SIMULATION METHODS FOR GENERATION PLANNING OF ELECTRIC UTILITY SYSTEMS WITH INTERMITTENT POWER SOURCES

By

YAHYA IBRAHIM SHARAF-ELDEEN

Bachelor of Science
University of Alexandria
Alexandria, Egypt
1967

Master of Science
University of Alexandria
Alexandria, Egypt
1973

Doctor of Philosophy
The Ohio State University
Columbus, Ohio
1979

Submitted to the Faculty of the Graduate College
of the Oklahoma State University
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Thesis Approved:

P. M. Moretti
Thesis Adviser

Jerald D. Parker

Joe H. Mize

R. Ramakumar

Norman N. Durham
Dean of the Graduate College

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Finally, I dedicate this thesis to my family -- The one who raised me, and the one I am helping to raise.

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LIST OF SYMBOLS

C	Weibull scale factor
K	Weibull shape factor
L	Original-Load on electric utility system
L'	Modified-Load on electric utility system
LDC	Load Duration Curve
P	Power Output of WTGS
P_m	Mean power output of WTGS
PR( )	Cumulative probability function
Pr( )	Probability density function
PR_N( )	Cumulative Probability function for NASA model
PR_R( )	Cumulative Probability function for Rayleigh model
PR_W( )	Cumulative Probability function for Weibull model
Pr_N( )	Probability density function for NASA model
Pr_R( )	Probability density function for Rayleigh model
Pr^W( )	Probability density function for Weibull model
P_{rat}	Rated power output of WTGS
V	Wind speed
V_m	Mean wind speed
V_{in}	Cut-in wind speed of WTGS
V_{out}	Cut-out wind speed of WTGS
V_{rat}	Rated wind speed of WTGS
WTGS	Wind Turbine Generating System(s)
σ_V	Standard deviation of wind speed

CHAPTER I

INTRODUCTION

There has been an increasing interest in using Wind Turbine Generating Systems (WTGS) for the generation of electricity in utility applications. The value of wind-generated power to an electric utility system depends upon the characteristics of the wind resource and load demand, cost of the conventional capacity and energy displaced by the WTGS, and the cost of additional backup units that may be required in order to accommodate the power fluctuations of the remaining load on the utility.

Because of the intermittent and random nature of the wind speed, wind power cannot be scheduled in advance and classical generation analysis does not work well. The best analyses have been carried out through an hour-by-hour simulation using several years of input data. Figure 1 outlines the basic methodology used in these analyses for establishing the value of WTGS to a utility. A standard utility generation expansion model is run, without WTGS present, to determine the fixed and variable costs that a utility would incur to meet its load and reliability requirements, using conventional sources. Wind systems are then added to the mix, at no cost to the utility, and hourly wind power used as a negative load to cancel out some of the hourly load that the utility would experience without WTGS present. The remaining load is then run through the standard utility generation model and the fixed

