A ROBUST AND RESPONSIVE METHODOLOGY FOR ECONOMICALLY BASED DESIGN OF INDUSTRIAL COGENERATION SYSTEMS

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NOMENCLATURE

AC	amortized cost of CHP system ($/yr)
c_a	auxiliary firing unit cost ($/ MMBTU)
c_e	cost of purchased electricity ($/kWh)
c_f	unit cost of fuel ($/MMBTU)
c_m	unit operation and maintenance cost ($/kwh)
c_p	annual plant fixed charge ($/kw-yr)
c_r	cost of rejecting heat ($/kWH)
c_u	CHP system unit cost ($/kWe)
EC	annual purchased electricity cost ($/yr)
ES	electricity sales to the grid ($/yr)
FC	annual fuel consumption cost ($/yr)
Hc	CHP plant thermal capacity (kWt)
Hd	CHP plant thermal demand (kWt)
IC	total CHP plant installed cost ($)
MC	annual operation & maintenance cost ($/yr)
N_a	auxiliary firing thermal efficiency
N_e	CHP plant fuel-to-electricity efficiency
Pc	CHP plant electrical capacity (kWe)
Pd	CHP plant electrical demand (kWe)
RC	annual heat rejection cost ($/yr)
r_c	system capacity heat to power ratio
r_d	demand or load heat to power ratio
s_e	Electricity cost, sales to the grid ($/kWh)
TEAC	Total Expected Annual Cost of CHP system ($/yr)
t	CHP plant operation time under load (hr/yr)

CHAPTER I

THE RESEARCH PROBLEM

1.1 Background

This thesis presents the development of a methodology for the economically based design of an industrial system with bivariate capacity subject to bivariate loads or demands. The methodology uses the utility-connected industrial cogeneration system or concurrent generation of heat and power as the demonstration mechanism.

The analytical methodology has been developed using an evolutionary approach. Thus, the development starts with the formulation of a deterministic (non-random) and linear-cost optimization model. Then, it evolves with the sequential introduction of stochastic loads, stochastic capacities and an exponentially decreasing system unit-cost, towards a probabilistic and non-linear-cost optimization model. The development includes illustrative examples for the various analytical models. As a background for the formulation of the research problem, the deterministic and probabilistic approaches to design are discussed below.

Traditionally, most engineering problems have been approached assuming that the "given data" is certain. Thus, in general, deterministic methods are considered to be more tractable, less complicated, with a lower computational burden, and with a lesser amount of data and data analysis.

Also, design methods that assume complete certainty have a valuable educational stand point. That is, for students to grasp and understand engineering science principles, simple (or simplified) procedures are needed. Consequently, the instructional design methods may not need to acknowledge the randomness of the underlying input figures (data) and output design variables (results). Also, it has been claimed that many experienced designers have developed a "feeling" for the randomness of the design variables, and that they are sometimes capable of intuitively handling random variation. That is, they are able to correct or adjust their designs accordingly. Thus, Haugen (1968, p. 3), one of the pioneers in probabilistic approaches to structural design, says: "operating in a domain fraught with uncertainty, that of statistics, and with tools not ideally suited to the task, the set of real numbers and conventional (deterministic) methods have performed surprisingly well in the past". He, however, does not elaborate on how cost effective are the operationally successful designs of conventional methods.

In many circumstances, by using deterministic methods and models, the engineer may obtain "adequate" estimates of the desired design variables. Consequently, this general design methodology is still widely utilized. Under the traditional concept, the system and the environment in which it is supposed to function, are designed assuming perfect certainty, or in terms of the so called design (or extreme) conditions. However, after a given system has been designed, constructed and implemented, the degree of adequacy of the design method -and its outcome- will be subject to the realities of a varying and sometimes risky environment. In fact, the environment may present input variables in a somewhat predictable pattern or may subject the system to a set of wildly varying causes. In addition, the system itself may not have a fully predictable performance.

Sometimes, an implicit acknowledgment of uncertainty leads the designer to develop "parametric" designs. A parametric study evaluates the system performance for a set of varying relevant parameters. For instance, fuel heat content can be one "parameter" in the design of an oil burner. In thermal system design, "maximum and minimum" values span the range of "possible" firing rates for a burner design. This kind of information usually appears in a nameplate. A similar approach is used in engineering economic analysis, i.e. the development of sensitivity or break-even analysis to evaluate the sensitivity of a project's cash flow attractiveness to probable changes in a cash flow parameter.

Both, parametric design and sensitivity/break-even analysis allow the analyst to explore the performance or profitability of the system under "what-if" scenarios. Thus, by varying one variable at a time, the sensitivity of both, the system performance (in design) or cost-effectiveness (in economic analysis) can be evaluated under different conditions.

An implicit assumption under most parametric/sensitivity evaluations is that the degree of uncertainty of a variable is such that any particular value in the range of interest is equally likely to occur. In this regard, Taha (1992) states that one of the criteria for decisions under uncertainty is the Laplace criterion. This criterion is based on what is known as the principle of insufficient reason. Since uncertainty implies that the probabilities associated with the occurrence of say n events are unknown, the criterion states that the states or events are equally likely to occur. Hence, a uniform distribution is implicitly assumed for the underlying variable.

However, once a system is installed in its environment, the engineer can gradually know how the system-environment pair responds to the design expectations. If the system and/or its environment significantly deviate from the deterministic model -or do so with a different frequency - then, it is not unlikely that the expected system performance is not attained. Most importantly, since the system implementation is a capital investment, it may subsequently be found that the system does not meet the economic expectations defined by the traditional methods.

Consequently, two examples of industrial systems are presented below to illustrate the problem. One is a flexible manufacturing systems (FMS), the other is a cogeneration system for the coincident production of heat and power. But the general underlying problem is presented first as follows.

1.2 Purpose

A general type of engineering problem is to "size" a given system, i.e. to determine an "adequate" system capacity when the system is subject to a varying demand. Several models for mechanical system/components subject to random loads are discussed by Kapur and Lamberson (1977). They show that the reliability model of component strength and stress can be represented by probability density functions.

This is illustrated in Figure 1.1. Here, changing loads cause random stress, and varying dimensions and physical properties produce strength variation.

In complex systems, however, the problem involves more than a unit subject to one random stress. A multiple load system is shown in Fig. 1.2; which illustrates the varying electrical and steam demand of a brewery. The multiple load problem is complicated by the existence of different load amplitudes, seasonal variation, random load duration or varying frequencies. This is further complicated when the system is subject to failures, which prevent its successful operation at any moment and for a random period of time. Two examples of this type of system are discussed below.

A flexible manufacturing system (FMS) is an automated production system in which different products are processed in small lots, taking statistically distributed throughput times. In FMS, the lots of parts arrive in a random sequence, the lot size is a random variable, and the frequency of arrival of different lots may also be stochastic. In addition, the FMS may be subject to random break-downs and multiple FMS units may be required. Asfahl (1985, p. 417) comments that a curious twist brought on by the FMS approach is that the problem becomes part of the solution. He says:

> Since the reason for designing a FMS was to permit a wide variety of short-run products and models to be processed by the same manufacturing system, such an objective forces the selection of very flexible material-handling equipment to serve the processing machines, which themselves are of varying degrees of flexibility. Once the flexible system has been installed, however, varying or randomizing the product and model mix can actually enhance the efficiency of the system!

The theoretical justification is that given a rather large number of processing variables, their randomness and

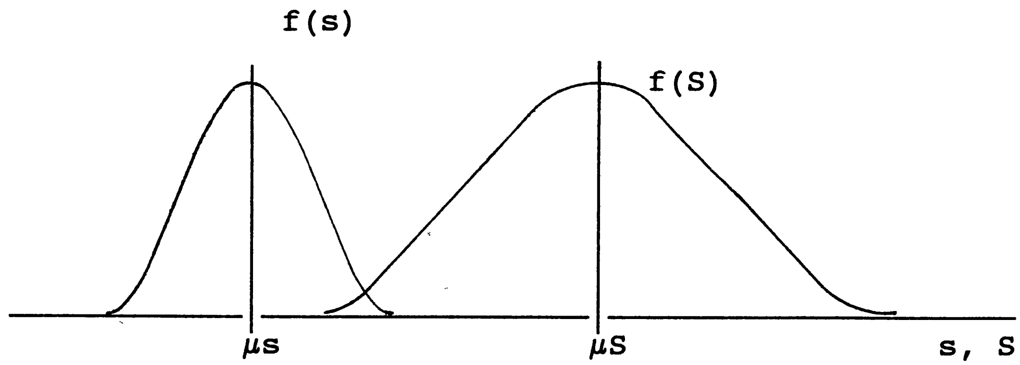


Figure 1.1 The stress (s) and strength (S) of a mechanical component are represented by the probability density functions f(s) and f(S)

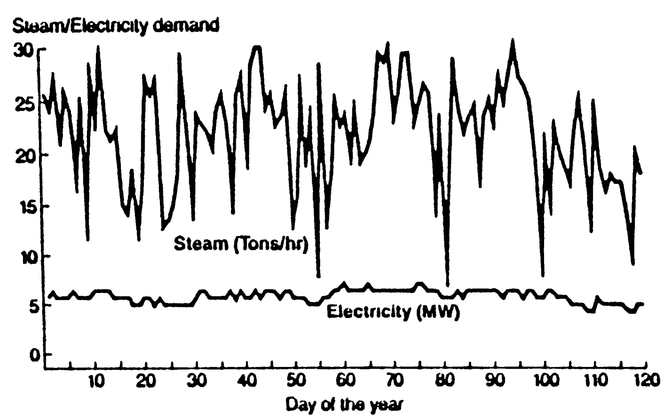


Figure 1.2 Typical steam & electricity demand in a brewery. Source: Gainey and Ward (1986)

thorough mix will allow the products to flow more or less smoothly through the FMS. Thus, it is possible to obtain a more balanced line with low process time items followed by large process time items, and so on. An analogy can be drawn by comparing this situation to the limited capacity of a set of containers for irregularly shaped items. By using mixed items of different sizes, voids can be minimized, i.e. space utilization can be maximized.

A counter-example, in which randomness works against the system performance, is that of combined heat and power (CHP) or cogeneration systems. For instance, in a production facility, during a period of time there may be a high power - low heat demand combination. This may occur just when the CHP system capacities are low on power, but high on heat. In addition, part-load or off-design operation usually involve lower system performance.

Thus, generally speaking, this kind of system may involve a random vector demand (a number of demand random variables present at a given time), a random vector capacity, and a set of failure (break-down) mechanisms for the CHP system. The CHP demands and capacities may or may not be correlated over time. These variables may or may not have seasonal patterns. In addition, the actual problem can be complicated if multiple units of the CHP system are used or required. In most of the cases, an increase in demand and/or capacity variation will reduce the cost effectiveness of the system. Figure 1.2 illustrates possible random thermal and electrical loads imposed in a CHP system.

Since economics plays a definite role in the design process, the problem is to specify a "nominal" CHP system (size, type, availability, scheduled maintenance time, etc.), which will likely meet the design requirements by optimizing a measure of economic merit. A different, but complementary problem, originates from the fact that a reduction in system and/or environment randomness can improve the performance and efficiency of the system, but at a price. In fact, the complementary problem becomes one in which a systematic and sequential analysis is needed to evaluate marginal reductions in the overall variation -to improve system performance- versus additional increments in system installed cost.

Thus, what is needed is a fundamental methodology for the engineering design and economic evaluation of a system with continuous stochastic capacities subject to continuous stochastic demands. Such a research should use the CHP design and evaluation problem as the illustration mechanism. Extremely little research has been conducted on such a problem. Consequently, the required general methodology to analyze, evaluate and model this problem is yet to be accomplished. In fact, as far as the available literature indicates, this thesis is the first of a kind that proposes a systematic approach -that utilizes and combines the realm of probability theory, stochastic processes, reliability theory and engineering economic analysis- to the underlying research problem. Without loss of generality, the methodology should incorporate the following systematic procedures and extensions, as applied to CHP systems:

1. The means and procedures to represent variable CHP load, equipment performance, equipment installed cost, and operation and maintenance costs.
2. The development of the underlying assumptions for (a) the economic criteria required and (b) the resulting life-cycle cost model.

3. A graphical design aid to conduct preliminary CHP designs evaluations, with an explicit randomness recognition, by using information from 1 and 2 above.

4. The general analytical methodology to obtain the optimal CHP system size. The methodology should first define optimal conditions for the case of deterministic (constant) CHP loads. Next, the methodology should determine the optimal conditions for the case of random CHP loads.

The following summary sections (1.3 through 1.7) outline the literature review (Chapter II) and further support the discussion above.

1.3 Probability and Stochastic Process

Gnedenko (1975) points out that the relationship between probability theory and practical engineering applications has been the reason for the rapid development of theory and methods in the past three decades. Thus, the application of probability theory in digital signal processing and spectral analysis has been at the forefront of telecommunications research and development. Discrete event modeling and simulation of complex industrial systems is another example.

In this regard, the Russian statistician P.L. Chebyshev (Gnedenko, 1975, p. 11) has remarked:

> The link-up between theory and practice yields the most salutary results, and the practical side is not the only one that benefits; the sciences themselves advance under its influence, for it opens up to them new objects of investigation or fresh aspects of familiar objects... If the theory gains much form new applications of an old method or from its new developments, then it benefits still more from the discovery of new methods, and in this case too, science finds itself a true guide in practical affairs.

A review of the fundamentals concepts of probability theory and stochastic process was required to formulate the research problem. Such material is not included in the literature review since it is readily available in many textbooks. The selected bibliography included Bendat and Piresol (1986), Ochi (1990) and Wenzel and Ocharov (1983).

Also, the field of reliability evaluation of utility power systems was reviewed, since it has received a large degree of research effort from academia and industry. See for example Billinton and Allan (1984) and Endrenyi (1978). On the contrary, CHP systems do not have -as far as the existing literature indicates- a formal reliability analysis method. This research intends to lay such a foundation.

Therefore, probability theory provides the foundation to tackle the problem of sizing -in an economic basis- a system subject to multiple continuous random loads and subject to random failures.

1.4 Energy and Energy Price Modelling

Once the stochastic nature of demand and capacity is recognized, economic evaluation requires one to predict the performance of the project, upon which investment is being considered. In essence, to estimate a cash flow stream for an energy system, one must first predict the system's 1) usage (energy), 2) demand (power) and 3) the price to be paid for energy and demand during the planning horizon.

Thus, Section 2.1 reviews a number of concepts and methods to model energy consumption and to predict energy prices. It also discusses some of the problems encountered in energy forecasting. Next, Section 2.1.1 presents several approaches to forecast CHP loads in new facilities. Some of the methods considered are: weather and building simulation, energy utilization indices, "top-down and bottom-up" approaches, regression and econometric models, and periodic or trigonometric models. In addition to the methods just listed, Section 2.1.2 considers a number of approaches that use records from existing facilities. It discusses prediction approaches used by industrial plants as well as those used by electric utilities. Then, Section 2.1.3 discusses how demand, supply, inflation and the latest geo-political event may complicate matters when one is trying to forecast energy prices. This section presents some practical approaches on how to "anchor and bound" the prices of the cogeneration staple fuels (diesel oil and natural gas), so they can be predicted with some sense and rationality.

1.5 Cogeneration System Design and Analysis

The combined heat and power (CHP) or cogeneration system problem is used as a vehicle to illustrate the research problem. Thus, current procedures to design and to analyze cogeneration systems are reviewed in Section 2.2. The following subtitles are further discussed in such a section:

1) General Considerations and Definitions - defines the general terminology of industrial cogeneration systems.

2) Basic Cogeneration Systems - describes the technological aspects of the basic CHP equioment and cycles.

3) Cogeneration Design Criteria - critically examines several methods and computer programs for CHP planning, design and economic evaluation.

4) U.S. Cogeneration Legislation - overviews the legal and regulatory aspects of American cogeneration as stated in the Public Utility Regulatory Policy Act (PURPA) of 1978 and subsequent regulations.

1.6 Cogeneration Research Needs

Section 2.3 identifies the link between different research needs stated by cogeneration researchers and practitioners. Several surveys on how CHP systems actually perform are presented; focusing on current user and designer needs. Thus, actual system performance is compared with expected or design performance. Questions on the lack of consideration to variable loads, part load performance and availability are risen in most of the reviewed literature.

For example, cogeneration regulation is just one of the many "faces" of cogeneration that requires an integrating method that explicitly takes into account its stochastic nature. Wooster (1989) aptly titles her paper: "Purpa Cogenerators: How Reliable", thus linking the planning and permitting stages of cogeneration plants with the ability of the cogenerator to demonstrate PURPA performance under risk. In this regard Steen (1990, p. 124) has said:

> I am of the opinion that (in cogeneration) to arrive at separate solutions for power reliability and quality problems independent of energy cost reduction efforts is to ignore optimal economics.

1.7 Cogeneration Development Gaps

After reviewing the existing cogeneration literature and interviewing a number of industrial designers and academic researchers, the following "gaps" have been identified:

1. There is not a consistent procedure for data collection of thermal and electricity demand of existing facilities. Thus, there are no guidelines to define the amount and kind of data required to obtain certain confidence level in the design of a system.

2. There exist no standard method to estimate and model the combined heat and power (CHP) demands in a prospective or new facility.

3. In general, there is not a basic methodology -using statistical concepts- which can provide the designer with CHP load forecasting for correlated loads and plant capacities.

4. In order to generate system design alternatives (given load duration curves for thermal and electric loads), there is not a simple but effective way to define and select a set of "suitable" CHP technologies.

5. For cogeneration economic evaluation, a standard set of criteria is needed to define discounted cash flow elements such as: finance options, interest rates, energy costs and escalation rates.

6. There is a need for a method to obtain an economics based CHP system size for a given application. The method should use "compact" CHP data and cogeneration system performance curves. It should consider the system reliability, as well as capital costs, fuel costs, "other" operation and maintenance (O&M) costs.

A coherent subset of these research gaps will be translated into the research objective of this thesis. The research objective and subojectives are stated in Chapter 3.

CHAPTER II

LITERATURE REVIEW

An overview of the literature relevant to the research objectives is presented in this chapter. In addition, a detailed substantiation for the proposed research is discussed. Also, related research efforts are reviewed.

This chapter contains four sections, which have been summarized in the previous chapter:

1. A discussion of statistical models utilized for energy and power demand modeling and forecasting.
2. A survey of the traditional approaches for industrial cogeneration design and economic analysis.
3. An overview of the U.S. regulations on cogeneration.
4. Identification of current cogeneration research needs.

2.1 Energy and Energy Price Forecasting

Aitchison and Dunsmore (1975) state the following etymology of prediction: "Prediction by its derivation (L. praedicere, to say before) means literally the stating before hand of what will happen at some future time". In their work, they caution the researcher, engineer and economist that do not acknowledge the presence of uncertainty in prediction. Specifically, they say that much of statistics is concerned with making inferences about unknown distribution parameters. And since the main purpose is, in general, to convey such inference statements as information upon which a second party will make decisions, many use the estimates as they were true values. Thus, they claim that prediction analysis suffers a neglect -as compared with the fields of estimation, hypothesis testing and experimental design-. Henceforth, they present a unified approach to aspects of statistical prediction theory related to decision analysis from both the frequentist and the Bayesian viewpoints.

There are many reasons to develop statements about what is likely to happen in the future. According to Schonberger (1985), however, the main purposes for demand forecasting are: (1) to determine the items to be produced, (2) to plan for adjustable capacity, and (3) to plan for facilities. He mentions that forecasts are short term (e.g. minutes in the fast food market) to some long lead time (months in industrial equipment sales).

To a certain extent, the purposes for demand prediction in this research are the same as those mentioned above. Here, however, we focus on purposes (2) and (3), i.e. to plan for adjustable -and varying- capacity and to plan for facility or system characteristics.

Brown (1963) says that the criteria for time-series-analysis falls into the following categories: (1) accuracy, (2) simplicity and (3) flexibility to adjust the rate of response. Bedworth and Bailey (1982) state that these criteria are generally valid for any forecast and that a trade-off of at least two of the three criteria is usually required. In addition, they point out two other criteria. These are (4) the elapsed time between making a forecast and implementing (or using) the forecast and (5) the frequency of data collection. Recognizing the forecast problem complexity, they maintain that only on some cost criteria can the multiple criteria be optimized, and possibly only through computer simulation.

Since CHP system demands are stochastic, one requires statistical estimates -i.e. forecasts- of the underlying random processes (or times series) and its parameters (e.g. mean values, variances). Parameter estimation in engineering and science is a modern discipline. Beck and Arnold (1977) present a comprehensive study for non-linear estimation and regression as applied to engineering and scientific models. The objectives of their treatise are to provide (1) methods for estimating constants or parameters appearing in mathematical models of physical systems, (2) estimates for developing accuracy of the estimated parameters, and (3) tools and insights for developing improved mathematical models.

In the CHP forecast problem, we are particularly concerned with the forecast of instantaneous rates of change (power units, e.g. kW) as we are with the prediction of sales (or purchases) of "items" during a time period (an energy unit, e.g. gallons of fuel oil per day). In addition, the CHP forecasting and prediction problem conveys a number of specific problems or questions. They are:

1) What data should be collected?

2) What practical problems exist in data collection and how can they be handled?

3) What particular forecasting models should be developed?

4) What prediction functions should be computed?

5) How should data be processed so as to reduce statistical bias and random errors?

6) How should computed quantities be interpreted so as to give physically and economically meaningful results?

Given a set of CHP load distributions, this research intends to provide ways to resolve the last question above as related to the CHP system design problem and to contribute a practical approach to evaluate the system cost effectiveness. For example, for economic evaluation, in the CHP problem, demand (kW or BTU/hr) and energy (kWH or BTU) must be estimated for the long term, i.e. the planning horizon or the expected economic life of the CHP system. Also, there is a need for both, intermediate-term and short-term forecasts. On the one hand, it is desired to forecast the long and intermediate terms to handle seasonal variations (e.g. monthly load variations). On the other hand, a microscopic, say hour-by-hour prediction, is required to evaluate the system capacity vs. demand performance. Thus, intermediate (seasonal) variations in load might be influenced by the difference in Summer-Winter demands. Conversely, short term forecasts are valuable in estimating the frequency and duration that the system state (under-loaded or over-loaded), and to compute peak demand charges.

An implicit assumption, behind the forecast problem stated here, is that the facility has a utility tie to make up for any electricity deficit -or to sell back excess power. Similarly, supplementary equipment provides for any heat deficit, otherwise a loss of load will occur. In fact, when these supplementary sources do no exist, the problem becomes a particular case of the general research problem. This case will not be discussed herein.

There are two basic scenarios that condition the way a forecast is accomplished for the CHP problem. One is when the CHP system is intended for a new facility. The other is when the CHP system is a retrofit for an existing facility. These two situations and a review of their corresponding forecasting methods are discussed as follows.

2.1.1 Forecasting CHP Loads in New Facilities

In this case, the facility to be served by the CHP system does not yet exist. CHP historical data does not exist either, and must be estimated by indirect means. As follows, several data items useful to predict CHP loads are listed.

1) the size of the energy consuming equipment to be installed in the facility,
2) the planned facility's operation schedule,
3) the facility's construction plans and
4) the prevailing weather conditions for the facility.

For new facilities, Wong et al. (1991) propose that the sum of all the maximum prospective process demands (rated or design loads) -likely to exist in the facility at a given time- defines an upper bound for seasonal forecasting. Conversely, they define a lower bound as the "true base load", i.e. the demand of equipment that is expected to run continuously in the facility. Then, an "expected" operation scenario determines the appropriate load curve between the two bounds. Whether the demand for energy is produced by causes in the exterior (weather load) or the interior (people and equipment) of a facility, it must be predicted in some fashion. Thus, below, some current methods to predict loads in new plants are discussed.

2.1.1.1 <u>Weather Dependent Loads and Building Simulation Models</u>. In the case of weather based loads, cooling and heating peak loads (and bounds) can also be defined. McQuiston and Parker (1988) compute building hourly cooling and heating loads using sensible and latent heat transfer rates for the "peak days". A weather model for the location and the facility's construction details establish the model structure for such days. These models are usually developed for "extreme or design" conditions; e.g. for the ambient temperatures that will be exceeded during 2.5% of the time. The majority of this kind of models use a sun-cloud model, and/or annual temperature data base (bin data).

To estimate heating and cooling demand for a complete year, Wong et al. (1991) have replicated the peak load calculations for "average" instead of "extreme" conditions, for different seasons of the year. Their approach assumes that, for a given season, the underlying random process exhibits a degree of stationarity that allows one to represent it by a daily load model, with adjustments for weekends and holidays. Hence, using this approach, the weather-dependent load for both new and existing facilities can be modeled and predicted for any time of the year.

Several "building simulation" programs such us ASEAM (1987), TRACE, and DOE 2.X, are commercially available. In general, these programs use as input the architectural characteristics of the building, a weather model for the location, an operation schedule, and "macros" or submodels of generic equipment.

For instance, the DOE 2.X program was developed by the Lawrence Berkeley Laboratory, in collaboration with the Los

Alamos Scientific Laboratory, and financed by the U.S. Department of Energy. DOE 2.X has been used as a building design and analysis tool by architectural and engineering (A&E) firms. DOE 2.X allows the designer to forecast energy consumption by modeling typical architectural features and interior loads for a generic building type while using default values for appropriate heating, ventilating and air conditioning equipment. Riegel et al. (1983) have used DOE 2.1 as an interactive design/analysis tool. Using the program, they tested a number of building design alternatives - upon a base line scenario- for cost effectiveness.

Deterministic building simulation models are currently widely use for energy use. Ritschard and Huang (1989) have estimated water heating and aggregate electricity buildings in multi family buildings. Their results were a data base created with the DOE-2 building energy analysis program for 15 locations. Ritschard and Handford (1989) have reported comparisons of multifamily heating and cooling loads from DOE-2 building simulation program with measured data. They conclude that many difficulties arise from comparing energy consumption for heating and cooling but that for aggregate electricity consumption compared within ±20% of the measured data from large samples. Wagner (1984) has conducted comparisons of predicted and measured energy data in 24 studies for occupied buildings. He concluded that in the absence of detailed building data, the comparison between simulated and actual energy consumption of occupied buildings is best made with "large" samples of data.

2.1.1.2 Data Bases and Energy Utilization Indices. Generic data for a new-facility forecast can be obtained from loads profiles of existing similar facilities or from consumption data bases. Data bases can be used as a validation tool. For instance, a predicted plant load, can be compared with the "standard" heating load in BTU/sq-ft-degree-hour for the periods of interest. These standard unit loads are usually called Energy Utilization Indices (EUI).

An example of standard data bases is the one developed by Silver and Burrows (1983) for hot water use demand in commercial buildings. They have compared their results with previously developed methods and show that hot water demand varies widely depending on the building type and hour of the day. These data are available for several different types of establishments (e.g., restaurants, hotels, apartments, etc).

Existing data bases of measured energy data, such as Residential Energy Consumption Survey (RECS) of the Energy Information Administration (1987) and space heating energy data from the American Gas Association (AGA), provide basic information for heating energy estimates for new facilities.

Kumar (1989) reports statistical analyses using Energy Utilization Indices for 1000 commercial facilities of various types and sizes in Jacksonville, Florida. The analyses are based on the correlation of his actual observation of energy to the size of the facilities. His paper also discusses the kW-per-square-foot index, and the extent of low-cost and no-cost conservation opportunities in a typical facility.

Hodge and Steele (1982) recommend a simplified method to conduct energy surveys of buildings belonging to the same generic class. Their study places special emphasis on determining the actual end-point energy usages for the building and on comparing these to target values that have been determined for similar buildings that run energy efficiently. Target or Energy Utilization Index (EUI) values are given for school, local government and small commercial buildings. EUI values constitute the so called "energy budget" for a building or building complex. EUI's are also useful to forecast consumption for new facilities. The EUI is calculated by dividing the total energy input into a building by the conditioned floor area. In order to generate an EUI, all sources of energy input must be converted to a common basis.

In the U.S., this seemingly trivial operation is associated with a serious standardization difficulty. Besides the loss of validity of EUI's due to changes in location, facility construction and equipment operation, there is a unit standardization problem. Fricke (1983) has conducted energy utilization comparisons on a national basis and points out the lack of uniformity when it comes to compare a National Standard for electricity-to-fuel conversion. He states the need for a single unit of energy accounting. Thus, the Federal Standard uses 10,000 BTU's per KWH, while the Engineering Standard uses 3412 BTU's per kWH. Unfortunately, he recommends to use both standards until one is officially adopted. Also, with the exception of the U.S., in most countries SI units are used for both heat and power consumption and demand; i.e. kWh and kW, respectively. Thus, for design and analysis, this author favors the engineering standard (3412 BTU/kWH) and SI units (with some exceptions).

2.1.1.3 Top-Down and Bottom-Up Approaches. Turner (1982) states that energy consumption can be estimated by using a top-down approach or a bottom-up approach. The top-down approach involves making an analysis of measured energy consumption and prorating it to the elements causing that consumption. The bottom-up approach involves the use of load calculation methods as in Section IV of the ASHRAE (1985) Handbook of Fundamentals. These methods are similar to those described under the Weather Dependent Loads subtitle above.

Using a "bottom -up" approach, Rayaran (1991) has developed a deterministic method to predict the CHP loads for a new facility. In both approaches, knowledge of the load characteristic of the energy consuming equipment along with their operating schedule is required. Here, we propose to extend such a methodology to the stochastic field and to use it as a prediction basis of CHP demand for new plants.

Henceforth, process energy demands could be predicted -between the two bounds defined above- according to the facility's operations schedule. Then, heating and cooling loads due to weather variation can be added to the process loads by using any of the approaches stated above. In addition, production process loads must be included in the model according to the expected production schedule.

Next, the forecast must incorporate means to model the intensity, frequency and duration of the energy-using activities within the facility. To develop a realistic forecast, the expected random variation or noise -for each demand item- can then be incorporated to the forecast. Random noise can be estimated from records of similar existing facilities and can be adjusted according to the expected operating conditions and energy control systems of the prospective facility.

2.1.1.4 <u>Statistical-Regression</u> <u>and</u> <u>Econometric</u> <u>Models</u>. Statistical models, such as the regression-based Princeton Scorekeeping Method (PRISM) have been developed to predict building energy usage (Fels, 1986). These approaches base their estimates on three arguments: time of the year, day-length and temperature. In a sense, PRISM is considered to be an econometric model, i.e. one that utilizes single or multiequation regression models with explanatory variables such as economic activity, prices, and weather to explain the energy usage. In this kind of model, energy-using equipment is not disaggregated by specific end use as in methods for heating/cooling load calculation. The explanatory variables are used to explain aggregated energy usage for the facility. Therefore, forecasts for the variables that describe the facility's activity for the time of interest are required.

Lee and Hadley (1988) have used PRISM to develop residential heating energy estimates. They adjusted the variance of PRISM estimates by using theoretical methods, i.e. heat transfer calculations.

Darwin and Mazzucchi (1988) have used PRISM to predict the temperature-sensitive energy demand of a facility. The time and day- length are captured by other variables.

Haberl, Smith and Kreider (1988) have developed Building Energy Analysis Consultant (BEACON), a prototype knowledge based system to track operation and maintenance problems related to energy consumption. PRISM was applied to develop "target" energy consumption patterns. BEACON was used to compare actual metered data with PRISM target results in order to detect "significant causes and events". In general, the consumption predictors used were found to be "accurate, yet time consuming to assemble test and reinstall". Random variation of actual consumption (metered data) was not acknowledged.

Mazzucchi and Devine (1988) have reported about the current status and planned progress in the development of improved energy base-lining (energy consumption targets) and refinement of energy analysis methods. The main emphasis of their research is in providing technical guidelines for federal agencies that undergo performance based contracts (e.g. shared energy savings contracts).

2.1.1.5 Periodic-Trigonometric Models and Fourier Analysis. Due to the periodicity of the energy demand in most cases, Fourier analysis has a large potential for application in new facility energy modeling. Bloomfield (1976) indicates that spatial series -i.e. equally spaced observations along a line- can be represented by a combination of sinusoids. He says that a basic property of the sinusoids -that makes them generally suitable for the analysis of time series- is the fact that their simple behavior remains in spite of changes in time scale. Thus a sinusoid of frequency w or period $2\pi/w$ may be written as

$$f(t) = R\cos(wt+\phi)$$

where R is the amplitude and ϕ is the phase. If we change the time variable to $u=(t-a)/b$, which incorporates a change in origin and in scale, this becomes

$$g(u) = f(a+bu) = R\cos(wbu+\phi+wa) = R'\cos(w'u+\phi')$$

where $R'=R$, $w'=wb$, and $\phi'=\phi+wa$. Thus the amplitude is unchanged, the frequency is multiplied by b (the reciprocal of the change in the time scale), and the phase is a altered by an amount involving the change of time origin and the frequency of the sinusoid. Since the time origin associated with a data set is often arbitrary, these simple relationships are useful. In particular, since the amplitude of the sinusoid depends on neither the origin nor the scale of the time variable, it may be regarded as an absolute quantity with no arbitrariness in its definition.

A number of trigonometric models can be used as the basis for load prediction in new facilities. These models are mainly used with seasonal demand patterns. Thomopoulus (1980) describes the following trigonometric models based on a pair of terms (sine-cosine) per wave.

-Three-term model: When the process follows a sinusoidal behavior but has a horizontal level mean value. The expected demand U at time t is defined by one sine wave by:

$$U_t = a_1 + a_2 \sin wt + a_3 \cos wt$$

where

a1 = long run mean level
a2 = amplitude of sin wt
a3 = amplitude of cos wt
w = 360o(1/T)
T = number of cyclic periods in a year.

-Four-term model: When in addition to a sinusoidal behavior, the process has a trend effect (a2t). Thus, the expected demand is defined by:

$$U_t = a_1 + a_2 t + a_3 \sin wt + a_4 \cos wt$$

-Six-term model: When the process is a combination of two sine waves and a trend effect.

$$U_t = a_1 + a_2 t + a_3 \sin wt + a_4 \cos wt + a_5 \sin 2wt + a_6 \cos 2wt$$

Hence, it can be suggested that by defining upper and lower bounds for the amplitude of sine waves, and by adding a random noise term based on "typical" residual variances, trigonometric models can be constructed as estimates of periodic random process -or process segments- for new facilities. The number of terms of the model would depend on the degree of non-stationarity of the random process and the degree of complexity required to model the underlying cyclic system.

An alternative cyclic analysis to estimate Y(t) fits the equation

$$Y'(t) = (A+Bt)\sin(2\pi t/p) + (C+Dt)\cos(2\pi t/p)$$

where the most significant period, p =1/w, is determined through spectral (Fourier transform) analysis. Additional terms -associated to additional periods- can be added to the equation above to model multi-frequency processes.

Bedworth and Bailey (1982), however, point out that "the user may require up to five cyclic fits (5 periods), although two is probably the maximum that should be utilized, or else the model might be fitting noise." They have developed PREDICTS (PREdiction of DIscrete Time Series), designed to allow a user to analyze historical data series in order to predict future values of the same series. PREDICTS can determine the most significant period p1 (and any other significant cyclic periods from the residuals). It also determines the amplitude coefficents -A,B,C, and D- through regression. This kind of analysis can be used with "discretized" data, i.e. integer (rounded-up) load values.

The main benefit from cyclic analysis is it ability to "compress" time series or random process data into a compact equation-model per random process, for the periods of interest. Thus, in the case of new plants, cyclic analysis could use load data from time series generated by combined weather-production schedule simulations.

A very recent development -discussed by Wallich, (1990), is the utilization of Wavelet theory. It is based on recent mathematical developments applicable to digital signal processing. During the 1980's, Jean Morlet, an engineer at Elf-Aquitaine and mathematicians Yves Meyer of the University of Marseille and Ingrid Daubechies of Bell Labs have been at the forefront of such developments. Wavelets differ from a Fourier transform -that breaks a stationary signal into continuously repeating components at various scales or frequencies- in its ability to represent signals that change suddenly over time -e.g. heat load demands affected by sudden weather changes or telecommunication subject to jamming.

Wavelets are able to isolate the location as well as the scale of features in a signal. As a result they can encode rapidly changing signals in a compact form. According to these authors, many potential applications in cyclic random process modeling may be warranted for this theoretical development.

2.1.2 Forecasting Loads in Existing Facilities

In addition to the models surveyed above -which are also valid for existing facilities- there are several approaches to forecast demands using records of continuous demands or utilities (e.g. steam, electricity, water etc).

Because of system operation and planning requirements, electrical companies have been the most active in developing various approaches to predict the load demand (i.e. the rate of change of energy usage). Since most electrical utilities use discrete sampling periods (e.g. 15-minute power demand metering window) and rounded figures due to constant meter multipliers, many forecasting methods for discrete parts production can be easily adapted to analog signals converted (or digitized) to integer quantities. Below, we discuss 1) some approaches used by this author and others for energy consumption analysis and 2) the approaches used by electric utilities to develop short, intermediate and long term forecasts.

2.1.2.1 Industrial Facility Energy Analysis. Measuring and documenting energy consumption constitutes the basic requirement for any energy analysis. In a large facility, several utilities are subject to metering by using a number of procedures. The most accurate way to allocate energy use in a large facility or complex is through effective submetering. Unfortunately, very few facilities actually do it. Submetering not only permits one to allocate more equitably energy costs, but also to prioritize energy conservation efforts. In other words, it is a basic requirement for an effective energy management plan.

Stebbins (1986) remarks that the advent of the personal computer (PC) has permitted quantum leap forward in the ability to manage large amounts of utility data in industrial facilities. The PC based utility data can be assimilated into a variety of formats for data acquisition, revenue billing, trend analysis and energy consumption monitoring. A variety of software packages, input/output ports, interfaces, and sensors are commercially available for energy metering and monitoring. In addition, many electric utility companies can provide magnetic media (tapes and disks) with electrical records such as peak day demand and load duration curves.

For field data recording, utility companies can sometimes provide strip and circular chart recorders. Recently, recorders with floppy disk drives have become available. Then, regardless of the recording method, data can be further processed to develop statistical forecasting models.

Pliscott (1985) criticizes the "black box" (i.e. traditional accounting allocation of energy) in building energy performance evaluation. As alternatives to the black box he proposes two approaches. One is using STAT PLAN, a statistical analysis program which only requires 24 months worth of (monthly) consumption data. It is a multiple regression model used previously by Redlin (1979) to model energy consumption in lodging facilities. The other approach builds upon STAT PLAN with a more detailed and technically oriented procedure, in which loads are allocated according to facility activities. This last approach develops energy utilization indices for energy accounting and cost tracking.

In industrial buildings, energy accounting is known as energy tracking. Sher (1985) suggests a regression analysis approach using only weather data and monthly utility bills. To obtain modelling data, he further proposes to sub-meter each utility stream and each large energy consuming activity or area in a facility.

Andrews and Olson (1985) present a methodology for allocating energy costs equitably among the users of a large facility. The methodology use room survey data, energy management computer logs, and other empirical data when assigning energy weighting factors to each room on a campus. The methodology appears to be a good estimator of relative energy consumption although it is not always a good predictor of a building's absolute energy consumption.

A different approach is the development of industry specific models. The National Center for Analysis of Energy Systems at Brookhaven National Laboratory has developed and is managing a set of mathematical programming models of energy-intensive industries in the United States. Hill et al. (1981) report the development of industry-specific models based on data from economic and engineering analysis of manufacturing processes. These are intended to represent energy flows within an industry in considerable detail. For example, their paper discusses models for the pulp and paper mills, iron & steel plants, cement plants, etc. The models generally consider five levels of activities: 1) purchases of raw materials, 2) sales of by-product energy, 3) material/ energy conversion, 4) capacity expansion and 5) regional transportation from plant to plant. The models are oriented toward the evaluation of technological innovation impact at the industry-wide level. However, they may be useful to predict energy usage of new plants and to define target indices for existing plants.

At the process control level, Weper and Li (1985) have developed a stochastic load prediction algorithm -that incorporates control strategies - to forecast building loads. The main purpose of the algorithm is to predict several hourly building loads as the basis for adaptive microprocessor-based load control. The approach uses a multiple regression model developed from a recursive statistical analysis of previous building performance.

A deterministic approach was used by Rajamani and Wong (1989) to disaggregate and estimate heating and cooling electrical load data for an existing building complex. Here, for each building of the complex, the load parameters were estimated by using (1) the equipment operation schedule, (2) the instantaneous electrical demand recorded during the peak day of each month and (3) the energy bill data for twelve consecutive months.

A different approach, using load factors, (i.e. the ratio of calculated average demand to metered peak demand) is described by Argawala et al. (1990) to estimate air conditioning loads for two Oklahoma State buildings. The objective of the study was to develop an estimation procedure of the buildings' cooling load to be shifted to "off-peak" utility hours by using modular ice storage.

Moore (1987) states that because of ever changing weather conditions and production levels on energy consumption, it is often difficult for plant managers to estimate a baseline level of energy consumption. He remarks that in the case of shared saving programs, it is especially important to predict and estimate energy consumption and savings. He presents the results of a basic energy usage model through statistical analysis by the Industrial Energy Extension Service at Georgia Tech. The regression model is based on five years of historical data of energy usage in a manufacturing plant, weather conditions and production output. The model can be used to predict energy consumption, or as a basis to evaluate energy conservation programs.

2.1.2.2 Electric Utility Load Forecasting. Electrical utilities are interested in short-term (24 hours), medium range (one year) and long range forecasts (5 to 10 years). Due to demand management efforts -to improve operation economy- during peaking hours, short-term forecasts methods have lately received greater attention. Hooke (1955) presents one of the first load prediction approaches. His paper "Forecasting the Demand for Electricity" presented an approach to deal with load forecast looking from 6 months to as much as 10 years or even more into the future. It produces the basic forecasts required in making studies of alternative methods of system expansion. They are also the forecasts to evaluate current generation capabilities.

The lead times -in electric forecasting- are related to planning or control purposes. They range from a few minutes ahead for the economic loading of power plant to over forty years for the economic planning of new generating capacity and transmission networks. Specifically, Bunn and Farmer (1984) list the following three purposes of electric load forecast methods:

-Plant scheduling, which deals with the day to day start-up and shut-down programs of large power plant units. The process is effected from several hours to days ahead, and is often termed unit commitment. It ensures that there is sufficient operational generating capacity to meet variable load, with a specified reliability, at each moment of the day.

-Load dispatching and security assessment, which refers to the minute-to-minute allocation of loads to generators to meet the varying demand at a minimum cost, while ensuring a required level of system security.

-Statistical allocation of reserve capacity, to allow for unpredictable variation in power plant capacity. This reserve contains the frequency of supply interruptions at acceptable levels.

The third purpose stated above -reserve capacity allocation- presents a similarity to the CHP load prediction problem. Thus, in the CHP case, we are concerned with the iteration of system capacity and demand, at the planning and design stage.

Load forecasting occupies a central role in the operation and planning of electric power systems. Huck et al. (1980) have surveyed load forecast bibliography. They point out that the subject is very broad in nature and that it includes many engineering considerations and economic analyses. They have compiled several papers that encompass the vast philosophy of load forecasting. On the contrary, CHP forecasting presents a limited scope; since it can be compared to that required for smaller power plants and smaller service areas (less than 100 MW). Thus, from their work we have reviewed a number of publications related to smaller industrial power systems and/or smaller load areas.

Menge (1977) describes the philosophy, methods and time series trend analysis for forecasting small area trend electricity. For modelling a small area, one may select from 12 curve shapes including S curves that closely follow load growth. Several power forecasting models are based on land use models. Willis (1977), for example, formulates a model for small area electric load forecasting by "dual level spatial frequency modeling". The method is similar to the classical urban model growth and incorporates a simulation of multidimensional space to forecast land use and power demand.

