LONG-TERM OPTIMISATION CASE STUDIES FOR COMBINED HEAT AND POWER SYSTEM

by

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In the next years distributed poly-generation systems are expected to play an increasingly important role in the electricity infrastructure and market. The successful spread of small-scale generation either connected to the distribution network or on the customer side of the meter depends on diverse issues, such as the possibilities of technical implementation, resource availability, environmental aspects, and regulation and market conditions. The aim of this approach is to develop an economic and parametric analysis of a distributed generation system based on gas turbines able to satisfy the energy demand of a typical hotel complex. Here, the economic performance of six cases combining different designs and regimes of operation is shown. The software Turbomatch, the gas turbine performance code of Cranfield University, was used to simulate the off-design performance of the engines in different ambient and load conditions. A clear distinction between cases running at full load and following the load could be observed in the results. Full load regime can give a shorter return on the investment then following the load. In spite combined heat and power systems being currently not economically attractive, this scenario may change in future due to environmental regulations and unavailability of low price fuel for large centralised power stations. Combined heat and power has a significant potential although it requires favourable legislative and fair energy market conditions to successfully increase its share in the power generation market.

Key words: *combined heat power, distributed generation, gas turbines*

Introduction

Increased demand on national power systems and incidence of electricity shortages, power quality problems, rolling blackouts, and electricity price spikes have caused many utility customers to seek other sources of high-quality, reliable electricity. Distributed poly-generation (DP), provide an alternative to, or an enhancement of, the traditional electric power grid. In essence, DP consists in electricity generation units placed strategically near to consumers and load centres, providing benefits to the user and a support to the operation of the distribution's grid.

DP has found a potential application in self- or domestic-generation, combined heat and power systems (CHP), and peak load shaving. CHP is the combined production of electricity and useful thermal energy from the same primary energy source. In CHP systems the residual heat is used to cover the thermal demand of an installation. Sale of electricity surplus to the grid maybe possible depending on the possibility to connect to the grid and the interest of local utilities. Small CHP systems have a typical efficiency of 72% and NO_X and CO_2 emissions can be up to 7 ppmv and 3.5-15% O_2, respectively, when fuelled with natural gas. The units are therefore clean enough to be sited among residential and commercial establishments [1].

The aim of this approach is to develop an economical and parametric analysis of a DP system based on gas turbines (GT) able to satisfy the energy demand of a Hotel located in Northern Greece. The number and the capacity of the hotel units in Greece are growing continuously. The majority of the existing hotels are consuming relatively high amounts of energy. Electricity is the most consumed energy source, while petroleum and natural gas are lagging. The usage of alternative energy sources is still low.

Energy demand analysis and design of the power system

Human activities are becoming increasingly energy demanding and affecting the environmental. When evaluating human interactions with the environment it is useful to have detailed information on the energy demand and the seasonal factors that influenced it. Despite of its importance, this sort of information is not often found in one unique source with sufficient detail. Then an extensive search has been carried out to collect all the data relevant to quantify the energetic demand of a hotel complex. Before making an investment, an evaluation of the energy consumption and the economic merit must be carried out. The knowledge of the investment's energy profile, gives the opportunity to understand environmental impact and the costs involved in the project.

The hotel is located in Northern Greece next to the sea level and the climate of the region is "Mediterranean" *i. e.* relatively cool summers and mild winters. The operation of the hotel is seasonal: it opens in April and closes in October each year.

In order to select the equipment for the CHP system, it is necessary to understand the energy demand required for the hotel. The main energy activities of a hotel are: space heating, cooling, water heating, cooking, and lighting. The energy demand can be classified in (a) electrical demand (electricity required for lighting, cooking, air conditioning, and others) and (b) thermal demand (hot water for swimming pools, bathrooms, and space heating). In this approach the calculation of the energy consumption and the power demand are based on a typical (average) day per month. The energy demands were multiplied by a "future demand increase factor" of 1.1, in order to cover the increase demand of the hotel over the life time of the project. The hotel uses air conditioner devices for cooling. A typical 2.49 energy efficiency ratio (*EER*) was taken into account for air conditioning devices. The electrical and thermal demand is shown in figs. 1 and 2. The maximum electrical and thermal demand happens during the summer while the minimum in the winter, as demand depends strongly on the occupancy of the hotel.

