DESIGN AND TECHNICAL ECONOMICAL AND ENVIRONMENTAL ANALYSES OF A HYDROGEN FIRED MULTI-OBJECTIVE COGENERATION SYSTEM

Ali DURMAZ*, M. Zeki YILMAZOĞLU*, Ayşegül PAŞAOĞLU*
adurmaz@gazi.edu.tr, zekiyilmazoglu@gazi.edu.tr, apasaoglu@gazi.edu.tr
***Gazi University Engineering & Architecture Faculty, Mechanical Eng. Dept.**

SUMMARY

Approximately 85% of rapidly increasing world energy demand is supplied by fossil fuels. Extreme usage of fossil fuels causes serious global warming and environmental problems in form of air, soil and water pollutions. The period, in which fossil fuel reserves are decreasing, energy costs are increasing rapidly and new energy sources and technologies do not exist on the horizon, can be called as the expensive and critical energy period. Hydrogen becomes a matter of primary importance as a candidate energy source and carrier in the critical energy period and beyond to solve the energy and environmental problems radically. In this respect, the main obstacle for the use of hydrogen is the high cost of hydrogen production, which is expected to be decreased in the feature.

The aim of this study is to examine how hydrogen energy will be able to be integrated with the existing energy substructure with technical and economical dimensions. In this sense, a multi objective hydrogen fired gas turbine cogeneration system is designed and optimized. Technical and economical analyses depending on the load conditions and different hydrogen production cost are carried out. It is possible that the co-generated heat is to be marketed for residence and industrial plants in the surrounding at or under market prices. The produced electricity however can only be sold to the public grid at a high unit support price which is only obtainable in case of the development of new energy technologies. This price should however be kept within the nowadays supportable energy price range. The main mechanism to be used during the design stage of the system to achieve this goal is to decrease the amortization and operational costs which lead to decrease investment and fuel costs and to increase the system load factor and co-generated heat revenues.

The electricity and heat co-production capacities of the designed cogeneration system are 7 MW_e and 12 MW_t , respectively. Generated heat in the waste heat boiler will be supplied to the near domestic district with 500 flats for heating, cooling, and warm water supply, and to the industrial district as industrial steam. Different economical analyses are carried out for determination of electricity production cost, considering the hydrogen production technologies and different heat utilization scenarios and heat revenues. The results show that cheapest electricity generation can be realized only by combustion of hydrogen produced from natural gas. The unit electricity cost is around 0.20 $/$kWh_e$ under high system load factors and market co-generated heat revenues.

1. Introduction

In the long run, the use of hydrogen in all range of life will be inevitable when the cost of natural gas and petroleum increases abnormally or the reserves of these fuels depleted. For the time been the main handicap of the use of the hydrogen in economical sector is very high hydrogen production cost. The cheapest hydrogen production has been realized today by using natural gas as row material. However, unit hydrogen production cost is three times higher than that of unit natural gas price (Table 1). Consequently, the use of hydrogen with present hydrogen production cost has no chance to compete with any fusil fuel fired energy system without required subvention. The question to be put here should be how design an operation feature to have hydrogen fired system which can be operated with acceptable subvention cost. Consequently, hydrogen fired energy conversion system should have maximum exergy (work potential) and show capability of maximum utilization of this potential as heat and electricity for different consumers. Exergy is power output of a fully reversible power cycle and depends on turbine inlet and environment temperatures. Exergy potential depending on fuel heat of a power cycle with turbine inlet temperature T_{ti} °C and environment temperature of T_{en} = 27 °C is given in Figure 1.

Table 1. Hydrogen Production Cost Depending On Hydrogen Row Material

H_2 Production Cost	Natural Gas	Hydrocarbons	Pyrolysis of Biomass	Coal	Biomass Gasification	Water
C_f [\$/kgH_2]	3.01	3.97	4.39	5.36	5.8	7.85

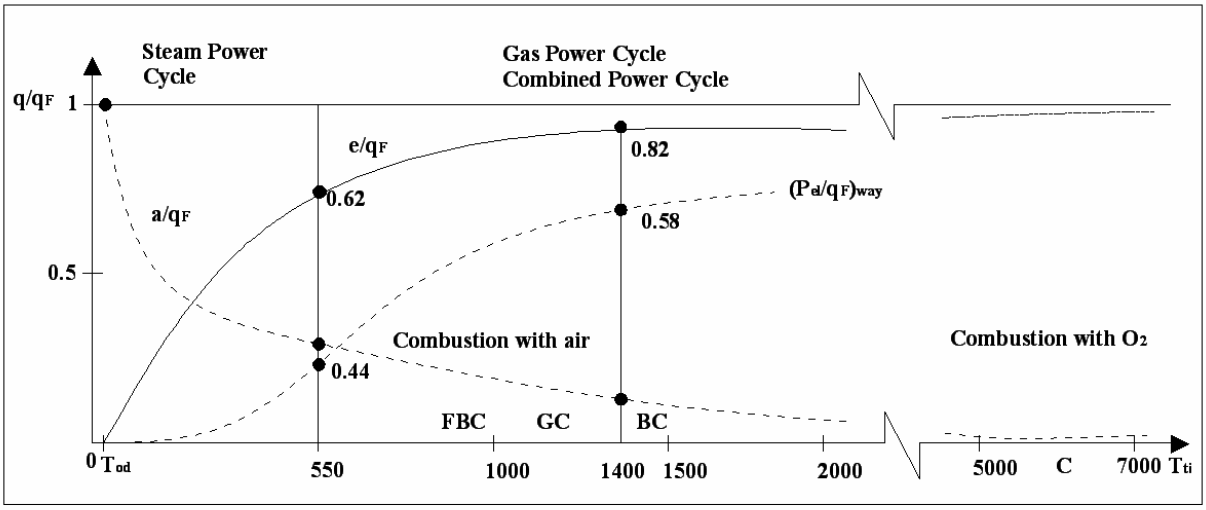

Figure 1: Fuel Exergy Ratio e/q_f Anergy Ratio a/q_f And Maximum Electricity Ratio $(p_{el}/q_f)_{max.}$ Versus Turbine Inlet Temperature [12]

Turbine inlet temperature of steam power cycle is a round 550 °C due to material temperature resistibility. Therefore, the fuel exergy potential of steam power cycle is a round $e/q_f = 0.62$. The turbine inlet temperature of combustion gases, which is used as power fluid in gas turbine, is over 1400°C for the time being due to blade cooling technologies being in the use. The corresponding maximum fuel exergy available in gas turbine power cycle is beyond $e/q_f = 0.82$. On the other hand the investment cost of the gas turbine power systems is lower and realization time is shorter than that of steam power cycle plants. The other requirement for the hydrogen fired system is the most economical utilization of the system exergy in form of heat with different exergy potential and electricity supply. All these requirements indicate that the system structure of hydrogen fired energy conversion system must be in the form of gas turbine co-generation power system. To minimize unit exergy utilization investment cost the system operation load factor to approach unity, and to decrease hydrogen consumption cost to a minimum the total system overall efficiency must approach to maximum. This requires simultaneous co-generation of heat and electricity by the system to be designed and co-consumption of these energies by different energy consumers in economic sectors with different exergy utilization levels. Such a hydrogen fired co-generation energy systems must based on healthy, economical and technical analyses. For realization of such a system first must be found energy consumers, ready to buy the heat and electricity generated by this system to be designed. The electricity generated can only be sold to the national electrical network with a defined sub vented higher selling price. The heat generated however can only be sold to private companies or communities as industrial heat, domestic district heat for the purpose of district heating, cooling, desalination and warm water supply for the application of such as green house applications and for agricultural heat. This requires the determination of present unit heat production cost of the related heat consuming clients. Heat generated by the hydrogen fired system can only be sold to these clients at a cost equal to or less than that of individual heat production cost.