In power generation, there is a similarity between the growth in land development and the growth in production capacity or progressive expansion in an industrial plant. For instance, the growth in power demand due to land development (or sales/production expansion) is expected to increase in very small increments in relation to the existing (and future requirements) power plant size. However, the long-range trend effect of electric demand in industrial plants, may be affected by a step-wise growth due to the addition of new and large production lines that involves new products and/or services. In conventional power plants, this is the case when a new and large consumer plant is built in the service area, involving a sudden "jump" in demand. These problems, which relate to the design and analysis of a system under demand growth, shall not be addressed herein.

For CHP design, we are particularly interested in the development of a forecasting model that deal with time series that are (or can be converted into) stationary series in the wide sense, i.e. those that represent random process with an affinity for a mean value in the long run. Thus, the required prediction model should (1) span over the economic evaluation planning horizon and, at the same time, (2) show a sufficient level of detail at the short term to represent load-capacity iterations. Hence, the required models must exercise a level of compromise between short-term and long-term. The following utility models are related to the CHP dual criteria forecasting model.

Stanton and Gupta (1969) describe six possible procedures for producing annual (or seasonal) peak demand probabilistic forecasts. Their models place greater emphasis on probabilistic monthly or weekly peak demand forecasting and the derivation of annual forecasts form monthly or weekly forecasts. An introduction to the use of stochastic models for demand forecasting is also included.

Stanton (1970) has developed statistical procedures for the preparation of weekly and seasonal peak demand forecast with lead times up to seven years. He reported that probability information in the form of both standard deviation and 99% confidence intervals gives a comprehensive basis for system planning but this can be supplemented by a tabulation of the forecast's probability distribution in cases where more detailed information is needed.

Gupta (1971) describes a stochastic procedure for producing probabilistic forecast of monthly peak demands for up to three years ahead. The procedure is based on well-known concepts of prediction of stationary stochastic time series, which is developed further to predict those types of non-stationary series that can be reduced to a stationary series by finite linear transformations. The procedure yields a technique for forecasting the evolving, nonstationary and seasonal peak power demands.

Dieck et al. (1987) present an approach to improve the accuracy of time series when outlying observations exist in predicting total energy demand. The approach is implemented using time series data of "Total Energy Demand". For simplicity and responsiveness, they use an univariate approach by applying (1) Box-Jenkins ARIMA, Winter's exponential smoothing, Harrison's harmonic smoothing and a naive model. By sequentially replacing previously removed outliers, they have tested the models just mentioned and conclude that " greater accuracy -in terms of the Mean Square Error (MSE)- results from replacing outlying observations with the model that most accurately forecasts adjacent data points than by automatically replacing with the same model that is used to forecast future observations". And, that as more outlying points are replaced, the choice of the most accurate model becomes less crucial. Their approach offers certain potential for CHP plants subject to a wide variation of loads that requires a robust model.

2.1.3 Forecasting Energy Costs

Energy costs constitute a very important (random) variable in the economic analysis of industrial energy projects. Turner, Estes and Tompkins (1981) have stated that "rapidly increasing prices and dwindling supplies are the twin jaws of a vice closing". But the rate at which these "jaws" close and its effect on industrial productivity and/or investment profitability may change over time; depending on the latest environmental, weather, or geo-political event. Thus, to monitor and budget energy costs, they have suggested an energy accounting approach based on the General Motors - Energy Responsibility Accounting (ERA) system. It is based on variance analysis performed on a multiple linear regression target model. The approach has three phases:

(1) energy and cost metering,

(2) energy and cost budgeting (linear regression) and

(3) performance reporting (price variance analysis).

Next, they discuss the Carborundum Accounting System, which is used to carry the analysis of variance several steps further by showing price variation as before, but consumption variance is broken down into volume/mix, weather, pollution, conservation, alternative fuels, and others.

2.1.3.1 Multiple Inflation Rates. Turner and Case (1979) have developed a procedure for economic analysis of energy proposals under inflation. They say that "perplexing problems of multiple rates of inflation" (different rates for different cash flow items) makes the analysis difficult and complex. Their work recognizes the fact that escalation rates different that the general inflation rate (as represented by the consumer price index, CPI) may exist in energy cost modeling. Thus, they present a technically correct way of analyzing cash flows of energy projects with multiple rates of inflation. They advise that great care must be taken in choosing inflation and interest rates for this kind of projects. Henceforth, the following question arises: How to forecast energy costs vis-a-vis their expected escalation rates? An answer to this question is attempted below.

2.1.3.2 Supply, Demand and Energy Prices. Kempski (1991) states that forecasting energy prices is like playing the child's game of Chutes and Ladders - prices climb and slide in ways that often appear completely unpredictable. He advises: "In making plans, keep in mind the quick shifts, or your energy dollars could slip away". Thus, many computer programs for cash flow analysis permit to input different energy prices for different years or different escalation rates. Also, economists have developed models to define a price level of a resource according to the amount consumed and/or supplied, i.e. using a resource's price elasticity. Consequently, by knowing the price elasticity of a resource -

i.e. the ratio of a change in its price to a change in its demand or supply- it is possible to predict prices by anticipating the amount consumed.

For example, Figure 2.1 shows the wide spectrum of the forecasts by different researchers for U.S. primary energy consumption. The spread of the forecasts increases as the

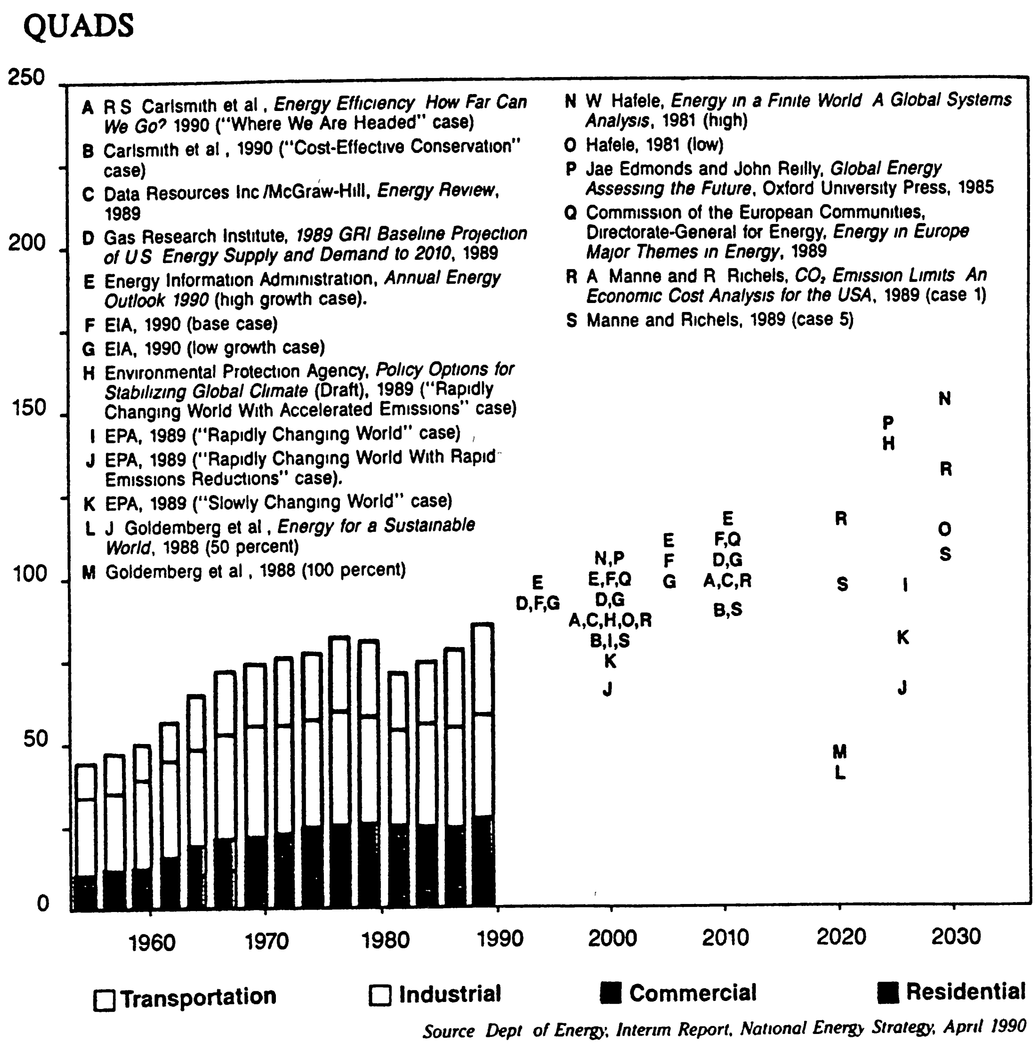


Figure 2.1 Projections of U.S. primary energy consumption

lead time progresses. This is not a very insightful graph, however, since it does not allow one to conclude whether energy consumption will grow, will stay the same or will be less in the future.

In this regard Kempski (1991) states the following: "This poses a dilemma for forecasting prices. If you forecast increased energy consumption, the prediction will put pressure on prices and lead to real cost increases in energy after inflation. If you forecast a decrease in energy consumption, you will place less pressure on energy markets, and energy prices probably will remain stable or decrease after inflation"

He then concludes: "If you believe future energy consumption will increase, then estimate real increases in energy prices. If you believe energy consumption will remain the same or drop, however, one can expect the cost of energy to equal the rate of inflation." Hence, depending on market demand expectations for the fuel(s) involved in an energy project, energy prices can be forecasted by setting the corresponding escalation rate for such a market.

For the proposed analysis for CHP systems, however, energy price prediction remains unclear and uncertain. Consequently, at least some limits (a reasonable range) for energy prices are required for sensitivity analysis or stochastic simulation. This is examined as follows.

2.1.3.3 Bounds for Energy Prices. The world depends on oil as a raw material and as the fuel for more than 40% of its energy supply. But oil is a naturally volatile commodity. Since 1945 the supply of oil has frequently been threatened by conflict. The price of oil has gone up to later come down. Nevertheless, in the long run, oil price seems to have been controlled by its economic servo-mechanism.

In economics, exponential growth rates define some limits to price levels. Thus, before the current Middle-East crises (1990-1991), oil was selling for $12 to $16 a barrel. Assuming a 15-percent escalation rate over a 20-year planning horizon, the value of that barrel of oil would be about $200. Many analysts believe that price level could not be sustained without a collapse of the industrial world. In fact, most economists predict dire results if the long-term price (10 to 20 years) of oil exceed the $60-a-barrel price limit.

Figure 2.2 shows how the economy has maintained a sense of control below such a limit. It also shows a lower price limit. For example, the average price of oil (1905-1990) has

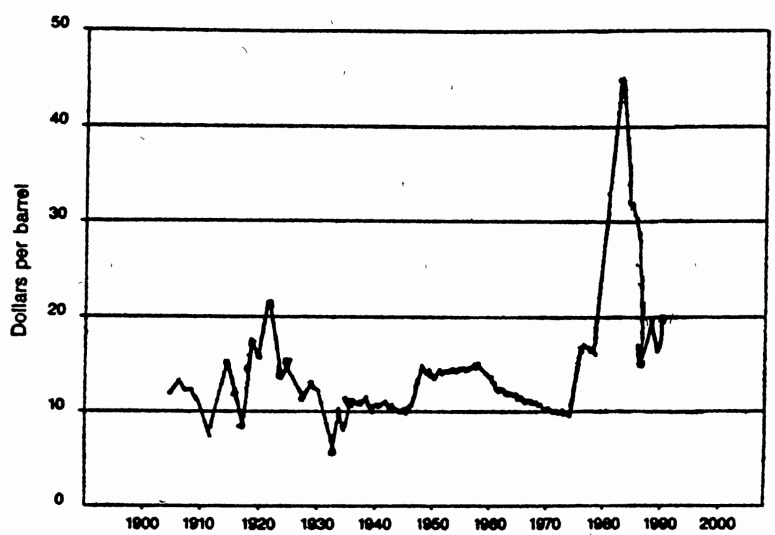


Figure 2.2 Average price for oil in "then" current dollars. Source: Kempski (1991).

roughly ranged from $10 to $40 a barrel ("then" current dollars). In general, real oil prices have been maintained -during the last 10 years- between $10 to $30.

Using the "rule of 72" -the doubling time of an investment is equal to 72 divided by an interest rate- it can be shown that an investment doubles in 5 years at 15% interest by it will double in 14 years at 5% interest. Exact figures are readily available in interest tables. Thus, using reasonable escalation rates (1 to 5 percent), the rule leads, approximately, to a doubling of energy prices within the next 20-year period. Hence, economists assert that escalation rates above the 1 to 5 percent range would be unacceptable by consumers and unbearable by the economy.

In conclusion, taking into consideration (1) the historical variation of energy prices and (2) the limits imposed by growth, Mapp (1990) states that for the next 20 years, the practical and steady maximum real price of oil is around $30 per barrel (1990 prices) and that the practical minimum would be about $12 per barrel (1990 prices).

In most CHP systems, fuel oil and natural gas are the staple fuels. Since natural gas prices historically lag oil prices by about one year, Mapp suggests a long-term ratio of oil to natural gas prices of 5:1. The ratio means that the price per barrel of oil will be about five times the cost of a thousand cubic feet (MCF) of natural gas. A barrel of oil contains 5×10^6 BTUs, while an MCF of natural gas 1×10^6 BTUs. Hence, he implies that in an energy content basis, oil and natural gas will be priced the same in the future. Therefore, the practical long-term limits -i.e. $\$6/10^6$ BTUs and $\$2.4/10^6$ BTUs, in 1990 prices- are valid for both natural gas and oil.

2.2 Cogeneration System Design and Analysis

The combined generation of useful heat and power or cogeneration is not a new concept. The U.S. Department of Energy (1978) reported that in the early 1900s, 58% of the total power produced by on-site industrial plants was cogenerated. However, Polimeros (1981) states that by 1950, on-site CHP generation accounted for only 15 percent of total U.S. electrical generation; and by 1974, this figure had dropped to about 5 percent.

In Europe, the experience has been different. The US-DOE report quoted above informs that "historically, industrial cogeneration has been five to six times more common in some parts of Europe than in the U.S." And that in 1972, for example, "16% of West Germany's total power production was cogenerated by industries; in Italy, 18%; in France, 16%; and in the Netherlands, 10%".

Since the issuance of the Public Utility Regulatory Act (PURPA) in 1978, however, U.S. cogeneration design, operation and marketing activities have significantly increased, and currently receive much attention from industry and academe. With this incentive, several new technologies -such as circulating-bed boilers, packaged cogeneration and combined cycles- have been developed. In 1990, cogenerators produced about 7% of the total power generated in the U.S. This trend is likely to increase since many consider cogneration as a supplementary way of increasing the existing U.S. power generation capacity. Thus, to promote industrial energy efficiency, PURPA obligates electric utilities to purchase cogenerated power at fair rates to both, the utility and the generator. It also orders utilities to provide supplementary and back-up power at non-discriminatory rates.

Below, an overview of current industrial cogeneration technology and design procedures is presented. Section 2.4 discusses further details on U.S. cogeneration legislation.

2.2.1 General Considerations and Definitions

Turner (1982) indicates that although cogeneration should be evaluated as a part of any energy management plan, the main prerequisite is that a plant shows a significant and concurrent demand for heat and power. Once this scenario is identified, he states that cogeneration systems can be explored under the following circumstances:

1. Development of new facilities
2. Major expansions to existing facilities which increase process heat demands and/or process energy rejection
3. When old process and/or power plant equipment is being replaced, offering the opportunity to upgrade the energy supply system.

The following terms and definitions are regularly used in the discussion of CHP systems:

Industrial Plant: the facility requiring process heat and electric and/or shaft power. It can be a process plant, a manufacturing facility, a college campus, etc.

Process Heat (PH): the thermal energy required in the industrial plant. This energy can be supplied as steam, hot water, hot air, etc. In the U. S., it is expressed in BTU/hr.

Process Returns (PR): the fluid returned from the industrial plant to the cogeneration system. For systems where the process heat is supplied as steam, the process returns are condensate.

Net Heat to Process (NHP): the difference between the thermal energy supplied to the industrial plant and the energy returned to the cogeneration system. NHP = PH -PR is the actual heat demand of the plant, which is considered to be a random process.

Plant Power Demand (PPD): the electrical power or load demanded by the industrial plant. It includes the power required in manufacturing processes, air-conditioning, lighting and so on. It is expressed in kW or mW.

Heat/Power Ratio (H/P): the heat-to-power ratio of the industrial plant (demand), or the rated heat-to-power ratio of the cogeneration cycle (capacity).

Topping Cycles: (H/P<3:1) thermal cycles where power is produced prior to the delivery of heat to the industrial plant. One example is the case of heat recovered from a diesel-engine generator to produce steam and hot water. Figure 2.3 shows a diesel engine topping cycle.

Bottoming Cycle: (H/P>5:1) power production from the recovery of heat that would "normally" be rejected to a heat sink. Examples include the generation of power using the heat from various exothermic chemical process and the heat rejected from kilns used in various industries. Figure 2.4 illustrates a bottoming cycle.

Combined Cycle: (H/P<5:1) this is a combination of the two cycles described above. Power is produced in a topping cycle -typically a gas-turbine generator. Then, heat exhausted from the turbine is used to produce steam; which is subsequently expanded in a steam turbine to generate more electric or shaft power. Steam can also be extracted from the cycle to be used as process heat. Figure 2.5 depicts a gas turbine based combined cycle.

Prime Mover: a unit of the CHP system that generates electric or shaft power. Typically, it is a turbine generator or a diesel-engine generator.

Bottoming cycles are generally used in the chemical process industry. In this research, however, we will focus on topping cycles as they are applied to industrial plants that are eligible as "qualifying facilities" by PURPA. That is, systems that have a thermal utilization of more than 5% of the energy input and a minimum overall efficiency of 42.5%.

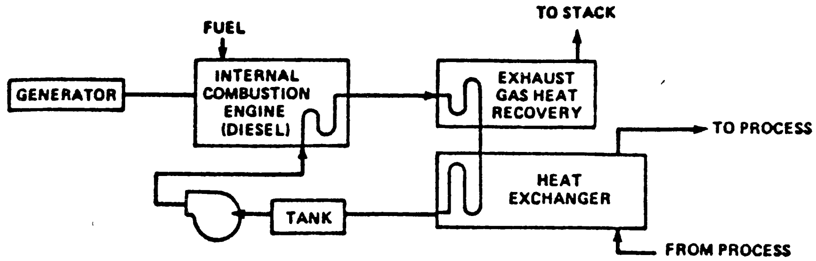


Figure 2.3 Diesel engine topping cycle*

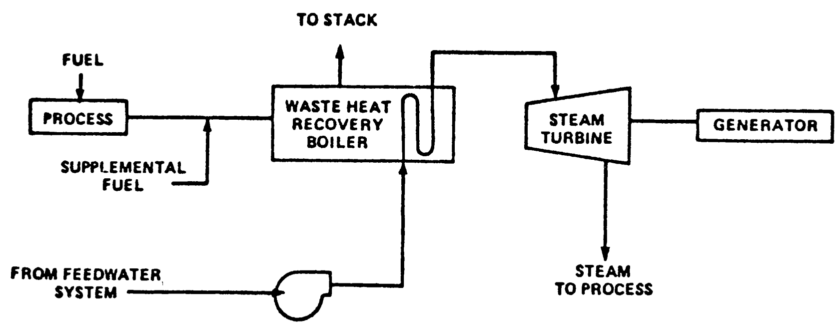


Figure 2.4 Bottoming cycle*

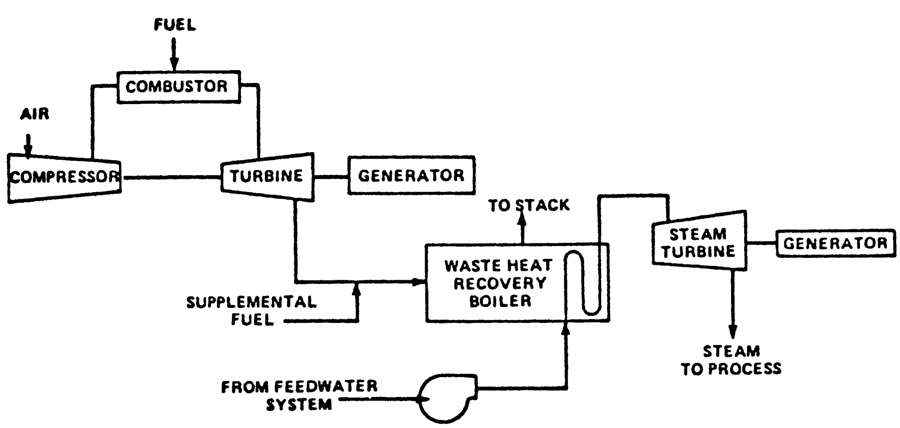


Figure 2.5 Gas turbine combined cycle*

* Source: Butler (1984).

2.2.2 Basic Cogeneration Systems

2.2.2.1 Steam Turbine Systems. Kovacik (1982) recommends that four factors must be examined to assure that the maximum amount of power from a CHP steam plant is economically generated based on the process heat required. These factors are: (1) prime-mover size, (2) initial steam conditions, (3) process pressure levels, and (4) feedwater heating cycle.

> 1. Prime-Mover Type and Size. Process heat and plant electric requirements define the type and size of the steam generator. The type of CHP system and its corresponding prime mover are selected by matching the CHP system heat output to the process heat load. If process heat demands are such that the plant power requirements can be satisfied by cogenerated power, then the size of the prime mover is selected to meet or exceed the "peak" power demand.
>
> However, in the usual case, cogeneration will supply only a portion of the total plant power needs. The balance has to be imported through a utility tie. In isolated plants, the balance is generated by additional conventional units. This discussion assumes that both heat and power demands remain constant all times. Hence, the design problem becomes one of specifying two decision variables: (1) how much power should be cogenerated on-site and (2) how much power should be imported. Thus, given the technological, economical and legal constraints for a particular plant, and assuming the CHP system must be constructed at a minimum overall cost, it becomes a constrained optimization problem.
>
> 2. Initial Steam Conditions. Kovacik indicates that most industrial plants do not have adequate process steam demands to generate all the power required. Thus, it is important for the designer to examine those variables over which he has control so he can optimize the amount of power that can be economically generated.
>
> One set of these variables are the initial pressure and temperature of the steam generated. In general, an increase in initial pressure and/or temperature will increase the amount of energy available for power generation. But the prime mover construction and cost, and the heat demand impose economical limits for the initial steam conditions. Thus, higher initial steam conditions can be economically justified in industrial plants having relatively large process steam demands.

3. <u>Process Steam Pressure.</u> For a given set of initial steam conditions, lowering the exhaust pressure also increases the energy available for power generation However, this pressure is limited -totally, with non-condensing turbines, or partially, with extraction turbines- by the maximum pressure required in the industrial process.

4. <u>Feedwater Heating.</u> Feedwater heating through use of steam exhausted and/or extracted from a turbine increases the power that can be generated.

2.2.2.2 <u>Calculation of Steam Turbine Power</u>. Given the initial steam conditions (psig, ^{o}F) and the exhaust saturated pressure (psig), Theoretical Steam Rates (TSR) specify the amount of steam heat input required to generate a kWH in an ideal turbine. The TSR is defined by

$$\text{TSR(lb/kWh)} = \frac{3412 \text{ BTU/kWH}}{\text{AE BTU/lb}} \qquad (2.3.1)$$

where AE is the difference in enthalpy from the initial steam conditions to the exhaust pressure based on an isentropic (ideal) expansion. These values can be obtained from steam tables or a Mollier chart. However, they are conveniently tabulated by the American Society of Mechanical Engineers.

The TSR can be converted to the Actual Steam Rate (ASR)

$$\text{ASR (lb/kWH)} = \frac{\text{TSR}}{n} \qquad (2.3.2)$$

where n is the turbine-generator overall efficiency, stated or specified at "design" or full-load conditions. Among the many factors that define the overall efficiency of a turbine-genertor set we have: the inlet volume flow, pressure ratio, speed, geometry of turbine staging, throttling losses, friction losses, generator losses and kinetic losses associated to the turbine exhaust. Most turbine manufacturers provide charts specifying either ASR or n values.

Once the ASR has been established, the net enthalpy of the steam supplied to process (NEP) can be calculated:

$$NEP\ (BTU/lb) = Hi - 3500/ASR - Hc - Hm \qquad (2.3.3)$$

where Hi = enthalpy at the turbine inlet conditions (BTU/lb)
3500 = conversion from heat to power (BTU/kWh), including the effect of 2.6% radiation, mechanical and generator losses
Hc = enthalpy of condensate return (BTU/lb)
Hm = enthalpy of make-up water (BTU/lb)

Hence, the net heat to process (BTU/hr) defined in Section 2.2.1 can be obtained by multiplying equation 2.3.3 by the flow rates in lb/hr. The analysis of the overall cycle would require the replication of complete heat and mass balance calculations at part loads efficiencies. To expedite these computations, there are a number of commercial software packages, which also plot flow balance diagrams.

2.2.2.3 Gas Turbine Systems. Gas turbines -using technology originally developed for aircraft engines- have been extensively applied in industrial plants. Two types of gas turbines are utilized in industry: one is the lighter aircraft derivative turbine and the other is the rugged industrial gas turbine. Nelson (1988) points out that the latter are generally larger and designed for longer lives with rigorous maintenance requirements. Hence, industrial turbines may have lower life cycle costs than aircraft derivatives in heavy duty applications.

Since gas turbines can burn a variety of liquid and gas fuels and run long times unattended, they are considered to be versatile and reliable. For a fixed capacity, they have the smallest relative foot-print (sq-ft per kW).

2.2.2.4 Gas Turbine Based CHP Systems. Exhaust gases from gas turbines (from 600 to 1200 ^oF) offer a large heat recovery potential. The exhaust has been used directly, as in drying processes. Topping cycles have also been developed by using the exhaust gases to generate process steam in heat recovery steam generators (HRSG's). Where larger power loads exist, high pressure steam is generated to be subsequently expanded in a steam turbine-generator; this constitutes the so called combined cycle.

If the demand for steam and/or power is even higher, the exhaust gases are used (1) as preheated combustion air of a combustion process or (2) are additionally fired by a "duct burner" to increase their heat content and temperature. All these options present a greater degree of CHP generation flexibility, allowing a gas turbine system to match a wider variety of heat-to-power demand ratios.

2.2.2.5 Gas Turbine Ratings and Performance. There is a wide range of gas turbine sizes and drives. Available turbines have ratings that vary in discrete sizes from 50 kW to 100,000 kW. Consequently, when selecting a CHP unit, the actual turbine-generator size does not necessarily match the "optimal" size required for a given plant. In addition, the output of gas turbines depends on the inlet air temperature.

Kovacik (1982) and Nelson (1988) list the following gas turbine data required for design and off-design conditions:

1. Unit Fuel Consumption-Output Characteristics. These data depends in the unit design and manufacturer. The actual specific fuel consumption or efficiency and output also depend on (a) ambient temperature, (b) pressure ratio and (c) part-load operation. Vendors usually provide this kind of information in the form of charts for "off-design" performance characteristics.

2. Exhaust Flow Temperature. This data item allows the development of the exhaust heat recovery system. The most common recovery system are HRSG's which are classified as unfired, supplementary fired and fired units.

   The amount of steam that can be generated in an unfired or supplementary fired HRSG can be estimated by the following relationship:

$$W_s = \frac{W_g\ C_p\ (T_1 - T_3)\ e\ L\ f}{h_{sh} - h_{sat}} \qquad (2.3.4)$$

   where W_s = steam flow rate
   W_g = exhaust flow rate to HRSG
   C_p = specific heat of products of combustion
   T_1 = gas temperature -after burner, if applicable
   T_3 = saturation temperature in steam drum
   L = radiation and other losses, 0.985
   h_{sh} = enthalpy of steam leaving superheater
   h_{sat} = saturated liquid enthalpy in the steam drum
   e = HRSG effectiveness, defined by Fig. 2.6
   f = fuel factor, 1.0 for fuel oil, 1.15 for gas.

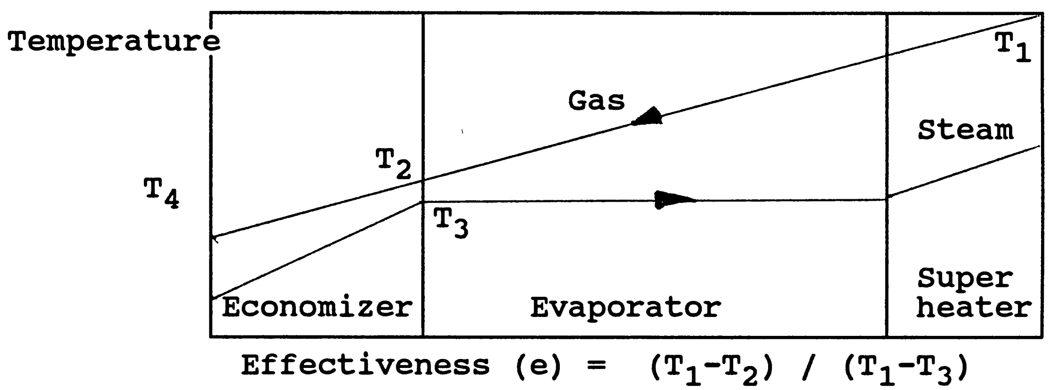


Figure 2.6 Heat recovery steam generator effectiveness

3. Parametric Studies for Off-design Conditions. Varying the amount of supplementary firing will change the HRSG steam output of the model shown in Fig. 2.6. Thus, with varying temperatures, several iterations of equation 2.3.4 are required to evaluate off-design or part load conditions. When the analysis is carried over a range of loads, firing rates, and temperatures, it is called a parametric study.

4. Exhaust Pressure Effects on Output and Exhaust Temperature. Heat recovery systems increase the exhaust back-pressure, reducing the turbine output in relation to simple operation (without HRSG). Turbine manufacturers provide test data about back-pressure effects in turbine output and efficiency.

2.2.2.6 Reciprocating Engine Systems. Reciprocating engines include a variety of internally fired, piston driven engines. Their sizes range from 10 bhp to 50,000 bhp. According to Kovacik (1982), the largest unit supplied by a U.S. manufacturer is rated at 13,500 bhp. In larger plants, several units are used to accommodate part load and to provide redundancy and better availability.

In these engines, combustion heat rejected through the jacket water, lube oil and exhaust gases, can be recovered through heat exchangers to generate hot water and/or steam. Exhaust gases have also been used directly. For instance, Wong (1985) discusses a way to mix diesel-engine exhaust gases with ambient air to dry paddy rice. Reciprocating engines are classified by:

- the thermodynamic cycle: Diesel or Otto cycle.
- the rotation speed: high-speed (1200-1800 rpm)
medium-speed (500-900 rpm)
low speed (450 rpm or less)
- the type of aspiration: naturally aspirated
turbocharged or
supercharged
- the operating cycle: two-cycle or
four-cycle
- the fuel burned: fuel-oil fired or
natural-gas fired.

Reciprocating engines are widely used to move vehicles, generators and a variety of shaft loads. Larger engines are associated with lower speeds, increased torque, and heavier duties. The total heat utilization of CHP systems based on gas-fired or fuel-oil fired engines approach 60-75%. Thus, reciprocating engines have a better part-load efficiency than simple gas turbines of comparable size. Figure 2.7 shows the CHP balance vs. load of a typical diesel engine.

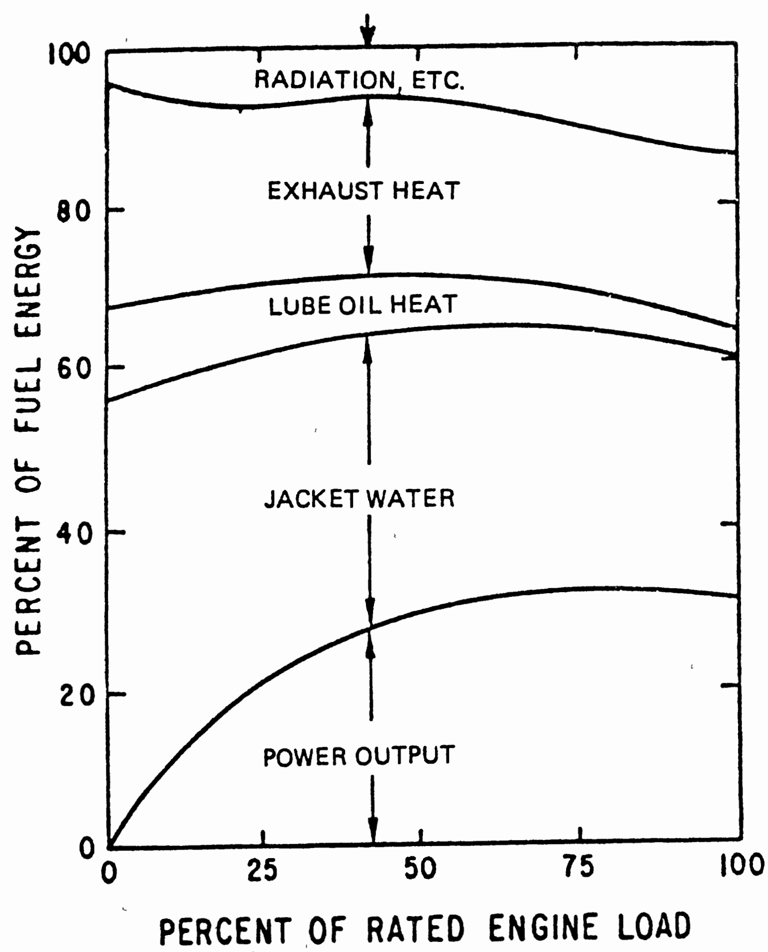


Figure 2.7 Diesel engine heat and power balance

2.2.3 Cogeneration Design Criteria

Polimeros (1981) discusses (1) a series of steps to estimate CHP demand requirements and (2) the design rationale for central heating-and-cooling cogeneration plant and its advantages. These two topics are summarized below.

2.2.3.1 CHP Demand Estimation. Demand estimates can be obtained by using the following methods:

- The Heating degree-day method
- Combined method degree-day and heat loss calculation
- The Bin method
- The cooling degree-day method
- The equivalent full load hour (EFLH) method
- The prediction of peak demand
    - demand factor method
    - radiation factor method
- Factors affecting heating consumption and demand
- Factors affecting cooling consumption demand
- Load calculation programs
- Facility simulation programs

2.2.3.2 Central Plant Design Rationale. Sizing the equipment for the "concurrent" peak heat-and-power loads and not for the sum of the maximum of individual and dispersed loads has the following advantages.

Advantages from the capital investment standpoint:

- Lower initial cost than decentralized units.
- When the CHP system is owned by a third party, there is no capital investment by the user.
- More usable or rentable space becomes available.
- Less mechanical equipment space is needed.
- Lower development cost than several dispersed plants.
- Take advantage of load diversity, i.e. the total capacity of a central plant is invariably less than the sum of multiple, smaller dispersed plants.

Advantages from the operation standpoint:

- Plant efficiency is maximized at partial load.

- Labor costs are minimized due to easier supervision, and centralized scheduling and maintenance.
- Fuel savings are possible due to the negotiation for more advantageous rates with fuel dealers, i.e. bulk rates and competitive buying.
- Central maintenance has the advantages of closely located repair shops, more effective preventive and predictive maintenance and lower parts inventory.
- Refinements in design, construction and controls are possible for central CHP plants.

The following specific evaluation steps are suggested by Kovacik (1982) to carry out a cogeneration system design.

1. Develop the profile of the various process steam (heat) demands at the appropriate steam pressures for the applications being studied. Also, collect data with regard to condensate returned from the process and its temperature. Data must include daily fluctuations due to normal variations in process needs, as well as seasonal weather effects; including the influence of not-working periods such as weekends, vacation periods, and holidays.
2. A profile for electric power must be developed in the same manner as the process heat demand profile. These profiles typically include hour-by-hour heat and power demands for "typical" days (or weeks) for each season or month of the year.
3. Fuel availability and present-day cost as well as projected future costs. The study should also factor process by-product fuels into the development of the energy supply system.
4. Purchased power availability and its present and expected future cost.
5. Plant discharge stream data in the same degree of detail as the process heat demand data.
6. Number and rating of major (demand and generation) equipment items. This evaluation usually establish whether spare capacity and/or supplementary firing should be installed.
7. Plant, process and CHP system economic lifes.

Kovacik points out that once this initial data bank has been established, the various alternatives that can satisfy plant heat and power demands can be identified. Furthermore, energy balances can be made, investment cost estimated, and the economic merit of each alternative evaluated.

Nelson (1988) presents a more structured approach for CHP system design and evaluation. It is based in a sequence of evaluation iterations, each greater than the previous and each producing information whether the costs of the next step is warranted. His suggested design process is based on the following steps.

Step 1: Site Walkthrough and Technical Screening

Step 2: Preliminary Economic Screening

Step 3: Detailed Engineering Design.

Similarly, Butler (1984) considers three steps to perform studies, engineering and construction of cogeneration projects. These are discussed as follow.

> Step 1. Preliminary studies and conceptual engineering. He states that this is achieved by performing a technical feasibility and economic cost-benefit study to rank and recommend alternatives. The determination of technical feasibility includes a realistic assessment with respect to environmental impact, regulatory compliance, and interface with a utility. Then, an economic analysis -based on the simple payback period- serves as a basis for more refined evaluations.
>
> Step 2. Engineering and Construction Planning. Once an alternative has been selected and approved by the owner, preliminary engineering is started to develop the general design criteria. These include specific site information such as process heat and power requirements, fuel availability and pricing, system type definition, modes of operation, system interface, review of alternatives under more detailed load and equipment data, confirm selected alternative and finally size the plant equipment and systems to match the application.
>
> Step 3. Design Documentation. This includes the preparation of project flow charts, piping and instrument diagrams, equipment layouts, process interface layouts, building and structural drawings, foundation drawings, electrical diagrams, and specifying an energy management system, if necessary.

This research is specifically concerned with the last engineering task of Step 2, i.e. the economic sizing of the equipment to match the application. The research intends to extend the state of the art to the those design cases that involve sizing CHP systems subject to variable loads.

In regard to Step 1 -as discussed by Nelson and Butler above- more detailed methods for cogeneration feasibility analysis have been developed by GKCO Consultants (1982). Also, preliminary "screening" methods have been developed at Texas A&M University by and Somasundaram et al. (1988). and Canton et al. (1987).

GKCO Consultants (1982) have developed a "Cogeneration Feasibility Analysis Manual" for the American Gas Association (AGA). The Manual is composed of three major sections:

1. <u>An introduction</u> which includes: "A brief summary of the concepts of cogeneration, the concepts of cogeneration, including a listing of owner benefits, a description of typical facilities where cogeneration is viable, a listing of existing facilities, and an overview of the process by which a specific site is examined"

2. <u>Cogeneration Feasibility Analysis Procedure-</u> It describes the procedure and necessary background data. It includes the following sections:

- How to analyze a Potential Site- describes the analytic procedure and discusses general input requirements and technique limitations.
- How are Economics Measured?- discusses measures of economic value used in the procedure.

- Supporting Data and Data Sources- lists the information required in the study and identifies sources of information; including site data, utility data, equipment cost and performance data, and plant/system design data.

- A Cogeneration Conceptual Design Guide- provides guidelines for the development of plant designs. It specifies the following steps to conduct the site feasibility study:

  a) Select the type of prime mover or cycle (piston engine, gas turbine or steam turbine);

  b) Determine the total installed capacity;

  c) Determine the size and number of prime movers;

d) Determine the required standby capacity.

According to the authors "the approach taken (in the manual) is to develop the minimal amount of information required for the feasibility analysis, deferring more rigorous and comprehensive analyses to the actual concept study".

This section includes the discussion of the following "Design Options" or design criteria to determine (1) the size and (2) the operation mode of the CHP system.

* Isolated Operation, Electric Load Following- The facility is independent of the electric utility grid, and is required to produce all power required on-site and to provide all required reserves for scheduled and unscheduled maintenance.

* Baseloaded, Electrically Sized- The facility is sized for baseloaded operation based on the minimum historic billing demand. Supplemental power is purchased from the utility grid. This facility concept generally results in a shorter payback period than that from the isolated site.

* Baseloaded, Thermally Sized- The facility is sized to provide most of the site's required thermal energy using recovered heat. The engines operated to follow the thermal demand with supplemental boiler fired as required. The authors point out that: "this option frequently results in the production of more power than is required on-site and this power is sold to the electric utility."

3. Cogeneration Data: Sources and Procedures - A description of sources of information or processes by which background data can be developed for the specific gas distribution service area. The section provides the information or process description to adapt the screening procedures to a specific utility.

2.2.3.3 Comments on the "Design Options" Suggested by the AGA Manual. The authors of the manual outlined above admit that "the number of available design options (in cogeneration) are limited only by the ingenuity of the engineer". However, they propose the three options described above because they "will allow the owner to asses the range of returns available from a cogeneration system". In regard to their design approach we have the following comments.

Since "a range of returns" is possible for different CHP system sizes and operation modes, they recognize that the "best" cogeneration system is not necessarily represented by one of the options stated above. In fact, the three options constitute criteria for sizing the installed capacity; using rules of thumb that are valid only in certain conditions.

Thus, in the case of electrically isolated site, they state that "the total installed capacity will be the derived from a detailed electrical load analysis in which the maximum loading conditions for the plant are defined". They suggest that, "for a typical site, with no special loads", the capacity can be obtained from historic billing data and an inventory of site motors. For a larger site, above 500 kW, the required capacity is (1) the sum of the maximum historic billing demand plus the starting requirements of the larges motor. For smaller sites, or for sites where the largest motor size is significant in comparison to the billing demand, the installed capacity should be (2) 150% of the historic maximum billing demand. They say that the actual capacity should be the smaller of these two values. In this case, for technical, economical, or legal reasons, the CHP system must be operated in isolation from the grid. After PURPA, however, we consider this to be a rare case in the U.S. Few CHP-system owners would operate without a firm utility back-up and/or without the benefit of some power exports.

GKCO Consultants state that the CHP system may be sized to produce a fraction of the required power on-site, i.e. electrically base-loaded. Then, the engine is sized at "minimum billing demand" and operated at a relatively high annual load factor or about 0.7. In this case, the generators are operated in synchronization with the utility grid and additional electrical interface equipment is installed. It is assumed that some power may be purchased from the utility, but sales of power to the grid are not allowed. Here, they explicitly associate a load factor -i.e. the average demand expressed as 70% of the annual peak demand- with the size of the CHP plant. This "option" presents two severe limitations: (1) It assumes that by sizing the cogeneration power capacity according to the "minimum annual billing demand" will warrant a load factor of 0.7 (or higher). In fact, the procedure assumes a "typical" load curve with mean demand equal to 70% of the annual peak demand. But, this load curve does not necessarily represent all possible cases. (2) It assumes that it is not technically (or legally) feasible to export power to the grid; or that power exports are not economically attractive at all. These assumptions make this option representative of a rather limited scenario, which may not be the case under scrutiny. Consequently, the electrically baseloaded plant will not warrant a "least total cost" or "most profitable" alternative.

According to the AGA manual, when the plant is thermally baseloaded, it is sized to track the site's thermal needs with recovered heat. Here, the authors assume that "the installed thermal capacity of the prime mover will be the 50% of the required peak demand capacity and that two-thirds of the site thermal requirements would be satisfied by recovering heat". The balance will be provided by a peaking boiler or supplementary firing. They suggest, however, to use daily load profile data -if available. Here, they present a rather vague design criterion. In this case, when no load data exist, a "typical" load curve (2/3 of the heat is used below 50% of the peak load). However, this criterion does not warrant a constant heat demand on the CHP system, nor qualifies the system as the most cost effective alternative.

