Economic evaluation of independent CHP projects

Aviel Verbruggen, Nadine Dufait and Adwin Martens

This article discusses the economic evaluation of CHP projects from the point of view of non-utility investors (industries, commercial facilities, local authorities). To obtain reliable estimates of CHP profitability, it is necessary to simulate the hourly operation of a CHP plant. This involves detailed modelling of the three most important determinants of economic profitability: electricity and heat load profiles, characteristics and size of the proposed CHP plant, and the electricity tariff conditions. Our computer model which copes with hourly detailed variations is described briefly. Results from case studies with the model show the high sensitivity of CHP profitability to variations in crucial parameters eg electricity and heat load patterns, reliability and size of the CHP plant.

Keywords: CHP; Economic evaluation; Modelling

In several policy plans for stimulating rational energy use, combined heat and power or CHP is proposed as an important tool to save on primary energy and to reduce environmental damage. For industry, commerce, and the residential sector CHP is a proven technology which can allow significant energy cost savings.

An industrialist or other non-utility investor who wants to build a CHP plant has to consider many aspects that influence the feasibility of the project. Figure 1 shows the flowchart of his decision path, consisting of seven steps numbered S1 to S7. Step 1 is the analysis of the electricity/heat load patterns of those applications to be provided with energy from the CHP plant. The results of this analysis offer a basis for initial design of a CHP system (S2). In step 3 this concept is evaluated by estimating the energy cost savings and the costs of CHP (operating costs, investment costs, insurance . . .). The energy cost savings follow from comparing boiler fuel costs and electricity purchase costs in the present situation (ie without CHP) with the CHP fuel costs and the electricity costs with CHP. Electricity tariffs (price of complementary and back up electricity, remuneration of surplus electricity delivered to the grid) and fuel prices for CHP are publicly regulated or must be negotiated with the utility/primary energy supplier (S4). Governmental financial support (investment subsidies, tax credits . . .) is also included in the profitability analysis.

In step 5 (S5) benefits and costs are balanced. When the analysis shows that the CHP design is not acceptably profitable, the project can be redesigned or the idea may be abandoned. When the CHP project which technically matches the requisite electricity/heat loads shows a sufficient return the investor looks for the best way of financing the project (S6). Before implementation, (S7) he has to take care that all relevant regulations/legislation are met eg building licences, environmental protection rules etc.

Modelling industrial CHP

Model components

The economic profitability of a CHP project is determined by three groups of factors:

- the electricity and heat loads and load profiles;
- the technical and economic parameters of the suitable CHP plant; and
- the conditions for grid connection and the electricity tariffs.

Aviel Verbruggen is with the Universitaire Faculteiten Sint-Ignatius (UFSIA), Prinsstraat 13, B-2000 Antwerpen, Belgium; Nadine Dufait and Adwin Martens are with Vlaamse Instelling voor Technologisch Onderzoek (VITO), Boeretang 200, B-2400 Mol, Belgium.

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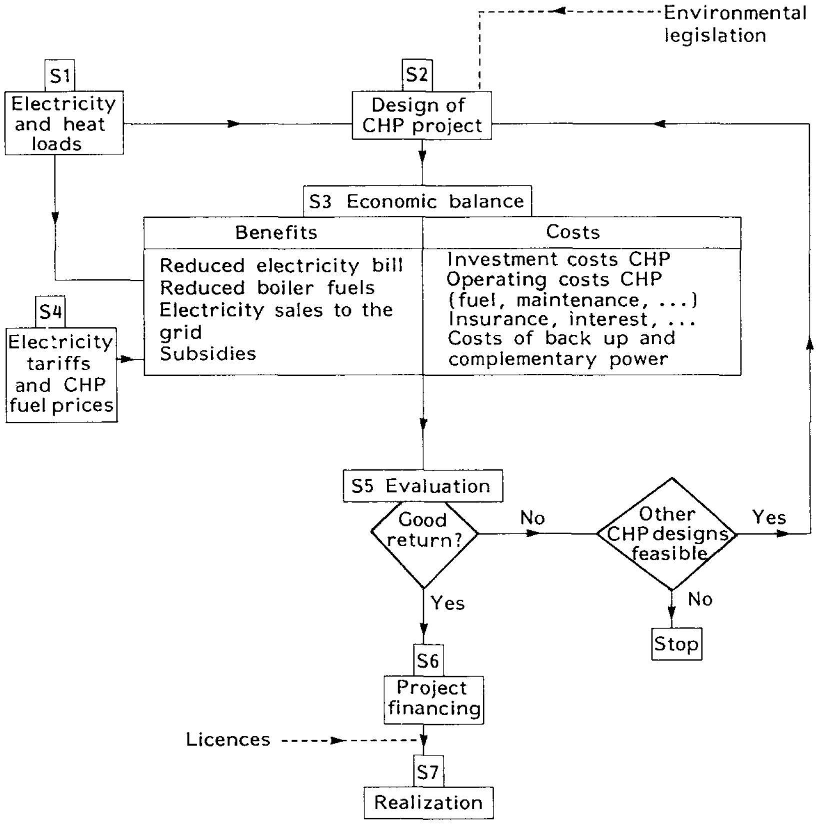

Figure 1. Flowchart of CHP project evaluation.