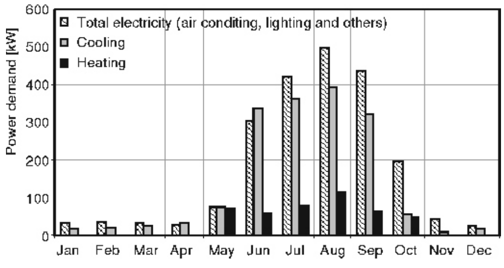

Figure 1. Hotel power demand in 2001 for a typical day [2]

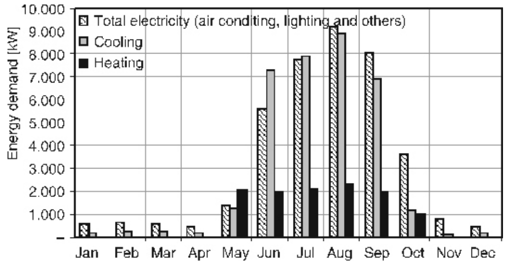

Figure 2. Hotel energy demand in 2001 for a typical day [2]

Design of the system and selection of the equipment

The energy demand data are presented as an average day per month. However, it is necessary to take into account the peaks of demand during the day. The energy system has to be able to cover the maximum peak energy demand. Then a "peak factor" of 1.2 (20% increase) will be taken into account in order to select the power capacity of the gas turbines (fig. 3). Gas turbines and boilers can typically be fuelled with natural gas or oil. In this approach natural gas was selected as the primary energy source. Two alternative CHP schemes were chosen in order to make the specifications of equipments.

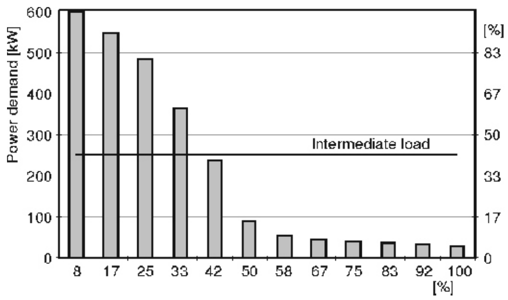

Figure 3. Load curve of the hotel (1.2 "peak factor" is applied)

Energy scheme #1

It consists of a gas turbine producing electricity for the total hotel demand. The exhaust hot gases are recovery by a heat recovery exchanger (HRE) in order to supply hot water for the hotel heating demand. The cooling demand is supplied by air conditioning devices.

Energy scheme #2

As in the first energy scheme a gas turbine supplies the total electricity demand. A HRE produces heat to an absorption chiller cooling system, which is able to supply the total cooling demand of the hotel during summer. The cooling system selected for this scheme is a double effect absorption chiller with a typical coefficient of performance (*COP*) of 1.2. The heating demand is supplied by a typical hot water boiler.

In this study, an economic evaluation was undertaken for six cases. In each case, a different combination of gas turbine, regime of operation and CHP scheme was chosen.

Conventional cases

This is the typical solution used by hotels to supply the energy demand. All the electricity demand is supplied by the local grid, air conditioning devices cover the cooling demand and hot water boilers the heating demand.

Case 1. The unit is able to produce the total electricity demand (the highest power demand is in August). The mode of operation is full load, which means the engine operates at its maximum power setting. The CHP system is designed for energy scheme #1. In this case the surplus of electricity is sold to the local utility.

Case 2. This case is similar to Case 1. The basic difference is on the regime of operation of the gas turbine. In this case the power system is following the load. That means electricity is produced only to supply the electricity demand. The gas turbine may operate at partial load over some period of the year and there is no surplus of electricity to be sold. Figure 4 shows the performance of the gas turbine over the year for cases 1 and 2.

