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ELECTRIC UTILITY FORECASTING OF CUSTOMER
COGENERATION AND THE INFLUENCE
OF SPECIAL RATES

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Cogeneration, or the simultaneous production of heat and electric or mechanical power, emerged as one of the main components of the energy conservation strategies in the past decade. Special tax treatment, exemptions from fuel use restrictions, and regulatory policy changes were crafted to encourage its more wide-spread adoption in anticipation of higher energy conversion efficiencies. The expansion of cogeneration still faces a broad spectrum of problems, current and future: environmental restrictions; capital constraints; fuel prices; utility rates and future utility economics; and the difficulties of management.

The most debated issue has been the reform of rates between individual cogenerators and the local electric utility. Many of the major cogeneration studies in the late 1970's urged an analysis of the exact impact from current electric utility rates upon cogeneration project economics (1,2,3). The changes mandated by the Public Utilities Regulatory Policy Act of 1978 (PURPA) are now reaching the final implementation stage and the cogeneration projects of the mid-1970s are nearing completion. To better understand the relationship between utility rates, the economics of cogeneration, and its potential development, the New England Electric System and the Massachusetts Institute of Technology Energy Laboratory Utility Systems Group began a study to refine methods for forecasting cogeneration in a specific utility service area with special attention devoted to the utility rates (4).

This paper surveys the insights gained from this effort, which is now nearing completion. Many of the central issues reflect conditions in New England, but this analysis should provide an approach for examining the question in other regions as well. Since the project has not undergone complete review, however, this paper reflects the opinions of the author alone.

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OVERVIEW

A complex network of details governs the operating and resulting economics of a cogeneration plant. For example, as anyone who has tried to read a typical industrial rate schedule knows, a variety of changes in electricity consumption patterns can alter electricity bills for years. Cogeneration plants are based upon a broad range of designs, with substantial differences in the fundamental technologies. Changes in fuel prices and other economic conditions mutually affect utility electricity production costs and the costs of cogenerated power. In New England, both industrial steam needs and the utility's load and operating costs are influenced by weather conditions, especially temperature. Figure 1 illustrates the major interactions between a customer, the utility, and economic conditions.

Cogeneration by an electric utility's customers affects it through several factors: utility revenues are reduced; power system operating costs change; and the overall profile of electricity production by the utility alters. To estimate the potential for local cogeneration and the associated economic conflicts between rates, anticipated electricity and fuel supplies, and cogeneration opportunities, the range of customers who could cogenerate must be assessed. Since it is the individual industrial or large commercial customer who eventually decides whether or not to build a cogeneration plant, this forecasting effort started with a very detailed look at cogeneration from the customer's perspective. The study proceeded in three steps:

1. Conduct a series of detailed on-site visits to about a half dozen plants and examine the cogeneration options available for these plants;
2. Distill the factors in the decision by a customer to build a cogeneration plant and apply this simplified analysis to a prior, extensive survey covering about two thirds of the major industrial customers;
3. Use the information from possible cogeneration development at the visited plants and the surveyed customers to make a system level forecast.

To express the complexity of the economics and the utility rates, the project developed a detailed computer model of the effects of differing cogeneration plant types and sizes upon on a customer's electricity bill, fuel costs, and capital expenditures. This model estimates annual operating costs from a shift-by-shift simulation of plant operation over a multi-year period. The expected minimum annual operating costs together with the financing costs and construction delays from different technologies are used to compute the net present value of the alternatives over the life of the project. Since there are substantial uncertainties in future fuel and electricity prices, the model calculates the discounted worth of the projects under several alternative scenarios allowing for operation to adapt to each year's economic conditions.

The great detail of this model, however, can be an obstacle to interpretation of the problem by the non-specialist. This paper identifies the major factors influencing customer cogeneration plant choice and discusses them in the context of the number and size of customers who might cogenerate.

