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The Economic Implications of Industrial Electricity/Steam Cogeneration

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ABSTRACT. This paper investigates the economic implications of the capital investment decision in industrial cogeneration of electric energy and steam. The influencing elements in the consideration are analyzed so that their applicability to a wider industrial spectrum can be determined specially in developing countries. The potential for gain is shown to increase with higher cost of purchased energy, reduced fuel cost, greater operating hours, increased plant load and greater steam requirement.

There is consideration of the elements of value and cost as functions of the individual industrial process requirements. The individual costs, whether expended or avoided, are viewed as elements of worth in a simple cost-effectiveness model for a balance between the avoided costs versus incurred expenses. An annual before and after tax cash flow analysis is set up where the relevant elements are expressed as functions of their cost effectiveness. The direct costs are shown to be dependent on the power-steam ratio and the savings are dependent on the demand and energy charges. Influence of government action on cogeneration is considered. The role of allowed tax savings element is translated into added effectiveness making cogeneration more attractive economically.

1. Introduction

Energy conservation in industry can be accomplished in two ways: the methods of energy consumption can be examined for improved energy utilization, and the methods of energy generation can be examined for improved energy output. While the consumption aspects of energy conservation have received considerable attention only since the oil embargo in 1973, the methods of energy generation for industrial use have been changing steadily since the 19*th* century.

At the turn of this century, the majority of industrial plants cogenerated their own electric energy and process steam. As the economics of scale began to favor central utility generation and the price of oil dropped after World War II, many firms discontinued the on-site generation of electricity, while retaining steam generation capabilities (*see* Fig. 1).

The separation of steam and energy generation, however, has eliminated many of the advantages available in the combined process.

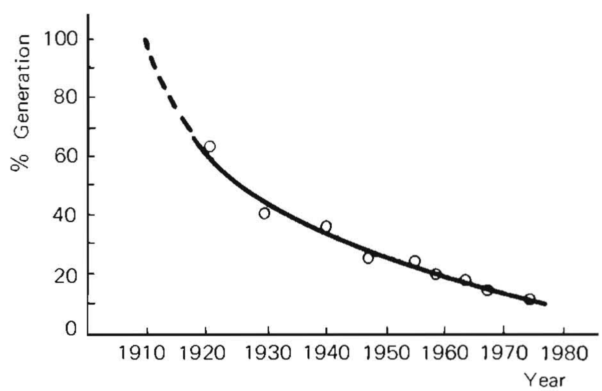


Fig. 1 History of industrial self-generation of electricity (Wilkinson and Barnes 1980).

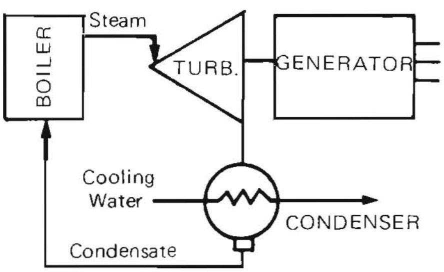


Fig. 2-a. Generating plant

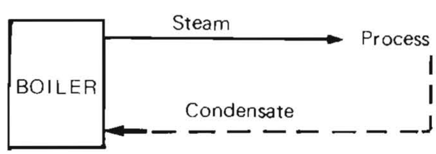


Fig. 2-b. Process steam plant

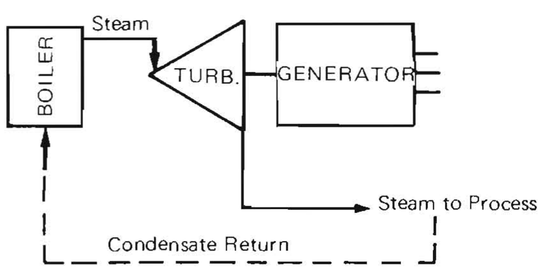


Fig. 2-c. Backpressure cogeneration plant (Comtois 1978).

In a simple thermal energy generation cycle, energy is converted from a prime source to generate steam, which, in turn, drives a turbine and generates electricity. All heat engines must reject some portion of the heat supplied to another system (heat sink). The typical power cycle uses a condenser with cooling water from the environment as its heat sink. It is in this component of the cycle that the cooling water carries away 50-60 percent of the inputted energy. As a result, the power supplied to a customer is the product of a process that is 30-40 percent efficient. (The differing loss being ejected out of the chimney stack); (Wark 1977).

In a simple steam generation cycle for industrial use, a boiler converts the energy of a prime source, into low pressure steam (Comtois 1978), Fig. 2. The steam is sent directly to an industrial process and/or space heating system. The condensate is returned to the boiler and all electric energy required is purchased from the utility company.

While a utility rejects considerable waste heat, in a simple boiler system there is relatively little waste and an efficiency of 85% is often realized. The waste heat rejected by a central power plant, however, is compatible with industrial use. Substantial savings can result by the utilization of this heat and the ensuing increase in cycle efficiency. The availability of these savings can arise from both colocation and cogeneration (Fig. 3 & 4).

Colocation involves the placement of industrial facilities within close proximity to power plant sites, thus utilizing the waste heat. This arrangement allows the power cycle to benefit not only from the improved cycle efficiency, but also from the economics of scale. Colocation should be taken into consideration in cases where developing countries are in the stage of planning their energy generating systems and industrial growth, or are in the primary stages of implementing these

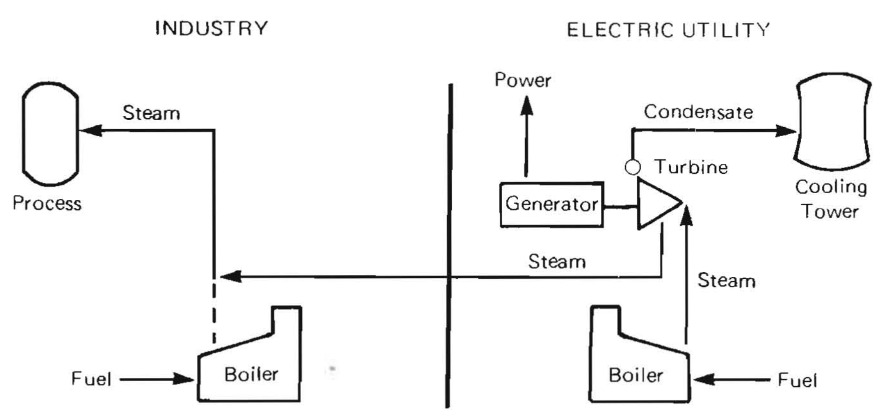


Fig. 3. Colocation schematic (Noyes 1978).

