured at the plant with an OMH-approved meter. The amount of gas used in each boiler is also measured for internal technical purposes. The use of fossil fuel is tracked under the quality management system of Ajka due to its ISO 9002 certification, and is included in invoices. In October 2001, Ajka Power received a certification from the IQNet (International Certification Network, www.iqnet-certification.com) and its local partner the MSZT, the Hungarian Standards Institution (www.mszt.hu), certifying that Ajka implements and maintains a quality management system, which fulfils the ISO 9002:1994 requirements for the field of activities covering electric power and heat production and mining (Certification Nr. MSZT-503/0702-568, valid from 24-10-2001 to 14-12-2003). The first audit was performed last year and another one is to take place in 2003..
        - Ignition fuel: this will be estimated from fuel use figures for the gas used as an ignition fuel, and default emission factors provided by IPCC.
        - Biomass fuel transportation within the area of the plant and other on-site activities related to the biomass project: the fuel use of the trucks and other vehicles will be determined from mileage indicators and per mileage fuel consumption, or per hour fuel consumption and total hours of operation for the other equipment. IPCC emission factors will be used to determine emissions.
        - Methane emissions from fuel wood storage: the duration of the storage of biomass will be monitored, not only to estimate the decrease in heating value, but also to estimate methane emissions from the biomass. The emission factors available from World Bank PCF Plus Research, Methane and Nitrous Oxide Emissions from Biomass Waste Stockpiles –Final Report, P.49, prepared by BTG Biomass will be used tailored to the specific Bakony Power's storage conditions (time) and biomass mix.
        - CH_4 and N_2O emissions from combustion: As no specific information of such emissions of displaced electricity generation is and will likely be available, and due to the fact that baseline and project emissions of such gases under realistic assumptions even out, we decided to not include these emissions in the calculations. Therefore, this plan does not require the monitoring of these gases from combustion. It should be noted that there is no commercially available technology for measuring N_2O emissions. Currently only a general emissions factor for combustion in energy industries is available from the IPCC, and no specific emissions factor is provided for fluid bed combustion for wood. Should monitoring of N_2O be deemed necessary, this general IPCC factor will be used, unless technology specific N_2O emissions factors become available during the lifetime of the project. Emissions would be estimated from fuel input levels and emission factor values for biomass and gas. CH_4 measurement is commercially available and cheap (cc. 1000 USD during the annual measurements with mobile measurement station). However, the method of fuel input and IPCC emission factors should accompany measurements, if monitoring of combustion related methane is of concern.

    - Off-site:
        - Biomass fuel production and transportation: The relevant data will be collected by the power plant using a uniform reporting format from the companies involved in the production of the biomass fuel. The relevant

activities are emissions from logging, collection of wood, dragging to the point of loading onto trucks or trains, and transport to the plant or to the contractors of the power plant. The emissions will be estimated using figures for the total hours of operation of the equipment used, and the number of hours that the equipment operates, as well as mileage and fuel use figures for road transport vehicles. For train transport, IPCC emissions data and distance traveled can be used in the absence of a better official estimate.

- Biomass fuel transport by third party: If the company delivering the fuel is not the same as the company producing it, then separate questionnaires will have to be distributed to both companies. The fuel use data will be calculated using the same methodology as described above.

- Indirect
  - On-site: There are no on-site indirect emissions resulting from the project. No monitoring is required here.
  - Off-site:
    - Effects on the local fuel wood (firewood) market and other fuel markets: The need for monitoring indirect effects on the local fuel market will arise if the power plant has a significant impact on fuel wood prices in the area. The fuel wood prices will be monitored, and if they change significantly, additional monitoring of these effects will be necessary. The effect on the fuel wood market can be estimated based on information from the companies supplying the Ajka plant with biomass, the companies involved in the production of the biomass and wholesalers of firewood to other customers. They will be considered as a representative sample of the companies on the local fuel market. A questionnaire will be distributed to these companies regarding the change in household and other consumer's demand for fuel wood, the quantitative change in logging behavior and in the amount of waste wood collected at the site of logging, and the effect on energy plantations. With the evaluation of the questionnaires, the effect of the power plant on the local fuel market will be evaluated. It will be assumed that the decrease in fuel wood is accompanied by an according increase in coal/heating oil/gas/electricity use. Trends on the other energy markets will also have to be tracked, regional statistical data of the Central Statistics Bureau will be used for this purpose, if at that time provided. This will be done in order to separate trends due to a general change in energy prices from changes in energy prices due to the project, and also to obtain data of changes in demand for other forms of energy locally. Once the fuel substitution effect (if any arises) was determined, applying household emission factors of IPCC for the project related change in the heating fuel mix yields the CO_2 leakage emissions.

Some of the data relevant for monitoring (data on output levels, input volume and efficiency) is collected already and processed within the information system at the plant handling production data. Other data related to invoices and bills of delivery is handled within the financial information system of the Ajka plant. This data will continue to be tracked by these systems, and will also be stored in a monitoring information system as part of the environmental information system which will be set up at the plant by the beginning of 2004, as this is made compulsory by the 10/2003 (VII. 11.) decree of the Minister of Environment and Water Management ("on the emission limits and conditions of operating combustion plants of 50 MW or larger capacity").

