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# A Basic Analysis of Cogeneration Economics

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## ABSTRACT

The economics of small scale gas turbine based cogeneration systems are analyzed on the basis of avoided costs for an electric utility exploiting such systems. This concerns a theoretical study in which the cogeneration system as a means for electricity generation is assumed to supplant the building of new central electricity generating plant.

The results show that with increasing oil and gas price levels, the economics of cogeneration will become more favourable when the supplanted capacity is for peak load rather than for base load electricity generation. This implies a preference for applications with cogeneration operation taking place mainly during on-peak hours of the electricity demand

## INTRODUCTION

Cogeneration economics can be looked at from two basically different points of view. One as a consumer of heat and electricity, employing cogeneration as an alternative to on-site heat production and buying electricity from an outside utility. The other as a utility company exploiting cogeneration as a means of supplying both heat and electricity to its customers.

An important difference lies in the value attributed to the produced electricity.

In the case of a consumer exploited cogeneration system this value will correspond to the utility tariff, with some deduction being made for any services that are still desired from the utility company (availability of standby capacity, possibility of supplemental or return delivery of electricity).

In the utility exploited case the value may be expected to conform more directly to the cost of meeting the same electricity demand by conventional generating means.

Because the purchase price of electricity is generally higher than the avoided costs, the economics will generally look better in the case of consumer exploited cogeneration systems. On the other hand, the economics of the utility exploited systems probably give a truer picture of the national cost benefits of cogeneration.

The general aim of the following paper is to explore the economics of small scale gas turbine based cogeneration systems (say 3 to 5 $MW_e$) on the latter basis. This concerns a theoretical cost analysis based on the assumption that the cogeneration installation as a means of electricity generation is to supplant the building of new central electricity generating capacity.

In both cases electricity is delivered to the national grid. In the case of cogeneration heat is delivered to (a) specific customer(s) at a price that is competitive with heat generation by means of an on-site boiler.

## HEAT RATE FOR ELECTRICITY GENERATION

As a preliminary to performing the proposed cost analysis it is proposed to first determine and compare the heat rate of electricity generation with and without net heat recovery. The heat rate is in this context defined in terms of kWh of fuel energy per kWh of electricity production.

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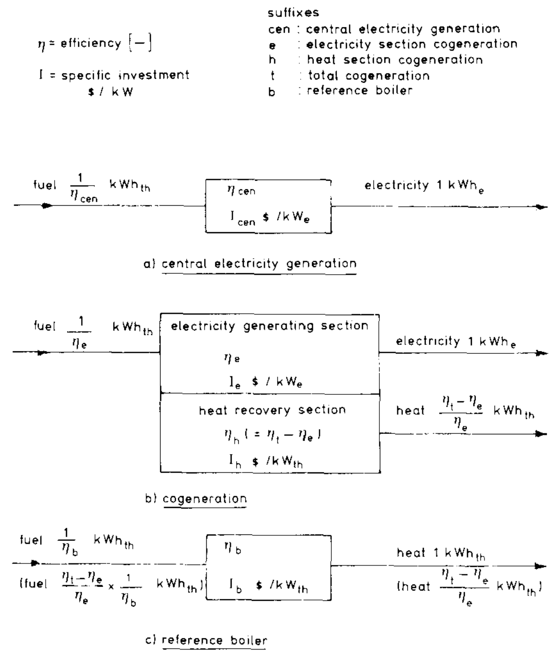



Figure 1. Block diagrams as a basis for deriving energy and cost equations.

In the case of central electricity generation without (net) heat recovery, the heat rate hr can be simply calculated with the equation:

$$hr_{cen} = \frac{1}{\eta_{cen}} \qquad [\frac{kWh_{th}}{kWh_e}] \qquad (1)$$

in which $\eta_{cen}$ is a thermal or power generating efficiency (figure 1a) that is assumed to include the losses of transport and distribution of electricity.

In the case of a cogeneration process the heat rate for electricity generation includes a credit for the produced heat. As illustrated in figure 1b and 1c, this is done by subtracting the fuel consumption of a reference boiler from the fuel consumption of the cogeneration installation. This implies that the whole of the energy savings is attributed to the electricity-generating function of the cogeneration process.