2. DESIGN AND TECHNICAL ANALYSIS OF HYDROGEN FIRED MULTI-POROPOSE CO-GENERATION SYSTEM

The system structure and its subsystems of the hydrogen fired multi purpose gas turbine co-generation system to be design is given in Figure2. in a simplified flow diagram.

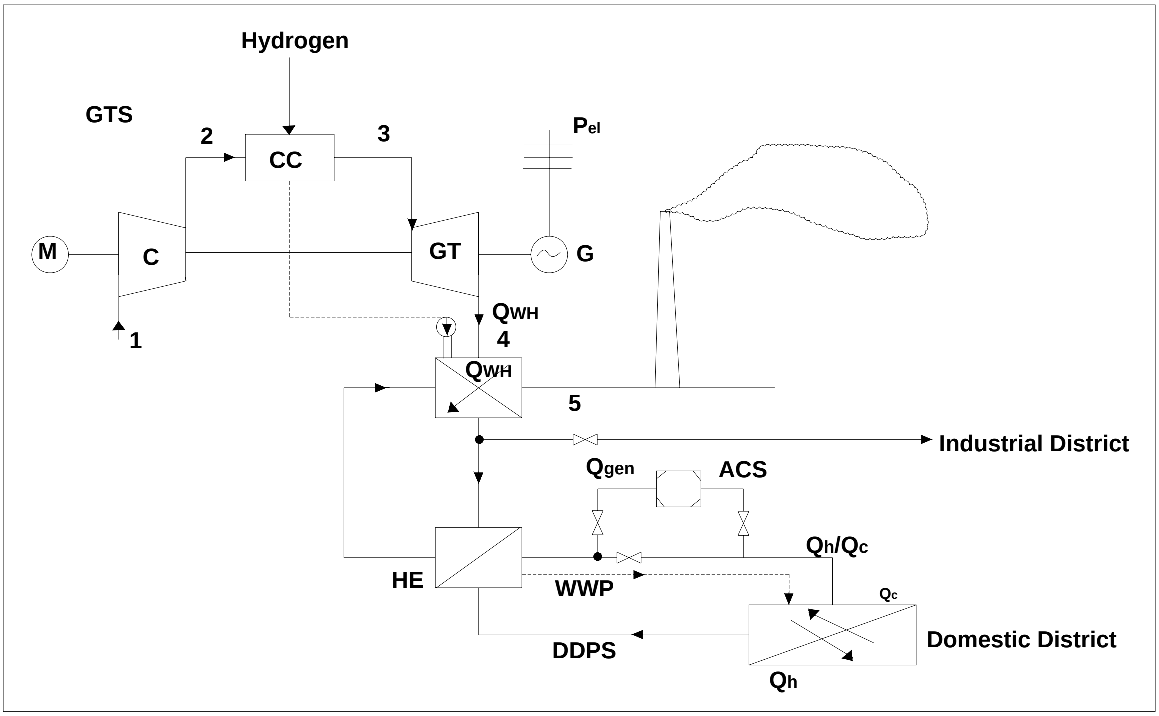

Fig. 2. System Structure and flow diagram of a hydrogen fired multi-purpose gas turbine co-generation system to be design and its subsystems [1].

System consists of a simple gas turbine power system (GTS), waste heat boiler (WHB), domestic district heat exchanger (HE), absorption cooling system (ACS), domestic high temperature district piping system (DDPS), a separate warm water piping (WWP) and steam pipe for industrial steam supply to industrial plants (ISP). The exhaust waste heat of gas turbine is used in the waste heat boiler to generate steam with temperature of t_s=200˚C and pressure of p_s=8 bars. From this steam, first of all, hot water with temperature of 120˚C is generated and supplied to the domestic district with 500 flats for domestic heating, warm water supply and to the generator unit of a absorption district cooling system. The surplus steam of waste water boiler during the year is supplied to the plants in the industrial district (Figure 4) [10].

2.1. Heat Load of the Gas Turbine Co-generation System to be Designed

The gas turbine waste heat (Q_{WH}) will be used for steam generation in a waste heat boiler (WHB) which will be used primarly to meet district heating (Q_h) and heat load of the domestic district absorption cooling system generator unit (Q_{gen}) and warm water supply (Q_{ww}) (Fig. 3,Fig. 4). The surplus steam during the year will be supplied to the industrial district, in the vicinity. The annual heating and cooling load of a domestic district is shown in Fig. 4.

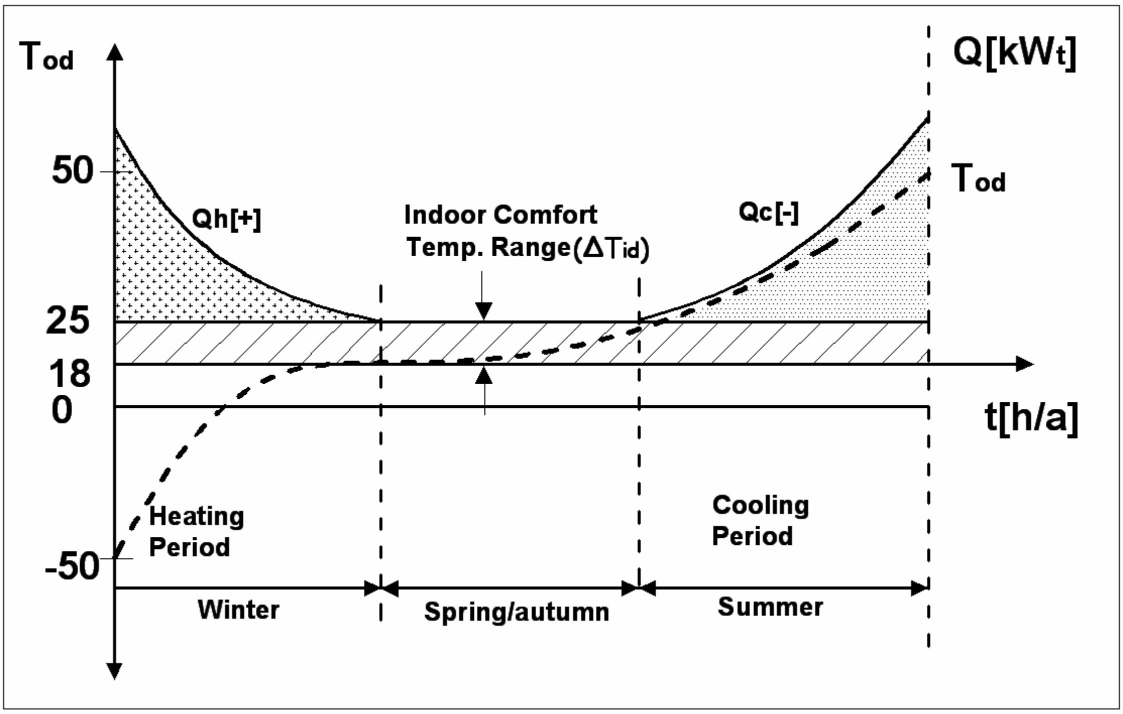

Figure 3: Change of Outdoor Temperature (T_{od}), District Heating Load (Q_h), Cooling Load (Q_c), Indoor Comfort Temperature (ΔT_{id}) during the year [2].

Domestic district has 500 flats. The design heat load data are given in Table 2. Location dependent outdoor temperature variation, during the year, and required heating and cooling loads are given in Figure 2.