In conclusion, if one considers that the best system is the one that minimizes the total system cost or maximizes the operating profit, then the three options do not necessarily include the "best" system. On the contrary, one of the three options may be optimal in a few cases. One way to determine that one of the three options could be the optimal one is to prove that they indeed constitute extreme points of the CHP feasible space. Otherwise the target or optimal capacity point may lay elsewhere on the CHP sub-plane. This target CHP capacity may or may not be represented by commercially available equipment. Thus, the actual -and feasible- optimal CHP system capacity would be a point -possibly close to the target CHP point- represented by a commercially available cogeneration plant. In addition, the actual optimal CHP system would meet the technical, economical, and regulatory constraints imposed on the underlying industrial facility.

2.2.3.4 Comments on the Approach by Somusandaram et al. The procedure by Somasundaram et al. (1988) is titled "A Simplified Self-Help Approach to Sizing of Small-Scale Cogeneration Systems." It is a workbook "compiled for use by the energy managers/physical plant directors of various Texas state agencies so that an initial screening of the potential candidates for cogeneration can be made." Thus, it has basically the same audience and scope than the AGA manual. The authors summarize their methodology as follows:

> "The procedure used in the study is extremely simple, and certain optimistic assumptions have been made to facilitate the approach. An approximate feasibility of a cogeneration system will be determined simply from the available billing data for electricity and natural gas use at the state agency. If the decision for a system is deemed to be "GO" or "POSSIBLE" on the basis of the initial screening, then the state agency/building complex will be considered a prime candidate for a more detailed feasibility analysis."

The approach discussed above has many drawbacks, even for a preliminary analysis. Thus, they recommend that "having determined the average thermal load, the prime mover (engine) selection can be made either on the basis of its rated electrical or thermal output." But the primary method used in their analysis -to define the size of the prime mover- is "the average monthly electrical demand (kW) determined form the past year's utility bill". The major problem with the whole approach is that it is based on average parameters. That is, average electrical prices, average gas prices, average electrical demand and average thermal loads. The only situation in which this approach may be valid is when the coefficient of variation of the CHP demands (the ratio of the standard deviation to the mean value) is insignificant or the signal to noise (SNR) ratio is very large. In other words, when the loads are "fairly constant" throughout the year. In all other cases, the variation or "load diversity" can present serious complications to the method. For example, two different facilities may have similar mean loads, thus similar results are obtained from the analysis. The facilities may, however, have very different CHP load variances. Then, one problem not accounted for in the "average" approach is that a facility with larger peak electrical loads will incur in larger -and possibly ratcheting- demand penalties. Another problem is that the larger the CHP load variation, the longer the time the CHP system may run under part-load conditions. Partial loads, in turn, affect the efficiency of the system. Consequently, even though the CHP systems run under the same average load, the may have a very different heat ratio (cycle efficiency) and economic performance.

An important problem should be identified at this point, i.e. larger load variances imply the accumulation of a series of penalties to departures from the "mean" load value or "rated" system capacity. Hence, the fact that, in general, the CHP problem involves stochastic demands and capacities, clearly states the need for a methodology that can overcome the limitations of the methods discussed above. The following approach, also developed at Texas A&M, makes an attempt to consider load variation in the selection of CHP systems.

Canton et al. (1987) have developed a set of seminar notes on cogeneration systems for the Energy Management, Combustion and Fuels Research Groups at Texas A&M. The notes include a series of graphs, which can be used as an aid in cogeneration system selection. The principal graphs are:

Graph 1. Determination of Heat/Power Ratio. The heat/power ratio is the ordinate and the process heat demand is the abscissa. A family of lines with the same slope represent different electrical demands.

Graph 2. Thermal and Power Needs of the Underlying Plant. The power demand is the ordinate and the process heat demand is the abscissa. A family of lines depict different heat/power ratios or slopes.

Graph 3. Selection of Cogeneration System to Match Power Needs (same coordinates that graph 2). The candidate CHP system is represented by a straight line that passes through the origin and defines the system heat/power ratio or slope. The power demand is always met, but two possible cases are shown (1) there is excess heating capacity and (2) there is heating deficit.

Graph 4. Selection of Cogeneration System to Match Heating Needs (same coordinates that graph 2). The candidate CHP system is represented by a straight line that passes through the origin and defines the system heat/power ratio or slope. The process heat demand is always met, but two possible cases are shown: (1) there is excess power capacity and (2) there is power capacity deficit.

The systems modeled by Graphs 3 and 4 may be operated under the following situations:

1. Match power, heat deficit results: use auxiliary firing
2. Match power, excess heat results: reject excess heat
3. Match heat, excess power results: sell excess power
4. Match heat, power deficit results: buy remaining power.

The four operating cases require that the CHP system be sized to meet or exceed the "maximum" power demand -in cases 1 and 2- and the "maximum" heat demand- in cases 3 and 4. These cases restrict the design problem to the situations in which the CHP system must be sized to meet or exceed the power or heat load. Unless it is proven that these operating conditions -which may lead to system oversizing- are truly optimal, as compared with smaller CHP systems, it can not be said that they represent the most cost effective options.

These four operating modes, however, can still be utilized with systems that are not sized to meet or exceed the peak demands. Thus, instead of "matching" the power or heat demand, the cogeneration system may "track or follow" the heat or power load -as long as the demand does not exceed the thermal or power capacity. When capacities are exceeded, power or heat is obtained from the utility or auxiliary equipment, respectively. Consequently, besides determining the size of the prime mover, the problem becomes one of defining its tracking mode. That is, the system might be sized to track power (with some utility imports) or might be sized to track heat (with possible auxiliary firing). In the most general case, the CHP system may allow power exports in times of low power demand.

The following modulation and control methods allow the dynamic operation-tracking of power load or heating load.

POWER MODULATION: Power demand tracking

1. Part Load Operation (excess power modulation)
2. Multiple Prime Movers (excess power modulation)
3. Utility Interconnect (power export/import)
4. Heat Storage (e.g. chilled water tanks)

HEAT MODULATION: Heating load tracking

1. Supplementary Boiler Fuel (heat deficit)
2. Heat Dumping (excess heat modulation)
3. Heat Storage (e.g., hot water tanks)

The graphs described above constitute a first step in recognizing the variable nature of CHP demands and the need for modulation in system operation. Thus, their approach to size a cogeneration system involves matching or exceeding one of the loads (heat or power), while the other load is met by "modulating" or adjusting the system capacity with the control methods outlined above. In this approach, there is an implicit intent of sizing the system to "always" meet one of the load (heat or power) while the other one "floats" or is satisfied with auxiliary equipment. In the "tracking" approach, however, it is recognized that "matching or exceeding" a load all the time is not necessarily the most cost effective criterion to determine the size of the system, and that the "optimal" CHP system type and size is a point located elsewhere in the feasible space of the CHP plane.

2.2.4 Computer Programs for Cogeneration Design and Evaluation

There are several computer programs available for detailed evaluation of cogeneration systems. In opposition to the rather simple methods discussed above, CHP programs are intended for system configuration or detailed design. For these reasons, they require a vast amount of input data. Below, we examine two of the most well known programs.

2.2.4.1 CELCAP. Lee (1988) reports that the Naval Civil Engineering Laboratory developed a cogeneration analysis computer program known as Civil Engineering Laboratory Cogeneration Program (CELCAP), "for the purpose of evaluating the performance of cogeneration systems on a life-cycle operating cost basis. He states that "selection of a cogeneration energy system for a specific application is a complex task." He points out that the first step in the selection of cogeneration system is to make a list of potential candidates. These candidates should include single or multiple combinations of the various types of engine available. This "search and match" procedure is a rather empiric process. The computer program does not specify CHP systems; these must be selected by the designer. Thus, depending on the training and previous experience of the designer, different designers may select different systems of different sizes.

After selecting a short-list of candidates, modes of operations are defined for the candidates. So, if there are N candidates and M modes of operation, then NxM alternatives must be evaluated. Lee considers three modes of operation:

1) Prime movers operating at their full-rated capacity, any excess electricity is sold to the utility and any excess heat is rejected to the environment. Any electricity shortage is made up with electricity imports form the utility. Process heat shortages are made-up by an auxiliary boiler.

2) Prime movers are specified to always meet the entire electrical load of the user. Steam or heat demand is met by the prime mover. But if there is a heat deficit, an auxiliary boiler is fired. Any excess heat is rejected to the environment.

3) Prime movers are operated to just meet the steam or heat load. In this mode, power deficits are made up by purchased electricity. Similarly, any excess power is sold back to the utility.

For load analysis, Lee considers that "demand of the user is continuously changing. This requires that data on the electrical and thermal demands of the user be available for at least one year". He further states that "electrical and heat demands of a user vary during the year because of the changing working and weather conditions." However, for evaluation purposes, he assumes that the working conditions of the user -production related CHP load- remain constant and "that the energy-demand pattern does not change significantly from year to year". Thus, to consider working condition variations, Lee classifies the days of the year as working and non-working days. Then, he uses "average" monthly load profiles and "typical" 24-hour load profiles for each class.

"Average" load profiles are based on electric and steam consumption for an average weather condition at the site. A load profile is developed for each month, thus monthly weather and consumption data is required. A best fit of consumption (BTU/month or kWh/month) versus heating and cooling degree days is obtained. Then, actual hourly load profiles for working and non-working days for each month of the year are developed. The "best representative" profile is then chosen for the "typical working day" of the month. A similar procedure is done for the non-working days of the month.

Next an energy balance or reconciliation is performed to make sure the consumption of the hourly load profiles agrees with the monthly energy usage. A multiplying factor K is defined to adjust load profiles that do not balance.

$$K_j = E_{mj} / (AE_{wj} + AE_{nwj})$$

where K_j = multiplying factor for month j
E_{mj} = average consumption (kWH) by the user for the month j selected from the monthly electricity usage versus degree day plot
AE_{wj} = typical working-day electric usage (kWH), i.e. the area under the typical working day electric demand profile for the month j
AE_{nwj} = typical non-working day usage (kWH), i.e. the area under the typical non-working day electric demand profile for the month j.

Lee suggest that each hourly load in the load profiles be multiplied by the K factor to obtain the "correct working and non-working-day load profiles for the month". Thus, the procedure is repeated for all months of the year for both electric and steam demands. Lee states that "the resulting load profiles represent the load demand for average weather conditions".

Once a number of candidate CHP systems has been selected, equipment performance data and the load profiles are feed into CELCAP to produce the required output. The output can be obtained in a brief or detailed form. In brief form, the output consists on a summary of input data and a life cycle cost analysis including fuel, operation and maintenance and purchased power costs. The detailed printout includes all the information of the brief printout, plus hourly performance data for 2 days in each month of the year. It also includes the maximum hourly CHP output and fuel consumption. The hourly electric demand and supply are plotted, along with the hourly steam demand and supply for each month of the year.

Despite the simplifying assumptions introduced by Lee to generate average monthly and typical daily load profiles, it is evident that still a large amount of data handling and preparation is required before CELCAP is run. By recognizing the fact that CHP loads vary over time, he implicitly justifies the amount of effort in representing the input data through hourly profiles for typical working and non-working days of the month. In our view, this is just a "microscopic" way to simulate the detailed operation of candidate systems.

However, there are some disadvantages with this approach. First, heat and electric load data for each typical working and non-working day of each month must be obtained or estimated. If for a given plant, hour-by-hour records exist for a year, a total of 17,520 load readings (2 x 8,760 hr/yr) should be converted to 1,152 data items. This constitutes a cumbersome and time consuming task, especially in the case of facilities with complex demand patterns. It is not objective, since it is based on the visual inspection of hourly load profiles to obtain a "typical" profile.

If a change occurs in the products, process or equipment that constitute the energy consumers within the industrial plant, a new set of load profiles must be generated. Thus, exploring different conditions, sensitivity analyses or parametric studies become very time consuming.

A problem that becomes evident at this point is that, to accurately represent varying loads, a large number of load data points must be estimated, handled and stored for subsequent use in a computer program like CELCAP. Conversely, the preliminary feasibility evaluation methods discussed previously, require very few and only "average" load data. Criticism of preliminary methods has arisen for not being able to truly reflect seasonality variations in load analysis (and economic analysis) and for lacking the flexibility to represent varying CHP system performance at varying loads.

2.2.4.2 COGENMASTER. Limaye and Balakrishnan (1989) of Synergic Resources Corporation have developed COGENMASTER. It is a computer program to model the technical aspects of various cogeneration options, evaluate economic feasibility, and prepare detailed cash flow statements.

According to the authors, COGENMASTER compares the CHP alternatives to a base case system where electricity is purchased from the utility and thermal energy is generated at the site. They extend the concept of an option by referring to different technologies and operating strategies, and also to different ownership structures and financing arrangements. The program has two main sections: a Technology and a Financial Section. The Technology Section includes 5 modules:

* Technology Database Module
* Rates Module
* Load Module
* Sizing Module
* Operating Module

The Financial Section includes 3 modules:

* Financing Module
* Cash Flow Module
* Pricing Module

In COGENMASTER, facility electric and thermal loads may be entered in one of three ways, depending on the available data and the detailed required for project valuation;

* A constant average load for every hour of the year.
* Hourly data for three typical days of the year
* Hourly data for three typical days of each month

Thermal loads may be in the form of hot water or steam; but system outlet conditions must be specified by the user.

The authors point out that the sizing and operating modules permit a variety of alternatives and combinations to be considered. The system may be sized for the base or peak, summer or winter, and electric or thermal load. There is also an option for the user to define the size the system in kilowatts. Once the system size is defined, several operation modes may be selected. The system may be operated in the electric following, thermal following or constantly running modes of operation. Thus, N sizing options and M operations modes define a total of NxM cogeneration alternatives, from which the "best" alternative must be selected. The economic analysis is based on simple payback estimates for the CHP candidates versus a base case or do-nothing scenario. Next, depending on the financing options available, different cash flows may be defined and further economic analysis -based on the Net Present Value of the alternatives- may be performed.

However, since the NxM options include only a limited set of pre-selected candidates, the true optimal CHP system may or may not be included in this set. Therefore, an optimal solution is not warranted through this procedure. In other words, the COGENMASTER economic analysis is performed after a set of units sizes and operation modes have been selected. Thus, in this program, economics plays no direct role in the sizing (or pre-selection) of alternative CHP systems; and economic evaluation is a posterior analysis.

As an alternative, this research proposes to develop a method that defines an economically selected target for the CHP system size; recognizing, a-priori, the variation of loads and capacities, and the impact of system availability. The basic thesis being that, to size a CHP system not only certain relevant sizing options must be evaluated, but the stochastic nature of the loads and capacities and system availability must be jointly included in the evaluation.

Specifically, the research proposes the development of a methodology to economically size a CHP system. Hence, the methodology should include a set of models that explicitly represent the stochastic loads and capacities of an industrial cogeneration system (interconnected with a utility) in conjunction with their relevant cost parameters. Probability theory provides the capability of establishing an innovative design method by maintaining a level of simplicity and cost-effectiveness without sacrificing load/system detail. For instance, instead of handling and processing lengthy "hour-by-hour" load profiles (the input data to a set of pre-selected candidate models), load data can be compressed and evaluated, without loss of information, in the form of load probability distributions as represented by estimates of its statistical parameters.

2.3 U.S. Cogeneration Legislation

In 1978 the U.S. Congress amended the Federal Power Act resulting in the promulgation of the Public Utility Regulatory Policies Act (PURPA). The Act recognized the energy saving potential of cogeneration and small power production, the need for real and positive incentives for development of these facilities and the private sector requirement to remain unregulated. PURPA has eliminated several institutional obstacles to cogeneration. As a result, cogenerators can now count on a more fair treatment by the local electric utility with regard to iterconnection, back-up power supplies, and the sale of excess power.

PURPA of 1978 contains the major federal initiatives regarding cogeneration and small power production. These initiatives are stated as rules and regulations pertaining to PURPA Sections 210 and 201; which were issued in final form in February and March of 1980, respectively. These rules and regulations are discussed in the following sections.

Initially, several utilities -especially those with excess capacity- were reticent to buy cogenerated power and have, in the past, contested PURPA. Power (1980) magazine reported several cases in which opposition persisted in some utilities to private cogeneration. But after the Supreme Court ruling in favor of PURPA, more and more utilities are finding that PURPA can work to their advantage. Polsky and Landry (1987) report that some utilities are changing attitudes and are even investing in cogeneration projects.

2.3.1 PURPA 201*

Section 201 of PURPA requires the Federal Energy Regulatory Commission (FERC) to define the criteria and procedures by which small power producers (SPP's) and cogeneration facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in Section 210 of PURPA, which is discussed later. Some PURPA 201 definitions are stated below.

2.3.1.1 Small Power Production Facility. A "Small Power Production Facility" is a facility that uses biomass, waste, or renewable resources, including wind, solar and water, to produce electric power and is not greater than 80 megawatts.

Facilities less than 30 MW are exempt from the Public Utility Holding Co. Act and certain state law and regulation. Facilities of 30 to 80 MW which use biomass, may be exempted from the above but may not be exempted from certain sections of the Federal Power Act.

2.3.1.2 Cogeneration Facility. A "Cogeneration Facility" is a facility which produces electric energy and at least one form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes, through the sequential use of energy. A Qualifying Facility (QF) must meet certain minimum efficiency standards as described later. Cogeneration facilities are generally classified a "topping" cycle or "bottoming" cycle facilities.

* Most of the following sections have been adapted from CFR-18 (1990) and Harkins (1980), unless quoted otherwise.

2.3.2 Cogeneration Facility and Small Power Production Facility

2.3.2.1 Cogeneration Facilities. To distinguish new cogeneration facilities which will achieve meaningful energy conservation from those which would be "token" facilities producing trivial amounts of either useful heat or power, the FERC rules establish efficiency standards for both topping-cycle and bottoming-cycle NEW cogeneration facilities. No efficiency standards are required for EXISTING cogeneration facilities regardless of energy source or type of facility.

For a new topping-cycle facility:

- No less than 5% of the total annual energy output of the facility must be useful thermal energy.
- For any new topping-cycle facility that uses any natural gas or oil :
  - All the useful electric power and half the useful thermal energy must equal at least 42.5% of the total natural gas and oil energy input to the facility for the calendar year; and
  - If the useful thermal output of a facility is less than 15% of the total energy output of the facility, the useful power output plus one-half the useful thermal energy output must be no less than 45% of the total energy input of natural gas and oil for the calendar.

For a new bottoming-cycle facility:

- If supplementary firing (heating of water or steam before entering the electricity generation cycle from the thermal energy cycle) is done with oil or gas, the useful power output of the bottoming cycle must, during any calendar year, be no less than 45% of the energy input of natural gas and oil for supplementary firing.

2.3.2.2 Small Power Production Facilities. To qualify as a small power production (SPP) facility under PURPA, the underlying facility must have a rated power production capacity of under 80 MW and must get more than 50 per cent of its total energy input from biomass, waste, or renewable resources. Also, use of oil, coal, or natural gas by the facility may not exceed 25% of total annual energy input to the facility.

Ownership rule applying to Cogeneration and Small Power Producers A qualifying facility may not have more than 50% of the equal interest in the facility held by an electric utility.

2.3.3 Procedures for Obtaining Qualifying Status

If a facility meets the qualifying criteria summarized here, its owner can choose one of two procedures for obtaining qualifying status. The owner can either; 1) furnish notice to FERC that it is a qualifying facility and provide specific information on the facility's location, fuel use, characteristics, and ownership; or, 2) apply for FERC certification as a qualifying cogeneration or small power production facility.

If applying for FERC certification, there are some additional application requirements specified for both cogenerators and small power production facilities. The application includes information on plant location, fuels and characteristics. Any application for certification must be processed by FERC and an order issued within 90 days or else the applying facility is automatically certified.

The regulations require cogeneration and small power production facilities of over 500 kW design capacity to notify the electric utility that it is a qualifying facility.

The utility does not have to purchase electric energy from qualifying facilities prior to 90 days after it has been notified by the qualifying facility or else 90 days after the qualifying facility has applied to FERC for certification.

2.3.4 PURPA 210

Section 210 of PURPA directs the Federal Energy Regulatory Commission (FERC) to establish the rules and regulations requiring electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities and provide for the exemption to qualifying facilities (QF) from certain federal and state regulations.

Thus, FERC issued in 1980 a series of rules to relax obstacles to cogeneration. Such rules implement sections of the 1978 PURPA and include detailed instructions to state utility commissions that all utilities must purchase electricity from cogenerators and small power producers at the utilities' "avoided" cost. In a nutshell, this means that rates paid by utilities for such electricity must reflect the cost savings they realize by being able to avoid capacity additions and fuel usage of their own.

Tuttle (1980) states that prior to PURPA 210, cogeneration facilities wishing to sell their power were faced with three major obstacles:

* Utilities had no obligation to purchase power, and contended that cogeneration facilities were too small and unreliable. As a result, even those cogenerators able to sell power had difficulty getting an equitable price.

* Utility rates for backup power were high and often discriminatory

* Cogenerators often were subject to the same strict state and federal regulations as the utility.

PURPA was designed to remove these obstacles, by requiring utilities to develop an equitable program of integrating cogenerated power into their loads.

Avoided Costs The costs avoided by a utility when a cogeneration plant displaces generation capacity and/or fuel usage are the basis to set the rates paid by utilities for cogenerated power sold back to the utility grid. In some circumstances, the actual rates may be higher or lower than the avoided costs, depending on the need of the utility for additional power and on the outcomes of the negotiations between the parties involved in the cogeneration development process.

The avoided-cost concept is, however, more easily said than implemented. Catalano (1981) reported two lawsuits filed by utilities to contest PURPA. One, a US District Court in Mississippi declared PURPA unconstitutional; the judge stated that Congress has no authority to impose regulatory or ratemaking rules on state commissions. In the other suit, several utilities charged the FERC with excessive authority under PURPA by requiring utilities to buy all of the cogenerated power, and to pay full avoided cost for it.

In other case, in 1982, the US District Court of Appeals of Washington, D.C. found the FERC's rules on avoided-cost payments and interconnections, which utilities must provide to cogenerators under PURPA, were on "inadequate reasoning". It was claimed that FERC forced utilities to pay cogenerators what they save by not generating the electricity themselves. This is 100% of the avoided cost. The commission also ruled that utilities must interconnect with cogenerators in order to receive power. The court held that by setting on 100% of the avoided cost, FERC violated Section 210 of PURPA, where Congress stated that the rates must be "just and reasonable to the electric consumers of the electric utility and the public interest".

Later FERC appealed the court's decision. Eventually, the decisions of the Mississippi federal district court and of the D.C. Court of Appeals where appealed to the U.S. Supreme Court by the Justice Department in 1982. The Supreme Court decided that the PURPA legislation and FERC implementation rules must prevail. After the Supreme Court decision, Limaye (1985) reports that most state commissions have completed the implementation of PURPA rules.

All utilities are now required by PURPA to provide data regarding present and future electricity costs on a cent-per-kWh basis during daily, seasonal, peak and off-peak periods for the next five years. This information must also include estimates on planned utility capacity additions and retirements (forecasts), cost of new capacity, and energy costs.

Tuttle (1980) points out that utilities may agree to pay greater price for power if a cogeneration facility can:

* Furnish information on demonstrated reliability and term of commitment.
* Allow the utility to regulate the power production for better control of its load and demand changes.
* Schedule maintenance outages for low-demand periods.
* Provide energy during utility-system daily and seasonal peaks and emergencies.
* Reduce in-house on-site load usage during emergencies.

* Avoid line losses the utility otherwise would have incurred.

In conclusion, a utility is willing to pay better "buy-back" rates for cogenerated power if it is short in capacity, if can exercise a level of control on the CHP plant and load, and if the cogenerator can provide and/or demonstrate a "high" system availability.

PURPA further states that the utility is not obligated to purchase electricity from a QF during periods that would result in net increases in its operating costs. Thus, low demand periods must be identified by the utility and the cogenerator must be notified in advance. During emergencies (utility outages), the QF is not required to provide more power than its contract requires, but a utility has the right to discontinue power purchases if they contribute to the outage.

2.3.5 Electric Utility Obligations Under Purpa

In order to encourage, and thereby implement, qualified facilities PURPA requires the electric utilities to:

- o Purchase electrical energy from the QF.
- o Sell electrical energy to the QF at just, reasonable, and non-discriminatory rates comparable to rates to other similar customers served by the utility.
- o Interconnect with QF.
- o Transmit to other utilities, if the QF agrees.
- o Operate in parallel with the QF.

Electric utilities are required to purchase any energy and capacity made available from a QF or wheel it to another utility (if the qualifying facility agrees to that). Section

210 regulations govern the sales and purchases of power between qualifying facilities and electric utilities. However, the regulations state that agreements between qualifying facilities and electric utilities can be negotiated with terms different from those set out in the regulations. Since qualifying facilities are by definition new facilities, the regulations do not affect any existing contracts between QF's and electric utilities.

Under Section 210 regulations, most electric utilities are required to provide cost data to qualifying cogeneration or small power production facilities so that "avoided costs" (the basis for setting rates) can be calculated.

Regulated utilities are to provide the required data to the state regulatory authority and nonregulated utilities are required to maintain the data for public inspection.

All utilities with retail sales over 500 million KWH are required to file data on:

- o The utility system's estimated avoided cost for the current year and the following five years for various levels of purchase from qualifying facilities;
- o The utility system's 10-year plan for addition of capacity retirements and for firm energy and capacity purchase and the associated estimated capacity costs and energy costs.

Utilities with over 500 million KWH but less than 1 billion KWH sales receive an exemption from the 1980 filling requirement, but must file in 1982.

Smaller utilities (total electric energy sales -other than resale- of under 500 million KWH for all calendar years after 1975), must provide the date only upon request. If the utility obtains all its power requirements from another electric utility, it may submit the data on its supplying utility and current purchase rates. If data is not provided by the utility, a qualifying facility can request and order from the state regulatory authority or FERC.

The state regulatory authority or a non regulated utility can require different data to determine "avoided costs" but must serve public notice, provide opportunity for comment, and notify FERC.

2.3.6 Rates for Purchases From Qualifying Facilities

Rates for purchases shall be "just and reasonable," "in the public interest," and non-discriminatory toward QF's. Under the section 210 regulations, a rate for utility purchases from new QF's meets these conditions if the rate equals the utility's avoided costs. (For QF's built before November 1978, a rate less than the avoided cost is permissible if the PUC or nonregulated utility determines that the rate is sufficient to encourage cogeneration and small power production.)

Section 210 specifies that in determining "avoided costs," the following factors shall, to the extent practicable, be taken into account:

- o System cost data;
- o The availability of the qualifying facility's capacity during peak periods (specific criteria for determining this are given in the regulations);
- o The possible reduction of fossil fuel use and capacity additions;
- o Cost or savings from variations in line losses.

The "avoided cost" provision applies even in the case where the electric utility purchasing power from a QF is simultaneously making sales to the QF (simultaneous buy/sell). Standard must be established for purchases from qualifying of 100 kW capacity. The standard rates may differentiate among facilities on the basis of supply characteristics of different technologies.

The QF's can either provide energy as it is available or provide it on a scheduled, legally and enforceable basis. In the first instance, the purchasing utility must pay a rate equal to the avoided cost at the time of delivery. In the second case, the QF has a choice of whether avoided cost are calculated at time of delivery or the time the legal obligation is incurred. Qualifying facilities must pay for interconnection costs established by the state regulatory authority or nonregulated utility on a non-discriminatory basis.

An electric utility can stop the purchase of electric energy or capacity during any period when, due to operational circumstances, the cost of purchases from a QF would exceed those the utility would incur if it did not make such purchases. The utility must notify the QF adequately. The state regulatory authority is responsible for verification of such situations.

2.3.7 Rates for Sales to Qualifying Facilities

Rates for sales to QF's shall be the same as rates charged to the class of customers which the QF would be assigned if it did not have its own generation, unless the utility can provide data to substantiate that load and cost of the qualifying facility are significantly different.

The regulations require utilities to offer rates for the following services: (1) Supplementary Power, (2) Back-up Power, (3) Maintenance Power and (4) Interruptible Power.

The state regulatory authority (FERC for non-regulated facilities) may waive these requirements if compliance would impair the utility's ability to render adequate service or would place an undue burden on the utility. Public notice and hearing is required prior to such determination.

The regulations specify that back-up or maintenance power sales rates shall not be based on assumptions that qualifying facilities' outages or reductions in output will occur simultaneously or during system peak. Also, the rates must take into account possible coordination of scheduled outages between qualifying facilities and utilities.

2.3.8 Non-Regulation of Qualifying Facilities

Generally, QF's are exempted from federal and state regulations governing electric utilities. All qualified cogeneration facilities and small power productions plants under 30 MW capacity are exempt from most of the provision of the Federal Power Act and all of the Public Utility Holding Company Act of 1935. QF's are also exempt from state laws and regulation regarding electric utility rates and the financial and organizational regulation of electric utilities. Small power production facilities using biomass are exempted from those state laws and regulations even if they are over 30 MW capacity facilities.

QF's have to meet reasonable standards established by the state regulatory authority or a nonregulated utility for ensuring system reliability of interconnected operations.

2.4 Cogeneration Research Needs

This section reviews research efforts and needs about cogeneration system design and evaluation. It provides further support to the research proposal by identifying: 1) the needs for new research and development as stated in the pertinent literature and 2) the problems currently encountered in the field by cogeneration designers and practitioners.

2.4.1 The Customer Needs

From the cogeneration point of view, Waite (1990) has studied: "mass customer power needs, individual customer power needs and a method to optimize the energy supply resources available to the customer". He identifies the following technical and cultural attributes required by mass customers (industrial or commercial):

Technical Attributes

* Kind of Power (voltage, phase, delta/wye, hertz)
* Quantity of Power (kW or MW range)
* Availability of Power (standard, interruptible)
* Power Quality (voltage, frequency, harmonics)
* Cost of Power (demand charge, kWH charge, etc.)

Cultural Attributes

* Fairness: non exclusive treatment of customers
* Public Safety: public and environmental protection
* Commitmment: continuity of service
* Flexibility: response to customer demands/needs
* Support: information on "best available rates"

For the individual customer he states a shorter list of attributes or needs:

* Reliable Power -less and shorter interruptions
* Regulated Power -state control of electric rates
* Low Capital Cost -least investment to have power
* Low Energy Cost -least expenditure to obtain fuel

Based on these customer attributes, the author suggests a method to formalize the customer needs and the power-energy system development and operation. Next, he recommends a Comprehensive Energy Commodity Value Analysis (CECVA) through a chart that specifies the actual attributes in function of the needs of different customers.

This method can be compared to the Quality Function Deployment (QFD) approach, as suggested by Bossert (1991). Both CECVA and QFD make the customer requirements their primary focus. According to Bossert, product or service development is (or must be) driven by what the customer wants, not by innovations in technology. Thus the product design phase must focus on key customer requirements. The main advantages of this approach are: 1) maximizing added value into the product by providing what the customer really wants; 2) shorter design phase (less time spent in redesign or modifications); 3) process information and product specification can be summarized in a concise format (trade-offs are identified early in the design process and product specification is more objective); 4) the design process as well as the resulting product become more robust (they can perform satisfactorily under varying scenarios); 5) system design is performed following a discipline that motivates team-work (rather than litigation) among all parties involved and customer-driven innovation among designers.

Henceforth, Waite gives the following guidelines for each attribute of his "Cogeneration Needs Spectrum":

Kind of Load (power/thermal): (Are distribution voltage level and in-house circuiting compatible with power production?). Check thermal pressure level and capacity distribution limitations and hurdles.

Availability: Verify CHP system and utility reliability interactions; including continuously changing loads.

Quantity: Capacity or Load Magnitude (kilowatt-megawatt). If small, there is little relative risk or benefit. If large, are you ready to get into the power business?

Power Quality: General vs. specific end use voltage regulation, protection, and cleanliness needs.

Energy Cost: Check the combined power and thermal cost relationship, and the longevity of the end use must be established. Speculative benefits achievable through wishful escalations projections are deceiving and dangerous. Use firm-contract fuel price estimates for evaluation.

Operation & Maintenance: If from outside vendors, then there is a loss of a portion of the benefit and potential loss of long term support is an added risk.

Cost of Outage: Compare known site history to CHP performance records. Evaluate if outage incurs labor or product losses, or loss of sales.

Match Load Analysis: Power and thermal load profiles overtime of use are critical to a proper economic evaluation of on-site generation.

Business Cycle: Facility needs change, how adaptable is the power supply system to load increase, site load center shifts. Also, is the end use in an up or down trend of need.

System Capacity Control: Can the supply resource output vary with moment by moment load changes.

Environmental: Examine the existing and trending regulations for unwarranted risks.

2.4.2. The Performance of Existing Cogeneration Systems

The needs stated above are amplified by field reports on the actual performance of cogeneration systems. Steen (1990) reports and advises the following:

> Actual metered data, thus far, does not support the optimistic economic estimates, exhibited in the engineering studies, which were used to justify the project. By (1) utilizing actual data at every opportunity and (2) by evaluating risks, a better evaluation can be made. So, before installing a cogeneration system, there are (3) some basic questions that should be asked, and (4) some research should be performed.
>
> Do not depend on averages to evaluate cogeneration because it provides unrealistically low payback periods, which in turn increase the financial risk. Know what the hourly electrical and thermal demand are for the facility and how well the cogeneration production matches the facilities needs. Increases in energy efficiencies do not automatically equate to decreases in total operating expenses...

Next, Steen describes the "probability assessment of savings" in regard to the operation of 14 CHP locations in the Detroit Edison Co. area and 24 turbines in Europe. He presents plots of the probability of occurrence of the actual payback period for the projects mentioned above. These plots are valuable to indicate how quick the industry as a whole is "paying back" its CHP investment. However, they are not valid to asses the feasibility of a particular site CHP potential.

Unfortunately, Steen does not mention 1) how actual data is supposed to be utilized, 2) how to evaluate risks, and 3) what are the basic questions that should be asked.

Other researchers, such as Keb and Limaye (1990), have urged manufacturers to avoid exaggerated savings claims. Here, it appears that the advise assumes that the savings are overstated, thus understating the payback period.

Spitzka (1990) and Somasundaram and Turner (1990) acknowledge that using average values for demands and capacities do overstate the savings and that may lead to major problems. However, purposely overstatement of savings is not necessarily true. Many simply do not acknowledge that the payback period or any other measure of economic merit are not fully predictable, because they just constitute functions of the many random variables involved in cogeneration.

Also, a survey about the performance of existing cogeneration and independent power production (IPP) systems was published by the Association of Energy Engineers (AEE) in AEE Energy Insight (1991). Some of the survey findings are:

* About 89% of the respondents said that the interest in cogeneration has remained the same or increased
* 39% stated their organization is planning on installing a cogeneration of IPP facility within the next 12 months.
* But 26% reported a "just" satisfactory or poor performance, 46% said it was good and 28% stated an excellent performance.
* Also, 27% said that their operation and maintenance (O&M) costs were higher than estimated.
* The overall savings: are less than estimated (22%), met estimated calculations (56%), are higher than the estimated (22%).
* The average installed cost was $1,428/nominal-kW.
* The average operation and maintenance cost was $0.062/kW.

Even though most cogeneration designers and developers use a rather "conservative" approach to estimate their installed and O&M costs (i.e. they would err in overestimating cost and understating revenues), the percentage of respondents with "above target costs and/or below target savings" seems rather high. This, taking into account, that most developers tend to emphasize good projects, but play down the slow ones.

To sum up, this limited survey may not tell us exactly how systems are performing in the field, but does inform two important things: one is the large interest in cogeneration, and the other is the wide spread of the results in system performance (O&M cost and payback) -as compared to the planned expectations. The fact is, that in most cases, these results constitute random variables -the best crystal ball cannot predict them accurately. The existing methods do not fully acknowledge the probabilistic aspects of the problem and do not state the results in terms of probabilities.

2.4.3 The Regulatory Needs

To become a qualifying facility (QF) -and receive the benefits of a QF- the prospect cogenerator must demonstrate to the regulatory agencies his/her capability of meeting the corresponding PURPA regulations. For example, to demonstrate a minimum 42.5% total fuel effectiveness (TFE) in any year, not only the cogenerator can show the estimated average TFE but also an statistical confidence limit. In this way, one can give more validity to the estimates in cases with load variations. Conversely, the utility may request higher back-up rates if a statistical analysis shows the CHP peak load is highly correlated with the utility load and the cogeneration system is prone to be down during peak hours. In both examples, the costs are best treated as expected values; weighted by the corresponding probabilities of occurrence.

Many utilities have questioned cogeneration for being a potential source of un-reliability. Whether a particular CHP plant contributes positively or adversely to a power system's availability, this is best stated in probabilistic terms. Further, the cost of reliability is usually stated as an expected value. Thus, to resolve conflicts during negotiations -or a litigation in the court room- the impact of cogeneration reliability is best addressed using the methods and language of reliability theory. The cogeneration evaluation method that integrates buy/sell rates, system reliability, and varying loads is yet to be accomplished.

2.4.4 A Synthesizing Design Methodology

The needs stated above can be synthesized as the demand for a suitable and integrating CHP design, sizing and evaluation methodology. These needs may only be met through the development of a design method that: 1) considers and quantifies all relevant customer needs but -at the same time- is time and cost effective; and 2) accepts and recognizes the statistical nature of the problem. Steen (1990) concluded his paper with the following statement:

> I am of the opinion that (in cogeneration) to arrive at separate solutions for power reliability and quality problems independent of energy cost reduction efforts is to ignore optimal economics.

CHAPTER III

OBJECTIVES AND ASSUMPTIONS OF THE RESEARCH

3.1 Introduction

In general, cogeneration system design is very complex. Depending on the application, industrial cogeneration or combined heat and power (CHP) systems can vary widely. There is variation in scope (i.e. the ultimate objective of the CHP plant), in technology, in loads, in capacities, and in costs.

Thus, to design a cogeneration system, various methods and approaches have been developed, from nomographs to computer programs; and from simulations to expert systems. Some of them, e.g. nomographs, make too many simplifying assumptions. On the other hand, computer packages require as input every possible variation in the technical and economical factors involved in a particular application making the evaluation very time consuming. Hence, for the existing methods, the more flexible and detailed the models, the larger the data requirements and the development time. Thus, an alternative design methodology is proposed herein.

The actual industrial cogeneration design process has the following major steps. See Figure 3.1 below.

1) Select Technology and Mode of Operation.
2) Determine Total Installed Capacity
3) Determine Size and Number of Prime Movers
   -including stand by capacity.

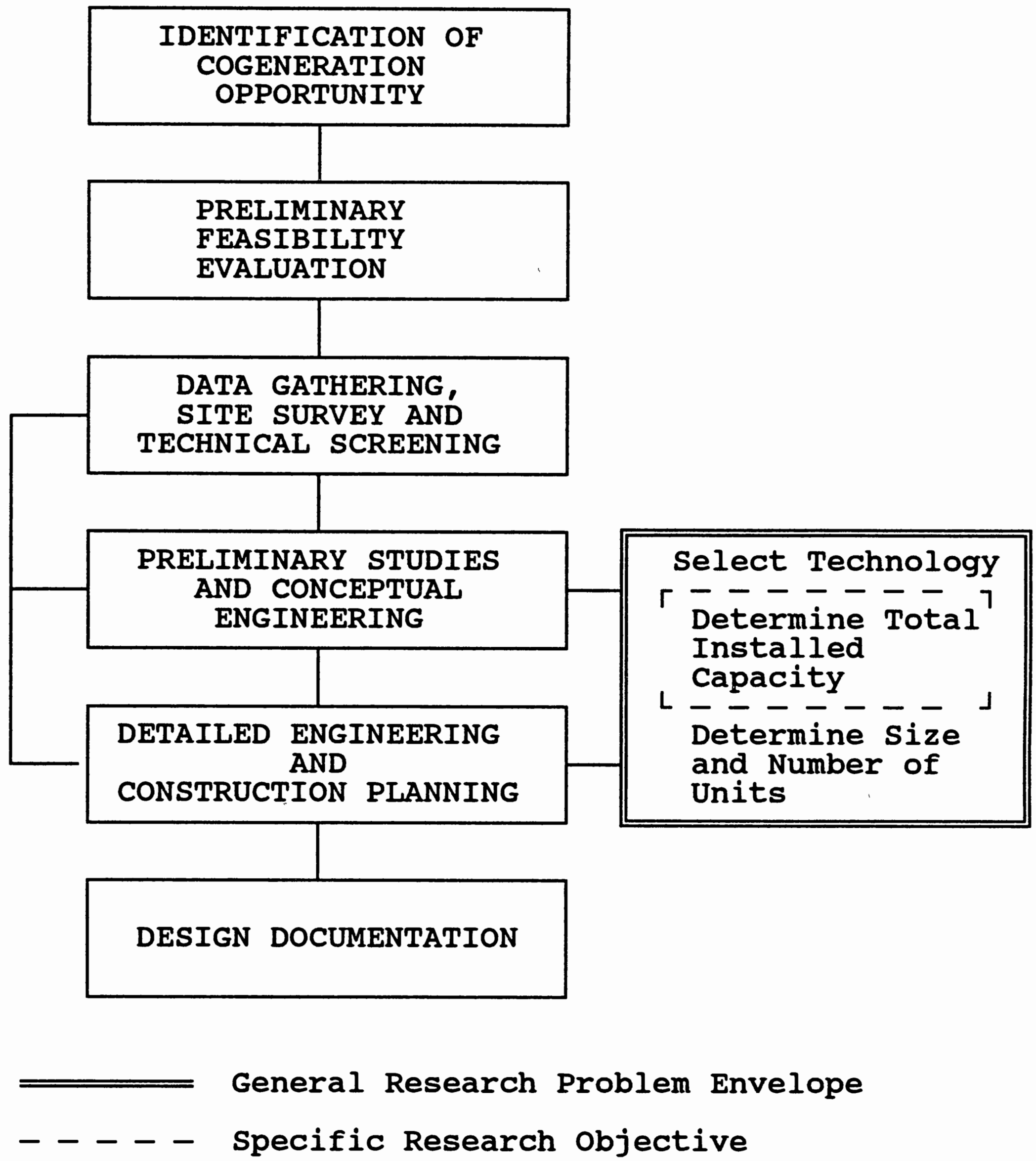


Figure 3.1 Cogeneration Design Process, Research Problem Envelope and Research Objective

Henceforth, the focus of this research is the development of a responsive and robust methodology for cogeneration system design. It must be responsive to adapt to the various cases and robust to maintain validity in spite of different applications. Specifically, we are concerned with step two above, i.e. the determination of the total system capacity. Figure 3.1 depicts the general cogeneration design process and the envelope of the research proposed here.

3.2 Scope of the Research

The underlying scope of the research is to use CHP sample data compressed into probability distributions and statistical parameters; and typical equipment performance equations, so variation in loads and system capacity are taken into account mathematically. Hence, the underlying methodology comprehend both, deterministic and probabilistic models that combine technology performance and CHP capacity/demand probability distributions. Thus, the methodology should be expressed -as long as it is feasible or practical- through closed form equations. When necessary, numerical methods will be used to implement the models.

Hence, the scope is to avoid the traditional hour by hour (deterministic) simulation methods discussed in section 2.2. Instead, the scope will be to represent data by using probability distributions and their relevant parameters.

Therefore, the convolution of (1) the demand/capacity probability distributions and (2) analytical relationships of equipment performance should be the essence of a responsive, robust and cost effective CHP design and plant size optimization method.