THE CUSTOMER'S PERSPECTIVE

When addressing the problems confronting the customer, two special factors are relevant in New England. One, an unanticipated

COGENERATION FORECASTING

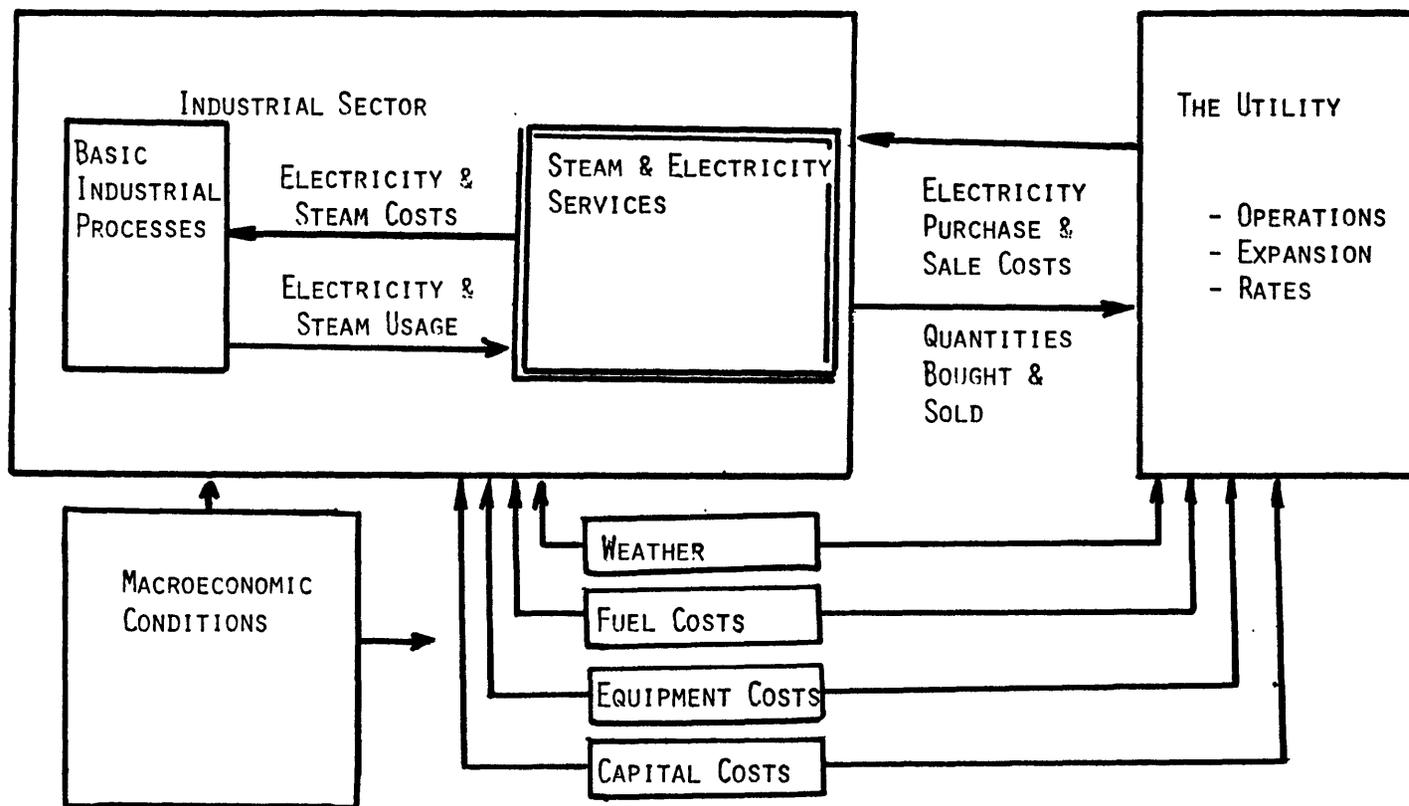


Figure 1

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finding of the on-site visits was the degree of fluctuation in steam usage even in the largest, most energy intensive plants. One site claimed constant steam loads, but examination of the fuel use records showed a winter/summer variation of 30%; this was the lowest variation found. A Major Fuel Burning Installation that already cogenerates had a winter/summer steam load variation of 3:1. Since cogeneration is a capital intensive technology requiring a high capacity factor for economic design, this means that the cogeneration potential should not be estimated from the total annual fuel consumption statistics. A method was needed, then, to calculate the base-load, year-around steam needs at the industrial sites.

Second, since New England is distant from traditional coal sources, oil is the most commonly considered fuel for anticipated cogeneration and boiler facilities. The extent to which New England utilities successfully shift away from oil could render operation of oil-fired cogeneration projects uneconomic although the early project years could produce short-term savings for the project sponsors. For example, as a part of NEESPLAN, New England Electric is planning to reduce its energy production from 78% oil in 1979 to 16% by 1996 through conversion of existing plants to coal and the promotion of conservation and alternate energy projects.