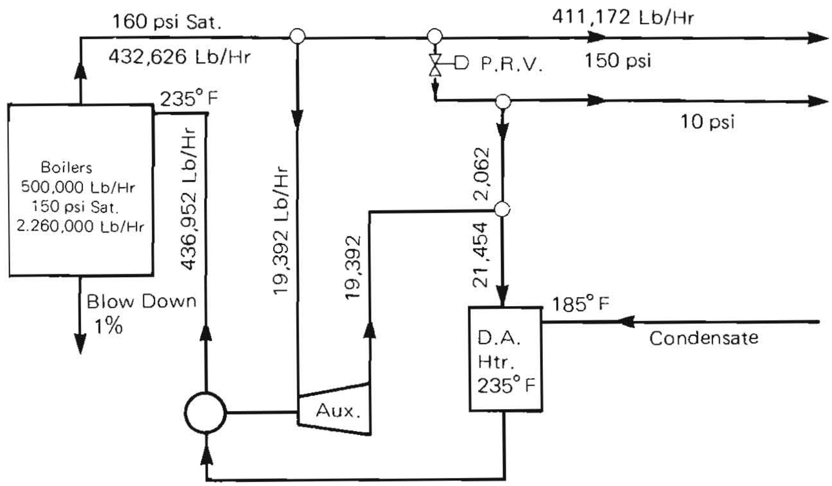


Fig. 4 A. Generation of steam only

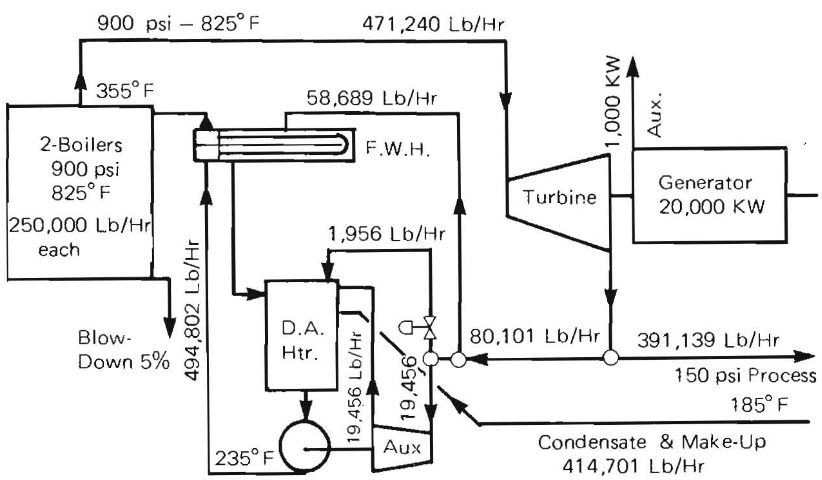


Fig. 4 B. Generation of energy and steam (Noyes 1978)
Note that the boiler capacity is the same in each case and the outlet steam to process is at 150 psi at practically the same mass flow rate.

plans. Otherwise, because of the cumbersome nature of planning and coordinating such mutual site locations between conflicting interests of established industries and power systems, the idea of colocation is for the most part impractical in developed countries.

Cogeneration, on the other hand, involves the utilization of high pressure steam from the boilers for driving bleeding and/or backpressure turbines to generate energy and then using the exhaust and/or bled steam for the process. This on-site cogeneration can be assessed and planned within a cost effectiveness framework relative to the individual firm alone. While the costs of central energy generation enjoy the values of the economy of scale, the costs, values and needs of energy and steam to a facility are unique to the industrial requirements of that firm. Therefore, although the cost considerations for on-site generation may benefit from improved power cycle efficiency, the economic assessment for the firm is sensitive to the financial and process cost make up of its production requirements.

Cogeneration brings the power generation cycle to the industrial site with the addition of high pressure steam production capabilities and the additional turbine-generator equipment (see Fig. 4). Therefore, the heat sink available can be the steam needs of the industrial process itself. Although the limiting cost consideration is the reduction in power cycle size, the loss of the economy of scale, the particular factors relative to the individual industrial process may combine with the improved cycle efficiency to overcome the decentralized costs. A rough approximation of how individual process requirements can affect the potential for utilizing cogeneration is seen in the graphs from Fig. 5 (Wilkinson and Barnes 1980) which show that the potential for gain from cogeneration is greater with higher cost of purchased energy, reduced fuel cost, greater operating hours, increased plant load and greater process steam requirements.

Although many plants have turned away from combined energy production systems, a few major industries have not. The paper, chemical, and petroleum industries use large amounts of both electricity and steam, and their energy economics have consistently favored cogeneration (Wilkinson and Barnes 1980). In fact, plants in these industries have not only maintained cogeneration systems, but have continued to install newer and more efficient systems (Petkovsek and Mangione 1975).

The elements of value and cost that made these systems attractive deserve scrutiny so that their applicability to wider, more general industrial spectrum can be determined. In fact, the economics of energy generation pricing, alone, are changing the parameters surrounding the capital investments in such projects, and they may make cogeneration more attractive to firms that would not have considered such investments before. The influencing elements in the consideration of the cogeneration investment include as primary factors:

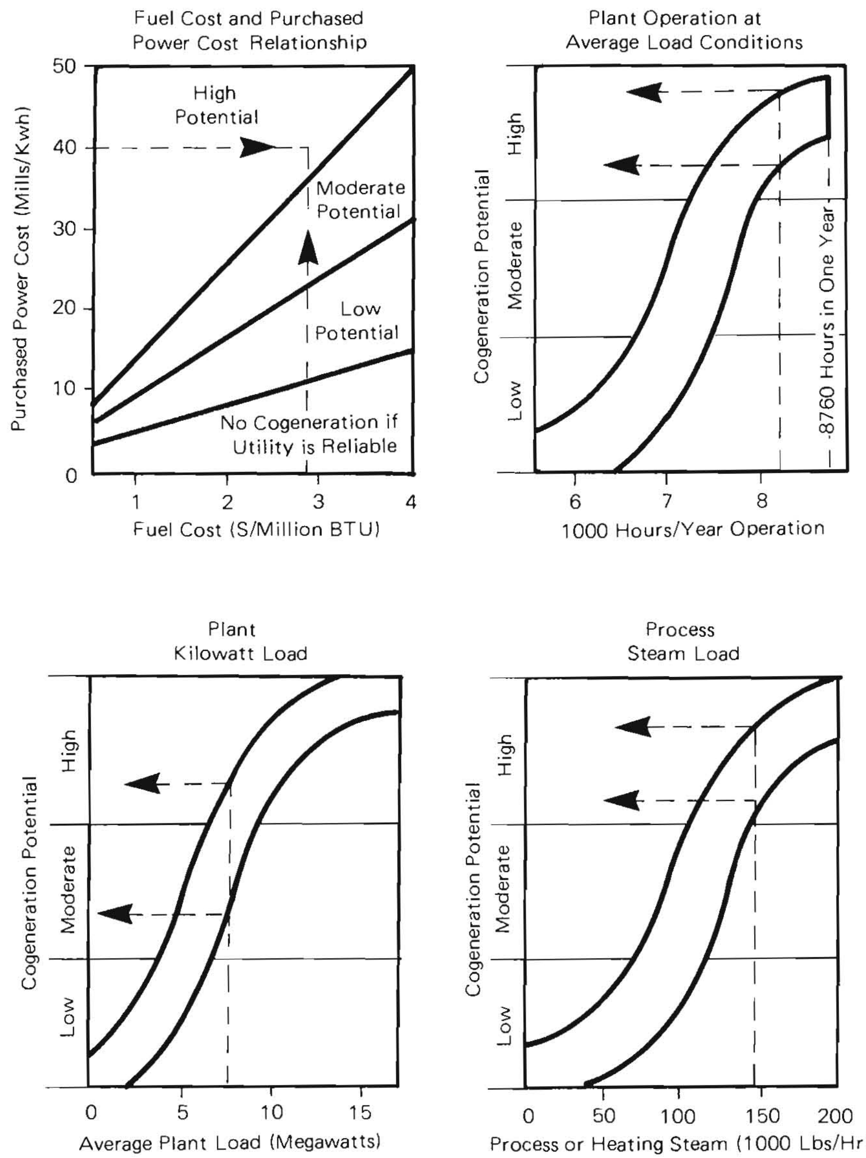


Fig. 5. Feasibility indicators for cogeneration potential. (Courtesy of W.B. Palmer. General Electric Company.) (Wilkinson and Barnes 1980)

1) The demand for steam and energy by the firm,

2) The cost to the firm of energy purchased from the utility,

3) Fuel costs available to the firm,

4) The tax environment of the firm.

They also include as less direct factors:

5) Questionable service from the local utility to meet electrical load demand,

6) Availability of waste fuel materials,

7) Obsolete boilers needing replacement,

8) Excess steam capacity in existing systems. (Taylor and Boal 1969)

II. Cost-effectiveness Model

The analysis of a cost-effectiveness model together with life cycle cost consideration will determine the feasibility of the cogeneration project and whether that course of action realizes the greatest overall advantage. The determination of the base case, in turn, provides a suitable alternative with which to measure the cost-effectiveness of such a project (Seiler 1969). In a new plant, this would be the investment in low pressure boilers for process steam and the annual cost of purchased energy. In an existing plant, the base case may be 'do nothing' and the consideration of the annual cost of purchased energy. As a viable alternative, cogeneration should then be viewed in the context of an investment in which a future stream of energy cost savings may be achieved by an additional capital outlay. The economic considerations, therefore, center around the incremental investment in equipment which would either adapt existing capabilities or be an addition to the capabilities that would have already been utilized in a new plant design.

The cost components of the cogeneration system can then be estimated, analyzed and weighed against the incremental savings of avoided costs in the base case. Each element of cost, which is dependent on specific factors relative to the demand of the industrial process considered, can be delineated in a model. The components to be considered are stated in equation form as follows:

$$B.T.A.C.F. = -[\Delta B + T]\,(A/P, \mathrm{i}\%, N) - \Delta F - \Delta OM + P.E.C. \qquad (1)$$

where:

$B.T.A.C.F.$ = Before Tax Annual Cash Flow
ΔB = Incremental Boiler Costs
T = Turbine Costs

ΔF	= Incremental Annual Fuel Costs
ΔOM	= Incremental Operating and Maintenance Costs
$P.E.C.$	= Purchased Energy Costs Avoided
	= Energy costs avoided in the base case – any costs of power continued to be purchased in parallel to cogeneration
$(A/P, i\%, N)$	= Capital Recovery Factor
	$= \dfrac{i(1+i)^N}{(1+i)^N - 1}$
$100i\%$	= Minimum Attractive Rate of Return
N	= Number of years at end of equipment life period

1. Limitations

a. The two main components of capital expenditure are the upgrading of low pressure boiler capability (ΔB) and the installed cost of turbine-generator equipment (T). The economy of scale is a significant factor in cogeneration equipment costs. The installed costs are dependent on the demand for steam and energy. From Fig. 6, it can be seen that the incremental costs decline steadily with an increase in steam production. The decline is most dramatic up to steam production of 400,000 lb/hr. The unit cost tends to level off above this production level due to costs of increased structural strength in the equipment to withstand the large amounts of high pressure steam.

b. The key considerations that make boiler capacity expensive at each level of fixed steam output are the type of fuel burned and the outlet steam pressure. Because of the expense of pollution control equipment necessary when coal is used as a fuel, oil and gas fired boilers are less expensive than coal fired. Coal as a fuel, however, may be cheaper to burn depending on the availability of oil in the market

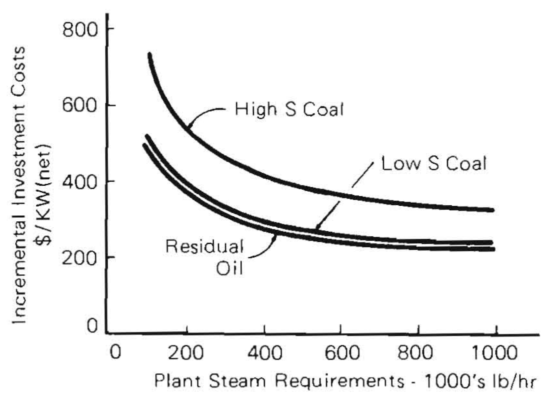


Fig. 6. Incremental investment costs of a cogeneration plant vs. plant size (Wilkinson and Barnes 1980).

place and the state of deregulation of gas prices. (The long term prospects of fuel prices are so dynamic, however, they may deserve careful consideration by themselves).

Higher pressure-temperature boilers are more expensive than low pressure-temperature ones because of the additional structural considerations of the equipment. Higher pressure steam, however, contains more useful energy per pound than does low pressure steam.

The determination of the quality of steam needed results from an understanding of the needs for steam by the industrial process under consideration, which must be known before the sizing and the costs of the equipment can be determined. The first consideration must be the steam requirements of the base case. There would be no need to produce any more or less steam in a cogeneration system than would be needed from the base case low pressure boiler system. Considering the mass flow rate of steam to be fixed by the process requirements, all other capacity requirements can be built from this amount (*see* Figure 4).

c. Conventional ratios of power-to-steam production capacity can be found in Fig. 7. With a fixed steam rate, a general level of power production can be determined. The power production level, in turn, dictates the inlet temperature and pressure conditions of the steam mass rate. These inlet turbine conditions and the mass flow rate specify the boiler capacity and its cost. Likewise, the power produc-