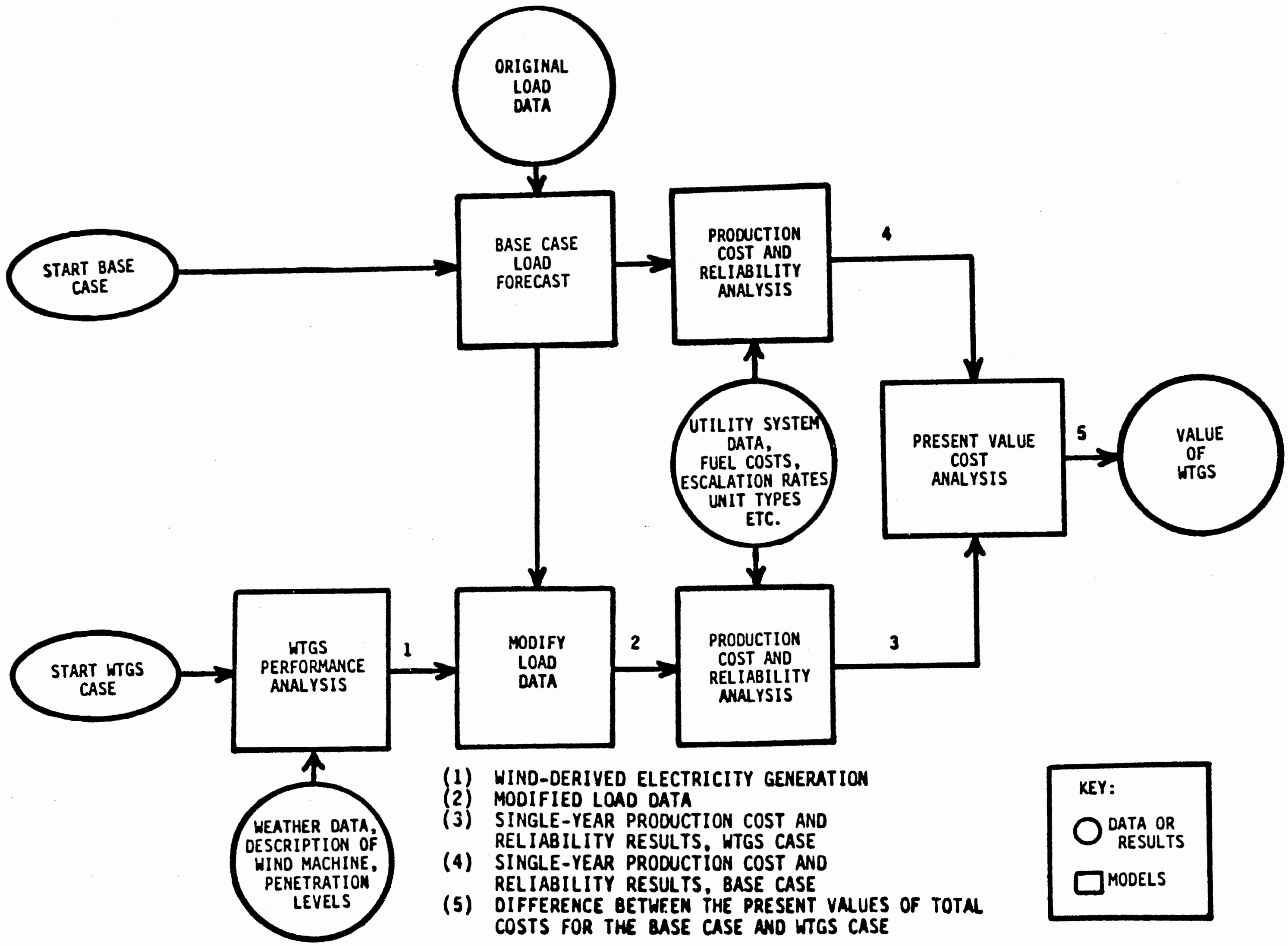


FIGURE 1. BASIC VALUE ANALYSIS METHODOLOGY.

and variable costs associated with meeting this reduced load are calculated. The difference between the costs of the meeting the total load, and the costs of meeting the reduced load (due to WTGS) are an indication of the "savings" in conventional source costs due to the WTGS being present. When these "savings" have been adjusted to account for the WTGS siting and grid interface costs and any additional operating reserve required, the remining savings can be used to calculate the value of WTGS to the utility.

Although the hour-by-hour simulation methods can be very detailed and complete, the computational effort and cost are excessive and the conclusions are often difficult, if not impossible, to generalize. Better methods for evaluating WTGS impacts are needed in order to remove some of the uncertainties which discourage the installation of wind turbines even in promising sites and applications.

CHAPTER II

OBJECTIVES AND SCOPE

This work concerns the development of a general methodology for conducting economic assessments of WTGS in electric utility applications. The basic approach involves first predicting the WTGS power outputs, and then appropriately reducing the load demand of the utility. Probabilistic methods are employed to properly represent the randomness in both the utility load and WTGS power output. Modified-load duration curves are obtained by convolution integration of wind power and original load distributions. Original- and modified-load duration curves are then compared in order to evaluate WTGS impacts on the generation capacity and energy requirements of the conventional equipment, and to estimate the associated savings in the annual costs.

The basic methods and procedures of this methodology are presented and discussed in Chapters 3, 4, and 5. Chapter 6 contains an application of the methodology to a model utility system. Chapter 7 provides a summary and outlines the main conclusions of this work. This chapter also outlines some recommendations for future research. The original data analyzed and the computer programs developed in this work may be obtained from the School of Mechanical and Aerospace Engineering at Oklahoma State University.

CHAPTER III

CHARACTERISTICS AND PLANNING PROCEDURES OF ELECTRIC UTILITY SYSTEM CONSIDERED

This chapter presents the general characteristics and planning procedures of the electric utility system developed for the purposes of this work. Section 3.1 concerns the probabilistic representations of electric utility loads. The characteristics of the load on the developed utility are presented in Section 3.2. This section also contains an analysis of the load growth and outlines a procedure for predicting anticipated load distributions for future years. Section 3.3 describes the composition and cost parameters of the conventional generating equipment that are selected to meet the load requirements in the year 1990, the "analysis year". This section also presents the methods and approaches used in determining the capacity and energy generation of the various equipment selected and in calculating the associated costs for meeting the load requirements in the given year. A summary of the overall planning and production costing procedures used is given in Section 3.4.

