

Techno-Economic Assessment of a Biomass-Based Cogeneration Plant with CO₂ Capture and Storage

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Interim Report

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Techno-economic Assessment of a Biomass-based Cogeneration Plant with CO₂ Capture and Storage

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Abstract

Reduction of CO₂ emissions from energy systems could be achieved through: CO₂ capture and storage, energy savings, fuel switching among fossil fuels, increased use of renewable energy sources, and nuclear power. In addition, atmospheric CO₂ reduction could also be achieved through increasing the carbon stock in soils and standing biomass. The CO₂ capture and storage option for mitigating CO₂ emissions from biomass-based cogeneration plants, considering critical aspects such as future development of technologies, economies of scale, carbon price, site-specific analysis, and future energy systems has received little attention in scientific studies. With the overall objective of improved understanding of the potential scope for its large-scale implementation, a techno-economic assessment of biomass-based cogeneration plants with CO₂ capture and storage was carried out. Most of the above-mentioned critical aspects have been considered for the techno-economic assessment of cogeneration plants with CO₂ capture and storage technology.

The results show the optimal scale of the conversion systems with respect to cost of electricity (COE). The optimal size for steam turbine-based cogeneration (CHP-ST) technologies without CO₂ capture lies in the range 98–106 MWe (COE is 5.7 USD/MWh) when fueled by forest/logging residues, but the optimal size increases to 200–227 MWe for integrated gasification combined cycle based cogeneration (CHP-IGCC) (COE is 16.73 USD/MWh). The optimal size range increases considerably to 249–288 MWe (COE 15.70 USD/MWh) for Salix fueled CHP-ST technology without CO₂ capture and 441–504 MWe (COE 27.52 USD/MWh) for CHP-IGCC technology. With the additional feature of CO₂ capture, transport, and storage (here we assume 100 km CO₂ transport distance from the plant site) the unit capital cost for CHP-ST and CHP-IGCC technology increases around 70 and 30 percent, respectively.

If one considers revenues from trading emission quotas earned through negative emissions one can estimate a market price of CO₂ (PC) at which the COE becomes negative (i.e. all capital and operating costs are covered by revenues from heat and negative emissions delivered). Scale effects significantly influence the economic feasibility of CO₂ capture. According to the model calculation, the PC at which the COE becomes negative significantly drops from 75 USD/tCO₂ for 10 MWe CHP-ST plants to 32 USD/tCO₂ for 90 MWe CHP-ST plants when fueled by Salix. The PC drop from 65 USD/tCO₂ for 10 MWe CHP-ST plants to 25 USD/tCO₂ for 90 MWe CHP-ST plants when fueled by forest/logging residues. For CHP-IGCC plants, the PC decreases from 72.5 USD/tCO₂ for 30 MWe to 37.5 USD/tCO₂ for 170 MWe when fueled by Salix. When fueled by forest/logging residue, the PC decreases from 62.5 USD/tCO₂ for 30 MWe plants to 30 USD/tCO₂ for 170 MWe.

The techno-economic assessment was based on electrical capacity of the plants and revenues from cogenerated heat and captured CO₂ were credited. In practice, the implementation of any cogeneration systems are limited by the heat sink, where the cogeneration systems should be optimized based on site-specific context.

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Techno-economic Assessment of a Biomass-based Cogeneration Plant with CO₂ Capture and Storage

Noim Uddin

1 Objective

In Sweden, the use of biomass has doubled since the 1970s and today represents 16 percent of total primary energy use (SEA, 2003). The major fraction is used in forest-based industries (67 percent) and district heating systems (21 percent). Biomass utilization in the district-heating sector alone experienced a four-fold increase between 1990 and 1999, and notably the cost of forest fuel, such as logging residues, has been reduced by 50 percent since the mid 1980s. Cogeneration or combined heat and power production (CHP) is one way to reduce primary energy consumption and therefore be an effective option in retarding the environmental impacts. Here, a techno-economic assessment has been carried out for both CHP based on integrated gasification combined cycle (CHP-IGCC) and steam turbine technology (CHP-ST) technology when both systems are equipped with CO₂ capture and storage, which theoretically identify the biomass-based energy system as a negative CO₂ emitting system. The techno-economic assessment gives an overview of economic scale for biomass-based CHP-IGCC and CHP-ST conversion technology with CO₂ capture and storage facility with respect to the cost of electricity (COE).

2 Introduction

2.1 Background

Energy is central to achieving the interrelated economic, social, and environmental aims of sustainable development. Present global primary energy use is, however, strongly linked to environmental and health issues, in particular climate change, as more than three-quarters of global primary energy use is based on fossil fuels, and three quarters of the anthropogenic emissions of CO₂ is due to the conversion of these fuels.

The consensus on reducing oil consumption, as a result of the oil crisis in the 1970s, triggered an increased use of modern biomass-based energy systems globally. In addition, the growing concern about the environmental impact of fossil fuels has increased the interest in renewable resources, such as biomass-based energy systems. In 2000, renewable energy accounted for 14 percent of the world's primary energy use, with an annual growth of 2 percent over the last 30 years (IEA, 2002b). A number of

studies have assessed the potential contribution of biomass to the world's energy supply to be as much as 50 percent of the global energy demand in 2050, depending on land availability and future energy demand (Turkenburg, 2000). Hence, the potential reduction in greenhouse gas emissions is large when fossil fuels are replaced by sustainably produced biomass.¹ Although the risk of climatic impacts associated with fossil-based energy resources has been known for more than a century, the issue has only been in focus since the early 1990s.

Historically, forestry has played a major role in the economies of Northern Europe and particularly the Scandinavian countries. For example, the total export value of the forestry sector in Sweden amounted to around 10 billion USD in 1999 (FAO/UNCEC, 2001). About two-thirds of the total biomass supply in Sweden originates from forest-based industrial residues but logging residues, imported biomass, and domestic fuel wood are also important sources. Less than one percent of the total biomass supply originates from the agricultural sector. The energy potential of biomass in Sweden, apart from black liquors from the pulp and paper industry, is estimated to be around 125–175 TWh annually (SEA, 2003). Thus, the potential for increased use of biomass in Sweden is large, despite the fact that Sweden already uses more biomass for energy purposes than most other industrialized countries.