Case 3. The CHP system is able to produce part of total electricity demand (intermediate load: between 40-50% of the total electrical load, fig. 3). The mode of operation is full load and then there are surplus and deficit of electricity depending on the month of the year (fig. 5).

Case 4. The design of the CHP system is the same as for Case 3. However, the regime of operation is following the load and then again there is no surplus of electricity to be sold.

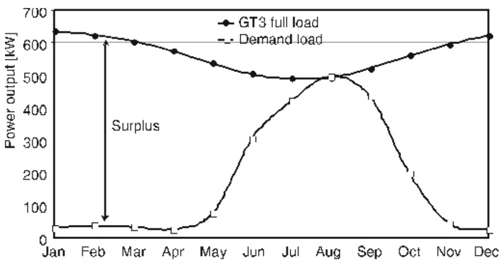

Figure 4. GT power output and power demand – cases 1 and 2

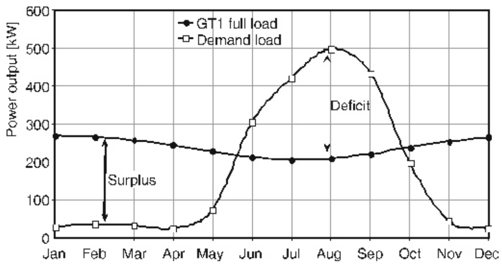

Figure 5. GT power output and power demand – cases 3 and 4

Case 5. The total electricity demand is supplied by the CHP system, which is designed for energy scheme #2. That means the peak of electricity demand will be lower than previous cases since the cooling demand will be supplied by an absorption chiller instead of air conditioning devices. The mode of operation is full load and the surplus of electricity is sold to the local utility.

Case 6. The CHP system is the same as for Case 5. However, the regime of operation is following the load, and then no surplus of electricity is available to be sold.

Table 1 summarizes all the cases analyzed. The prime movers selected for the CHP systems are regenerative cycle single shaft gas turbines. In order to simulate the performance of the gas turbines at on-site conditions (off-design), the program Turbomatch, the gas turbine performance code of Cranfield University, was used (tab. 2).

Table 1. Summary of all case studies

Case #	CHP scheme #	GT #	Operation
1	1	3	Full load
2	1	3	Following the load
3	1	1	Full load
4	1	1	Following the load
5	2	2	Full load
6	2	2	Following the load

Table 2. Design point of gas turbines

Parameter	GT1	GT2	GT3
Inlet mass flow [kgs^{-1}]	2.10	3.15	4.40
Compresion pressure ratio [–]	4.0	4.5	5.0
Turbine entry temperature [K]	1.150	1.150	1.150
Exhaust mass flow [kgs^{-1}]	2.12	3.18	4.42
Exhaust temperature [K]	531	541	551
Power output [kW]	250	401	587
Thermal cycle efficiency [%]	31.4	32.0	32.2

Long-term decision-making economic model

For long-terms projects, the timing of cash revenue and payments often becomes critical and this section deals with the discounted cash Flow model chosen as a decision-making instrument to support selection of alternative investments [3-5]. The following paragraphs describe the costs involved in constructing and operating a CHP system.

In order to carry out the pre-feasibility analysis it is necessary to estimate the initial net cash flow (ICF) for year $t = 0$ and the annual net cash flow (ACF) for years t 1. The capital cost of the boiler is usually not taken into account, because it is assumed that a boiler would anyway be installed for back up.

$$ICF = CC + AC_{ac} \tag{1}$$

where CC is the capital cost and AC_{ac} is the avoided cost of conventional air conditioning when cooling air is produced by absorption chillers.

Capital cost consists basically of purchase of GT, heat recovery exchanger (HRE), boilers, absorption chiller, and their respective installation costs. The equipment costs depend on their capacity and particular specifications (tab. 3).