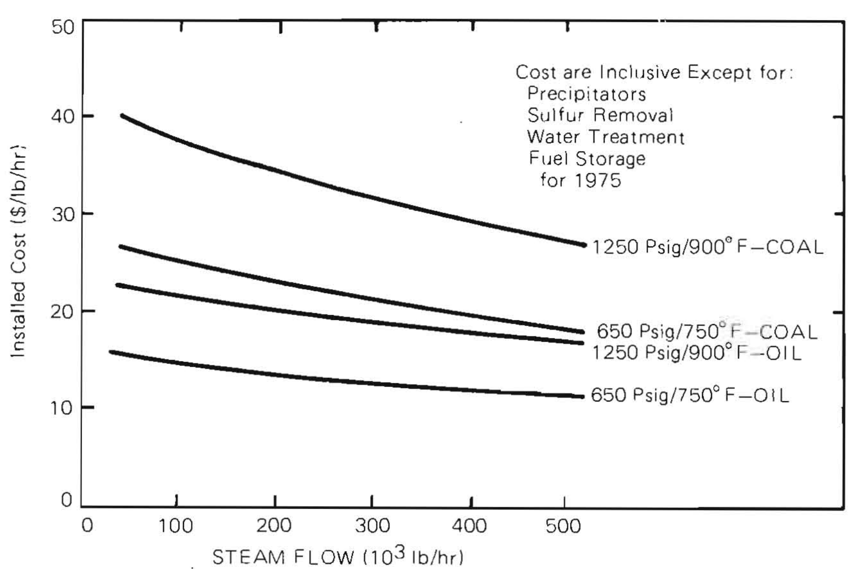


Fig. 7. Installed costs (1975 Dollars) vs capacity for field erected steam boilers (Noyes 1978).

tion requirements and the steam mass flow rate specify the turbine generation system and its corresponding cost (*see* Fig. 8).

The turbine, at a fixed mass flow rate, can, however, be sized to generate more power, if desired, by increasing the pressure gradient between its inlet and outlet conditions. The additional power capacity, however, is more expensive per unit cost than are the conventional levels, but the net incremental costs for more power are justified up to the price level of purchased power. The correlation between electricity-to-steam demand ratio to steam flow rate at rated boiler pressure and temperatures is shown in Fig. 9. The larger the turbine pressure gradient, the more energy that has been taken out of the steam for conversion to power, and the more that must be supplied by the boiler so that the fixed exhaust conditions of steam for process use can be maintained. If excess power is desired, therefore, an optimal power-to-steam ratio can be found within the cost constraint of the purchased power. The equipment cost then is a function of this new ratio.

d. The other costs cogeneration plants incur are the additional annual costs of operating labor, maintenance, and fuel. The incremental fuel costs result from the quantity and condition of steam produced and is a function of the determined power-steam ratio. It can be calculated from a combustion analysis of the boiler system.

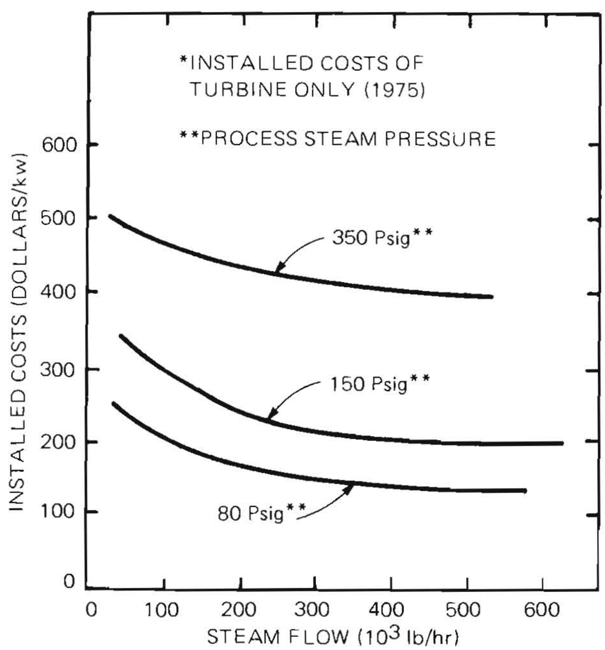


Fig. 8. Installed costs for installation of back pressure turbine vs. steam flow (Noyes 1978).

Likewise, the operating and maintenance costs (OM) are dependent on the quantity and quality of output of the plant. Various projections have been made for an estimate of the incremental operating and maintenance costs (ΔOM) for cogeneration over the base case. The thermo-electron study (Noyes 1978) proposes an incremental annual cost for operating and maintenance of $ 003/kwh. Hannon and Joyce (1982) propose a cost of 6% of the incremental capital cost. It is to be noted that present-day values are considerably higher than those mentioned by Noyes (1978) and in the following examples. An estimate of costs, operating, maintenance, and otherwise, can be made by examining cases of existing facilities and example calculations made in several studies.

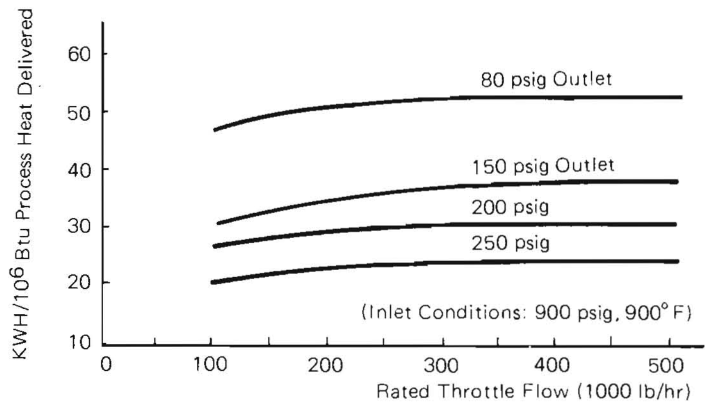


Fig. 9-a.

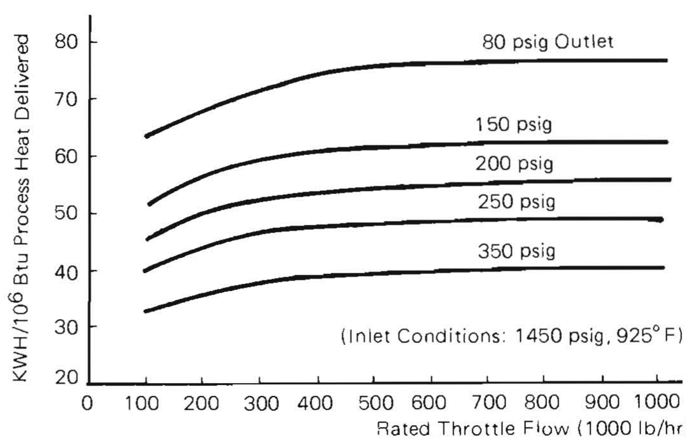
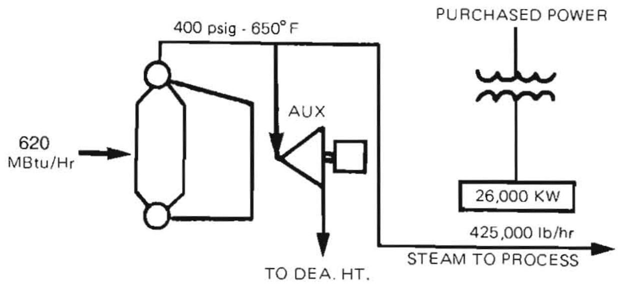


Fig. 9-b. (Kohl 1980).