The equation for calculating the heat rate for electricity generation by means of cogeneration $hr_{e.cog}$ then becomes:

$$hr_{e.cog} = \frac{1}{\eta_e} - \frac{\eta_t - \eta_e}{\eta_e} \times \frac{1}{\eta_b} \quad [\frac{kWh_{th}}{kWh_e}] \qquad (2)$$

in which:

$\eta_e$ = the power generating efficiency of the cogeneration system [-]
$\eta_t$ = the total efficiency of the cogeneration system [-]
$\eta_b$ = the efficiency of the reference boiler [-]

In figure 2 the resulting heat rate values are presented as a function of the various energy conversion efficiencies (with all efficiency values assumed to be related to the lower heating value of fuel).

Characteristic for the cogeneration process is that the heat rate is very much less influenced by a change in the power generating efficiency $\eta_e$. In fact, when the total efficiency $\eta_t$ is equal to the reference boiler efficiency $\eta_b$, the heat rate is completely independant of the value of $\eta_e$. As the value of $\eta_t$ drops below the value of $\eta_b$, the heat rate increases, the rate of increase being higher at the lower levels of $\eta_e$ and $\eta_t$. There remains however, a distinct advantage in comparison with electricity generation without heat recovery.

Indicated in figure 2 are also lines of constant heat to power ratio for the cogeneration proces H/E. As may be expected, this ratio increases with decreasing value of $\eta_e$.

## SPECIFIC FUEL CONSUMPTION COSTS

A similar looking but significantly different picture emerges when considering the fuel costs per kWh of electricity production.

For central electricity generation the value of these specific fuel consumption costs (sfcc) is very simply calculated as the quotient of fuel price and electricity generating efficiency:

$$sfcc_{cen} = \frac{fp_{cen}}{\eta_{cen}} \qquad ¢/kWh_e \qquad (3)$$

The fuel price fp is expressed in ¢/kWh of net calorific heating value of the fuel, which is equal to 100/293 of the fuel price in $/MMBtu.

For electricity generation by cogeneration means the equation for determining the specific fuel consumption costs is again rather more complicated. These costs will be equal to the fuel costs of the cogeneration installation per kWh of electricity production, from which must be subtracted a certain cost benefit for the produced heat. This cost benefit should take into account the possibility of the fuel price for the cogeneration installation being different from that for the reference boiler(s)(which may consist of a large number of decentralized boilers). Also there may be a need for offering a discount on the price of the heat delivered to the consumers as an incentive for buying this heat rather than choosing for on-site heat production by means of a proprietary boiler.

The equation for calculating the specific fuel consumption cost then becomes:

$$sfcc_{e.cog} = \frac{fp_{cog}}{\eta_e} - \frac{H}{E} \times \frac{fp_b}{\eta_b} \times (1 - \frac{d}{100}) \quad ¢/kWh_e \qquad (4)$$

in which:

$fp_{cog}$ = fuel price for cogeneration ¢/$kWh_{th}$
$fp_b$ = fuel price for the reference boiler(s) ¢/$kWh_{th}$
d = a discount percentage on the price of delivered heat

$$\frac{H}{E} = \frac{\eta_t - \eta_e}{\eta_e}$$ = heat/power ratio of the cogeneration process.

The results can be expressed in a non-dimensionalized form by dividing the values of the sfcc by some value of a fuel price, for instance the fuel price for cogeneration $fp_{cog}$.

The results are presented in figure 3. Lines A and B represent electricity generation by cogeneration means. The total efficiency is assumed to be 0.85 (for a reference boiler efficiency of 0.90) and the fuel price for cogeneration installation and reference boiler are assumed to be the same. Line A represents a discount of 0% and line B a discount of 10% on the price of heat delivered to the consumers. For further evaluation purposes the cross-hatched area will be considered representative of what may be achieved with present-day gasturbines based cogeneration installations with a capacity of say 3 $MW_e$ or higher.

Lines C and D represent (central) electricity generation without net heat recovery.

For line C the fuel price for (central) electricity generation is assumed to be 10% lower than the fuel price for the cogeneration and reference boiler installations. This would be representative of a situation in which natural gas is consumed in all cases, but in which a 10% discount is given for quantity delivery.

On this line point 1 may be regarded as representative for a combined cycle (steam and gasturbine) plant for base load electricity generation ($\eta_{cen}$ = 0.48) and point 2 for a simple cycle gasturbine for peak load duty ($\eta_{cen}$ = 0.35).

Line D is based on the fuel price ratio for central electricity generation relative to cogeneration being 0.75. This is meant to represent a situation in which the oil and gas price level is sufficiently high to make coal gasification economically attractive.