3.3 CHP Technologies

The basic CHP technologies considered for modelling are:

1) Internal combustion engine with waste heat boiler or water heater
2) Gas turbine with non-fired waste heat boiler

However, after some adjustments, the models proposed here should be applicable to most CHP technologies.

3.4 Basic Assumptions

The basic underlying assumptions used in the research and development of this thesis are:

1) The heat and power demands are represented by ergodic stationary time series. Thus, they generally constitute Gaussian distributed random processes.
2) The CHP system will be eligible to export and to import electricity to a utility grid as needed.
3) The CHP plant output will be 100% of the available capacity throughout a given number of hours per year.
4) There exist a very large amount of auxiliary thermal capacity (auxiliary equipment) -but with a lower efficiency- to supplement any heat capacity deficit.
5) CHP capacities are functionally dependent: They have a constant (linear) heat-to-power ratio. But the capacities are statistically independent of demands. Also, heat demands are independent of power demands.
6) The system power capacity is always fully utilized, either, for on-site use and/or for export. That is, the maximum available power capacity available from the CHP system is generated at any time.

7) Any excess electricity is sold to the utility grid at a given rate, which is normally less than the purchase cost of that electricity.
8) All heat surplus is rejected to the environment.
9) When the electrical capacity is exceeded by the demand, the difference is purchased from the grid.
10) When the heat demand exceeds the capacity, auxiliary equipment absorbs the excess demand. It is assumed that the auxiliary equipment capacity is always larger than the thermal deficit demand.
11) A definite upper bound for the system size is defined by PURPA regulations: The total useful CHP system output must be no less than 42.5% of the total fuel input.

3.5 Research Objective

Given that one technology or a reduced set of technologies have been selected for a specific application, the proposed research intends to develop a methodology that economically sizes the CHP plant, in terms of its rated mean or nominal capacity typically in kW_e, for the above mentioned technologies. Thus the primary objective of the research is:

> *To develop a CHP design methodology which determines a target size of the CHP plant that minimizes the expected total annual cost (TEAC) of owning and operating the CHP system.*

The target CHP plant size is the "ideal" plant size for a given set of CHP load distributions and for a specific technology. The target system size may not be commercially available, but it can be used as a CHP system surrogate indicator in selecting an available system that is closest to the target. In fact, using further analysis, a set of commercially available plants can be compared against the target size and the actual "nearest-optimal" plant size can be selected.

3.6 Sub-Objectives

The following sub-objectives are required to meet the research objective.

1) For the technologies mentioned above, develop the basic economic criteria to size CHP systems under variable loads. The following deterministic cost items shall be considered in the development:
   - Minimum attractive rate of return
   - Capital costs: principal and interest
   - CHP system Fuel cost
   - Imported electricity cost
   - Exported electricity cost
   - Auxiliary/supplementary firing cost
   - CHP regular maintenance cost
2) Develop a conceptual model to determine the CHP system size that minimizes the expected total annual cost when heat demand (Hd) and electrical power demand (Pd) are constant. Also, the CHP system heat capacity (Hc) and electrical power capacity (Pc) are constant. This is the case of an internal combustion engine CHP system subject to constant loads or base-loading.
3) Develop a conceptual model to determine the CHP system size that minimizes the expected total annual cost when the heat and electrical demands are independently

distributed Gaussian random variables. The CHP system heat capacity and electrical capacity are constant. This is the case of an internal combustion engine CHP system subject to random loads.

4) Develop a conceptual model to determine the CHP system size that minimizes the expected total annual cost when heat demand and electricity demand are independently distributed Gaussian random variables. The CHP system heat capacity and electricity capacity are also Gaussian random variables. Here, the CHP demands are statistically independent of CHP equipment capacity. This is the case of a gas turbine CHP system operating under random air temperature and subject to random loads.
5) Conclude on the applicability and validity of the models, and define related topics for further research.

CHAPTER IV

A ROBUST AND RESPONSIVE METHODOLOGY FOR ECONOMICALLY BASED DESIGN OF INDUSTRIAL COGENERATION SYSTEMS

4.1 Cogeneration System Design Economic Criteria

4.1.1 General Considerations and Assumptions

The development of a general stochastic model for cogeneration optimal design will be based in the Bayesian approach to decision theory. Stark and Woods (1986) state that Bayesian decision theory defines as optimal the decision that minimizes the average cost of risk. This is obtained by partitioning the heat and power space in sub spaces that can be associated with specific cost items. The cost items, are in turn terms of the objective cost function, i.e. the total expected annual cost (TEAC) of owning and operating the CHP system. Therefore, the problem is in essence the selection of the CHP plant size that minimizes the TEAC.

The rationale of the economically based design-decision model -to obtain the plant size- is discussed as follows.

First, in the space **W** there exist a set partitioned into N states of nature w_j, j= 1, ... N and that the states prevail according to a probability distribution known to the observer. Hence, the elements of **W** consists of the totality of outcomes that we associate with the states of nature w_j. Four basic outcomes are defined by the following relations:

1) Pc > Pd

2) Pc ≤ Pd

3) Hc > Hd

4) Hc ≤ Hd

Where:

Pc = the system electrical power capacity
Hc = the system thermal or heat capacity
Pd = the electrical demand
Hd = the thermal demand

In the CHP system with random electricity capacity and random heat capacity - subject to electricity demand and heat demand- there exist the following states of nature w_j:

$$w_j = \begin{bmatrix} w_1 & : & Hc > Hd & \text{and} & Pc > Pd \\ w_2 & : & Hc > Hd & \text{and} & Pc \leq Pd \\ w_3 & : & Hc \leq Hd & \text{and} & Pc > Pd \\ w_4 & : & Hc \leq Hd & \text{and} & Pc < Pd \end{bmatrix}$$

where heat and electricity demands are expressed in power unit, i.e kWt and kWe, respectively.

Each state w_j is a combination of two elementary outcomes (e.g. an elementary outcome is Hc > Hd), which have been grouped to obtain a convenient portioning of the CHP space.

Second, the observer obtains a demand vector sample **D** = $(d_1, d_2)^t$, which is probabilistic in nature and represents a sample realization of the states of nature. The observation vector **D** is a two-dimensional r.v. whose domain Ω and range is R_d. As **D** roams over W, it generates numerical data according to the probability law $f(\mathbf{X}/w_j)$ -i.e. heat and power demand samples are taken. Hence, for a particular value $x_i \epsilon w_j$, **D** assumes the value $D(x_j) = (d_1(x_j), d_2(x_j))^t)$; which represents a CHP demand sample point.

Similarity, in the most general case, the observer takes a two-dimesional capacity vector sample $\mathbf{C} = (c_1, c_2)^t$, whose domain is also Ω, but its range is R_c. Thus, for a particular CHP capacity $Y_i \epsilon w_j$, C assumes the value $\mathbf{C}(Y_j) = (c_1(Y_j), c_2(y_j))^t)$; which represents a CHP capacity sample point.

Third, the existence of a set of costs C_{jk} (k= 1,...K) (known to the observer) associated to each state w_j is postulated. There is a one to one correspondence of a particular set of costs items and a state w_j. Table 4.1 below summarizes the states of nature just defined, i.e. the feasible space of a general CHP system.

TABLE 4.1

STATES OF NATURE OR FEASIBLE SPACE
OF THE CHP SYSTEM

STATE	DESCRIPTION	
	HEAT IS:	ELECTRICITY IS:
w_1	rejected	sold back to utility
w_2	rejected	purchased from utility
w_3	Aux. fired	sold back to utility
w_4	Aux. fired	purchased from utility

4.1.2 Economic Analysis Notation

The following is the general notation used in this work. However, notation specific to particular models will be defined later throughout the analysis. Fuel rated and efficiencies are based on high heating values (HHV).

AC = Amortized Cost of CHP system ($/yr)

c_p = Annual plant fixed charge ($/kw-yr)

c_a = auxiliary firing unit cost ($/ MMBTU)

c_e = cost of electricity purchased from the grid ($/kWh)

c_f = unit cost of fuel ($/MMBTU)

c_m = unit operation and maintenance cost ($/kwh)

c_r = cost of rejecting heat, $/kWH

c_u = CHP system unit cost, $/kWe

EC = Annual purchased electricity cost ($/yr)

FC = Annual fuel consumption cost ($/yr)

Hc = CHP plant thermal capacity (kWt)

Hd = CHP plant thermal demand (kWt)

IC = Total CHP plant installed cost ($)

N_e = CHP plant fuel-to-electricity efficiency

N_a = Auxiliary firing thermal efficiency.

MC = Annual operation & maintenance cost ($/yr)

Pc = CHP plant electrical capacity (kWe)

Pd = CHP plant electrical demand (kWe)

RC = Annual heat rejection cost ($/yr)

r_c = system heat to power ratio

s_e = electricity cost, sales to the grid, $s_e<0$, ($/kWh)

ES = Electricity sales to the grid ($/yr)

TEAC = Total expected sales annual cost of CHP system

t_1 = CHP plant time of operation (hr/yr)

t_2 = Auxiliary equipment time of operation (hr/yr)

t_3 = Electricity deficit time (hr/yr)

In general, lower case symbols represent unit costs and/or constants and upper case symbols represent annual costs and/ or random variables.

4.1.3 CHP System Costs - A General Deterministic Formulation

The problem defined in Section 4.1.1 is normally probabilistic in nature. In this section, however, the formulae are expressed in terms of the time (hours/year) of the cost associated with a given system state. Thus, a deterministic formulation is obtained. The basic modeling assumptions were stated in Chapter III. Next, the following relationships define the basic annual costs of owning, operating and maintaining the underlying CHP system (To keep the model manageable, escalation factors are avoided):

Amortization CHP System Cost. This is essentially a before-tax cost of owning the system. It is expressed in terms of an uniform amount based on the Equivalent Annual cost (EAC) of the CHP system total installed cost and an annual plant fixed charge (insurance, overhead, etc). It is defined by

$$AC = IC\ (A/P\ \ i,\ n) + c_p.Pc \qquad [4.1]$$

AC = annual equipment owning cost (\$/yr)
IC = total CHP plant installed cost (\$)
= $c_u.Pc$
(A/P i,n) = uniform-series capital-recovery factor
i = Minimum Attractive Rate of Return (MARR)
n = expected project life (years)
c_p = annual plant fixed charge, if any (\$/kW-yr)

Economies of scale make the cogeneration unit system cost c_u a decreasing (exponential) function of the system size Pc:

$$c_u = b + a.e^{-(kPc)} \qquad [4.2]$$

where a, b and k are constants. For a small range of Pc, c_u can be approximated by a linear equation with slope a ($a<0$) and intercept b ($b>0$). That is $c_u = b + a.Pc$. However, c_u can be assumed to be constant (c_u=K) in the asymptotic or "flat" portion of equation [4.2] (see Figure 4.1). Then, IC = K.Pc, and [4.1] can be rewritten as the *linear equation*

$$AC = (K.Pc)\ (A/P\ i,\ n) + c_p.Pc$$
$$= a.Pc \qquad [4.1a]$$

where $a = K.(A/P\ i,n)+c_p$.

For the "curve" part of equation [4.2] (Figure 4.1) the annualized owning cost can be represented by

$$AC = (A/P\ i,n)\ \ (b+a.e^{-kPc})\ Pc + c_p.\ Pc \qquad [4.1b]$$

Fuel Cost. If both, capacity and demand are deterministic, then the fuel cost for the plant is calculated as

$$FC = c_f\{(Pc/n_e.t_1) + (Hd-Hc)/n_a.t_2\};\quad Hd>Hc \qquad [4.3]$$

Electricity Cost. This is the cost of electricity consumed from the grid whenever Pd>Pc. It is estimated by

$$EC = (Pd-Pc)\ t_3(c_e);\qquad Pd>Pc \qquad [4.4]$$

Operation & Maintenance Cost. This cost includes personnel and preventive maintenance conducted in the CHP system. It is proportional to the amount of energy generated (fuel usage and equipment wear) in the plant. It is defined as

$$MC = c_m\ (Pc.t_1) \qquad [4.5]$$

Heat Rejection Cost. This cost considers the additional power consumption, cooling water treatment, etc, required to reject excess heat in the plant. If t_2 is the time of heat deficit, then t_1-t_2 is the time of rejection. This cost is

$$RC = c_r.(Hc-Hd).(t_1-t_2);\qquad Hc>Hd \qquad [4.6]$$

Electricity Revenue. Whenever Pc>Pd, electricity is sold back to the grid. The revenue is

$$ES = (Pc-Pd)\ (t_1-t_3)(s_e);\qquad Pc>Pd \qquad [4.7]$$

Total Equivalent annual Cost. The total equivalent annual cost of owning, operating and maintaining the CHP system is:

$$TEAC = AC + FC + EC + MC + RC + ES \qquad [4.8]$$

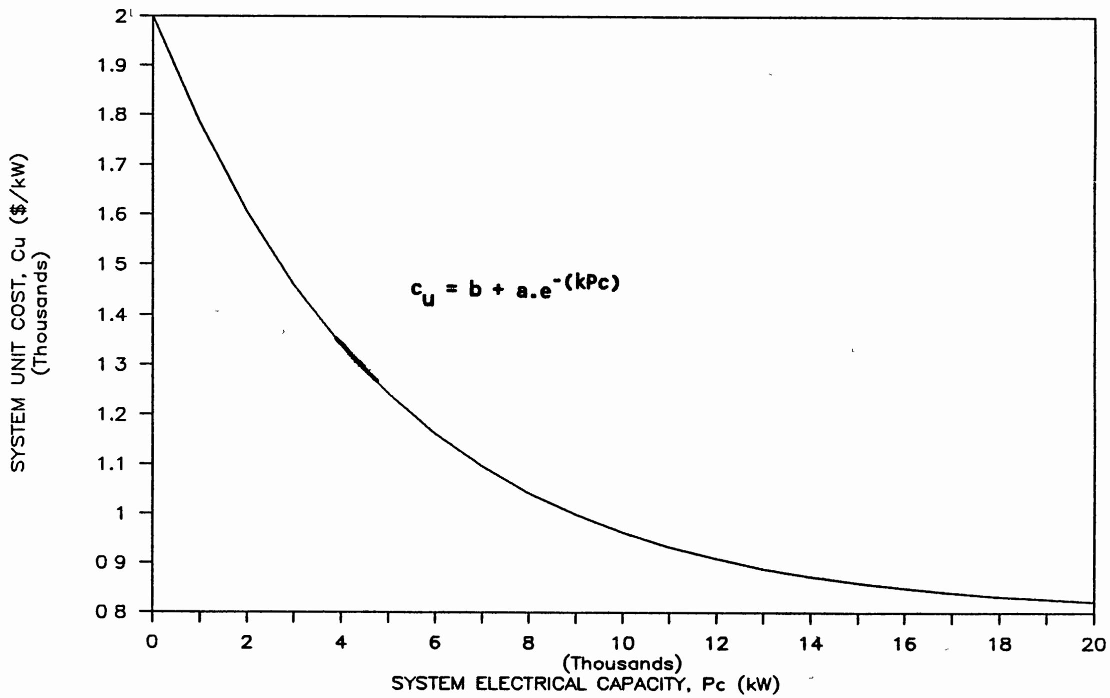


Figure 4.1 Exponentially decreasing system unit cost

4.2 Constant Capacities and Constant Demands (CCCD) Model

In this case, the economic criteria is to select the optimal size Pc* of a CHP system that minimizes TEAC when both, CHP capacities and demands are constant. TEAC is generally defined by equation [4.8]. If the linear equation [4.1a] is used, then equation [4.8] is linear. If the exponential unit cost model [4.1b] is assumed, then [4.8] is non-linear.

Also, depending on the values assumed for the parameters Hc, Hd, Pc, and Pd; different terms appear and/or vanish in equation [4.8]. Figure 4.2 corresponds to the first quadrant of the Heat (H) and Power (P) space, which defines the sub-space W containing all the feasible CHP demands (≥ 0). For a constant heat-to-power ratio r_C, the CHP capacity curve is defined by the linear equation

$$Hc = r_C \, Pc \qquad [4.9]$$

Thus, W is partitioned by the capacity curve in two regions:

<u>Zone A:</u> which contains all the possible CHP demands located to the left of the system curve, e.g. point a.

<u>Zone B:</u> which contains all the possible CHP demands located to the right of the system curve, e.g. point b.

But the most important PURPA regulation imposes a definite upper bound on the system capacity Pc (See section 2.4). PURPA establishes that "the total useful output of the system must be no less than 42.5% the total annual fuel input to the system based on lower heating value". However, to be prudent in meeting PURPA requirements according to previously defined equations, higher heating values are considered here.

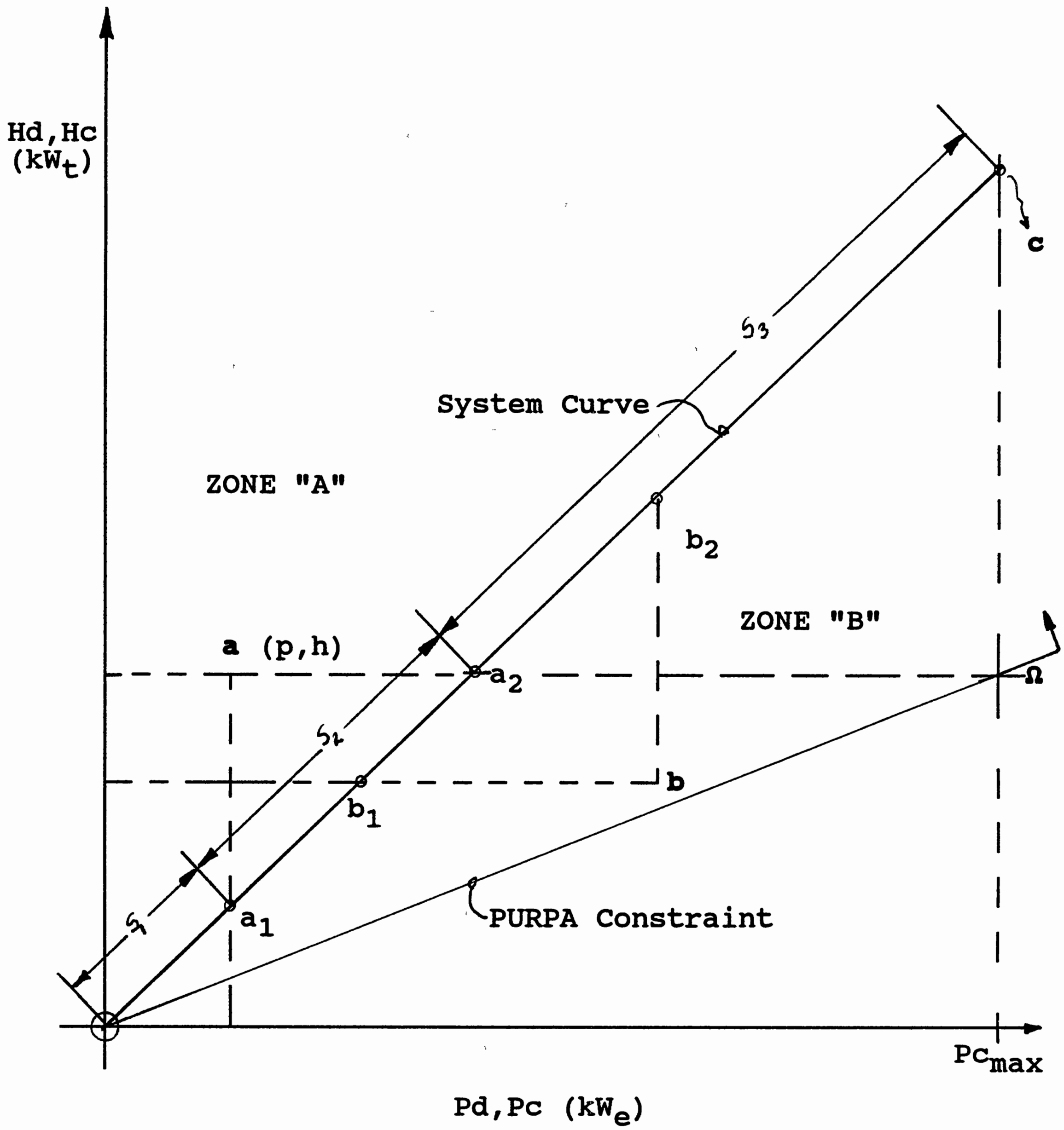


Figure 4.2 CHP Feasible Space and System Capacity Curve

Thus, for any given CHP demand point (Pd,Hd) the PURPA constraint is: $(Pc + Hd) \geq 0.425\ (Pc/n_e)$

or $$Hd \geq Pc\ (0.425/n_e - 1) \qquad [4.10]$$

Hence, if point **a** in Figure 4.2 defines the power and heat demands (p,h) respectively, then the insersection of line Hd = h and the PURPA line defines point **Ω** -which projected on the System curve gives the maximum legal operating point **C.** Next, **Ω** projected on the abscissa gives the maximum feasible (legal) capacity Pc_{max}.

Equation 4.10 defines an effective size constraint as long as $n_e < 0.425$; which is generally the case of the CHP systems considered here. That is internal combustion engines or gas turbines, with heat recovery for industrial processes.

4.2.1 <u>CHP System Sizing Strategies</u>

In this model, we are concerned with the optimality of the system size in the neighborhood of the demand point. Henceforth, the following sizing strategies are defined in terms of the above described regions **A** and **B:**

In region **A,** point **a** defines the demands Pd and Hd. Then point $\mathbf{a_1}$ represents a system with capacities defined by

$\mathbf{a_1}$: $Pc = Pd$ and $Hc = Pd/r_c$ $(Hc<Hd)$

Conversely, point a_2 defines a system size with

$\mathbf{a_2}$: $Pc = r_c Hd$ and $Hc = Hd$ $(Pc>Pd)$

Similarly, in region **B,** the demand point **b** can be projected to b_1 and b_2

$\mathbf{b_1}$: $Pc = r_c Hd$ and $Hc = Hd$ $(Pc<Pd)$

$\mathbf{b_2}$: $Pc = Pd$ and $Hc = Pd/r_c$ $(Hc>Hd)$

Since points $\mathbf{a_1}$ and $\mathbf{a_2}$ (points $\mathbf{b_1}$ and $\mathbf{b_2}$ in the B region) on the capacity curve S constitute points at which the objective function (OF) defined by [7.4] changes in basis (i.e. some of the terms vanish and/or other terms become positive), then they are extreme points.

Hence, without loss of generality, the demand point **"a"** defines $\mathbf{a_1}$ and $\mathbf{a_2}$; which in turn partitions the system capacity line in three segments: S1, S2 and S3. Note that PURPA defines the upper limit for S3. (See Figure 4.2). **S1** represents all systems with Hc < Hd and Pc < Pd. Assuming a constant CHP-system unit cost (equation [4.1a]), and using [4.3] through [4.8], the cost to own and operate over S1 is

$$TEAC_1 = (a'.Pc) + c_f\{(Pc/n_e.t_1) + (Hd-Hc)/n_a.t_1\} + c_m.Pc.t_1 + (Pd-Pc)\ t_1.c_e \quad [4.11]$$

Similarly, S2 represents all systems with Hc < Hd and Pc > Pd. The cost to own and operate over S2 is

$$TEAC_2 = (a'.Pc) + c_f\{(Pc/n_e.t_1) + (Hd-Hc)/n_a.t_1\} + c_m.Pc.t_1 + (Pc-Pd)\ t_1.s_e \quad [4.12]$$

Next, S3 represents all systems with Hc > Hd and Pc > Pd. The cost to own and operate over S3 is

$$TEAC_3 = (a'.Pc) + c_f\{(Pc/n_e.t_1) + + c_m\ (Pc.t_1) + (Pc-Pd)\ (t_1.s_e) + (Hc-Hd)\ t_1.c_r \quad [4.13]$$

4.2.2 <u>CHP CCCD-1: A Linear Model</u>

Since equations 4.11, 4.12 and 4.13 are linear over PC, the TEAC functions are optimal at extreme points. Here, the underlying assumption is that the unit system cost c_u is constant. Hence, for typical values of the coefficients of the TEAC functions, the CHP space is convex with the global minimum existing at the end of one of the intervals S_i. Since PURPA ultimately defines a constrained convex feasible space, from equation [4.10],

$$Pc(\mathbf{c}) = Pc_{max} = Hd.n_e\ /(0.425-n_e) \qquad [4.10a]$$

which gives **c** the final feasible point on the system line. Henceforth, the CCCD linear model can be formulated as:

Minimize { min $TEAC_1$, min $TEAC_2$, min $TEAC_3$ } subject to the constraint set:

$$CS : \left[\begin{array}{ll} \text{System curve:} & Hc = rc.\ Pc \\ \text{PURPA constraint:} & Pc \le Hd.n_e\ /(0.425 - n_e) \\ \text{Efficiency constraint:} & n_e < 0.425 \quad \text{[per Eq. 4.10]} \\ \text{Non-negative size:} & Pc \ge o \end{array}\right]$$

The optimal solution to this model can be obtained by evaluating the extreme points (0,0), a_1, a_2 and c. Since these points warrant the optimal CHP-size Pc* for the minimum TEAC*, a search over the intervals S1, S2 and S3 is not necessary. Thus, for a demand point **a** ϵ **CS**, the problem boils down to find the system size which satisfies:

$$TEAC^* = \min \{ TEAC[0],\ TEAC[Pc(a_1)],\ TEAC[Pc(a_2)],\ TEAC\ [Pc_{max}]\} \qquad [4.14a]$$

Where TEAC[Pc] is the total equivalent annual cost of owning and operating the system of size Pc. $Pc(a_1)$ and $Pc(a_2)$ are the CHP system sizes defined by Section 4.2.1 and Fig. 4.2. A similar solution is valid for a demand point **b** ϵ **CS,** using

$$TEAC^* = \min \{ TEAC[0],\ TEAC[Pc(b_1)],\ TEAC[Pc(b_2)],\ TEAC\ [Pc_{max}]\} \qquad [4.14b]$$

COROLLARY 1: If $Pc(a_1) < Pc_{max} < Pc(a_2)$, then

$$TEAC^* = \min \{ TEAC[0],\ TEAC\ [Pc(a_1)],\ TEAC\ [Pc_{max}]\} \qquad [4.15]$$

COROLLARY 2: If $Pc_{max} < Pc(a_1)$, then

$$TEAC^* = \min \{ TEAC[0],\ TEAC\ [Pc_{max}]\} \qquad [4.16]$$

Example 4.1: CCCD-1. Table 4.2 lists an example of the application of the CCCD-1 model. The top portion of the table includes all the relevant input data. By definition, both demand and capacity parameters are constant (they are not random variables). Thus, the electrical demand is 800 kW and the thermal demand is 3.5 MMBTU/hr.

The CHP capacities Pc and Hc are listed in the left hand side of the table. An economic analysis including all the costs defined by equations [4.3] through [4.8], for Pc =0 to Pc = 2700, is listed in the body of the table. The last two columns list the TEAC and PURPA efficiency for each Pc.

Since evaluation of extreme points warrant the optimum Pc*, a search, is not required. However, Table 4.2 includes a search list (Pc = 0, 2700) for model verification. The TEAC corresponding to the extreme points **(0,0)**, **b1**, **b2**, and **C** (which defines Pc_{max}) are included in the list.

Note that the heat-to-power ratio (HPR) relations define the slope of the demand and the slope of the system curve. In this example: [HPR(demand)=0.92] < [HPR(system)= r_C=1.364]. Therefore, the formulation is a CCCD-1 model for the **B** zone. Hence the extreme points **EP** in the CHP space are:

(0,0): Pc=0 and Hc =0

b1 : Hc = Hd =2.5 MMBTU/hr

Pc = Hd/rc

= 2.5/1.364/(0.003412 MMBTU/kWh)

= 537.2 kW

b2 : Pc = Pd = 800 kW

Hc = rc. Pc

= (1.364)(800)(0.003412 MMBTU/kWh)

= 3.72 MMBTU/hr

TABLE 4.2

CCDD-1 MODEL FOR EXAMPLE 4.1

INPUT DATA

Pd:	800	KW	cr:	$0.100	/MMBTU	cu:	$1,000	/kW	MARR:	15%	
Hd:	2.5	MMBTU/	se:	$0.034	/kwh	Dem-s:	$50.00	/kW-yr	Proj Life:	20	years
Ne:	0.33		ce:	$0.038	/kWh	Dem-b:	$70.00	/kW-yr	(A/P i,n):	0.15976	
Nt:	0.45		cf:	$2.000	/MMBTU						
T:	8000	hr/yr	cf:	$2.000	/MMBTU	Na:	0.75		HPR (de	0.92	
Avail.	0.9132		cp:	$10.00	/kW	cm:	$0.0040	/kWh	HPR (sys)	1.36	

	Pc kw	Hc MBTU/	RC $/yr	Aux fire $/yr	FC $/yr	EC $/yr	ES $/yr	MC $/yr	IC $	O&M $/yr	AC $/yr	TEAC $/yr	PURPA EFF
	0	0.00	0	53333	53333	299200	0	0	0	352533	0	352533	N/A
	100	0.47	0	43408	59951	261800	0	3200	100000	324951	16976	341927	78.00%
	200	0.93	0	33482	66568	224400	0	6400	200000	297368	33952	331320	78.00%
	300	1.40	0	23556	73185	187000	0	9600	300000	269785	50928	320713	78.00%
	400	1.86	0	13630	79802	149600	0	12800	400000	242202	67905	310107	78.00%
	500	2.33	0	3704	86419	112200	0	16000	500000	214619	84881	299500	78.00%
Pc(b1):	537	2.50	0	0	88889	98243	0	17194	537319	204326	91216	295542	78.00%
	600	2.79	233	0	99258	74800	0	19200	600000	193491	101857	295348	73.30%
	700	3.26	606	0	115801	37400	0	22400	700000	176207	118833	295040	67.54%
Pc(b2):	800	3.72	978	0	132344	0	0	25600	800000	158922	135809	294731 ★	63.22%
	900	4.19	1350	0	148887	0	32200	28800	900000	179037	152785	299623	59.87%
	1100	5.12	2094	0	181973	0	96600	35200	1100000	219268	186738	309405	54.98%
	1300	6.05	2839	0	215059	0	161000	41600	1300000	259498	220690	319188	51.60%
	1500	6.98	3583	0	248145	0	225400	48000	1500000	299729	254642	328971	49.12%
	1700	7.91	4328	0	281232	0	289800	54400	1700000	339959	288594	338754	47.22%
	1900	8.84	5072	0	314318	0	354200	60800	1900000	380190	322547	348537	45.73%
	2100	9.77	5817	0	347404	0	418600	67200	2100000	420420	356499	358319	44.51%
	2300	10.70	6561	0	380490	0	483000	73600	2300000	460651	390451	368102	43.51%
	2500	11.63	7305	0	413576	0	547400	80000	2500000	500881	424404	377885	42.67%
Pcmax	2545	11.84	7474	0	421053	0	561953	81446	2545197	509973	432076	380096	42.50%
	2700	12.56	8050	0	446662	0	611800	86400	2700000	541112	458356	387668	41.96%

C : $Pc = Pc_{max}$

$= Hd.n_e / (0.425-n_e)$

$= (2.5)(0.33)/[(0.425-0.33)(0.003412 \text{ MMBTU/kWh})]$

$= 2{,}545.2 \text{ kW}$

$Hc = rc.Pc$

$= (1.364)(2542.2)(0.003412 \text{ MMBTU/kWh})$

$= 11.83 \text{ MMBTU/hr}$

The system size Pc versus TEAC has been plotted in Figure 4.3. The extreme point b2 corresponds to the optimal size PC* = 800 kW with a TEAC* = $294,73 per year.

Note that Pc=0 corresponds to a "base case" or "do nothing" alternative. In other words, TEAC(0) should be comparable to the annual operation and maintenance cost of the existing facility or the facility's most recent (or forecasted) equivalent uniform annual energy cost (EUAC). In the example above TEAC(0) = $352,533/yr. If TEAC(0) were no comparable to EUAC, the model should be calibrated. Model calibration is examined in Chapter 5.

In a new facility, the base case cost is not necessarily comparable to TEAC(0); since the total cost would include the cost to own and operate a new conventional boiler system, and electricity would be purchased from the utility grid. In either case, the TEAC corresponding to the base alternative should be a horizontal line on the graph.

If several CHP technologies are feasible, their Pc-vs-TEAC plots could be superimposed to create a multiple-technology break-even chart. Such a chart allows one to perform further sensitivity analysis in terms of Pc sizes. This feature makes the model a truly robust analysis tool to evaluate the various CHP investment alternatives and cases.

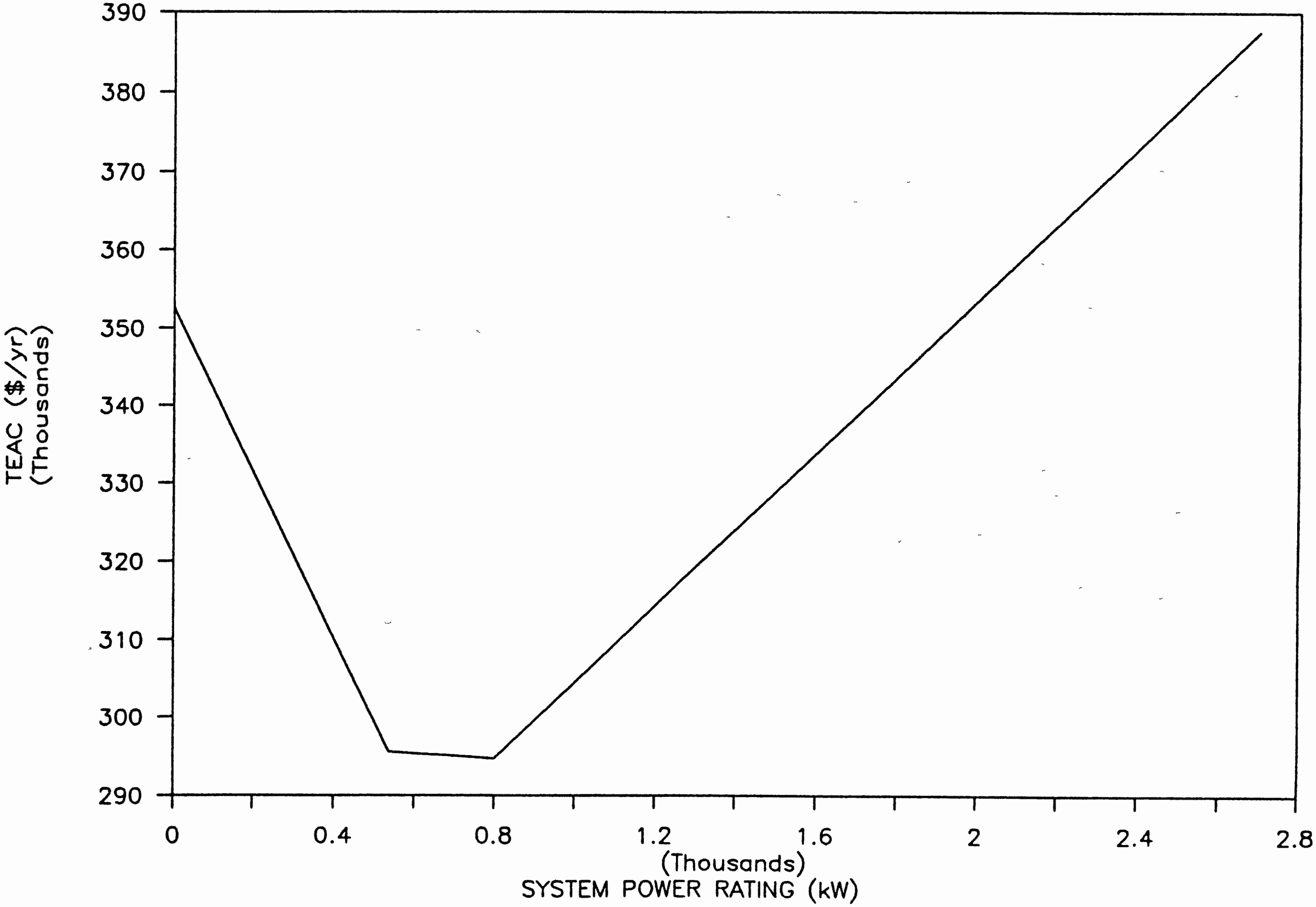


Figure 4.3 Example 4.1: Appliction of CCCD-1 Model

4.2.3 CHP CCCD-2: A Non-Linear Model

To achieve a linear program in the previous model, the main simplifying assumption was that the system unit cost was constant. However, as stated in section 4.1.2, economies of scale can make c_u a function of Pc. Hence, the linear term AC = (a.Pc) in equations [4.11] through [4.13] should be substituted using equation [4.2]. Thus

$$AC_e = (b + a.e^{-kPc})Pc(A/P\ i,n) + c_p.Pc$$
$$= (C1.Pc.e^{-kPc}) + C2.Pc \qquad [4.17]$$

where C1 = [a.(A/P i, n)] and C2 = [b.(A/P i, n) + c_p]
Then, the TEAC functions for S1, S2 and S3, respectively (in terms of Pc and Hc= rc.Pc) are

$$TEAC_1 = AC_e + c_f\{(Pc/n_e.t_1) + (Hd-r_c.Pc)/n_a.t_1\}$$
$$+ c_m\ (Pc.t_1) + (Pd-Pc)\ t_1(c_e) \qquad [4.18]$$
$$TEAC_2 = AC_e + c_f\{(Pc/n_e.t_1) + (Hd-r_c.Pc)/n_a.t_1\}$$
$$+ c_m\ (Pc.t_1) + (Pc-Pd)\ (t_1)(s_e) \qquad [4.19]$$
$$TEAC_3 = AC_e + c_f\{(Pc/n_e.t_1) + c_m\ (Pc*t_1) + (Pc-Pd)\ (t_1)(s_e) +$$
$$c_r.(r_c.Pc-Hd).(t_1) \qquad [4.20]$$

Compare equations 4.18, 4.19 and 4.20 to the linear model in 4.11, 4.12, and 4.13. Linearity has vanished in the objective function expressed by equations 4.18 through 4.20. They, however, still span a convex objective function. Thus, the first derivative of $TEAC_i$ with respect to Pc is

$$TEAC_i' = AC' + O\&M_i' \qquad \text{for } i = 1,2 \text{ and } 3.$$

where

$$AC' = C1.e^{-kPc}\ (1-kPc) + C2, \text{ and}$$
$$O\&M_1' = [c_f(1/n_e - r_c/n_a) + c_m - c_e].t_1$$
$$O\&M_2' = [c_f\{1/n_e - r_c/n_a\} + c_m + s_e].t_1$$
$$O\&M_3' = [c_f.1/n_e + c_m + s_e + c_r.r_c].t_1$$

Note that (a+ $O\&M_i$)' constitute the constant slopes of the $TEAC_i$ functions in the linear model CCCD-1.

Next, the second derivative of $TEAC_i$ with respect to Pc is

$$TEAC_i'' = -(k.C1.e^{-kPc})\ (2-k.Pc)$$

Since $k > 0$, then for $k.Pc < 2$, $TEAC_i''$ is negative definite, and therefore, $TEAC_i$ is concave (convex downwards) for typical values of Pc. In general, $k \in (0.0001, 0.0002)$ and $Pc \in (100, 10{,}000)$. In fact, if $k.Pc = 2$, then $TEAC_i'' = 0$, and the CCCD-2 model becomes the linear CCCD-1 model. In other words, CCCD-1 is the particular case of CCCD-2 -for the asymptotic portion of the plot of equation [4.2]. For plots of installed capacity (kW) vs system unit cost ($/kW), that assume typical values of k and Pc, the reader is referred to works by GKCO Consultants (1982) and RCG/Hagler Bailly, Inc. (1991).

Henceforth, the "extreme points" represented by **(0,0), a1, a2** and **C** are linked by the curves **$TEAC_i$ (i= 1, 2, 3)**; which are concave for the parameter values of interest, i.e. $Pc \in (100, 10{,}000)$. Figure 4.4 shows that the objective function defined by the curves **Si** (i=1,2,3) is amenable to extreme point optimization, so the "extreme point" optimality of the previous model (CCCD-1) prevails. Therefore, one just need to evaluate TEAC at the extreme points to find the optimum Pc* (i.e. min TEAC*). Thus, $Pc^* \in [0, Pc(a_1), Pc(a_2), Pc_{max}]$.

The rationale is that although the previous linear model has been modified to a non-linear one, the optimum should "anchor" on one of the linear extreme points, at which significant changes in the OF's slope occur.

Hence, the CCCD-2 model is generally represented by

Minimize {min $TEAC_1$, min $TEAC_2$, min $TEAC_3$}

subject to the constraint set CS.

Therefore, the optimum Pc* of CCCD-2 can be found using the TEAC values defined by equations [4.18] through [4.20], then substituted in equations [4.14a], [4.14b] or in Corollaries I and II, depending on the case.

Example 4.2 CCCD-2. Table 4.3 lists an example of the application of the CCCD-2 model. The top portion of the table includes all the relevant input data; which is essentially the same data of the CCCD-1 example, except the system unit cost c_u. Here, c_u is expressed in terms of the exponential unit cost function parameters a=900, b=600 and k=0.0002 (these cost parameters are not equivalent to the flat unit cost in the CCCD-1 example). Thus using equation 4.2 the unit system cost is

$$c_u = 600 + 900\ e^{-(0.0002Pc)}$$

and using equation 4.17 the annual owning cost is

$$AC = c_u \cdot Pc\ (A/P\ i,n) + c_p \cdot Pc$$

The rest of the computations and the method are the same as in the CCCD-1 example; including the determination of the extreme points.

Since the evaluation of extreme points warrants the optimum Pc*, a search is not required. However, the search list from Pc = 0, 2700 has been included in table 4.3 to generate points for model verification and to plot the curves TEACi. The TEAC of the extreme points (0,0), b1, b2, and C (which defines Pc_{max}) are included in the list. The system size Pc versus TEAC has been plotted in Figure 4.4 below. In this example, the extreme point $\mathbf{b_1}$ corresponds to the optimal size Pc* = 537 kW with a TEAC* = $325,218/year.

