AN OPTIMIZATION SCHEME FOR THE ECONOMIC ASSESSMENT OF COGENERATION SYSTEMS

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ABSTRACT

This paper presents an optimization scheme to assess the economic operational benefits associated with the cogeneration systems from the industry strategic perspective. The economic assessments are based on examining the increase in the investment cost for the alternative being considered relative to the alternative to which it is being compared and determining whether the savings in annual operating cost justify the increased investment. For this purpose, a discounted cash flow analysis is employed to provide a discounted measure of project worth such as the net present worth, internal rate of return, or net benefit- investment ratio. A production simulation model is used to simulate the optimum operation problem and to determine the optimum operating cost. A sensitivity analysis for the most significant or unpredictable parameters in the economic evaluation is performed for each alternative.

INTRODUCTION

Cogeneration can offer a method to reduce the amount of waste energy by simultaneously producing electricity and useful thermal energy from a common primary energy source. Because of its potential for efficient use of energy, cogeneration is receiving increasing attention from both industries and utilities. In recent years, new factors have emerged to make cogeneration increasingly attractive [1]. Most important has been the enormous escalation of energy prices over the last decade, which has made energy efficiency an important economic factor for most industrial energy users. The overall effect of these factors has been to stimulate interest in cogeneration as a means to lower energy costs and to achieve national energy conservation goals. Because of the efficiency of cogeneration systems, they offer economic benefits to both the industry and the utility. Co-operative efforts between industry and utilities can lead to the implementation of the optimum cogeneration systems, providing benefits to industry, utilities, and society.

Cogeneration may be an attractive or an unattractive component of an energy strategy in terms of its effects on capital and operating costs, what it does to consumption of oil and natural gas, tax effects, pollution, .. etc. Although cogeneration should be evaluated as part of any plant energy management program, experience [2,3] has shown that it can most easily be justified under the following circumstances:-

* development of gross-roots facilities,
* major expansions to existing facilities which increase process heat demands and/or process energy rejection, and
* when old process and/or power plant equipment is being replaced, offering the opportunity to upgrade the energy supply system.

Kirby, et al. [4] have presented a typical system analysis and design procedure for developing a cost effective cogeneration facility. The existing power system included four gas turbine driven generators with waste heat boilers, and steam plant consisting of seven fired boilers. A comparative design analysis was developed for the uprating and refurbishing of the industrial cogeneration facility. Several alternative repowering designs were developed for the gas turbine plant and compared with the new substation option on the basis of initial capital investment and annual operating cost.

Kovacik [5] has presented an economic analysis procedure for cogeneration plants. The base case was a process heating plant to supply the steam demand and the electric demand was supplied from the utility. The base case has the lowest investment cost , but annual operating costs were higher than those available with cogeneration alternatives. The economic evaluation for each alternative was based on the gross payout period.

Wohlschlegel, et al. [6] have presented a typical system analysis for incorporating a gas turbine cogeneration system into a representative industrial process. Four configurations for incorporating a gas turbine were presented. A mathematical model based on the discounted cash flow and the more commonly used simple payback evaluation techniques were used for the economic evaluation of each configuration.

The economic evaluation in references [4,5] are based on a less sophisticated techniques, such as " gross payout period " or " payback period ". These techniques can provide an easy method for quickly ranking and eliminating alternatives that may be particularly unattractive. However, these techniques are applicable only if the annual operating costs do not change significantly with time. Thus, these techniques do not truly reflect the profitability of a cogeneration investment, neglect the life of assets, and do not properly consider the time value of the money. Also, the escalation rates for the operating costs and the power purchased cost are not taken into consideration. In references [4-6], the optimum operation problem for each alternative is solved over one hour as a representation for a year and the electric and the steam demands are assumed to be fixed during the year. Although the above assumptions highly simplify the simulation of the operation problem, the economical assessment may not be accurate because the cost effectiveness of cogeneration is greatly affected by the dynamic characteristics of the thermal and electrical loads.