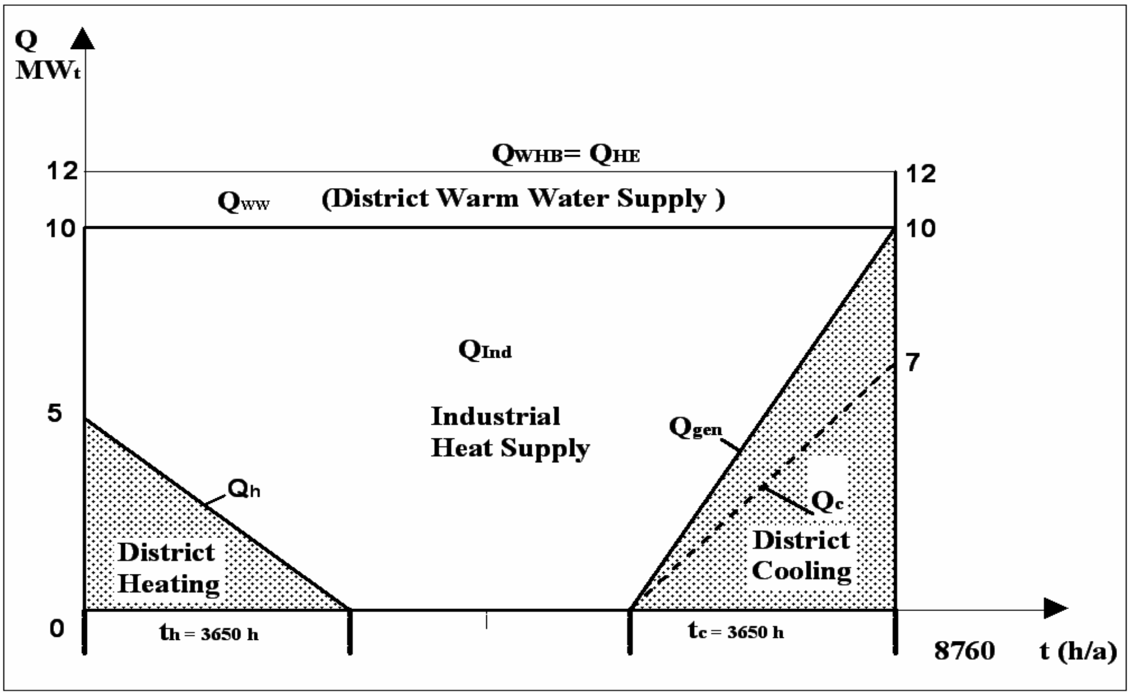

Figure 4: Heat Load Diagram of the Gas Turbine Co-generation System to be Designed [1].

Table 2: Design Data for the Gas Turbine Co-generation System at Full Load Operation Conditions ($F_L = 1$)

	Flat	Flat Spec. Load kWt	Qmax MWt	Qmin	Ann. Uti.	Ann. Load [kWh/a]
District Heating	500	10	5	0	3650	9.13E+06
District Warm Water	500	4	2	0	8760	1.75E+07
District Cooling	500	14	7	0	3650	2.56E+07
ACS Gen. Heat (COP=0.7)	500	20	10	0	3650	3.65E+07
Industrial Steam	---	---	10	5	8760	1.54E+07
Waste Heat Boiler	1	---	12	---	8760	1.05E+08
Domestic Dist. Heat Exc.	1	---	12	2	8760	6.31E+07
Electric Load	---	---	7.15	---	8760	6.26E+07

The total heat load of the co-generation system and its related constituent heat loads are given in Figure 4.

2.2. Design of the District Piping System

The heat loads required by domestic district (Fig. 4) are supplied over district heating piping system (Fig. 2, Fig. 5). Considering the steam requirement of the industrial district and its distance to the co-generation system the pressure and temperature of steam at the WHB outlet is determined as p_s=8 bars and ts=200˚C. The heat load of the domestic district will be supplied via hot water with supply and return temperature of t_{sp}= 120 ˚C and t_r=50 ˚C. The district heating piping will be used also in summer period as district cooling piping with supply and return temperature of t_s=6 ˚C and t_r=12 ˚C. The cooling load of the domestic district Q_c (Fig.2, Fig.4) will be pumped by a simple LiBr-H_2O absorption cooling system over cooling tower to the environment (Figure 5). The evaporator, absorber, generator and condenser temperatures of the ACS are chosen as t_B=5˚C, t_A=30˚C, t_G=120˚C and t_{con}=40˚C respectively. In ACS, the refrigeration compression work is carried out of by exergy potential between generator and absorber. The system structure and main design data of the piping system is given in Figure 5.

2.3. Design and Optimization of the Gas Turbine Power System

System structure of the simple power cycle gas turbine system is given in Fig.2. It consists of compressor (C), combustion chamber (CC), gas turbine (GT), electric generator (G) and starter motor (M). For the reason of high exergy potential and high system revenue, the turbine inlet temperature of combustion gases (power fluid) is chosen as t_{ti}=1200˚C. Under reversible air power cycle condition, the optimum compression ratio of the compressor is calculated as p_2/p_1=13 which makes the power cycle efficiency to maximum at 1200˚C turbine inlet temperature. In optimization calculations the pressure losses of combustion chamber and waste heat boiler are also considered [6].

The adiabatic combustion temperature of hydrogen at stoichiometric conditions (n=1) is found as 2156 ˚C. In order to cool the combustion temperature to 1200˚C turbine inlet temperature, the combustion must be carried out with an appropriate excess air. Applying the energy balance to the CC, the excess air number is calculated as n=1.96. The combustion must be realized with 96% excess air. The gas turbine power cycle calculation has been carried out under optimum compression ratio and foreseen turbine inlet temperature. The calculation results are given below:

Compression ratio of compressor p_2/p_1= 13
Compressor outlet temperature = 377 [˚C]
Specific compressor work w_c = 368 [kJ/kg]
Specific turbine work w_t = 700 [kJ/kg]
Turbine exhaust temperature t_4= 590 [˚C]
Brayton power cycle efficiency η_{BC} = 0.4
Overall gas turbine efficiency η_{GT}= 0.36
Specific electricity generation P_{el}=29.8 [kWe/kg-pf]

For the calculation of over all gas turbine efficiency, the following efficiencies are assumed. η_{comb}= 0.99, η_{mech}= 0.99, η_G=0.97, η_{transf}= 0.98, $\eta_{int-cons.}$= 0.96

2.4. Design of Waste Heat Boiler

A turbine exhaust gas enters the waste heat boiler with a temperature of 590˚C and cools down to the chimney temperature of 79 ˚C, giving its heat to the heating surfaces (namely, super heater (SH), evaporator (EV), and feed water heater or economizer (ECO). Feed water temperature and super heater outlet temperature are determined as t_{fw} = 55˚C, t_s=200˚C respectively (Figure 5). At full load conditions the capacity of WHB is Q_{WHB}=12 MW_t. Using energy balance at WHB, the mass flow rate of gas turbine exhaust gases $\dot{m}_4$ for generation of 12 MW_{heat} (18 t/h steam), must be $\dot{m}_4$ = 24 kg/s = 86 t/h.

For generation of 18 t/h steam in WHB, 24 kg/s combustion gases must flow through the gas turbine which generates an electric power of P_{el}=7.152 MW_{el}. Using the low heating value of hydrogen, Hu= 33.33 [$kWhH_2/kgH_2$], P_{el}= 7.152 MW_{el} and η_{GT}=0.36 [kWhel/kWht], the H_2 consumption is calculated as m_{H2}= 596 [kgH_2/h].

An additional burner is applied to the WHB, in order to meet the future higher total heat loads above 12 MW_t. Steam generation load is distributed according to the steam generation process (Mollier Diagram) to the heating surfaces and then the required surfaces areas are calculated.

2.5. Design of the Absorption District Cooling System

For design the entire district ACS the following data are assumed:

District cooling load = 7 MW_t , Evaporation temperature = 5 °C , Absorber temperature = 30 °C , Generator temperature = 120 °C . Single effect cooling system cycle is assumed. Water as refrigerant, LiBr as absorbent are used. District cooling water supply temperature and return temperature are taken 6 °C and 12 °C respectively. Absorption cooling cycle calculations are carried out and the COP = 0.7 is found. With this COP value the cooling system generator heat load is calculated and found as $Q_{gen.}$ = 10 MW_t (Figure 4, Figure 5) [2,5].