Mindful of these conditions and the large uncertainties in future oil and electricity prices and supplies, the potential cogenerator must ponder the following questions:

- In operating the plant,
 - how do you dispose of the power generated by the plant?
 - how would you operate the plant given the electricity usage or sale arrangements?
- In selecting the design,
 - how much do the alternative cogeneration or steam plants cost, and what uncertainties could make the choice of a given plant regrettable?
 - how big should the cogeneration plant be in relation to the steam needs?
 - how should the final size, fuel capability, and technology be determined?

The utility needs to explore which cogenerating customer actions might most significantly affect the stockholders or other customers. This project built several detailed simulation models to tie these and other factors together in analyzing the possible cogeneration plant economics.

Sale of power First, consider the short and long-term disposition of the power produced by the cogeneration plant. The new PURPA rules, in a sense, simplified this problem by allowing the customer to sell all the output of the cogeneration plant directly to the connected electric utility while the customer continues to purchase all its power requirements from the utility (arbitrage); in this case, in-plant electricity usage patterns are of no consequence to the economics of the cogeneration plant. The customer may alternatively sell only the power in excess of its needs to the utility; in this case, the in-plant usage patterns can be important to the cogeneration plant economics. This choice, shown in Table 1, simply depends upon whether the customer can gain more from selling its net needs or by selling in an arbitrage arrangement. The impact on the utility

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POWER SALES CHOICE

	Standard Industrial Rate > Avoided Costs	Standard Industrial Rate < Avoided Costs
Customer Choice	Sell power net of needs	Sell all cogenerated power output
Impact on utility and other customers	utility revenue is down more than cost so the rate base is concentrated across reduced sales	unaffected

Table 1

will be discussed later.* As electricity cost and rate conditions change, customers will want to switch from one type of sales arrangement to another.

Operation Next, how the cogeneration plant is operated depends upon the performance of the specific technology, its fuel price, and the price at which the customer can sell the power. Assuming that the cogenerator sells all its power at avoided fuel costs under an arbitrage contract simplifies this discussion, although this only reflects the conditions of an excess capacity utility with rates below the incremental cost of fuel for power generation. Figure 2 illustrates the possible conditions in the relationship between the cogenerator's and the utility's incremental generation heat rates and their fuel costs. For example, if the cogenerator owns a steam turbine back-pressure cogeneration plant with an incremental heat rate of 4500 Btu/kWh running on low sulfur #6 oil, the "avoided cost" utility plants have a heat rate of about 10000 Btu/kWh on coal, and the coal costs 50% per Btu as much as the low sulfur oil, then the cogeneration plant would be in operation (point A). If it was a diesel cogeneration plant with an incremental heat rate of 6600 Btu/kWh, it would be cheaper to shut down the cogeneration plant and get the steam needs from a back-up package boiler also running on the low sulfur #6 oil (point B). If the utility was also running on low sulfur #6 oil as its avoided cost fuel, either type of cogeneration plant design would be economic to operate. If the steam turbine cogeneration plant operated on coal, however, it could always compete with any coal-fired generation by the utility.

This is intended to demonstrate the importance of looking ahead to possible modes for the cogeneration plant operation throughout the projected life of the plant. A plant that is not operating does not help recover its capital costs. On the other hand, a slightly economic plant can become more advantageous if a utility slips from coal as its incremental fuel to oil on the increment. Given the unknowns in coal conversion plans by utilities and in future oil prices, a plant's economic analysis must allow for flexible operating conditions. This can mean the switching from continuous operation to cooperative dispatching with the utility when oil is the incremental

* For simplification, this paper discusses all power purchases in terms of 100% of the utility's avoided fuel costs; in practice, the need for long-term contracts often results in power purchase agreements in which the current year's payment is below from 100% of the current avoided costs. If the utility needs to make no new capacity commitments, then fuel costs reflect the only avoided costs.