Fig. 9. Byproduct energy rate vs. turbine size for various exhaust pressures; inlet conditions

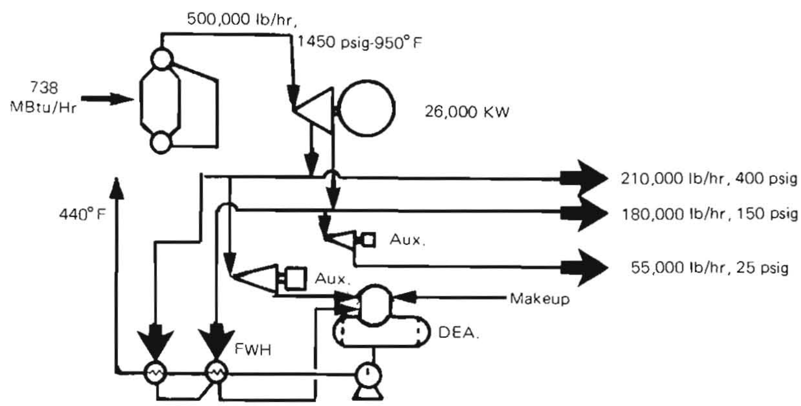
2. *Examples*

i. A listing of costs for a cogeneration facility for Mobil Oil in Beaumont, Texas, is shown in Fig. 10. Mobil has utilized cogeneration at this facility since 1906. Its large requirements for steam and electricity have provided sufficient economy of scale throughout the century to warrant continuous on-site energy and steam generation.



BASE CASE (Steam Generation & Energy Purchase)

Capital Investment	$10,000.000
Operating Costs:	
Fuel	5,,000.000
Labor	100,000
Water	160,000
Taxes & Insurance	80,000
Maintenance	300,000
Purchased Energy	3,500.000
	$ 9,640.000



COGENERATION

Capital Investment	$18,000,000
Operating Costs	
Fuel	6,450,000
Labor	100,000
Water	315,000
Taxes & Insurance	145,000
Maintenance	540,000
	$ 7,550,000

Fig. 10. Cogeneration analysis for mobil oil refinery at Beaumont (Petkovsek and Mangoine 1975).

Table 1. Comparative costs for cogeneration and present operation (Kohl 1979).

King's mountain	Cogeneration	Present Operation
O & M	$ 1,220,000	$ 1,625,000
Fuel	$ 5,610,300	$ 6,346,300
Purchased Energy	$ 2,080,350	$ 5,449,070
Annualized Capital Costs	$ 3,550,000	$ 960,000
Totals	$12,460,650	$14,380,370
Annual Savings due to cogeneration		$ 1,919,720

ii. A cogeneration facility at King's Mountain has projected costs listed in Table 1 (Kohl 1979). This plant is jointly utilized by nine industrial facilities. It is interesting to note that their projected costs for operating, maintenance, and fuel have actually declined due to the efficiency of the new system over the old. This is because the old system, consisting of nine separate steam generating plants and associated costs, has been replaced by a single central system. This system gains the advantage of both the improved economics of scale and the improved efficiencies.

iii. Doherty (1980) published a study for which his example costs analyses are listed in Table 2. He varied the amount of net power produced relative to a constant steam demand. It is interesting to note that, in this example, an increase in net power produced beyond 23,720 kw does not yield a greater incremental savings. This example illustrates the value in examining costs reflected in the power-to-steam ratio. The additional production of power at the same steam rate is increasingly expensive, although the incremental costs may still be lower than purchased power costs.

3. Purchase Power Costs

Purchased energy costs represent the single factor of savings in the cogeneration cost model which would offset the additional annual cost imposed by the cogeneration system. The components of the utility charge deserve careful consideration if a true value of savings can be measured. The utility charge to industrial customers is made up of a demand charge and an energy charge. The demand charge is a function of the peak demand for power by the customer over the previous 12-month period. The energy charge results from the direct consumption of kilowatt hours and will decrease in direct proportion to the energy consumed from a potential cogeneration process.

i. The major element of savings will invariably be the reduction or elimination of the demand charge, depending on the capacity of the cogeneration plant consid-

Table 2. Economic evaluation of example cogeneration plants (Wilkinson and Barnes 1980).

Premises of Economic Evaluation

Category	Premise
annual operation	8400 hr/yr
fuel costs:	
residual oil	\$2.50/M Btu (HHV)
High-sulphur coal	\$1.25/M Btu (HHV)
Purchased energy cost	sensitivity to a range of 2.5, 2.75, 3.0 ¢/KWH
Annual maintenance Cost	2.5% of investment
Operating Labor:	
Process Boiler Cases	Base
Cogeneration Cases	Base + \$300,000/yr
Plant size	400,000 lb/hr process steam load.

Note: Cost data from 1979.

Annual Operating Costs & Economic Evaluation of Example Cogeneration Plants

	Base Case	850 psig	1250 psig	1450 psig	
Fuel Consumption (M btu/hr)	476	571.60	595.80	606.80	
Net Power (KW)	(440)	23,720	29,500	31,600	
Annual Costs (\$1000)					
Fuel	10,000	12,000	12,500	12,750	
Energy	100	−(5500)*	−(6800)*	−(7300)*	saving
Labor	Base	300	300	300	
Maintenance	300	460	530	550	
Totals	10,400	7,260	6,530	6,300	
Annual Savings	Base	3,140	3,870	4,100	
Gross Payout (years)	Base	2.07	2.40	2.41	

ered. The demand charge reflects the capital recovery costs that the utility must incur for investment in plant capacity to be ready to meet the peak demand when it is called for. Several factors combine to make this charge vary from a simple marginal cost for incremental investment in additional capacity.

Consumption of energy at peak hours requires the more intensive operation of high energy-cost peaking units, while off-peak consumption can be met at a lower cost by operating cheaper energy-cost plants (Taylor and Boal 1969). The marginal cost of meeting peak demand, therefore, is considerably higher than the marginal cost to meet off-peak demand. The demand component of purchased energy costs, therefore, represents a considerable incentive in the price mechanism for the industrial customer to stabilize his peak demand for purchased energy. This single factor of the energy cost structure weighs heavily in the possible savings realized from a potential cogeneration system.