In Sweden, 65 percent of the total land area is covered with forest (compared to world average around 30 percent), of which 23 million hectares are classified as productive forest available for forestry. The timber resources within the sub-region of Northern Europe have developed steadily since the early 1900s (FAO/UNCEC, 2001), as a result of long-term silvicultural management and modest levels of felling. This is due to national forestry policies and forest acts, where the sustainable use of forests has been an important objective during most of the twentieth century. In Sweden, annual growth is currently about 100 million cubic meters, whereas felling accounts for only 70–75 million cubic meters. An estimate of the potential for biomass production from forest and arable land around 2015 is shown in Table 1 (Johansson, 1996).

Table 1: Estimated of biomass resources in Sweden by 2015.

Biomass resources	Biomass potential, production conditions 2015 (TWh/yr)
Energy crop alternatives	
Rape, seed and straw	4
Winter wheat, grain and straw	29
Reed canary-grass	36
Lucerne	45
Salix	59
Straw from food production	11
Forest/Logging residues	53–65
Industrial by-product	47–51

¹ Biomass, in broad terms, includes wood fuels, biomass-based industrial by-products, wood waste, and agricultural products but excludes municipal refuse and peat.

2.2 Complex Links between Energy and Environment

Environmental issues are strongly linked in complex and dynamic ways to production, distribution, conversion and use of energy carriers and have often been grouped into local, regional, and global problems. Historically, air pollution was seen as a local issue while acid rain, when recognized, was described as a regional problem. Climate change is one of the most well known global environmental issues. By using modern energy technologies, most of the local and regional impacts from fuel-based energy systems seem to be manageable. In contrast, climate change is a global, complex and multidimensional issue that must be addressed from a long-term perspective. Although the risk of climate change associated with the combustion of fossil fuels has been known for more than a century, the issue has only been in focus since the 1990s.

Implementation of the international agreements of United Nations Framework Convention on Climate Change (UNFCCC) in 1992 and the Kyoto Protocol of 1997 is an important first step in the reduction of greenhouse gas (GHG) emissions through international agreements. Although implementation of the Kyoto Protocol is complex, several possibilities exist for the reduction of GHG emissions. Reduction of CO₂ emissions from energy systems could be achieved through: CO₂ capture and storage, energy savings, fuel switching among fossil fuels, increased use of renewable energy sources, and nuclear power. Most of these options are applicable for stationary energy and industrial infrastructures. In addition, atmospheric CO₂ reduction could also be achieved through increasing the carbon stock in soils and standing biomass. Like most of the renewable energy resources, sustainably produced biomass will significantly reduce the specific long-term net CO₂ emissions, since the CO₂ released during the combustion of biomass is normally equal to the amount absorbed from the atmosphere by the forest over time. In addition, negative CO₂ emissions could be achieved from biomass systems through CO₂ capture and storage in large-scale biomass-based energy systems, such as large cogeneration (CHP) plans (Möllersten *et al.*, 2003).

Biomass-based energy systems include different conversion routes to produce heat, electricity and fuels. The implementation of biomass-based energy systems conversion technologies is site and country (rich in biomass resources) specific. Small-scale or traditional conversion technologies are fairly common in developing countries where conventional biomass or forest resources are usually sufficient to meet local energy demand. In some developed countries, environmentally sound energy systems are beginning to be common, and advanced biomass-based conversion technologies are evolving, especially in the area of heat and electricity production. New technologies, such as CO₂ capture and storage may change the preconditions of biomass-based energy systems strategies. Substituting biomass for fossil fuels in the electricity and heat sectors appears to be more cost efficient and provides a larger reduction per unit of biomass than would be the case if biomass were substituted for fossil fuels in the transportation sector (Gustavsson *et al.*, 1995).

2.3 Biomass-based Cogeneration (CHP)

Cogeneration or CHP are defined as the sequential generation of two different forms of useful energy from a single primary energy source, typically mechanical energy and

thermal energy. CHP is possible with all heat machines and fuels from a few kW-rated to 1000 MW steam-condensing plants but the potential of CHP could be restricted due to the constraint of necessary heat demand. The biomass-based energy systems for heat and power production, in general, comprise either a single-step (such as large-scale cogeneration systems district heating system) or two-steps (such as combination of biomass-based power and heat-pump) conversion technologies (Karlsson, 2003). Excess electricity production from cogeneration would be supplied to electric utilities and credited. Moreover, a heat-distribution network is necessary.

The conversion technologies based on CHP and fueled by biomass include:

- Biomass-based Steam Turbine technology (CHP-ST); and
- Biomass-based Integrated Gasification Combined Cycle technology (CHP-IGCC).

Important technical parameters for cogeneration plants include: heat-to-power ratio, availability of fuels, quality of thermal energy needed, load patterns, systems reliability, grid dependent systems versus independent systems, retrofit versus new installation, electricity buy-back, and local environmental regulations (UNESCAP, 2000). Heat-to-power ratios and other parameters of cogeneration systems are given in Table 2.

Table 2: Heat-to-power ratios of cogeneration plants (UNESCAP, 2000).

Cogeneration systems	Heat-to-power ratio (kWth/kWel)	Power output (as percent of fuel input)	Overall efficiency (percent)
Back-pressure steam turbine	4–15	14–28	84–92
Extraction-condensing steam turbine	2–10	22–40	60–80
Gas turbine	1–2	24–35	70–85
Combined cycle	1–2	34–40	69–83
Reciprocating engine	1–3	33–53	75–85

Typical CHP-ST technologies include extraction/back pressure steam turbines, gas turbine with heat recovery steam generator (HRSG — with or without bottoming steam turbine), and reciprocating engines with HRSG. Typical CHP-IGCC systems are a set of integrated gasifier and gas turbine technology, which offers the potential of low unit capital costs and high thermodynamic efficiency at modest scales. The high efficiency of cogeneration (up to 90% or more) and efficient use of fuel compared with stand-alone power conversion systems results in a significant reduction of CO₂ emission and can therefore be an effective GHG mitigation option (IPCC, 2001). However, cogeneration can have environmental implications in the form of CO, SO₂ and NO_x emissions to the atmosphere. The quantity of each of the pollutant generated depends largely on the type of fuel used and the characteristics of the cogeneration technology adopted.