The plant is committed to carrying out the monitoring plant and will take the necessary steps to ensure that financial resources are set aside for this purpose, and that staff are trained or employed if necessary, to implement the monitoring plan.

10 STAKEHOLDER COMMENTS

10.1 The process of gathering stakeholder comments

The Bakony Power Plant has held both a residential forum, and a public hearing in Ajka concerning the fuel switch investment converting the plant from a coal-fired plant to a plant partly fired by gas and partly by biomass. The emphasis was placed on the combined cycle gas turbine. A four-page series of articles also appeared in the local environmental NGO's newspaper.[30] Stakeholders were provided with the possibility of commenting on the investment through telephone and in writing. However, no further comments were received following the residential forum and public hearing. Comments received and answers given at the forums themselves are summarized below. Public consultation is not obligatory by law for biomass projects of this size in Hungary.

The residential forum took place in Ajka on the 19th May 2003 at 4 pm. Forum participants were János Rénes, the Executive Director of the Bakony Combined Cycle Building and Development ltd, László Kanczler, the Environmental Manager, some invited participants, and local residents. The forum took place with the participation of a moderator.

The public hearing was held on the 2nd of June 2003 at 4 pm at the Ajka Mayor's Office. Public hearing participants were János Rénes, Executive Director and Béla Szellem Environmental Manager as the representatives of the investor, as well as representatives of the Interministerial Body set up by the 73/1996 (V. 22.) Government Decree, representatives of Mediator Ltd, and the residents of Ajka. The comments and presentations of the participants were documented, an official record was made of both meetings.

In both cases, the event began with a brief description of the purpose of the hearing by Erika Farkas followed by a brief introduction of the gas and biomass projects by János Rénes, and a brief description of the environmental effects of the project by the environmental manager representing the investor.

The description of the technology included the following facts:

- The necessity of the project is justified by the fact that the coalmines are becoming depleted, thus producing coal of lower calorific value. This is occurring at the same time stricter environmental regulations are coming into force.
- The new technology includes a combined cycle technology fuelled by gas or gas turbine oil, which produces water vapor of 600°C at 70-80% efficiency.
- Parallel to the gas CHP project a biomass project has also begun, which will replace about one third of the coal used as of 2004, thus decreasing SO_2 and CO_2 emissions from the plant.

The environmental effects of the two technologies were briefly presented to the public, including effects on air quality (SO_2, NO_x, CO and particulate emissions), effects on soil, effects on water, and noise pollution effects.

10.2 Summary of the comments received and action taken

Some participants expressed concerns about the new technology, including both the biomass and the gas-fired technology. Comments concerning the biomass project, and the answers given to the questions of the participants are summarized below.

[30] Zöld Béka. A Zöld Alternatíva Szövetség lapja. XI. évf., 3. sz.

Table 16 Comments received at the residential forum held on the 19th of May, 2003

Name of stakeholder	Stakeholder comment or question, answer to stakeholder comment
Károly Kozma	If the power plant will be fuelled by wood, all kinds of solid matter will be used. What will happen if natural gas becomes expensive? Will biomass be used only then? What is biomass? We would not like rotting organic matter to be brought into the area.
Bakony response[31]	Biomass is a concept that includes wood chips from different species of trees, which is what we are planning on using. This is provided by 3rd and 5th class forests, as well as waste and remnants at the site of the logging. Other materials (such as straw) can be used in small quantities as well. No decomposing material can or will be used in the process.
Member of the Biokultúra Association	It is not a good idea to burn straw. It has to be recycled back into the soil. Artificial fertilizers exploit the soil, so straw is needed by the soil.
Bakony response	It was the farmers themselves who made the suggestion of using straw. Not all of it can be recycled back into the soil because it would cause cellulose contamination. With the currently planned technology we would only be able to use a minimal amount of straw.

Table 17 Comments received at the public hearing held on the 2nd of June, 2003

Name of stakeholder	***Stakeholder comment or question***
Imre Keller	Wood chip technology was mentioned. How much woodchip do we have in Hungary? Also, it was mentioned that the amount of hazardous waste produced would be reduced significantly. By how much would the waste be reduced, and what are these substances?
Bakony response	The available wood is of a large quantity. All requested loggings should be authorized. The authorities have the possibility of authorizing more loggings than they currently do. There is also waste left at the area of logging. Around 1.5-2 million tons remain in the forests. Three power companies (Pécs, Borsod, Bakony) will use less than 1 million tons. The income from the power sector can also contribute to the reforestation and improvement of 3rd and 5th category forests. About the hazardous wastes (...) this quantity is around a few dozen tons.
Imre Keller	What are the hazardous substances? We know of the slurry storage lakes already. What hazardous substances do the combustion of gas produce? We can see clear-cutting in our forests. What amount of wood does the power plant use?
Bakony response	The question was what kinds of hazardous wastes are produced. All waste is to be treated as hazardous waste until it is officially classified as not hazardous. All waste is temporarily deposited in a hazardous waste storage facility. There are oils and heavy oils. We have to account for these, and have to contract a company with the necessary permit for the disposal, elimination or deposition of these in a landfill. Concerning clear-cutting, the question was whether we have enough wood. There are one million tons which experts estimate can be collected from waste currently left at the area of logging. The three power plants mentioned earlier will use less than this amount. The plant at Ajka needs a minimum of 150 thousand tons a year to be economical, and the maximum amount that can technically be used is 300 thousand tons a year.
Károly Kozma	When the power plant was built, a 25-year contract was signed to ensure that the input was available. Can Mr. Hanzéli guarantee that wood chip would be