ECONOMIC OPERATION OF A COGENERATION PLANT

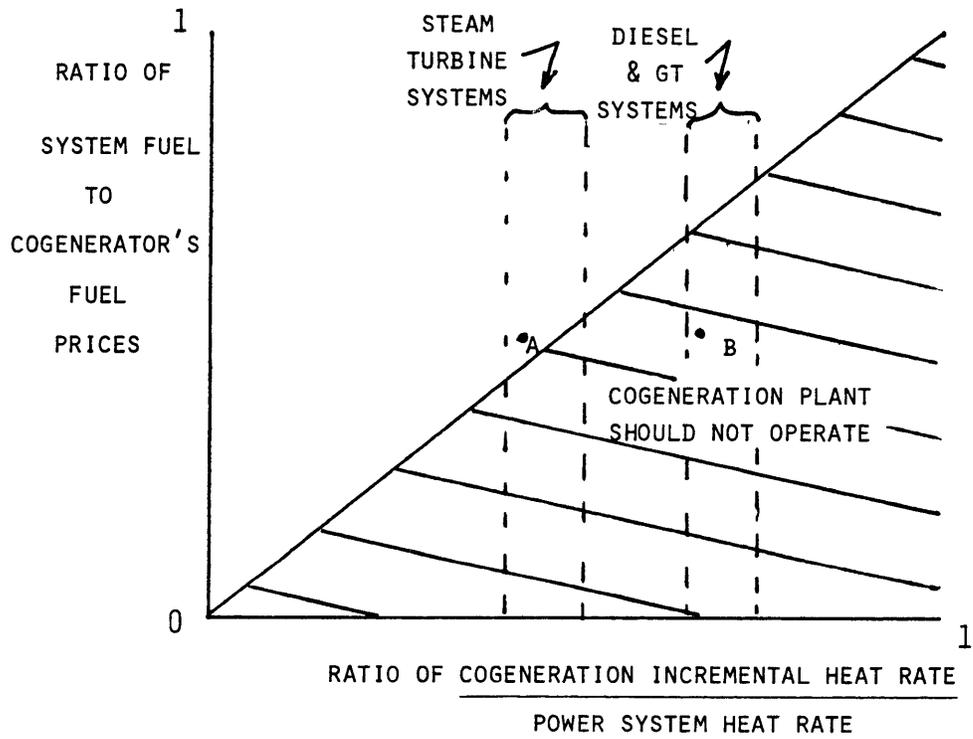


Figure 2

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fuel (reference 5 suggests one mechanism for carrying out such dispersed dispatching).

Total plant costs Most approaches to examining the total costs of cogeneration look at the cost in cents per kilowatt-hour. When taking the customer's perspective, however, it is more meaningful to calculate the costs in dollars per million BTUs supplied, although the two approaches are theoretically equivalent. Figure 3a shows the O&M, fuel, capital, cost and power credit components for a #6 oil-fired diesel cogeneration plant on the basis of its design operating time per year; the cost of operating an existing #6 oil-fired boiler is shown at the side. Since the fuel cost and the operating power credit are such a major portion of the total costs, small changes between them heavily influence the final economics. In contrast, the oil-fired back-pressure steam turbine plant cost components shown in Figure 3b have a lower share influenced by the power credit; also a reduction in the plant's capacity factor does not increase the total costs as quickly as in the diesel design. Figure 3c shows the costs for a coal-fired back-pressure steam turbine cogeneration plant. In a region that is burning oil for power generation, if you can meet the environmental restrictions, it has an overwhelming economic advantage. The size of the different cost components demonstrate how sensitive each plant type is to changes in the underlying factors. In an area that is so uncertain, this gives a quick feeling for the comparative shifts in total plant costs as a function of shifts in the relative prices of fuel, power, O&M, and capital equipment.*

Figure 4a summarizes the total costs for the different plant designs on the basis of 1981 fuel costs in the northeast. The coal-fired system breaks even in cost with an existing oil-fired boiler when it is sized to achieve a very low 35% capacity factor, thus serving most of a typical customer's annual heat load. This extends down to plants significantly smaller than 100 MBtu/hour. If coal is not a viable option, oil-fired cogeneration plants do not appear favorable unless they are designed to operate at high capacity factors; both break even with an existing boiler when sized for about a 75% capacity factor. Even then, they are not a risk-free alternative. Figures 4b and c show two comparative cases for 1985. In the case most advantageous for the cogeneration plants, oil prices have risen by 28% and the local utility still has oil as its incremental fuel 100% of the time. In the worst case, oil prices have dropped 7% while the utility has converted enough of its plants to coal so that oil is the avoided cost fuel only 60% of the year. In this case, it is uneconomic for the diesel plant to operate when coal is the incremental utility fuel, so the diesel plant capital costs must be spread over fewer operating hours. Under these price conditions, the oil and coal steam turbine plants still operate, but the power credit is reduced to reflect the share of coal in the avoided costs.

In summary, uncertainties in fuel and electricity supplies require the examination of possible future operating conditions and not just prices and conditions during the next few years. This demonstrates the flexibility needed in adapting utility rates and cogeneration plant operation. These in turn, show the large uncertainties in cogeneration plant costs; these are risks the customer must recognize. Furthermore, most oil-fired designs are only economic for serving the base steam loads in a retrofit installations.