Detailed modelling of these factors is necessary to obtain reliable estimates of CHP return. Using overall aggregates and averages (global electricity and heat demand instead of hourly demand, average electricity prices instead of exact tariff structures and so on) results in overestimation of the profitability of a CHP installation.

At the University of Antwerp (UFSIA/SESO) a computer model has been developed to analyse CHP investments, and this model has been adopted and developed at VITO.[1] The model can cope with hourly detail. It simulates the operation of a CHP plant hour by hour for every hour of the year; the simultaneous heat and electricity demand of a facility is compared with the heat and electricity production possibilities of a CHP installation.

Modelling electricity/heat load patterns

For every hour of the year electricity and heat loads are estimated and their ratio is compared with the electricity/heat production ratio of the CHP installation. Not many firms know their hourly electricity and heat requirements. COHEPO is a computer program that turns available information about the heat and electricity demand during a representative year into simultaneous hourly demand patterns. The input data for COHEPO are, therefore, first the quantities of electricity and heat required by the facility, and second the information about the time of occurrence of the loads.

First we consider the yearly heat and electricity demand of those processes in the firm that is to be provided with energy from the CHP installation. This input can be given at different hierarchical levels, shown in Figure 2. For example, total electricity demand (level 1) is shown as the aggregate of electricity for industrial processes, for space heating and for lighting applications (level 2). Total heat demand (level 1) is the sum of heat for industrial processes and for space heating (level 2). Level 3 distinguishes different process units.

Second, we want to represent the patterns of heat and electricity demand of the facility or of the several processes or process units. Here the model also uses different hierarchical levels of data input, shown in Figure 3. The year analysed is structured by means of typical weeks (TW) and typical days (TD). Weeks with a similar demand pattern refer to the same typical week. Each week of the year analysed is indexed according to its peak demand level in relation to the yearly peak demand. Figure 4 is an example of electricity demand during three

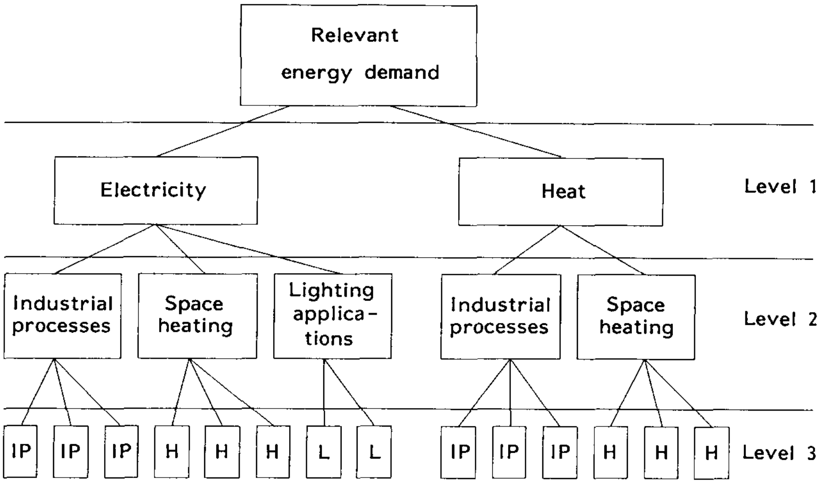

Figure 2. Process levels distinguished and modelled in COHEPO.[a]
[a]IP = industrial process unit; L = lighting unit, H = heating unit.

weeks. The evolution of demand during week 12 and week 33 is similar. They refer to the same typical week. Week 23 is a different typical week. Let the peak demand of the year occur in week 33. Then an index of 100 is assigned to week 33. Weeks 12 and 23 are indexed as 50 and 75 respectively by comparing their peaks to that in week 33. Weeks of the same type are composed of the same typical days.

A typical day represents all days with a similar hourly demand pattern. Every day of the week has an index compared to 100, this maximum value being attributed to the peak load day of the week. A typical day can show the loads differently at all 24 hours of the day, or constant loads during a sequence of hours can be brought together in segments. The hours or segments are indexed according to their demand level relative to the peak during the day. Corresponding segments of all days of the same type receive the same index number. Table 1 gives an example of the relationship between typical weeks, typical days and segments.

The accuracy of the output of the model COHEPO, ie the profiles of electricity and heat demand of the relevant processes for every hour of the year, is dependent on the availability of input data. If the information from Figures 3 and 4 is given in a detailed way at all levels, the hourly demand values will be realistic.