[31] The stakeholder comments listed were answered by János Rénes, Executive Director of the Ajka Power Plant.

	available every year?
Bakony response	Nowadays it is almost impossible to sign contracts for 10-20 years. (...) We are also considering on having energy plantations established, which, based on our consultations with mayors in the area, would be welcome, and the benefit to the national economy would be significant. The renewable energy input can thus be assured.
Lajos A. Tóth	What price is paid for the felled trees so that people are not encouraged to cut out too many trees? How can this be controlled?
Bakony response	This is independent of the price. The laws require that all forest managers submit their plans for logging to the forestry authorities for authorization. Any other mode of forest management is illegal.
Péter Mádai, deputy mayor	With the privatization of the power plant, the responsibility of remediation remained with the plant. Will this responsibility remain after 2006?
Bakony response	The privatization agreement contains the necessary provisions. The necessary steps are being taken. This can be seen in Padrag and Csinger, and at Inota where the first stage of the remediation of the slurry storage lakes has taken place. It is now cultivated, and the eastern part of it has been restored. It has been covered with soil and plants have been planted. The Bakony Power Plant will continue to exist and continue to fulfil its obligations. The owners of the company have the necessary financial assets, which can provide for the fulfilment of these obligations.
Gyula Sz□ke	Shouldn't a sound barrier be built to protect against secondary resonance?
Bakony response	The residents have no reason to worry. The companies we are in contact with do not sign contracts that they cannot fulfil. We also have to fulfil all requirements; in absence of this, the new plant will not receive a permit to operate.

The stakeholder comments received at the public hearing and the residential forum were questions rather than requests to be dealt with in the investment plant. These questions were answered on the spot, as seen above. No other stakeholder comment was received.

11 ENVIRONMENTAL IMPACT

11.1 Introduction

A preliminary environmental impact assessment of a fuel switch investment plan at the power plant at Ajka has been conducted. This preliminary impact assessment examined a fuel switch option partly to 50-50 co-fired coal and biomass and partly to gas. A voluntary environmental impact assessment for the current project proposal (100% biomass combustion in two boilers) is currently being prepared and is expected to be ready by the fall of 2003. For an indication of how biomass affects the environmental performance of the plant, a summary is given of the available assessment of the previous plan.

The environmental impact assessment was conducted for the planned investment because it involved the firing of gas as well as biomass. Conducting a preliminary environmental impact assessment for a fuel switch to a purely biomass fired plant is not a legal obligation. Both fuels are considered solid fuels by Hungarian law, and thus a change in fuel from coal to biomass is not considered a fuel switch project. The plans for the investment for which the preliminary impact assessment was conducted have, however, changed. The project planned at that point was a partial fuel switch from coal to biomass. (The conversion of the remaining part of the coal plant to gas is likely to take place in a few years.) Although an environmental impact assessment, or a preliminary environmental impact assessment, does not have to be conducted for the fuel switch project, a permit must be obtained from the Central Trans-Danubian Environmental Inspectorate (KDKF) for the planned investment. The permit for firing biomass at maximum capacity of one boiler (2 times 44 MW) has already been obtained from the Central Trans-Danubian Environmental Inspectorate. The permit number is 30034-8/2003. With the change in the investment plan, a permit for an additional boiler is being sought.

The official preliminary Environmental Impact Assessment (EIA) for the previously planned investment was prepared by Enviroinvest Ltd. at the request of Ökono 2000 Ltd. It was completed in May of 2003. A trial operation was also conducted at Ajka in boiler number IX on the 25th of February 2003. During the trial operation air emissions from three fuel options were measured: 50-50 biomass-coal mix, pulverized coal, and coal-gas sustaining flame. A new EIA has not yet been prepared, but one is currently under preparation. The results summarized below are taken from the EIA performed for co-firing biomass and coal.

Bakony is currently in the process of applying for an IPPC license. This license has to be obtained by all power plants with a rated thermal input higher than 50 MW. The deadline to acquire the license is 31 October 2007. The license can be obtained if a clear and comprehensive action plan is prepared laying out how the IPPC requirements will be fulfilled.

11.2 Historical background and technology currently used

The Ajka CHP has been operational since the 1940s. It is a coal-based plant, supplied with coal from the area. However, the technology has become obsolete. The electricity produced by the plant is too costly to remain competitive. The operating permit for the power plant's main installations expires between 2000 and 2006, and electricity production at the plant has a disproportionately large environmental impact (SO_2, cinder and ash). However, the heat supplied by the plant is needed. The plant supplies heat to the Alumina plant in Ajka, as well as for district heating to the city of Ajka.

