Carbon Emissions Reduction Potential in the US Chemicals and Pulp and Paper Industries by Applying CHP Technologies.

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ABSTRACT

The chemical and the pulp/paper industries combined provide 55% of CHP generation in the US industry. Yet, significant potential for new CHP capacities exists in both industries. From the present steam consumption data, we estimate about 50 GW of additional technical potential for CHP in both industries. The reduced carbon emissions will be equivalent to 44% of the present carbon emissions in these industries. We find that most of the carbon emission reductions can be achieved at negative costs.

Depending on the assumptions used in calculations, the economic potential of CHP in these industries can be significantly lower, and carbon emissions mitigation costs can be much higher. Using sensitivity analyses, we determine that the largest effect on the CHP estimate have the assumptions in the costs of CHP technology, in the assumed discount rates, in improvements in efficiency of CHP technologies, and in the CHP equipment depreciation periods. Changes in fuel and electricity prices and the growth in the industries' steam demand have less of an effect. We conclude that the lowest carbon mitigation costs are achieved when the CHP facility is operated by the utility and when industrial company that owns the CHP unit can sell extra electricity and steam to the open wholesale market. Based on the results of our analyses we discuss policy implications.

Introduction

Recent studies (Onsite, 1998, Kaarsberg, Elliott, 1998) identified combined production of heat and power (CHP)[1] as one of the most important technologies for improving energy efficiency and reducing carbon emissions in the US.

CHP uses energy from fuels to both provide useful thermal energy and produce electrical power. Historically, it was used by industrial facilities with large steam requirements as a way to provide process steam more efficiently and economically. CHP is especially attractive in industries with constant steam loads and those that generate byproduct fuels. Chemicals and pulp/paper industries are the two largest industries dominating the CHP market. Combined CHP capacity in these two industries in 1994 was 24.2 GW – 55% of the total industrial CHP capacity (GRI, 1997). Currently, CHP capacity in both industries has been realized mostly at the sites with high steam loads. However, significant potential still exists at the remaining sites (Onsite, 1998, Onsite, 1997).

The purpose of this paper is to estimate the remaining CHP potential in the chemicals and pulp/paper industries by capacity size, and estimate energy savings and associated costs of carbon emission reductions by applying CHP technologies.

Assessment of the technical potential of CHP is a difficult task that requires plant-level data to match boiler characteristics, steam and electricity loads of industrial plants with the technical specifications of CHP technologies (Blok, Turkenburg, 1994). Evaluating economic potential of CHP

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[1] Also called cogeneration.

and costs of carbon reduction is even more complex. This evaluation involves uncertainties in forecasting future fuel prices, difficulties in estimating carbon burden of existing and planned CHP capacities and associated costs. Such detailed evaluation is beyond the scope of our task of estimating CHP potential. Instead, we use simplified assumptions from literature review and results from discussions with industry specialists to derive an order-of-magnitude figure of CHP potential in both industries.

First, based on aggregate steam and electricity data for each industry we provide a current estimate of the technical potential of CHP for a simple case of a pre-selected gas turbine cogenerator. Second, we estimate the economic potential of CHP capacity. Third, we present sensitivity analyses for variations in CHP technologies, internal-rates-of-return, electricity and fuel prices, hours of operation of CHP equipment, changes in steam demand, and rates of depreciation of CHP equipment. Fourth, we estimate specific carbon mitigation costs per unit of carbon emitted, and total carbon emissions reduction potential by means of CHP technologies. Finally, on the basis of the sensitivity analysis we summarize factors that have the largest effect on the economic potential of applying CHP technologies in the chemicals and the pulp/paper industries.

Methodology

Technical Characteristics of CHP Equipment

One of the main features in selecting the right equipment for a CHP system is the power-to-heat ratio. The average power-to-heat ratio for the chemicals industry, as well as for the pulp/paper industry, is 0.2 (GRI, 1997). Without plant level data on industrial electricity and steam demand patterns it is impossible to find the optimal CHP system configuration that will satisfy industry's needs for steam and electric power. Therefore, our choice of CHP system is arbitrary. Since electricity is a more valuable form of energy than heat and can be more easily exported via existing power networks, we assume that meeting industry's heat demands is more desirable than satisfying its power demands (given that exported electricity can find a market). Therefore, we quantify the size of CHP potential by matching industry's thermal requirements to the characteristics of the CHP system, and maximizing CHP system's electric output[2].

We use the aggregate data on steam demand in industries from the Industrial Boiler Database of the Integrated Planning Model of ICF Kaiser (ICF, 1998). The Database provides the available steam load of boilers that is not covered by the existing CHP capacity. We also exclude steam load covered by renewable fuels (biomass) or internally generated wastes (black liquor in the case of the pulp/paper industry)[3]. Biomass and black liquor fuels may have a better application with biomass and black liquor gasification technologies that are currently at the stage of commercialization (Larson, Raymond, 1997, Kreutz, Larson, Consonni, 1998). Steam load remaining after this adjustment represents the chemicals and pulp/paper industries thermal demand that has the potential for CHP application.