Modelling CHP technologies

Common CHP techniques are internal combustion engines (gas or diesel engine), gas turbines and steam turbines. Internal combustion engines, mainly recovering heat as hot water, are not usual in industrial CHP systems, because of the steam (eg 10 bar) requirements.

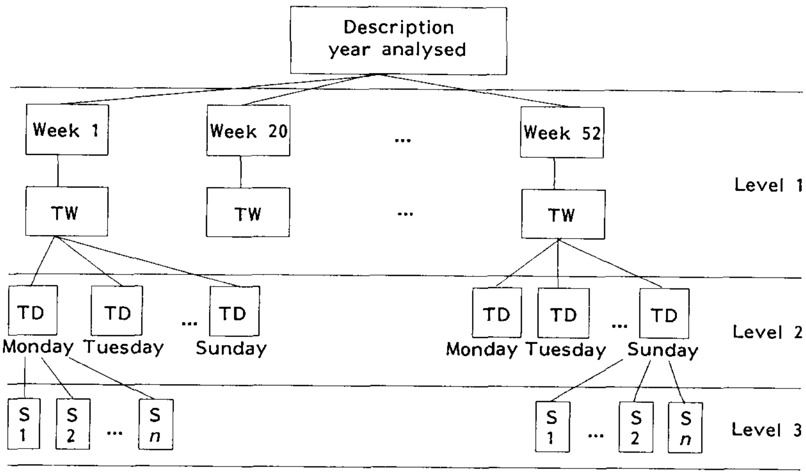

Figure 3. Levels of period characterized by COHEPO.[a]
[a]TW = typical week; S = segment; TD = typical day.

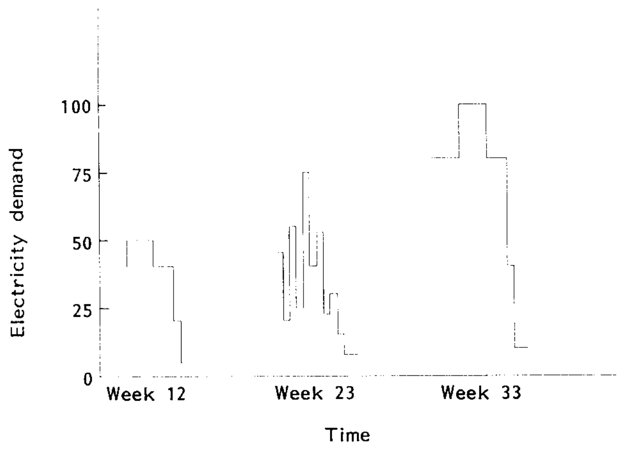

Figure 4. Electricity demand pattern of three different weeks.

Table 2 shows the main characteristics of CHP techniques, including the combined cycle, consisting of a gas and a steam turbine. The values mentioned in the table are representative ranges only and should be used with care.

The model SIMCHP is based on the principle of production possibility sets.[2] A production possibility set (PPS) describes the possibilities of the simultaneous production of heat and power by a CHP system in the heat/power plane, illustrating *inter alia* the boundaries of operating a CHP system. If the hourly electricity and heat demands of an industrial plant (output of model COHEPO) are set out in the same heat/power plane, it can easily be verified whether the plant can meet the energy requirements of the facility.

Figure 5 shows typical production possibility sets of the common CHP processes. In order to compare the PPSs of the various processes, the electric capacity at maximum power and heat output (point A) of each process is equal to 100 units.

The PPSs of an internal combustion engine (Figure 5a) and a gas turbine (Figure 5b) look very similar. Strictly speaking the PPSs of these technologies are represented by the curves AB. If the energy demand point is situated at the left side of segment AB (ie the dashed area) it is possible to meet the (heat–power) loads by valorizing only part of the heat output of the CHP process. So the practical PPS of an engine and of a gas turbine can be represented by areas $ABCD$.

In a back pressure turbine, steam expands to a pressure level dependent on the steam requirements of the industrial process. Because there is no cold condenser (low pressure, near vacuum) available, a back pressure turbine cannot be operated when there is no heat load. That is why the PPS is a small pin, the width of which depends on the layout and performance of the hot water or steam condenser(s) (Figure 5c).

In an extraction/condensing steam cycle (Figure 5d) only part of the steam input is extracted at the required pressure and temperature level(s), the remaining steam expanding to a low pressure level (condenser pressure eg 0.05 bar). Unlike the back pressure turbine, the ratio between the amount of heat and electricity produced by an extraction/condensing turbine is widely variable (see Figure 5d).

Along segment AB the plant operates as a back pressure turbine. If live steam supply to the turbine is kept constant at lower heat loads, more of the steam mass expands to the low pressure of a condenser resulting in an increase in electricity production (curve AD). The maximum electricity production (point D) occurs at maximum live steam flow without heat extraction: all steam expands to condenser

Table 1. Example of model input for structuring hourly load profiles for a year.