The plant has been continuously upgraded since it began operating. Between 1990 and 1993 four boilers at the Ajka II plant were converted to hybrid fluid technology. Seven pulverized coal fuelled boilers of the Ajka I plant were decommissioned in 1997. The Ajka I and II plants provide Ajka with the necessary heat and also produce electricity for the grid. All five currently operating boilers are located at Ajka II. They produce steam for three condensation gas turbines located at Ajka II, which produce electricity only, and three extraction turbines located at Ajka I, primarily producing heat and some electricity.

11.3 The technological alternatives investigated

Plant upgrading is intended primarily to lessen the environmental impacts of electricity and heat production. At the same time, it should provide a competitive option and a reliable source of heat and electricity to consumers.

Three fuel alternatives were evaluated in the environmental impact assessment:

1. Pulverized coal fired technology (currently used by the power plant).
2. Coal-natural gas sustaining flame technology.
3. Biomass (wood chip) fired technology (elaborated below).

The wood fed into the hybrid-fluid boilers will be uncontaminated, untreated forestry waste wood and woodchips. The boilers can be made ready to receive the wood with minor adjustments. This will enable the operation of the power plant with fuel wood, providing a good efficiency and the necessary availability and controllability. It will also ensure that emissions remain below the limits set for the power plant. In the long term, it is planned that two hybrid-fluid boilers, XI and XII will be converted to biomass boilers.

Investments are needed for the following parts of the system:

a. fuel transport and receiving system,
b. fuel storage system,
c. fuel preparation system,
d. fuel conveying system to boilers,
e. modification of the air and flue gas of the boilers,
f. modification of garners,
g. boiler feeding equipment,
h. structural changes to fluid bed,
i. additional investment into existing electrostatic filter, and
j. combustion waste treatment system for ash and slurry.

Table 18 Comparative data regarding the coal and biomass technologies

(Calorific value for coal 7000 kJ/kg, calorific value for wood 12000 kJ/kg)		
	coal	wood
Boiler input capacity	85,822 kW	85,822 kW
Used capacity	72,939 kW	72,939 kW
Boiler efficiency	84.98 %	84.98 %
Mass flow of coal	12.26 kg/s (44,13 t/h)	-
Mass flow of wood	-	7.14 kg/s (25.7t/h)
Volume flow of per unit smoke	88.063 m^3/s 317,028 m^3/h 197,960 Nm^3/h	62.53 m^3/s 225,114 m^3/h 140,696 Nm^3/h
Ash flow attributable to fuel	4.53 kg/s	0.12 kg/s

Table 19 Expected sources of biomass as was foreseen at the time of the EIA

Type of biomass	Calorific value (dry, in MJ/kg))	Quantity (wet, in tons)
Forest industry by-products	≈14.5	
By-products from wood processing		
bark	≈13.5*	
lath waste		
wood chip		≈50,000
Firewood, fiber wood (oak, Austrian oak, pseudoacacia, beech)	≈13.5*	≈ 150,000
Energy plantations (future plans)	≈13.3	
Total		≈200,000[32]

*These are heat values for dry wood. For the "half wet" biomass transported to Ajka the lower heating values are expected around 12 MJ/kg. The at time of the delivery of the biomass, the biomass is estimated to have a moisture content of 30% and the 12 MJ/kg heating value is based on that condition.

11.4 Measurement results of emissions to air of the trial operation of biomass at Ajka

Along with the permitting process of the planned biomass and gas-fired investments, a trial operation was carried out at the Ajka plant on the 25th of February 2003. Emissions from the following three fuel options were measured: pulverized coal; coal gas sustaining flame; and co-fired wood-chip and coal. Measurements were taken at the number IX hybrid fuel steam boiler. Since all the boilers at Ajka are of the same construction and output capacity, these measurements can be considered valid for all the boilers.

The Central Trans-Danubian Environmental Inspectorate has determined the emission limits for P002 and P003 point sources (the only two chimneys at Ajka) in a legal decree (30034-77/02). These emission limits are shown in the table together with the emissions measured during the trial operation, as well as emissions measured in the year 2000 during the annually compulsory emissions monitoring.

[32] A more optimistic long-term supply includes an additional 50 000 tons with a 60% probability, and 50 000 tons from energy plantations. So far price and quantity offers have been received by the plant for 297,500 tons for the year 2004, (without any biomass from energy plantation) so the estimate may be achievable.

Table 20 Emission limits measured at Ajka and emission limits set by the Central Trans-Danubian Environmental Inspectorate for the point sources P002 and P003 at the Ajka plant.