Most of the existing Swedish cogeneration plants are CHP-ST technology and wood fueled. A detailed survey by Wahlund (2003) gives an overview of fourteen

cogeneration plants in Sweden. The electrical capacity varies from 2 MWe to 39 MWe with the electrical efficiency of 20–30 percent and the systems configuration includes steam turbine with different combustion boilers (centrifugal fluidized, boiling fluidized bed, grate-fired type). The specific investment costs are much higher for smaller plants (typically USD 2390/kWe); whereas they are significantly lower for larger plants (typically USD 1690/kWe). Finland experienced the largest biomass-fired CHP-ST plant of 240 MWe with annual electricity and heat production of 700 GWh and 1300 GWh, respectively (Alholmens Kraft, 2002). Larson and Marrison (1997) reported ten or more BIG/GTCC commercially oriented demonstration projects worldwide. The development of efficient BIGCC is nearing commercial realization, several pilot and demonstration projects have been evaluated with varying degree of success (IPCC, 2001). Capital investment of a high pressure, direct gasification combined-cycle plant of the pilot and demonstration scale is estimated to fall from over USD 2000/kWe to around USD 1100/kWe by 2030 (IPCC, 2001). Sweden experienced the world's first cogeneration plant based on biomass integrated gasification combined cycle (BIGCC) technology in Värnamo with a 6MWe/9MW heat capacity in 1996 (Larson and Marrison, 1997). The United Kingdom experienced an air-blown circulating fluidized bed gasifier operating at atmospheric pressure will generate 10 MWe, the Arable Biomass Renewable Energy (ARBRE) project (VTT, 2001).

The large-scale conversion technologies considerably affect primary energy use, emissions and the cost of the energy systems to a certain extent. Scale effects within biomass-based energy systems are very significant for both their energetic and economic performance. Dornburg and Faaij (2001) concluded that at the scale ranges 0.1–300 MWth-input, the relative primary energy savings, i.e., the primary energy saved per unit of biomass energy input, generally improve with increasing scales and the total costs per unit of primary energy saved mostly decrease with increasing scale. The study by Larson and Marrison (1997), examined the BIG/GTCC power production facility in the US and Brazil and concluded that with pressurized BIG/GTCC, the optimum capacity ranges from 230–320 MWe. Here, the optimum capacity was defined as that which yields the minimum calculated cost of electricity (COE). For atmospheric pressure BIG/GTCC power production facility, optimum plant facility ranges from 110–142 MWe. Cameron *et al.* (2002) studied three different biomass resources and economic plant size with respect to power price in Western Canada and concluded that forest harvest residue have the smallest economic size of 137 MW and highest power costs USD 63/MWh. The optimum size for agricultural residues is 450 MW and the power cost is USD 50/MWh, and if it were possible to build a larger boiler, the optimum size for straw would be 628 MW, whereas the whole forest (see details in Cameron *et al.*, 2002) showed a very large optimal size up to 900 MW without considering nutrient replacement.

None of the above-mentioned studies have been carried out on cogeneration, where the selection of a cogeneration plant is based on the heat sink. Also, with an additional CO₂ capture and storage facility a theoretically carbon neutral biomass-based energy system would be a negative CO₂ emitting energy system. The capture of CO₂ from the flue gases of fossil fuels and its disposal, for example exhausted gas or oil wells, is being actively investigated in a number of countries. The use of CO₂ capture and storage technology will, however, lead to reduced energy efficiency and higher investment cost.

3 Methodology

The overall methodology for this techno-economic assessment followed the following steps:

- A review of literature on biomass-based CHP and the selection of different scales of conversion plants;
- Identifying parameters that will serve for the comparison of biomass-based energy systems with and without CO₂ capture and storage;
- Assessment of scale effects on specific investment costs, CO₂ capture and storage, biomass-supply needed, and related biomass cost with respect to transporting distances; and
- Assessment of electricity generating cost (COE), which is a function of specific investment cost, biomass-supply needed, biomass transportation distance, plant capacity factor, and heat-to-power ratio.

The methodology in the techno-economic work resembles a well-to-wheel approach of energy systems chain. The costs and resources use in every step of the energy chain (production, transportation and conversion) has been considered. In-terms of GHG emission only CO₂ emissions have been taken into consideration from the conversion processes. The modeling work begins with analyzing the supply of biomass to centrally located cogeneration plants, assessing the performance of alternative cogeneration plants; and ends with the determination of COE with and without the CO₂ capture option. The specific investment costs of CHP plants were estimated using literature data and a simple curve fitting method. The detailed calculations for optimal sizing of cogeneration systems are based on spreadsheet calculation, which is a linear and static modeling approach. The cost of biomass (production, transportation) was estimated from a literature review. Due to the unavailability of data on the cost of CO₂ capture, transport and storage, a model based on pipeline data was applied. The techno-economic assessment has been concluded by using spreadsheet calculations for estimating the COE when CHP plants were integrated with a CO₂ capture, transport and storage facility.

4 Models and Assumptions

The choice of biomass resource with its respective production, extraction, and transportation characteristics has implications for the suitable scale of biomass-based cogeneration systems. A large-scale system requires a higher biomass feedstock volume than smaller systems, which generally elevates the average cost of fuel transportation while a higher supply volume has lower transactional costs. In contrast, increasing scale reduces unit capital cost and the specific cost of CO₂ transportation and storage. In this techno-economic assessment, the conversion systems were assumed to be located near the heat load center and also to be centrally placed in a biomass production area. Salix and forest/logging residues were chosen as two biomass feedstock alternatives. Biomass transportation to the conversion plant was assumed to be carried out by truck. Data for fuel supply cost and cogeneration technologies' performance and capital costs were gathered from literature. The performance and capital cost of cogeneration plants with CO₂ capture were estimated using the Matlab code and literature data. The state-of-the-

art CHP technologies based on steam turbine (CHP-ST) and integrated gasification combined cycle (CHP-IGCC) have been considered. The analysis considers Salix and forest/logging residues as feedstock to a centrally located CHP plant and biomass transportation was by truck. A simple curve-fitting method was used to construct a model describing the specific capital cost of the analyzed cogeneration plants as a function of capacity. Alternative models for the calculation of CO₂ transportation and storage costs were assessed and one selected to be used in the present techno-economic evaluation. Finally, a model was developed for techno-economic assessment considering scale, fuel supply cost, specific investment costs and technical performance of cogeneration plants, and CO₂ transportation and storage costs. The models and assumptions applied are described in more detail below.