According to EPRI, 1988 this situation may be expected to occur when the price of natural gas rises to a level of around 6 $/MMBtu (circa 2 ¢/kWh).

That coal gasification will result in a change in various fuel price ratios is based on the following rather simplified line of reasoning.

In the case of base load central electricity generation, the coal gasification plant may be located near or even be integrated with the electricity generating installation. The quality of the gas (e.g. the heating value) can also be less than what would be required if the gas is to be transported to decentralized cogeneration installations. In the latter case the gas produced from coal would very probably have to be in the form of a synthetic natural gas. The higher cost of producing such a gas, together with the cost of distribution, implies a reduction of the fuel price ratio which for evaluation purposes is assumed to be equal to 0.75. Point 1' would then be representative for the relative specific fuel consumption costs for base load central electricity generation.

The situation will be somewhat different for peak load central electricity generation. The relatively low number of operating hours would seem to preclude an integration of gasification and electricity generating installations. Also some kind of storage capacity would

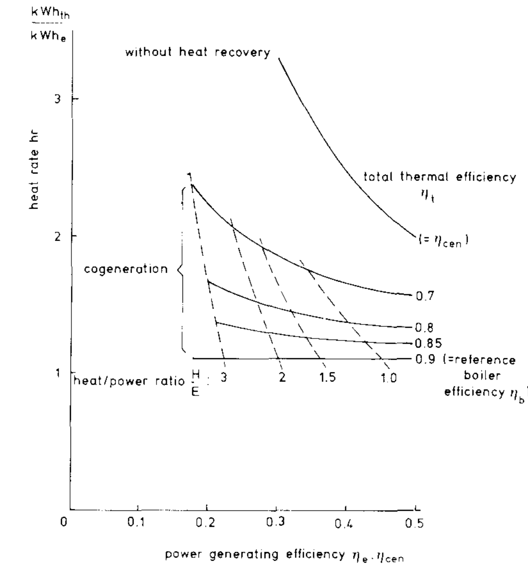
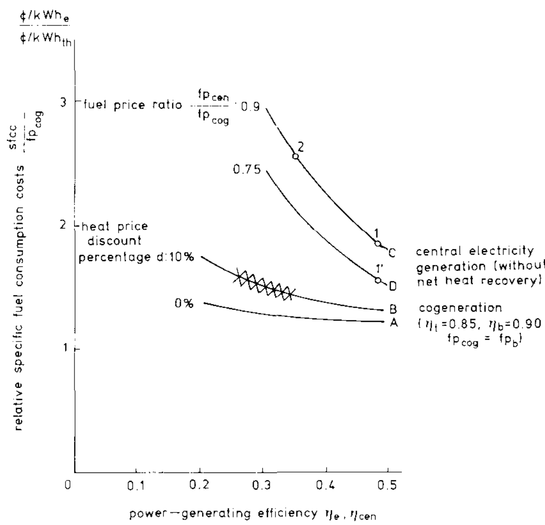



Figure 2. Heat rate as a function of energy conversion efficiencies




1 natural gas fired combined cycle steam and gasturbine
1' coal gas fired combined cycle steam and gasturbine
2 natural gas fired simple cycle gasturbine
XXXX small scale gasturbine based cogeneration installations

Figure 3. Relative specific fuel consumption costs.

be required in order to ensure a sufficiently high utilization in the case of a separate coal gasification plant.

As a result the price of coal gas would still be relatively high, notwithstanding the acceptability of producing a lower quality gas. For evaluation purposes the fuel price ratio is therefore assumed to remain 0.9, with point 2 still being representative of the sfcc for peak load central electricity generation.

## IMPLICATIONS FOR COGENERATION ECONOMICS

An important implication of what is shown in figure 3, is that the economics of a cogeneration system may be heavily influenced by the type of central electricity generating plant it is supposed to be supplanting.

If this is a base load unit, due to the cogeneration plant also operating during nights and on weekends, then the specific fuel cost savings will correspond to the difference between the sfcc according to the points 1 or 1' and the sfcc corresponding to some point in the cross-hatched area. This difference can be very much smaller than in the case of cogeneration being restricted to mainly peak-hours of the electricity demand. In this case the difference in sfcc will be between point 2 and the cross-hatched area. It is quite conceivable that the latter case will yield the highest fuel cost savings per year, notwithstanding the number of operating hours being very much lower than in the base load case.