Pollutant	**Decree 10/2003 of the MEWM on the emission limits of combustion plants using solid fuel, for plants with a permit dated before decree's coming into effect (for $P_{th} \geq$ 100 MW)**	**Decree 10/2003 of the MEWM on the emission limits of combustion plants using solid fuel, for plants with a permit dated after the decree's coming into effect (for $P_{th} \geq$ 100 MW)**	**Emission limits set by KDKF*******	**Measurement of emissions (2000)[1]**	**Measurement of emissions during the trial operation (25.02.2003)**		
					Pulverized coal	**Coal-gas[3]**	**Co-fired wood chips and coal (50-50%)[4]**
	mg/m^{3*}						
Particulates	100	50	50	41	41	42	40
CO	250	250	250	47	47	36	58
NO_x (expressed as NO_2)	600-650	200 (300 for biomass, but 400 if P_{th} < 100 MW)	600	591	547	580	718
SO_2 and SO_3 (expressed as SO_2) [5]	400-2000** (1695.2 for Ajka)	200	1,695.2	5,681	1,570	1,694	843
Chlorides (expressed as HCl)	200	200	100	1.6	8.7	7.9	0.5
Fluorides	30	30	15	<3.5	5.2	4.7	<1.6

* The concentrations expresses in mg/m^3 are calculated for dry smoke of a temperature of 273 K, 101.3 kPa pressure, 6% oxygen content

**It is a requirement for Ajka's HF technologies that the reduction in emissions of SO_2 (desulphurization rate) has to be at least 60%; from 2005 at least 75%.

*** The emission limits were set by the Central Trans-Danubian Environmental Inspectorate in decree 30034-77/02.

[1] Measurements conducted on the 2nd of February 2000 for emissions of the hybrid fluid boilers. Desulphurisation ratio: 76.2 %.

[2] Desulphurisation ratio: 90.1 %

[3] Desulphurisation ratio: 88.9 %

[4] Desulphurisation ratio: 88.7 %

[5] The SO_2 emission caps are presently not relevant for the power plant, because hybrid fluid plants, and plants using domestic brown coal have to observe the desulphurisation requirements only (a minimum of 60% desulphurisation ratio) until 2005. After 2005 this figure will be 75%.

Results of this trial operation are valid for co-fired biomass and coal. The plans at the power plant involve firing only biomass in two boilers. The environmental impact assessment for this investment plan has not yet been prepared. The plant is currently not ready for a trial operation with biomass only, but the preparation for a trial operation is currently underway. For illustration, the expected environmental effects on the elements of air, surface water, groundwater, and soil, as well as the waste produced, effects on the living environment, and noise effects *of the biomass and coal co-fired plant* are thus summarized below. This information is taken from the Environmental Impact Assessment that has been prepared for the co-firing of biomass and coal.

11.5 Expected environmental impacts of biomass-coal co-fired electricity production

11.5.1 Effects on air quality

The plant has the largest impact area with respect to effects on air quality. This impact area exceeds that of the other elements. The power plant's impact on air quality, and in particular the spread of pollutants through the air, is influenced by factors such as chimney height, as well as external factors such as wind conditions (speed and direction).

Spread models were prepared for the major pollutants. These models were estimated for the two most important pollutants, SO_2 and NO_x, whose hourly and annual averages for the most common meteorological conditions have been calculated. The maps showing the dispersion of pollutants thus obtained were then compared under different fuel option scenarios.

As can be seen from table 19 above, all emissions of the co-fired coal and biomass satisfy the emission limits set by the Central Trans-Danubian Environmental Inspectorate, except the NO_x emissions, which slightly exceed the emission limits. This is because woodchips have a higher calorific value than the coal for which the boiler was designed. This can cause over-heating, resulting in an excess of NO_x emissions. The emissions of NO_x for pulverized coal are also quite high, due to the fact that the firing technology is outdated. This technology will be modified and renovated in the two fluidized bed boilers, which will be used to burn 100% of biomass. A decrease in emissions can be achieved by controlling the amount of oxygen in the furnace chamber. With the proper system calibration and continuous emission monitoring until a stable operation mode is reached (which could not be achieved during the short period of trial operation) and additional investment, the level of NO_x emissions can be reached which satisfy the emission limits. This is underpinned by the relevant literature.

The area affected by SO_2 pollution for the investigated technologies is in a 1.5 km radius of the plant. The area affected by NO_x emissions for biomass coal co-firing is within a 7 km radius of the plant.

Using emission factors from the literature it has been estimated that SO_2 emissions will fall back by 70 to 98% in case of wood combustion in comparison with coal firing. The actual decrease in emissions will depend on the type of wood that is combusted.

11.5.2 Noise effects

Noise effects arise for the biomass coal co-firing option at several stages of the installation and operation of the power plant:

a) building stages
b) operating stages:
    a. transport of the fuel
    b. preparing the fuel for combustion (chopping)
    c. combustion

The three technologies studied (pulverised coal, coal gas sustaining flame, and co-firing biomass and coal) all have similar levels of noise emissions. The areas affected are in the immediate proximity of the power plant. The noise emission limits set for installations by the 4/1984 decree of the Minister of Health are shown in the table below.