The operation of a CHP system causes expenses, but it results in savings (avoided cost of electricity that otherwise would be purchased from the grid and heat that would be produced by a boiler), and also in revenues, if excess electricity is sold. The annual income of the CHP system is defined by eq. (2). The residual value of the investment at the end of the economic life was neglected.

Table 3. Capital and maintenance cost of equipment [6]

Equipment	SCC* [€kW^{-1}]	Maintenance cost [€kW^{-1}]
CHP system (GT and HRE)	1.034	0.0040
Boiler	63.36	0.0002
Air conditioning	178.92	–
Absorption chiller	174.72	0.0016

* Specific CC of installed equipment

$$ACF = AC_e + RS_e + AC_h - FC - O\&M + DTB \tag{2}$$

where AC_e is the avoided cost of electricity (cost of electricity that in the conventional case it would be purchased from the grid), RS_e – the revenue from selling surplus of electricity, if any, AC_h – the avoided cost of heat (cost to produce heat in a conventional case), FC – the cost of fuel for the CHP system, $O\&M$ – the operation and maintenance cost (except fuel) of the CHP system, and DTB – the depreciation tax benefit.

The avoided cost of electricity, AC_e, is a function of the electricity consumed in the conventional case, and on the tariff structure for electricity supplied by the grid. Usually utility companies consider not only energy rates, but also power rates, power factor, time of the day and taxes. The revenue RS_e from surplus of electricity sold to the grid depends on the amount of electricity sold and on the tariff structure for surplus of electricity sold to the grid. The avoided cost of heat AC_h includes cost of fuel for the boiler that would produce the thermal demand, in the conventional case, as well as other operation and maintenance expenses.

Fuel cost (*FC*) usually is the most significant cost in the economic of the system. It depends on the performance of the gas turbines, quality of the fuel (heat value) and mainly on the fuel tariff.

O&M can be divided into fixed and variable costs. Fixed costs (operation costs) are expenses that must be paid independently if the CHP system is operating or not. Fixed cost includes operator's salary, administrative and management fees and interest on loan. It depends on the size of the system and the degree of automation. In this approach operation costs were neglected as the investment comes from private resource (no loan) and smaller CHP systems (up to about 10 MW) can operate unattended. Variable cost (maintenance costs) depends on factors such as type of prime mover, type of fuel, operation cycle, and operating environment. In this approach gas turbines are fuelled with natural gas, which is considered a clean fuel, and they are going to run in a clean environmental. Then reduced maintenance costs are expected.

The *DTB* refers to the recent incentives in European countries government taxation and in this approach linear depreciation was used, (eq. (3):

$$DTB = i_{\mathrm{d}} \frac{IC}{N} \tag{3}$$

where N is the life time of the project and i_{d} – the depreciation tax benefit rate.

CC and *O&M* used to be expressed in specific units. Specific *CC* of equipments are likely to vary widely. In this approach the figures presented for capital cost of equipments are on average of different manufactures prices, (tab. 3).

A measure of economic performance is used either as an indication of whether an investment in a CHP system is viable in itself, or as a basis for comparison among alternative investments. The conventional case for covering electrical and thermal needs will be considered as reference.

Finally, the net present value (*NPV*), internal rate of return (*IRR*), and discounted payback period (*DPB*) were calculated following the equations below, where *ICF* and *ACF* are considered constant with time:

$$NPV = \sum_{t=0}^{N} \frac{NCF}{(1+i)^t} \tag{4}$$

$$NPV = \sum_{t=0}^{N} \frac{ACF}{(1+IRR)^t} = 0 \tag{5}$$

$$DPB = \frac{-\ln\left(1 - \frac{ICF}{ACF} i\right)}{\ln(1+i)} \tag{6}$$

The cost to produce electricity can also be indicative of the economic performance of the investment. In this approach the total electricity generation cost (*GC*) consists of:

$$GC = \frac{CC \cdot CRF + FC + O\&M}{AEP} \tag{7}$$

where *CRF* is the capital recovery factor, (eq. (8), and *AEP* is the annual electricity produced, in MWh.

$$CRF = \frac{i}{1-(1+i)^{-N}} \tag{8}$$

Table 4 shows the economic market parameters used in this approach.