The year as a sequence of weeks

Number of week	**Reference to typical week (TW)**	**Index relative to yearly peak load**
12	TW1	50
23	TW2	75
33	TW1	100

Description of the typical weeks considered

Typical weeks (TW)	**Monday**		**Tuesday**		**Wednesday**		**Thursday**		**Friday**		**Saturday**		**Sunday**	
	Ref[a]	**Ind[b]**	**Ref[a]**	**Ind[b]**	**Ref[a]**	**Ind[b]**	**Ref[a]**	**Ind[b]**	**Ref[a]**	**Ind[b]**	**Ref[a]**	**Ind[b]**	**Ref[a]**	**Ind[b]**
TW1	TD1	80	TD1	80	TD1	100	TD1	100	TD1	80	TD2	80	TD1	10
TW2	TD2	60	TD2	60	TD2	70	TD2	100	TD2	75	TD2	40	TD1	10

Description of the typical days considered

Typical day (TD)	**Segment 1 6h–8h Ind[b]**	**Segment 2 8h–13h Ind[b]**	**Segment 3 13h–18h Ind[b]**	**Segment 4 18h–6h Ind[b]**
TD1	100	100	100	100
TD2	100	100	50	50

Notes: [a]Ref = reference to typical day; [b]Ind = index.

Table 2. Characteristics of CHP technologies.

CHP technology	Unit size[a] (MW_e)	Heat/power ratio (MW_{th}/MW_e)	Electric efficiency (%)	Overall efficiency (%)
Gas engine	0.02 – 2	1.5 – 2.0	25 – 35	80 – 90
Diesel engine	0.07 – 30	1.2 – 1.4	35 – 45	75 – 80
Gas turbine	0.30 – 100	1.5 – 3.0[b]	15 – 35	70 – 85
Steam turbine:				
Back pressure	0.5 – 50	3.0 – 8.0	10 – 30	75 – 90
Extracting/condensing	10.0 – 100	2.0 – 5.0	20 – 40	70 – 80
Combined cycle	3.0 – 100	1.0 – 1.5	30 – 45	80 – 90

Notes: [a]A maximum size of 100 MW_e is mentioned, although larger units have been built; [b]without supplementary firing.

pressure and the turbine is being operated like a condensing turbine.

If the instantaneous power–heat load combination is situated outside the PPS of a CHP system, one or a mixture of the following measures must be taken in order to match electricity and heat loads:

- purchasing electricity from the grid;
- selling electricity to the grid;
- producing heat in additional boilers; or
- wasting heat in a cooling tower.

Of course, the CHP plant must be equipped with the necessary hardware to take the above measures, eg the plant must be connected to the power grid.

The costs of various measures for meeting electricity and heat load combinations are calculated hourly in our model: SIMCHP chooses the hourly operating point of the CHP plant where heat and electricity demand are met at the lowest operating costs (economic optimum).

Modelling electricity tariffs

In many industrial nations electricity tariffs are based on the time of day, because electricity differs in value according to when it is supplied, eg distinction is made between peak, average and off peak hours. A distinction between different seasons shows that electricity has a time value: electricity bought during winter is more expensive than during summer in moderate climate areas, the reverse being true in sunbelts with high cooling loads.

Most electricity tariffs are two part with a variable (kWh) and a fixed (kW) term. The fixed part of the electricity bill can be based on different methods of capacity measurement eg on maximum or average capacity demand during the various tariff peiods, or on the difference between subscribed and actual peak load etc.

An investment analysis of a CHP project should take into account the details of the entire tariff structure. This is true for the electricity tariffs in a situation with or without CHP. Tariff conditions for CHP cover three major issues:

- Complementary electricity purchased from the grid: when a CHP plant in normal operation cannot meet the full power load, complementary power has to be purchased from the grid. Attention should be paid to the time dependence of the applied electricity tariffs.
- Back up power: if a two-part tariff for complementary electricity (when the CHP plant is