TABLE 4.3

CCDD-2 MODEL FOR EXAMPLE 4.2

INPUT DATA

Pd:	800	KW	cr:	$0.100	/MMBTU	Demand-s	$50.00	/kW-yr	MARR, I:	15%	
Hd:	2.5	MMBTU/H	se:	$0.034	/kwh	Demand-b	$70.00	/kW-yr	Proj Life:	20	years
Ne:	0.33		ce:	$0.038	/kWh	Na:	0.75		(A/P I,n):	0.15976	
Nt:	0.45		cf:	$2.000	/MMBTU	a:	900		cp:	$10.00	/kW
t:	8000	hr/yr	cf:	$2.000	/MMBTU	b:	600		HPR (dem):	0.92	
Avail.:	0.9132		cm:	$0.0040	/kWh	k:	0.00020		HPR (sys):	1.36	

	Pc kw	Hc MMBTU/h	RC $/yr	Aux fire $/yr	FC $/yr	EC $/yr	ES $/yr	MC $/yr	IC $	O&M $/yr	AC $/yr	TEAC $/yr	PURPA EFF
	0	0.00	0	53333	53333	299200	0	0	0	352533	0	352533	N/A
	100	0.47	0	43408	59951	261800	0	3200	148218	324951	23680	348630	78.00%
	200	0.93	0	33482	66568	224400	0	6400	292942	297368	46801	344169	78.00%
	300	1.40	0	23556	73185	187000	0	9600	434276	269785	69381	339166	78.00%
	400	1.86	0	13630	79802	149600	0	12800	572322	242202	91435	333637	78.00%
	500	2.33	0	3704	86419	112200	0	16000	707177	214619	112980	327599	78.00%
Pc(b1):	537	2.50	0	0	88889	98243	0	17194	756706	204326	120892	325218 *	78.00%
	600	2.79	233	0	99258	74800	0	19200	838937	193491	134030	327521	73.30%
	700	3.26	606	0	115801	37400	0	22400	967696	176207	154600	330807	67.54%
Pc(b2):	800	3.72	978	0	132344	0	0	25600	1093544	158922	174706	333628	63.22%
	900	4.19	1350	0	148887	0	32200	28800	1216569	179037	194361	341198	59.87%
	1100	5.12	2094	0	181973	0	96600	35200	1454494	219268	232372	355040	54.98%
	1300	6.05	2839	0	215059	0	161000	41600	1682130	259498	268740	367238	51.60%
	1500	6.98	3583	0	248145	0	225400	48000	1900105	299729	303564	377892	49.12%
	1700	7.91	4328	0	281232	0	289800	54400	2109009	339959	336938	387098	47.22%
	1900	8.84	5072	0	314318	0	354200	60800	2309403	380190	368954	394943	45.73%
	2100	9.77	5817	0	347404	0	418600	67200	2501818	420420	399694	401514	44.51%
	2300	10.70	6561	0	380490	0	483000	73600	2686757	460651	429240	406891	43.51%
	2500	11.63	7305	0	413576	0	547400	80000	2864694	500881	457668	411149	42.67%
Pcmax:	2545	11.84	7474	0	421053	0	561953	81446	2903981	509973	463944	411964	42.50%
	2700	12.56	8050	0	446662	0	611800	86400	3036078	541112	485048	414360	41.96%

The discussion with respect to base case and alternative system comparison and sensitivity analysis also apply to this model.

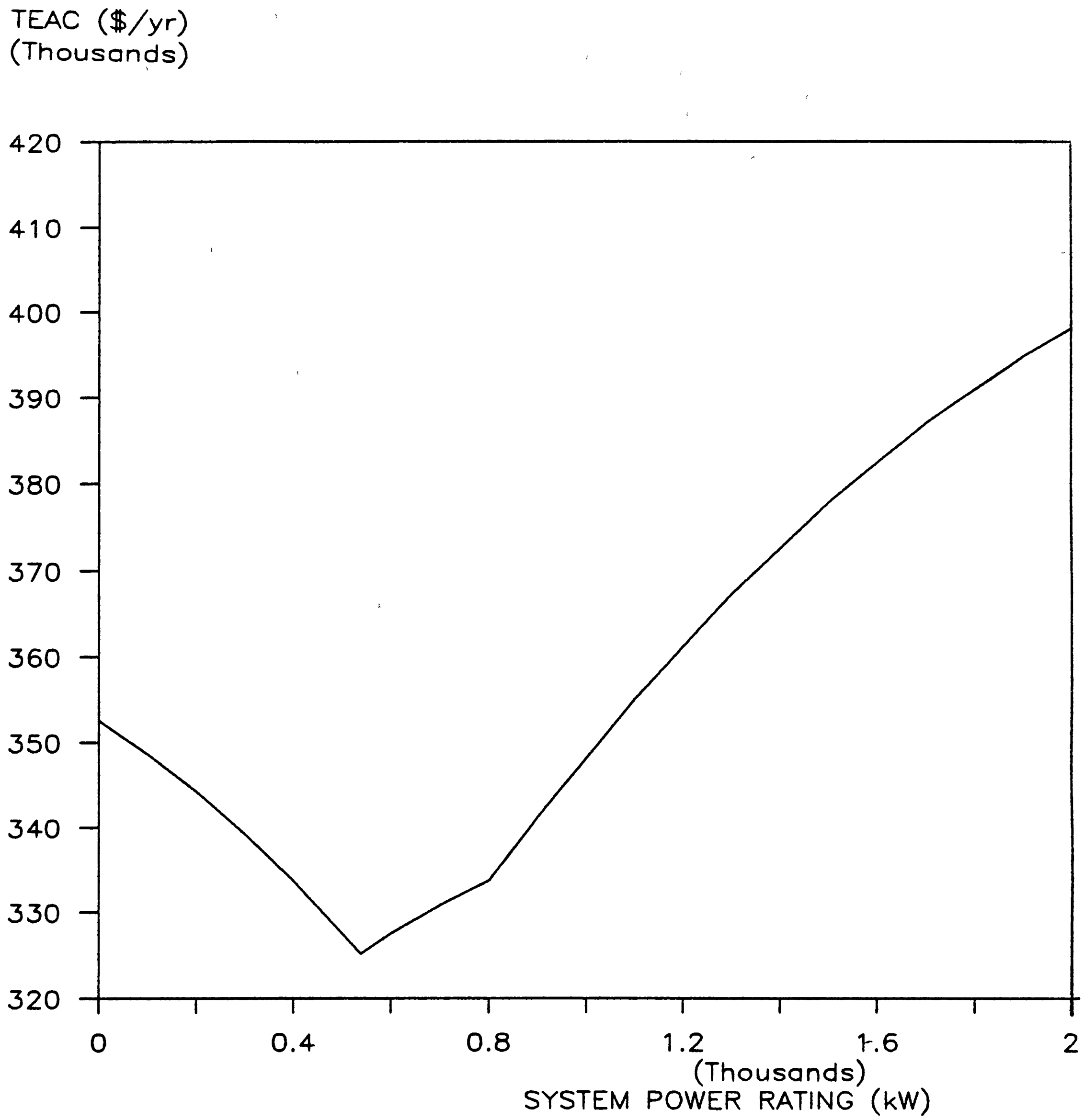


Figure 4.4 Application of CCCD-2 Model

<u>Example 4.3: PURPA Machine</u>. Another example based on the exponential unit cost or CCCD-2 model is shown in Table 4.4 and Figure 4.5. Here, some of the unit cost parameters (e.g. a=600 and b=500) were modified to explore the sensitivity of the model (and CHP system) to a dramatic reduction in the system unit installed cost. Also, a reduced fuel cost (c_f= \$1.8/MMBTU) was utilized to obtain a larger system as the optimum. The analysis and computations are the same as in the previous examples. The results are shown in Table 4.4.

In this case, TEAC is a generally (but not necessarily a monotonically) decreasing function of Pc (See Figure 4.5). Thus, at least a local maximum TEAC might exist. This is important, since a local maximum of TEAC defines a system size Pc_{no} that should be avoided.

Next, the optimal CHP plant size can be obtained from the constraint

$$Hd \geq Pc\ (0.425/n_e - 1) \qquad [4.10]$$

Thus,

$$Pc^* = Pc_{max} = \frac{Hd}{(0.425/n_e - 1)}$$

$$= \frac{(2.5\ \text{MMBTU/Hr})/(0.003412\ \text{MMBTU/kWH})}{(0.425/0.33\ -1)}$$

$$= 2545\ \text{kW}$$

From Table 4.4, by evaluating TEAC(Pc) at Pc = Pc_{max}, we obtain TEAC* = \$276,925/yr. Hence, this example yields as optimum the maximum legally feasible CHP system size; i.e. the so called "PURPA machine".

The discussion with respect to base case and alternative system comparison and sensitivity analysis also apply to this model and example.

TABLE 4.4

CCDD-2 MODEL FOR EXAMPLE 4.3
(PURPA MACHINE)

INPUT DATA

Pd:	800	KW	cr:	$0.100	/MMBTU	Demand-s	$50.00	/kW-yr	MARR, I:	15%	
Hd:	2.5	MMBTU/H	se:	$0.034	/kwh	Demand-b	$70.00	/kW-yr	Proj Life:	20	years
Ne:	0.33		ce:	$0.038	/kWh	Na:	0.75		(A/P I,n):	0.15976	
Nt:	0.45		cf:	$1.800	/MMBTU	a:	600		cp:	$10.00	/kW
t:	8000	hr/yr	cf:	$1.800	/MMBTU	b:	500		HPR (dem):	0.92	
Avail.:	0.9132		cm:	$0.0040	/kWh	k:	0.00020		HPR (sys):	1.36	

	Pc kw	Hc MMBTU/h	RC $/yr	Aux fire $/yr	FC $/yr	EC $/yr	ES $/yr	MC $/yr	IC $	O&M $/yr	AC $/yr	TEAC $/yr	PURPA EFF
	0	0.00	0	48000	48000	299200	0	0	0	347200	0	347200	N/A
	100	0.47	0	39067	53955	261800	0	3200	108812	318955	17384	336339	78.00%
	200	0.93	0	30134	59911	224400	0	6400	215295	290711	34396	325107	78.00%
	300	1.40	0	21200	65866	187000	0	9600	319518	262466	51047	313513	78.00%
	400	1.86	0	12267	71822	149600	0	12800	421548	234222	67347	301569	78.00%
	500	2.33	0	3334	77777	112200	0	16000	521451	205977	83308	289285	78.00%
Pc(b1):	537	2.50	0	0	80000	98243	0	17194	558202	195437	89179	284616	78.00%
	600	2.79	233	0	89332	74800	0	19200	619291	183566	98939	282505	73.30%
	700	3.26	606	0	104221	37400	0	22400	715130	164627	114250	278877	67.54%
Pc(b2):	800	3.72	978	0	119110	0	0	25600	809029	145688	129252	274939	63.22%
	900	4.19	1350	0	133999	0	32200	28800	901046	164149	143952	275901	59.87%
	1100	5.12	2094	0	163776	0	96600	35200	1079662	201070	172488	276959	54.98%
	1300	6.05	2839	0	193553	0	161000	41600	1251420	237992	199929	276921	51.60%
	1500	6.98	3583	0	223331	0	225400	48000	1416736	274914	226340	275854	49.12%
	1700	7.91	4328	0	253108	0	289800	54400	1576006	311836	251785	273821	47.22%
	1900	8.84	5072	0	282886	0	354200	60800	1729602	348758	276324	270882	45.73%
	2100	9.77	5817	0	312663	0	418600	67200	1877879	385680	300013	267093	44.51%
	2300	10.70	6561	0	342441	0	483000	73600	2021171	422602	322905	262507	43.51%
	2500	11.63	7305	0	372218	0	547400	80000	2159796	459524	345052	257176	42.67%
Pcmax:	2545	11.84	7474	0	378947	0	561953	81446	2190507	467867	349959	255873 ★	42.50%
	2700	12.56	8050	0	401996	0	611800	86400	2294052	496446	366501	251147	41.96%

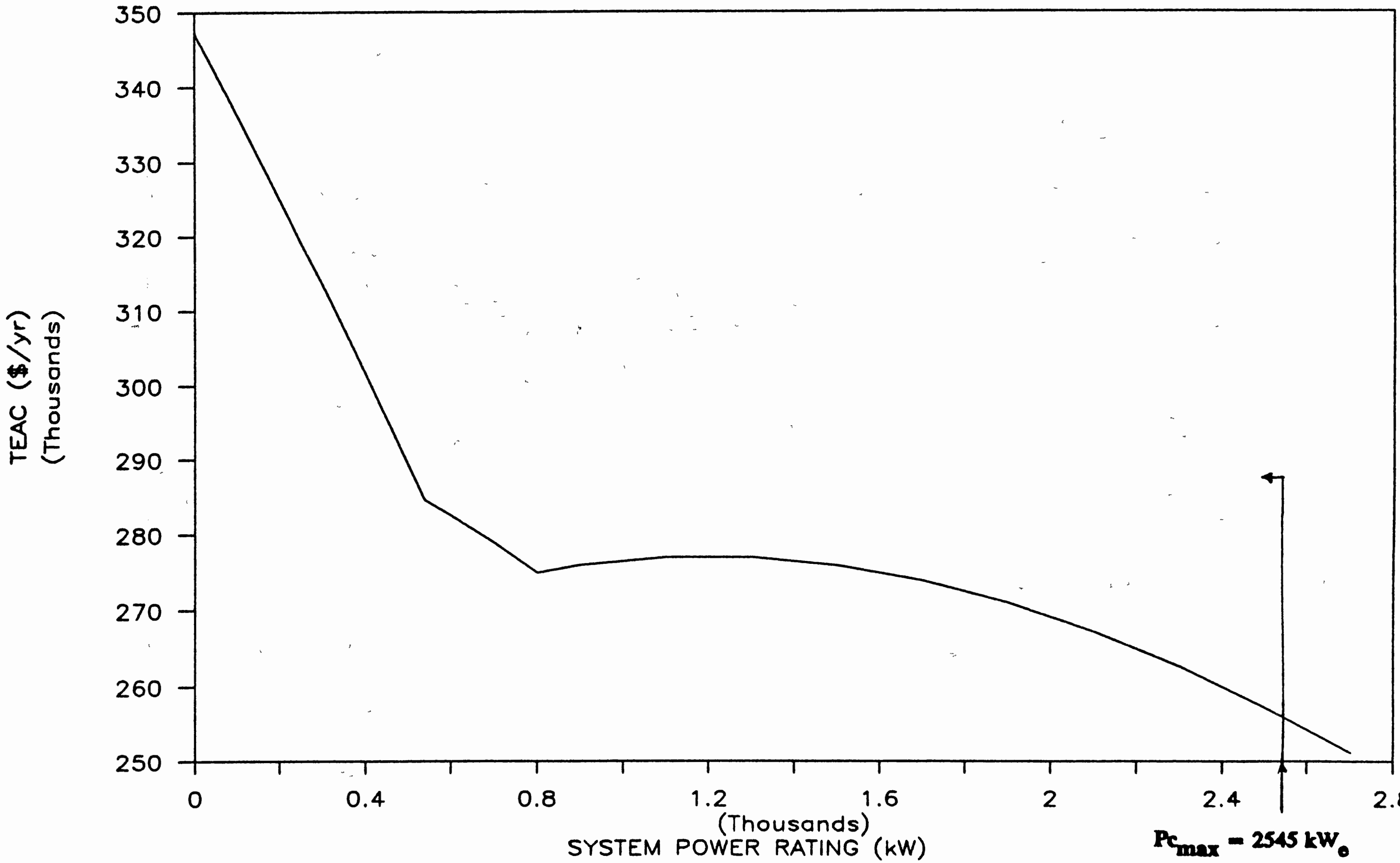


Figure 4.5 CCCD-2 Model and PURPA Machine

4.3 Constant Capacities and Gaussian Demands Model (CCGD)

In this case, the economic criteria is to select the optimal size Pc* of a CHP system that minimizes TEAC when the CHP system capacities are constant and the demands are Gaussianly distributed. The following formulation, however, is given for a generally distributed demand with a probability density function f(d) and cumulative distribution F(d). Later, this general formulation will be changed to the Gaussian case.

Considering that the CHP demand is the function of two random variables: heat (H) and power (P), then the CDF of the joint CHP demand is

$$G(z) = \iint_{D(z)} f(p,h)\,dp.dh$$

where Z = CHP(p,h) is the CHP demand and f(p,h) is the joint density function of the variables P and H, and D(z) is the domain for which CHP(p,h) < z. The pdf g(z) can be determined by means of differentiation of g(z); i.e, g(z) = G'(z). Figure 4.6 corresponds to the first quadrant of the Heat (H) and Power (P) space, which defines the sub-space W containing all the feasible CHP demands. For a constant heat-to-power ratio r_c, the CHP capacity curve S is defined by the equation

$$Hc = r_c\ Pc \qquad [4.9]$$

Thus, in Figure 4.6, W is partitioned by the capacity curve in two main zones:

Zone A: which contains all the possible CHP demands (>0) located to the left of the capacity curve.

Zone B: which contains all the possible CHP demands (>0) located to the right of the capacity curve.

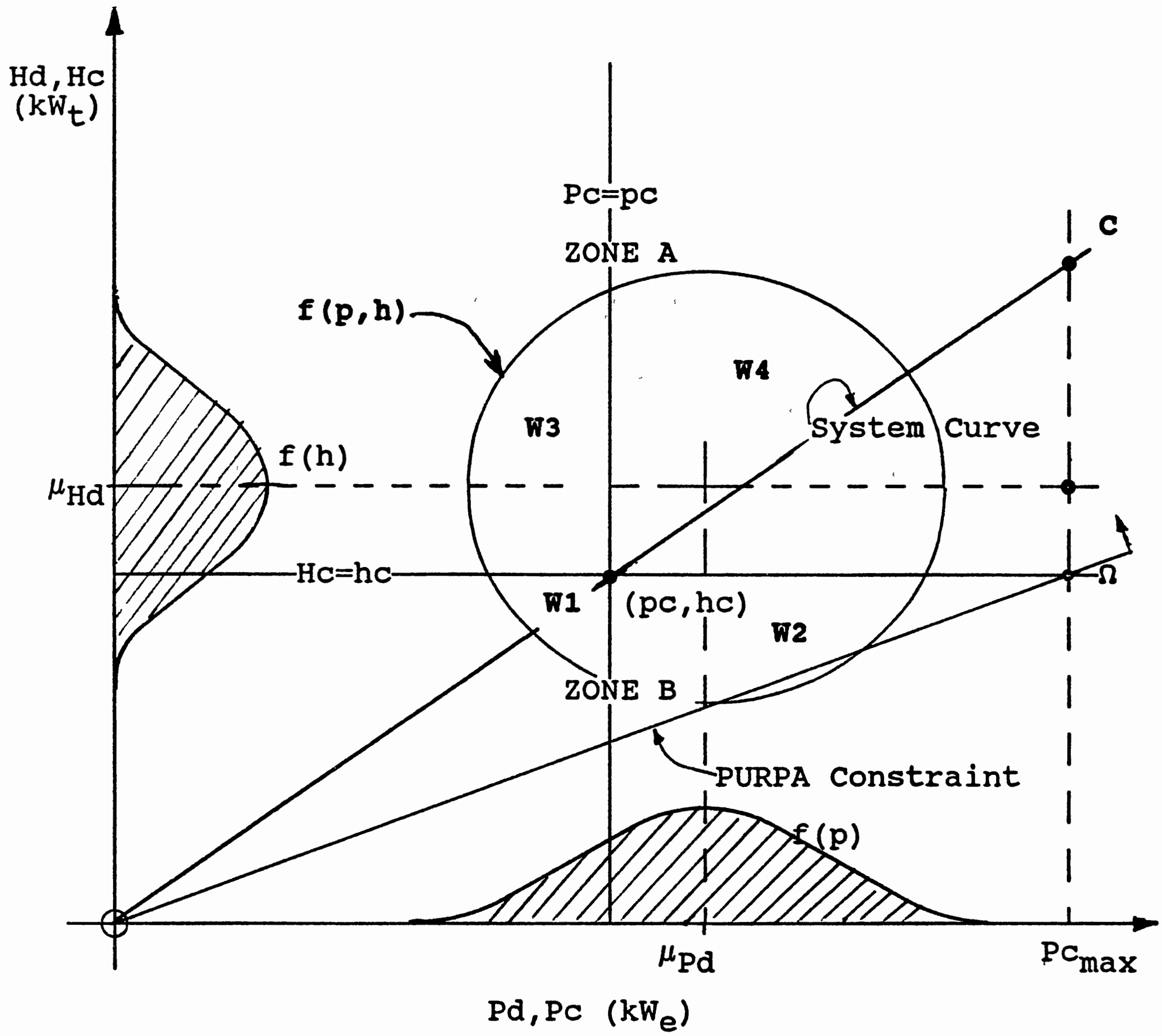


Figure 4.6 CHP Feasible Space and System Capacity Curve

The marginal pdf's of p and h, f(p) and f(h) respectively define a bivariate JDF f(p,h). Here, we assume that the variables P and H are statistically independent. Henceforth

$$f(p,h) = f(p).\ f(h)$$

This is a critical assumption that sometimes will not be satisfied, since correlated CHP loads might exist in some facilities. Future research should examine this problem.

In Fig 4.6, the CHP space W is also partitioned by the lines defined by an arbitrary system-size point (pc, hc) and an arbitrary bivariate density contour line f(p,h) in four regions. Each region has a one to one correspondence to the four states previously defined in section 4.1.1 and Table 4.1. The regions or states are

W_1: Hc > Hd and Pc > Pd
W_2: Hc > Hd and Pc < Pd
W_3: Hc < Hd and Pc > Pd
W_4: Hc < Hd and Pc < Pd

Since Pd and Hd are independent random variables, then the probability of each CHP state is defined by the product of the marginal probabilities of each state:

$$P\ (W_1) = P(Hc > Hd).\ P(Pc > Pd)$$
$$P\ (W_2) = P(Hc > Hd).\ P(Pc < Pd)$$
$$P\ (W_3) = P(Hc < Hd).\ P(Pc > Pd)$$
$$P\ (W_4) = P(Hc < Hd).\ P(Pc > Pd)$$

Thus, states W_i are complementary and their probabilities form a joint probability mass function, that is

$$P(W_1) + P(W_4) + P(W_2) + P(W_3) = 1$$

4.3.1 <u>General Linear Unit Cost Formulation</u>

For a system size [Pc,Hc]: Pc>0 and Hc>0, there is an expected linear cost function TEACi associated with each state Wi (i=1,2,3,4). Thus, for t operating hours per year, and using Hc= rc.Pc the expected (state) linear costs are:

$$TEAC_1 = \int_o^{Hc} \int_o^{Pc} \{(a.Pc) + c_f\{(Pc/n_e) + (rc.Pc-Hd)c_r + c_m.Pc + (Pc-Pd)\ s_e\}\ t\ f(p)\ f(h)\ dp\ dh \qquad [4.21]$$

$$TEAC_2 = \int_o^{Hc} \int_{Pc}^{\infty} \{(a.Pc) + c_f(Pc/n_e) + (rc.Pc-Hd)c_r + c_m.Pc + (Pd-Pc)\ c_e\}\ t\ f(p)\ f(h)\ dp\ dh \qquad [4.22]$$

$$TEAC_3 = \int_{Hc}^{\infty}\int_{o}^{Pc} \{(a.Pc) + c_f[(Pc/n_e) + (Hd-rc.Pc)/n_a] + c_m.Pc + (Pc-Pd)\ s_e\}\ t\ f(p)\ f(h)\ dp\ dh \qquad [4.23]$$

$$TEAC_4 = \int_{Hc}^{\infty}\int_{Pc}^{\infty} \{(a.Pc) + c_f[(Pc/n_e) + (Hd-rc.Pc)/n_a] + c_m.Pc + (Pd-Pc)\ c_e\}\ t\ f(p)\ f(h)\ dp\ dh \qquad [4.24]$$

Then, the total expected annual cost is a function of a single variable (Pc) and is defined by:

$$TEAC = \Sigma\ TEAC_i \quad (i= 1,2,3,4) \qquad [4.25]$$

Taking derivatives of equations 4.21 to 4.24 with respect to Pc and equating to zero we have (the necessary condition):

$$TEAC_i' = a + O\&M_i' = 0$$

Where:

$$O\&M_1' = [c_f.1/n_e + c_m + s_e + c_r.r_c].t.P(W_1)$$

$$O\&M_2' = [c_f.1/n_e + c_m - c_e + c_r.r_c].t.P(W_2)$$

$$O\&M_3' = [c_f(1/n_e - r_{c/}n_a) + c_m + s_e].t.\ P(W_3)$$

$$O\&M_4' = [c_f[1/n_e - r_{c/}n_a) + c_m - c_e].t.\ P(W_4)$$

and: $$P(Wi) = \int\int_{D(Wi)} dp\ dh$$

are the state probabilities. D(Wi) is the integration domain of state Wi previously defined (equations 4.21 through 4.25). Thus, P(Wi) is a function of Pc, i.e. P(Wi) = g(Pc). Then, for an extreme point, equation 4.25 can be restated as:

$$TEAC' = a + \Sigma\ O\&M_i.t.g(Pc) \quad i=1,2,3,4$$

Now, for TEAC(Pc)' = 0, by solving for Pc or through a search algorithm, we obtain Pc = Pc_o. Then depending on the values of the second derivative of TEAC with respect to Pc (TEAC"),

	If:	**Then the unconstrained TEAC(Pc) function (viewed from below) is:**
CASE (1)	$TEAC''(Pc_o) > 0$	Convex (a global minimumm exists)
CASE (2)	$TEAC''(Pc_o) < 0$	Concave (a global maximum exists)
CASE (3)	$TEAC''(Pc_o) = 0$	Indefinite (see note below)

In case (3) [TEAC (Pc*), Pc*] is an inflexion point (a point of a flat bottom) if there is (not) a change in sign in the neighborhood of TEAC(PC*)'. But, since Pc is bounded by the constraints defined in Section 4.2.2, then the CCGD linear model spans a convex feasible space determined by the constraint set (CS):

CS :		
	System curve:	$Hc = rc. Pc$
	PURPA constraint:	$Pc \leq Pc_{max}$
	Efficiency constraint:	$n_e < 0.425$ [per Eq. 4.10]
	Non-negative size:	$Pc \geq o$

Where: $Pc_{max} = \mu_{Hd} . n_e / (0.425 - n_e)$ is the PURPA limit, and

μ_{Hd} = the mean or expected average value of the heat demand (Hd) random variable.

Next, the <u>necessary</u> general condition for a relative minimum TEAC(Pc) to exist is:

$$\Sigma \; O\&M_i . P(W_i) = -a/t$$

Thus, for an unconstrained optimum Pc_o to exist, the hourly expected incremental O&M cost (the left hand side of equation 4.27) must be equal to the system owning cost per hour (a/t). Henceforth, to solve the constrained linear model

Min $\quad TEAC = \Sigma \; TEAC_i \quad (i= 1,2,3,4)$

Subject to: CS

the following general decision rules are defined. The rules also constitute the <u>sufficient</u> optimal conditions, which are defined to obtain the constrained optimum Pc* for a unimodal (single peak or single valley) TEAC function. The rules are:

(1): If $TEAC(Pc_o)'' > 0$, TEAC is Convex (a minimum exists).

(a) If $0 \leq Pc_o > Pc_{max}$, then $Pc^* = Pc_{max}$

(b) If $0 \leq Pc_o \leq Pc_{max}$, then $Pc^* = Pc_o$

(2): If TEAC(Pc_o)" < 0, TEAC is Concave (a maximum exists). In this case, TEAC is evaluated at the extreme points Pc=0 and $Pc=Pc_{max}$. The optimum is

$Pc* = Pc$, such that

$TEAC* = Min \{TEAC(Pc=0), TEAC (Pc=Pc_{max})\}$

(3) If TEAC(Pc_o)" = 0 , TEAC is indefinite. If a local minimum des not exist in the interval Pc= (0, Pc_{max}),

(a) If TEAC'(Pc_{max})>0, then Pc* = 0

(b) If TEAC'(Pc_{max})≤0, then Pc* = Pc_{max}

For any CHP demand distributions, if TEAC has multiple feasible minimums -i.e. equation 4.27 has several real roots in the interval (0, Pc_{max})- then a relative global optimum $Pc_o \in (0, Pc_{max})$ must be found by evaluating TEAC at each minimum in the interval. Then rule **(1)** is evaluated for Pc_o. However, the following section (4.3.2) shows that for most typical cost parameters and independent CHP demand densities, TEAC(Pc) is strictly convex. Thus, there exist one global optimum. The next two examples illustrate an application of the methodology.

Example 4.4, CCUD-1 Model. Develop the general necessary and sufficient conditions to obtain the optimal system size when the heat H and power P demands are independent random variables with the following uniform density functions:

Heat demand: $f(H) = \dfrac{1}{H_2 - H_1}$ $\quad H_1 \le H \le H_2$

$f(H) = 0$ $\quad$ elsewhere

Power demand: $f(P) = \dfrac{1}{P_2 - P_1}$ $\quad P_1 \le P \le P_2$

$f(P) = 0$ $\quad$ elsewhere

SOLUTION. First equations 4.21 through 4.24 are written in terms of the densities f(H) and f(P) and give

$$TEAC_1 = \int_{H1}^{Hc} \int_{P1}^{Pc} \{(a.Pc) + c_f\{(Pc/n_e) + (rc.Pc-H)c_r + c_m.Pc + (Pc-P)\ s_e\}\ J(t)\ dP\ dH \qquad [4.21]$$

$$TEAC_2 = \int_{H1}^{Hc} \int_{Pc}^{P2} \{(a.Pc) + c_f(Pc/n_e) + (rc.Pc-H)c_r + c_m.Pc + (P-Pc)\ c_e\}\ t\ J(t)\ dP\ dH \qquad [4.22]$$

$$TEAC_3 = \int_{Hc}^{H2} \int_{P1}^{P2} \{(a.Pc) + c_f[(Pc/n_e) + (H-rc.Pc)/n_a] + c_m.Pc + (Pc-P)\ s_e\}\ J(t)\ dP\ dH \qquad [4.23]$$

$$TEAC_4 = \int_{Hc}^{H2} \int_{Pc}^{H1} \{(a.Pc) + c_f[(Pc/n_e) + (H-rc.Pc)/n_a] + c_m.Pc + (P-Pc)\ c_e\}\ t\ J(t)\ dP\ dH \qquad [4.24]$$

Where $J(t) = \dfrac{t}{(H_2-H_1)(P_2-P_1)}$ is the time domain joint density function.

Then, the total expected annual CHP cost of a system of size (Pc,Hc) is:

$$TEAC = \Sigma\ TEAC_i \quad (i= 1,2,3,4) \qquad [4.25]$$

Collecting the common terms in equations above we have:

$$TEAC(Pc) = \iint_{(W)} (a + cf/n_e.t + cm.t)Pc\ f(P).f(H)\ dpdh + EC_1 + EC_2 + EC_3 + EC_4 \qquad [4.25a]$$

Where:

$$EC_1 = \int_{H1}^{Hc} \int_{P1}^{Pc} \{c_r(Hc-H) + s_e(Pc-P)\}\ J(t)\ dPdH$$

$$EC_2 = \int_{H1}^{Hc} \int_{Pc}^{P2} \{c_r(Hc-H) + c_e(P-Pc)\}\ J(t)\ dPdH$$

$$EC_3 = \int_{Hc}^{H2} \int_{P1}^{Pc} \{c_f/n_a\ (H-Hc) + s_e(Pc-P)\}\ J(t)\ dPdH$$

$$EC_4 = \int_{Hc}^{H2} \int_{Pc}^{H1} \{c_f/n_a\ (H-Hc) + c_e(P-Pc)\}\ J(t)\ dPdH$$

These equations can be integrated and simplified to yield (Please refer to the Appendix for detailed proof)

$$TEAC = A.Pc^2 + (B1+ B2)Pc + C \qquad [4.26]$$

where:

$A = 1/2\ [rc^2(c_r+c_f/n_a)(P_2 - P_1) + (c_e+s_e)(H_2 - H_1)].J(t)$

$B1 = [(c_eP_2 + s_eP_1)\ (H_1 - H_2)$

$\qquad + r_c(c_r.H_1 + c_f/n_a.H_2)(P_1 - P_2)].J(t)$

$B2 = a + (c_f/n_e)t + c_m.t$

$C = 1/2\ [(c_r.H_1{}^2 + cf/(n_a)H_2{}^2)(P_2 - P_1)$

$\qquad + (c_eP_2{}^2 + s_eP_1{}^2)(H_2 - H_1)].\ J(t)$

Then, the <u>necessary</u> optimal condition is

$$TEAC'(Pc) = 2A.Pc + B1 + B2 = 0 \qquad [4.27]$$

and the <u>sufficient</u> condition for a global minimum is

$$[TEAC''(Pc) = 2A\ ] > 0$$

where $2A = \{(c_r+c_f/n_a)(P_2 - P_1)rc^2 + (c_e+s_e)(H_2 - H_1)\}.J(t)$.

Given that $(c_r, c_f, n_a, r_c, c_e, J(t)) > 0$

$P_2 > P_1$, $H_2 > H_1$ and

$c_e \geq s_e$, since $s_e < 0$ (by definition)

therefore, TEAC"(Pc) is >0 and TEAC(Pc), a quadratic function, is strictly convex for the case of uniformly distributed CHP loads. Hence, the unconstrained optimum $\mathbf{Pc_o}$ can be obtained directly by solving equation [4.27], That is

$$\mathbf{Pc_o} = -(B1 + B2)/(2A) \qquad [4.28]$$

Then the optimum Pc* is obtained as follows for $Pc_o > 0$.

If	then
$Pc_o > Pc_{max}$,	$Pc^* = Pc_{max}$
$Pc_o \leq Pc_{max}$,	$Pc^* = Pc_o$
$Pc_o < 0$,	$Pc^* = 0$ ▪

<u>Example 4.5: CCUD-1 Model</u>. Use the following uniformly-distributed CHP demands and cost data with the results and equations of the Example 4.4 to determine the unconstrained optimum Pc_o and the optimum under PURPA constraint Pc*. Plot TEAC(Pc) vs Pc.

<u>SOLUTION</u> Table 4.5A lists all the relevant input data. Table 4.5B shows the equations needed to calculate TEAC for uniform CHP loads and various Pc and their corresponding calculated TEAC(Pc) values. Figure 4.5 shows a plot of Pc vs TEAC(Pc).

TABLE 4.5A

COST DATA AND DISTRIBUTION PARAMETERS FOR EXAMPLE 4.5 (CCUD-1)

<u>Operation and Maintenance Cost Data</u>	
c_e = 0.038 + 70/8760	(\$/kWH$_e$)
s_e = -[0.034 + 50/8760]	(\$/kWH$_e$)
c_r = (0.1)(0.003412)	(\$/kWH$_t$)
c_f = (2.0)(0.003412)	(\$/kWH$_t$)
c_m = 0.004	(\$/kWH$_e$)
<u>Owning Cost data</u>	
c_u = 1000	(\$/kW-installed
c_p = 10	(\$/yr/kw-installed)
i = 0.15	(MARR)
n = 20	(years)
<u>System Performance Data</u>	
t = 8000	(hours/year)
n_e = 0.33	
n_t = 0.45	
n_a = 0.75	
rc = n_t/n_e	
<u>Distribution Parameters</u>	
P_1 = 600	(kw$_e$)
P_2 = 1000	(kw$_e$)
H_1 = 500	(kw$_t$)
H_2 = 1000	(kw$_t$)

See notation in Section 4.1.2 and Example 4.4

Example 4.5, Continued. For constant system-unit- cost (c_u = k), the equivalent annual cost of owning the CHP system is $a = c_u.A + c_p$, where: $A = i\ (1+i)^n/[(1 + i)^n - 1]$. For uniformly distributed loads, the time domain joint density distribution is

$$J(t) = t.f(Pd,Hd) = \frac{t}{(P2 - P1)\ (H2 - H1)}$$

Then, using MATHCAD, Anderson (1989), a numerical analysis software, an exhaustive search is performed for $Pc_k = 100.k$, (k = 0, 20), i.e. in the interval Pc ϵ (0, 2000 kW_e), to generate points for the TEAC vs Pc plot (Figure 4.5). Using the data of Table 4.5A, the TEAC equations in Table 4.5B are solved for each Pc_k. The results are shown in Figure 4.7.

TABLE 4.5B

EXAMPLE 4.5: TEAC EQUATIONS FOR CCUD-1 MODEL (MATHCAD FORMAT)

$$A := \left[\frac{1}{2}\right]\cdot\left[\left[Cr + \frac{Cf}{Na}\right]\cdot(P2 - P1)\cdot rc^2 + (Ce + Se)\cdot(H2 - H1)\right]\cdot Jt$$

$$B1 := \left[(Ce\cdot P2 + Se\cdot P1)\cdot(H1 - H2) + \left[Cr\cdot rc\cdot H1 + Cf\cdot\frac{rc}{Na}\cdot H2\right]\cdot(P1 - P2)\right]\cdot Jt$$

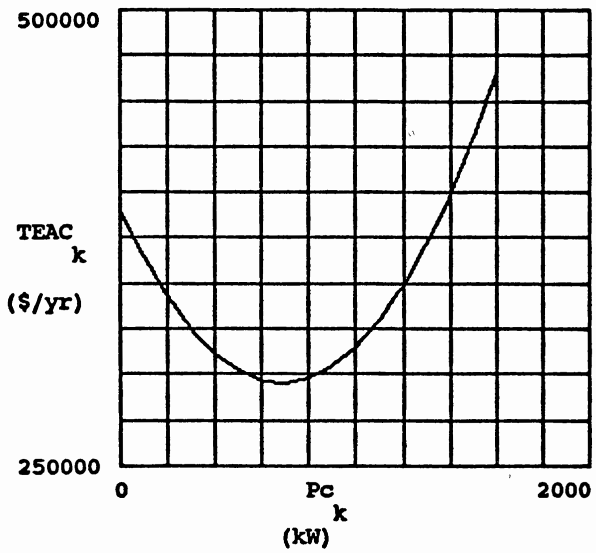
$$B2 := \left[a + \frac{Cf}{Ne}\cdot t + Cm\cdot t\right]$$

$$C := \left[\left[\frac{Cr}{2}\cdot H1^2 + \frac{Cf}{2\cdot Na}\cdot H2^2\right]\cdot(P2 - P1) + \left[\frac{Ce}{2}\cdot P2^2 + \frac{Se}{2}\cdot P1^2\right]\cdot(H2 - H1)\right]\cdot Jt$$

$A = 0.203$ $\quad B1 = -645.563$ $\quad B2 = 367.192$ $\quad C = 3.904\cdot10^5$

$$TEAC_k := A\cdot Pc_k^2 + (B1 + B2)\cdot Pc_k + C$$

Example 4.5-Continued: Plot and table of TEAC vs Pc show optimal system size and cost. Pcmax and Pc* are computed below.



Pc_k	$TEAC_k$
0	$3.904 \cdot 10^{5}$
100	$3.646 \cdot 10^{5}$
200	$3.429 \cdot 10^{5}$
300	$3.252 \cdot 10^{5}$
400	$3.116 \cdot 10^{5}$
500	$3.021 \cdot 10^{5}$
600	$2.966 \cdot 10^{5}$
700	$2.952 \cdot 10^{5}$
800	$2.978 \cdot 10^{5}$
900	$3.045 \cdot 10^{5}$
$1 \cdot 10^{3}$	$3.153 \cdot 10^{5}$
$1.1 \cdot 10^{3}$	$3.302 \cdot 10^{5}$
$1.2 \cdot 10^{3}$	$3.491 \cdot 10^{5}$
$1.3 \cdot 10^{3}$	$3.721 \cdot 10^{5}$
$1.4 \cdot 10^{3}$	$3.991 \cdot 10^{5}$
$1.5 \cdot 10^{3}$	$4.302 \cdot 10^{5}$
$1.6 \cdot 10^{3}$	$4.654 \cdot 10^{5}$
$1.7 \cdot 10^{3}$	$5.046 \cdot 10^{5}$
$1.8 \cdot 10^{3}$	$5.479 \cdot 10^{5}$
$1.9 \cdot 10^{3}$	$5.953 \cdot 10^{5}$
$2 \cdot 10^{3}$	$6.467 \cdot 10^{5}$

The maximum legally feasible system is

$$Pcmax := \frac{H1 + H2}{2} \cdot \frac{Ne}{0.425 - Ne}$$

$$Pcmax = 2.605 \cdot 10^{3} \text{ kW.}$$

Then, the unconstrained optimum size is :

$$Pco := \frac{-(B1 + B2)}{2 \cdot A}$$

$$Pco = 684.77 \text{ kW.}$$

Since Pco < Pcmax

Pc* = Pco = 684.77 kW is the global optimum.

Next, the minimum cost is:

$$TEAC := A \cdot Pco^{2} + (B1 + B2) \cdot Pco + C$$

$$TEAC = 2.951 \cdot 10^{5} \text{ Dollars/year.}$$

Figure 4.7 Constant Capacity Cogeneration System with Uniformly Distributed CHP Loads

4.3.2 Model For Constant Capacity and General Probabilistic Demands (CCPD-1)

This section develops the necessary and sufficient condition for optimality for a model with generally distributed loads. For the stochastic CHP demand space W (Figure 4.6), we have the following general and independent (marginal) density distributions and their corresponding domains:

Heat demand:	$f(Hd) =$	$f(H)$	$0 \leq H \leq \infty$
	$=$	0	elsewhere
Power demand:	$f(Pd) =$	$f(P)$	$0 \leq P \leq \infty$
	$=$	0	elsewhere

Since the densities are independent, then the joint density distribution is

$$f(P,H) = f(P).f(H)$$

Hence, equations 4.21 through 4.24 can be restated as follows

$$TEAC_1 = \int_0^{Hc}\int_0^{Pc} \{(a.Pc) + c_f(Pc/n_e) + c_r(rc.Pc-H) + c_m.Pc + s_e(Pc-P)\}\ t\ f(P).f(H)\ dP\ dH \qquad [4.21]$$

$$TEAC_2 = \int_0^{Hc}\int_{Pc}^{\infty} \{(a.Pc) + c_f(Pc/n_e) + c_r(rc.Pc-H) + c_m.Pc + c_e(P-Pc)\}\ t\ f(P).f(H)\ dP\ dH \qquad [4.22]$$

$$TEAC_3 = \int_{Hc}^{\infty}\int_0^{Pc} \{(a.Pc) + c_f[(Pc/n_e) + (H-rc.Pc)/n_a] + c_m.Pc + s_e(Pc-P)\} t\ f(P).f(H)\ dP\ dH \qquad [4.23]$$

$$TEAC_4 = \int_{Hc}^{\infty}\int_{Pc}^{\infty} \{(a.Pc) + c_f[(Pc/n_e) + (H-rc.Pc)/n_a] + c_m.Pc + c_e(P-Pc)\} t\ f(P).f(H)\ dP\ dH \qquad [4.24]$$

Then, the total expected annual CHP cost of a system of size (Pc,Hc) is:

$$TEAC = \Sigma\ TEAC_i \quad (i= 1,2,3,4) \qquad [4.25]$$

Note that the capacities Pc and Hc are constants with respect to the variables of integration -the demands P and H. Hence, collecting common terms in the equations above we have:

$$TEAC = EC_0 + EC_1 + EC_2 + EC_3 + EC_4 \qquad [4.25a]$$

Where:

$$EC_0 = \int_0^{\infty}\int_0^{\infty} (a + cf/n_e.t + cm.t)Pc\ f(P,H)\ dPdH \qquad [a0]$$

$$EC_1 = \int_0^{Hc}\int_0^{Pc} \{c_r(Hc-H) + s_e(Pc-P)\}t\ f(P,H)\ dPdH \qquad [a1]$$

$$EC_2 = \int_0^{Hc}\int_{Pc}^{\infty} \{c_r(Hc-H) + c_e(P-Pc)\}t\ f(P,H)\ dPdH \qquad [a2]$$

$$EC_3 = \int_{Hc}^{\infty}\int_0^{Pc} \{c_f/n_a(H-Hc) + s_e(Pc-P)\}t\ f(P,H)\ dPdH \qquad [a3]$$

$$EC_4 = \int_{Hc}^{\infty}\int_{Pc}^{\infty} \{c_f/n_a\ (H-Hc) + c_e(P-Pc)\}t\ f(P,H)\ dPdH \qquad [a4]$$

Since equation **[a0]** spans the whole CHP domain W, that is

$$\iint_{(W)} f(P,H)\ dP\ dH \equiv 1 \qquad (\text{ by definition})$$

then it can be simplified to yield

$$EC_0 = (a + cf/n_e.t + cm.t)Pc \qquad [a0]$$

Next, equation **[a1]** can be rewritten as

$$EC_1/t = Pc(c_r\ rc + s_e) \int_0^{Hc}\int_0^{Pc} f(P).f(H)dPdH$$

$$- c_r \int_0^{Hc}\int_0^{Pc} H.f(P).f(H)dPdH - s_e \int_0^{Hc}\int_0^{Pc} P.f(P).f(H)dPdH$$

Next, using the following definitions for statistically independent marginal density functions,

(1) $$F_x(a) \equiv \int_o^a f(x)dx$$

(2) $$E(x_i) \equiv \int_{W_i} x.f_x(x)dx$$

(3) $$\int_o^a \int_o^b f(x,y)\ dxdy \equiv \int_o^a f_x(x)dx \ . \int_o^b f_y(y)dy$$

we have from equation [a1]

$$EC_1/t = Pc(c_r rc + s_e)\ F_p(Pc).F_h(Hc) - c_r.E(H_1).F_p(Pc) - s_e.E(P_1).F_h(Hc) \quad [b1]$$

Similarly, using $1 - F_x(a) = \int_a^\infty f(x)dx$, equations [a2] through [a4] can be reduced to

$$EC_2/t = Pc(c_r rc - c_e)\ F_h(Hc).[1-F_p(Hc)] - c_r.E(H_2).[1-F_p(Pc)] + c_e.E(P_2).F_h(Hc) \quad [b2]$$

$$EC_3/t = Pc(-c_f rc/n_a + s_e).[1-F_h(Hc)].[F_p(Hc)] + c_f/n_a.E(H_3).F_p(Pc) - s_e.E(P_3).[1-F_h(Hc)] \quad [b3]$$

$$EC_4/t = Pc(-c_f rc/n_a - c_e).[1-F_h(Hc)].[1-F_p(Hc)] + c_f/n_a.E(H_4).[1-F_p(Pc)] - c_e.E(P_4).[1-F_h(Hc)] \quad [b4]$$

Note that in the last four equations **[bi]** above

$$E(H_a) = E(H_1) = E(H_2) = \int_o^{Hc} H\ f_h(H)dH$$

$$E(H_b) = E(H_3) = E(H_4) = \int_{Hc}^\infty H\ f_h(H)dH$$

$$E(P_a) = E(P_1) = E(P_3) = \int_o^{Pc} P\ f_p(P)dP$$

$$E(P_b) = E(P_2) = E(P_4) = \int_o^{Hc} P\ f_p(P)dP$$

Then, using the expected values $E(H_k)$ and $E(P_k)$, $k = a,b$; summing and collecting terms in the equations **[bi]** we have

$$(EC_1 + EC_2 + EC_3 + EC_4)/t = \qquad [4.29]$$

$$[(c_r+c_f/n_a)rcF_h(Hc) + (s_e + c_e).F_p(Pc)]\ Pc$$

$$- c_r.E(Ha) - s_e.Ep(Pa) + c_f/n_a.E(Hb) + c_e.E(Pb)$$

$$- c_f/n_a.rc - c_e$$

Next, substituting [4.27] in [4.25a] we obtain

$$TEAC(Pc) = (a + c_f/n_e.t+ c_m.t)Pc \qquad [4.30]$$

$$+ \{ [(c_r + c_f/n_a)rc.F_h(Hc)$$

$$+ (s_e + c_e)F_p(Pc) -c_f/n_a.rc -c_e]Pc$$

$$- c_r.E(H_a) - s_e.Ep(P_a)$$

$$+ c_f/n_a.E(H_b) + c_e.E(P_b) \}.t$$

The <u>necessary</u> condition for a minimum is obtained by taking the derivative (') of equation [4.30] with respect to Pc and equating it to zero. Hence, after collecting terms we have

$$TEAC'(Pc) = 0$$

$$= (a + c_f/n_e.t+ c_m.t) \qquad [4.31]$$

$$+ [(c_r + c_f/n_a)rc.F'_h(Hc) + (s_e + c_e).F'_p(Pc)]Pc$$

$$+ [(c_r + c_f/n_a)rc.F_h(Hc) + (s_e + c_e).F_p(Pc)$$

$$- c_r.E(H_a) - s_e.Ep(P_a)$$

$$- c_r.E'(H_a) - s_e.E'(P_a) + c_f/n_a.E'(H_b) + c_e.E'(P_b)\}t$$

If a closed form of Pc is obtained from the equation above, then it can be solved for the unconstrained optimum Pc_o. Otherwise, a search is required to approximate Pc_o.