Since our main concern is reduction of carbon emissions, we select a CHP system that works with less carbon-intensive fuels, such as natural gas. Currently, the cheapest available technology is a combined cycle plant (Zink, 1998a). In order to make our estimate conservative, we select a technology

[2] Without plant level power-to-heat ratio data it is impossible to separate CHP potential from power only (sites with small thermal requirements but large electricity demand) potential. Therefore, we quantify all the on-site potential (heat & power and power only) as CHP.

[3] About 33% of boiler steam output in pulp and paper industry is covered by recovery boilers using black liquor (Cadmus, 1997). Steam load satisfied by biomass and sludge represents 18% in pulp and paper industry and 30% in chemicals industry (EIA, 1998).

with high first cost – a gas turbine combined with a heat-recovery steam generator (HRSG)[4]. Gas turbines are available in many configurations, designs, and sizes, with a range of power-to-heat ratio from about 0.3 to 1 (Caton, Turner, 1997). The base load electrical efficiency of gas turbines with HRSG is size-dependent:

$$\eta_e = 0.32\,(0.1*P)^{0.09} \qquad \text{for } P \leq 27 \text{ MW}$$
$$\eta_e = 0.34 \qquad \text{for } P > 27 \text{ MW}$$

where η_e = electrical efficiency of the gas turbine under full load conditions based on lower heating value of fuels[5], and P = gas turbine capacity in MW (Blok, Turkenburg, 1994). Based on the capacity distribution of the non-CHP steam load, we assume an average electric efficiency of 33%. Total fuel utilization of the selected CHP equipment is assumed to be 80%. Currently available commercial gas turbines have higher electric and overall efficiencies. We use lower efficiencies in order to make our estimate more conservative.

CHP equipment is most efficient if utilized at 100% of the rated capacity. For practical applications the rated capacity utilization factor is about 90%. However, only 47% of boiler capacity in the chemicals industry and 58% of the boiler capacity in the pulp/paper industry is utilized (GRI, 1996). We assume the CHP equipment to be operated at its rated capacity (about 7880 hours/year). In this case we match 64% of the remaining steam load to the CHP equipment for the pulp/paper industry, and 52% of the chemicals industry steam load.

Cost Estimates

The economic evaluation of the CHP potential will differ, depending on the operator of the CHP facility. We consider two cases of operating a CHP facility: operation by utility/third party[6] and operation by the industrial company itself.

Two main indicators are usually used in economic evaluations of the benefits of CHP: simple payback time and the internal-rate-of-return on investment. We also consider carbon emission reduction costs. The simple payback time is defined as $PBT=I/NB$, where I is the capital invested in the CHP equipment, and NB are net annual benefits from CHP. Internal-rate-of-return is defined as the rate of discount that makes the net present value of an investment equal to zero (Brealey, Myers, 1991). Carbon emission reduction costs are calculated as the net annual costs divided by the net annual carbon emissions avoided:

$$C_C = (\alpha * I - NB) / m_C \qquad (2)$$

where $\alpha = r/(1 - (1+r)^{-n})$ is the annuity factor with an assumed interest rate r and the lifetime of the CHP plant n; and m_c is the net annual emissions avoided (Blok, Turkenburg, 1994).

In the case of operation by industrial company, the net annual benefits are calculated as $NB=E+S+PG+PS+DTS-F-OM-SP$, while in case of utility operation, the net annual benefits consist of the following: $NB= EU+SU+DTS-FU-OM$, where

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[4] Another reason is that gas turbines are a better application for sites with smaller capacity demand. Most of the current CHP units have been installed at sites with large capacity demands.

[5] It is customary to quote efficiencies in lower heating values (or net calorific values). This is because the latent heat of vaporization of the water vapor produced during the combustion of fuel is practically useless as an energy source. However, with space heating and other low temperature requirements, this heat can be captured with condensing heat exchangers (Evans, 1993). In this study, we do not consider the possibilities of harnessing the low-temperature heat.

[6] Third party providers are usually energy service companies. In this case we assume a direct utility ownership of the CHP plant at the industrial site, e.g. CHP operator sells electricity to an open wholesale market.

E – annual saved electricity purchase costs;
S – annual saved steam purchase costs;
PG – annual receipts for electricity sold to the utilities;
PS – annual receipts for electricity sold from non-renewable sources under the conventional system of power generation;
DTS – depreciation tax shield;
F – annual additional fuel costs for operation of the CHP facility compared with steam generation in boilers;
OM – annual operation and maintenance costs (O&M) of the CHP equipment;
SP – annual costs for standby power.
EU – the value of electricity produced per year;
SU – annual receipts for steam delivered to the industrial company;
FU – annual fuel costs for the operation of CHP facility.

Data Inputs

Efficiency and carbon emissions factors, fuel and carbon savings.

In order to estimate fuel savings and carbon emissions avoided we find the difference between fuel inputs and carbon emitted in a conventional system and a CHP system. Energy supplied by conventional system consists of steam from on-site boilers, and electricity and steam purchased from the central power system and non-utility generators.