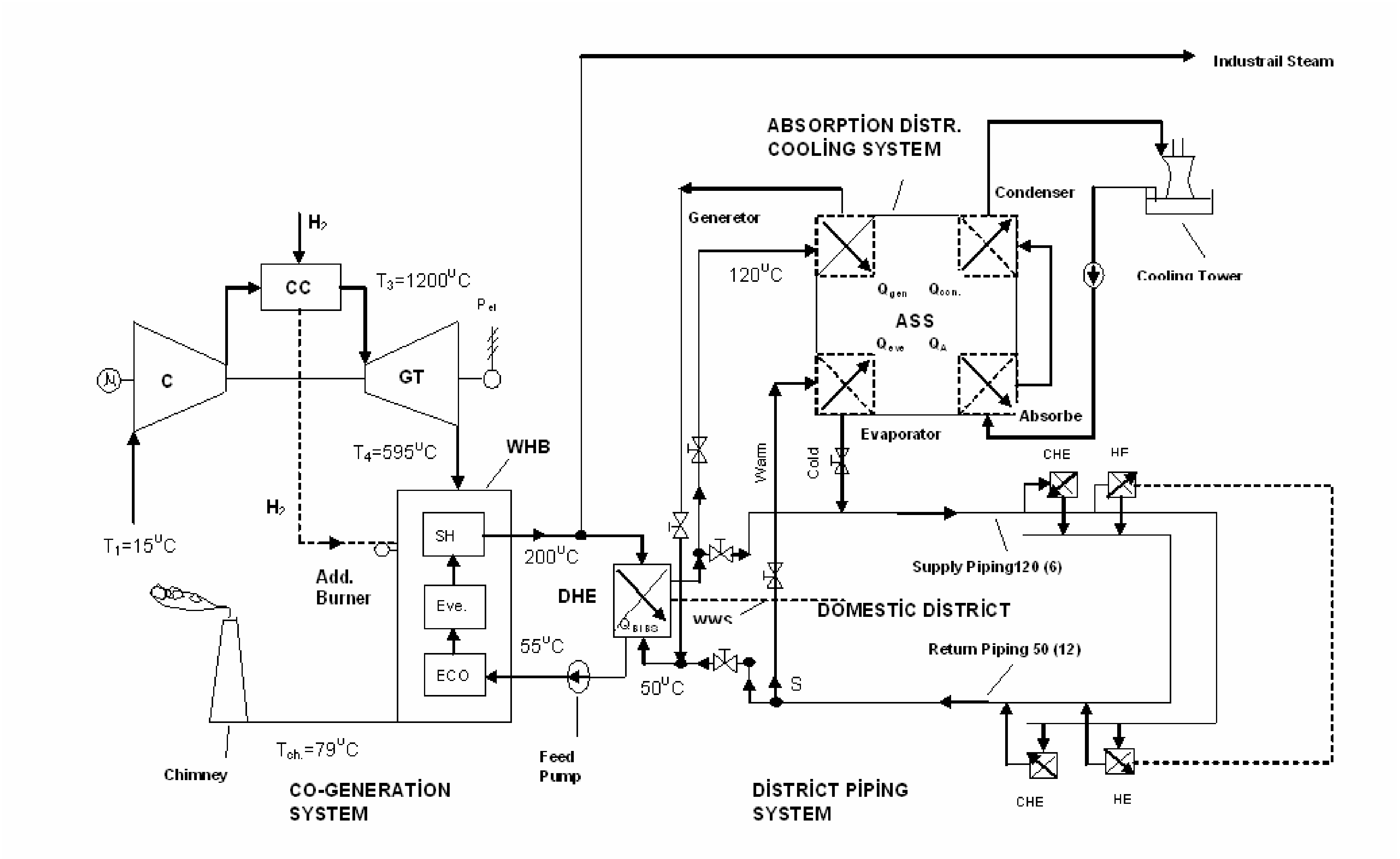

Fig. 5. General system description of a hydrogen fired cogeneration system (gas turbine, waste heat boiler, Absorption chiller, district piping)

3. Economical Analysis of the Hydrogen Fired Co-generation System

3.1. Annual Expenditure of the Cogeneration System

Annual costs or expenditures of the cogeneration system consist of annual fuel, amortization t and other costs such as personal, maintenance, consumables etc. Annual system internal electricity consumption is considered by efficiency $\eta_{int.cons.}$ of the cogeneration system.

3.1.1. Annual Fuel Cost (AFC)

Annual hydrogen cost is calculated using unit hydrogen cost, load factor (F_L) dependent annual hydrogen consumptions. The hydrogen production cost depends primarily on hydrogen raw material as shown in Table 3. For economical analysis the cost of hydrogen produced from natural gas is used, which is the lowest compared with others hydrogen produced (Table1).

Table 3. Annual Fuel (H_2) Consumption and Fuel Cost

Hydrogen Conseption and Cost	**Load Factor F_L**			
	1.0	**0.8**	**0.6**	**0.4**
Hourly H_2-Konseption [kg/h]	**606**	**485**	**364**	**242**
Annual H_2 Conseption [kg/a]	**$5.3x10^6$**	**$4.24x10^6$**	**$3.18x10^6$**	**$2.12x10^6$**
Annual H_2 Conseption [$/a]	**$15.95x10^6$**	**$12.76x10^6$**	**$9.57x10^6$**	**$6.38x10^6$**

3.1.2. Annual Amortization Cost of the Co-generation Systems (AAC)

Annual amortization cost (AAC) of the system is calculated using the system investment cost (Table 4). The total cost of the system considered $8x10^6$ \$, and can be seen from Table 4. piping network total cost is considered $1.45x10^6$ \$.

Table 4. Investment Cost of Co-generation and District Heating-Cooling System [1,2]

System Investment Cost		Cost [$]
Co-generation and District Heating-Cooling System	Gas Turbine System	4x10^{6}
	Waste Heat Boiler	0.75x10^{6}
	Absorption Cooling System	0.300x10^{6}
	Others	1.500x10^{6}
	Sub Total	6.55x10^{6}
Piping Network	Piping and DHE Systems	1.45x10^{6}
Total	Total Cost	8x10^{6}

Linear amortization procedure is used for amortization calculations. In this approach the present value of the total investment cost after amortization will be pied during the amortization time with equal annual installment. The annual amortization cost is calculated as follow:

$$\mathrm{AAC} = \mathrm{TIC}.\ \mathrm{AAR} \tag{1}$$

where, TIC [$] = total investment cost,
AAR [1/a] = annual amortization ratio, which is calculated as below:

$$\mathrm{AAR} = \frac{F(1+F)^{n_A}}{(1+F)^{n_A}-1} \tag{2}$$

where, F [-] = interest rate
n_A[a] = amortization period in year.

For economic analysis F = 0.1 (10%), n_A = 30 years are taken. From Eq. 2 one obtains AAR = 1.06[1/a]. Using TIC = 8 x 10^{6}[$] (Table 4) and AAR = 1.06[1/a] one obtains from Eq. 1, AAC = 0.864[$/a]. Present value of TIC after 30 years amortization time PTIC is calculated as 25.92 x 10^{6}[$].

3.1.3. Annual Other Cost of the System (AOC)

The annual other cost (AOC) such as personal, maintenance, consumables, etc. is assumed to be 5% of the annual hydrogen cost at the full load operation conditions.

3.1.4. Total Annual Expenditures of the Co-generation System (TAC)

Total annual expenditures or cost of the co-generation system is calculated as follow:

$$TAC = AFC + AAC + AOC \ [\$/a] \quad (3)$$

The total annual expenditures of the co-generation system depending on the system load factor are given in Table 5.