This paper presents an optimization scheme to assess the economic and operational benefits associated with the cogeneration systems from the industry strategic perspective. The economic assessments are based on examining the increase in the investment cost for the alternative being considered relative to the alternative to which it is being compared and determining whether the savings in annual operating cost justify the increased investment. For this purpose, a discounted cash flow analysis is employed to provide a discounted measure of project worth such as the net present worth, internal rate of return,or net benefit- investment ratio. A production simulation model is used to simulate the optimum operation problem and to determine the optimum operating cost. A sensitivity analysis for the most significant or unpredictable parameters in the economic evaluation is performed for each alternative.

PROBLEM FORMULATION

The more commonly cogeneration options [3-6] that can be used for industrial applications are extraction steam turbines, back pressure steam turbines, gas turbines, gas turbines with waste heat boiler and combined cycles (steam turbine and gas turbine). Four cogeneration alternatives representing the more common options are used in this analysis to find the most cost effective cogeneration facility. The first alternative is based on the installation of two double extraction steam turbines. The second alternative contains three types of the steam turbines (double extraction, single extraction condensing and noncondensing). For both the first and the second alternatives, the electric demand is supplied by the in-plant generation and the serving utility company. In the third alternative, the existing steam generation (base case) is supplemented by adding three unfired gas turbine and an associated heat recovery steam generator system (HRSG). In the fourth alternative, supplementary firing burners are located in the HRSG inlet ductwork of the third alternative to increase the steam generation. For both the third and the fourth alternatives, the electrical power generated meets the electric demand and provides a surplus for sale to the electric utility.

It is required to assess the economic and the operational benefit associated with a cogeneration system, in stead of the traditional modes of separate heat and power generation, from the industry strategic perspective. For this purpose, a discounted cash flow analysis is employed to provide a discounted measure of project worth such as the net present worth, internal rate of return, and net benefit-investment ratio. The discounted cash flow analysis is based on the net incremental cost and benefit that form the incremental cash flow. The incremental benefit of each cogeneration alternative to supply a certain electric and process steam demands is considered as the avoided cost of producing the electric energy when the process steam demand is supplied by the in-site cogeneration system and the existing boiler system, in stead of purchasing the electric energy from the utility. The incremental cost of each cogeneration alternative consists of the fuel chargeable to power, operation and maintenance, insurance, local tax, interest on the debt service and electric energy purchase cost. To determine the benefits and costs for a cogeneration system, a production simulation model is developed to solve the optimum operation problem for each state with certain combination of electric and steam demand. To extend the benefit and cost over each year of the economic life of the project, the effect of inflation and real price increases is taken into account.

Production Simulation

The production simulation model is used to solve the optimum operation problem for a cogeneration system for each state (certain combination of electric and steam demands). The optimum operation problem of a steam turbine cogeneration system is a complex and nonlinear problem specially when the steam demands are supplied at different pressure levels and the turbine units are fed from different levels. Each of the steam turbine cogeneration system operates as thermal load following and maximizes the output power during the normal and the maintenance periods while the shortage of the electric demand is supplied by the utility. The operating strategy for a gas turbine cogeneration system is to operate each unit at its maximum power, and the process steam demand is supplied partially or totally from the thermal energy recovered from the exhaust gas by using a heat recovery steam generator (waste heat boiler). The shortage of the process steam demand is supplied by the existing boiler system. The most efficient utilization of the waste energy is the key parameter to minimize the total energy cost for a gas turbine cogeneration system. The optimization model to the optimum operation problem of a cogeneration plant may be split into an objective function and imposed constraints.

System Constraints

Each cogeneration system is subjected to several constraints. For each turbine (steam or gas) the following constraints should be satisfied:-

a- Electric power constraint

For the steam alternatives, assuming linear steam-flow versus electric power characteristic curves for the steam turbine generator (double extraction) and constant fraction and heat losses, the power equation for turbine i may be written in the following form:-

$$PG_i = M_{hi}\,K_{hi} + M_{mi}\,K_{mi} + M_{li}\,K_{li} - LK_i \qquad \text{--- (1)}$$

Where,

PG_i is the generated electric power;

M_{hi}, M_{mi} are the high and medium pressure extraction flows;

M_{li} is the low (condenser or exhaust) pressure extraction flow;

K_{hi}, K_{mi}, K_{li} are constant coefficients; and

LK_i is the loss constant.