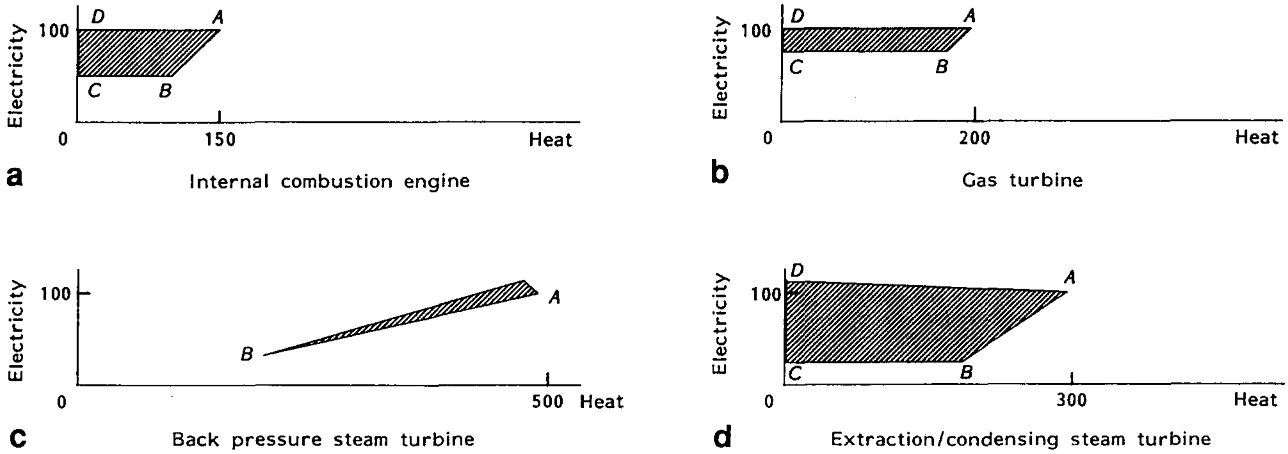

Figure 5. Production possibility sets of CHP process (capacities shown relative to maximum power output = 100).

operating) is also applied for delivering back up electricity when the CHP plant is out of order, the cost of back up power is dependent on the weight of the fixed term in the tariff and on the mode of charging capacity demand (based on maximum, average capacities, measured by time of day etc). If evaluations are based on average electricity prices, the negative impact of charging back up power as complementary power on the profitability of CHP will be underestimated. If the cogenerator can sign a separate contract for back up power, the calculation model should include the modalities of the contract such as back up power prices according to reliability of the CHP installation, several periods with different prices, the possibility of switching from the special back up meter to the meter measuring complementary electricity, the maximum allowed consumption of back up kWh, etc.

- Remuneration of cogenerated electricity delivered to the grid by the CHP plant: here also, the precise programming of the electricity tariff is important, because surplus electricity delivered to the grid is not always remunerated in particular tariff periods and because capacity allowance generally varies by time of day.

SIMCHP gives a full account of the Belgian electricity tariffs,[3] being quite elaborated. High-voltage customers are divided into three tariff groups, A, B and C, depending on the yearly capacity demand and on load duration:

Group A: capacity < 1 MW_e
or 1 MW_e $<$ capacity $<$ 4 MW_e and load duration $<$ 4000 hours
Group B: 1 MW_e $<$ capacity $<$ 4 MW_e and load duration $>$ 4000 hours
Group C: capacity $>$ 4 MW_e

Very large consumers negotiate an individual contract with the electric utility.

The tariffs have two important characteristics. The Belgian electricity supply being based on capital intensive power plants using cheap fuels (nuclear, coal), the electricity tariffs are two part with a high fixed term and a low variable term. The high fixed term is applied to the monthly peak demand measured during a quarter of an hour. This results in a significant fixed portion of the electricity bill (generally between 50 and 75% of total billing). In addition, the tariffs allow time of day pricing, distinguishing peak, average and off peak hours. Off peak hours are at night and weekends. Customers of class A and B can opt for a time of day and seasonally different tariff taking into account three seasons (winter, spring and autumn, summer) and peak hours during working daytimes in winter. Class C customers can opt for a seasonal tariff.

Cogenerators are charged the same tariff for complementary and back up electricity. Customers with a peak less than 4 MW_e before they start a CHP unit are charged the time of day and seasonally different tariffs. For class C customers the C seasonal tariff is valid but a penalty is added to the already very high fixed term during the four winter months.

The remuneration tariff for surplus electricity delivered to the grid is derived from the C seasonal tariff. The fuel term is the same. The capacity term is reduced and applied to the minimum capacities delivered during the average and peak hours (2×2 hours a day during the winter months, 3 hours a day during the other months except July and August). Capacity delivered during off peak hours and during July and August is not paid for by the grid.

Case study of CHP in a chemical plant

To illustrate the performance of the model, the analysis of a CHP project in a chemical plant is presented.

Energy demand of the chemical plant

The plant is in operation 351 days a year on a continuous, 24 hour a day, 7 day a week basis (8424 hours a year). During two weeks in June the plant is shut down for maintenance activities. The annual electricity demand is 174.3 GWh. The average electric load during night (from 10.00 pm until 6.00 am) is 50% of that during day (about 25 MW_e). Before installing CHP all electricity was purchased from the grid (C seasonal tariff).

The plant requires heat in the form of saturated steam of 25 bar. The annual heat demand amounts to 1524 TJ. About 75% of the annual steam demand is used in processes, the remaining 25% being used for space heating. Originally all steam required was generated in a natural gas fired boiler. Figure 6 shows the energy demand fluctuations during January.