Table 5: Annual Expenditures of the Co-generation System [1]

Load Conception	**Load Factor F_L**			
	1.0	**0.8**	**0.6**	**0.4**
Annual Fuel Cost [$/a]	**15.95×10^6**	**12.76×10^6**	**9.57×10^6**	**6.38×10^6**
Annual Amortization Cost [$/a]	**0.864×10^6**	**0.864×10^6**	**0.864×10^6**	**0.864×10^6**
Annual Other Cost [$/a]	**0.786×10^6**	**0.786×10^6**	**0.786×10^6**	**0.786×10^6**
Total Annual Cost [$/a]	**17.6×10^6**	**14.41×10^6**	**11.22×10^6**	**8.03×10^6**

3.2. Annual Revenues of the Co-Generation System Due to Heat and Electricity Selling

Annual total revenue of the co-generation system consist of revenues due to heat selling at market prices to the private sector applications such as district heating, absorption district cooling, warm water supply, industrial and agricultural heat supply. Heat can only be sold at a price equal or less than that of individual production cost of related clients via boiler, kombi heater (wall hanged boiler), industrial boiler, etc. The electricity generated can be sold with acceptable sub vented selling price to the national electricity network.

3.2.1. Annual Heat and Electricity Production by Co-generation System to Meet Clients Energy Requirements

The annual heat loads [kWht/a] for district heating (Q_{dh}), warm water supply (Q_{ww}), ACS generator unit ($Q_{gen.}$), industrial requirement ($Q_{ind.}$) are calculated according to Figure 4 for different load conditions and given in Table 6. In the same table are also given the annual electricity productions.

Table 6: Annual electricity and heat, produced by co-generation system to be supplied to electric network, domestic and industrial piping systems.

Load Conception	**F_L**			
	1.0	0.8	0.6	0.4
P_{elmax}[kW]	7.125	5.722	4.275	2.850
Annual Production[kWht/a]	62.415×10^6	49.932×10^6	37.449×10^6	24.966×10^6
District Heating $Q_{max.}$	5.000	4.000	3.000	2.000
Annual District Heating Demand	9.126×10^6	7.3×10^6	5.475×10^6	3.65×10^6
Warm Water Q_{max}	2.000	1.600	1.200	800
Annual Warm Water	17.52×10^6	14.02×10^6	10.51×10^6	7.01×10^6
District Cooling Load Q_{max}	7.000	5.600	4.200	2.800
Annual District Cooling Demand	12.775×10^6	10.22×10^6	7.665×10^6	5.11×10^6

3.2.2. Determination of Unit Selling Price of Heat and Electricity Generated by Co-generation System

3.2.2.1. Determination of Heat Selling Price Generated by Co-generation System

The selling price of unit heat generated by co-generation system should equal to or less than that of specific conventional individual total unit heat generation cost. This total unit cost consists of specific fuel, amortization and other cost as calculated below.

a) Specific fuel cost of conventional individual heat generation (C_f)

Fuel cost for a heat generator (stove, kombi heater, boiler, etc.) can be calculated depending on operational factors as follows:

$$C_f = \frac{g_f}{H_U \cdot \eta_{av}} \qquad [\$/kWht] \qquad (4)$$

where, g_f [\$/kg$_F$] = average cost of fuel.

H_u [kWhf/kg-$_f$] = average lower heating value of fuel.

η_{av} [kWht/kWhf] = average load factor dependent thermal efficiency of heat generator (Figure 6).

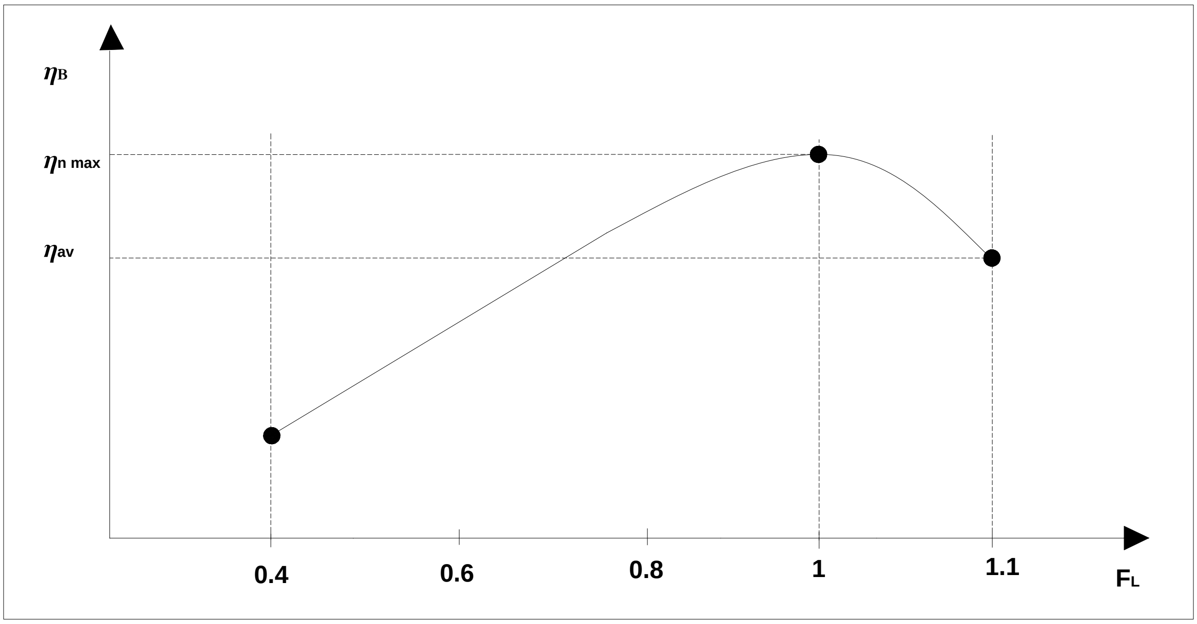

Figure 6. Boiler efficiency versus load factor (F_L) [10]

b) Specific amortization cost of conventional individual heat generation (C_{amr})

Specific amortization cost of conventional individual heat generation (Camr.) can be calculated as given below:

$$C_{amr.} = \text{Annual Amortization Cost / Annual Heat Generation} = \frac{TIC.AAR}{Q.F_L.8760} = \frac{\dot{Q}.SIC.AAR}{\dot{Q}.F_L.8760}$$

$$= \frac{SIC.AAR}{F_L.8760} \qquad [\$/kWh_t] \qquad (5)$$

where, TIC [\$] = total investment cost

$\dot{Q}$ [kW$_t$] = installation capacity of heat generator

SIC [\$/kW$_t$] = specific investment cost of heat generator

F_L [-] = load factor of the heat generator, 8760 [h/a] = hours of a year.

AAR [1/a] = annual amortization ratio (Eq.2) for linear amortization.

c) Specific other cost (C_{other})

C_{other} [\$/kWh$_t$] can be assumed to be 5-10% of the specific fuel cost.

d) Unit total specific cost of conventional individual heat generation (C_{tshg})

Unit total specific cost of conventional individual heat generation (C_{tshg}) can be caculated as follows:

$$C_{tshg} = C_f + C_{amr} + C_{other} \quad [\$/kWh_t] \tag{6}$$

3.2.2.2. Revenue from heat selling for district cooling

Annual revenue is calculated using unit cooling heat pumping cost and annual cooling load. The ACS generator heat supply revenue to meet district cooling load should equal or less than that of individual simple steam compression refrigerator (split type air conditioner) cost which is required to pump unit cooling load to the outdoor. It consists of unit cooling electricity cost, amortization cost and other cost of the individual refrigeration system.

a) Unit cooling load electricity cost (C_{el})

Unit cooling electricity cost can e calculated as following:

$$C_{el} = \frac{q_c}{COP_{av}.\eta_m.\eta_{comp}}.C_{el} \quad [\$/kWh_t] \tag{7}$$

where,

q_c [kW$_{tc}$] = Unit heat to be pumped out from indoor of the flat to the atmosphere
COP_{av} [-] = Annual average coefficient of performance of the refrigeration system
η_m, η_{comp} = Average electric motor and compressor conversion efficiency
C_{el} [\$/kWh$_{el}$] = Average unit price of electricity

b) Unit Cooling load amortization cost (C_{amr})

The average unit cooling load amortization cost can be calculated by using Eq. 5.

c) The other costs (C_{other})

The other costs of the refrigeration system can be taken of approximately 5% of the unit electricity cost.

d) The total unit cooling load pumping cost (C_{cpc})

The total unit cooling load pumping cost (C_{cpc}) can be calculated as given below:

$$C_{cpc}\ [\$/kWh_{el}] = C_{el} + C_{amr} + C_{oth} \tag{8}$$

3.2.2.3. Calculation of the electricity selling price

Unit electricity selling price can be calculated depending on subvention policies, payback time etc.