4.1 Plant Performance

Cogeneration plants were assumed to have constant performance regardless of size. Two cogeneration technologies were investigated; combined heat and power based on biomass boilers and steam turbine technology (CHP-ST) and biomass-integrated gasification combined cycle technology (CHP-IGCC), respectively. The steam turbine-based CHP systems were based on a biomass boiler producing super-heated high-pressure steam at 140 bar/540°C. The return temperature of the district heating water was assumed to be 70°C and the temperature of the hot water leaving the plant 100°C. In the case of steam turbine-based cogeneration, the analysis assumes post-combustion CO₂ capture by chemical absorption from flue gases. The heat consumption for regeneration of chemical absorbent was assumed to be 2.9 MJ/kgCO₂ captured. Table 3 presents the assumed performance of a steam turbine-based cogeneration plant.

Table 3: Performance of CHP-ST.

Plant type	Electrical efficiency (%) ^a	Total efficiency (%) ^b	Carbon capture ratio (%) ^c
Steam turbine CHP	30	90	0
Steam turbine CHP with post-combustion CO ₂ capture	23	57	90

^a Net electricity delivered/Fuel in.

^b Net electricity delivered + Net heat delivered/Fuel in.

^c Carbon captured/carbon in fuel.

The assumed technology for the studied CHP-BIGCC cases is pressurized, oxygen-blown gasification with an option for pre-combustion CO₂ capture. When the CO₂ capture option is applied in the BIGCC case, the producer gas undergoes a water-gas shift reaction in a CO-shift reactor downstream gasifier whereby CO is reacted with water to form CO₂ and H₂. The formation of additional CO₂ in the CO-shift reactor raises the fraction of the fuel's carbon content, which can be captured. CO₂ is separated from the shifted gas through physical absorption, which is a suitable process for gas streams at elevated pressures and CO₂ concentrations. Capture of CO₂ induces energy losses in the system and thus reduction in efficiency. Since the physical solvent is regenerated by pressure reduction, the main energy requirement for physical absorption

is to pump physical absorbents. The work consumed for CO₂ absorption depends on the partial pressure of the CO₂ in the gas mixture. In this study the work required was assumed to be 0.14 MJ/kgCO₂ captured. In all cases with CO₂ capture, the CO₂ is compressed to 80 bars, which consumes 0.12 kWh_e/kgCO₂. The CO₂-lean syngas is used to fuel a combined cycle for power generation. Table 4 presents the assumed performance of a CHP-BIGCC cogeneration plant.

Table 4: Performance of CHP-BIGCC.

Plant type	Electrical efficiency (%) ^a	Total efficiency (%) ^b	Carbon capture ratio (%) ^c
CHP-BIGCC	43	86	0
CHP-BIGCC with pre-combustion CO ₂ capture	37	81	90

^a Net electricity delivered/Fuel in.

^b Net electricity delivered + Net heat delivered/Fuel in.

^c Carbon captured/carbon in fuel.

4.2 Specific Investment Costs

The total installed unit capital cost (UC in USD per unit capacity) for an energy conversion plant can be assumed to vary with capacity (Cap) as follows (based on Larson and Marrison, 1997):

$$UC = C + D * (Cap)^E$$

where C, D, and E are constant for a given configuration that is determined from available cost projections; E is a negative unit, i.e., unit cost falls with increasing capacity; and C corresponds to the unit cost that is reached asymptotically at a large scale.

The values of D and E are calculated based on the following equations:

$$D = (\text{UnitCost}_1 - C) / \text{Capacity}_1^E$$

where $E = \{\log ([\text{UnitCost}_1 - C] / [\text{UnitCost}_2 - C])\} / \{\log (\text{Capacity}_1 / \text{Capacity}_2)\}$; Capacity₁ and Capacity₂ are the two other plant sizes, and UnitCost₁ and UnitCost₂ are their respective unit costs.

The specific investment costs for the CHP-ST and CHP-IGCC plants with and without the CO₂ capture option were calculated based on the above mathematical expression. Data concerning biomass-based cogeneration plants with CO₂ capture were not available from the literature. Instead, data for conversion plants without CO₂ capture were combined with estimated costs for the additional components necessary. In the estimation of the capital cost for components in the plants with a CO₂ capture option it was necessary to adjust cost data from the literature for size. One typical way of doing this, which was followed in this work, is to assume that investment costs per unit is a function of scale is given by:

$$I_1 = I_0 * (C_1/C_0)^R$$

where I_k is the investment cost per unit; C is the capacity; Index 0 and 1 refer to two different plants; and R determines how fast the cost per unit increases with size (Remer, 1990; Jenkins, 1997). For R , the value 0.7 was used.

Table 5 presents the estimated capital costs of CHP-ST and CHP-IGCC with and without CO₂ capture and storage.

Table 5: Unit capital costs for selected cogeneration plants.

Plant Type and Capacity	Unit Investment Costs (USD/kWe) with out CO ₂ capture, transport and storage	References	Estimated Unit Investment Costs (USD/kWe) with CO ₂ capture
CHP-ST 10 MWe	2350	Energimyndigheten (2000)	4550
CHP-ST 30 MWe	1790	Energimyndigheten (2000)	3090
CH-ST 80 MWe	1330	Energimyndigheten (2000)	2330
CHP-BIGCC 30 MWe	2671	Naringsdepartementet, (1995); Lehtila and Tuhkanen (1999)	3300
CHP-BIGCC 60 MWe	1820	Gustavsson and Börjesson, (1998)	2300
CHP-BIGCC 136 MWe	1190	Craig <i>et al.</i> (1994) ^a	1600

^a Craig *et al.* (1994) is based on a power plant. The data was used as the basis for calculations of a CHP plant.