Description of the CHP system

Technical aspects. On the basis of the average electric load during the day (25 MW_e), the heat quality required (saturated steam of 25 bar), the average heat/power ratio (about 2.4) and the availability of natural gas, a CHP system consisting of a natural gas fired gas turbine with supplementary fired waste heat boiler is an attractive option. Figure 7 gives an overview of the CHP plant. The electric efficiency of

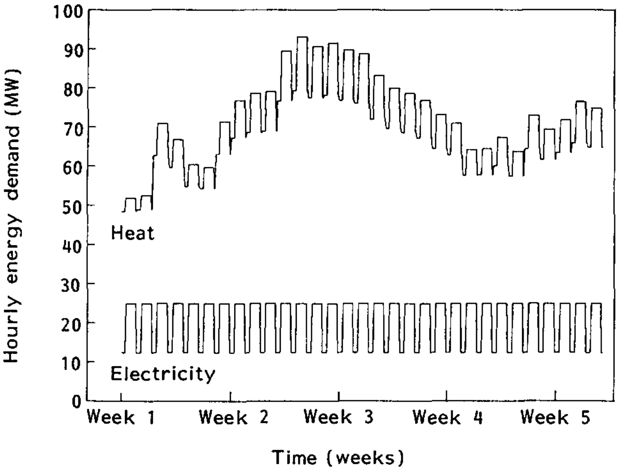

Figure 6. Energy demand during January.

the gas turbine is 34%. The overall efficiency of the CHP plant varies between 82% (no supplementary firing) and 87% (maximum supplementary firing). In the reference situation the unplanned unavailability is assumed to be 0%. All maintenance activities are supposed to be carried out during the two weeks in summer when the chemical plant is shut down.

Economic aspects. The investment costs of the CHP system amount to BF714 million (US$21 million),[4] the variable exploitation costs (excluding fuel costs) to BF2005 (US$59) per running hour;[5] the lifetime of the CHP system is expected to be 15 years. The average industrial fuel price of natural gas is BF132/GJ (US$3.9/GJ).

Results model calculation

The CHP system runs for 6582 hours, producing 158.0 GWh electricity and 1524 GJ heat (including 718 GJ supplementary firing); 27.5 GWh of electricity is purchased from and 11.2 GWh is sold to the grid. The primary energy savings resulting from the operation of the CHP system are determined by comparison with the original system, assuming a central electricity production efficiency of 37% and a boiler efficiency of 95% (Table 3). From Table 3 it appears that annual savings of primary energy amount to 605.9 TJ or 18.4% of present consumption. According to Table 4 the annual energy cost savings are US$4.8 million or 29.8% of present expenditure.

Table 5 shows the investment analysis of the reference scenario. From Table 5 it appears that the simple payback period of the CHP project is 4.8 years and the internal rate of return amounts to 20.0%. As such this project is very typical of most CHP opportunities: profitability is borderline for private investors but well above the standards applied by utilities. When the payback gap in energy decision making cannot be bridged CHP will be developed far below its optimum social level.

Table 3. Annual primary energy consumption.

Energy consumption	No CHP	CHP
Fuel		
Boiler (TJ)	1603.8	–
CHP plant (TJ)	–	2426.2
Electricity		
Purchased from the grid (GWh)	174.3	27.5
Corresponding primary energy use in public supply system (TJ)	1695.9	267.6
Total primary energy consumption (TJ)	3299.7	2693.8

Table 4. Annual energy costs reference situation (US$ million).

	No CHP	CHP
Fuel costs	6.2	9.4
Power costs	9.9	1.9
Total energy costs	16.1	11.3

Table 5. Investment analysis reference case (US$ million).

Total investment costs CHP	21.0
Calculation yearly benefit	
Yearly energy cost savings	4.8
Yearly exploitation costs CHP (excluding fuel)	0.4
Total yearly net exploitation result	4.4
Profitability values	
Simple payback period (years)	4.8
Internal rate of return (%)	20.0

Variations on the reference situation

In addition to the reference scenario, we investigated six other cases (see Table 6 for an overview).

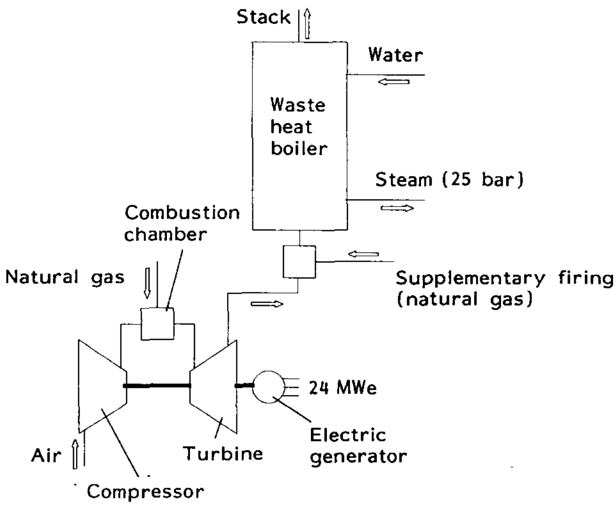

Figure 7. Gas turbine with supplementary firing.

Table 6. Results of model calculations.