* These costs were derived from representative plant costs listed in the appendix. They reflect differences in tax treatment. Unless noted, the avoided utility fuel is assumed to be oil. The discussion of only diesel and steam turbine cogeneration systems is intended for illustration.

THE COMPONENTS IN THE COST OF COGENERATION SYSTEMS ON A PER UNIT HEAT BASIS

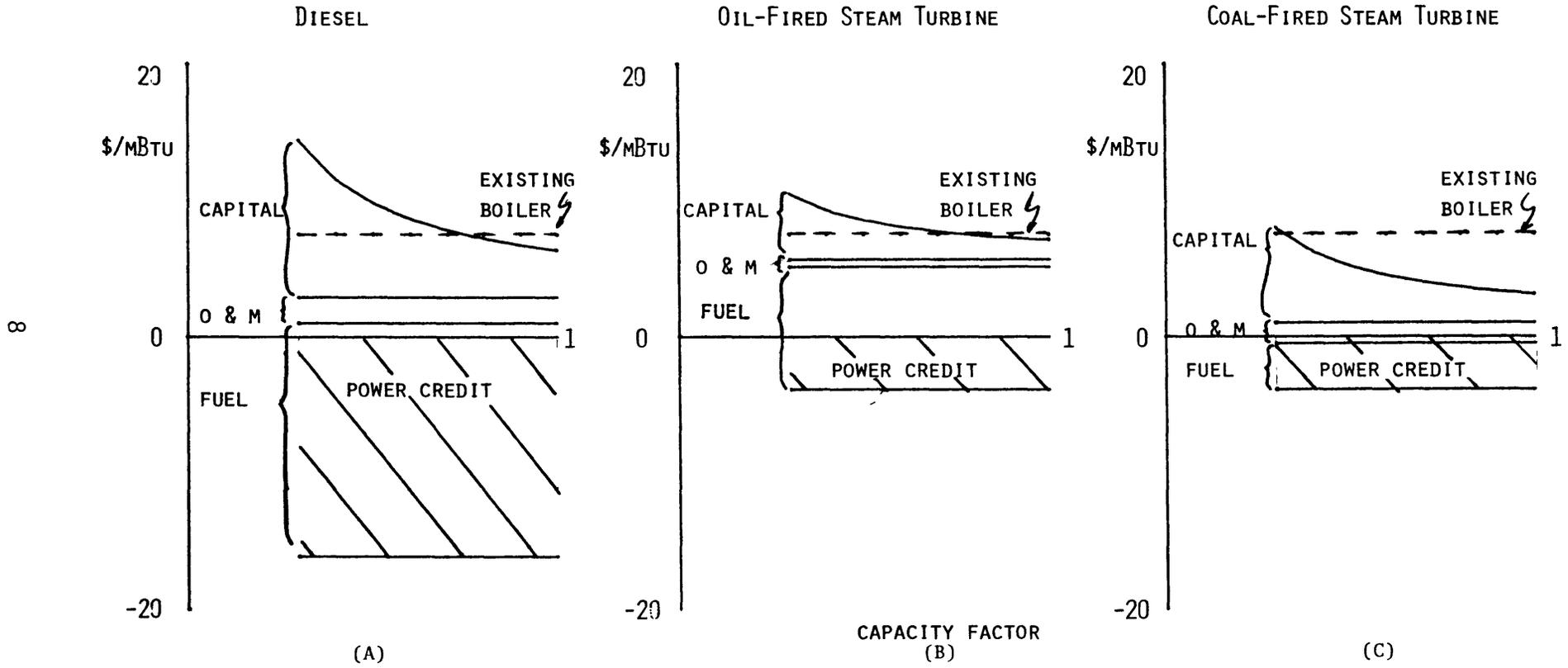


Figure 3

THE COMPARATIVE COSTS OF COGENERATION UNDER DIFFERENT SCENARIOS

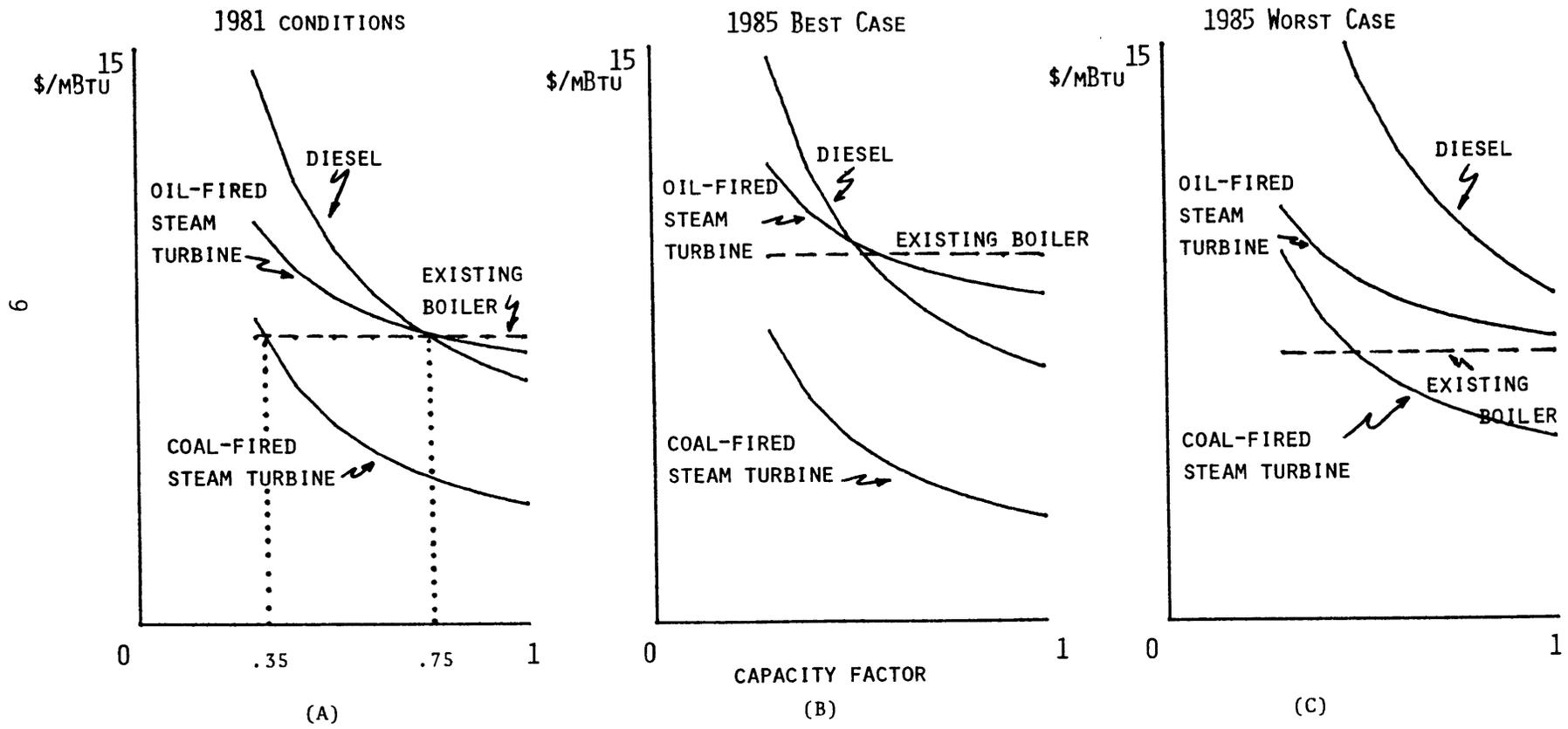


Figure 4

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ESTIMATING THE TOTAL IMPACT OF CUSTOMER COGENERATION

A quick, approximate upper limit to the total amount of customer cogeneration can be found by multiplying the total steam load that cogeneration plants could serve and the typical ratio of power to heat output for the corresponding design. Since oil-fired designs are only economic for base load, this requires an estimate of the base heat load, which is difficult to estimate from annual average fuel use; the relationship between the two will vary substantially between even similar plants in the same region. This is the key weakness in many earlier projections.

If coal-fired cogeneration plants can be installed to meet the local environmental requirements, the estimate can be based on the cumulative annual average heat load. The power to heat output ratio for the coal system, however, is much lower than the diesel plant, so the estimate is substantially reduced.