We assume that the total efficiency of fuel inputs into purchased electricity is equal to the average efficiency of electricity generation in the U.S. power generating industry (EIA, 1998). Fuel efficiency of purchased steam is assumed to be the same as the average efficiency of heat produced by boilers in industry[7]. We calculate efficiency of electricity generation in the US, excluding industrial CHP, from the International Energy Agency Extended Energy Balances (IEA, 1998). The resulting efficiency of electricity generation in the US in 1994 was 35%, and the efficiency of heat generation was 70%. We assume carbon factor for purchased electricity to be equal to the average carbon factor of the US power generating system. The carbon factor of purchased steam is assumed to be equal to the carbon factor of steam produced in boilers in each industry. In 1994, carbon factor for electricity generation was 50.5 ktC/TBtu, and for heat generation was 18.6 ktC/TBtu in the chemicals industry, and 21.2 ktC/TBtu in the pulp/paper industry. Further we extrapolate the heat and electricity primary efficiency coefficients and carbon factors through year 2015 using the scenarios for electric generators from the Annual Energy Outlook 1999 (EIA, 1998).

More than 50% of energy consumed within the chemicals industry and above 80% of energy within the pulp/paper industry were used as inputs for steam generation in conventional boilers in 1994[8] (EIA, 1998). From that renewable fuels, which we exclude from our calculations, contributed about 29% to boiler inputs in the chemicals industry and about 55% in the pulp/paper industry. Carbon that

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[7] This makes our estimate of energy savings more conservative, because 77% of the purchased steam in the chemicals industry and half of the purchased steam in the pulp/paper industry were bought from non-utility generators. Possibly, a significant amount of steam from non-utility suppliers is produced by CHP technologies. Therefore, actual heat efficiency of non-utility suppliers may be lower than the fuel efficiency of the central heat generation system (about 50%).

[8] Manufacturing Energy Consumption Survey (MECS) presents fuels at their higher heating values (gross calorific values). We convert the HHV to LHV, in order to exclude latent heat from vaporization and make our estimates more conservative. We assume 5% vaporization for oil, 10% for gas, 7% for coal, and 17% for biomass fuels (IEA, 1998).

was emitted from the conventional on-site steam generation was calculated using simplified carbon coefficients[9] (IEA, 1997).

Base case price developments.

For the base case scenario we use the base case energy price scenario from AEO99[10] (EIA, 1997). We take average fuel prices for industrial consumers, for the case of industrial plant operation, assuming prices for steam to be equal average prices for primary energy. Under PURPA, utilities are mandated to purchase power from qualified facilities (QF) of non-utility generators, and are required to pay for this power that amount that they would otherwise spend to generate or acquire power[11]. The average price that utilities paid for electricity produced by non-utility generators in 1996 was \$6.9/MBtu[12] (EIA, 1996a, EIA, 1996b). We assume that this price follows the trend in electricity generation and the average price of electricity for all consumers in the AEO99 scenario. In the case of a utility operating the CHP facility we take natural gas prices for power generators.

Costs of CHP equipment.

We assume a life time of 20 years for CHP equipment, 34% corporate tax rate, and 20-year tax depreciation schedule with accelerated cost recovery system (Brealey, Myers, 1991). For a more conservative aggregate estimate we consider all the CHP installations to be greenfield[13]. From the data provided by (Gerhardt, 1998) we derive the costs of CHP equipment as following:

$$I = 843.3\, P^{0.93}$$
$$FOM = 24.7\, P^{0.95}$$
$$VOM = 0.0015\, T P^{0.5}$$

where, I – capital investment (including installation costs), in thousand \$US; FOM – annual fixed operations and maintenance costs, in thousand \$US; VOM – annual variable operations and maintenance costs, in thousand \$US; T – number of running hours per year; P – gas turbine capacity in MW.

Other costs.

The rates for back-up power differ widely between utilities. Different rate schedules are available depending on the installed capacity, demand for reactive power, off-peak or peak demand for power services. There are also possibilities for special standby power contracts. Generally, the rates for independent producers who purchase additional power from the grid will be the same as the rates of industrial/commercial customers. In addition, the utility will charge reservation charges for installed CHP capacity. For the aggregate estimate we assume monthly reservation charges on average to be

[9] The simplified carbon factor for residual fuel oil is 21.1 ktC/PJ, 20.2 ktC/PJ for distillate fuel oil and diesel, 17.2 ktC/PJ for LPG, 15.3 ktC/PJ for natural gas, and 25.8 ktC/PJ for coal (EIA, 1997).

[10] All the prices in AEO99 scenario are provided in 1997 constant US dollars.

[11] These so-called "avoided costs" are costs of utility operation, excluding costs of transmission, distribution, and other expenses not related directly to power production.

[12] Equal 2.1c/kWh. Those costs differ on a state-by-state basis, however such detailed information is not available. Therefore, we assume that the avoided-costs are approximately equal to the power generating production expenses of major U.S. utilities. Utility avoided costs are estimated in the following way: total fuel expenses are added to other operating expenses of power production and further divided by the total amount of generated electricity (EIA, 1996a, EIA, 1996b).

[13] Capital and installation costs for smaller turbines (<27 MW) run from \$697/kW for a retrofit installation to \$778/kW for a greenfield plant. For larger turbines (>27 MW) the costs range from \$480/kW for brownfield to \$605/kW for greenfield installations. Fixed O&M costs range from \$19.5/kW for small turbines to \$23.4/kW for large, while variable O&M costs are in the range of 1.1-1.41 mills/kWh (Gerhardt, 1998).