Table 21 General noise emission limits

Function of nearby area	**Daytime limits** $6^{00}-22^{00}$	**Night time limits** $22^{00}-6^{00}$
	(L_{Aeq}, dB)	
Recreational area	45	35
Residential area and non-residential area with a low level of built-in density	50	40
Residential area and non-residential area densely built-in	55	45
Industrial area with some residential and non-residential area	60	50

L_{Aeq}: the allowed equivalent A-weighted sound level

The Central Trans-Danubian Environmental Inspectorate has not yet set noise emission levels for the power plant. The power plant and the nearby alumina plant, as well as some nearby smaller installations, together cause the noise level to exceed the night-time allowed limits for some nearby residential housing, assuming no additional investment for the purpose of limiting noise effects. This is true for all three of the investigated technologies/fuels. The noise emissions for wood combustion have not been measured, but it can be assumed that they would be similar to the combustion of coal, since the combustion of wood will involve similar levels of input in terms of mass, and similar volumes of output, thus similar levels of activity at the plant.

Some fuel preparation (chopping of wood) will also take place on the area of the plant, but this is not expected to add to the noise level, since the machinery used for grinding the wood will be placed in a sound insulated environment.

The area affected by noise emissions from the power plant is within a 0.5 km radius of the plant.

11.5.3 Effects on surface water, ground water and soil

The power plant affects both the quantity and the quality of the nearby surface and ground water.

The quantitative effects stem from the large water demand of the technological processes of the power plant; this demand is satisfied mostly from subsurface waters, and in smaller part from surface waters. The demand for water stems from the following activities:

- water for the production of steam in the boilers,
- cooling water,
- desalinated water (for district heating),
- slurry (for the removal of cinder and ash),
- water for fire protection, and
- drinking water demand (for drinking water and other communal water supply).

At present two types of wastewater are produced by the power plant, communal wastewater (500-600 m^3/d) and industrial wastewater. The communal sewage is collected by the Ajka sewage system and treated at the sewage treatment plant of the city. The industrial wastewater is produced by different technological processes and collected in a separate sewage system. . The wastewater from the combustion process (slurry) is collected by a closed slurry system. The water that leaves the system through cracks in the pipes is collected and recycled back into the system. Due to the recycling of the water the pollutants accumulate. The environmental assessment of the power plant in 1996 showed that a high concentration of salts and other inorganic substances, phosphor and sulphates had accumulated in the water of the slurry storage lakes, making them very alkaline, with high conductivity and high soluble content.

There is no wastewater treatment capacity installed at the power plant. Due to the recycling of the water, the plant does not emit industrial wastewater into its surroundings.

The surface and groundwater quality, as well as soil quality was measured near the power plant. It was found that although some of the surface waters (e.g. of the Torna stream) are polluted and of low water quality, this pollution is not caused by the power plant. The groundwater and soil quality is affected by the power plant in two places: the area of the plant and the slurry storage lakes. In the area of the slurry storage lakes the concentration of molybdenum determines the size of the area affected by the plant. This is also the case for the area of the power plant, where the groundwater and soil is polluted with molybdenum in the northern-North-Eastern area of the plant, where a valley was filled with cinder that was a by-product of coal firing. Here the level of molybdenum pollution of the soil exceeds the intervention C1 level standard contained in the 10/2000. (VI.2.) joint decree of the Ministers of Environment, Health, Agriculture and Rural Development, and Transport, Communication and Water Management.

The molybdenum pollution is due to the molybdenum content of the coal used at Ajka. The molybdenum content of the coal fired is 23-26 mg/kg. Although the combustion of biomass emits fewer pollutants, which enter the groundwater and soil, the state of these elements is not likely to change in the short term due to a decrease in load.

11.5.4 Waste

At nominal load of a boiler, using coal 4.53 kg/s cinder and ash are produced. Using wood chips on the other hand produces only 0.12 kg/s cinder and ash. Currently the burning of Ajka coal produces 35% ash, which is diluted with water at a 1:10 ratio and pumped through a 300mm pipe over a distance of 7 km to a slurry landfill/lake. After biomass will be used as fuel, the ash production will decrease to 2-3%. Furthermore, in order to generate the same amount of electricity output less biomass needs to be combusted than coal due to higher energy content in biomass, therefore the overall reduction of ash can be even larger. It is therefore anticipated that ash production will decrease to about 6-8% of the original level.

The treatment of the waste is similar for all technologies: depositing the waste in a landfill. The amount of ash and cinder, as well as the amount of slurry produced is greatly reduced by a switch to biomass combustion, thus decreasing the need for landfill deposition and slurry storage. Also, the ash left over from the combustion of wood can, due to its high potassium content, be used as a fertilizer for soil improvement. This will only be possible if the ash left from the combustion of wood contains less than 1mg/kg of heavy metals, and is subject to authorization by the authorities – this issue still needs investigation.

11.5.5 Effect on the living environment

The effect of the power plant on the living environment - humans, the flora and fauna - is difficult to estimate. With emissions of pollutants into the air, the power plant contributes to the impact on the ecosystem and humans. Coal fired technology affects the living environment mostly through its emissions of SO_2, and biomass fired technology affects the living environment through emissions of NO_x. Two to three kilometres from the power plant there are significant natural assets. In the more distant region there are highly valuable plant communities and habitats. The Balaton Highland National Park and several other protected areas are to be found in the region. Some contain wetlands, which are the habitats most sensitive to pollution. They also provide a habitat to several protected species, especially birds and butterflies.