Table 4. Economic scenario of the case studies [7]

Currency rate	1.3 €/US$
Annual interest rate (i)	2.7% pa
Project life time (N)	10 year
Depreciation tax benefit rate (i_d)	41.0%
CHP incentive benefit rate	40.0 % of the CC
Average electricity price (with 10% tax)	59.29 €/MWh$_e$
Average price paid for the surplus of electricity	44.00 €/MWh$_e$
Natural gas tariff (with 9% tax)	
– CHP installations	0.23 €/Nm³
	20.90 €/MWh
– Industrial and commercial installations	0.38 €/Nm³
	34.06 €/MWh

Results and discussion

In all the cases analysed, results show that the investment is not profitable (negative *NPV* and large *DPB*) with the current economic scenario in the energy market. Despite of that it is possible to compare the different cases analysed in order to identify the optimal solution between the investment alternatives.

In fig. 6, it is possible to see that the generation cost of electricity is higher than both import/export (deficit/surplus) average price of electricity from the network. Cases 1, 3, and 5 have the lower generation electricity cost. In these three cases there are surplus of electricity been sold to the grid and higher the *AEP* lower the generation cost (*GC*). This explain why it is possible to see in fig. 6 a clear distinction between cases with full load (cases 1, 3, and 5) and following the load mode of operation (cases 2, 4, and 6). Despite of the income from selling surplus of electricity, it was not enough to offset production costs as the sale price of electricity is lower than the generation cost. Figure 7 shows the break down of the generation cost in relative units. The *GC* depends on *CC*, *FC*, and *O&M*. The share of the fuel in the generation cost is the highest (up to 87%).

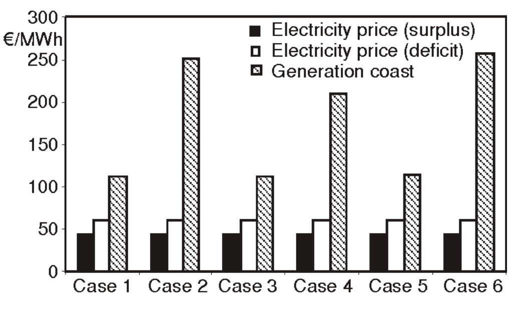

Figure 6. Generation cost and electricity prices for all the cases

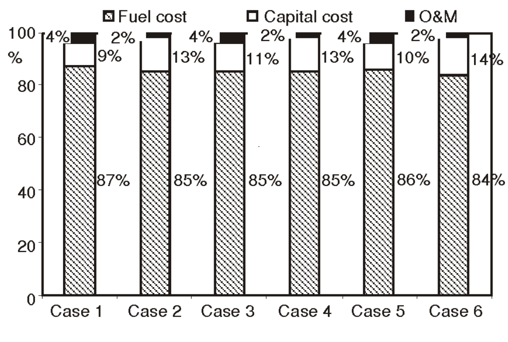

Figure7. Share of the generation cost components

Table 5. NG tariff for different constraints

NG tarrif			
Case	*NPV* > 0	*IRR* > 0	*GC* < *AEP*
1	<0.100	<0.100	<0.11
2	<0.040	<0.045	<0.03
3	<0.106	<0.108	<0.11
4	<0.056	<0.058	<0.04
5	<0.110	<0.112	<0.11
6	<0.060	<0.063	<0.02

Parametric analysis

A parametric analysis for natural gas tariffs was developed for all the cases. The target was to find out the minimal natural gas tariff which can turn the investment attractive (different constraints are applied) under the current economic scenario. The results are summarised in tab. 5. The economic performance parameters *NPV*, *IRR*, and *DPB* were calculated for each case studied in a range of natural gas tariffs (fig. 8).