$3.5/kW of installed capacity, based on the maximum stand-by charges listed by several large and medium utilities (GP, 1998, Ontario Hydro, 1997, PG&E, 1998). If additional power is required, we assume it will be supplied at the average price for industrial consumers.

There are other costs and charges that CHP project developers may encounter, which vary widely among projects. Those include charges by utilities (interconnection charges, stranded asset recovery fees, unreasonable access and stand-by charges, etc.), and costs needed to comply with current environmental regulations[14]. Those charges will vary from project to project. Most of the utility related charges are contract-based, while environmental requirements will vary from state to state. With the utility restructuring process, those charges and regulations are likely to change. Due to complexity of estimating additional costs we omit them in our calculations. However, it must be noted that these charges may be significant, and often make smaller CHP projects uneconomic (Onsite, 1998, Casten, Hall, 1998, Elliott, Spurr, 1998).

Results

Capacity and Regional Distribution of the Technical Potential for CHP

The results of the aggregate estimate of the remaining CHP potential in the chemicals and pulp and paper industries are presented in Figure 1. Remaining CHP generation potential in the pulp/paper industry is about 1.7 times the amount of existing CHP capacity, while CHP potential in the chemicals industry is more than two times larger than the installed capacity. About 69% of the CHP potential in the chemicals industry lie within the sites with smaller capacity of 15 to 30 MW. In the pulp/paper industry about 62% of CHP potential is within the plants between 30 and 70 MW capacity.

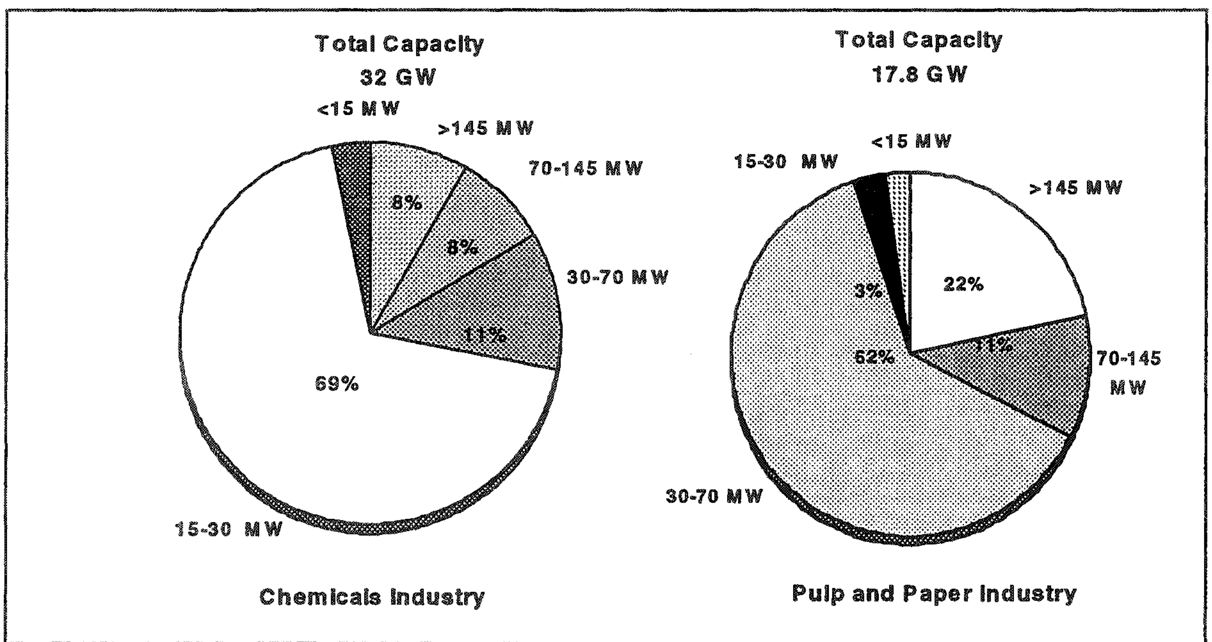

Figure 1. Capacity Distribution of the Remaining CHP Potential

[14] Costs of compliance with Best Available Control Technology, Lowest Achievable Emission Rate, New Source Performance Standards, etc.

Sensitivity Analyses

We performed sensitivity analyses on the internal-rate-of-return[15] (IRR), energy costs, investment costs, gas turbine efficiencies, CHP operating hours, growth in steam demand, and different CHP depreciation periods. These sensitivity analyses are performed for both the case of operation of the CHP facility by industry and the case of operation by the utility. The results of these sensitivity analyses are presented in Table 1.