All three technologies affect the living environment in a similar way. However, the biomass technology affects the living environment to a lesser extent compared to the other two technologies and only in the closer proximity of the power plant.

11.5.6 Conclusion

The area affected by the technologies is smaller and less impacted with biomass production than in the case of the other two technologies. Based on the results of the trial operation and model calculations the best option from an environmental point of view is biomass-fuelled power production. Emissions of local air pollutants, especially SO_2 will decrease dramatically, and waste production will fall back by more than 90%. The technology used by the biomass combustion plant will satisfy all Hungarian and European environmental requirements.

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  - Ervin Trenka, Investment Manager
  - Szellem Béla, Environmental Manager
  - Zóltan Kovács, Director of Strategy and Development
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13 ANNEX I: DETAILED GHG CALCULATIONS

EMISSIONS FROM TRANSPORTATION
AJKA POWER PLANT, BIOMASS PROJECT

LOCATION SPECIFIC INPUT DATA	Unit	Scenario 1	Scenario 2	Scenario 3
Distance of transportation	km	100	100	100
Quantity of biomass	ton/year	240 000	300 000	360 000
Load per truck	ton	10	10	10
Gasoline consumption of loaded truck	liter/100 km	25,6	25,6	25,6
Fuel consumption of empty truck	liter/100 km	20,5	20,5	20,5
Ratio of road transport		90,00%	90,00%	90,00%
Ratio of railway transport		10,00%	10,00%	10,00%
emissions		40%	40%	40%

GENERAL INPUT DATA	Unit	
Energy content of gasoline	MJ/liter	36,52
CO2 emissions of fuel consumption	t/TJ	73,3
CH4 emissions of fuel consumption	t/km	0,0000008
N2O emissions of fuel consumption	t/km	0,00000003

COMPUTED DATA as if all biomass was transported on road	Unit	Scenario 1	Scenario 2	Scenario 3
Quantity of biomass	ton/year	240 000	300 000	360 000
Number of truck loads	load/year	24 000	30 000	36 000
Total road distance (one way)	km/year	2 400 000	3 000 000	3 600 000
Gasoline consumption for loaded trips	liter/year	614 400	768 000	921 600
Gasoline consumption for empty trips	liter/year	492 000	615 000	738 000
Total gasoline consumption	liter/year	1 106 400	1 383 000	1 659 600
Energy contenct of consumed gasoline	TJ	40,41	50,51	60,61
EMISSIONS				
CO2 emissions	t/year	2961,74	3702,17	4442,61
CH4 emissions	t/year	3,84	4,80	5,76
N2O emissions	t/year	0,14	0,18	0,22
GWP EMISSIONS				
CO2 emissions	t GWP/year	2961,74	3702,17	4442,61
CH4 emissions	t GWP/year	80,64	100,80	120,96
N2O emissions	t GWP/year	44,64	55,80	66,96
Total emissions	t GWP/year	3087,02	3858,77	4630,53

EMISSIONS FOR MIX OF ROAD AND RAILWAY TRANSPORT	Unit			
Road transport emissions	t GWP/year	2778,32	3472,90	4167,48
Railway transport emissions	t GWP/year	123,48	154,35	185,22
Total emissions	**t GWP/year**	**2901,80**	**3627,25**	**4352,70**

BASELINE AND PROJECT SCENARIO EMISSIONS

INPUT DATA

Scenario input	Unit	Scenario 1	Scenario 2	Scenario 3
Biomass input	PJ/year	2,4	3	3,6
Energy content of biomass	MJ/kg	10	10	10
Quantity of biomass	ton/year	240 000	300 000	360 000
Natural gas input				
- As a percentage of all input	%	10%	10%	10%
- Computed	PJ/year	0,2667	0,3333	0,4000
- Indirectly as ignition fuel (natural gas)	TJ/year	1,7	1,7	1,7
Efficiency factor of electricity generation		0,257	0,257	0,257
On-site gasoline consumption	liter/year	64 564	80 705	96 845
Off-site gasoline consumption	liter/year	720 000	900 000	1 080 000

Annual input		2004	2005	2006	2007	
Grid emission coefficients	tCO2/GWh	658	648	637	626	
		2008	2009	2010	2011	2012
		616	605	594	584	573

General input

Emission factors	Unit	Biomass	Natural gas	Coal
CO2	t/PJ	0	56100	
CH4	t/PJ	30	1,715	3,5
N2O	t/PJ	4	3	14

Biomass storage emission factors		for 1st year	for 1st month	for 1st week
CH4	m3/kg dry mat	0,0125	0,001040	0,000240