On the other hand, the economics of cogeneration will also be determined by the investment and maintenance costs of the central generating capacity being supplanted. In the case of a combined cycle base load station, the specific investment will be considerably higher than for a simple cycle peak load station. This implies a higher investment allowance for a cogeneration installation supplanting base load capacity than for a cogeneration installation supplanting peak load capacity.

It is obviously necessary to quantify such differences in order to reach any conclusions as to what type of cogeneration application has the best economic potential. This is done by differentiating between three generic types of cogeneration application and making cost comparisons with the appropriate type of central electricity generating capacity. The distinction mainly concerns the number of (equivalent) full load operating hours per year.

a. 2000 hrs/yr of operation during on-peak hours of the electricity demand (2000 hrs/peak load)

This would be representative of cogeneration operation mainly taking place during the daytime hours of working days. This would be due to either the heat demand mainly occurring during these periods, or due to the application of heat storage facilities in order to shift cogeneration operation from off-peak to on-peak hours of the electricity demand.
The type of central electricity generating capacity being supplanted is assumed to be a simple cycle gasturbine for peak load duty.
The specific investment of such a unit has been set at 300 $\$/kW_e$ (EPRI, 1988) and the thermal efficiency is assumed to be 0.35.

b. 4500 hrs/yr during on- and off-peak hours (4500 hrs/base load)

This may be considered representative of cogeneration being applied for meeting a space-heating demand on a more or less continuous basis (without thermal storage). The type of central electricity generating capacity being supplanted might typically be a combined cycle base load plant with a specific investment of 600 $\$/kW_e$ (EPRI, 1988) and a thermal efficiency of 0.48.

c. 6000 hrs/yr during on- and off-peak hours (6000 hrs/base load)

This case may be regarded as typical for many industrial applications with basically a year-round heat demand. The type of central electricity generating capacity might again be a combined cycle base load plant ($\eta_{cen}$ = 0.48, specific investment 600 $\$/kW_e$), but in this case the economic feasibility of an integration with coal gasification would occur at a lower level of the natural gas price.

TABLE 1 ASSUMED VALUES FOR COST CALCULATIONS

| | | |
|---|---|---|
| $\eta_b$ | = | 0.9 |
| $\eta_t$ | = | 0.85 |
| d | = | 10% |
| $sfp_{cog}$ | = | sfpb |
| i | = | 0.06 |
| rf | = | 0.04 |
| rm | = | 0.02 |
| m | = | 0.05 |
| L | = | 15 yrs. |

## METHOD OF ASSESSING COGENERATION ECONOMICS

For an electric utility contemplating the choice between electricity generation by cogeneration means or by central generating means, it would seem suitable to make a cost comparison on the basis of a difference in life cycle costs. As indicated in appendix I, these life cycle costs may be calculated as the sum of the present worth of fuel costs, investment costs and maintenance and miscellaneous other costs.

However, rather than making a direct comparison between the calculated differences in life cycle costs, it is considered preferable to express the results in terms that relate more directly to the costs of the gasturbine and electrical equipment forming part of the total cogeneration system.
According to this approach (and as indicated in figure 1) the cogeneration system is distinguished in an electricity generating section and a heat recovery section. The life cycle costs for electricity generation by cogeneration means is then determined by subtracting a certain credit for heat production from the total life cycle costs of the cogeneration system. For a certain value of the specific investment of the electricity generating section $I_e$, these costs will be equal to the life cycle costs of the central electricity generating capacity with which a cost comparison is to be made. The value of this specific investment is then referred to as the (maximum) allowable value $I_{e.all}$.

For each of the generic types of cogeneration application being compared with the appropriate type of central electricity generating plant, the value of $I_{e.all}$ is calculated as a function of fuel price levels and power generating efficiency of the cogeneration process. The assumed values for all other cost and performance parameters are as indicated in table 1.

The method used for calculating $I_{e.all}$ is explained in appendix II. As indicated in eq. (14) this value is determined as the sum of a number of investment terms that can be distinguished in two categories. One concerns actual investments and the other differences in fuel costs that are expressed as equivalent investment allowances.

Investment allowances corresponding to differences in fuel cost

The difference in fuel costs mainly concerns the fuel cost savings according to the specific fuel consumption costs indicated in figure 3. The equivalent (specific) investment allowance $\Delta I_{fcs}$ is calculated as indicated in eq. (12a).