	Reference scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4 Scenario 4a	Scenario 4b	Scenario 5	Scenario 6
Characterization scenario								
CHP plant								
Prime mover	1 gas turbine	1 gas turbine	1 gas turbine	1 gas turbine	2 gas turbines	2 gas turbines	2 gas turbines	2 gas turbines
Unit size (MW_e)	24	24	24	24	12	12	12	12
Electricity efficiency of gas turbine (%)	34	34	34	34	32	34	32	32
Electricity demand pattern	Constant	Seasonal	Constant	Constant	Constant	Constant	Constant	Constant
Failures	0	0	1	2	0	0	1	2
Simulation results								
Electricity production CHP (GWh)	158.0	158.1	152.7	152.6	168.5	168.5	168.4	168.4
Net electricity purchases[a] (GWh)	16.3	16.2	21.6	21.7	5.8	5.8	5.8	5.9
Energy costs CHP (US$ million)								
Fuel	9.4	9.4	9.3	9.3	10.0	9.6	10.0	10.0
Electricity[a]	1.9	1.8	2.5	2.6	0.4	0.4	0.7	0.8
Total energy costs CHP	11.3	11.2	11.8	11.9	10.4	10.0	10.7	10.8
Energy costs no CHP	16.1	15.8	16.1	16.1	16.1	16.1	16.1	16.1
Energy cost savings	4.8	4.6	4.3	4.2	5.7	6.1	5.4	5.3
Energy cost savings (%)	29.8	29.2	26.4	25.8	35.3	38.1	33.4	32.8
Simple payback period (years)	4.8	5.0	5.4	5.6	4.7	4.3	5.0	5.1
Internal rate of return (%)	20.0	19.0	17.0	17.0	20.0	22.0	19.0	18.0

Notes: [a]Electricity purchases – electricity sales.

Table 7. Diseconomies of scale of smaller gas turbines.

	Gas turbine 24 MW_e	Gas turbine 12 MW_e
Specific investment costs (US$/$kW_e$)	875	1005
Specific operating costs (US$/$kWh_e$)	0.0025	0.0034

Variation electricity/heat load pattern. In contrast to the reference case where electricity demand is constant during all seasons of the year, in scenario 1 the electricity demand during summer is significantly larger than during winter. In order to compare the results of the reference situation with scenario 1 total annual electricity demand is kept constant.

Including CHP plant power cuts. In scenario 2 and 3 it is assumed that the CHP plant fails once or twice a year:

- Scenario 2: power cut for 3 power system average hours in winter.
- Scenario 3: power cut for 3 power system average hours in winter and 4 power system average hours in summer.

Scenarios 2 and 3 correspond to a reliability (maintenance downtime excluded) of 99.97% and 99.92% respectively, which is very high.

Changing CHP technology. In scenarios 4, 5 and 6 a CHP plant consisting of two smaller gas turbines (2 × 12 MW_e) instead of one large gas turbine (24 MW_e) is considered. The smaller gas turbines have an electric efficiency of 32% (large gas turbine: 34%). In scenario 4b a calculation is made with an electric efficiency of 34% for the small turbines.

- Scenario 4: no power cuts; 4a, electric efficiency gas turbines 32%; 4b, electric efficiency gas turbines 34%.
- Scenario 5: power cut of one gas turbine for 3 power system average hours in winter.
- Scenario 6: power cut of one gas turbine for 3 power system average hours in winter and during 4 power system average hours in summer.

Table 6 shows the simulation results of the different scenarios. These results will be discussed briefly.

Variation electricity/heat demand pattern. In scenario 1 the CHP plant runs for 6588 hours (reference scenario 6582 hours). As a result of the seasonal electricity demand fluctuations, electricity purchases and sales are 49% and 122% respectively higher than in the reference case, resulting in a reduction in annual power costs of US$0.1 million. From Table 6 it appears that the energy cost savings in scenario 1 are US$0.2 million less than in the reference case, causing a prolonged payback period (an additional 0.2 years) and a lower internal rate of return (1.0%).

Including CHP plant break downs. In Belgium back up electricity is charged as complementary electricity. The fixed term of the tariff for additional electricity is applied to the maximum power demand during a quarter of an hour of the month. Therefore, the fixed part of the monthly electricity bill is based on the maximum power demand during power failures of the CHP plant.

A failure in February during average hours (scenario 2) results in an increase in yearly electricity costs of 32% and extends the payback period by about 7 months. An additional shutdown in summer (scenario 3) raises electricity costs by 37%. Note that this is only 5% more than in scenario 2 because the second failure occurs in a summer month for which the fixed part in the Belgian electricity tariff is only 35% of the fixed part for a winter month. Additional failures in other months would result in a further encroachment on profitability.

In all countries where the weight of the fixed part in a two-part electricity tariff is significant and no separate contract for back up power is possible, only CHP installations which are extremely reliable can be profitable. Auxiliary equipment should also be of high quality, for unplanned unavailability of CHP units is mostly due to failures of auxiliary equipment.