Table 2. Results of the Sensitivity Analyses for Different Scenarios

	CHEMICALS INDUSTRY						PULP AND PAPER INDUSTRY					
	Industrial Operations			Utility Operations			Industrial Operations			Utility Operations		
INTERNAL-RATE-OF-RETURN SCENARIOS												
	20% IRR	25% IRR	30% IRR	55% IRR	60% IRR		20% IRR	25% IRR	30% IRR	55% IRR	60% IRR	
Installed CHP capacity (GW)	31.4	28.2	25.5	29.7	24.7		15.7	14.1	12.7	15.0	12.6	
Electricity production (TWh)	248	223	201	234	195		124	111	100	118	100	
Heat production (TBtu)	1218	1095	989	1150	959		609	547	493	583	490	
Primary energy savings (TBtu)	1575	1416	1279	1487	1239		787	706	637	754	634	
Carbon savings (MtC)	30.0	27.0	24.4	28.3	23.6		15.3	13.5	12.1	12.9	10.8	
ENERGY PRICE SCENARIOS												
In GW	20% IRR	25% IRR	30% IRR	55% IRR	60% IRR		15% IRR	20% IRR	25% IRR	55% IRR	60% IRR	
Base case forecast	31.4	28.2	25.5	29.7	24.7		16.8	15.7	14.1	15.0	12.6	
High-oil price	30.4	27.5	24.9	30.0	25.0		17.1	15.3	13.8	15.2	12.8	
Low-oil price	30.7	27.6	24.9	29.3	24.5		17.0	15.2	13.7	14.9	12.5	
High macroeconomic growth	30.9	27.8	25.1	29.8	24.8		17.2	15.5	13.9	15.1	12.7	
Low macroeconomic growth	30.6	27.5	24.9	29.4	24.6		17.1	15.4	13.8	14.9	12.6	
Wholesale electricity market	32.7	28.8	25.6	29.4	24.5		19.1	16.5	14.5	14.9	12.5	
INCREASED EFFICIENCY OF GAS TURBINES SCENARIOS												
	IRR 20%			IRR 60%			IRR 15%			IRR 60%		
	5% increase	10% increase	15% increase	5% increase	10% increase	15% increase	5% increase	10% increase	15% increase	5% increase	10% increase	15% increase
Electricity production (TWh)	262	277	293	254	275	298	147	157	166	128	137	147
Primary energy savings (TBtu)	1887	2061	2149	1825	2045	2192	1030	1081	1133	893	946	1003
CO2 savings (MtC)	34.8	34.8	39.6	33.6	34.5	40.4	17.5	18.5	19.5	15.2	16.2	17.3
REDUCED HOURS OF OPERATION SCENARIOS												
	IRR=20%	IRR=25%	IRR=30%	IRR=55%	IRR=60%		IRR=15%	IRR=20%	IRR=25%	IRR=55%	IRR=60%	
Electricity production (90% utilization) (TWh)	248	223	201	234	195		132	124	111	118	100	
80% utilization	226	202	182	179	153		127	113	101	92	79	
70% utilization	204	181	162	138	119		115	102	90	72	62	
60% utilization	182	159	142	105	92		102	91	79	55	48	
EFFECT OF INCREASED STEAM DEMAND SCENARIOS												
	20% IRR			55% IRR			15% IRR			55% IRR		
	Base case	BAU	Efficien. improvements	Base case	BAU	Efficien. improvements	Base case	BAU	Efficien. improvements	Base case	BAU	Efficien. improvements
Electricity production	248	255	252	234	246	246	132	144	141	118	125	123
CHP capacity	31.4	32.4	31.9	29.7	31.2	31.3	16.8	18.2	17.9	15.0	15.8	15.6
CO2 savings (MtC)	30.0	30.9	30.5	28.3	29.8	29.9	14.4	15.6	15.3	12.9	13.6	13.3
EFFECT OF ACCELERATED DEPRECIATION SCENARIOS												
	25% IRR			60% IRR			20% IRR			60% IRR		
	Base case	10-year depreciation	7-year depreciation	Base case	10-year depreciation	7-year depreciation	Base case	10-year depreciation	7-year depreciation	Base case	10-year depreciation	7-year depreciation
Electricity production	223	236	232	195	223	212	124	131	129	100	113	108
Net primary energy savings	2392	2539	2494	2093	2400	2284	787	833	820	634	722	688
CO2 savings (MtC)	27.0	28.6	28.1	23.6	27.1	25.8	13.5	14.2	14.0	10.8	12.3	11.8

[15] Discount rate on investment.

Internal-rate-of-return.

We assume that an investment into a CHP plant will be attractive when its IRR is higher than the real interest rate. We start our calculation of the economic potential of industrial CHP with an IRR of 10%, and calculate it for several higher IRRs.

In the case of industrial operation the economic potential of CHP capacity is smaller than in the case of utility operation. At IRR over 14% the economic potential of CHP capacities operated by the pulp/paper industry fells below its technical potential of 17.8 GW. The economic potential for CHP equipment operated by the chemicals industry fells below its technical potential of 32 GW at 19% IRR.

Theoretically, if the utility can sell excess steam to other industries, nearby commercial or residential buildings, etc., the economic potential of CHP is limited only by steam demand. We take a more conservative approach, and assume that utility cannot sell excess steam to other industries, e.g., the economic potential for CHP is limited by steam demand in the pulp/paper and chemicals manufacturing[16]. At low IRR, the economic potential of utility installing CHP plants is theoretically unlimited, e.g., it is profitable for the utility to install CHP plants in the industry even if all steam demand is met and excess steam is wasted. Only at an IRR of 51% in the pulp/paper industry and at an IRR 53% in the chemicals industry the economic potential of utility installing and operating CHP capacities matches the technical potential in industry. At higher IRR economic potential for CHP, in case of utility operation, declines. Overall, the effect of increasing internal-rate-of-return is significant, and larger in the pulp/paper industry.