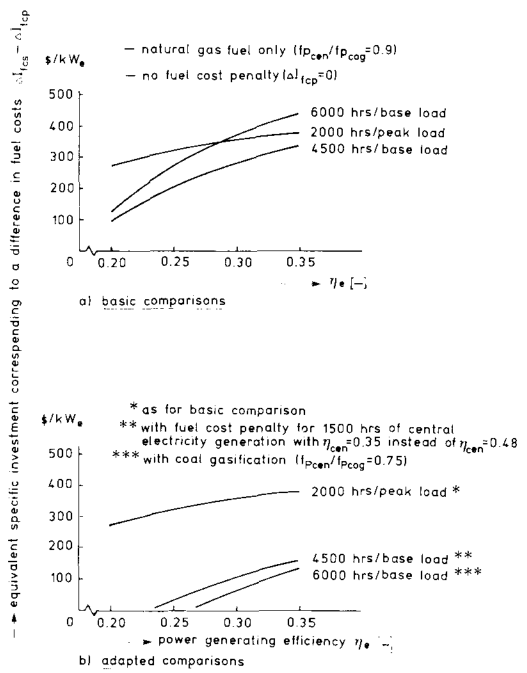



Figure 4 Equivalent specific investment corresponding to net fuel cost savings of cogeneration proces (for cogeneration fuel price $fp_{cog}$=2 ¢/kWh or 5.86 $/MMBt)

The values of $\Delta I_{fcs}$ are presented in fig. 4a as a function of the electricity generating efficiency $\eta_e$ and fuel prices of 2 ¢/kWh and 1.8 ¢/kWh for cogeneration and central electricity generation respectively. This represents the situation of natural gas being used in both cases (fuel price ratio of 0.9).

The results confirm the expectation that due to higher differences in specific fuel consumption costs the yearly fuel cost savings in the 2000 hrs/peak load case are comparable with those for the 4500 hrs/base load and 6000 hrs/base load cases. This notwithstanding the very much lower number of operating hours per year.

This already favourable situation for the 2000 hrs/peak load case is further enhanced when considering two disadvantages that may be expected to especially apply to the base load cases. This concerns the effect of coal gasification reducing the fuel price for central electricity generation and the effect of electricity generation by cogeneration means being limited to periods with a substantial heat demand.

The disadvantageous effect of coal gasification causing the fuel price ratio $fp_{cen}/fp_{cog}$ to decrease from 0.9 to 0.75 is shown in figure 4b for the 6000 hrs/base load case.

The disadvantageous effect of electricity generation by cogeneration means being limited to periods with a substantial heat demand is expected to apply especially to the 4500 hrs/base load case.

The cogeneration installation supplanting base load central electricity generating capacity will in this case result in a reduced availability of high efficiency capacity during the non-heating season. This implies the necessity for an increase in the operating time of central generating capacity with a lower efficiency. The corresponding increase in fuel costs should consequently be debited to the cogeneration system.

The resulting reduction in the equivalent specific investment for the 4500 hrs/base load case is shown in figure 4b for an assumed 1500 hrs of central electricty generation with a thermal efficiency of 0.35 instead of 0.48 (calculated with the use of eq. (13) in appendix II). Obviously the disadvantageous effect would be even greater if it were coupled with the effect of a fuel price decrease due to coal gasification.

Total allowable specific investment $I_{e.all}$

The value of the total allowable specific investment $I_{e.all}$ is determined by adding various (differential) investment terms to the previously determined investment allowances for net savings in fuel costs (eq. (14)).

The main item is an investment allowance conforming to the specific investment $I_{cen}$ of the central electricity generating capacity which is supposed to be supplanted by the cogeneration system. For a combined cycle base load installation (600 $/kW$_e$) this allowance is assumed to be considerably higher than for a simple cycle peak load unit (300 $/kW$_e$).

A next item is indicated by the term H/E x $\Delta I_h$ which represents an increased investment for the heat recovery section of the cogeneration system as compared to an investment credit which is given for supplanting the reference boiler(s). The heat/power ratio acting as a multiplicator indicates that the negative effect on the value of $I_{e.all}$ increases with decreasing value of the electricity generating $\eta_e$ (figure 2).

In the context of this cost analysis the value of $\Delta I_h$ is assumed to be only 25 $/kW$_{th}$, suggesting cogeneration applications that do not require significant investment increases for additional heat transport or heat storage facilities.