3.2.3. Calculation of total Annual Revenues of the cogeneration system

3.2.3.1. Annual revenue of cogeneration system from district heating and warm water supply

a) Unit district heating and warm water supply heat selling price

Unit heat selling price is assumed to be equal to the total unit heat generation cost of a individual conventional kombi heater with following design and operational data:

Installed capacity IC = 18 [kW_t]

Total investment Cost TIC = 1900 [$]

Specific nominal thermal efficiency η_{ste} = 0.85 [kWh_t / kWh_f]

Average thermal efficiency η_{Avr} = 0.75 [kWh_t / kWh_f] (Figure 6)

LHV of natural gaz Hu = 13.46 [kWh_t/kg_f]

Using above data the following specific cost for full load operation condition is calculated.

C_f = 0.121 [$/$kWh_t$] (Eq. 4)

C_{Amr} = 0.021 [$/$kWh_t$] (Eq. 5)

C_{other} = 0.032 [$/$kWh_t$] (Sec. 3.2.2.1b)

C_{hsp} = 0.194 [$/$kWh_t$] (Eq. 6) (9)

b) Annual amount of heat generated by co-generation system to be sold to the district for heating and warm water supply

Annual amount of heat to be sold to the district for heating and warm water supply is calculated considering the load factors (Figure 4) and given in Table 6.

c) Annual Revenue of Co-generation System from District Heating and Warm Water Supply

Annual revenue of co-generation system from district heating and warm water supply is calculated using unit heat selling price (Eq. 9) and annual heat production (Table 6) and given in Table 6.

3.2.3.2. Annual revenue of co-generation system from district cooling

Annual revenue of co-generation system from district cooling is calculated using unit district cooling cost of a conventional split refrigeration system (Eq. 8), and annual district cooling load Q_{dc} (Table 6)

a) Calculation of the unit district cooling revenue C_{dcr}

Unit district cooling revenue is assumed to be equal to the total unit cooling cost of a individual conventional split cooling system with following design and operational data:

Installed capacity IC = 20 [kW_{tc}]

Total investment Cost TIC = 1480 [$]

Specific nominal COP = 3 [kWh_{tc} / kWhel)

Average COP = 1.5 [kWh_t / kWhel

Cost of electricity Cel = 0.129 [$/ kWhel]

Using above data the unit cooling cost of the split cooling system or unit district cooling revenue of cogeneration system is calculated as given below.

C_{cel} = 0.129 (Eq .7)

C_{amr} = 0.032 (Eq. 5)

C_{oth} = 0.032 (Sec. 3.2.2b)

C_{crev} [$/kWh] = 0.193 (Eq. 8)

b) **Calculation of the annual district cooling load Q_{dc}**

The annual district cooling loads Q_{dc} are calculated using system load curve (Fig. 4) and load factors F_L and given in Table 6.

c) Calculation of the total annual district cooling revenue

The total annual district cooling revenues are calculated using unit district cooling revenue C_{dcr} and annual district cooling loads Qdc and given in Table 7.

4. ECONOMICAL ANALYSES OF DIFFERENT SCENARIOS INVESTIGATED

The following four scenarios are investigated for different amortization times. (30 years, 10 years, 5 years)

Scenario 1: HSP = individual heat generation cost (IHGC) of client
Scenario 2: HSP = 0.8 IHGC (HSP is equal 80% of IHGC)
Scenario 3: HSP = 0.5 IHGC (HSP is equal 50% of IHGC)
Scenario 4: HSP = 0 (No heat selling)

The load dependent annual expenditures, revenues and unit electricity production cost for scenario 1 are given for 30 years amortization time in Table 7, for 10 years amortization time in Table 10 and for 5 years amortization time in Table 13.

Variation of unit electricity production cost versus load factor is compared with different scenarios in Fig.7.

Table 7. Annual expenditures, revenues and unit electricity selling price (amortization time n_A= 30 years, unit heat selling price is equal to the individual heat production cost.

Annual Expenditures and Revenues (n_A = 30 years)	Load Factor (F_L)			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.837E+07	1.519E+07	1.159E+07	8.830E+06
Annual Heat Revenue [$]	9.670E+06	7.730E+06	5.800E+06	3.870E+06
Annual Electricity Revenue [$]	8.703E+06	7.463E+06	5.793E+06	4.960E+06
Annual Electricity Gen. [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.139	0.149	0.154	0.198

Table 8. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 20% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 30 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.837E+07	1.519E+07	1.159E+07	8.830E+06
Annual Heat Revenue [$]	7.736E+06	6.184E+06	4.640E+06	3.100E+06
Annual Electricity Revenue [$]	1.064E+07	9.009E+06	6.953E+06	5.730E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.170	0.180	0.185	0.229

Table 9. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 50% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 30 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.837E+07	1.519E+07	1.159E+07	8.830E+06
Annual Heat Revenue [$]	4.840E+06	3.865E+06	2.900E+06	1.935E+06
Annual Electricity Revenue [$]	1.353E+07	1.133E+07	8.693E+06	6.895E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.216	0.226	0.231	0.275

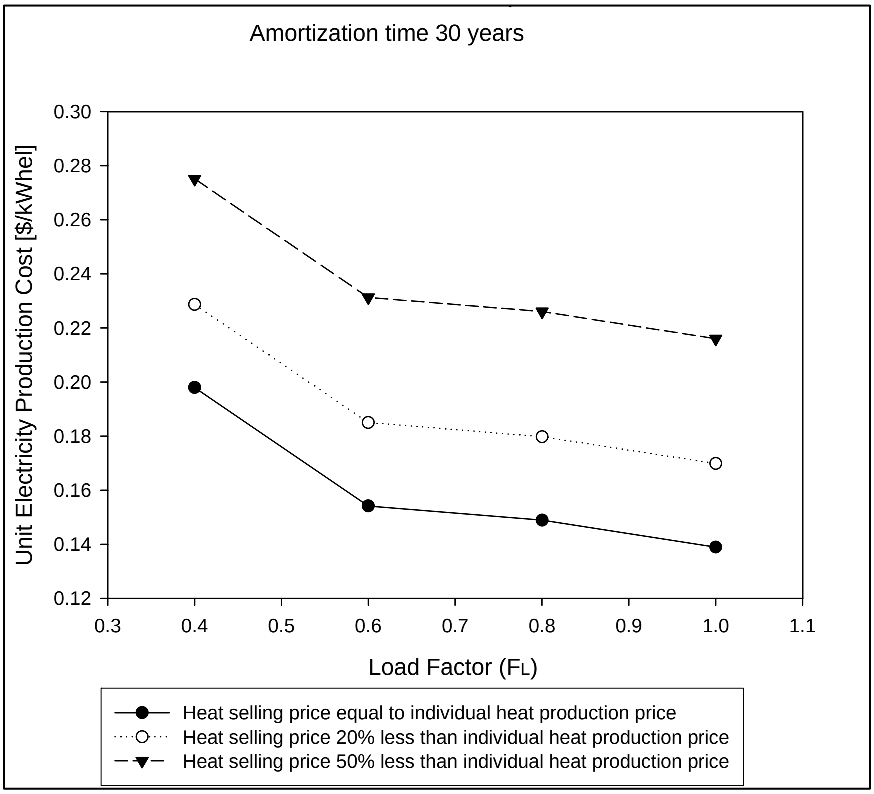

Figure 7. Unit electricity selling price versus load factor in 30 years amortization time (Table 7,8,9)

The load dependent annual expenditures, revenues and unit electricity production cost for scenario 2 are given for 10 years amortization time in Table 8, for 10 years amortization time in Table 11 and for 5 years amortization time in Table 14.