For the gas turbine alternatives, the generated electric power of turbine i is given by:

$$PG_i = \eta_i * Q_i \qquad \text{--- (2)}$$

Where,

η_i is the thermal efficiency; and

Q_i is the rate of fuel consumption, KW.

The total power generated by the turbines plus the interchange power of the tie line (P_{tl}) is equal to the electric load demand (LD).

This constraint is given by:-

$$\sum_{i=1}^{NT} PG_i \pm P_{tl} = LD \qquad \text{--- (3)}$$

Where,

NT is the number of the turbine units.

b- Capacity limits constraint

The output power of each turbine i is restricted by its upper and lower limits, hence;

$$PG_{i(min)} \leqslant PG_i \leqslant PG_{i(max)}$$

Where,

$PG_{i(min)}$ is the minimum output power; and

$PG_{i(max)}$ is the maximum output power.

c- The mass balance constraint

The input steam flow to each steam turbine is equal to the sum of the output steam flows. This constraint is given by:

$$M_{thi} = M_{hi} + M_{mi} + M_{li} \qquad --- (4)$$

Where,

M_{thi} is the throttle steam flow for turbine i.

Objective Cost Function

The plant energy cost is mainly consisting of:

* The fuel cost (for the in-plant boilers and / or the gas turbine units plus the burners).
* The power sale or purchase cost.

The in plant boilers cost (BC) may be expressed in the form:

$$BC = \sum_{i=1}^{N} (a_i M_i^2 + b_i M_i + c_i)$$

Where,

N is the number of the in plant boilers;

M_i is the amount of the steam generated from boiler i; and

a_i, b_i, c_i are constant coefficients for boiler i.

Then, the cost of the total plant energy for each state is given by:

$$TEC = BC \pm EC * P_{tl} + F * GC \qquad --- (5)$$

Where,

TEC is the total energy cost, \$/Hr;

EC is the tie line energy cost, \$/MWh;

P_{tl} is the tie line power, MW;

F is the gas turbine system fuel consumption, MBtu/hr; and

GC is the gas turbine fuel cost, \$/MBtu.

The above mentioned optimization problem for each state has a set of linear constraints but its objective cost function is nonlinear. So, it is a nonlinear optimization problem. In order to solve this problem by a linear optimization technique, which is efficient and more reliable, the nonlinear cost function can be rewritten using a piece-wise linear approximation as;

$$TEC = \sum_{i=1}^{N} \sum_{j=1}^{K(i)} M_{ij} C_{ij} \pm EC * P_{tl} + F * GC \qquad --- (6)$$

Where,

M_{ij} is the steam flow supplied by boiler i in segment j;

C_{ij} is the unit cost for steam generation from boiler i in segment j; and

K(i) is the number of segments for in plant boiler i.

The Generalized Network optimization technique [7] is used to solve the steam turbine optimization problem. The outage for each unit due to routine maintenance can be simulated in the network technique by limiting the throttle arc flow to zero. Under the operating strategy for a gas turbine cogeneration system, the optimization problem can be easily solved. The outage of each unit due to the maintenance is simulated by solving the optimization problem with output power and exhaust gas for this unit limiting to zero. For each state, the optimum output power, fuel consumption, tie line power and the total energy cost are determined by solving the optimization problem for each alternative (steam or gas). The process steam demand is satisfied for each state during the normal and maintenance periods.

Discounted Cash Flow Analysis

The discounted cash flow analysis is based on the net incremental costs and benefits that form the net cash flow. The internal rate of return (the rate of discount at which the present value of benefits is made equal to the present value of the project costs), the net present worth and the net benefit-investment ratio are calculated for each alternative to determine the most economic cogeneration system. For a cogeneration system, the incremental costs are the fuel chargeable to power, operation and maintenance cost and the associated taxes on the capital cost while the incremental benefit is the power revenue.