4.3 Costs of Biomass Extraction

Suitable biomass resources for power and heat production are short-rotation forests such as Salix, forest/logging residues, reed canary grass, and straw. Larger plants require more biomass feedstock. Also, cogeneration or poly-generation facilities result in comparatively lower electrical efficiency and higher heating efficiency, which corresponds to higher biomass-feedstock input.

The productivity of perennial crops (willow, eucalyptus, switch grass) varies between 8 to 12 tons of dry mater (TDM) per year (Turkenburg, 2000). The potential biomass yield for Salix is high in Sweden as yields up to 30 dry ton/ha/year (480 GJ/ha/year) have been achieved from commercial Salix clones with optimized fertilization combined with irrigation. Energy yields and energy use for biomass production are given in Table 6 according to Börjesson and Gustavsson (1996).

Higher yields together with improved energy efficiency in the use of motor fuels and energy used in production of, e.g., seeds, fertilizers, pesticides and machinery, may result in a 30–45 percent lower primary energy use per unit biomass produced for fossil-based energy inputs by 2015.

Table 6: Energy yields and primary energy use for different biomass production.

Biomass resources	Energy yield GJ/ha, yr	Primary energy use GJ/ha, yr
Reed canary crops	110	8.9
Salix	150	6.3
Straw	30	1.1
Forest/Logging residues	13	0.51

The biomass production costs are thus assumed to be reduced in the future by 20–39 percent due to improved cultivation, and recovery methods resulting in, for example, lower labor, machinery; fuel, commercial fertilizer and pesticides requirements per GJ biomass produced. The production costs of different biomass in central Sweden by using fossil-fuel-based systems (all machinery used are running on diesel fuel) are in Table 7 according to Börjesson and Gustavsson (1996).

Table 7: Biomass production cost.

Biomass resource	Soil preparation and sowing	Fertilizing and pesticide application	Recovery and harvesting operations	Administration and compensation to land owner	Total USD/GJ
Reed canary grass	0.51	1.7	1.3	1.1	4.6
Salix	0.78	1.6	0.57	1.1	4.1
Straw	-	-	1.8	0.76	2.6
Forest/Logging residues	-	0.15	2.2	0.58	2.9

A biomass conversion facility accepting feedstock from a surrounding region may be shown to have an optimum size when the assumption of a positive economy of scale (decreasing cost with increasing size) in capital and non-fuel operating costs is combined with an increasing delivered fuel cost as the facility size increases. If the biomass conversion facility is centrally located in a rectangular space, the cost of biomass transportation is dependent on the maximum axial distances from conversion facility to biomass production site (Jenkins, 1997). For a centrally located biomass facility in a circular space, the transportation cost of biomass is directly proportional with the cubic power of the transportation distance (Nguyen and Prince, 1996). The cost of biomass delivery to a conversion plant site includes the cost of biomass production, and the cost of biomass transportation with the additional cost of biomass loading and unloading associated with transportation. The cost of biomass transportation depends on the transportation distance and the mode of transport. Costs for transportation of different biomass by different transportation mode are given in Table 8 based on Börjesson and Gustavsson (1996).

Based on different literature reviews, the cost function for biomass transportation in a centrally located plant were chosen from Börjesson and Gustavsson (1996) for Salix and forest/logging residues as biomass feedstock as given below. The transportation mode was considered for both cases by truck.

Table 8: Biomass transportation cost as function of transportation distance (d) in km.

Biomass resource	Tractor USD/TJ	Truck USD/TJ	Train USD/TJ	Boat USD/TJ
Reed canary grass	373+22*d	880+4.7*d	1900+0.71*d	1400+0.31*d
Salix	280+16*d	420+9.4*d	860+1.4*d	1000+0.63*d
Straw	520+29*d	1200+6.3*d	2700+0.90*d	2100+0.39*d
Forest/Logging residues	230+13*d	350+7.9*d	740+1.1*d	850+0.45*d

The cost function (USD/TJ) of Salix transportation by truck to a centrally located plant is:

$$420+9.4*d$$

where d is the transportation distance in km.

The cost function (USD/TJ) of forest/logging residues transportation by truck to a centrally located plant is:

$$350+7.9*d$$

where d is the transportation distance in km.

The transactional costs also have implications on biomass cost at a conversion facility site since a large-scale biomass conversion facility needs a higher volume of biomass-feedstock, which subsequently decreases the transactional costs. This component has not been considered in this techno-economic assessment.

4.4 Emissions of CO₂ and Cost of CO₂ Transportation and Storage

CO₂ emissions for a typical coal-fired power plant are in the range 130–260 kg CO₂/second (500–1000 MWe) and typical natural gas-fired power plants can be expected to emit half as much per second. A biomass-based conversion facility is often thought of as small-scale technology. Most of the biomass-based conversion facility in the world is currently used in traditional ways (for cooking), which is inherently very small-scale. One might expect small-scale uses to continue to be important, e.g., residential heating where the biomass is burnt as wood fuel or pellets. Under these conditions, scale considerations rule out CO₂ capture and storage from biomass because of high costs. However, there are larger sized operations in use, and these can be expected to become even more important in the future. Currently, pulp mills are major sources of CO₂, as are district heating plants and CHP plants (Möllersten *et al.*, 2003). For instance, a typical chemical pulp mill may produce 1500–3000 tons of pulp per day, which corresponds to 36–72 kg CO₂/second from biomass-based black liquor and bark. District heating plants, for example, would be the size of 10–100 MW, heat results with CO₂ emissions ranging from 1–10 kg CO₂/second at full capacity if fed with biomass. CO₂ capture and storage from natural-gas-based systems could reduce the CO₂ emission by about 70 percent, while in a biomass-based system the net CO₂ emission would be

negative. Cogeneration could probably improve the economic feasibility of biomass energy with CO₂ capture and storage because multiple product systems raise the total biomass fuel feed and, thus, increase the CO₂ emissions rate.