To illustrate the impact of the demand charge, an example from Dwon (1983) can be considered. Two customers, who have both consumed 3000 KWH in the same time period, are shown in Fig. 11. The demand for that energy, however, is considerably different. The energy consumption of customer A is unrealistic, however, unless his demand from the utility is made stable by absorbing his firm's fluctuating demand in some other manner. Using the rate schedule of the local Power Company utility, it can be seen that customer B pays 25 percent more for the same daily energy demand of 3000 KWH.

ii. When a firm considers operating a cogeneration system in parallel with a utility hook up, the additional energy desired beyond the onsite generation can be purchased in this manner. That is, the rated capacity of the cogeneration plant may, in fact, equal or exceed the demand peak that the firm experiences, and the output of the system can then vary with the fluctuating portion of the firm's demand. The savings, therefore, result not only in the avoided costs by replacing the supply of energy, but also in reducing the cost of additional energy still purchased.

The cost model can be restated utilizing the consideration of dependency that each function displays:

$$\begin{aligned} B.T.A.C.F. = & -[\Delta B(P/S) + T(P/S)] \quad (A/P, i\%, N) \\ & -\Delta F(P/S) - \Delta OM(P/S) + PEC(D+E) \end{aligned} \tag{2}$$

where:

(P/S) = Cost expressed as a function of the power-steam ratio
$(D+E)$ = Cost expressed as a function of the demand and energy charges.

To simplify, the gross savings can be considered as:

$$G.S. = -\Delta F(P/S) - \Delta OM(\mathrm{P/S}) + PEC(D+E) \tag{3}$$

The calculation of the After-Tax Annual Cash Flow ($A.T.A.C.F.$), which is a complicated calculation in reality, can be considered in a simplistic representation as:

$$\begin{aligned} A.T.A.C.F. = & -[\Delta B(P/S) + T(P/S) - T.C.] \quad (A/P, i\%, N) \\ & -\Delta F(P/S) - \Delta OM(P/S) + PEC(D+E) - [G.S.]\, T.R. \end{aligned} \tag{4}$$

Where:

$T.C.$ = Investment Tax Credit
$T.R.$ = Tax Rate.

(It is to be noted that depreciation costs of the capitalized equipment are not considered cash flow values and are not included in this equation).

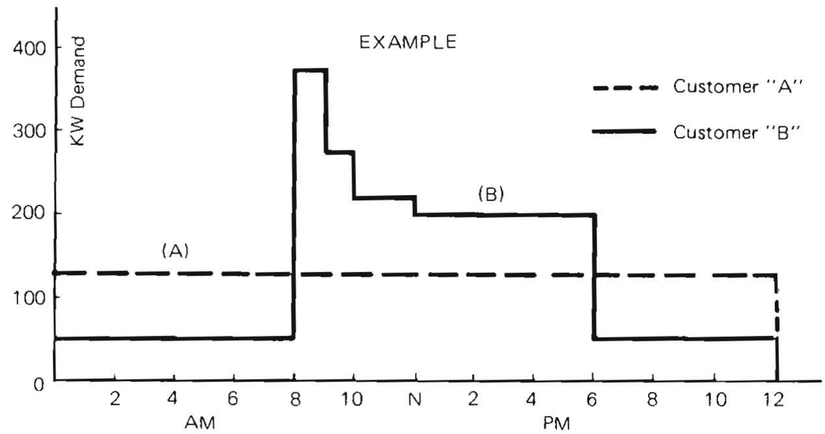


Fig. 11

BILLING RATES

First 125KWH/KW Billing Demand/Month		*Next 275 KWH/KW Billing Demand/Month*	
\$7.83 + .1959¢/KWH for the first	100KWH	2.4359¢/KWH for the first	140,000KWH
6.0459¢/KWH for the next	1,170KWH	2.2259¢/KWH for the next	60,000KWH
5.0359¢/KWH for the next	1,730KWH	2.0059¢/KWH for the next	200,000KWH
4.4759¢/KWH for the next	27,000KWH	*All Over 400KWH/KW Billing Demand/Month*	
4.2459¢/KWH for the next	30,000KWH	1.9759¢/KWH for the first	1,000,000KWH
4.0959¢/KWH for the next	30,000KWH	1.8959¢/KWH for all over	1,000,000KWH

CUSTOMER 'A' (Ideal Case)

1. KWH/month = 125 × 24 × 30 = 90,000 KWH, Billing Demand = 125 KW
   Rate Schedule: Industrial (I)

2. 1st. Block: 125 hrs × 125 KW = 15,625 KWH — \$ Charge = \$ 730.97
   2nd. Block: 275 hrs. × 125 KW = 34,375 KWH — \$ Charge = \$ 837.34
   3rd. Block: 90,000 − (15,625 + 34,375) = 40,000 KWH — \$ 790.36

3. Total Charge for 90,000 KWH with 125 KW Billing Demand = \$2,358.67

CUSTOMER 'B'

1. KWH/month = (50 × 8 + 375 × 1 + 275 × 1 + 225 × 2 + 200 × 6 + 50 × 6) × 30 = 90,000 KWH
   Billing Demand = 375 KW − Rate Schedule: Industrial (I)

2. 1st. Block: 125 hrs × 375 KW = 46,875 KWH — \$ Charge = \$2,090.87
   2nd. Block: 275 hrs × 375 KW = 103,125 KWH but needs only
   90,000 − 46,875 = 43,125 KWH — \$ Charge = \$1,050.48
   3rd. Block: no KWH applies since none remain — \$ Charge = \$ 0.00

3. Total charge for 90,000 KWH with 375 KW Billing Demand = \$3,141.35

i.e. Customer 'B' pays \$782.68 more than Customer 'A' for the consumption of the same amount of energy of 90,000 KWH/month.

III. Cost Effectiveness

The value of the cogeneration system concept resides not only with its savings of directly quantifiable cost, but also its less direct and often qualifiable costs. The utility of a system is a measure of the 'desired effects' of its implementation (English 1968) and therefore, cost-effectiveness is a measure of a system's total worth. The cost model elucidates for the decision maker the most tangible values of expense, while other values of expense may, in fact, alter the cost considerations for individual investments.

An important value for some situations, and a necessary value for others, is the standby capabilities that cogeneration systems can offer. A hospital may require cogeneration, for example, not for its cost savings in comparison with purchased energy, but rather because of the hospital's need for constant power in lieu of a utility power failure. While an individual hospital may exist in an area that has never undergone a power failure and has a high probability that it never will, the value of one lost life is not measurable in monetary terms (Padia 1980). Such an investment for nonuse is considerable, although not only are the non-monetary costs minimized but also the potential availability of the system for other uses has a value.

The measure of cost-effectiveness is the ability of the decision process in the system design to maximize the system's overall utility (English 1968). The system at this hospital was designed so that it is available to be used as a peak shaving facility in the future to cut power costs. In addition, the total energy recovery system for which the cogeneration is an integral part, is designed so that it can be readily supplemented by solar heat when it becomes feasible. The effectiveness of the expended costs are, therefore, validated by not only the necessary need for safety, but also by the design accommodation to enable the system to readily take advantage of future changes in energy economics.