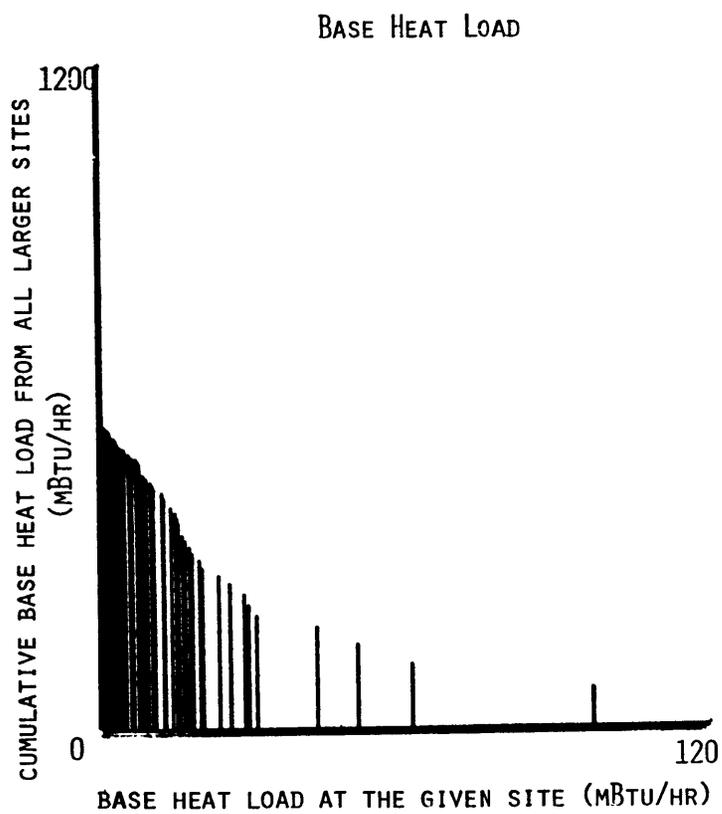
Figure 5a shows data similar to that collected in the 150 customer surveys plotted with the base heat load of each site on the bottom axis and the cumulative hourly base heat load for that and all larger sites plotted on the vertical axis. Each vertical bar represents one customer, demonstrating the concentration of customers in the smaller size range. For example, the total hourly base heat load for all sites greater than 20 MBtu/hour is about 300 MBtu/hour. If all this load was served by steam turbine cogeneration, a total of about 15-20 MW of cogeneration could result; if it was all served by diesel, 90-120 MW could be in service. The disparity in the estimates reflects the significant difference between the technologies in the power output per unit heat load served, as the comparative sizes of the power credits in Figures 3a and b illustrate. This crude approach must be expanded to account for existing cogeneration at these sites; in the actual survey, much more than half of the group with over a 20 MBTU/hour base heat load already had old oil-fired steam turbine cogeneration plants on their sites.

Figure 5b shows cumulative average annual heat loads plotted against each site's average annual per hour heat load. A comparison with Figure 5a demonstrates the low load factors for heat use in New England and also shows the paucity of energy intensive industries. It is this average load chart that can be used for estimating the potential for coal-fired cogeneration -- with the crucial question being the minimum economic size for coal-fired plants.

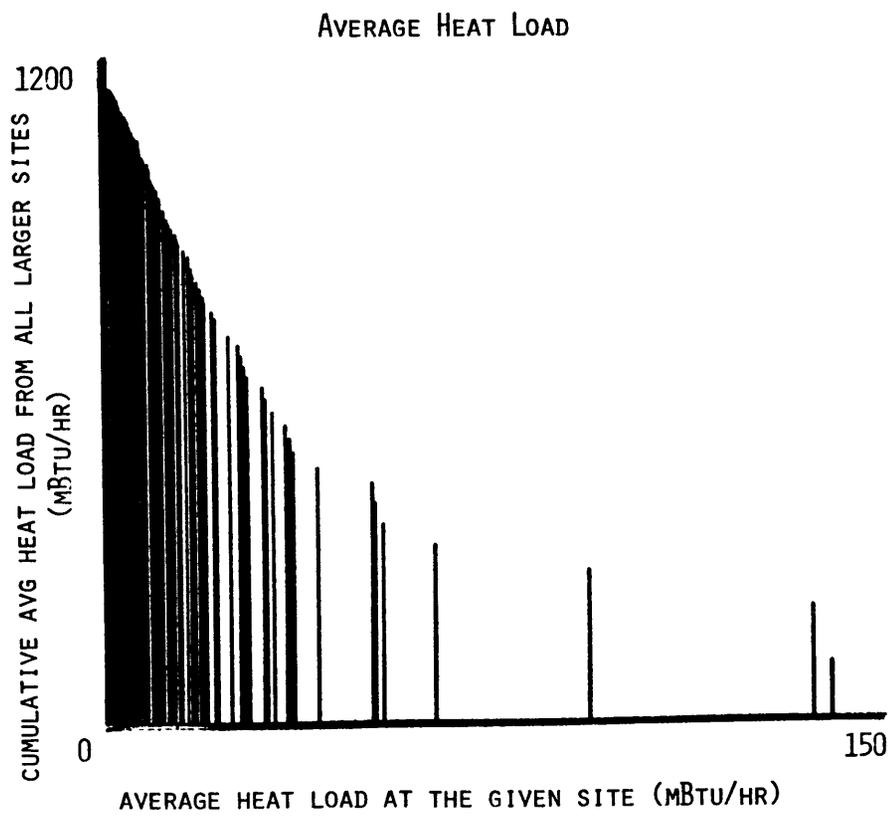
A careful estimate requires analysis of the existing equipment at each site along with knowledge of the site's heat load characteristics and steam pressure requirements. The survey data then must be expanded to account for the survey coverage of the customer size classes. For example, the 150 customer surveys mentioned above included about 2/3 of all major commercial and industrial electricity customers and half of the major fuel burning installations in the service territory. Potential industrial growth necessitates further adjustment of the forecast, although this increase will be small in relation to cogeneration conversions within New England.