Because of the large volumes of captured CO₂ from large-scale plants, pipelines are the leading option for the transportation of CO₂ to a storage location once it has been captured. Transportation of CO₂ can best be done in the supercritical state with pressures in the range of 80 to 140 bars. The compression and pipeline transportation of CO₂ is feasible and technically proven through several commercial enhanced oil recovery projects (Holloway, 2001). In addition, the use of large tankers might be economically attractive for long-distance transportation of compressed/liquefied CO₂ over water.

Models for estimating the cost of CO₂ transportation and storage have been presented by the IEA GHG R&D Program (IEA, 2002a) and Ogden (2002), respectively. The IEA model is a calculation tool, which estimates capital cost, fixed and variable operating costs for the pipelines and injection wells, as well as booster compressor requirements.² Ogden (2002) presents a cost function based on published pipeline data. The model represents the pipeline capital cost per unit length in terms of the flow rate Q and the pipeline length L with the equation:

$$C_{\text{pipeline}} \text{ (USD/m)} = \text{USD } 700/\text{m} * (Q/Q_0)^{0.48} * (L/L_0)^{0.24}$$

where Q₀ = 16 000 t/day; L₀ = 100 km; and, furthermore, the installed capital cost per injection well with the equation :

$$C_{\text{inj. well}} \text{ (USD/well)} = \text{USD } 1.6 \text{ million} * \text{well depth (km)} + \text{USD } 1.25 \text{ million.}$$

The economies of scale of CO₂ transportation and storage using the two models were investigated. The costs of transportation and storage were calculated for a set of CO₂ flow rates and transportation distances. CO₂ injection is assumed to take place in on-shore wells with negligible seepage back to the atmosphere and the depth of the injection wells was set to 1000 m. A practical upper limit on the injection rate per well was taken to be 50 kg CO₂/second. Capital costs were annualized using an interest rate of 8 percent and a plant life of 25 years. The IEA model enables the setting of geographical location of the project, which was selected to Europe, representing an average to high cost level in the model. Furthermore, the terrain was assumed to be cultivated land, representing an average cost level in the model. The results of the cost assessment are presented in Figure 1; showing costs normalized to USD/tCO₂ as a function of transportation distance. Costs calculated with the IEA (2002a) model are shown with a dotted line and the results from Ogden (2002) with a line. To be conservative in the techno-economic assessment in the present report the Ogden model was chosen to estimate the cost of CO₂ transportation and storage.

For a CO₂-generating facility in a coastal location Ekström *et al.* (1997) estimated the cost for CO₂ transportation and injection using a tanker at 17 USD/ton CO₂. A 700 km transportation distance, infrastructure for loading and intermediate storage of the CO₂,

² Booster compressors assure that the CO₂ stays in a liquid phase all the way along the pipeline.

and a CO₂ production rate of approximately 20 kg/second was considered. Since the cost of CO₂ transportation by tanker is quite insensitive to the transportation distance and the rate of CO₂ production, this value may be considered as a cap on the transportation and storage cost for projects allowing for transportation over water.

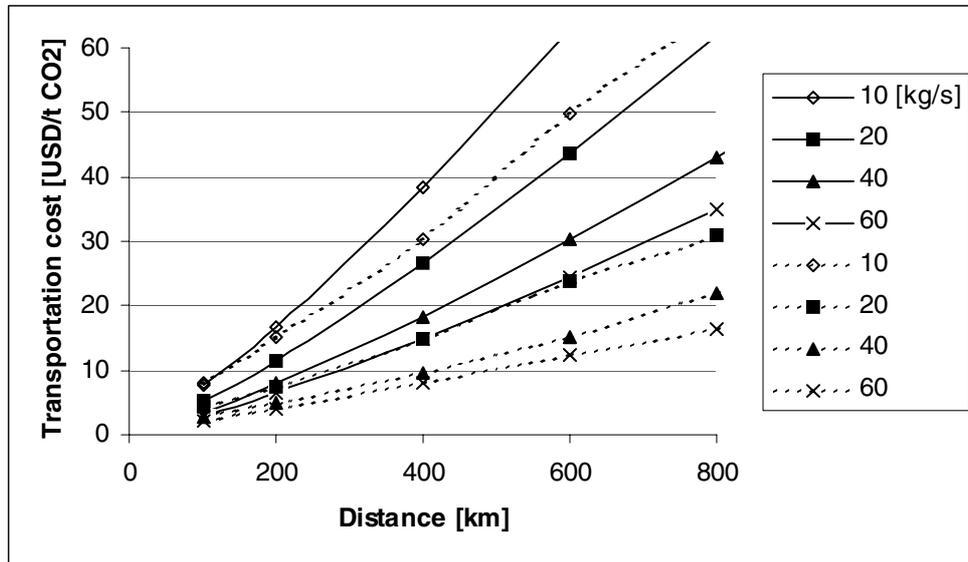


Figure 1: CO₂ transportation cost in varied distances.

An important consideration is that the cost assessment used in the present report assumes dedicated single pipelines for each project. If a CO₂ grid with trunk pipelines becomes a reality, similar to the case for natural gas, allowing numerous CO₂ emitting point sources to be connected to a CO₂ transport network, the average scale of the transportation system would increase thus decreasing the average cost. For example, the cost of transporting CO₂ 5000 km in large-diameter pipelines has been estimated at 25 USD/ton CO₂ (IEA, 2002a).

4.5 Annual Operating Costs

The annual operating cost of a plant is a function of plant capacity, biomass requirement as feedstock of the conversion plants, biomass transportation distance, mode of biomass transportation, specific investment cost of the plant, annual capacity factor, heat-to-power ratio (2 for CHP-ST, and 1 for CHP-IGCC) since the price of produced heat were credited, and cost of CO₂ transportation and storage. A cost function, which expresses the annual operating costs of a plant, C (USD/year) would look like this:

$C = \text{annualized capital costs} + \text{annual operation and maintenance (O\&M) costs} + \text{annual biomass costs} - \text{annual revenue of heat} + \text{annual sequestration costs of CO}_2 - \text{revenue from sequestered CO}_2.$

The above equation could be presented as follows:

$$C = (SCC)*(Cap)*0.11 + (SSC)*(Cap)*0.04 + (\alpha)*8760*(BM)*(P_{BM}) - H_{out}*P_H + C_{seq}*seq.cost - C_{seq}*PC$$

where

SCC is the specific capital cost, USD/kWe and the incremental capital costs were annualized by using 8 percent interest rate. And the incremental annual O&M cost is 4 percent of the incremental capital costs;

Cap is the capacity of plant, kWe;

α annual capacity factor;

8760 is the number of hours in one year;

0.11 is the annual capital charge factor;

BM is the biomass requirement, kW;

P_{BM} is the price of biomass, USD/kWh;

H_{out} is the annual heat delivered, kWh;

P_H is the price of heat, USD/kWh;

C_{seq} is annually CO₂ put in storage, tCO₂/year;

seq.cost is the cost of transporting and injecting the captured CO₂ to permanent storage, USD/tCO₂; and

PC is the market price of CO₂, USD/tCO₂.