In an industrial application, the loss of power may be less of a safety consideration and more of a probable cost consideration. Depending upon the history of service from the local power company, the changes in local peak power demand, and the potential for natural calamity, a probability can be assessed for a local power outage. The value of lost production, relative to the cost of a shut down, may qualify an investment decision made for conditions of perfect certainty. In many economy studies, it is necessary or desirable to extend the results of assumed certainty analyses by directly considering the risk and uncertainty involved due to variability in the outcome of elements (Canada and White 1980).

The investment decision for cogeneration may rest on a qualification factor which can act as a general variable whose valuation is a function of relevant future scenarios of which a power outage may be only one. Some scenarios an industrial decision maker may have to consider are:

1) technological changes making alternative energy sources attractive

2) economic changes making conventional energy sources unattractive

3) availability in the future of waste products as a fuel source

4) power outages resulting in:

   a. loss of safety

   b. loss of production.

Thus, an industrial decision maker may wish to view the probability of such situations as these in connection with their corresponding costs and benefits to arrive at an applicable value that determines their worth in regard to the investment analysis.

The ensuing value can most likely be viewed as the addition of annual savings or avoided annual costs that are dependent on a corresponding probability distribution. The evaluation can then be made entirely subjectively by determining a certain monetary equivalence or by a more statistical technique (Canada and White 1980). The certain monetary equivalence would establish a monetary cost that would be equal in the eyes of the decision maker, to avoiding the risk. Expected value criterion, expectation-variance criterion, and other statistical techniques, can be more exacting, but their projected arithmetic accuracy is the result of probabilities which themselves are oftentimes arrived at subjectively. The qualifying factor, therefore, must be determined by the individual effectiveness potentials relevant to the project under consideration within the subjective parameters that make them, in fact, effective.

Decision criteria for risk and uncertainty can evaluate the probable value of potential outcomes under consideration and, although the results may be subjective, the impact on an investment's cost-effectiveness can often be reduced to a tangible value. In fact, whether the qualification of effectiveness is a safety factor, availability factor, or a probabilistic value, it can be included with the direct cost figures to create a more expanded cost-effectiveness model. The expanded model can be stated as follows:

$$\begin{aligned} A.T.A.C.F. = & -[\Delta B(P/S) + T(P/S) - T.C.] \quad (A/P, \mathrm{i}\%, N) \\ & -\Delta F(P/S) - \Delta OM(P/S) + PEC(D + E) \\ & -[G.S.]\, T.R. + E.V.(S) \end{aligned} \tag{5}$$

where:

$E.V.$ = effectiveness value expressed as a function of subjectivity (S).

It is interesting to note that the only elements of savings in this model are the net avoided purchased energy costs and the effectiveness value. These two elements must equal or exceed the direct costs to make a cogeneration investment attractive. Therefore, considering that the cash flow for the incremental investment at the minimum attractive rate of return should be equivalent to the base case, the equation can be modified as:

$$\begin{aligned} E.V.(S) \quad &+ PEC(D+E) \\ &= [\Delta B(P/S) + T(P/S) - T.C.] \quad (A/P, \mathrm{i}\%, N) \\ &+ \Delta F(P/S) + \Delta OM(P/S) + [G.S.]\ T.R. \end{aligned} \tag{6}$$

IV. Conclusion

While the measure of cost-effectiveness to the firm affects the decision for a system investment, the measure of cost-effectiveness to the society of an industrial investment can also affect its viability. Cogeneration is an energy conservation concept and, although its conservation effectiveness to the firm is measurable in direct costs of fuel and energy, the conservation effectiveness to the society is more a measure of national resource allocation. It is, therefore, cost-effective to stimulate invest-

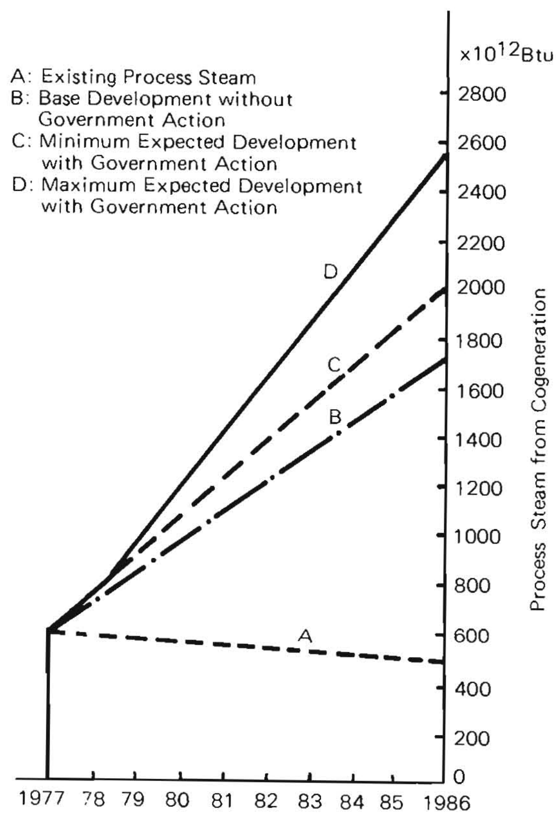


Fig. 12. Process steam from industrial cogeneration from 1977 through 1985 (Noyes 1978)

ment in systems on a national basis which engender energy resourcefulness and, thus, stem the tide of potential crisis.

In the same regard, the thermal pollution caused by central power stations has joined the list of social concerns for the environment. The value to society of environmental protection can be reflected, not only in regulations that restrict activity, but also in tax incentives to stimulate industrial investment. The tax structure serves as a mechanism in which macroscopic concerns can be evaluated as costs to society and savings to industries. The tax savings allowed by the government are an investment by society relative to the measure of effectiveness that the proposed system holds for the nation at large.

The impact on cogeneration investment for industrial firms as a result of governmental action is considerable. Figure 12 shows the range of process steam that would be produced by cogeneration in the U.S. given various levels of possible government action. The incremental energy savings is shown in Fig. 13. As significantly more industrial facilities turn to cogeneration, the pressure on industry, utilities, and the consumer to find ways of financing new power stations is reduced.

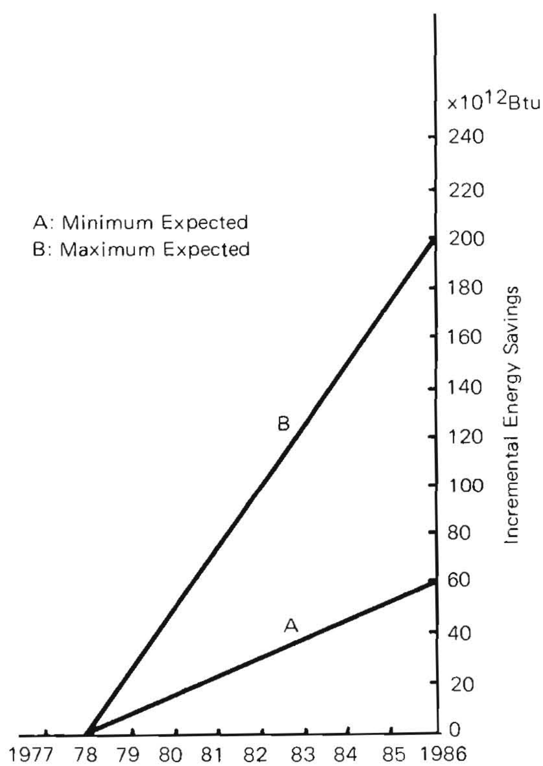


Fig. 13. Energy savings from industyrial cogeneration with government action (Noyes 1978)

Figure 14 shows the improved potential that can develop in the U.S. as the return on investment in cogeneration becomes more attractive.