Next, the <u>sufficient</u> condition for an unconstrained global minimum is obtained by taking the second derivative (") of TEAC(Pc) with respect to Pc, and verifying whether it is positive definite. Thus

$$TEAC''(Pc) = [(c_r + c_f/n_a)rc.F''_h(Hc) + (s_e + c_e).F''_p(Pc)]\ Pc$$

$$+ 2\ [(c_r + c_f/n_a)rc.F'_h(Hc) + (s_e + c_e).F'_p(Pc)]$$

$$- c_r.E''(H_a) - s_e.E''(P_a)$$

$$+ c_f/n_a.E''(H_b) + c_e.E''(P_b)\}t \qquad [4.32]$$

Next, recall that

$$F_h(Hc) = \int_o^{Hc} f_h(H)\,dH$$

$$F_p(Pc) = \int_o^{Pc} f_p(H)\,dH$$

$$E(Ha) = \int_o^{Hc} H.f_h(H)\,dH$$

$$E(Hb) = \int_{H_c}^{\infty} H.f_h(H)\,dH$$

$$E(Pa) = \int_o^{Pc} P.f_p(P)\,dP$$

$$E(Hb) = \int_{H_c}^{\infty} P.f_p(P)\,dP$$

Next, we use x = Pc, y= Hc,Pc and apply the following (Leibniz equation) to the six relationships above. Thus, the derivative of $F(x) = \int_{a(x)}^{b(x)} f(x,y)\,dy$ with respect to x is:

$$\frac{d}{dx}F(x) = \int_{a(x)}^{b(x)} \frac{d}{dx} f(x,y)dy + \left[\frac{d}{dx}b(x)\right] f[x,b(x)]$$

(Leibniz Rule)

$$- \left[\frac{d}{dx}a(x)\right] f[x,a(x)]$$

Hence, for constant first derivatives F'(.) and E'(.) we obtain the following

$$\begin{aligned}
F'_h(Hc) &= rc.f_h(Hc) > 0, & F''_h(Hc) &= 0\\
F'_p(Pc) &= f_p(Pc) > 0, & F''_p(Pc) &= 0\\
E'_h(Ha) &= Hc.f_h(Hc) > 0, & E''_h(Ha) &= 0\\
E'_p(Pa) &= Pc.f_p(Pc) > 0, & E''_p(Pa) &= 0\\
E'_h(Hb) &= -Hc.f_h(Hc) < 0, & E''_h(Ha) &= 0\\
E'_p(Pb) &= -Pc.f_p(Pc) < 0, & E''_p(Pa) &= 0
\end{aligned} \qquad [4.33]$$

In fact, for any $f_p(.)$ and f_h (.), the second derivative terms in [4.32] are negligible and should vanish. Therefore

$$TEAC(Pc)" = 2[(c_f/n_a + c_r)\ rc^2.f_h(H) + (s_e + c_e).f_p(P)] \qquad [4.32a]$$

Then TEAC"(Pc) is positive definite as long as

$$(c_f/n_a + c_r)\ rc^2.f_h(H) + (S_e + c_e).f_p(P) > 0$$

or

$$(c_f/n_a + c_r)\ rc^2.f_h(H) + c_e.f_p(P) > -s_e.\ f_p(P)$$

Since {cf/na, cr, rc, ce, fh(H), fp(P)} ≥ 0, and $|s_e| < c_e$, then the inequality above is in general true for typical values found in industry. Thus the total expected annual cost TEAC(Pc) is typically convex for independent demands.

4.3.3 Non Linear Formulation (CCPD-2)

Recall that Section 4.2.3 models a non-linear (exponentially decreasing) unit cost to account for economies of scale of larger CHP plants. Then, using [4.17] the cost is

$$\begin{aligned} TEAC(Pc) = {} & C1.Pc.e^{-kPc} + (C2 + c_f/n_e.t + c_m.t)Pc \qquad [4.34] \\ & + \{ [(c_r + c_f/n_a)rc.F_h(Hc) + (s_e + c_e)F_p(Pc) \\ & - c_f/n_a.rc - c_e]Pc - c_r.E(H_a) - s_e.Ep(P_a) \\ & + c_f/n_a.E(H_b) + c_e.E(P_b) \}.t \end{aligned}$$

where $C1 = a.(A/P\ i, n)$ and $C2 = b.(A/P\ i,n)+c_p$.

Next, the first derivative of TEAC with respect to PC is

$$\begin{aligned} TEAC'(Pc) = {} & C1.e^{-kPc}(1-kPc) + (C2 + c_f/n_e.t + c_m.t) \qquad [4.35] \\ & + [(c_r + c_f/n_a)rc.F'_h(Hc) + (s_e + c_e).F'_p(Pc)]Pc \\ & + [(c_r + c_f/n_a)rc.F_h(Hc) + (s_e + c_e).F_p(Pc) \\ & - c_r.E(H_a) - s_e.Ep(P_a) - c_r.E'(H_a) - s_e.E'(P_a) \\ & + c_f/n_a.E'(H_b) + c_e.E'(P_b)\}t \end{aligned}$$

Hence the second derivative of TEAC with repect to Pc is

$$\begin{aligned} TEAC"(Pc) = {} & - C1.k.e^{-kPc}\ (2-kPc) + [(c_r + c_f/n_a)rc.F"_h(Hc) \\ & + (s_e + c_e)\ F"_p(Pc)]Pc + 2\ [(c_r + c_f/n_a)rc.F'_h(Hc) \\ & + (s_e + c_e)\ F'_p(Pc)] - c_r.E"(H_a) - s_e.E"(P_a) \\ & + c_f/n_a.E"(H_b) + c_e.E"(P_b)\}t \end{aligned}$$

Using [4.33] and removing negligible second order derivatives

$$TEAC(Pc)'' = 2[(c_f/n_a + c_r)rc^2.f_h(H) + (s_e + c_e).f_p(P)] - C1.k.e^{-kPc}\ (2-kPc) \qquad [4.36]$$

Here, for $s_e<0$, TEAC"(Pc) is positive definite as long as

$$2[(c_f/n_a + c_r)\ rc^2.f_h(H) + c_e.f_p(P)] \ > \ C1.k.e^{-kPc}\ (2-kPc) - 2s_e.f_p(P)$$

which is the case of typical values found in industry. But, recall from section 4.2.3 that an exponential unit cost term introduces partially concave TEAC functions. Thus, for some combinations of cost coefficients, equation 4.36 can be indefinite; showing inflexion points and/or local maxima.

4.3.4 Constant Capacities and Gaussian Demands Model (CCGD-1)

Since CHP loads are the sum of many individual random loads from multiple processes and machines in an industrial plant, then they can be considered realizations of random process that follow the so called "Law of the Large Numbers".

But most heating and cooling loads are seasonal. Nevertheless, even with seasonal effects, each season or period associated with a load variance can assume normally distributed loads. Thus, the methodology developed here can be replicated for each set of seasonal CHP distributions.

Consequently, CHP demands constitute wide-sense stationary processes. Thus, most CHP loads encountered in industrial facilities can be regarded as Gaussian stationary, since they have a definite affinity for a mean value and converge stochastically to a constant. Recall that the

Gaussian or normal pdf for the random variable x is

$$f(x) = \frac{1}{\sqrt{(2\pi)}.\sigma} e^{-(x-\mu)^2/(2\sigma^2)} \quad [4.37]$$

and the Gaussian CDF is

$$F(x) = \int_{-\infty}^{\infty} \frac{1}{\sqrt{(2\pi)}.\sigma} e^{-(x-\mu)^2/(2\sigma^2)} dx \quad [4.38]$$

Then, using the results of section 4.3, the total expected equivalent annual cost of a constant capacity CHP system subject to normally distributed loads (CCGD) is

$$\begin{aligned} TEAC(Pc) = \; & (a + c_f/n_e.t + c_m.t)Pc \quad [4.39] \\ & + \{ [(c_r + c_f/n_a)rc.F_h(Hc) \\ & + (s_e + c_e)F_p(Pc) - c_f/n_a.rc - c_e]Pc \\ & - c_r.E_h(H_a) - s_e.E_p(P_a) \\ & + c_f/n_a.E_h(H_b) + c_e.E_p(P_b) \}.t \end{aligned}$$

where:

$$F_h(Hc) = \int_o^{Hc} \frac{1}{\sqrt{(2\pi)}.\sigma_h} e^{-(H-\mu_h)^2/(2\sigma_p^2)} dH$$

$$F_p(Pc) = \int_o^{Pc} \frac{1}{\sqrt{(2\pi)}.\sigma_p} e^{-(H-\mu_p)^2/(2\sigma_p^2)} dP$$

$$E_h(Ha) = \int_o^{Hc} \frac{H}{\sqrt{(2\pi)}.\sigma_h} e^{-(H-\mu_h)^2/(2\sigma_p^2)} dH$$

$$F_p(Pa) = \int_{Pc}^{\infty} \frac{P}{\sqrt{(2\pi)}.\sigma_p} e^{-(H-\mu_p)^2/(2\sigma_p^2)} dP$$

$$E_h(Ha) = \int_{Hc}^{\infty} \frac{H}{\sqrt{(2\pi)}.\sigma_h} e^{-(H-\mu_h)^2/(2\sigma_p^2)} dH$$

$$F_p(Pa) = \int_o^{Pc} \frac{P}{\sqrt{(2\pi)}.\sigma_p} e^{-(H-\mu_p)^2/(2\sigma_p^2)} dP$$

μ_j and σ_j^2 are the mean and the variance of demand j = (h,p).

<u>Example 4.6</u>. Use the Gaussian distributed CHP demand and cost data listed in Table 4.6a, and the equations of Section 4.3.4 to calculate TEAC. Next find approximated values for the unconstrained optimum Pc_o and the optimum under PURPAPc*. Then plot TEAC(Pc) vs Pc, Pc ϵ (0,2000 kW_e).
<u>SOLUTION</u> The numerical analysis software MATHCAD 2.5 was used in this example to compute and plot the results. Table 4.6A lists all the relevant input data. Then, Table 4.6B shows the equations needed to calculate TEAC for normally distributed CHP loads. Next, Table 4.7 lists TEAC(Pc) for Pc ϵ (0,2000 kW_e). Finally, Figure 4.8 depicts a plot of TEAC vs Pc, showing the optimal size at Pc_o = Pc* ≈ 700 kW.

TABLE 4.6A

INPUT DATA AND DISTRIBUTION PARAMETERS
FOR EXAMPLE 4.6 (MATHCAD FORMAT)

$\mu p := 800$ $\sigma p := 50$ $Cr := 0.1 \cdot .003412$	$\mu h := 730$ $\sigma h := 50$ $Cf := 2 \cdot .003412$	$Cu := 1000$ $Cp := 10$ $i := 0.15$ $n := 20$
$Se := -\left[0.034 + \frac{50}{8000}\right]$ $Se = -0.04$	$Ce := 0.038 + \frac{70}{8000}$ $Ce = 0.047$	$in := (1 + i)^n$
$Ne := 0.33$	$Na := 0.75$	$AP := i \cdot \frac{in}{in - 1}$
$Nt := 0.45$	$Cm := 0.004$	$a := Cu \cdot AP + Cp$
$rc := \frac{Nt}{Ne}$ $rc = 1.364$	$t := 8000$	$k := 0 ..20$ $Pc_k := 100 \cdot k$
$P1 := \mu p - 3 \cdot \sigma p$	$H1 := \mu h - 3 \cdot \sigma h$	$Hc_k := rc \cdot Pc_k$
$P2 := \mu p + 3 \cdot \sigma p$	$H2 := \mu h + 3 \cdot \sigma h$	

TABLE 4.6B

CCGD-MODEL EQUATIONS FOR EXAMPLE 4.6 (MATHCAD FORMAT)

$$ECO_k := \left[a + \frac{Cf}{Ne}\cdot t + Cm\cdot t\right]\cdot Pc_k \qquad TOL := 0.01$$

$$FPc_k := \int_{P1}^{Pc_k} \frac{1}{\sqrt{2\cdot\pi}\cdot\sigma p}\cdot e^{-\left[\frac{(P-\mu p)^2}{2\cdot\sigma p^2}\right]}\,dP \qquad FHc_k := \int_{H1}^{Hc_k} \frac{1}{\sqrt{2\cdot\pi}\cdot\sigma h}\cdot e^{-\left[\frac{(H-\mu h)^2}{2\cdot\sigma h^2}\right]}\,dH$$

$$EHa_k := \int_{H1}^{Hc_k} \frac{H}{\sqrt{2\cdot\pi}\cdot\sigma h}\cdot e^{-\left[\frac{(H-\mu h)^2}{2\cdot\sigma h^2}\right]}\,dH \qquad EHb_k := \int_{Hc_k}^{H2} \frac{H}{\sqrt{2\cdot\pi}\cdot\sigma h}\cdot e^{-\left[\frac{(H-\mu h)^2}{2\cdot\sigma h^2}\right]}\,dH$$

$$EPa_k := \int_{P1}^{Pc_k} \frac{P}{\sqrt{2\cdot\pi}\cdot\sigma p}\cdot e^{-\left[\frac{(P-\mu p)^2}{2\cdot\sigma p^2}\right]}\,dP \qquad EPb_k := \int_{Pc}^{P2} \frac{P}{\sqrt{2\cdot\pi}\cdot\sigma p}\cdot e^{-\left[\frac{(P-\mu p)^2}{2\cdot\sigma p^2}\right]}\,dP$$

$$C1_k := \left[\left[Cr + \frac{Cf}{Na}\right]\cdot rc\cdot FHc_k + (Se + Ce)\cdot FPc_k - \frac{Cf}{Na}\cdot rc - Ce\right]\cdot Pc_k$$

$$C2_k := -Cr\cdot EHa_k - Se\cdot EPa_k + \frac{Cf}{Na}\cdot EHb_k + Ce\cdot EPb_k$$

$$TEAC_k := ECO_k + t\cdot\left[C1_k + C2_k\right]$$

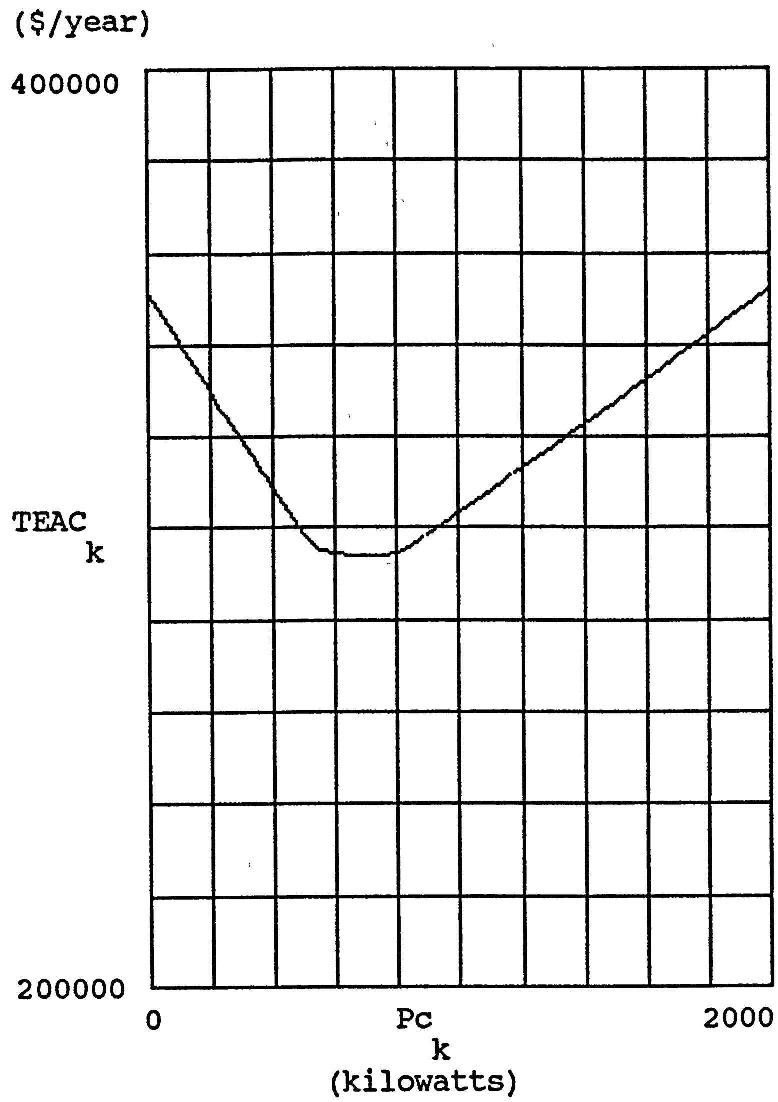
$$Pcmax := \mu h\cdot\frac{Ne}{0.425 - Ne}$$

TABLE 4.7

COMPARISON OF RESULTS OF EQUATION 4.39 AND EQUATIONS 4.21 TO 4.25 USING EXAMPLE 4.6 DATA

Pc (kWe):	0	200	400	600	800	1000	1200	1400	1600	1800	2000
EQUATIONS	TEAC(Pc) [$10,000/year]										
(A) 4.21 - 4.25 TOLERANCE: 1.0	3.515	3.302	3.090	2.944	2.948	3.035	3.132	3.229	3.327	3.424	3.522
(B) 4.39 (CCGD) TOLERANCE: 0.01	3.526	3.326	3.126	2.964	2.966	3.052	3.159	3.265	3.372	3.488	3.600
% Variance:	0.3%	0.7%	1.2%	0.7%	0.6%	0.6%	0.9%	1.1%	1.3%	1.8%	2.2%

NOTE:
Tolerance is the treshold limit used by the integration routine to establish convergence.
Lower tolerances give more accurate results but may produce overflow or underflow, and may not warrant convergence.



Note: The optimum Pc* is approximated as the mean value of the flat bottom

Figure 4.8 Plot of Pc vc TEAC(Pc) for Example 4.6 Shows convex TEAC function.

4.3.5 Computation Efficiency and Accuracy of Equation 4.39.

One of the advantages of the methodology developed in this thesis is its computation efficiency with respect to plain double numerical integration of the general cost formulation expressed by equations 4.21 through 4.25 -method (A). With a gross convergence tolerance = 1, and using data from Example 4.6, the execution of equations 4.21 to 4.25 using numerical integration takes about 5 hours. The actual computations were performed using the mathematical analysis software MATHCAD 2.5, in a 10 MHz computer with an 80286 microprocessor and mathematical co-processor.

However, in spite of the smaller tolerance used (0.01), the same problem only takes about 4 minutes to run using relationship 4.39 -method (B)- in the same machine.

For other ranges of Pc, $Pc \in (0, Pc_{max})$, relationship 4.39 is even faster. Thus, in general, using the same numerical integration routine (Newton-Cotes trapezoidal rule) the methodology of the CCGD model or method (B) is about 70 to 100 times faster than double numerical integration using the general equations 4.21 through 4.25 or method (A).

Table 4.7 shows the results for the two methods (A & B) discussed above. To accelerate the computation of method (A), a tolerance of 1.0 was used; whereas a tolerance of 0.01 was used with method (B).

However, note that in method (A) the computation error (variance) increases as Pc increases. Thus, since equation 4.39 only requires single numerical integration, it gives quicker and more accurate results.

4.4 Gaussian Capacities and Gaussian Demands Model

Variable production capacities are present in most industrial processes. In power plants, the temperature of boilers varies randomly according to differences in fuel heat content, ambient temperature and humidity. Changes in furnace temperature, in turn, produce variation in boiler heat transfer rates; with subsequent fluctuations in the amount and/or temperature of steam produced. For instance, Deming (1986) discuses the use of control charts to monitor utility boiler temperature -which is typically Gaussian. He uses cause-and-effect graphs to show the effect of boiler temperature variation on random monthly production costs.

Several examples of variable output capacity exist in conventional and cogeneration plants that use bio-mass and/or refuse derived fuel (RDF). Thus, the RDF fed into power boilers is a mixture of various components, with varying proportions throughout the day. In addition, unpredictable moisture content in bio-mass fuels make their heat of combustion a random variable. For instance, this author has witnessed the large variation in the power output of a sugar-mill power station caused by the hour-to-hour variation of moisture content in the bagasse used as fuel.

Also, since an increase in air temperature represents a reduction in air density, gas or combustion turbines exhibit output capacity variation according to the prevailing ambient air temperature -which is a random variable. Hence, increases in air temperature reduce the turbine output. Conversely, low air temperatures increase the turbine capacity.

Henceforth, in this case, the economic criteria is to select the optimal size Pc* of a CHP system that minimizes TEAC when <u>both</u>, the CHP system capacities and the demands are Gaussian or normally distributed. The model is based on the fact that the algebraic sum of two independent and normally distributed random variables (capacity and demand) also has a normal distribution. Thus, the results obtained for a normal distribution are also applicable to the sum or convolution of two independent normal random variables, (See Section 2.1.3).

Consequently, the CHP demand is represented by two random vectors with two components each: Capacity (Pc, Hc) and Demand (Pd, Hd) (See Figure 4.9). This model, however, shall be stated in terms of the difference between demand and capacity (Figure 4.10). Thus, the transform random variables

$$Z_p = Pc - Pd \qquad \text{and} \qquad Z_h = Hc - Pd \qquad [4.40]$$

are the power and heat differences, respectively. Then the CDF of the joint CHP demand difference is

$$G[z(p,h)] = \iint_{D(z)} f(Z_p, Z_h) \quad dZ_p . dZ_h$$

where Z (p,h) is the CHP demand difference and f(p,h) is the joint density function of the variables Z_p and Z_h, and D(Z) is the domain for which Z(p,h) < z. The pdf g(z) can be determined by means of differentiation of g(z); i.e, g(z) = G'(z). Figure 4.9 corresponds to the first quadrant of the Heat (H) and Power (P) space, which defines the space W, which contains all the feasible CHP demands and capacities. Hence, for a constant demand heat-to-power ratio r_d, the CHP demands are related by

$$Hd = r_d \, Pd \qquad [4.41]$$

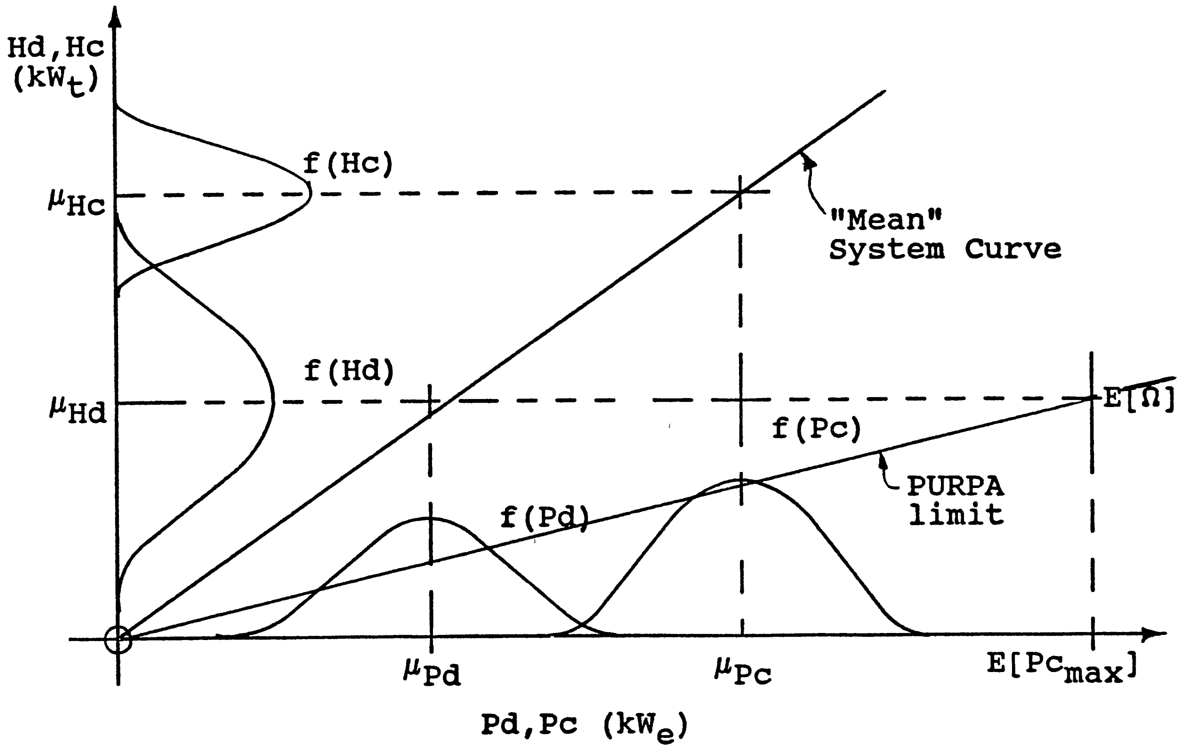


Figure 4.9 CHP Space for the Gaussian Capacity and Demand Model

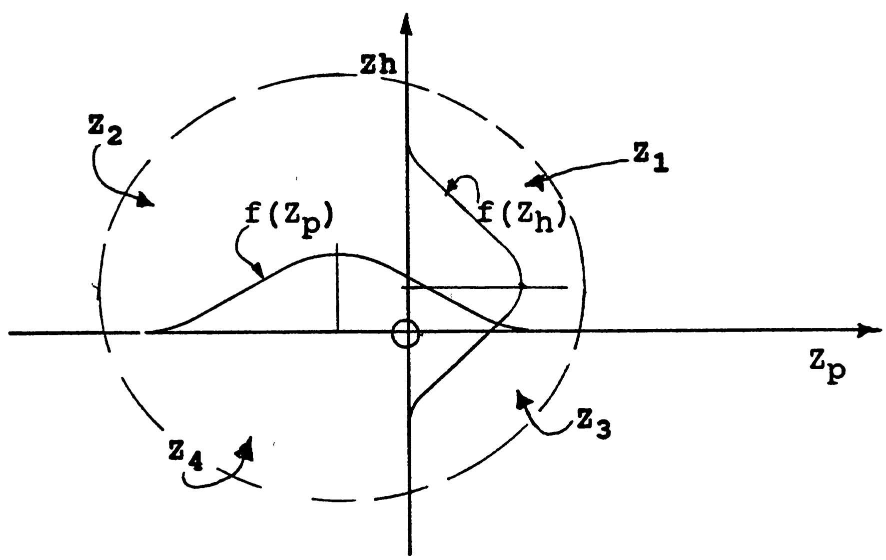


Figure 4.10 CHP difference space (Z) is the domain of the heat difference (Z_h) and power difference (Z_p) random variables

Furthermore, capacity variation is in general proportional to the rated mean capacity. Then, the CHP capacity coefficient of variation v_c is defined as:

$$v_c = \sigma_{hc}/\mu_{hc} = \sigma_{pc}/\mu_{pc} \qquad [4.42]$$

where σ_{hc} and σ_{pc} are the standard deviations of the heat and power capacities, and μ_{hc} and μ_{pc} are the means of the heat and power capacities.

The marginal pdf's of Z_b and Z_h, $f(Z_p)$ and $f(Z_h)$ jointly define a bivariate JDF $f(Z_p,Z_h)$. Here, the variables Z_p and Z_h are statistically independent. Thus

$$f(Z_p,Z_h) \equiv f(Z_p).\ f(Z_h)$$

Again, this is a critical assumption that is not always satisfied. Proposed future research should examine this.

In Fig 4.10, the CHP space W is transformed into the difference space Z. Here, an arbitrary contour curve of a bivariate normal density, the abscissa (Z_h=0) and the ordinate (Z_p=0) partition Z in four sub-spaces. Thus, each region has a one to one correspondence to the four states previously defined in section 4.1.1 and Table 4.1. In the difference (Z) domain, however, the regions or states are

$$Z_1:\ Z_h > 0 \text{ and } Z_p > 0$$
$$Z_2:\ Z_h > 0 \text{ and } Z_p < 0$$
$$Z_3:\ Z_h < 0 \text{ and } Z_p > 0$$
$$Z_4:\ Z_h < 0 \text{ and } Z_p < 0$$

Since Z_h and Z_p are independent random variables, then the probability of each CHP state is defined by the product of the marginal probabilities of each state:

$$P(Z_1) = P(Z_h > 0).P(Z_p > 0)$$

$$P(Z_2) = P(Z_h > 0).P(Z_p < 0)$$

$$P(Z_3) = P(Z_h < 0).P(Z_p > 0)$$

$$P(Z_4) = P(Z_h < 0).P(Z_p < 0)$$

Thus, states Z_i are complementary and their probabilities form a joint probability mass function, that is

$$P(Z_1) + P(Z_4) + P(W_2) + P(W_3) = 1$$

4.4.1 General GCGD Formulation for Linear Unit Cost (GCGD-1)

This section develops the TEAC equations for a general GDGC formulation. Thus, using equations 4.40, i.e. the transformations

$$Z_p = Pc - Pd$$
$$Z_h = Hc - Hd = rc.Pc - rd.Pd \qquad [4.40]$$

equation 4.25a can be restated as follows

$$TEAC = EC_0 + EC_1 + EC_2 + EC_3 + EC_4 \qquad [4.25b]$$

Where:

$$EC_0 = \int_{-\infty}^{\infty}\int_{-\infty}^{\infty} [a + cf/n_e.t + cm.t)\ Pc\ f(Zp,Zh)\ dZp\ dZh \qquad [a0]$$

$$EC_1 = \int_{0}^{\infty}\int_{0}^{\infty} [c_r.Zh + s_e.Zp]t\ f(Zp,Zh)\ dZp\ dZh \qquad [a1]$$

$$EC_2 = \int_{0}^{\infty}\int_{-\infty}^{0} [c_r.Zh - c_e.Zp]t\ f(Zp,Zh)\ dZp\ dZh \qquad [a2]$$

$$EC_3 = \int_{-\infty}^{0}\int_{0}^{\infty} [-c_f/n_a.Zh + s_e.Zp]t\ f(Zp,Zh)\ dZp\ dZh \qquad [a3]$$

$$EC_4 = \int_{-\infty}^{0}\int_{-\infty}^{0} [-c_f/n_a.Zh - c_e.Zp]t\ f(Zp,Zh)\ dZp\ dZh \qquad [a4]$$

Since equation [a0] spans the whole CHP domain Z, that is

$$E(Pc) \equiv \int\int_{(Z)} P\ f(P,H)\ dP\ dH \equiv \mu_{Pc} \quad \text{(by definition)}$$

and using $E(k.Pc) \equiv k.\mu_{Pc}$ (Pc is a r.v. and k is non-random), equation [a0] can be simplified to yield

$$EC_0 = (a + cf/n_e.t+ cm.t).\mu_{Pc} \qquad [b0]$$

Where μ_{Pc} is the mean or nominal CHP system capacity in kW_e. Next, equations [a1] through [a2] can be rewritten as

$$EC_1/t = \int_0^{\infty} \int_0^{\infty} [c_r.Zh + s_e.Zp]\ f(Zp,Zh)\ dZp\ dZh \qquad [b1]$$

$$EC_2/t = \int_0^{\infty} \int_{-\infty}^{0} [c_r.Zh - c_e.Zp]\ f(Zp,Zh)\ dZp\ dZh \qquad [b2]$$

$$EC_3/t = \int_{-\infty}^{0} \int_0^{\infty} [-c_f/n_a.Zh + s_e.Zp]\ f(Zp,Zh)\ dZp\ dZh \qquad [b3]$$

$$EC_4/t = \int_{-\infty}^{0} \int_{-\infty}^{0} [-c_f/n_a.Zh - c_e.Zp]\ f(Zp,Zh)\ dZp\ dZh \qquad [b4]$$

Then, using the following definitions for statistically independent marginal density functions,

(1) $$F_x(a) \equiv \int_o^a f(x)dx$$

(2) $$E(x_i) \equiv \int_{W_i} x.f_x(x)dx$$

(3) $$\int_o^a \int_o^b f(x,y)\ dxdy \equiv \int_o^a f_x(x)dx\ .\ \int_o^b f_y(y)dy$$

(4) $$1 - F_x(a) \equiv \int_a^{\infty} f(x)dx$$

equations [b1] through [b4] can be simplified to yield:

$$EC_1/t = c_r[1-F_p(0)].E(Zh_a) + s_e[1-F_h(0)].E(Zp_a) \qquad [b1]$$

$$EC_2/t = c_r[F_p(0)].E(Zh_a) - c_e[1-F_h(0)].E(Zp_b) \qquad [b2]$$

$$EC_3/t = -c_f/n_a[1-F_p(0)].E(Zh_b) + s_e[F_h(0)].E(Zp_a) \qquad [b3]$$

$$EC_4/t = -c_f/n_a[F_p(0)].E(Zh_b) - c_e[F_h(0)].E(Zp_b) \qquad [b4]$$

Note that in the four equations [bi] above the partial first moments or centers of mass are:

$$E(Zh_a) = \int_{o}^{\infty} Z_h \; f_h(Z_h) dZ_h \quad > 0 \qquad [c1]$$

$$E(Zh_b) = \int_{-\infty}^{0} Z_h \; f_h(Z_h) dZ_h \quad < 0 \qquad [c2]$$

$$E(Zp_a) = \int_{o}^{\infty} Z_p \; f_p(Z_p) dZ_p \quad > 0 \qquad [c3]$$

$$E(Zp_b) = \int_{-\infty}^{0} Z_p \; f_p(Z_p) dZ_p \quad < 0 \qquad [c4]$$

And the probabilites are:

$$F_h(0) = \int_{-\infty}^{0} f_h(Z_h) d_h \quad > 0 \qquad [d1]$$

$$1 - F_h(0) = \int_{0}^{\infty} f_h(Z_h) d_h \quad > 0 \qquad [d2]$$

$$F_p(0) = \int_{-\infty}^{0} f_p(Z_p) d_p \quad > 0 \qquad [d3]$$

$$1 - F_p(0) = \int_{0}^{\infty} f_p(Z_p) d_p \quad > 0 \qquad [d4]$$

Then, summing and collecting terms in equations [b1] through [b4] we have

$$(EC_1 + EC_2 + EC_3 + EC_4)/t = \qquad [4.43]$$

$$c_r.E(Zh_a) + s_e.E(Zp_a) - c_e.E(Zp_b) - c_f/n_a.E(Zh_b)$$

Hence, substituting [4.43] in [4.25b] we obtain the total expected equivalent annual cost for the GCGD model, i.e.

$$\begin{aligned} TEAC(Pc) = \; & (a + c_f/n_e.t + c_m.t)\mu_{Pc} \qquad [4.44] \\ & + [c_r.E(Zh_a) + s_e.E(Zp_a) \\ & - c_e.E(Zp_b) - c_f/n_a.E(Zh_b)].t \end{aligned}$$

Where μ_{Pc} is the mean or nominal CHP system capacity in kW_e.

4.4.2 <u>Necessary and Sufficient Conditions for Optimality (GCGD-1)</u>

The <u>necessary</u> condition for a minimum is obtained by taking the derivative (') of equation [4.44] with respect to μ_{Pc}, and equating it to zero. Hence, collecting terms we have

$$TEAC'(Pc) = 0 = (a + c_f/n_e.t + c_m.t) + [c_r.E'(Zh_a) + s_e.E'(Zp_a) - c_e.E'(Zp_b) - c_f/n_a.E'(Zh_b)].t \quad [4.45]$$

A closed form of Pc can not be obtained from equation 4.45 above, but it can be solved for the unconstrained optimum Pc_o through numerical integration.

The <u>sufficient</u> condition for an unconstrained global minimum is obtained by taking the second derivative (") of TEAC(Pc) with respect to Pc, and verifying whether it is positive. Thus

$$TEAC''(Pc) = [c_r.E''(Zh_a) + s_e.E''(Zp_a) - c_e.E''(Zp_b) - c_f/n_a.E''(Zh_b)].t \quad [4.46]$$

Since $[E'(Zp_a), E'(Zh_a), E''(Zp_a), E''(Zh_a)] \geq 0$ and

$[E'(Zp_b), E'(Zh_b), E''(Zp_a), E''(Zh_a)] \leq 0$

Then, TEAC"(Pc) is positive semi-definite as long as

$$c_r.E''(Zh_a) + s_e.E''(Zp_a) - c_e.E''(Zp_b) - c_f/n_a.E''(Zh_b) \geq 0$$

The inequality above is in general true for typical energy costs found in industry. See Table 4.10 (Example 4.7).

Therefore, the total expected equivalent annual cost TEAC(Pc) for the GDGC case is typically convex. Thus, in general, there exist an unconstrained global optimum for the GDGC case. But, indefinite TEAC functions might exist, showing local maxima and inflexion points. Then, local maxima should be identified, since operating a CHP system close to a local maximum is not economical and should be avoided.

4.4.3 <u>Formulation with Exponentially Decreasing System Unit Cost (GCGD-2)</u>

Recall that in Section 4.2.3 a model is defined for non-linear (exponentially decreasing) unit cost to account for economies of scale of larger CHP plants. Then, using equation 4.17, we have

$$TEAC(Pc) = C1.Pc.e^{-(k\mu_{Pc})} + (C2 + c_f/n_e.t + c_m.t)\mu_{Pc} + [c_r.E(Zh_a) + s_e.E(Zp_a) - c_f/n_a.E(Zp_b) - c_e.E(Zh_b)].t \quad [4.47]$$

Where $C1 = a.(A/P\ i,\ n)$ and $C2 = b.(A/P\ i,n)+c_p$.

Next, the first derivative of TEAC with respect to μ_{Pc} is

$$TEAC'(Pc) = C1.e^{-(k\mu_{Pc})}.(1-kPc) + (C2 + c_f/n_e.t + c_m.t) + [c_r.E'(Zh_a) + s_e.E'(Zp_a) - c_f/n_a.E'(Zp_b) - c_e.E'(Zh_b)].t \quad [4.48]$$

Then the second derivative of TEAC with respect to μ_{Pc} is

$$TEAC''(Pc) = -C1.k.e^{-(k\mu_{Pc})}.(2-kPc) + [c_r.E''(Zh_a) + s_e.E''(Zp_a) - c_f/n_a.E''(Zp_b) - c_e.E''(Zh_b)].t \quad [4.49]$$

Here, TEAC"(Pc) is positive semi-definite as long as

$$-C1.k.e^{-(k\mu_{Pc})}.(2-kPc) + [c_r.E''(Zh_a) - s_e.E''(Zp_a) - c_f/n_a.E''(Zp_b) - c_e.E''(Zh_b)].t \geq 0$$

which is the case of typical values encountered in industry. But, the positive semi-definiteness of the TEAC function -for the case of exponential unit cost- indicates that inflexion points and/or local maximums might exist. See Example 4.8.

<u>Example 4.7: GCGD-1.</u> Using the data listed in Table 4.8 and the GCGD model for a constant unit cost, evaluate the expected values defined by equations c1 trough c4. Next plot TEAC vs Pc showing the optimum. Estimate the maximum legal size and verify the cost of the "do nothing" option TEAC(0).

<u>Solution</u> Table 4.8 lists -in MATHCAD 2.5 format- (1) the relevant input data, (2) the input normal distribution parameters for the demands and capacities, and (3) the preliminary equations required to determine the mean (μ) and standard deviation (σ) of the power (Z_p) and heat (Z_h) differences. The table also defines the limits ($\mu \pm 3\sigma$) and the convergence tolerance (TOL) required for numerical integration. In the INPUT DATA section, the search index k = (0, 20) is defined to compute $TEAC_k$ for Pc_k = (0, 2000 kW).

The TEAC solution for this problem is obtained by calculating the GCGD-1 model equations, shown in Table 4.9. Note that the expected values $EZha_k$, $EZpa_k$, $EZhb_k$ and $EZpb_k$ defined in Table 4.9 (MATHCAD format) are equivalent to E(Zha), E(Zpa), E(Zhb) and E(Zpb). The expected values are defined by equations [c1] to [c4], or in general by

$$E(Z_x) = \int_a^b Z_x \, f_x(Z_x) dZ_x$$

Note that $E(Z_x)$ is also the center of mass (a first moment) of the surface defined by the limits of integration **a** and **b**, and the density curve fx(Zx). For model verification, the expected values $E(Z_x)$, and their first and second derivatives are estimated and listed in Table 4.10 for various μ_{pc}. Table 4.10 also shows the computed values of TEAC(μ_{pc}). These values have been plotted in Figure 4.11.