4.6 Cost of Electricity (COE)

Electricity generating cost is commonly used as an indicator for the calculation/evaluation of the expected economy of biomass-based energy systems with or without CO₂ capture and storage compared to conventional systems and/or among different combination technologies of biomass-based energy systems. The calculation of electricity generating costs is based on an annuity method. In operating a stationary energy generation facility different kinds of expenses are associated, which are dependent on capital, consumption, operation and further payments with periodically and non-periodically incurred costs. The COE is defined as:

$$COE = C \text{ (USD/year)} / E_{out} \text{ (MWh/year)}$$

where E_{out} is the annual electrical output (MWh).

5 Optimal Sizing of Biomass-based Cogeneration

The techno-economic assessments performed indicate the optimal scale of the conversion systems with respect to COE when the conversion systems integrated with CO₂ capture, transport and storage option. The optimal size of CHP-ST varies between the ranges of 98–106 MWe (COE is 5.7 USD/MWh) when fueled by forest/logging residues without CO₂ capture, transport, and storage, and 150 MWe (COE is 27.75

USD/MWh), when CO₂ is captured, transported 100 km and stored. The optimal size range considerably increases with Salix fueled CHP-ST from 249–288 MWe (COE is 15.70 USD/MWh) without CO₂ capture, transport, and storage and 310–330 MWe (COE is 37.24 USD/MWh) when CO₂ is captured, transported 100 km and stored. The optimal size for CHP-IGCC varies between the ranges of 200–227 MWe (COE is 16.73 USD/MWh) when fueled by forest/logging residues without CO₂ capture, transport, and storage, and 210 MWe (COE is 23.25 USD/MWh) when CO₂ is captured, transported 100 km and stored. The optimal size range considerably increases with Salix fueled CHP-IGCC from 441–504 MWe (COE is 27.52 USD/MWh) without CO₂ capture, transport, and storage and 410–450 MWe (COE is 29.81 USD/MWh) when CO₂ is captured, transported 100 km and stored.

If one considers revenues from trading emission quotas earned through negative emissions, one can estimate a market price of CO₂ (PC) at which COE becomes negative (i.e., all capital and operating costs are covered by revenues from heat and negative emissions delivered). Scale effect significantly influences that PC as shown in Figures 2, 3, 4, and 5. According to the model calculation, the PC significantly drops from 75 USD/tCO₂ for 10 MWe CHP-ST plants to 32 USD/tCO₂ for 90 MWe CHP-ST plants when fueled by Salix. The PC drops from 65 USD/tCO₂ for 10 MWe CHP-ST plants to 25 USD/tCO₂ for 90 MWe CHP-ST plants when fueled by forest/logging residues. For CHP-IGCC plants, the PC decreases from 72.5 USD/tCO₂ for 30 MWe to 37.5 USD/tCO₂ for 170 MWe when fueled by Salix. When fueled by forest/logging residue, the PC decreases from 62.5 USD/tCO₂ for 30 MWe plants to 30 USD/tCO₂ for 170 MWe.

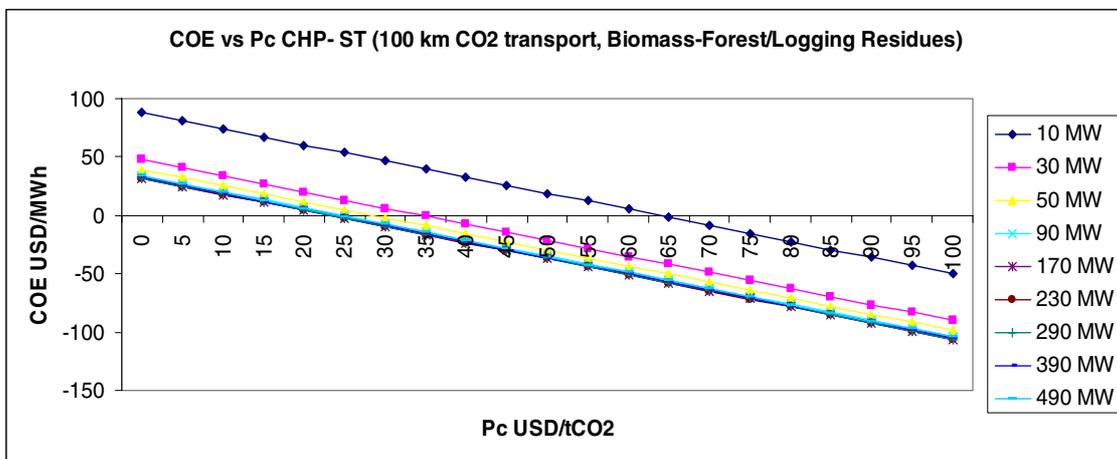


Figure 2: COE vs PC (CHP-ST, 100 km transport of CO₂ and biomass forest/logging residues).