The social value of cost-effectiveness can readily be translated into the cost model by considering the tax elements as functions of perceived social effectiveness. The model can be stated as:

$$\begin{aligned} E.V.(S) \quad &+ PEC(D+E) \\ &= [\Delta B(P/S) + T(P/S) - TC(SE)] \quad (A/P, \mathrm{i}\%, N) \\ &+ \Delta F(P/S) + \Delta OM(P/S) + [G.S.]\, T.R.(SE) \end{aligned} \tag{7}$$

where:

SE = social effectiveness expressed as a cost function

All the elements in the model now are expressed as functions of their cost-effectiveness. The direct costs are dependent on the power-to-steam ratio with the cost-effectiveness of the purchasing dollar increasing as the amount of energy and steam produced increases. The savings due to avoided costs of purchased energy are dependent on the demand and energy charges. The savings affect the investment costs in direct proportion to the amount of energy demanded and the peak of consumption. The effectiveness value or qualifying factor is a function of the

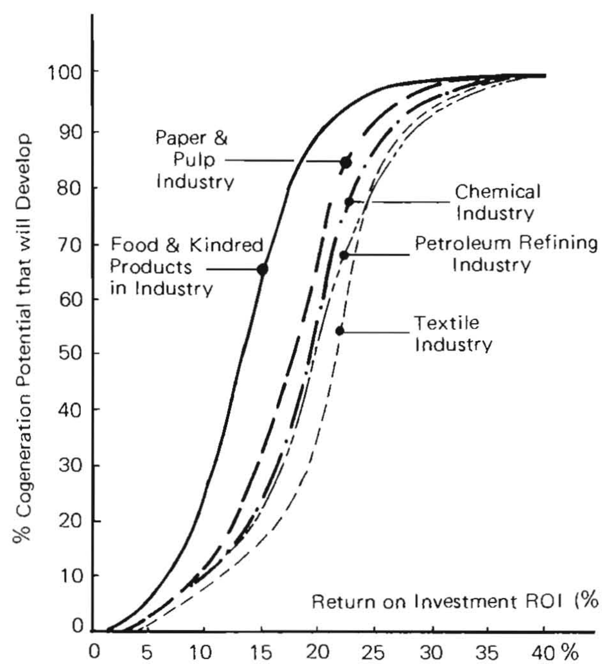


Fig. 14. Cogeneration potential that will develop under normal (ROI) hurdle rates (Noyes 1978)

subjective determination of the industrial decision maker to the qualified worth of the investment. Finally, the tax structure, as a determination of direct cost in the investment decision, is directly proportional to the measure of effectiveness the society chooses to place on cogeneration.

The most likely factor that would make an impact on cogeneration potential would be if the cost of purchased energy escalated faster than the cost of fuel. This would be a result of the increasing costs for additional power plant construction and the cost to finance such capital intensive ventures. From Fig. 15, it can be seen how the return on investment improves with increases in cogeneration power plant size and purchased energy cost as example. Kohl and Mulligan 1980) do, however, state that the greatest financial measure to influence cogeneration potential is the availability of low cost loans that could alleviate the need for company financing.

V. Appendix

Figures and tables listed are reproductions from the indicated studies in the references. All costs are shown in real dollars at the times indicated. Although present-day values are substantially higher, the importance of these figures and tables is not the exact costs *per se* but rather depiction of costs as a function of a particular parameter. Regardless of changes in unit costs over the last few years, the changes in costs as a dependency on individual factors remains generally valid.

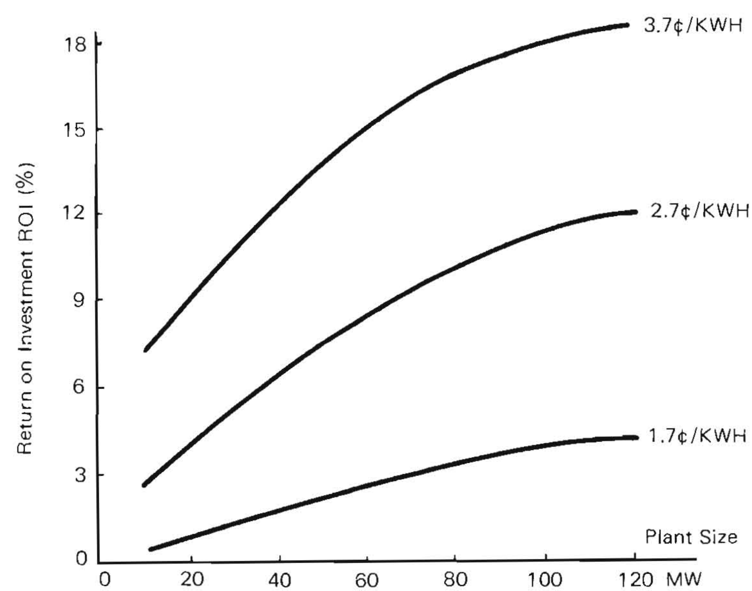


Fig. 15. Incremental ROI of coal-fired cogeneration plants with varying electric prices at existing manufacturing facilities (Noyes 1978).

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نمـــوذج ريـــاضى لتحليـل فاعليـة التكلفـة والاستثمار فى المشاريع الصناعية المشتركة الطاقة

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يحلل هذا البحث عناصر التكلفة المتعلقة بتقرير رأس المال المستثمر فى المشاريع الصناعية المشتركة الطاقة - باعتبار كل عنصر دالـة أولية للجهـاز أو الشركة أو النظام الضرائبى . ويفحص البحث فى كل حالة التكاليف المتعلقة بالدالة اذا أمكن تحديدهـا مبـاشرة أو يقـدم تحليلا لحسـاب هذه التكـاليف . وفى جميع الحـالات اعتـبرت المكونات الفردية للتكلفـة ، سواء المنصرفة أو الموفرة ، على أنها عوامل مقومة لنموذج كفاءة التكلفة . كما يوضح البحث اعتماد هذه الكفاءة على عوامل مختلفة يمكن حسابها . وأخيرا يكوّن هذا النموذج الرياضى مقياسا لفاعلية التكلفة الموفرة بالنسبة للتكلفة الفعلية .