Energy prices.

The CHP potential is also calculated for five different energy price scenarios. Four of them are from the EIA Annual Energy Outlook 99 – the high- and low oil prices scenarios, and high- and low-macroeconomic growth scenarios (EIA, 1997). The fifth scenario that we consider is the scenario when industrial CHP operators can sell electricity to the open wholesale market. Currently, the average price that industrial consumers pay for electricity is about two times the average price that industrial electricity producers can sell their electricity for to the grid. In the fifth scenario, we assume the difference between the two prices reach 20% by the year 2010, and all the prices follow the base case scenario.

We can observe that the effect of price scenarios is small – less than 5%, except for the pulp/paper industry in the fifth scenario. When the pulp/paper industry can sell excess electricity to the wholesale market, its CHP potential increases by 13%.

Lower investment cost, economies of scale.

More companies are recognizing opportunities for gas turbine applications in today's power generation market and are introducing new and improved technologies. This trend caused the cost of gas turbines to decline in recent years[17]. It is expected that the cost of gas turbines will significantly decline in the next decade. We calculate the CHP potential with a reduced investment cost for gas turbines below 27 MW range. We assume that the cost of these turbines will fall to an average of $650/kW. This will increase the CHP potential by about 11% for each industry in the case of industrial operations.

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[16] In practice, steam host should be located close to the steam generating facility. In most cases, the CHP unit will be located at the industrial facility of the steam host. However, in densely populated areas excess steam from an industrial CHP unit can satisfy thermal demand of other buildings and facilities located nearby.

[17] For example, Trigen Corp. sells packaged systems at $650/kW for 4.6 MW units. In our base scenario we use higher costs to make our estimate more conservative.

Currently there are sizable economies of scale in the CHP market, and realizable potential at the higher end of the market is about 30% of total. However, with utilities deregulation, smaller units[18] may become more attractive, providing reliability and cost savings by more closely meeting demand growth (Zink, 1998a). Apart from thermal and power load requirements, the economics of installing several small units instead of one large unit will depend on contracts for interconnection charges, back-up power costs, real-time-pricing options, etc. (Elliott, Spurr, 1998, Casten, Hall, 1998). Ignoring the above-mentioned considerations, the combined costs of an installed gas turbine with an HRSG will have to fall to about $540/kW in order to meet the technical CHP potential with incremental installations of smaller units (e.g., no economies of scale are present).

Higher gas turbine efficiencies.

Energy efficiency of gas turbines is steadily increasing. Currently, manufacturers are offering mid-range turbines with 38.5% efficiency in a simple cycle, and 58% efficiency in the combined cycle[19]. Several government and industry programs help fund research and development of gas turbine generators with higher efficiency, lower emissions, fuel flexibility, and improved reliability (Zink, 1998a, 1998b). Therefore, it is reasonable to assume that gas turbines will be about 10-15% more efficient by the year 2010. We calculate the potential CHP capacity for three different cases of improvements in gas turbine efficiency, also assuming that overall efficiency of fuel utilization in CHP installations has increased to 85%.

Operating hours.

Chemicals and pulp/paper industries have predominantly a three-shift continuous operating process. In the most favorable case CHP operation would be in the range of 7880 hrs/year. In practice, equipment repairs, business cycle fluctuations in pulp and paper and chemicals demand can reduce hours of operation down to 5000 hrs/year. This will reduce the amount of electricity and steam produced by CHP facilities. We calculate the effect of reduced hours of operation for three different cases. We see that this effect is much stronger in the case of utilities operation.

Growth in steam consumption.

The growth in manufacturing activities will cause an increase in demand for steam and electricity. On the other hand, technological improvements, more efficient steam use will lead to decline in demand for steam and electricity. For the growth in manufacturing sector activity we use the assumptions from the GRI CHP Projection Report (GRI, 1997). We assume that the excess steam and electricity can be sold by industrial company/utility to other industries in the manufacturing sector. For energy conservation we assume two scenarios: business-as-usual (BAU) and high efficiency (HEF) scenario. Manufacturing energy intensity[20] from 1984 to 1994 has been declining at annual rate of 1.1%. However, since 1990 energy intensity in manufacturing has increased about 0.17%. Therefore for the BAU scenario we assume 1.1% annual decline in energy intensity. For the HEF scenario we assume 1.5% rate of decline in energy intensity. The combined effect of industrial activity growth and energy conservation will increase steam demand by 22% in the BAU scenario and by 7.7% in the HEF

[18] Smaller units are below 27 MW capacity, larger are more than 27 MW capacity.
[19] Westinghouse 501G (230 MW η_e=38.5%), Siemens V84.3A (170 MW η_e=38.5%), ABB GT24 (183 MW η_e=38.5%), etc.
[20] Economic energy intensity is equal to the amount energy consumed per unit of output (value added).

scenario by the year 2020[21]. The effect of the increase in steam demand on potential CHP capacity is medium, and is larger for the pulp/paper industry in case of industry operating the CHP facility.