Figures 8(a) and (b) shows that the *NPV* and *IRR* lines are crossing over each other. This means the most attractive case can change with the natural gas tariff. Then it is possible to conclude that higher the price of natural gas, small CHP systems are more economically feasible. Again a clear distinction between cases with regime of operation full load (cases 1, 3, and 5) and following the load (2, 4, and 6) can be identified in figs. 8(c) and 8(d). Full load regime can give a shorter return on the investment then following the load. Table 6 summaries the optimal solutions for each economic performance parameter in different classes of NG tarrif.

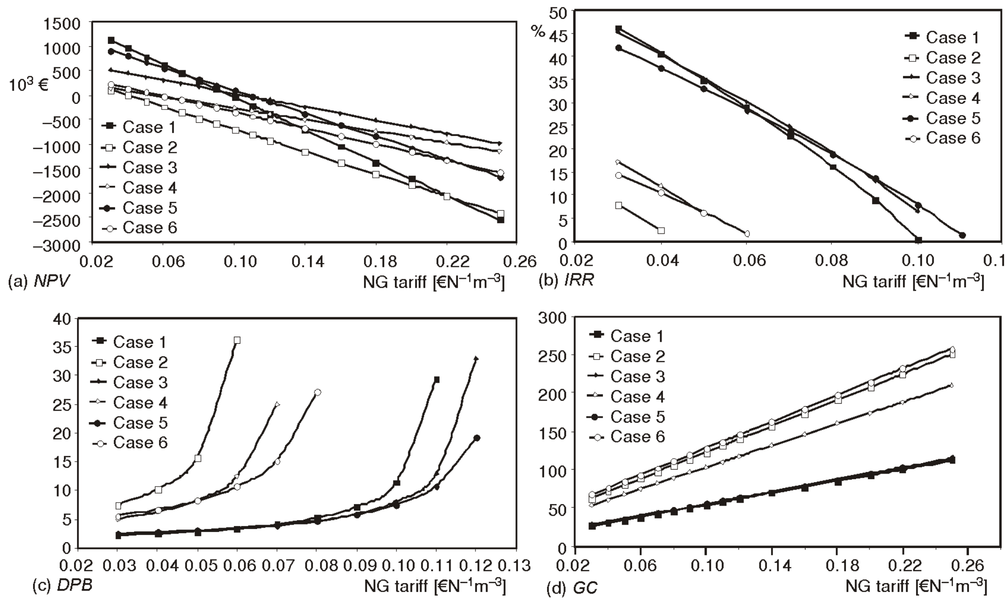

Figure 8. Comparison of economic performance for all the cases for different natural gas tariffs
(a) NPV [10^3 €], (b) IRR [%], (c) DPB [year], (d) GC [€(MWh^{-1})]

The electricity rate is another important factor to take into account in this approach and its influence on the feasibility of the investment was analysed. The electricity rate in Greece is relatively low comparing with other European countries. Thermal power plants have the majority share of the power generation market (65%) and they are fuelled with lignite, which is a primary energetic source relatively cheaper than others. Figure 9 shows the average electricity price in Europe.

Greece is supplied with NG since 2001. The gas is transported either from Russia by pipeline, or by ship as liquefied natural gas from Algeria. The average tariff of this primary source is significantly higher than some others countries in Europe (fig. 10).

Despite of the government incentives for CHP the current scenario in Greece is not favourable to the spread of such power generation system. However the feasibility of the investment may change in countries with lower natural gas tariff and higher electricity rates. This sub-section presents an analysis taking into account the variation of both natural gas tariff and electricity rate, which together can define a specific scenario. The *DPB* was chose to indicate the economic performance of the investment. Fig. 11 shows the investments feasibility in different energy market scenarios. The range of NG tariff analysed is between 0.05 and 0.14 €/m^3 and the electricity rate goes from 60 to 150 €/MWh, which covers the typical variation in European countries.