Once the optimum operation problem of each cogeneration system is solved, the output power, the fuel consumption and the tie line power can be determined. To determine the annual benefit and cost, it is required to solve the optimization problem over all load states. So, it is essential that loads be modelled in detail to accurately determine the impact of a cogeneration installation. The daily chronological data of the steam and electric demands are represented by probability distributions. The probability distributions are constructed by estimating a range of values for each load and then assigning the probabilities of occurrence to values within that range. If each load is estimated by its optimistic, mean, and pessimistic values, a beta distribution should be fitted to these three points, with a standard deviation of 1/6 of the spread between the lower and the upper bounds. If these estimates be denoted by b, a, and m, respectively, the mean (μ) of the corresponding distribution is given by:

$$\mu = \frac{a + 4m + b}{6} \qquad \text{--- (7)}$$

and its standard deviation (σ) is given by:

$$\sigma = \frac{b - a}{6} \qquad \text{--- (8)}$$

Assuming that the steam demand is required at three pressure levels with independent distribution, the probability of a state k (a combination of a certain electric and process steam demand distribution) can be written in the form:

$$P_k = P(E_L) * \prod_{i=1}^{3} P(S_{ij}) \qquad \text{--- (9)}$$

Where,
P_k is the probability of the state K;
$P(E_L)$ is the probability of a certain value of the electric demand; and
$P(S_{ij})$ is the probability of the jth value of the steam distribution at the ith pressure level.

For each alternative, the total power generated for all the states (TPG) may be written in the form:-

$$TPG = \sum_K PG_K * P_k \qquad \text{--- (1}$$

Where,
PG_k is the output power for state K.

By a similar manner, the fuel consumption and the tie line power for all the states can be calculated. The annual electric energy production benefit E(t) for year t, is equal to the annual electric energy produced during the normal and maintenance periods multiplied by the per unit energy avoided cost. This relation may be written in the following form:-

$$E(t) = [TPG_n * T_n + \sum_{m=1}^{NT} TPG_m * T_m] * EC(t) \qquad \text{--- (11)}$$

Where,
TPG_n , TPG_m are the output power during the normal and maintenance periods , respectively;
T_n , T_m are the number of the normal and maintenance days per year;
NT is the total number of turbine units; and
EC(t) is the per unit electric purchase cost for the year t.

The annual incremental cost C(t) for year t, is given by:

$$C(t) = F(t) + OM(t) + I(t) + Ep(t) + A(t) \qquad \text{--- (12)}$$

Where,
F(t) is the cost of fuel chargeable to power;
OM(t) is the operating and maintenance cost;
I(t) is the interest on the debt service;
EP(t) is the energy purchase cost; and
A(t) is the insurance and local taxes.

For each year of the economic life of the project, the thermal and electric load growth, the rate of real price change for fuel and power and the effect of inflation to the operation and maintenance cost are taken into consideration.

the incremental cash flow CF(t) for year t, is given by:-

$$CF(t) = (1-T)*E(t) - (1-T)*C(t) + T*D(t) + ITC - P(t) \qquad \text{--- (13)}$$

Where,
T is the income tax rate;
ITC is the investment tax credit;
D(t) is the depreciation in year t; and
P(t) is the principal of debt service in year t.

The discounted cash flow DF(t), for the incremental cash flow CF(t), at year t is given by:-

$$DF(t) = CF(t) * PWF(i,t) \qquad \text{--- (14)}$$

Where PWF(i,t) is the present worth factor for year t and interest i.

The accelerated depreciation D(t) for year t is given by:-

$$D(t) = \frac{2(L-t+1)}{L(L+1)} (I_0 - S) \quad \text{--- (15)}$$

Where,

I_0 is the initial investment;
S is the salvage value;
L is the number of years of the economic life .

The principal of the debt service P(t) for year t is given by:-

$$P(t) = \frac{t}{R} (I_D) \quad \text{--- (16)}$$

And the interest on the debt service I(t) for year t is given by:-

$$I(t) = DR(I_D - \sum_{i=1}^{t-1} P(i)) \quad \text{--- (17)}$$

Where,

I_D is the debt investment;
DR is the debt rate.

The incremental cash flows (the cash flow differences between cogeneration alternative and the base case) are discounted and summed over the economic life of the project to arrive at the Net Present Worth (NPW). The higher NPW the higher project contribution to the net worth of the equity investor. The internal rate of return and the net benefit-investment ratio are also calculated for each alternative to find the most economic cogeneration system. The net present worth (NPW); the difference between the present value of the alternative revenues and costs, is given by:

$$NPW = \sum_{t=1}^{L} \frac{CF(t)}{(1+i)^t} + \frac{S}{(1+i)^L} - I_E \quad \text{--- (18)}$$

where,

i is the internal rate of return;
I_E is the equity investment which is given by:-

$$I_E = I_0 - I_D$$

Eq. 18 is used to calculate the internal rate of return, (the value of i at which NPW =0).