Finally, the financial impact on the utility and its non-cogenerating customers depends on how the cogenerators dispose of their power. If electricity and fuel price conditions encourage customers to sell on an arbitrage basis, there is no negative impact on the system. As shown in Table 1, if conditions encourage the net sale of power to the utility because the industrial rate reflects substantial prior capacity costs imbedded in the rate, the utility's other customers will bear the difference between the industrial rate and the utility's avoided operating costs. A 1¢ difference between the industrial rate and the utility's avoided fuel costs can mean up

CUMULATIVE HEAT LOAD FROM SURVEYED SITES



(A)



(B)

Figure 5

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to an additional \$87,600 per year gain per 1 MW of capacity for the cogenerator and an identical burden for the other customers.

CONCLUSIONS

This continuing project on utility cogeneration forecasting has focused in detailed on the changing, uncertain cost conditions and electricity rates. The following factors influencing potential customer cogeneration have been indentified:

- Continued oil use by the utilities -- This determines the economic attractiveness of oil-fired cogeneration plants; the degree of utility coal conversion's impact upon the desirability of a given plant type differs substantially between cogeneration technologies.
- Base load designs -- If a cogenerator cannot install a coal-fired plant, and if it can absorb the economic risks associated with an oil-fired plant, the plant will probably serve only the base heat loads with the intermediate and peak steam needs being served by existing oil-fired boilers.

The total impact upon the utility of customer cogeneration depends upon:

- The total amount of cogenerated power -- The first problem in producing an estimate of oil-fired cogeneration is determining the total base-load heat usage in the system. Second, any forecast is very uncertain because of the closeness in the comparative economics and the significant differences in the electrical output per unit heat load between cogeneration technologies.
- Payment for the delivery of cogenerated power -- If industrial rates are higher than the avoided fuel costs, the cogenerating customers will first reduce their own bills by internal usage as allowed under the PURPA regulations; this results in a negative impact on the other customers. If the utility's rates are less than or equal to the avoided fuel costs, as is likely under successful utility coal conversion, there will be no adverse impact. In addition, under these conditions it will be to the advantage of oil-fired cogenerators to run only when the utility is also running oil-fired plants as the incremental power source.

The principle source of harm to the utility is the difference between the avoided cost and the standard industrial rate when a cogenerator uses the power internally or on a net sale basis. This difference may diminish two ways: the average costs reflected in the rates falling relative to the avoided costs as the utility reduces its dependence upon oil; or standard rates matching more closely the changing avoided costs, within the limits of the overall revenue requirements.

APPENDIX

The examples in this paper were based upon cogeneration plants providing 15 psig steam to heat loads in the size range of 50 to 100 MBtu/ hr. Base year fuel prices was assumed to be \$6.00/MBtu for the low sulfur #6 oil used by the cogeneration plants, \$5.00/MBtu for the high sulfur #6 used by the power system, and \$2.25/MBtu for coal. The cost figures in Table 2 below represent the combined power and steam related costs divided by the heat output.

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PLANT COSTS

Technology	Power/Heat Ratio kWh/MBtu	Incremental Heat Rate Btu/kWh	Total Eff. %	Capital Cost \$/ kW	O&M Cost \$/MBtu
Diesel	290	6600	70	560	1.82
Oil back-pressure steam turbine	70	4110	83	940	.53
Coal back-pressure steam turbine	70	4110	83	1580	1.53
Existing oil boiler	0	0	83	0	.25

Table 2

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