Table 6. Optimal solution for different NG tariffs

Case				
NG tarrif	*NPV*	*IRR*	*DPB*	*GC*
Low (0.03 €/m^3)	#1	#1	#1, 3, 5	#1, 3, 5
Intermediate (0.10 €/m^3)	#5	#5	#5	#1, 3, 5
Current (0.23 €/m^3)	#3	–	–	#1, 3, 5

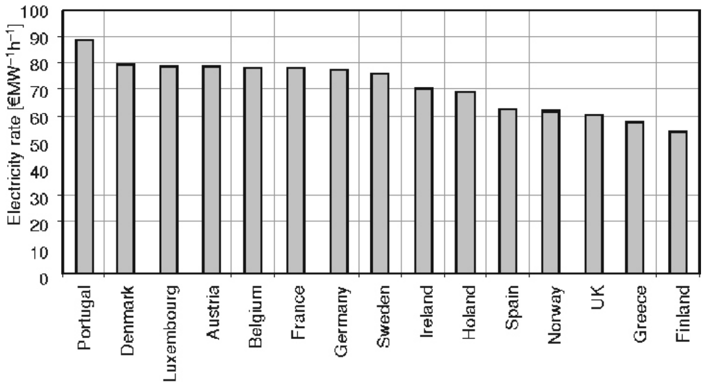

Figure 9. Electricity prices in Europe in 2008

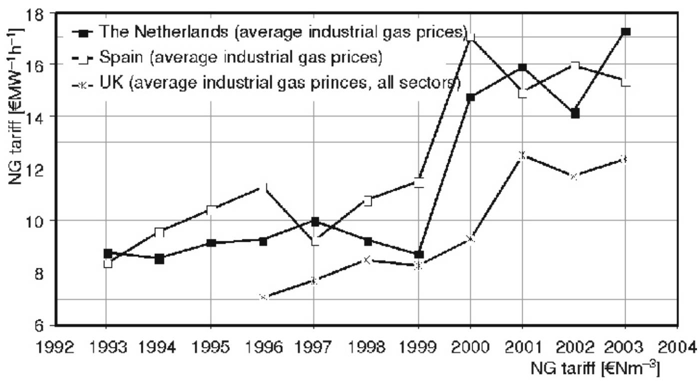

Figure 10. European natural gas prices [8, 9]

Conclusions

The main objective of this approach was to optimise a CHP system to attend the energy demand of a Hotel located in Northern Greece. Hotels are potential applications of new power generation technologies. Different schemes were designed to supply electricity, heating, and cooling demand of the hotel [10].

An economic and parametric analysis was carried out to evaluate the feasibility of different alternatives. Despite of the cases analysed do not perform an interesting feasibility under