The net benefit-investment ratio (B/I) is given by:-

$$B/I = (\sum_{t=1}^{L} \frac{CF(t)}{(1+i)^t} + \frac{S}{(1+i)^L}) / I_E$$

The project is profitable as long as the net benefit-investment ratio (B/I) is greater than 1.

SENSITIVITY ANALYSIS

If the factors (initial investment, costs, revenue, salvage value, and economic life) that enter an economic assessment problem were known certainly, the evaluation of the investment profitability would simply be a deterministic analysis, and there would be no need for a probabilistic study. However, the values of input factors for most practical problems are not accurately known and there is usually uncertainty associated with them.

To fully understand the economic attractiveness of a cogeneration project, it is important to perform a sensitivity analysis for the most significant or the most unpredictable parameters in the economic evaluation. For a cogeneration plant, the most significant variables in determining its economic attractiveness are the electric rate, the fuel price, and the capital cost. A particular use of sensitivity analysis is to take high, low, and medium values of the key elements and compute the value of the measure of merit(internal rate of return, net present worth and benefit-investment ratio) for various combination of these three levels of estimate, thus providing a range of possible results.

APPLICATIONS

To determine the economic and operational benefit associated with a cogeneration system, in stead of the traditional mode of separate heat and power generation, four cogeneration alternatives are considered and the discounted cash flow analysis is used to determine the most profitable cogeneration system. The performance analysis for each alternative is studied to determine the most efficient cogeneration alternative from the efficiency point of view to determine whether the most economic alternative is the most efficient or not. In the base case, two oil-fired process boilers are installed to supply steam to the plant 400-Psig steam header.

Each of the plant requirements, the process steam and the electric demands, is represented by a probability distribution. The probability distribution is characterized by mean and standard deviation (μ, σ). The process steam demands are supplied at three pressure levels (400, 150 and 30 Psig). The thermal energy is recovered from the steam at the three pressure levels by three process steam demands, and a mechanical drive back pressure steam turbine. The probability distribution of the process steam and the electric demands are specified as: (50,000 Kg/hr, 1.66), (100,000 Kg/hr ,3.33), (180,000 Kg/hr, 6.67), and (45 MW, 1.66) respectively. The schematic diagrams of the steam turbine alternatives(1 and 2) are shown in Fig. 1 and Fig. 2, respectively. The gas turbine alternatives (3 and 4) are shown in Fig. 3.

Test system

The steam turbine alternatives contain four types of steam turbines. The data of the steam turbines are taken from [8]. These data are:

* Type 1. Double extraction (noncondensing);
  Steam flow limitations are: $X2 \leqslant 285$, $X3 \leqslant 180$, $X4 \leqslant 137$, $5 \leqslant X5 \leqslant 70$;and
  Power flow limitations are: $7.5 \leqslant PG1 \leqslant 18.74$.
* Type 2. Single extraction (noncondensing);
  Steam flow limitations are: $X6 \leqslant 148$, $X7 \leqslant 140$, $5 \leqslant X8 \leqslant 80$; and
  Power flow limitations are: $3.5 \leqslant PG2 \leqslant 9.4$.
* Type 3. Single extraction (condensing), condensate at 0.5 Psig;
  Steam flow limitations are: $X9 \leqslant 148$, $X10 \leqslant 140$, $5 \leqslant X11 \leqslant 80$; and
  Power flow limitations are: $7.0 \leqslant PG3 \leqslant 18.8$.
* Type 4. Noncondensing (back pressure);
  steam flow limitations are: $Xp \leqslant 37$; and
  Power flow limitations are: $0.2 \leqslant PG4 \leqslant 2$.