Changing CHP technology. Diseconomies of scale in investment and operation are significant when replacing a large gas turbine by two smaller ones. Table 7 shows the specific investment costs (per kW_e) and specific operating costs (per kW_e, excluding fuel costs) of gas turbines of 24 MW_e and 12 MW_e.[6] The specific investment and operating costs of a gas turbine of 12 MW_e are 15% and 36% respectively higher than those of a 24 MW_e gas turbine.

Because of the pronounced day/night pattern of electricity demand, the two gas turbines even with a lower electricity efficiency of 32% (scenario 4a) still increase energy cost savings by 5.5% compared to the reference situation. However, diseconomies of scale nullify this improvement in energy cost saving, leading to a profitability that is about the same as in the reference case. Scenario 4b compared to 4a shows that the reduction in electric efficiency by 2% increases the payback period by 0.4 years and lowers the internal rate of return by 2%. We observe a significant difference in economic viability between a CHP plant consisting of one large rather than two smaller gas turbines when breakdowns are taken into account. In scenarios 5 and 6 the profitability of the two gas turbines is considered assuming that one of the gas turbines fails twice a year. Scenario 5 is compared with scenario 2 (one gas turbine, one failure), scenario 6 with 3 (one gas turbine, two failures).

One of two gas turbines of 12 MW_e failing in February results in a decrease in electricity costs of US$1.8 million as compared with the failure of one 24 MW_e gas turbine; but this positive effect is partly undone by the higher fuel costs of the CHP installation (one gas turbine of 12 MW_e is still working). The energy cost savings in scenario 5 are significantly higher (7.0%), resulting in a payback period that is 0.4 years shorter than in scenario 2. In case of two breakdowns (scenario 6) the energy cost savings are also 7.0% higher than in scenario 3, reducing the payback period by 0.5 years.

In order to compare the impact of breakdowns on the payback period of different plant configurations, the following ratios are calculated:

$$\frac{\text{Payback period scenario 2}}{\text{Payback period reference scenario}} = 1.13$$

$$\frac{\text{Payback period scenario 5}}{\text{Payback period scenario 4a}} = 1.06$$

It appears that a parallel configuration of smaller units instead of one large unit strongly reduces the impact of breakdowns on the profitability. Therefore, especially in countries where the fixed portions in two part electricity tariffs are high and where a separate contract for back up power is not offered, parallel configurations of small CHP units can be attractive in spite of diseconomies of scale.

Conclusion

Estimating the economic profitability of a CHP project requires the simulation of the hourly operation of the CHP plant. This involves detailed modelling of the three most important determinants of economic profitability of a CHP project ie hourly electricity and heat loads, characteristics of the CHP technology and electricity tariff conditions.

For this purpose a computer simulation program has been developed and is described briefly in this article. A few results are presented, showing the need for detailed knowledge about the electricity and heat load patterns of the facility, about the impact of failures and about the diseconomies of scale when replacing a large CHP unit by smaller ones. The sensitivity of CHP profitability to variations in the crucial parameters is high. This sensitivity is not exposed when CHP projects are evaluated by rough and ready tools based on performance indicators using average values. A thorough analysis of proposed CHP projects carries a high return. Such analysis cannot be peformed without state of the art computer models that were developed by several people. Our model aims at an hourly scanning of CHP performance and has proved to closely match reality.

We have observed our models predicting payback times that are about twice those promised by engineering–contractor–vendor companies of CHP equipment. The CHP market should be provided with the right numbers and not with window dressing.

We have also found that most viable CHP projects have payback times between three and six years. This is borderline or beyond the requirements of most private investors but well within the profitability criteria of energy utilities. This shows the crucial importance of bridging the well known payback gap in energy policy decision making for CHP to have a bright future.

[1]F. Dierick and A. Verbruggen, *Modellisatie van de vraag naar electriciteit en naar warmte in een onderneming of instelling*, UFSIA/SESO, Antwerp, January 1987; Aviel Verbruggen, 'A system model of combined heat and power generation in district heating', *Resources and Energy*, No 4, North-Holland Publishing Company, 1982, pp 231–263.
[2]*Ibid*, Verbruggen.
[3]BCEO (Central Electricity Board), *Hoogspanningstarieven voor leveringen in het distributienet*, Document BCEO No 3176, Brussels, January 1992; BCEO, *Hoogspanningstarieven voor leveringen aan de secundaire klemmen van de grote posten, spanning van 15 kV of lager*, Document BCEO No 3177, Brussels, January 1992; BCEO, *Tarieven voor aankoop bij zelfproducenten, spanning van 15 kV of lager*, Document BCEO No 3178, Brussels, January 1992.
[4]US$1 = BF34; Kornelius Blok, *On the Reduction of Carbon Dioxide Emissions*, University of Utrecht, Utrecht, 1991, pp 98–99.
[5]*Ibid*.
[6]*Ibid*.