Change in depreciation schedule.

Currently, gas turbines that are used to make electricity are subject to a 20-year tax life, while the same turbines used to power airplanes or equipment have 5-7 year tax life. It has been argued (Casten, Hall, 1998, William, Davidson, 1998, Elliot, 1998) that such high depreciation schedule presents a barrier to successful application of CHP technologies. We consider two different depreciation schedules in our sensitivity analysis – 10 and 7-year tax life of CHP equipment with accelerated cost recovery system (Brealey, Myers, 1991). The results show that increase in the tax shield increases CHP potential by about 6% in case of industrial company operations, and by about 14% in case of utility operations in each industry.

Cost Effectiveness of Reductions in Carbon Emissions and Simple-Pay-Back Period

We calculate the cost effectiveness of applying CHP technology for reducing carbon emissions for three different cases of industry operations and for a case of utility operations. For the first case of industry operations (*A*) we assume, that all the new CHP capacity will be first installed at the facilities that purchase electricity from outside generators. Only after all the purchased electricity is substituted by on-site generation, the excess electricity will be sold to the utilities. In the second case of industry operations (*B*) electricity produced is equally distributed between purchased and sold electricity, e.g. plants that want to satisfy their internal need for electricity are installing CHP facilities at the same pace as plants that sell excess electricity to the grid. In the case (*C*) of industrial operation we assume that industry can sell electricity in the open wholesale power market. In the case of utilities (*D*) we assume that the demand for steam is limited by the remaining steam load suitable for application of CHP technology in each industry. The interest rate is assumed to be 10%[22] and the lifetime of the CHP plant 20 years.

In *Case A* of industrial operations average and marginal costs are negative until the industry is saving on purchased electricity by installing CHP capacity. As the industry starts selling excess electricity to the grid, the average cost of carbon mitigation increases, and the marginal cost becomes positive. If the industry is installing CHP capacity both to save on electricity bill and to sell excess electricity to the grid, as in *Case B*, average carbon mitigation costs are larger, and the cost is negative until CHP installations do not exceed thermal demand. Average and marginal costs of carbon mitigation are negative when industrial producers are able to sell electricity in open market at wholesale prices as shown in *Case C*. In *Case D* of utility operation, average carbon mitigation cost are negative even after the thermal demand in industry is exceeded. In both *Case C* and *Case D* the total marginal cost of carbon mitigation is the lowest. The marginal and average carbon mitigation costs as a function of the amount of carbon avoided are presented in Figure 2 for the highest and lowest marginal cost cases.

The amount of carbon emissions avoided depends on the assumption of type of fuels substituted in the industry's steam generating system, as well as utilities' power generating system. With the increasing share of natural gas and renewable fuel sources in the central power generating system, the amount of carbon avoided due to CHP installation will decline.

[21] Average for the industrial sector. In fact, since the chemicals and the pulp/paper industries are high growth industries, the growth in their steam demand will be larger than the average for the whole industrial sector.

[22] This corresponds to an annuity rate of about 12%.