CH4 density	kg/m3	0,654
Biomass moisture content	%	40%

GWP units		
CO2	GWP	1
CH4	GWP	21
N2O	GWP	310

RESULTS

Baseline emissions of CO2		2004	2005	2006	2007		
Scenario 1	tCO2/year	125 264	123 360	121 266	119 172		
Scenario 2	tCO2/year	156 580	154 200	151 582	148 965		
Scenario 3	tCO2/year	187 896	185 040	181 899	178 758		
		2008	2009	2010	2011	2012	Total
Scenario 1	tCO2/year	117 268	115 174	113 080	111 176	109 082	565 781
Scenario 2	tCO2/year	146 585	143 968	141 350	138 970	136 353	707 226
Scenario 3	tCO2/year	175 902	172 761	169 620	166 764	163 623	848 671

SCENARIO RESULTS

		Scenario 1	Scenario 2	Scenario 3
Electricity production	GWh/year	190,3703704	237,962963	285,5555556

On-site emissions in natural units		Scenario 1	Scenario 2	Scenario 3
CO2 from biomass	t/year	0,00	0,00	0,00
CH4 from biomass	t/year	72,00	90,00	108,00
N2O from biomass	t/year	9,60	12,00	14,40
CH4 emissions from the storage of biomass:	m3/year	150 000,00	187 500,00	225 000,00
CH4 emissions from the storage of biomass:	m3/year	34 615,38	43 269,23	51 923,08
CH4 emissions from the storage of biomass	t/year	98,10	122,63	147,15
CH4 emissions from the storage of biomass	t/year	22,64	28,30	33,96
CO2 from natural gas	t/year	15 055,37	18 795,37	22 535,37
CH4 from natural gas	t/year	0,46	0,57	0,69
N2O from natural gas	t/year	0,81	1,01	1,21
CO2 from gasoline	t/year	172,83	216,04	259,25
CH4 from gasoline	t/year	0,22	0,28	0,34
N2O from gasoline	t/year	0,01	0,01	0,01

On-site emissions in GWP		Scenario 1	Scenario 2	Scenario 3
CO2 from biomass combustion	t/year	0	0	0
CH4 from biomass combustion	t/year	1 512	1 890	2 268
N2O from biomass combustion	t/year	2 976	3 720	4 464
CH4 emissions from the storage of biomass:	t/year	2 060	2 575	3 090
CH4 emissions from the storage of biomass:	t/year	475	594	713
Total from biomass	*t/year*	*7 024*	*8 779*	*10 535*
CO2 from natural gas	t/year	15 055	18 795	22 535
CH4 from natural gas	t/year	10	12	14
N2O from natural gas	t/year	250	312	374
Total from natural gas	*t/year*	*15 315*	*19 119*	*22 923*
CO2 from gasoline	t/year	173	216	259
CH4 from gasoline	t/year	5	6	7
N2O from gasoline	t/year	3	3	4
Total from gasoline	*t/year*	*180*	*225*	*270*
Total on-site emissions	***t/year***	***22 518***	***28 124***	***33 729***
Total on-site emissions without biomass (	***t/year***	***18 030***	***22 514***	***26 997***

Off-site emissions in GWP				
Transport emissions	t/year	2 902	3 627	4 353
Off-site gasoline emissions	t/year	2 009	2 511	3 013
Total off-site emissions	***t/year***	***4 911***	***6 138***	***7 366***

Scenario results excluding non-CO2 emissions from biomass combustion and CH4 from one week biomass decomposition

Scenario 1									
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012
Baseline emissions	125 264	123 360	121 266	119 172	117 268	115 174	113 080	111 176	109 082
Project emissions	22 466	22 466	22 466	22 466	22 466	22 466	22 466	22 466	22 466
Emission reduction	102 798	100 894	98 800	96 706	94 803	92 709	90 614	88 711	86 617

Scenario 2									
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012
Baseline emissions	156 580	154 200	151 582	148 965	146 585	143 968	141 350	138 970	136 353
Project emissions	28 058	28 058	28 058	28 058	28 058	28 058	28 058	28 058	28 058
Emission reduction	128 522	126 142	123 525	120 907	118 527	115 910	113 292	110 913	108 295

Scenario 3									
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012
Baseline emissions	187 896	185 040	181 899	178 758	175 902	172 761	169 620	166 764	163 623
Project emissions	33 650	33 650	33 650	33 650	33 650	33 650	33 650	33 650	33 650
Emission reduction	154 246	151 390	148 249	145 108	142 252	139 111	135 970	133 115	129 973

Scenario 1	Total ERUs	Total AAUs	Total
Year	2008-2012	2004-2007	2004-2012
Baseline emissions	565 781	489 061	1 054 842
Project emissions	112 328	89 862	202 190
Emission reduction	453 453	399 199	852 652

Scenario 2	Total ERUs	Total AAUs	Total
Year	2008-2012	2004-2007	2004-2012
Baseline emissions	707 226	611 327	1 318 553
Project emissions	140 289	112 231	252 519
Emission reduction	566 937	499 096	1 066 033

Scenario 3	Total ERUs	Total AAUs	Total
Year	2008-2012	2004-2007	2004-2012
Baseline emissions	848 671	733 592	1 582 263
Project emissions	168 249	134 599	302 849
Emission reduction	680 422	598 993	1 279 415

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