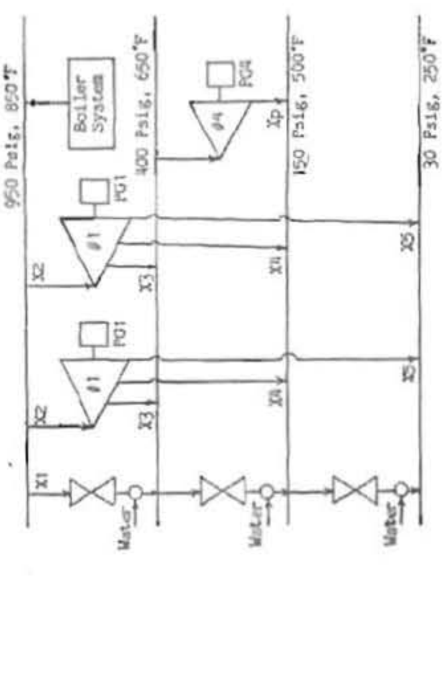

Fig. 1 Steam turbine system for alternative 1

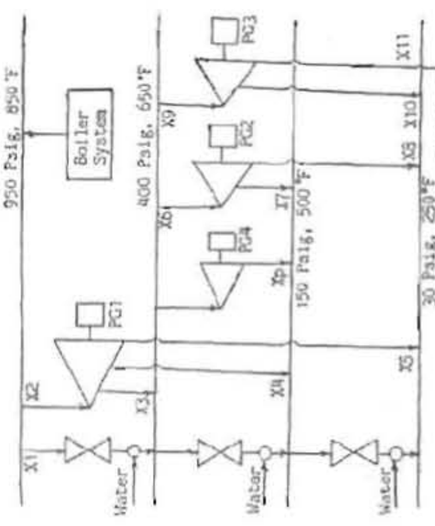

Fig. 2 Steam turbine system for alternative 2

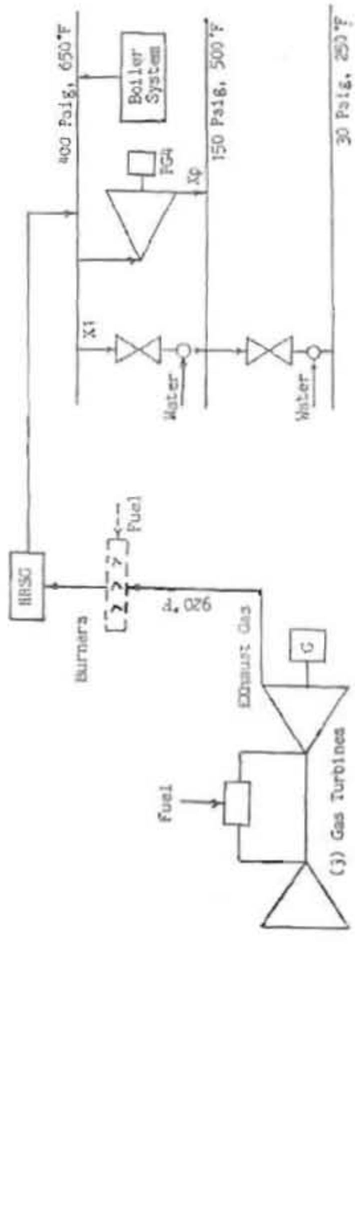

Fig. 3 Gas turbine system for alternatives 3 and 4

All steam flows are in thousands kilogram per hour and all power flow are in MW. The data of the gas turbines are taken from [5]. For each unfired gas turbine and associated heat recovery steam generator, the data are:-

fuel consumption = 297 MBtu/Hr, output power = 21.8 MW, steam generation = 50,000 Kg/hr at 400 Psig, 650°F and exhaust temperature = 920°F; and The nominal outage time for each steam or gas turbine unit = 170 Hr/Year.

The economic evaluation parameters are taken from [6,3]. These data are:

Economic life	= 10 years
Debt	= 50 %
Debt Cost	= 14 %
Return On Equity	= 18 %
Property Tax Rate	= 1.5 %
Insurance Rate	= 1.5 %
Investment Tax Credit	= 10 %
Income Tax Rate	= 48 %
Tax Depreciation	= 10 years
Conventional Boiler Fuel Cost	= $3.60 / MBtu
Cogeneration Fuel Cost	= $4.0 / MBtu
O & M Cost	= $2.5 / MWh
Electric load growth	= 2 %
Thermal load growth	= 2 %
Cost Of Purchased Electricity	= $40 / MWh
Conventional Boiler Efficiency	= 84 %
General Inflation Rate	= 6 %
Electricity Escalation Rate	= 8 %
Fuel Escalation Rate	= 10 %

The installation cost for the alternatives are: 15, 19.7, 21.62 and 23.12 Million- dollar, respectively.