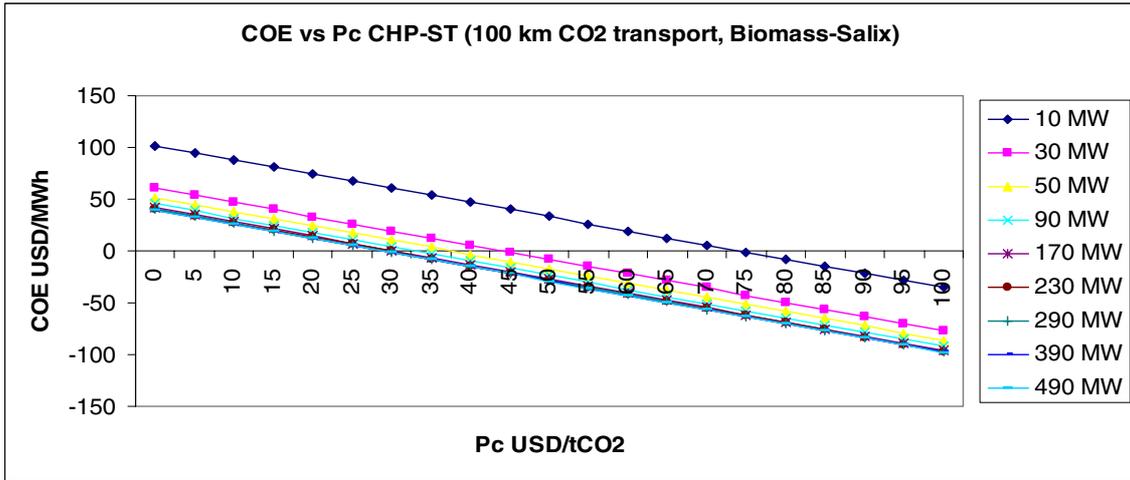


Figure 3: COE vs PC (CHP-ST, 100 km transport of CO₂ and biomass Salix).

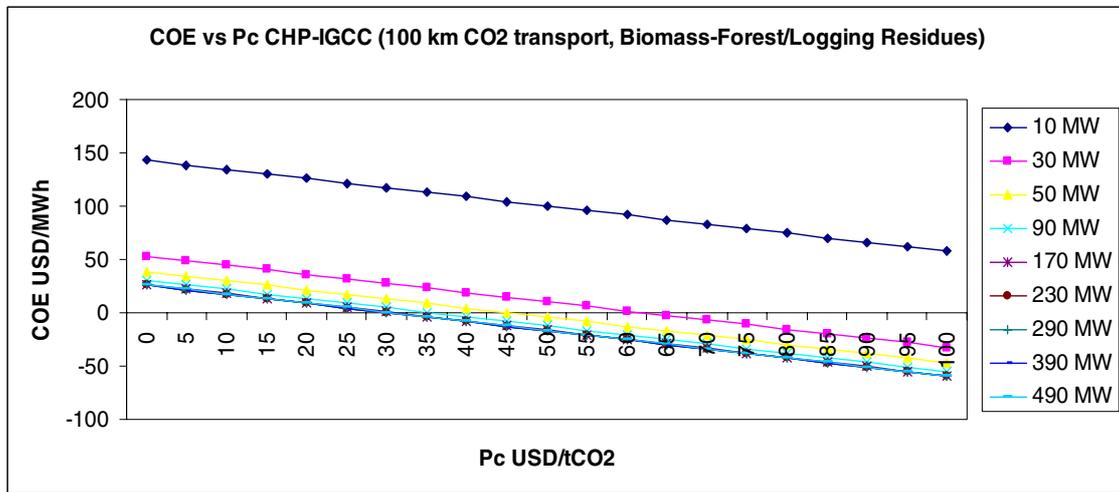


Figure 4: COE vs PC (CHP-IGCC, 100 km transport of CO₂ and biomass forest/logging residues).

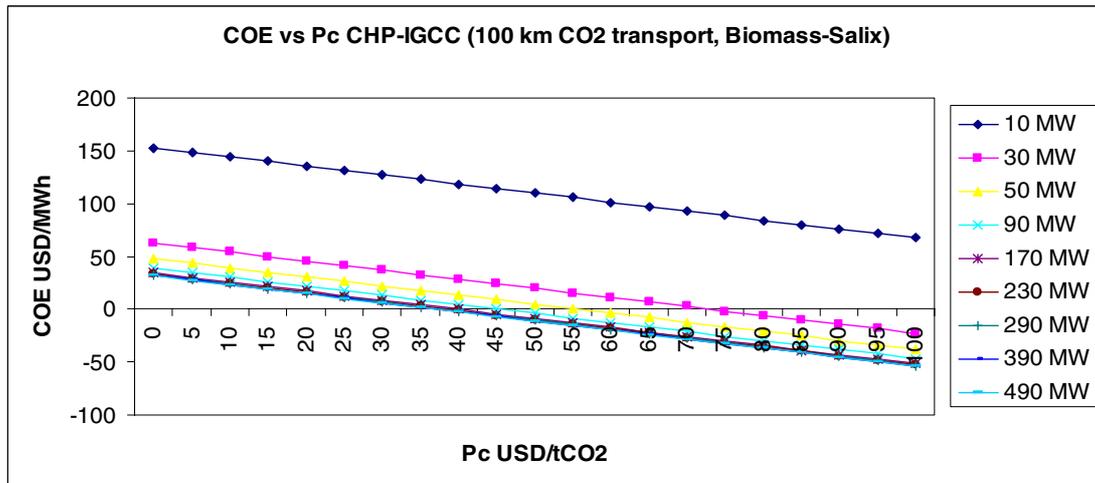


Figure 5: COE vs PC (CHP-IGCC, 100 km transport of CO₂ and biomass Salix).

6 Discussion

For the different conversion systems a comparison of three important parameters, costs, environmental impacts, and resource use should be considered; here, the analysis is based on cost parameter. Here, a 100 km distance from the plant site was chosen for CO₂ transportation and storage. A similar assessment should also be carried out for a range of CO₂ transport from 100–1000 km. The feedstock — Salix productions were based on sustainable cultivation and forest/logging residues from sustainably managed forest. The techno-economic assessment was based on the electrical capacity of the plants and revenues from cogenerated heat and captured CO₂ were credited. In practice, the implementation of any cogeneration system is limited by the heat sink, where the cogeneration systems should be optimized based on site-specific context. A further study would be called for taking into consideration the transactional costs for feedstock handling related to large biomass-based cogeneration facility; comparison of electricity prices when comparing two different technologies that do not have the same magnitude of heat output because of different heat-to-power ratio; several possible CO₂ transportation distances, mode of transport and storage options; and also possibilities of other feedstock.

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