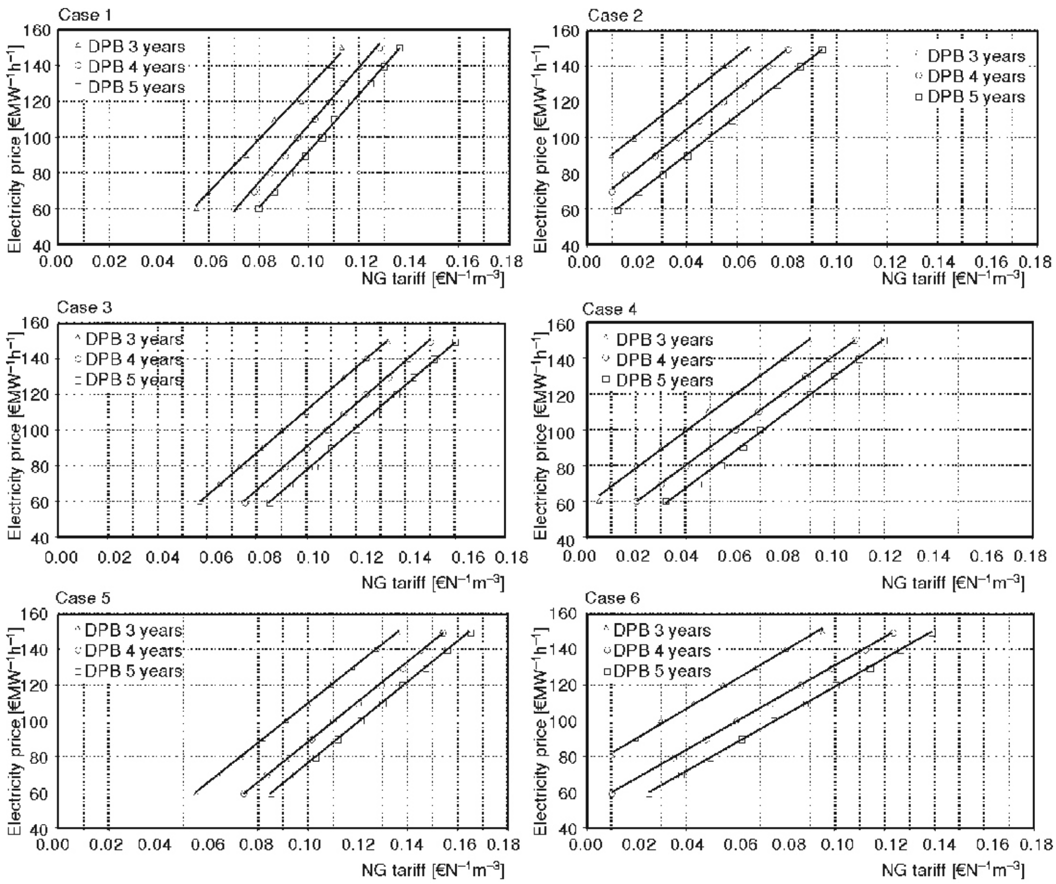

Figure 11. Payback for natural gas tariff variation and electricity price variation

the current economic scenario, the parametric study indicated that this kind of business can turn around its economic performance in different scenarios.

Fuel cost has performed an important role in the generation cost portfolio and low price paid for the surplus of electricity can make the full load mode of operation unattractive.

The economic performance of the cases analysed were compared against each other under a possible variation of the fuel tariff. CHP systems working full load have shown more economically interesting than following the load.

A parametric analysis combining fuel tariff and electricity rate variation was carried out and then the economic performance of such systems in different markets is accessible.

Peak load application is gain attention as an alternative to reduce electricity bills and improve the quality and reliability during peak time. In this application the power system runs only during hundreds of hours in the year, and there is a significantly reduction in the running costs comparing with base load. On the other hand, frequent cycling (start-up and shut-down) will increase thermal stresses, which results in increased maintenance costs and reduced life time. Also the same power system used to save peak load can also be applied to supply “standby” or “emergency” service. Although the cases analysed in this paper do not show an interesting economic feasibility, simple cycle gas turbines running at peak time may have a better economic performance, but further analyses is necessary.

Therefore, the main barriers that make CHP systems not economically attractive in Greece are low electricity rates and the current high NG tariff. However, in the future this scenario may change due to the environmental regulations or lack of lignite. CHP systems fuelled with NG can offer reduction in polluting emissions besides its cost-effective benefits. Such systems may help European countries to achieve the current goals of the EU energy policy. CHP has a significant potential but it requires favourable legislative and fair energy market conditions to successfully increase its share in the power generation market.

Acronymes

AC – avoided cost
ac – air conditioning
ACF – annual net cash flow
AEP – annual electricity produced
CC – capital cost
CHP – combined heat power
COP – coefficient of performance
CRF – capital recovery factor
DP – distributed poly-generation
DPB – discounted payback period
DTB – depreciation tax benefit
EER – energy efficiency ratio
HRE – heat recovery exchanger
GC – generation cost
GT – gas turbine
FC – cost of fuel
ICF – initial cash flow
IRR – internal rate of return
NG – natural gas
NPV – net present value
O&V – operation and maintenance cost
RSe – revenue from selling surplus of electricity
*SCC** – specific capital cost

Subscripts

e – electricity
h – heat

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