Results

The performance parameters for the four alternatives are shown in Table 1. The performance parameters for the steam turbine alternatives are the electric power generation, the thermal energy supplied by the boiler system, the input fuel to the boiler system and the power plant loads. While, the performance parameters for the gas turbine alternatives are the electric power generation, the contribution of the heat recovery steam generation (HRSG) and the boiler system (B.S.) in the thermal energy, the input fuel to the boiler system, the gas turbine system and the burner and the plant loads. For comparative purposes, steam and power production levels have been converted to MW equivalents. The efficiency calculations include the power plant loads (fuel pumps, compression station, boiler feed water pumps and draft fan). The overall thermal efficiencies for the four alternatives are 85, 74, 74 and 81% respectively. So, Alternative 1 is the most efficient alternative from the performance point of view.

Table 2 shows the cash flow and discounted cash flow calculations for the four alternatives, in million dollar, over a ten years economic life. The initial investment and the salvage value are the annual cash flow at years 0 and 11 respectively. The net benefit-investment ratio for these alternatives are 2.03, 1.35, 1.51 and 2.08 respectively. From the results, alternative 4 is the most profitable alternative with the higher internal rate of return (48.7), net present worth (12.48) and benefit-investment ratio (2.08). The internal rate of return of any alternative is higher than the internal rate of return required by the investors for cogeneration projects (20%), thus cogeneration is extremely attractive.

Fig. 4 shows the effects of changing the capital cost, the electricity rate, and the fuel cost on the net benefit-investment ratio. The breakeven line is the dashed line at which (B/I)=1; below this line the project is not profitable. If the electricity rate is decreased by 8% or the fuel rate is increased by 11%, alternatives 2 and 3 become non-profitable. The factors affecting the profitability of cogeneration project are the increase in electricity rate and the decrease in both the capital cost and the fuel rate

Table 1 Alternative Performance

Performance parameters	Alt.1 (MW)	Alt.2 (MW)	Alt.3 (MW)	Alt.4 (MW)
Elec. power generated	37.0	47.5	65.4	65.4
HRSG	-	-	118.4	260.5
Boiler system (B.S.)	260.5	260.5	142.0	-
Plant loads	-0.88	-0.88	-1.46	-1.46
Total output energy	296.62	307.12	324.34	324.34
Gas T. fuel input	-	-	261.0	261.0
B. S. fuel input	347.0	415.6	177.6	-
Burner fuel input	-	-	-	138.6
Total input energy	347.0	415.6	438.6	399.6
Thermal Efficiency %	85	74	74	81

Table 2 Cash Flow And Discounted Cash Flow Calculations

Year	Alternative 1		Alternative 2		Alternative 3		Alternative 4	
	CF(t)	DF(t)	CF(t)	DF(t)	CF(t)	DF(t)	CF(t)	DF(t)
0	-7.5	-7.5	-9.85	-9.85	-10.81	-10.81	-11.56	-11.56
1	4.5	3.81	5.0	4.24	5.98	5.07	7.42	6.29
2	2.97	2.13	2.87	2.06	3.61	2.59	4.97	3.57
3	2.95	1.79	2.67	1.63	3.39	2.06	4.87	2.96
4	2.96	1.53	2.51	1.30	3.20	1.65	4.80	2.48
5	2.98	1.30	2.35	1.03	3.03	1.32	4.76	2.08
6	3.04	1.13	2.28	0.84	2.82	1.05	4.70	1.74
7	3.14	0.99	2.04	0.64	2.61	0.82	4.69	1.47
8	3.28	0.87	1.97	0.52	2.41	0.64	4.68	1.25
9	3.42	0.77	1.83	0.41	2.19	0.49	4.67	1.05
10	3.58	0.68	1.78	0.34	2.03	0.39	4.76	0.91
11	1.50	0.24	1.50	0.24	1.50	0.24	1.50	0.24
I	45.5		28		35		48.7	
NPW		7.74		3.40		5.51		12.48
B/I		2.03		1.35		1.51		2.08