Variation of unit electricity production cost versus load factor is compared with different scenarios in Fig.8.

Table 10. Annual expenditures, revenues and unit electricity selling price. (Amortization time n_A= 10 years, unit heat selling price is equal to the individual heat production cost)

Annual Expenditures and Revenues (n_A = 10 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.882E+07	1.564E+07	1.240E+07	9.265E+06
Annual Heat Revenue [$]	9.670E+06	7.730E+06	5.800E+06	3.870E+06
Annual Electricity Revenue [$]	9.153E+06	7.913E+06	6.603E+06	5.395E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.146	0.158	0.176	0.215

Table 11. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 20% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 10 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.882E+07	1.564E+07	1.240E+07	9.265E+06
Annual Heat Revenue [$]	7.736E+06	6.184E+06	4.640E+06	3.100E+06
Annual Electricity Revenue [$]	1.109E+07	9.459E+06	7.763E+06	6.165E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.177	0.189	0.207	0.246

Table 12. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 50% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 10 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.882E+07	1.564E+07	1.240E+07	9.265E+06
Annual Heat Revenue [$]	4.840E+06	3.865E+06	2.900E+06	1.935E+06
Annual Electricity Revenue [$]	1.398E+07	1.178E+07	9.503E+06	7.330E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.223	0.235	0.253	0.292

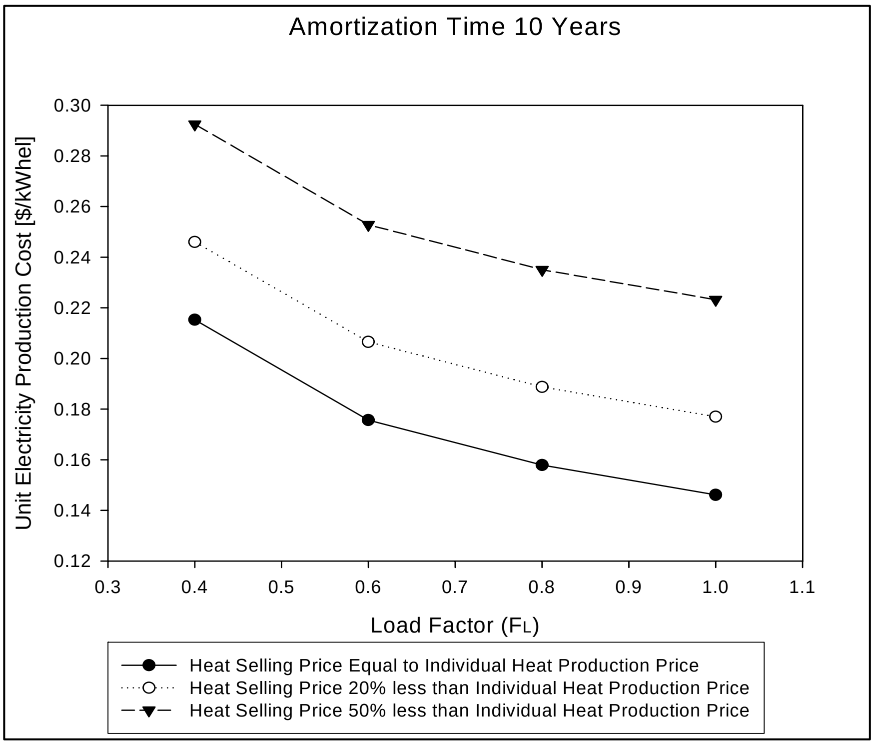

Figure 8. Unit electricity selling price versus load factor in 10 years amortization time (Table 10,11,12)

The load dependent annual expenditures, revenues and unit electricity production cost for scenario 3 are given for 30 years amortization time in Table 9, for 10 years amortization time in Table 12 and for 5 years amortization time in Table 15.

Variation of unit electricity production cost versus load factor is compared with different scenarios in Fig.9.

Table 13. Annual expenditures, revenues and unit electricity selling price (amortization time n_A= 5 years, unit heat selling price is equal to the individual heat production cost.

Annual Expenditures and Revenues (n_A = 5 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.963E+07	1.645E+07	1.321E+07	1.007E+07
Annual Heat Revenue [$]	9.670E+06	7.730E+06	5.800E+06	3.870E+06
Annual Electricity Revenue [$]	9.963E+06	8.723E+06	7.410E+06	6.202E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.159	0.174	0.197	0.247

Table 14. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 20% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 5 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.963E+07	1.645E+07	1.321E+07	1.007E+07
Annual Heat Revenue [$]	7.736E+06	6.184E+06	4.640E+06	3.100E+06
Annual Electricity Revenue [$]	1.190E+07	1.027E+07	8.570E+06	6.972E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.190	0.205	0.228	0.278

Table 15. Annual expenditures, revenues and unit electricity selling price. (Unit heat selling price is 50% less than individual heat production cost)

Annual Expenditures and Revenues (n_A = 5 years)	F_L			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.963E+07	1.645E+07	1.321E+07	1.007E+07
Annual Heat Revenue [$]	4.840E+06	3.865E+06	2.900E+06	1.935E+06
Annual Electricity Revenue [$]	1.479E+07	1.259E+07	1.031E+07	8.137E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.236	0.251	0.274	0.325

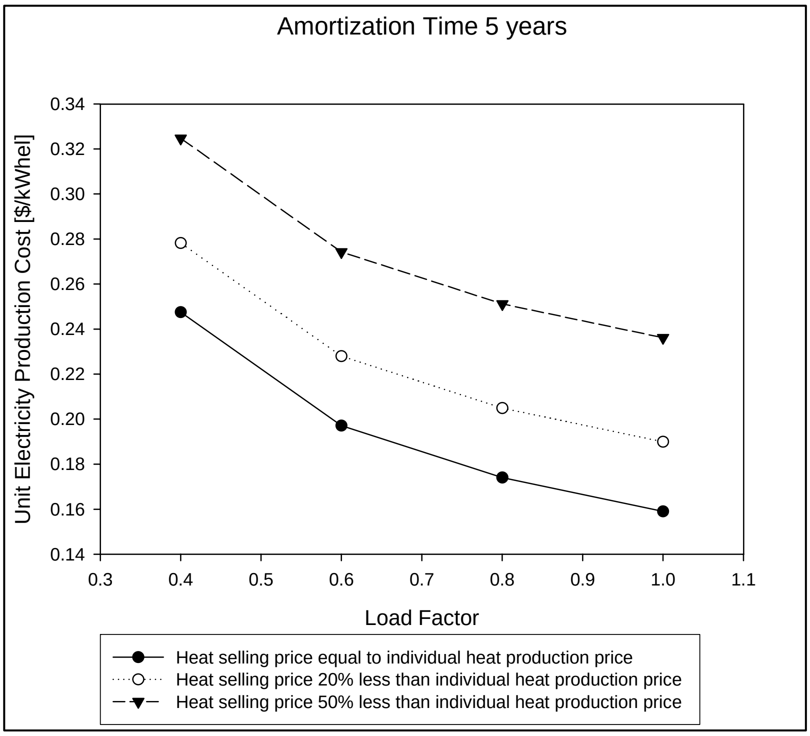

Figure 9. Unit electricity selling price versus load factor in 5 years amortization time (Table 13,14,15)

The scenario for no heat selling is analyzed for amortization time of 10 years and results are given in Fig. 10.