Finally there is the possibility of certain credits being allowed as a result of the relatively small scale cogeneration systems providing decentralized electric generating capacity. This concerns credits for a reduction in investments for the electricity grid ($\Delta I_{tr}$) and/or for acting as reserve capacity for providing emergency power in the case of a grid failure ($\Delta I_{res}$). However, because such credits will not basically affect the comparison between the generic cogeneration applications, they are mentioned here for reference purposes only.

The results presented in figure 5a are correspondingly calculated according to eq. (14) for $\Delta I_{tr}$ and $\Delta I_{res}$ being equal to zero. The values of the investment allowance for differences in fuel costs ($\Delta I_{fcs}$ - $\Delta I_{fcp}$) are taken according to what is presented in figure 4b.

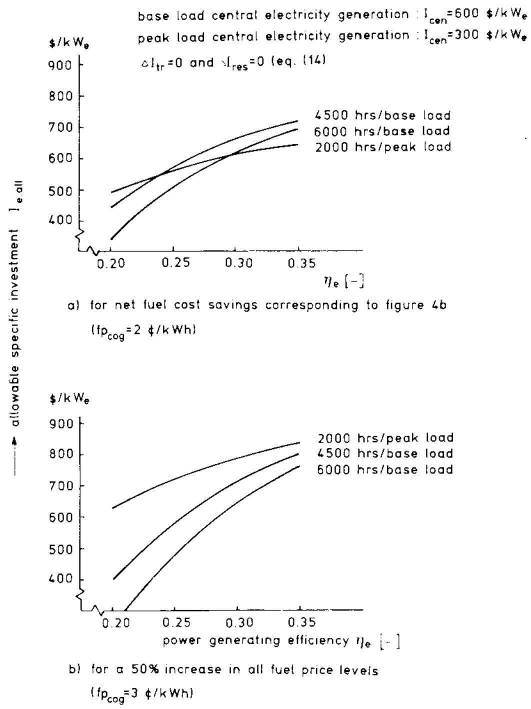



Figure 5 Allowable specific investment for electricity generating section of cogeneration system.

Comparing figure 5a with figure 4b then makes it clear that the marked advantage in fuel cost savings for the 2000 hrs/peak load case would be practically wiped out by the allowance for the specific investment for the supplanted central generating capacity $I_{cen}$ being 300 $/kW$_e$ lower.

However, figure 5b shows that if all fuel prices are assumed to be 50% higher, the 2000 hrs/peak load case will again show a clear advantage over the two base load cases.

These results suggest that with increasing levels of oil- and gas prices the economics of cogeneration will require electricity to be generated mainly during the peak periods of the electricity demand. This trend will be accentuated if a further decrease in fuel price ratio $fp_{cen}/fp_{cog}$ is accompanied by an increase in the thermal efficiency of central electricity generation. This may be the result of further advances in gas turbine technology or to the introduction of new energy conversion technologies, for example fuel cells with basically a higher ceiling for the attainable thermal efficiency.

It also worth noting that the economics of cogeneration in the peak load case are less susceptible to a decrease in the value of the power generating efficiency of the cogeneration process. This suggests that a greater emphasis should be placed on achieving low investment and maintenance costs rather than on achieving the highest level of the power generating efficiency. However, because a lower value of $\eta_e$ also results in an increasingly negative influence of any additional heat recovery investment (proportional to the heat/power ratio H/E), this compromise should not be allowed to go too far.

## CONCLUSIONS

The results of a simplified theoretical cost analysis indicate that future increases in oil- and gas prices will very likely cause the economics of cogeneration to become increasingly more favourable for systems being operated mainly during peak periods of the electricity demand. This applies to the case of an electric utility exploiting relatively small scale gas turbine based cogeneration systems as an alternative to installing new central electricity generating capacity.

## REFERENCE

[1] Utility Turbopower for the 1990s, EPRI Journal, April/May 1988.