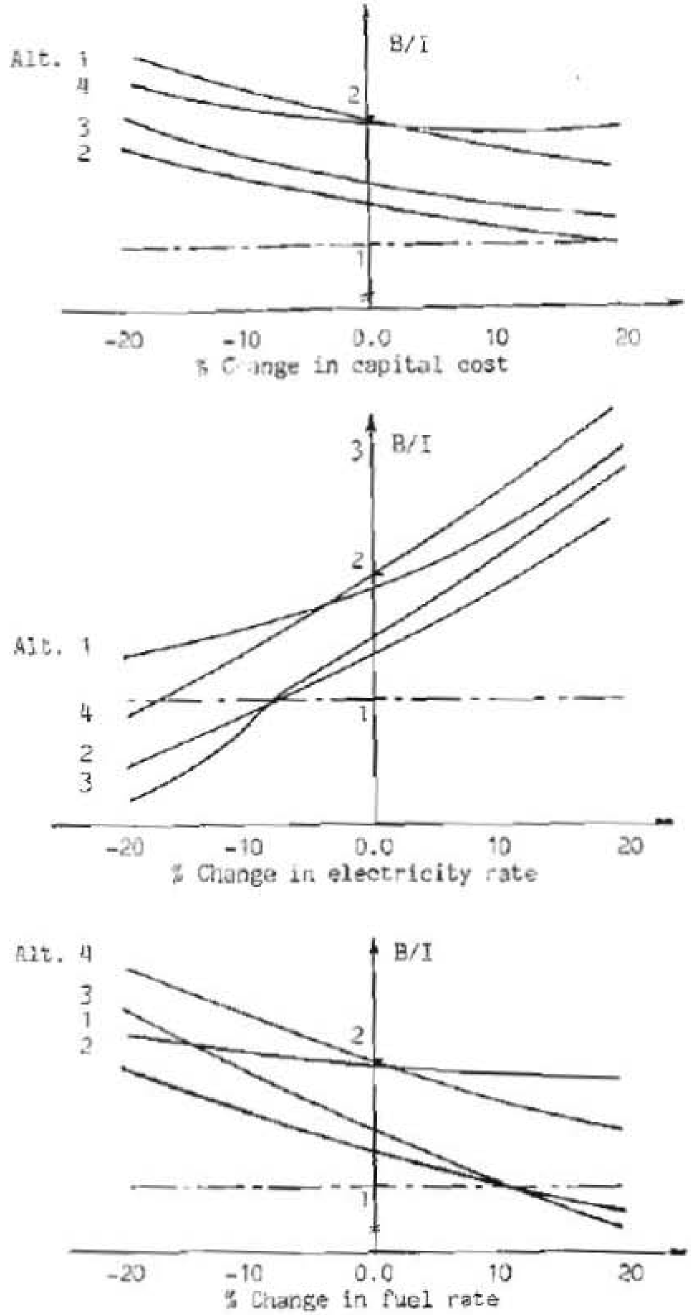

Fig. 4 The effects of changing the capital cost, electricity rate, and the fuel rate on the net benefit-investment ratio (B/I).

CONCLUSIONS

Cogeneration is most favourable in areas with high electricity rates and low fuel rates, since the system economics are most dependent on the value of the electric output and the fuel consumption.. The electricity and fuel costs that exist today create great opportunities for cogeneration investment. As more electric utilities bring on line expensive new coal or nuclear generating capacity, the difference between fuel and electricity costs will continue to widen, further enhancing the attractiveness of cogeneration. Cogeneration, and gas turbine systems in particular, offer the potential for substantial cost saving to industrial energy users. Gas turbine systems with waste heat boilers can provide attractive investment options to energy intensive process industries, and meet a wide range of energy demands by judicious selection of alternative components. Cogeneration system enhancements such as burners can provide very attractive incremental investment options which can improve the profitability of the gas turbine cogeneration project.

The most efficient cogeneration plant is not always the most profitable one. The site specific loads and equipment characteristic, the tax status of the facility owner and the size and operating mode of a cogeneration system all play an important role in determining whether or not a cogeneration investment will provide an acceptable return. The financial incentives, along with the increasing interest on the part of electric utilities, have created a wide range of opportunities for cogeneration systems.

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