Table 16. Annual expenditures, revenues and unit electricity selling price. (No heat selling)

In Case of None Heat Selling (n_A = 10 years)	FL			
	1	0.8	0.6	0.4
Annual Expenditure [$]	1.882E+07	1.564E+07	1.240E+07	9.265E+06
Annual Heat Revenue [$]	-	-	-	-
Annual Electricity Revenue [$]	1.882E+07	1.564E+07	1.240E+07	9.265E+06
Annual Electricity Generation [kWhel/a]	6.265E+07	5.012E+07	3.759E+07	2.506E+07
Electricity Selling Price [$/kWhe]	0.300	0.312	0.330	0.370

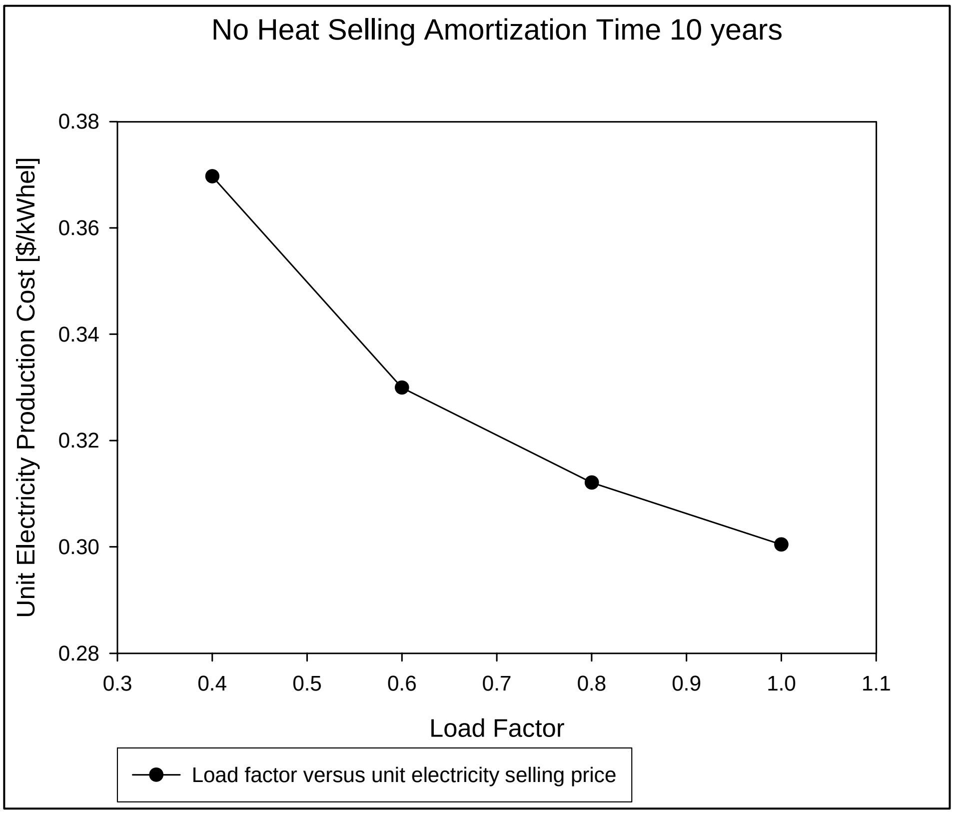

Figure 10. Unit electricity selling price versus load factor in 5 years amortization time (Table16)

Unit electricity production cost for different scenarios depending on different amortization times are compared in Table 17. The same results are also given in bar chats in Fig. 11.

Table 17. The unit electricity selling price variation for four different scenarios for 30 years, 10 years, 5 years amortization times.

Amortization Time(Years)	**n_A = 30 years**	**n_A = 10 years**	**n_A = 5 years**
ESP[$/kWhe] (HSP = IHPC)	**0.15**	**0.17**	**0.18**
ESP[$/kWhe] (HSP = 0.80 IHPC)	**0.170**	**0.19**	**0.21**
ESP[$/kWhe] (HSP = 0.50 IHPC)	**0.21**	**0.23**	**0.25**
ESP[$/kWhe] (HSP = 0, No heat selling)	**0.28**	**0.300**	**0.31**

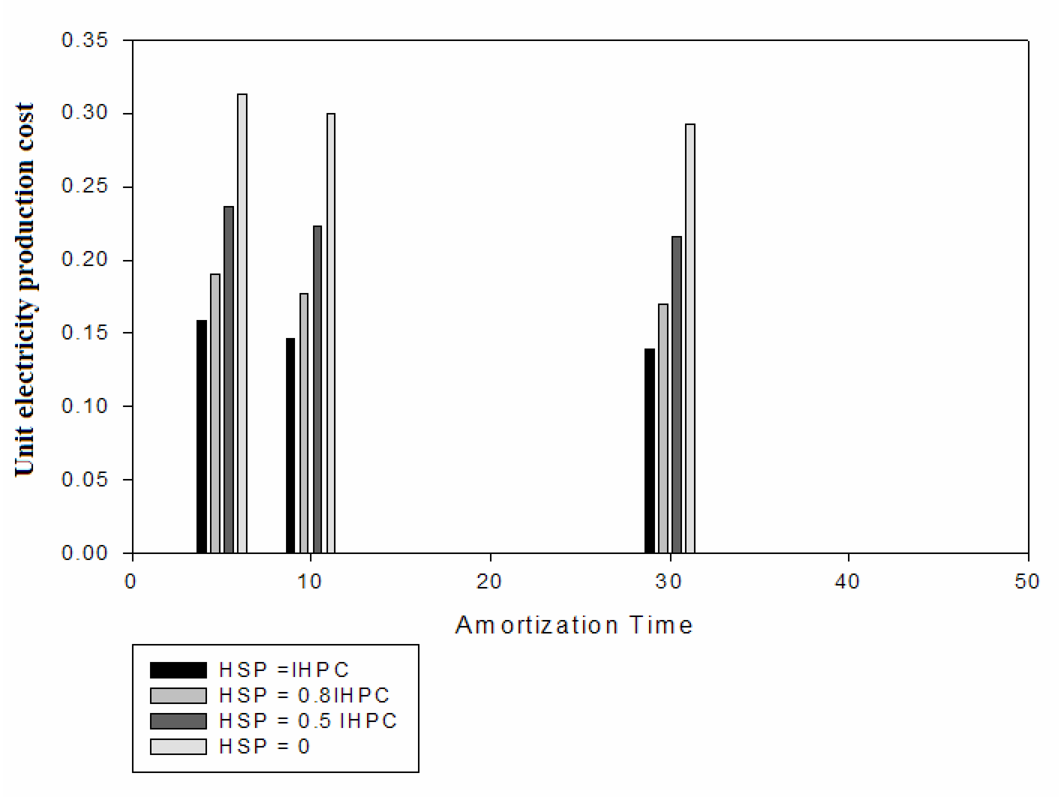

Figure 11. Unit electricity production cost of the hydrogen fired co-generation system versus amortization time, nA (years) for different heat selling price (HSP) scenarios. IHPC: Individual heat production cost of client

5. CONCLUSION

For the time being the main handicap of the use of the hydrogen in economical sectors is very high hydrogen production cost. Consequently, the use of hydrogen with present cost has no chance to compete with any fossil fuel fired energy systems without subvention. This subvention should be within the range of acceptable limits for realization of such systems. In order to achieve this goal the system to be designed should have high exergy potential, maximum exergy utilization ability, high system efficiency and maximum operational load factor. Considering these conditions a hydrogen fired multipurpose gas power cycle cogeneration system is designed, optimized and for different heat selling scenarios unit electricity production costs are calculated and the results are compared in Table 17. The results show that this unit electricity production cost is within the limit of 0.15 – 0.24 $\$/kWh_{el}$.

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