Next, the expected value of the maximum legal system as defined by PURPA is

$$E(Pc_{max}) = \mu_{hd} \frac{N_e}{0.425 - N_e}$$

$$= 12,000 \text{ kW}_e$$

From Figure 4.11 below, we see that the unconstrained

TABLE 4.8

INPUT DATA, DISTRIBUTION PARAMETERS AND PRELIMINARY EQUATIONS FOR EXAMPLE 4.7

INPUT DATA (MATHCAD 2.5)

$$Se := -\left[0.034 + \frac{50}{8000}\right] \qquad Ce := 0.038 + \frac{70}{8000}$$

$Cu := 900$
$Cp := 10$
$i := 0.15$
$n := 20$

$Cr := 0.1 \cdot .003412$ $\quad Na := 0.75$ $\quad in := (1 + i)^{n}$
$Cf := 2 \cdot .003412$ $\quad k := 0 ..20$
$Cm := 0.005$ $\quad t := 8000$
$Ne := 0.40$ $\quad Nt := 0.45$ $\quad AP := i \cdot \frac{in}{in - 1}$

INPUT DISTRIBUTION PARAMETERS

The mean values and standard deviations of the CHP demands are

$\mu pd := 800 \quad \sigma pd := 80 \quad \mu hd := 750 \quad \sigma hd := 75$

The coefficient of variation of the CHP capacity is $Vc := 0.2$

INPUT PRELIMINARY EQUATIONS

The equivalent annual system unit cost is $a := Cu \cdot AP + Cp$

The capacity (rc) and the demand (rd) heat-to-power ratios are

$$rc := \frac{Nt}{Ne} \qquad rd := \frac{\mu pd}{\mu hd}$$

The mean and standard deviation of the power capacity are

$$\mu pc_k := 100 \cdot k \qquad \sigma pc_k := \mu pc_k \cdot Vc$$

The mean and standard deviation of the heat capacity are

$$\mu hc_k := rc \cdot \mu pc_k \qquad \sigma hc_k := \mu hc_k \cdot Vc$$

The mean power (μzp) and mean heat (μzh) differences are

$$\mu zp_k := \mu pc_k - \mu pd \qquad \mu zh_k := \mu hc_k - \mu hd$$

The power (σzp) and heat (σzh) difference standard deviations are

$$\sigma zp_k := \sqrt{\sigma pc_k^{2} + \sigma pd^{2}} \qquad \sigma zh_k := \sqrt{\sigma hc_k^{2} + \sigma hd^{2}}$$

The limits for numerical integration (μ +/- 3σ) are

$$p1_k := \mu zp_k - 3 \cdot \sigma zp_k \qquad p2_k := \mu zp_k + 3 \cdot \sigma zp_k$$
$$h1_k := \mu zh_k - 3 \cdot \sigma zh_k \qquad h2_k := \mu zh_k + 3 \cdot \sigma zh_k$$

The convergence tolerance for integration is $TOL := 0.01$

TABLE 4.9

MODEL EQUATIONS OF EXAMPLE 4.7
MATHCAD FORMAT

$$EZha_k := \int_0^{h2_k} \frac{Zh}{\sqrt{2\cdot\pi}\cdot\sigma zh_k}\cdot e^{-\left[\frac{\left[Zh-\mu zh_k\right]^2}{2\cdot\sigma zh_k^2}\right]} dZh$$

$$EZpa_k := \int_0^{p2_k} \frac{Zp}{\sqrt{2\cdot\pi}\cdot\sigma zp_k}\cdot e^{-\left[\frac{\left[Zp-\mu zp_k\right]^2}{2\cdot\sigma zp_k^2}\right]} dZp$$

$$EZhb_k := \int_{h1_k}^{0} \frac{Zh}{\sqrt{2\cdot\pi}\cdot\sigma zh_k}\cdot e^{-\left[\frac{\left[Zh-\mu zh_k\right]^2}{2\cdot\sigma zh_k^2}\right]} dZh$$

$$EZpb_k := \int_{p1_k}^{0} \frac{Zp}{\sqrt{2\cdot\pi}\cdot\sigma zp_k}\cdot e^{-\left[\frac{\left[Zp-\mu zp_k\right]^2}{2\cdot\sigma zp_k^2}\right]} dZp$$

$$EC0_k := \left[a + \frac{Cf}{Ne}\cdot t + Cm\cdot t\right]\cdot\mu pc_k$$

$$TEAC_k := EC0_k + t\cdot\left[Cr\cdot EZha_k - \frac{Cf}{Na}\cdot EZhb_k + Se\cdot EZpa_k - Ce\cdot EZpb_k\right]$$

TABLE 4.10

EXPECTED VALUES, FIRST & SECOND DERIVATIVES OF MASS CENTERS OF SUBSPACES Zi EXAMPLE 4.7, GCGD-1 MODEL

μpc (kWe)	E(Zha)	E'(Zha) x 100	E"(Zha) x 100	E(Zhb)	E'(Zhb) x 100	E"(Zhb) x 100	E(Zpa)	E'(Zpa) x 100	E"(Zpa) x 100	E(Zpb)	E'(Zpb) x 100	E"(Zpb) x 100	TEAC(μpc) $/year
0	0.68			-748.55			0.73			-798.57			3.529E+05
100	0.51	0.17		-636.29	-112.26		0.58	0.15		-698.69	-99.88		3.405E+05
200	0.32	0.19	-0.03	-523.90	-224.80	112.54	0.41	0.16	-0.02	-598.79	-99.90	0.02	3.280E+05
300	0.11	0.21	-0.02	-411.50	-112.23	-112.57	0.23	0.18	-0.02	-498.89	-99.91	0.01	3.155E+05
400	0.08	0.03	0.18	-299.27	-107.52	-4.71	0.04	0.19	-0.01	-398.97	-99.92	0.01	3.031E+05
500	4.76	-4.68	4.71	-191.75	-86.30	-21.22	0.25	-0.21	0.40	-299.44	-99.52	-0.40	2.910E+05
600	30.65	-25.90	21.22	-105.45	-53.73	-32.57	5.08	-4.82	4.62	-204.54	-94.91	-4.62	2.808E+05
700	89.12	-58.47	32.57	-51.72	-27.65	-26.08	25.74	-20.66	15.84	-125.47	-79.07	-15.84	2.738E+05
800	173.67	-84.55	26.08	-24.08	-12.95	-14.70	70.57	-44.84	24.17	-70.57	-54.89	-24.17	2.701E+05
900	272.92	-99.25	14.70	-11.13	-5.91	-7.03	137.49	-66.92	22.08	-37.76	-32.81	-22.08	2.686E+05
1000	379.21	-106.28	7.03	-5.22	-2.73	-3.18	219.30	-81.81	14.90	-19.84	-17.92	-14.90	2.685E+05
1100	488.67	-109.46	3.18	-2.48	-1.30	-1.43	309.64	-90.34	8.52	-10.45	-9.39	-8.52	2.690E+05
1200	599.57	-110.90	1.43	-1.19	-0.63	-0.66	404.49	-94.84	4.51	-5.57	-4.89	-4.51	2.699E+05
1300	711.13	-111.56	0.66	-0.55	-0.31	-0.32	501.65	-97.16	2.32	-3.00	-2.57	-2.32	2.709E+05
1400	823.01	-111.88	0.32	-0.24	-0.15	-0.16	600.00	-98.35	1.19	-1.62	-1.38	-1.19	2.720E+05
1500	935.06	-112.04	0.16	-0.09	-0.07	-0.09	698.98	-98.98	0.62	-0.87	-0.75	-0.63	2.732E+05
1600	1047.00	-111.95	-0.10	-0.02	2.70	-2.76	798.29	-99.31	0.34	-0.45	-0.42	-0.33	2.744E+05
1700	1159.00	-112.00	0.05	-2.72	-2.71	5.40	897.79	-99.50	0.19	-0.22	-0.23	-0.19	2.756E+05
1800	1272.00	-113.00	1.00	-0.01	0.02	-2.73	997.39	-99.60	0.11	-0.09	-0.13	-0.11	2.768E+05
1900	1384.00	-112.00	-1.00	-0.03	0.03	-0.01	1097.00	-99.61	0.00	-0.09	0.00	-0.13	2.780E+05
2000	1496.00	-112.00	0.00	-0.06	0.03	0.00	1197.00	-100.00	0.39	-0.09	0.00	0.00	2.793E+05

NOTE: The estimates of the first (') and second (") derivatives above were obtained through finite differencing,
i.e. E'(Pc + 100) = [E(Pc + 100) - E(Pc)]/(100) and
E"(Pc + 100) = [E'(Pc + 100)- E'(Pc)]/100

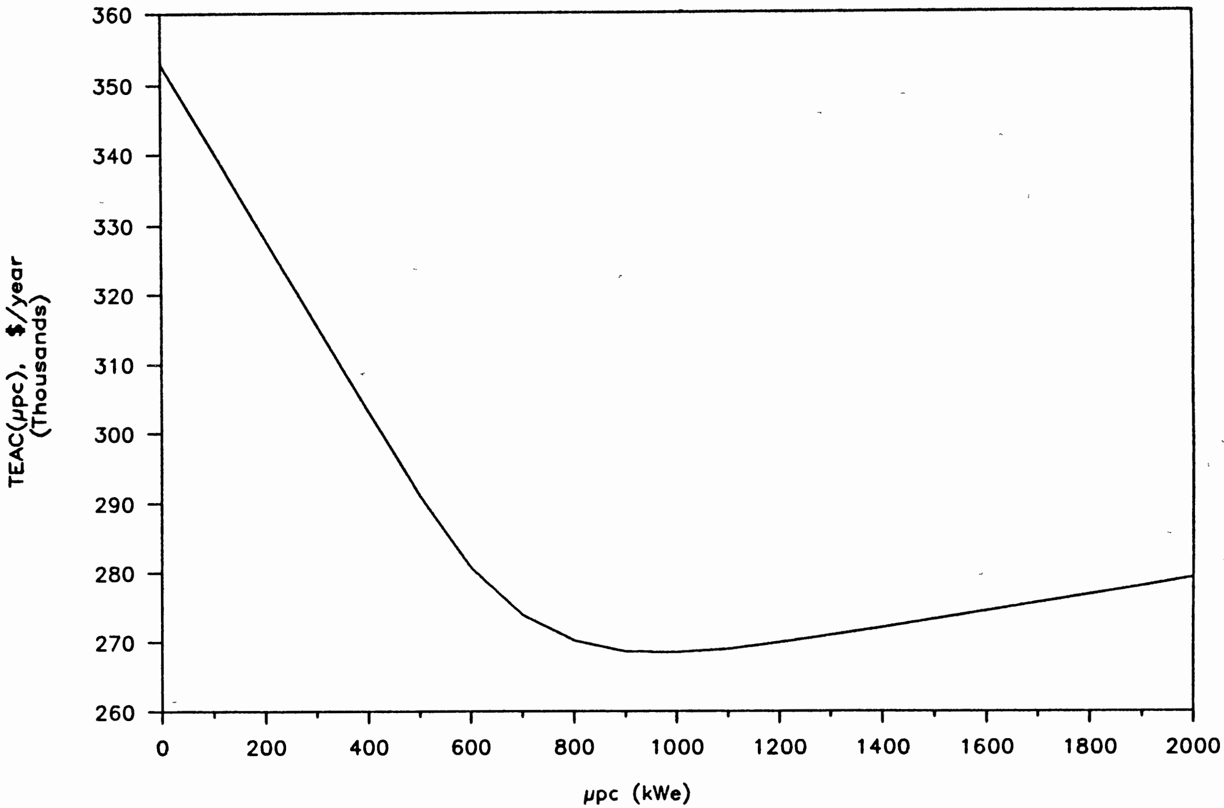


Figure 4.11 TEAC vs μ_{PC} for Example 4.7
(GCGD-1 Model)

optimum [$\mu_{pco} \approx 1000$ kWe] < [$E(Pc_{max})$=12,000 kWe]. Then the optimal size is $\mu_{pc}* = \mu_{pco} \approx 1000$ kWe, and from Table 4.10 the optimal TEAC* ≈ \$2.586 x 10^5 per yar. Next we calculate the actual expected value of the cost of the "do nothing alternative", i.e. TEAC(μ_{pc}=0), with

$$TEACo = (Cf/Na.\mu_{hd} + Ce.\mu_{pd}).t \qquad [4.50]$$
$$= \$3.538 \times 10^5/year$$

By comparing TEACo above and TEAC(0) obtained through numerical integration using the GCGD model, we can verify the accuracy of the model. Thus, when TEAC(0) is computed using the GCGD-1 equations of Table 4.9 (TOL = 0.01), we see in Table 4.10 that TEAC(0) is \$3.529 x 10^5/year or just 0.254% lower than the actual expected value of TEACo. Which shows that the GCGD model is quite accurate. ▪

Example 4.8 GCGD-2 Model. This example illustrates the case of an industrial cogeneration system with random CHP output, which is subject to random loads. All the random variables are normally distributed. The capacities are statistically independent of the demands. Also, the heat and power demands are mutually independent. Here, economies of scale are accounted for using an exponentially decreasing installed system unit cost. The input data, distribution parameters, preliminary equations and parameters for numerical integration are listed in Table 4.11. In this example, it is required: (1) to calculate the expected legal maximum $E(Pc_{max})$, (2) to plot TEAC vs μ_{pc}, (3) to find an approximated value for the optimum Pc*, and (4) to verify whether an inflexion point/local maxima exist in the neighborhood of Pc_o.

TABLE 4.11

INPUT DATA, DISTRIBUTION PARAMETERS AND PRELIMINARY EQUATIONS FOR EXAMPLE 4.8

INPUT DATA (MATHCAD 2.5)

$Se := -\left[0.034 + \dfrac{50}{8000}\right]$ $\quad Ce := 0.034 + \dfrac{50}{8000}$ $\quad Cp := 10$

$i := 0.18$

$n := 15$

$Cr := 0.1 \cdot .003412$ $\quad Na := 0.80$ $\quad in := (1 + i)^n$

$Cf := 2. \cdot .003412$ $\quad j := 0 \,..40$

$Cm := 0.008$ $\quad Vc := 0.25$

$Ne := 0.33$ $\quad t := 8000$ $\quad AP := i \cdot \dfrac{in}{in - 1}$

$Nt := 0.25$

INPUT DISTRIBUTION PARAMETERS

The mean values and standard deviations of the CHP demands are

$\mu pd := 8000 \quad \sigma pd := 2000 \qquad \mu hd := 15000 \quad \sigma hd := 3500$

The parameters for the exponential unit cost function are

$a := 700 \qquad b := 500 \qquad k := 0.0001$

INPUT PRELIMINARY EQUATIONS

The capacity (rc) and the demand (rd) heat-to-power ratios are

$rc := \dfrac{Nt}{Ne} \qquad rd := \dfrac{\mu pd}{\mu hd}$

The mean and standard deviation of the power capacity are

$\mu pc_j := 2500 \cdot j \qquad \sigma pc_j := \mu pc_j \cdot Vc$

The mean and standard deviation of the heat capacity are

$\mu hc_j := rc \cdot \mu pc_j \qquad \sigma hc_j := \mu hc_j \cdot Vc$

The mean power (μzp) and heat (μzh) differences are

$\mu zp_j := \mu pc_j - \mu pd \qquad \mu zh_j := \mu hc_j - \mu hd$

The power (σzp) and heat (σzh) difference standard deviations are

$\sigma zp_j := \sqrt{\sigma pc_j^{\,2} + \sigma pd^2} \qquad \sigma zh_j := \sqrt{\sigma hc_j^{\,2} + \sigma hd^2}$

The limits for numerical integration (μ +/- 3σ) are

$p1_j := \mu zp_j - 3 \cdot \sigma zp_j \qquad p2_j := \mu zp_j + 3 \cdot \sigma zp_j$

$h1_j := \mu zh_j - 3 \cdot \sigma zh_j \qquad h2_j := \mu zh_j + 3 \cdot \sigma zh_j$

The convergence tolerance for integration is $TOL := 0.01$

<u>Solution</u> The GCGD-2 model required to solve this example uses the same expected values -i.e. E(Zha), E(Zpa), E(Zhb) and E(Zpb)- defined in Table 4.9 for the GCGD-1 model. But, the GCGD-2 model includes an exponential cost term. So, the TEAC equation required is:

$$TEAC(Pc) = C1.Pc.e^{-(k\mu_{Pc})} + (C2 + c_f/n_e.t + c_m.t)\mu_{Pc} \quad [4.47]$$
$$+ [c_r.E(Zh_a)+s_e.E(Zp_a)-c_f/n_a.E(Zp_b)-c_e.E(Zh_b)]t$$

Thus, the upper part of Figure 4.12 includes the equations for the GCGD-2 model in MATHCAD format. Note that the search index is j. The required solution is explained as follows.

1) The expected legal maximum system size is

$$E(Pc_{max}) = \mu_{hd} \frac{N_e}{0.425 - N_e}$$
$$= 5.211 \times 10_4 \ kW_e$$

2) The Plot of TEAC vs Pc is depicted in Figure 4.12

3) The local (positive) minimum shown in Figure 4.12 is

$$\mu_{pco} \approx 30{,}000 \ kW_e < E(Pc_{max})$$

Then the constrained optimum is

$$\mu_{pc}^* = \mu_{pco} \approx 30{,}000 \ kW_e$$

4) Figure 4.12, however, readily shows that in fact the function is concave for some Pc and convex for other Pc. Next, Table 4.12 lists values of TEAC, TEAC'(μ_{pc}) and TEAC"(μ_{pc}) estimated through finite differentiation. Table 4.12 shows that there exist a local minimum ($\mu_{pc} \approx 30000$) and a local maximum ($\mu_{pc} \approx 5000$). Finally, Figure 4.13 is a plot of TEAC'(μ_{pc}) and TEAC"(μ_{pc}). It shows that for the feasible space $0 \le \mu_{pc} \le Pc_{max}$, there is a point of inflexion at $\mu_{pc} \approx 13{,}750$.

(Example 4.8) GCGD Model Equations

$$C1 := a \cdot AP \qquad C2 := b \cdot AP + Cp$$

$$ECO_j := C1 \cdot \mu pc_j \cdot e^{-\left[k \cdot \mu pc_j\right]} + \left[C2 + \frac{Cf}{Ne} \cdot t + Cm \cdot t\right] \cdot \mu pc_j$$

$$TEAC_j := ECO_j + t \cdot \left[Cr \cdot EZha_j - \frac{Cf}{Na} \cdot EZhb_j + Se \cdot EZpa_j - Ce \cdot EZpb_j\right]$$

$$Pcmax := \mu hd \cdot \frac{Ne}{0.425 - Ne} \qquad Pcmax = 5.211 \cdot 10^4$$

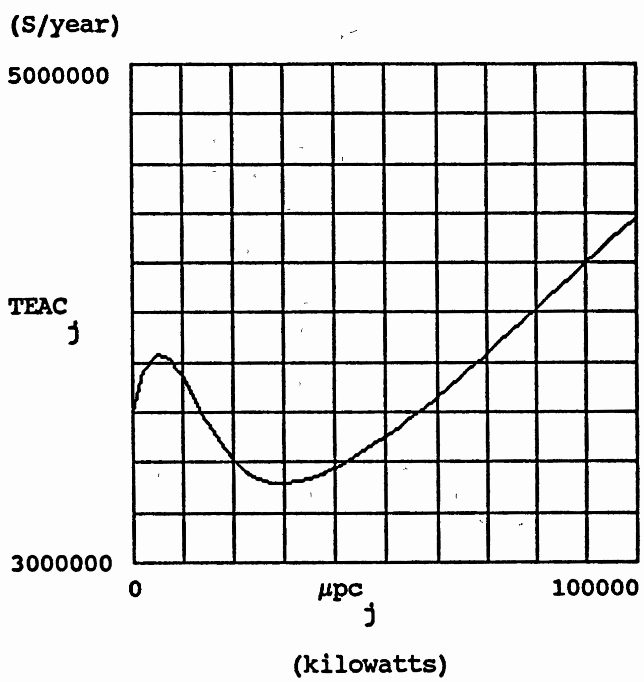


Figure 4.12 GCGD-2 Model Equations and TEAC vs μ_{pc}

TABLE 4.12

TEAC, TEAC' AND TEAC" OUTPUT FOR EXAMPLE 4.8

μpc kW	μpc* kW	TEAC(μpc) $/year	TEAC'(μpc*) $/yr/kW	TEAC"(μpc*) $/yr/kW/kw (x1000)
0	0	3.590E+06		
2500	1250	3.770E+06	72.000	
5000	3750	3.832E+06	24.800	-18.880
7500	6250	3.814E+06	-7.200	-12.800
10000	8750	3.748E+06	-26.400	-7.680
12500	11250	3.657E+06	-36.400	-4.000
15000	13750	3.561E+06	-38.400	-0.800
17500	16250	3.477E+06	-33.600	1.920
20000	18750	3.411E+06	-26.400	2.880
22500	21250	3.365E+06	-18.400	3.200
25000	23750	3.336E+06	-11.600	2.720
27500	26250	3.321E+06	-6.000	2.240
30000	28750	3.318E+06	-1.200	1.920
32500	31250	3.324E+06	2.400	1.440
35000	33750	3.336E+06	4.800	0.960
37500	36250	3.355E+06	7.600	1.120
40000	38750	3.378E+06	9.200	0.640
42500	41250	3.405E+06	10.800	0.640
45000	43750	3.436E+06	12.400	0.640
47500	46250	3.469E+06	13.200	0.320
50000	48750	3.505E+06	14.400	0.480
52500	51250	3.542E+06	14.800	0.160
55000	53750	3.581E+06	15.600	0.320
57500	56250	3.622E+06	16.400	0.320
60000	58750	3.663E+06	16.400	0.000
62500	61250	3.705E+06	16.800	0.160
65000	63750	3.749E+06	17.600	0.320
67500	66250	3.792E+06	17.200	-0.160
70000	68750	3.837E+06	18.000	0.320
72500	71250	3.881E+06	17.600	-0.160
75000	73750	3.926E+06	18.000	0.160
77500	76250	3.971E+06	18.000	0.000
80000	78750	4.017E+06	18.400	0.160
82500	81250	4.063E+06	18.400	0.000
85000	83750	4.108E+06	18.000	-0.160
87500	86250	4.154E+06	18.560	0.224
90000	88750	4.200E+06	18.240	-0.128
92500	91250	4.247E+06	18.800	0.224
95000	93750	4.293E+06	18.400	-0.160
97500	96250	4.339E+06	18.400	0.000
100000	98750	4.385E+06	18.400	0.000

NOTE: The estimates of the first (') and second (") derivatives were obtained through finite differentiation for the midpoints μpc*.

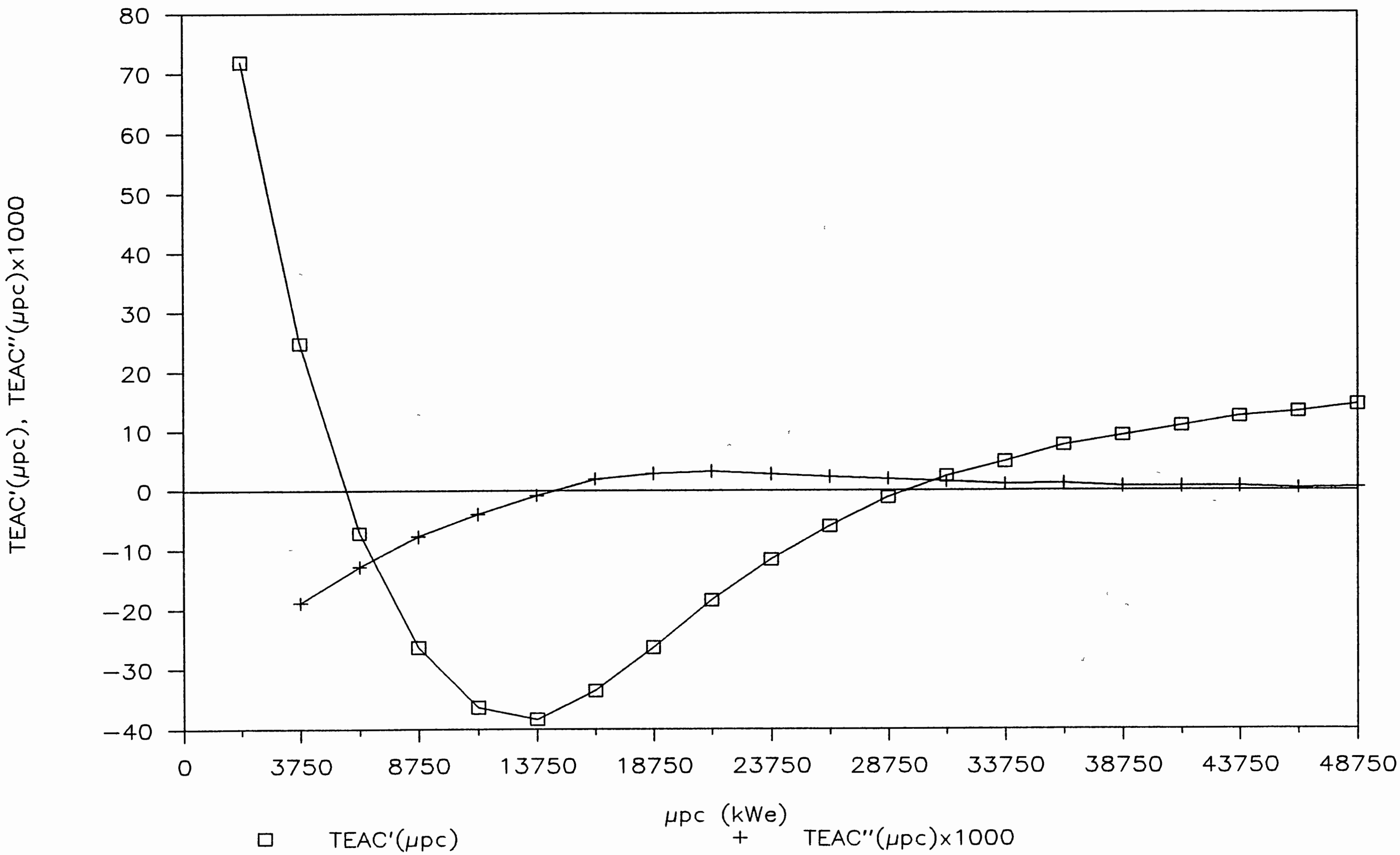


Figure 4.13 TEAC'(μpc) and TEAC''(μpc)

4.5 Summary

This chapter presented the analysis and development of the methodology proposed in Chapter III. Hence, after defining general considerations and assumptions, a basic notation and a general formulation was established. Next, the models were developed in an evolutionary fashion -from a base model with linear unit cost and totally deterministic loads, to a complex model with non-linear unit cost, and stochastic outputs and loads. Thus, Table 4.13 summarizes the models that comprehend the proposed methodology for economically based design of industrial cogeneration systems.

TABLE 4.13

A METHODOLOGY FOR ECONOMICALLY BASED DESIGN OF COGENERATION SYSTEMS

MODEL	DESCRIPTION	SECTION/EXAMPLE
CCCD-1	Constant Capacities and Constant Demands - Constant c_u	4.2.2/4.1
CCCD-2	Constant Capacities and Constant Demands - Exponential c_u	4.2.3/4.2 /4.3
CCSU-1	Constant Capacities and Uniformly distributed Demands - Constant c_u	4.3.1/4.4 4.5
CCPD-1	Constant Capacities and general Probabilistic Demands - Constant c_u	4.3.2/4.6
CCPD-2	Constant Capacities and general Probabilistic Demands - Exponential c_u	4.3.3/
CCGD-1	Constant Capacities and Gaussian Demands - Constant c_u	4.3.4/4.6
GCGD-1	Gaussian Capacities and Gaussian Demands - Constant c_u	4.4.1/4.7
GCGD-2	Gaussian Capacities and Gaussian Demands - Exponential c_u	4.4.3/4.8

CHAPTER V

ANALYSIS OF RESULTS

5.1 Introduction

This chapter presents a unifying analysis for all the models previously developed. We first examine, from a probabilistic approach, how the methodology should be integrated to the actual cogeneration design process.

Then, we present a number of observations about the models. The discussion is focussed on the constant-unit-cost models. Some extensions of the methodology to other research problems are also considered.

Since the methodology is based on mathematical models, it has some limitations. Thus, one of the following sections addresses verification, calibration and limitations of the models presented herein. Next, a sensitivity analysis is performed to assess the validity of the methodology. This is achieved through a sensitivity analysis, i.e. by comparing the response of the models (to changes in cost coefficients and in distribution parameters) with what is generally expected from actual cogeneration systems. The application of some extensions of the models to actual cogeneration projects is also considered.

These topics are discussed in the following sections, which also define how the methodology extends to other design problems and how it can be linked to future research.

5.2 A Probablisitic Cogeneration Design Paradigm

Figure 5.1 synthesizes the design process suggested in this thesis. Its three phases are discussed below.

First, Phase I consists of the data analysis and preparation tasks accomplished through conventional statistical methods. Phase I also includes the characterization of the bivariate load in terms of parameter estimates and the selection of a technically feasible technologies (i.e. those that meet the thermal demand of the industrial plant or thermal host).

Next, Phase II is the focus of this thesis. Thus, its objective is the determination of the optimal combination of system technology and total capacity. Consequently, Phase II comprehends all the models developed herein and others that might be constructed in the future. Basically, any chart that shows TEAC vs Pc in Chapter 4, can serve as the common template for the evaluation of several alternative technologies. For example, Figure 5.2 presents 4 curves that could represent four different technologies for a given CHP load distribution. Therefore, the designer can visualize, for each technology, both the optimal capacity and the sensitivity of the TEAC to changes in capacity. But most importantly, the engineer can determine *simultaneously* which technology and what size gives the best expected total equivalent annual cost of owning, operating and maintaining the CHP system. Thus, the Oklahoma Energy Analysis Center at Oklahoma State University is currently using the methodology of Phase II for preliminary cogeneration evaluation.

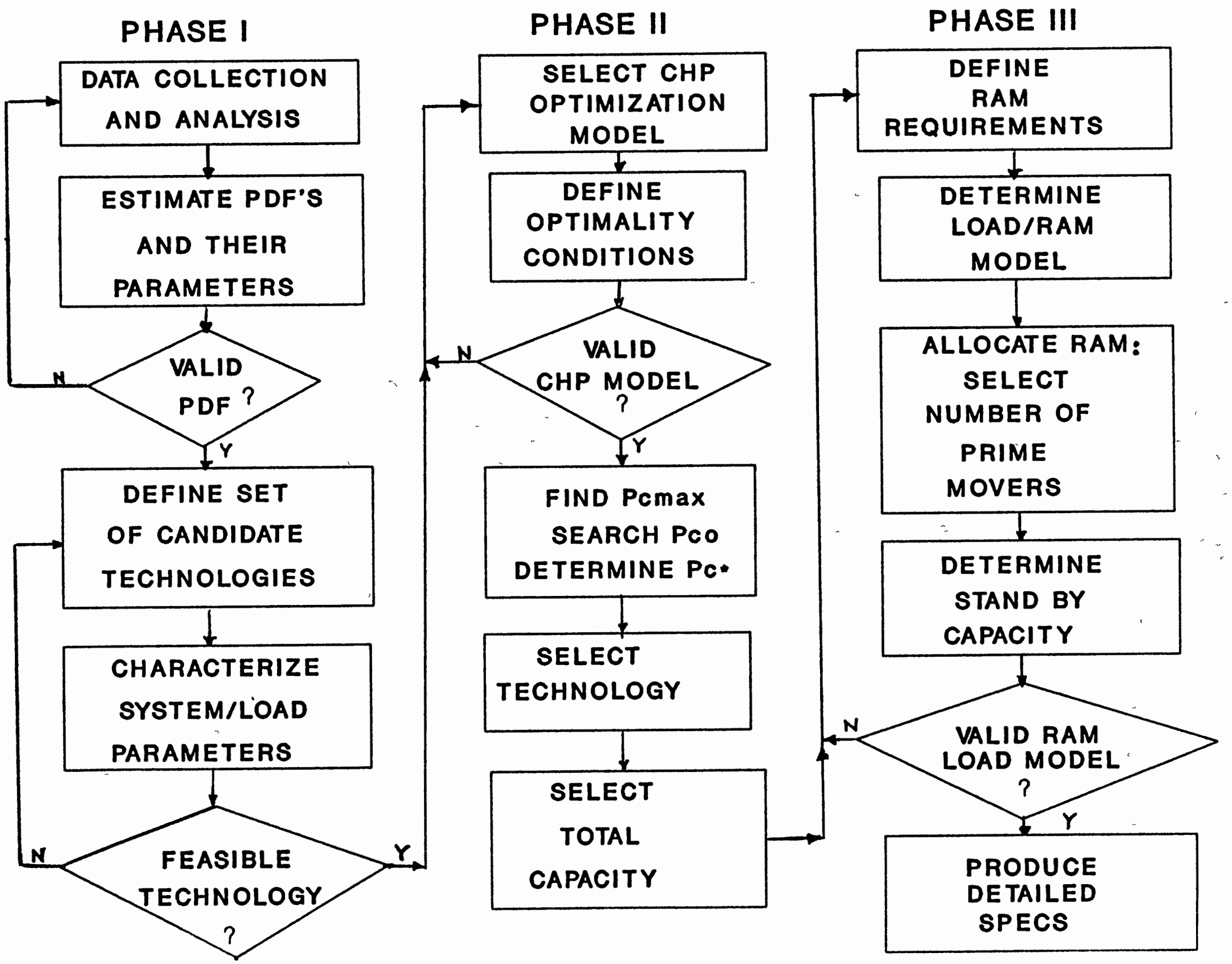


Figure 5.1 A Probabilistic Cogeneration Design Paradigm

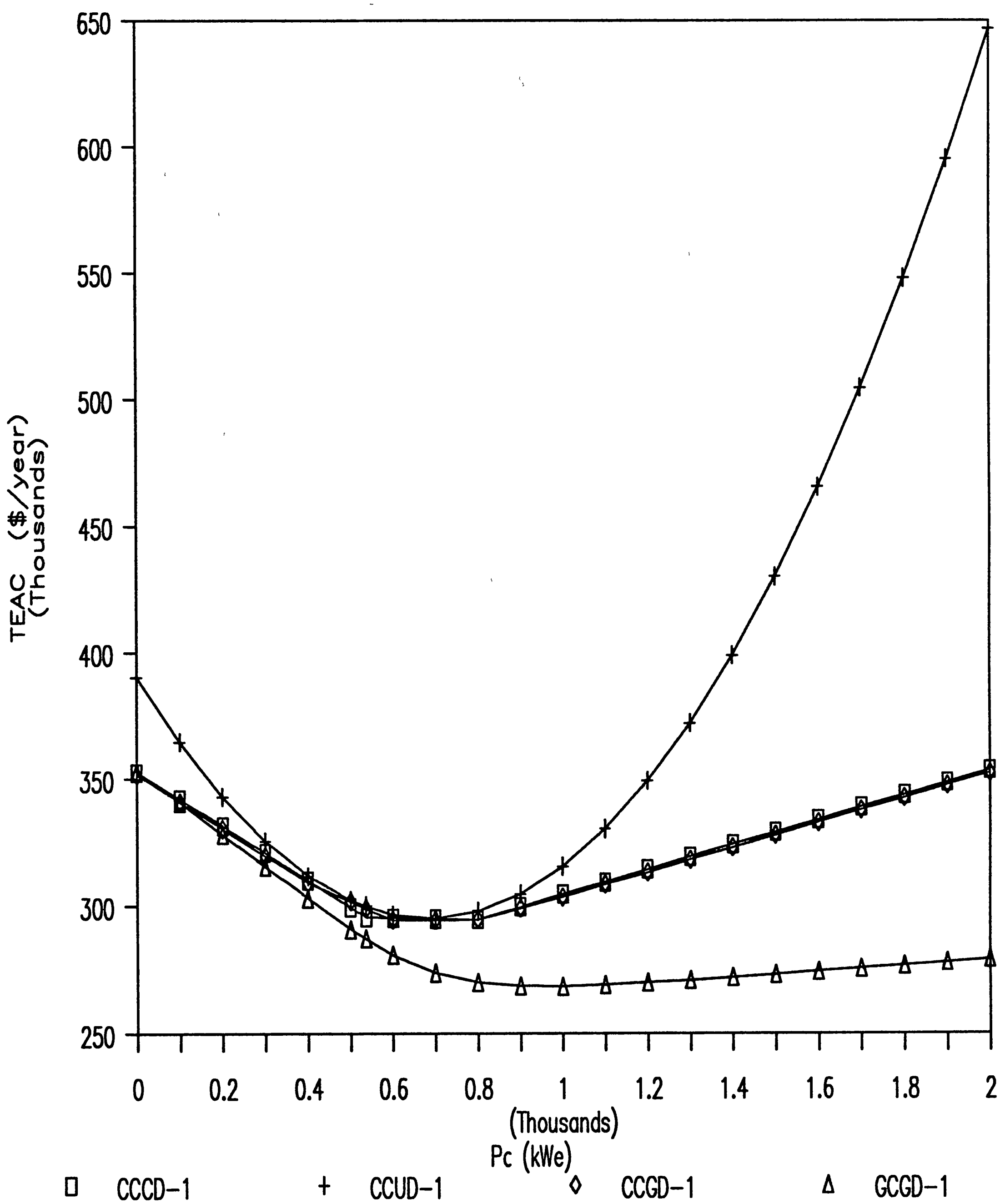


Figure 5.2 Constant Unit Cost Models

In Phase II, and in our methodology, system availability is implicitly acknowledged by using an "expected hours of operation" figure. E.g. t = 8000 "up-time" hours per year implies a system availability of 8000/87060 = 0.91324.

Phase III -the logical continuation of Phase II- is suggested for further research. Phase III would involve the development of a subsequent methodology that evaluates and allocates the CHP system's Reliability, Availability and Maintainability (RAM) in conjunction with random CHP loads and capacities. In other words, for a CHP system, this phase would define the required mean time between failures (MTBF) and mean time to repair (MTTR). Then the number of prime mover units and their corresponding size would be determined.

But, continuous pdf's f(x) for $x \geq 0$ can not model "system and/or component" down-time, nor can model "no-load" periods. Hence, for all those cases in which a discrete capacity and down-time exist; and when a discrete or "step-function" variation of load occur (including periods with no load whatsoever) mixed discrete-continuous pdf's are needed to model the CHP system. Branson (1992) has suggested that this could be accomplished with a similar procedure to those used to represent queuing systems with "no waiting in line time" and with "no service time". In other words, when the probability $P(x=o) > 0$ and/or there is a step-wise random process over time, mixed continuous-discrete pdf's can be utilized. Again, examples of x can be CHP system (or component) down-time and no-load-time.

Another approach is the development of a Load-RAM model through continuous Markov chains. These type of models have been used extensively in power plant reliability evaluation.

A rather complete discussion can be found in Billinton and Allan (1984). Thus, for the CHP problem, the four states Zi defined in section 4.4 can have at least two additional states (one for CHP system down-time, and another one for industrial load down-time). Other states which are different "derated" discrete levels and their relevant load-capacity combinations could also be defined.

In our case, however, instead of starting with a set of given stochastic transition rates towards the determination of state probabilities; we might start with a limited set of state probabilities in order to define transition rates that in turn would provide the frequency of arrival to the states (and their expected associated costs). Thus, some states could represent discrete changes in CHP system capacity and other states discrete partial changes in CHP demands.

Also, an interesting development of a likely application in future research is the method of "level crossing" utilized in the fields of random vibrations and digital signal processing. Here, a crossing of certain levels of a continuous rv x represent a "change of state". For details, see for example DeNewland (1984) and Stark and Woods (1986).

However, we should keep in mind that the ultimate objective of Phase III is the optimal determination of the number of units that conform the total capacity -including any stand by capacity, if deemed cost effective. This should be modeled taking into consideration all the cost items used in our methodology. In addition, other costs such as failure and "loss-of-load" costs should be integrated in a total cost objective function.

5.3 Analysis of Results and Extensions

Due to the built-in generality of the TEAC equations, the results of the research could also be extended to various problems encountered in energy systems design and also in manufacturing systems optimization. We saw at the beginning of Chapter 1 an example on how randomness helps minimizing the throughput time of a flexible manufacturing system. In the case of a cogeneration system, however, the benefit of randomness is not that obvious. In fact, depending on the actual magnitude of the cost parameters involved in a particular model, larger variations in CHP capacity might or might not imply larger investment risk and lower returns. But this can not be easily generalized. So, Figure 5.2 is in reality the plot of four models developed in this thesis for the case of constant unit-cost (c_u=k). In the figure, the plots were obtained from the examples used to illustrate the models: CCCD-1, CCUD-1, CCGD-1 and GCGD-1. That is examples 4.1, 4.5, 4.6, and 4.7, respectively. In general, the examples use the same cost coefficients and the same (or similar) CHP average demands. However, depending on the underlying load and capacity distributions, different results are observed. Some observations are discussed as follows:

1) The CCCD-1 model is almost identical to the CCGD-1 model. In fact, a variation analysis (not shown) indicated that there was an average of about 0.2% difference between the TEAC estimates of the CCCD-1 and the CCGD-1 models. This shouldn't come as a surprise, since the standard deviations for the CCGD-1 model were selected to be small (10% of their corresponding means), so as to use the deterministic CCCD-1 model as a control; i.e. a means of verification and validation.

2) The CCUD-1 model depicts the largest sensitivity of TEAC to changes in Pc. It shows how the "uncertainty without central tendency" of uniformed distributed

CHP loads makes TEAC a quadratic function of Pc. Hence, a deviation from the target Pc* (or Pc_o) imply an increase in TEAC proportional to the square of the deviation in Pc. This presents a remarkable similarity to the postulated by the "Taguchi loss function", which states that the loss to society due to "off-target" decisions, products or services is proportional to the square of the deviations from the target. For more details on this Quality Control concept, see for example Lochner and Matar (1990).

3) The GCGD-1 model shows the effect of the convolution between random demands and capacities. Since a convolution is solely defined for the algebraic sum of independent density functions, then the effect in the TEAC function is a reduction in risk (or in the sensitivity of TEAC(Pc). A casual explanation for this follows the same rationale of the flexible manufacturing system with random capacity and random demands. Thus, in the GCGD-1 case, a low capacity has an equal probability to occur with a "high" as well as with a "low" demand. But in the CHP case, PURPA permits that the surplus (deficit) electrical energy be absorbed (provided) by the utility grid. Since typically $c_e > |s_e|$, the larger variance of the power σ_{zp} is "buffered" by the utility system.

4) In figure 5.2, from Pc = (0... 400 kW_e) the CCCD-1 CCGD-1 and GCGD-1 models show very small differences.

5) The GCGD-1 models shows the overall minimum.

Similar conclusions can be obtained for the models that include an exponentially decreasing system unit-cost to account for economies of scale. However, the most relevant effect of such models (XXXX-2) is that regardless of the underlying CHP load distributions, they exhibit at least one inflexion point. In some cases, as shown in examples 4.2 and 4.8 the TEAC functions have local maximums. This should be further explored, since local maximums define points of operation that should be avoided.