## APPENDIX I

### CALCULATION OF LIFE CYCLE COSTS LCC

$$LCC = PWF + PWI + PWM = PWF + (1 + f_m) \times I \qquad \$/kW_e \tag{5}$$

in which:

PWF = present worth of life cycle fuel costs

$$= sfcc \times T \times \left\{1 - \frac{\left(1 - \frac{i-rf}{1+rf}\right)^{-L}}{\frac{i-rf}{1+rf}}\right\} \tag{6}$$

PWI = present worth of investment costs
= initial investment I (for no other investments during life cycle period and residual worth = 0)

PWM = present worth of life cycle maintenance costs

$$= m \times I \times \left\{1 - \frac{\left(1 - \frac{i-rm}{1+rm}\right)^{-L}}{\frac{i-rm}{1+rm}}\right\}$$

$$= f_m \times I \tag{7}$$

and with:

- T = number of equivalent full load operating hours, hrs/yr
- L = life cycle duration, yrs
- i = interest rate
- rf = yearly rate of increase in fuel price level
- rm = yearly rate of increase in maintenance costs
- m = yearly maintenance costs as a proportion of investment I
- $f_m$ = life cycle maintenance costs as a proportion of investment I

## APPENDIX II

### CALCULATION OF (MAXIMUM) ALLOWABLE SPECIFIC INVESTMENT FOR ELECTRICITY GENERATING SECTION OF COGENERATION INSTALLATION ($I_{e.all}$)

From figure 1:

$$I_{cog} = I_e + H/E \times I_h \qquad \$/kW_e \tag{8}$$

in which:

$I_{cog}$ = specific investment of total cogeneration system $\$/kW_e$

$I_e$ = specific investment of the electricity generating section of a cogeneration system $\$/kW_e$

$I_h$ = specific investment of heat recovery section of cogeneration system $\$/kW_{th}$

H/E = heat/power ratio of the cogeneration proces $\left(= \frac{\eta_t - \eta_e}{\eta_e}\right)$

The (maximum) allowable specific investment $I_{e.all}$ is the value of $I_e$ for which the life cycle costs of electricity generation by cogeneration means is equal to life cycle costs for central electricity generation, or:

$$\left\{PWF + I \times (1 + f_m)\right\}_{e.cog} = \left\{PWF + I \times (1 + f_m)\right\}_{cen} \tag{9}$$

The left side of this equation represents a difference between the life cycle costs for the whole cogeneration system and (1 - d/100) x the life cycle costs for a reference boiler system (d = a discount percentage).

Disregarding certain cost credits and cost penalties, and introducing a number of simplifying assumptions, the value of $I_{e.all}$ can be calculated as follows.

$$I_{e.cog} = I_{cog} - H/E \times (1 - d/100) \times I_b \quad \$/kW_e \tag{10}$$

In which $I_b$ = specific investment of reference boiler in $\$/kW_{th}$.

Combining eq. (8) and (10) and with $I_e = I_{e.all}$:

$$I_{e.cog} = I_{e.all} + \frac{H}{E} \times \left\{I_h - (1 - \frac{d}{100}) \times I_b\right\}$$

$$= I_{e.all} + \frac{H}{E} \times \Delta I_h \qquad \$/kW_e \tag{11}$$

Assuming m, $r_m$, $r_f$ and L to be the same for all installations, and combining (9) and (11):

$$I_{e.all} = \frac{PWF_{cen} - PWF_{e.cog}}{1 + f_m} + I_{cen} - H/E \times \Delta I_h \tag{12}$$

in which the equivalent specific investment differential corresponding to the fuel cost savings is:

$$\Delta I_{fcs} = \frac{PWF_{cen} - PWF_{e.cog}}{1 + f_m} \tag{12a}$$

$PWF_{e.cog}$: calculate with the use of equations (4) and (6)

$PWF_{cen}$ : calculate with the use of equations (3) and (6)

The disregarded cost credits and penalties concern the following:

- A fuel cost penalty due to cogeneration operation being limited to periods with a substantial heat demand. When supplanting base load central electricity generating capacity with a high thermal efficiency $\eta_1$, this may lead to the need for T'hrs/yr of central electricity generation with a lower thermal efficiency $\eta_2$. The equivalent specific investment differential corresponding to this fuel cost penalty is calculated with the equation:

$$\Delta I_{fcp} = \frac{PWF_2 - PWF_1}{1 + f_m} \tag{13}$$

- (Possible) credits for the cogeneration system due to the decentralization of electric generating capacity. This concerns reduced investments for electricity transport ($\Delta I_{tr}$) and availability of reserve capacity for providing emergency power in the case of a failure of the main electricity grid ($\Delta I_{res}$).

Taking into account these additional terms changes (12) to:

$$I_{e.all} = \Delta I_{fcs} - \Delta I_{fcp} + I_{cen} + \Delta I_{tr} + \Delta I_{res} - H/E \times \Delta I_h \ \$/kW_e \tag{14}$$