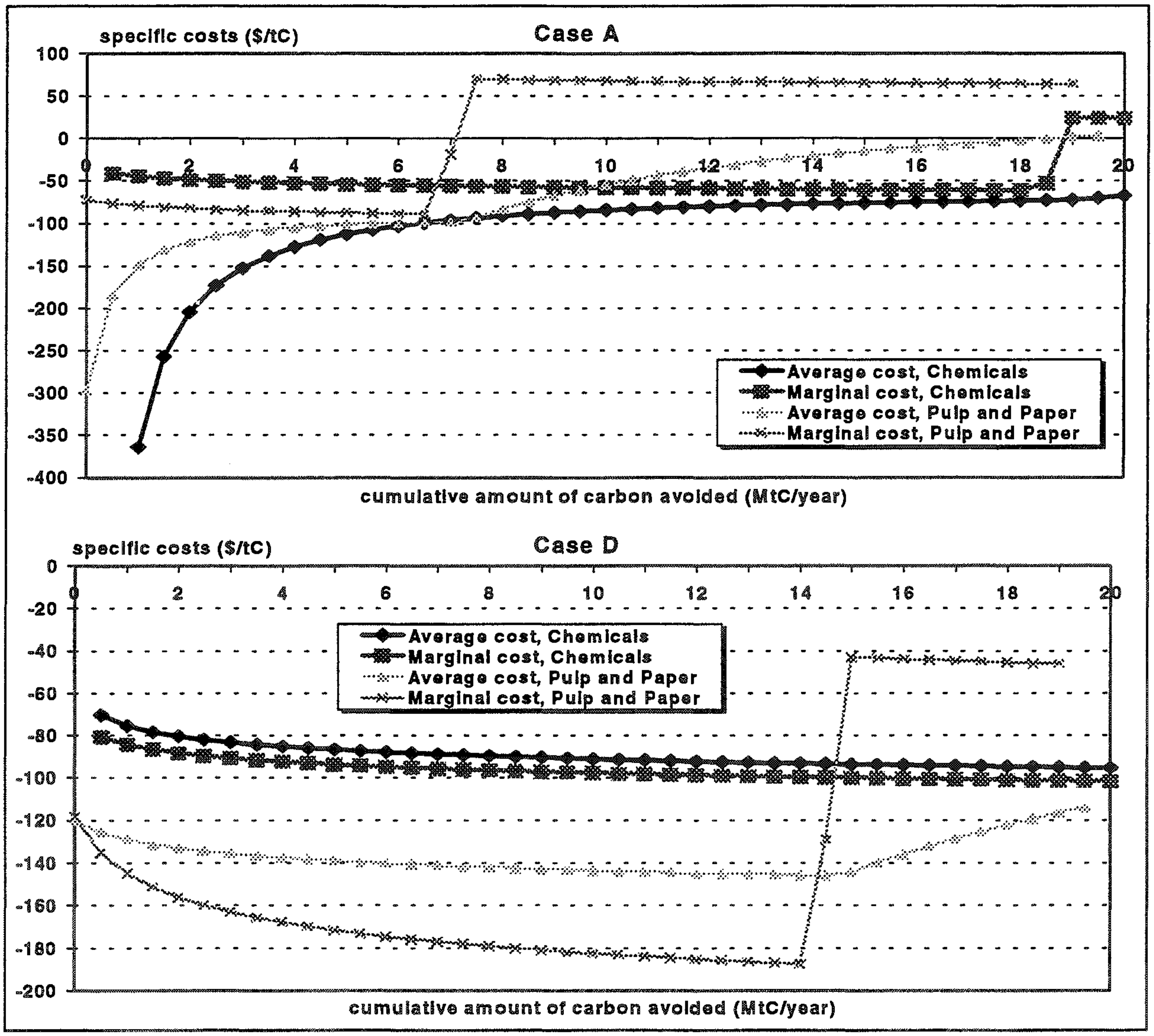

Figure 2. Average and Marginal Costs of Carbon Emissions Reductions

The industry's adopted payback period of CHP projects is between 3 to 5 years (Wimberly, 1998, Blok, Turkenburg, 1994). At the cut-off rate of 5 years all of the technical potential in the chemicals industry in all cases will qualify. All of the technical potential in the pulp/paper industry will qualify at this cut-off rate in *Case C* and *Case D*. In *Case A*, 15.8 GW of the CHP potential in the pulp/paper industry will qualify, and only about 3.5 GW in *Case B*. However, these may change if the analysis is done on a plant-by-plant basis.

Policy Implications

CHP is a low-cost option for saving energy and reducing carbon emissions in the chemicals and pulp/paper industries. However, the economics does not favor small-scale projects where there is the largest remaining technical potential of CHP installations in both industries. Mainly, it is caused by the current costs of CHP technology and existing electric utilities and environmental regulations (Casten, Hall, 1998, Elliott, Spurr, 1998).

Further development and improvement of small-scale industrial turbines and other CHP technologies is needed. Reductions in capital and siting costs and costs of operations and maintenance of CHP technologies will lead to growing implementation of small- and large-scale CHP projects. Improvements in fuel efficiency of CHP technology also will have a positive impact on CHP projects. Further R&D efforts should continue in this direction.

Economic and environmental benefits from implementing projects should be accounted in utility restructuring policies at the state and federal level. CHP generators should be allowed to sell electricity in the open market, as well as they should be charged standard interconnection and standby power charges.

Improvements should be made in the current tax regulations to eliminate the disparity in depreciation time of the same technologies, that is based on ownership and application of the technologies.

These measures will improve economic prospects for small- and large-scale CHP projects.

Conclusions

CHP presents a significant opportunity for improving energy efficiency and reducing carbon emissions in the pulp/paper and the chemicals industries. The amount of electricity that could be generated by CHP in both industries is about 390 TWh, which is about 1.8 times the amount of electricity currently used in both industries. Overall, CHP generated electricity and steam can save annually about 2500 TBtu of primary energy, and lead to the reduction of 46 MtC per year. Depending on the operation of CHP facilities, significant amount of carbon reductions can be achieved at negative cost.

There are about 17.8 GW remaining technical potential for CHP in the pulp/paper industry, and 32 GW of CHP potential in the chemicals industry. The largest potential remains within the facilities with fuel input capacity below 70 MW. However, facilities in the MW-range above 70 MW are more likely to adopt CHP installations first, due to economies of scale in CHP investments.

This technical potential can be economically achieved at a discount rate below 15% in case of industrial facility operation and below 50% in case of utility operation. Overall, the economic potential for CHP is higher in the case of utility operation. It is limited only by the demand for steam from industrial facilities.

The economic potential for CHP will depend on whether the CHP facility will be operated by utility or industrial company itself. Several other factors can influence the economics of CHP installations. The largest effect will have the improvements in CHP technology (both efficiency improvements and installation cost reductions), capacity utilization of the CHP equipment, the required discount rate on investment, and depreciation time of CHP equipment. The effect of increasing steam consumption within industry and the effect of changes in prices for fuels, electricity, and steam are less pronounced. However, more accurate plant-level matching of CHP technologies may change the sensitivity of CHP economic potential to the above mentioned factors.

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