Further research is suggested for the case of the integration of this methodology with the characterization and evaluation of technologies for load variance reduction. For example, thermal energy storage TES (in the form of ice, hot water, chilled water or compressed air) is used to level the load "seen" by the CHP system. Recall from observation 3 above, that "moderate" load variation does not have a significant impact on the sensitivity of TEAC, specially when the price differential between c_e and $|s_e|$ is not large. But, for isolated systems or when $c_e >> |s_e|$, reduction in load variation will certainly affect the sensitivity of TEAC and its optimality. Hence TES and cogeneration systems can be evaluated jointly. Then optimal combinations of TES-CHP capacities can be obtained.

5.4 Verification, Calibration and Limitations

Verification tests have been conducted through the examples of Chapter 4. The tests have shown that the numerical output of the models are the same or almost the same as those obtained through double numerical integration. Also, the results have shown that the models provide more accurate and much quicker results than plain (double) numerical integration. In addition, Figure 5.2 generally provides a visual means to verify the numerical results obtained in the model-examples. By extension, Figure 5.2 provides a means to establish the relative validity of all the models developed here. Thus, the figure shows that the models behave as expected. That is they provide a convex function with a global minimum for typical cost coefficients.

"Calibration" of the models is readily attained by linearly adjusting the TEAC at the starting point of the search, i.e. TEAC (Pc = 0). Recall from Example 4.1 that CHP model calibration is the process of verifying that TEAC(Pc=0) is comparable to the existing total annual energy cost.

Thus, the following relationship can be used to calibrate, if necessary, any of the models. Henceforth,

$$TEAC_{cal} = \alpha + \beta . TEAC(0) = AEC \qquad [5.1]$$

where :

$TEAC_{cal}$ = calibrated TEAC function
TEAC(0) = model TEAC evaluated @ Pc =0
AEC = existing or predicted Annual Energy Cost without cogeneration.
α, β = calibration constants

Since in general β=1, i.e. the model may be simply shifted from AEC, then the calibration constant α can be solved from equation [5.1]. However, if a change in scale is detected, then β can be obtained by solving equation 5.15 at TEAC(Pc) for a value of Pc > 0. TEAC(Pc) can be obtained from historical costs of existing cogeneration plants.

The ultimate validation, however, lies on the proper application of the models. For example, in the case of seasonal costs and/or seasonal CHP loads, a different model can be used for each season. Then, the owning costs can be prorated according to the energy generated in each season. Finally, all expected seasonal costs can be added together.

The following section on sensitivity analysis further demonstrates the validity of the models. However, we should quote Taha (1982, pp 657-658):

> The apparent reason for this (application) difficulty is that ... models available rarely satisfy the conditions under which the real system operates. *However, we must keep in mind that this difficulty is typical of all mathematical models. What we need then is a clear recognition of the limitations of available (queuing) models from the point of view of their applications to real life situations*. These limitations should be investigated in a manner that would reveal the degree of sensitivity of approximating a real system by a given mathematical model."

Thus, one of the main limitations of the methodology is the fact that many facilities exhibit correlated loads and capacities. For example, a hospital has high demand for air-conditioning electricity during summer and high demand for heating steam during winter. Again, one way to mitigate and sometimes to totally circumvent this problem is through the buffering effects of energy management technologies for the reduction of load variance.

Also, load displacement techniques can be used. For the hospital example with negatively correlated CHP loads, steam heat can be used for cooling through absorption cycles. In this way, electrical demand is substituted by heat demand. Similarly, in winter a mix of electricity using heat pumps and steam coils might be used to "shave" the steam demand peak. But all these techniques are available at a cost. Therefore: How much reduction in either load variation or load-capacity correlation is cost effective?

However, the correlation problem prevails. A symmetrical covariance matrix $\mathbf{K_{hp}}$ (4x4) of CHP loads and capacities is a good starting point:

$$\mathbf{K_{hp}} = \begin{array}{c|cccc|} & Hc & Pc & Hd & Pd \\ \hline Hc & V_{11} & & & \\ Pc & C_{21} & V_{22} & & \\ Hd & C_{31} & C_{32} & V_{33} & \\ Pd & C_{41} & C_{42} & C_{43} & V_{44} \\ \hline \end{array}$$

CHP-utility exchange is generally the rule, but some may consider a limitation the fact that the methodology is only for cogeneration with electricity import and export. Thus, for the exceptional cases, the problem can be circumvented by modifying the underlying model equations so they emulate:

1) A system that tracks the internal electrical load and only purchases electricity deficits

2) A system that is totally isolated from the utility.

In the first case, this is done by modifying states w_1 and w_3 (CCxx models) or z_1 and z_3 (GCGD models), so power is not sold back but it's only purchased from the grid. This is actually accomplished by dropping the terms on s_e of equations EC_1 and EC_3. In addition, to represent power load tracking, equation EC_0 should be function of Pd instead of Pc. Thus, for the GCGD model, one load tracking equation is

$$EC_0 = \int_{-\infty}^{\infty} \int_{-\infty}^{\infty} [a + cf/n_e.t + cm.t) \, Pd \, f(Zp,Zh) \, dZp \, dZh$$

Based on the rationale just stated, two discrete cogeneration sizing models for load tracking has been developed by Turner, Wong and Viswanathan (1992). Such models develop quadratic TEAC functions. The models have been applied in a World Bank project (in Mexico) to evaluate potential cogeneration sites. Mexican and international experts have agreed with the logic and the results of the models.

The second case is not a trivial one and it certainly warrants a topic for further research. Here, in addition to the modifications stated for the plain load tracking model, it is necessary to define at least one additional term to account for "loss of load" occurring in the states with capacity deficit, i.e. w_2 and w_4 (CCxx models) or z_2 and z_4 (GCGD models). However, other than plants isolated from utility transmission/distribution lines or in countries where cogeneration with a utility tie is not allowed, the case has limited applications in practice. In the U.S.: Who would plan, design and install a cogeneration without the utility back-up (and other benefits) provided by PURPA?

5.5 Validation and Sensitivity Analysis

This section provides a validation scheme through sensitivity analysis. Thus, by making some changes in model parameters and coefficients, the models are validated by comparing their response to (a) the results of similar changes in actual cogeneration plants and to (b) generally accepted expectations.

First notice that an underlying assumption has been that energy costs are non random (20-year contracts for firm fuel costs are becoming commonplace in cogeneration). But there have been a few cases in which a drop in electricity rates has caused a cogeneration developer to reduce the rates he was charging to a client. Thus we wanted to further investigate the effects of changes in energy costs and changes in load/capacity variances. For instance, Fore (1988, pp 1) reports that, after a change in rates by Pacific Gas & Electric, a cogeneration plant had to (contractually) reduce its tariffs. Fore says that "such a developer had trouble meeting debt obligations as a result of the drop in prices". Then, the developer decided not to expand the CHP plant. On the other hand, it is not unusual that a potential industrial developer may obtain a better deal from his cogeneration-averse electric utility when he gives a serious consideration to cogeneration. Thus, a number of parametric analysis were performed using the CCUD-1 and the GCGD-1 models. These models were selected since they are the "most general" and "well behaved". The sensitivity analysis will explore changes in: (1) electricity costs, (2) gas cost, (3) the ratio s_e/c_e and, (4) the variances of load and output.

5.5.1 Changes in Electricity Costs

Figure 5.3 shows a TEAC vs Pc plot using the CCUD-1 model for various multipliers ($1+m_i$). The multipliers adjust the base values of c_e and s_e used in Example 4.5. Note that TEAC(0) is linearly proportional to the electricity cost. That is the model is valid at the "do-nothing" level. Also notice that as the electricity costs increase TEAC(Pc*) decreases and, at the same time, Pc* increases. In other words, a larger CHP plant is more profitable with increasing electricity costs. These results indicate that the CCUD-1 model, which is the foundation of all the stochastic models developed here, behaves as expected and is in general valid.

An interesting observation is the locus point L, which shows that regardless of the changes on electricity costs, TEAC(Pc) ≈ \$300,000/yr is constant for Pc = μ_{pd} = 800 kW. Note that the optimum points [Pc*,TEAC(Pc*)] spread around L. Thus, it can be said that for typical electricity rates, the optimum Pc* is in the neighborhood of μ_{pd}. This is useful since TEAC(Pc=μ_{pd}) is a good starting search point. Then the result challenges the conventional criterion of base-loading as a likely optimum. Thus, instead of sizing at the lower tail of one of the CHP load distributions, this result indicates that many optimal solutions are closer to the mean load than to the lower tail. Also, the result is similar to the optimality conditions obtained for the CCCD models. Note that beyond L, the ranking given by the TEAC equations is reversed. So, under decreasing electricity rates, it becomes more risky to oversize the CHP plant beyond L. This is just the case presented by Fore (1988), which was discussed above.

5.5.2 Changes in Fuel Cost

Figure 5.4 is a TEAC vs Pc plot of the CCUD-1 model for various multipliers $(1+m_i)$ of the fuel cost c_f. The base cost (m=0) is from Example 4.5. This graph shows what we generally expected for changes in c_f. Thus, it shows that Pc* slowly increases as c_f decreases, and at the same time, TEAC(Pc) decreases. Note that the convexity of TEAC diminishes as c_f decreases, making less risky to oversize the plant. Also, note how the optimal Pc*'s are located just to the left of Pc= μ_{pd} = 800 kW. Hence, as discussed in the literature, the model emulates closely actual CHP systems, by showing a much larger sensitivity to changes in electricity costs than to changes in fuel cost. The CCUD-1 model allows one to verify this by comparing the sum of the partial derivatives of TEAC with respect to c_e and s_e, with the partial derivative of TEAC with respect to c_f. The partial derivatives of TEAC equation [4.26] are given by

$$\frac{\delta TEAC}{\delta c_e} = \frac{t}{2\ (P_2-P_1)}\ (Pc - P_2)^2 \qquad (kWh/yr) \qquad [5.1]$$

$$\frac{\delta TEAC}{\delta s_e} = \frac{t}{2\ (P_2-P_1)}\ (Pc - P_1)^2 \qquad [5.2]$$

$$\frac{\delta TEAC}{\delta c_e} + \frac{\delta TEAC}{\delta s_e} = \frac{t}{2(P_2-P_1)}\ [(Pc-P_2)^2 + (Pc-P_1)^2] \qquad [5.3]$$

$$\frac{\delta TEAC}{\delta c_f} = \frac{t}{n_a(H_2-H_1)}\ \{Pc^2/2 + Pc[(n_a/n_e)(H_2-H_1) - H_2] + H_2^2\} \qquad [5.4]$$

Note that equations 5.1 and 5.2 have one quadratic term of electrical power P. But in equation 5.3, the combined effect of both c_e and s_e is represented through two quadratic terms of electrical power (between brackets).

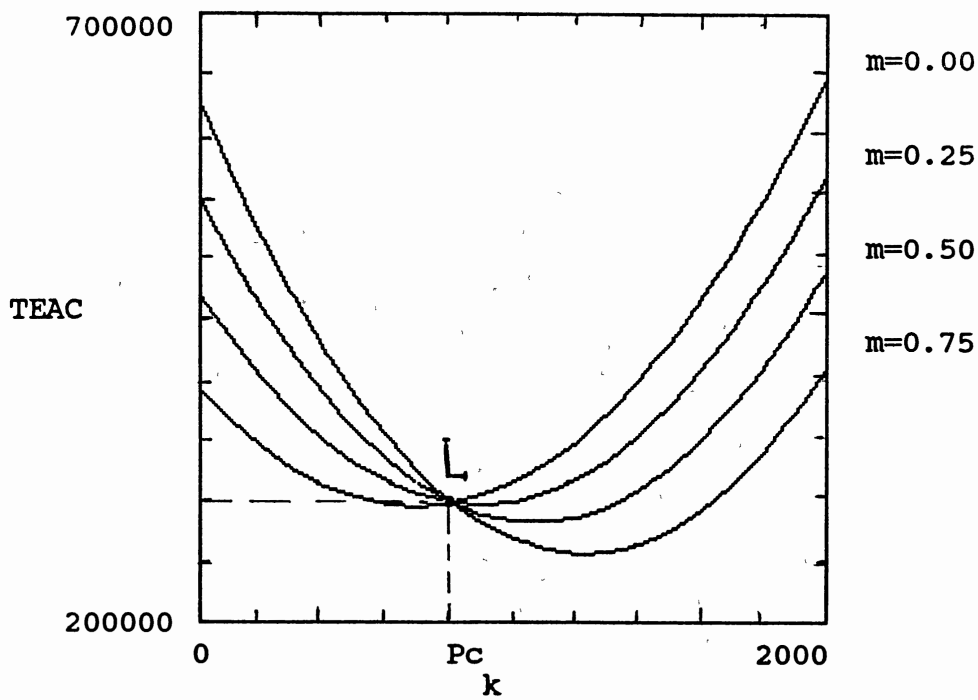


Figure 5.3 CCUD-1 model for various electric cost multipliers

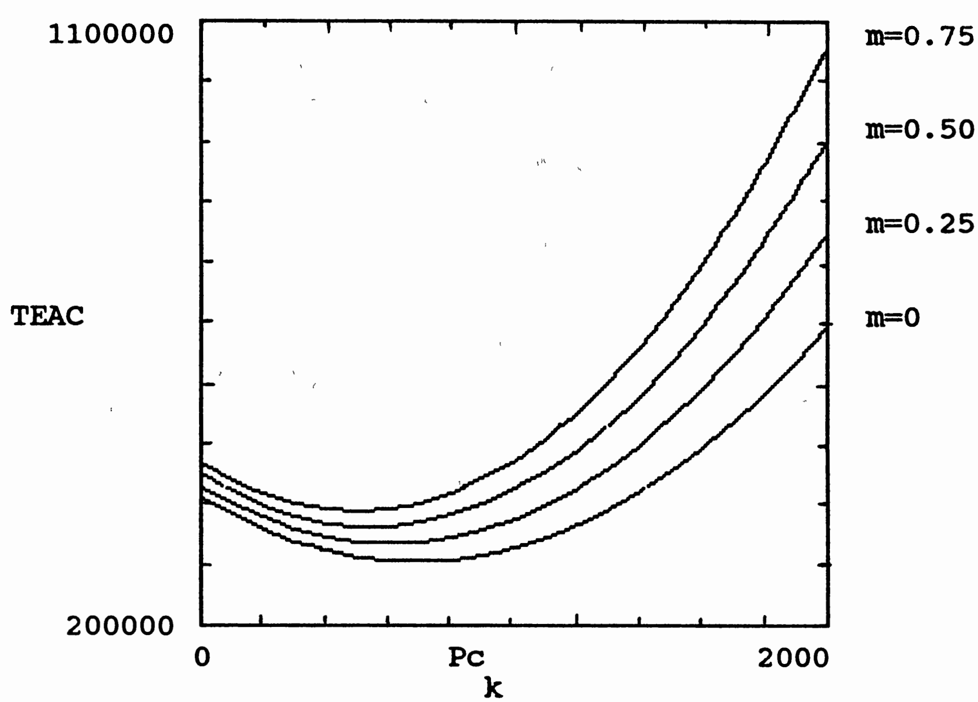


Figure 5.4 CCUD-1 model for various fuel cost multipliers

Whereas there is only one quadratic function of electrical power in equation 5.4. Thus, with regard to power loads, TEAC is much more sensitive to c_e and s_e, than to c_f. Note however that equation 5.4 includes quadratic terms of the thermal load (H). Hence, as generally expected, TEAC becomes more dependent of c_f with larger thermal loads.

5.5.3 Changes in the Relative Cost of Electricity

Here we explore relative changes in the ratio r=|se/ce| or $r=-s_e/c_e$ (for se<0, ce>0). The base cost and distribution data is from Example 4.7. Figure 5.5 shows realizations of the GCGD-1 model for various ratios r of the electricity costs. Note that to the left of the optimum Pc*'s, the TEAC(Pc) functions are totally insensitive to relative changes between the electricity costs s_e and c_e. Again, all Pc*s are around the mean demands μ_{pd}=800 and μ_{hd}=750; showing that the optimal solutions are generally "anchor" between μ_{pd} and μ_{hd}.

Note that about the optimal region, the functions are curved. But, to the right of the "optimal region", the TEAC functions behave linearly; with slopes inversely proportional to the ratios r. Hence, for smaller r, i.e. decreasing s_e (revenues) with respect to c_e (costs), TEAC increases and it is more risky to oversize a CHP plant. This is what we expected from the model.

5.5.4 Changes in the Variances

Figure 5.6 depicts a parametric plot of TEAC vs Pc for various coefficients of variations (v_c, v_d). The cost data

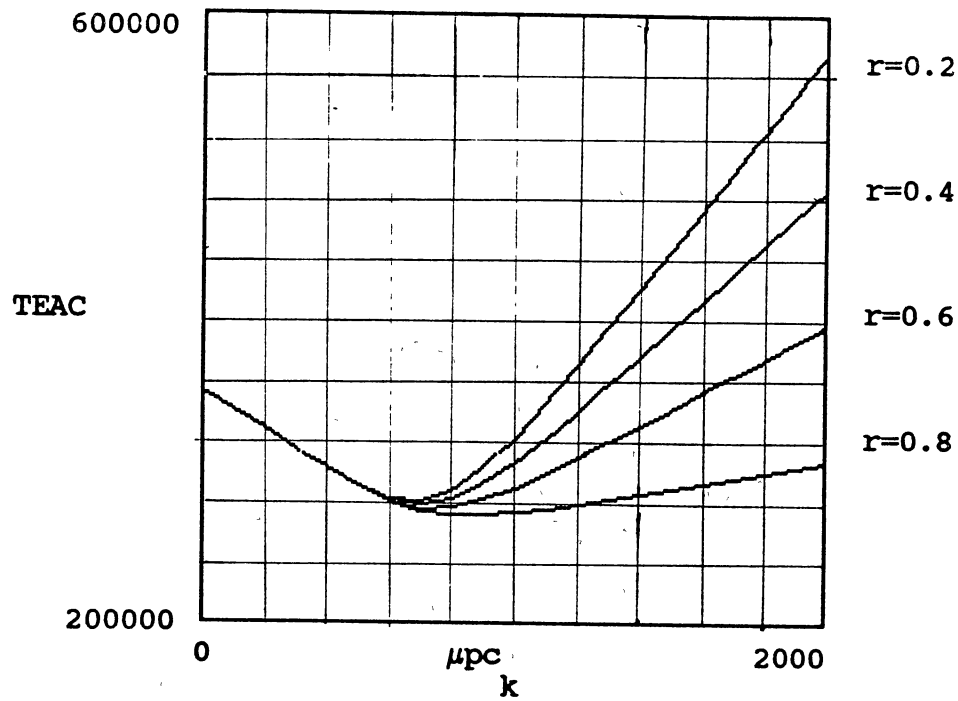


Figure 5.5 GCGD-1 model for various ratios $r=-s_e/c_e$ of the electric costs

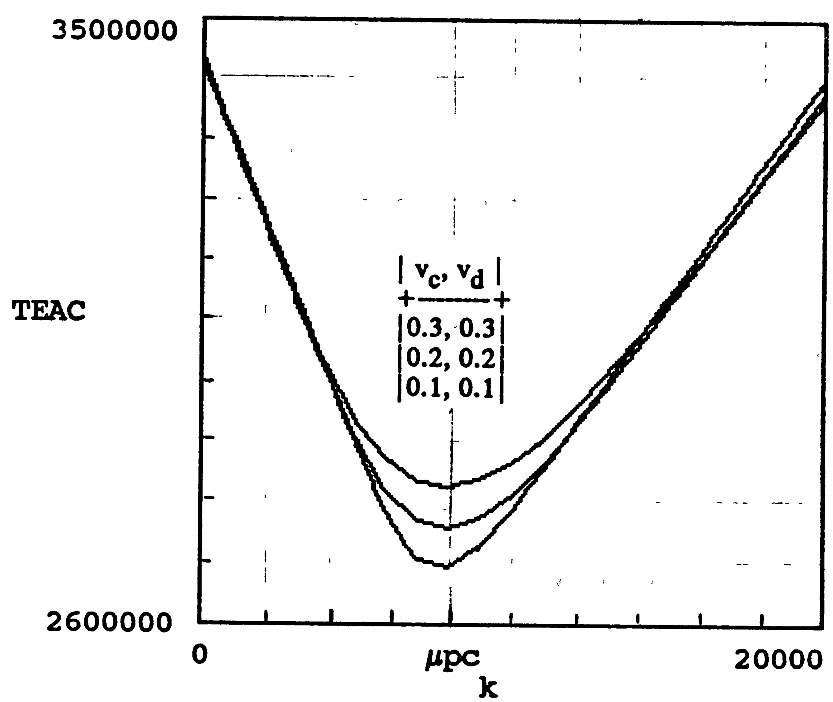


Figure 5.6 GCGD-1 model for various coefficients of variation (v_c, v_d)

is from Example 4.7. Due to the buffering effect of the utility tie, TEAC is not very sensitive to changes in the variance of capacity or demand. Note that all the optimums Pc* "anchor" at the mean power demand μ_{pd}=800. However, in the neighborhood of Pc*, TEAC is larger (less profitable) with larger coefficients of variation. An interesting and unexpected observation is that, with higher (v_c, v_d), the TEAC functions tend to flatten as μ_{pc} increases.

5.6 Summary

This chapter has analyzed the results of the models developed in Chapter 4. It discussed how the results of models have been verified through examples and how the models can be calibrated, if necessary. Next, some limitations of the models were addressed. Then, the chapter is concentrated on a sensitivity analysis for the validation of the models CCUD-1 and GCGD-1, the first and last constant-unit-cost models. Therefore, since all the probabilistic models of the methodology were derived from these two models, then by extension, the whole methodology was validated.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This thesis has presented the development of a robust and responsive methodology for cogeneration system design. Throughout the development, there has been a deliberate attempt to present the material in a didactical manner: with demonstrative examples amenable to educational endeavors. As seen in section 4.5, the methodology has been developed through an incremental modelling of the randomness that naturally occur in industrial cogeneration systems. Thus, Figure 5.1 globally illustrates a probabilistic cogeneration design paradigm. The figure shows a design process composed of three phases which are prescribed for an explicit acknowledgment of randomness in the operation of CHP systems. Thus, Phase I uses statistical methods to convert CHP data into CHP distributions, Phase II is the focus of this thesis and Phase III, RAM analysis, is proposed for future research.

Then, it can be seen that the research envelope shown in Figure 3.1 has evolved to Phases II and III of Figure 5.1. Also, it can be said that, in essence, Phase II and this methodology are almost indistinguishable. This is a good sign that the main research objectives have been accomplished.

We have obtained insightful results and observations from this research. These are summarized in this chapter. Next, we discuss how the methodology extends to other design problems and how it can be linked to future research.

6.1 Conclusions

The following conclusions are drawn from this research:

1) The research effort has allowed us to convert a random process **[Hd, Hc, Pd, Pc]** into a set of discrete states $[w_1, w_2, w_3, w_4]$ and $[z_1, z_2, z_3, z_4]$. This was accomplished through the definition of the CHP space and the CHP difference space, respectively. Subsequently, the formulation of the TEAC equations for each model determine a global objective function for the optimization of various cogeneration systems.
2) The development process proceeded in an evolutionary fashion. But, first it was necessary to conduct a rather exhaustive literature review. Thus, studying and understanding the research problem allowed us to formulate the problem integration mechanism defined by the TEAC model equations.
3) The models summarized in Table 4.13 constitute the robust and responsive methodology for economically based design of cogeneration systems proposed in the definition of the research objective in Section 3.5. The development of the models presented in Chapter 4, and the analysis of Chapter 5 accomplish the mission defined by the Subobjectives stated in Section 3.6. Thus, Subojective 1, the basic economic criteria for CHP systems, is accomplished through Section 4.1. Subojective 2, a conceptual model for constant demands and capacities, is obtained in Section 4.2. Subojective 3, a conceptual model for a CHP system with constant capacity subject to Gaussian demands, is discussed in Section 4.3. Next, Subojective 4, a

conceptual model for a CHP system with Gaussian distributed capacities and loads, was developed in Section 4.4. Finally, Subojective 5, conclude on the applicability and validity and define topics for further research, is accomplished throughout Chapter 5 and in Chapter 6. In addition, a model for uniformly distributed loads and another one for constant capacities and generally distributed demands are included in Chapter 4.

4) The methodology shows that for most typical cost coefficients and distribution parameters the objective functions are generally convex. The only exception is the set of models that account for economies of scale, which always show at least one inflexion point and sometimes might have local maxima.

5) An interesting characteristic of the models is their ability to represent the buffering effects of a utility tie with electricity import and export. In fact, as the randomness of the models increases, the economic effects of over-sizing the system are mitigated. In other words, with respect to constant load models, the TEAC of the GCGD models become rather insensitive to random loads and capacities. The reality of the US cogeneration market indicates just that. According to Turner (1992) most of the new cogeneration output installed during the last decade accounts for more than 50% of the new total US power generation capacity; and the majority of the plants are gas turbine based systems. But, in spite of their random outputs, gas turbine systems keep steadily growing in size and number. This shows that in many cases they are more cost effective than conventional power plants.

6.2 Research Contribution

The comprehensive methodology for the economically based sizing of bivariate capacity/demand systems, is the first analytical attempt -as far as the available literature indicates- to effectively integrate existing statistical methods and probability theory to the realm of industrial energy systems design. Energy systems such as cogeneration plants, thermal energy storage, and steam distribution networks are some of the direct applications of the developed methodology. The methodology could also be extended to the design and analysis of flexible manufacturing systems with and without inventories.

Research needs, stated in the pertinent literature, strongly indicated that the methodology proposed here has been needed and awaited for a long time. Recall that the underlying problems of randomness in design and economic decision analysis under risk have been widely recognized and understood and it is not suggested that they have recently come to fore. But the literature and industry repeatedly indicate that an effective solution procedure for CHP plant design must recognize and incorporate the stochastic nature of the problem. Thus, the correct application of the results of this research will allow engineers, analysts and decision makers involved in design and/or evaluation of this kind of problem to resolve the impasse caused by its probabilistic nature.

In addition, the models developed in this research will be able to serve as a powerful research and development tool. For instance, by knowing the "most likely" operating range of a gas turbine CHP system for a given market segment or for a type of application, the manufacturer can improve the overall value of the product by enhancing the performance characteristics of the machine for the relevant range and frequency of operation. Consequently, using our methodology, robust designs (i.e. designs that economically operate under wide load variation) could be developed for CHP and other similar systems. In this context, our methodology becomes a quality improvement technique that could be even extended to conduct market research.

The research results presented in this thesis should also serve as the basic conceptual framework upon which further and more sophisticated methods can be developed. In particular, as a result of this research, CHP system design improvements could be evaluated under probabilistic scenarios. For example, a systematic incremental economic analysis for marginal improvements -as related to reductions in variance of capacity and/or demand- can be conducted. Another example of the research usefulness is the economic assessment of reliability improvements in the underlying CHP system.

In addition, regulatory compliance can be demonstrated by expressing the requirements of cogeneration regulation within the CHP sizing methodology. For instance, statistical limits on the performance of prospect cogeneration systems could be formulated to show compliance to system effectiveness requirements. Also, a probabilistic approach can help in the negotiation process of setting rates between developer and utility, and to show the impact of the CHP plant on the utility system's reliability and availability.

Finally, this methodology is said to be robust because the engineer or analyst can use one of various models to suit a particular cogeneration application. In other words, the methodology remains valid, withstanding the variation in cases and applications. The methodology is also responsive. Thus, to construct valid evaluation models, the methodology can be easily adapted to the characteristics and/or details of a particular site. In this context, robustness and responsiveness provide the analyst with the means to create better and valid models.

6.3 For Further Research

The following are topics recommended for further research:

1) The modification of the methodology for the cases with correlated CHP capacities and/or loads.
2) The extension of the models to consider (a) load tracking (no electricity export) and (b) for isolated plants.
3) The development of the CHP-RAM capacity allocation (i.e how many units and what size each) models discussed in Section 5.1
4) The development of a model for load variance reduction. For instance, an optimization methodology for the design of CHP-TES systems. In other words: What is the optimal combination of CHP-plant-size and TES-size?
5) The estimation of the variance of the TEAC functions, which should follow a development similar to the one used for the TEAC equations.
6) The development of a cogeneration design expert system based on the models presented and/or proposed herein.

7) The optimization of the n-multivariate demand and load problem discussed below.

6.4 Concluding Remarks

From determining the diameter (and the tolerances) of a bolt to estimating the number of gates in an airport; and from sizing an electrical conductor to establishing the useful pay-load of a space ship, one of the most important design tasks that always have confronted engineers is the specification of the size or capacity of an engineering system. Thus, much judgement and many trade-offs have to be exercised by engineers in order to specify the "right" system capacity. This is more critical when the engineer is confronted with technological constraints and limited resources -an ever present problem. Furthermore, the system sizing problem becomes more complex when two or more design parameters (e.g. weight, volume and strength) have to be specified.

This thesis has presented an evolutionary approach to the economical system sizing problem for the case of bivariate capacities and bivariate demands. The cogeneration or CHP problem has been used throughout as the vehicle to develop the methodology.

It is hoped that, in a fashion similar to the developments of vector analysis, linear algebra and linear programming, in which two variables and the X-Y plane are used to demonstrate the theory of an n-dimensional problem, the two-variable case of CHP size optimization will serve as the basis for the development of a conceptual optimization method for the general case of a system with n-random-variable capacities subject to n-random-variable demands.

Thus, for instance, the problem of industrial steam utilization (or any other fluid) at different temperatures and pressures has triggered much research in the so called field of "thermo-economics"; but under pure deterministic conditions.

Since steam at different temperatures and pressures represents different levels of "exergy" or energy availability (i.e. the capacity to perform work), then the fluid becomes a multi - commodity, or better, a set of commodities. For example, in cogeneration topping cycles, a hot fluid is always used to produce electrical or shaft power first, then it is subsequently used to make steam distributed to various processes in cascade through a network with several pressure levels.

So, each commodity or fluid stream (S_j) has a value proportional to its absolute temperature (T_j) and a cost proportional to the temperature difference ($Tj - T_{j+1}$) of the process that constitute its demand. Henceforth, in an industrial plant where steam is utilized at multiple pressures and is supplied from a multiple unit CHP plant, we can visualize a realization of the multivariate-capacity multivariate-demand problem. But, the methodology to determine, under stochastic conditions, both the total optimal capacity and the capacity allocated to each commodity remains to be accomplished.

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APPENDIX

PROOF FOR THE CCUD-1 MODEL [EQUATION 4.26]

Recall from equation 4.25a (Example 4.4) that the expected total equivalent annual cost for uniformly distributed heat H and power P loads is

$$TEAC(Pc) = EC_0 + EC_1 + EC_2 + EC_3 + EC_4 \qquad [4.25a]$$

Where:

$$EC_0 = \int\int (a + cf/n_e.t + cm.t)Pc\ f(P).f(H)\ dPdH$$

$$EC_1 = \int_{H1}^{Hc}\int_{P1}^{Pc} \{c_r(Hc-H) + s_e(Pc-P)\}\ J(t)\ dPdH$$

$$EC_2 = \int_{H1}^{Hc}\int_{Pc}^{P2} \{c_r(Hc-H) + c_e(P-Pc)\}\ J(t)\ dPdH$$

$$EC_3 = \int_{Hc}^{H2}\int_{P1}^{Pc} \{c_f/n_a\ (H-Hc) + s_e(Pc-P)\}\ J(t)\ dPdH$$

$$EC_4 = \int_{Hc}^{H2}\int_{Pc}^{H1} \{c_f/n_a\ (H-Hc) + c_e(P-Pc)\}\ J(t)\ dPdH$$

$$J(t) = t.f(H,P) = t/[(H2-H1)(P2-P1)]$$

Next, all terms within the integral equations are developed. Thus for EC_1, over the integration domain W1, we have

$$EC_1 = \int\int_{(W1)} [c_rHc- c_rH + s_ePc -s_eP]\ J(t)\ dPdH$$

$$= [c_rH_c + c_eP_e] \int\int_{(W1)} J(t)\ dPdH$$

$$+ \int\int_{(W1)} [-c_rH -s_eP]\ J(t)\ dPdH$$

$$= \{[c_r H_c + s_e P_e] \quad P.H \Big|_{H1}^{Hc} \Big|_{P1}^{Pc}$$

$$+ [-c_r H^2 P - s_e H P^2]/2 \Big|_{H1}^{Hc} \Big|_{P1}^{Pc} \} \; J(t)$$

$$= [(c_r Hc + s_e P_c) \; (P_c - P_1) \; (H_c - H_1)$$
$$+ (-c_r (Hc^2 - H_1^2)(Pc - P_1)/2 - s_e (Hc - H_1)(Pc^2 - P1^2)/2] \; J(t)$$

$$= [c_r Hc^2 Pc - c_r H_1 HcPc - c_r P_1 Hc^2 + c_r P_1 H_1 Hc \qquad \textbf{[A1]}$$
$$+ s_e HcPc^2 - s_e P_1 HcPc + s_e P_1 H_1 Pc - s_e Pc^2 H_1$$
$$- (c_r Hc^2 Pc + c_r Hc^2 P_1 + c_r H_1{}^2 Pc - c_r H_1{}^2 P_1$$
$$- s_e HcPc^2 + s_e HcP_1{}^2 + s_e H_1 Pc^2 - s_e H_1 P_1{}^2)/2] \; J(t)$$

Next for EC_2, over the integration domain W2, we have

$$EC_2 = \iint_{(W2)} [c_r H_c - c_r H + c_e P - c_e Pc] \; J(t) \; dPdH$$

$$= [[c_r Hc - c_e Pc] \; P.H - c_r H^2 P/2 + c_e H P^2/2] \; J(t) \Big|_{H1}^{Hc} \Big|_{Pc}^{P2}$$
$$= [(c_r Hc - c_e Pc) \; (P_2 - Pc) \; (Hc - H_1) - (c_r/2)(H_c{}^2 - H_1{}^2)$$
$$(P_2 - Pc) + (c_e/2)(Hc - H_1)(P_2{}^2 - Pc^2)] \; J(t)$$

$$= [c_r P_2 Hc^2 - c_r P_2 H_1 Hc - c_r PcHc^2 + c_r H_1 PcHc \qquad \textbf{[A2]}$$
$$- c_e P_2 PcHc + c_e P_2 H1Pc + c_e HcPc^2 - c_e H_1 Pc^2$$
$$- (1/2)(c_r P^2 Hc^2 + c_r Hc^2 Pc + c_r H_1{}^2 P^2 - c_r H_1{}^2 Pc$$
$$+ c_e P_2{}^2 Hc - c_e HcP_c{}^2 - c_e H_1 P_2{}^2 + c_e H_1 P_c{}^2)] \; J(t)$$

Next for EC_3, over the integration domain W3, we have

$$EC_3 = \iint_{(W3)} [(c_f/n_a)H - (c_f/n_a)Hc + s_e Pc - s_e P] \; J(t) \; dPdH$$

$$= [(-c_f/n_a . Hc + s_e Pc) H.P + c_f/2n_a \; H^2 P - s_e/2HP^2] \; J(t) \Big|_{Hc}^{H2} \Big|_{P1}^{Pc}$$

$$= [(-c_f Hc + s_e Pc)(H_2 - Hc)(Pc - P_1)$$
$$+ (1/2)(c_f/n_a)(H_2{}^2 - Hc^2)(Pc - P_1)$$
$$- (s_e/2)(H_2 - Hc)(Pc^2 \; P_1{}^2)] J(t)$$

$$= [-c_f/n_a.H_2HcPc + c_f/n_a.H_2P_1Hc + c_f/n_a.Hc^2Pc - c_f/n_a.P_1Hc^2$$
$$+(s_eH_2Pc_2 - s_eH_2P_1Pc - s_eHcPc^2 + s_eP_1HcPc \qquad [A3]$$
$$+(c_f/n_a.H_2{}^2Pc - c_f/n_a.H_2{}^2P_1 - c_f/n_a.Hc^2Pc + c_f/n_a.P_1Hc^2$$
$$- s_eH_2Pc^2 + S_eH_2P_1{}^2 + S_eHcPc^2 - S_eP_1{}^2Hc)/2]\ J(t)$$

Next for EC_4, over the integration domain W4, we have

$$EC_4 = \iint_{(W4)} [c_f/n_a.H- c_f/n_a.Hc+ c_eP- c_ePc]\ J(t)\ dPdH$$

$$= [(-c_f/n_a.Hc-c_ePc)HP + c_f/(2n_a)H^2P + (c_e/2)HP^2] \Big|_{Hc}^{H2} \Big|_{Pc}^{P2}$$

$$= (-c_f/n_a.Hc - c_ePc)(H_2 - Hc)(P_2 - Pc)$$
$$+c_f/(n_a2)(H_2{}^2-Hc^2)(P_2-Pc] + (c_e/2)(H_2- Hc)(P_2{}^2-Pc^2)$$

$$= [(-c_fH_2P_2Hc + c_fH_2HcPc + c_fP_2Hc^2 - c_fHc^2Pc)/n_a \qquad [A4]$$
$$-c_eH_2P_2Pc + c_eH_2Pc^2 + c_eP_2HcPc - c_eHcPc^2$$
$$+1/2(c_f/n_aH_2{}^2P_2 - c_f/n_aH_2{}^2Pc - c_f/n_aP_2Hc^2 + c_f/n_aHc^2Pc$$
$$+ c_eH_2P_2{}^2 - c_eH_2Pc^2 - c_eP_2{}^2Hc + c_eHcPc^2)]\ J(t)$$

In equations A1, A2, A3, and A4 above, all the third degree terms containing Hc^2Pc and $HcPc^2$ cancel out. Henceforth, collecting all the second degree terms (i.e. those containing Pc_2, $Pc.Hc$ and $Hc^2 = r_c{}^2.Pc^2$), from all the above equations, we obtain the following partial coefficients of Pc^2:

$$A_1 = (-s_eH_1 + s_eH_1/2 - c_eH_1 + c_eH_1/2$$
$$+ s_eH_2- s_eH_2/2 + c_eH_2 - c_eH_2/2)\ J(t)$$
$$= 1/2\ (-s_eH_1 - c_eH_1 + s_eH_2 + c_eH_2)\ J(t)$$
$$= 1/2\ (s_e + c_e)\ (H_2 - H_1)\ J(t)$$

$$A_2 = rc(-c_rH_1 - s_eP_1 + c_rH_1- c_eP_2$$
$$- c_f/n_aH_2 + s_eP_1 + c_f/n_aH_2 + c_eP_2)\ J(t)$$
$$= 0$$

$$A_3 = rc_2[-c_rP_1 + c_r/2P_1 + c_rP_2 - c_r/2P_2$$
$$- c_fP_1 + c_fP_1 + c_f/n_aP_2 - c_f/2n_aP_2]\ J(t)$$
$$= rc_2[-c_r/2P_1 + c_r/2P_2 - c_f/2n_aP_1 + c_f/2n_aP_2]J(t)$$
$$= rc_2[c_r/2(P_2 - P_1)+ c_f/2n_a\ (P_2 - P_1)\ J(t)$$
$$= rc_2/2\ (P_2 - P_1)\ (c_r + c_f/n_a)\ J(t)$$

Thus, we define the global coefficient A (of Pc^2) as follows

$$A = A_1 + A_2 + A_3 \qquad \textbf{[A5]}$$
$$= 1/2[(c_e + s_e)(H_2 - H_1) + (c_r + c_f/n_a)(P_2 - P_1)r_c^2]$$

Next, considering $Hc = r_c.Pc$, the terms containing Pc are:

$$B_a = r_c(c_rP_1H_1 + s_eP_1^2/2 - c_rP_2H_1 + c_eP_2^2/2$$
$$+ c_f/n_a.H_2P_1 - s_eP_1^2/2 - c_f/n_a.H_2P_2 - c_eP_2^2/2)$$
$$= r_c[c_rH_1(P_1 - P_2) + c_f/n_a.H_2\ (P_1- P_2)]\ J(t)$$
$$= r_c[(P_1 - P_2)\ (c_rH_1 + c_f/n_aH_2)]\ J(t)$$

$$B_b = [s_e\ P_1H_1 + c_rH_1^2/2 + c_eP_2H_1 - c_rH_1^2/2$$
$$- s_eH_2P_1 + c_fH_2^2/(2n_a) - c_eH_2P_2 - c_f/2H_2^2/(2n_a)]J(t)$$
$$= [(s_eP_1\ (H_1 - H_2)+ c_eP_2\ (H_1 - H_2)]\ J(t)$$
$$= (H_1 - H_2)(s_eP_1 + c_eP_2)\ J(t)$$

Next, from equation **4.25a** above we have

$$EC_0 = \iint_{(W)} (a + c_f/n_e.t+ c_m.t)Pc\ f(P).f(H)\ dpdh$$

Since the integral of f(P) and f(H) over whole domain W gives

$$\iint_{(W)} k.f(P).f(H)\ dpdh \equiv k.1 \equiv k, \quad \text{by definition,}$$

where k is a constant independent of the rv's P and H.

Then, we have $EC_0 = [a + (c_f/n_e)t + c_m.t)Pc$

and by making $B2 = a + (c_f/n_e)t + c_m.t$ we obtain

$$EC_0 = B2.Pc$$

Hence, the global coefficient of Pc is

$$B = B1 + B2 \qquad \textbf{[A6]}$$

where:

$$B1 = B_a + B_b$$
$$= [r_c(P_1-P_2)(c_rH_1 + c_f/n_a.H_2) + (H_1-H_2)(s_eP_1 + c_eP_2)]J(t)$$
$$B2 = a + (c_f/n_e)t + c_m.t$$

Finally, the remaining terms are grouped to form

$$C = (1/2)[-c_rH_1{}^2P_1 - s_eH_1P_1{}^2 + c_rH_1{}^2P_2 - c_eH_1P_2{}^2$$
$$- (c_f/n_a)H_2{}^2P_1 + s_eH_2P_1 + (c_f/n_a)H_2{}^2P_2 + c_eH_2P_2{}^2]J(t)$$
$$= (1/2)[c_eP_2(H_2 - H_1) + c_rH_1{}^2(P_2 - P_1)$$
$$+ (c_f/n_a)H_2{}^2(P_2 - P_1) + s_eP_1{}^2 (H_2 - H_1)]J(t)$$
$$= 1/2[(c_eP_2{}^2 + s_eP_1{}^2)(H_2 - H_1) \qquad \textbf{[A7]}$$
$$+ (c_rH_1{}^2 + (c_f/na)H_2{}^2)(P_2 - P_1)]J(t)$$

Therefore from equations **A5, A6** and **A7**, we obtain the TEAC function for the CCUD-1 model:

$$\boxed{TEAC = APc^2 + (B1 + B2)Pc + C} \qquad [4.26]$$

Where:

$$A = 1/2[(s_e+c_e)(H_2-H_1) + r_c{}^2(P_2-P_1)(c_r+c_f/n_a)]J(t)$$
$$B1 = [(H_1-H_2)(s_eP_1+c_eP_2) + r_c(P_1-P_2)(c_rH_1+(c_f/n_a)H_2)]J(t)$$
$$B2 = a + (c_f/n_e)t + c_mt$$
$$C = 1/2[(c_eP_2{}^2 + seP_1{}^2)(H_2 - H_1)$$
$$+ (c_rH_1{}^2 + (c_f/n_a)H_2{}^2)(P_2 - P_1)]J(t)$$

Which demonstratres equation [4.26] ▪

<u>Note:</u> A verification of model equation 4.26 was carried out using data given in Example 4.5. The results for (A) numerical integration of equation 4.25a above, and for (B) direct computation of [4.26] were identical. It took over 4 minutes to run method A and just less than two seconds to compute and display the same results through method B.

VITA

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