3.1. Probabilistic Representations of Electric Utility Loads

The determination of the characteristics of anticipated loads on an electric utility system for future years is one of the primary functions in the planning procedures of the electric utility industry. The most important element in the projection of future loads is the historical load data seen by the utility. These data, which are usually recorded on an hourly basis, are analyzed in order to establish the characteristics of the system load. Several years of historical hourly load data are often required in order to obtain a good representation of the load on the electric utility system.

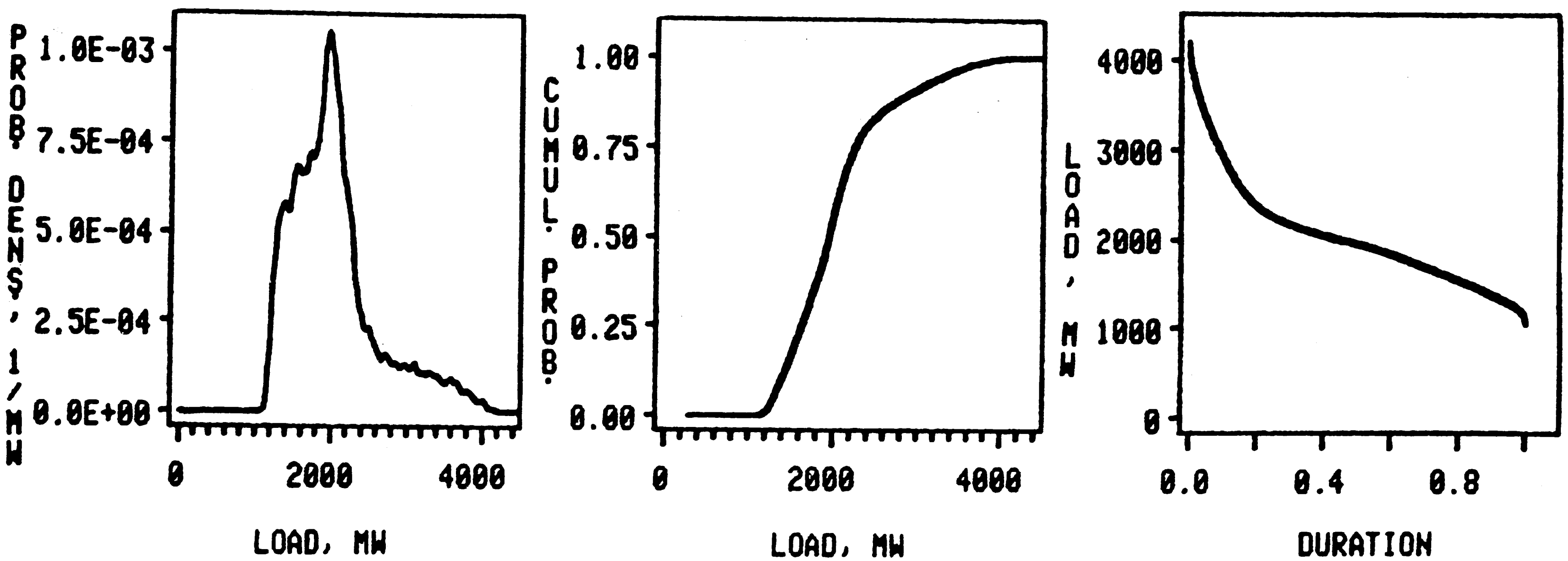
Accurate representation of electric utility loads, however, has been a significant problem. For a typical utility, the system load is a constantly changing variable. On a daily basis, it varies between a peak and a minimum level. Furthermore, electric utility loads exhibit daily, weekly, and seasonal variations, in addition to the growth that may be experienced from one year to the next.

Because of the random nature of electric utility loads, most planning procedures use probabilistic representations for describing the system load. These representations are shown graphically in Figure 2. The mathematical aspects involved and the evaluation procedures used are outlined below:

(a) The probability density function, Pr(L), is given by:

$$[Pr(L)]\, dL = Prob[L \leq \tilde{L} \leq (L + dL)] \qquad [3.1]$$

where $[Pr(L)]\, dL$ is the probability that a random load $\tilde{L}$ takes a value between L and (L + dL). This continuous probability function is often approximated by a discrete distribution developed from the hourly load data. The approximation procedure involves sorting the load into uniform bands, counting the number of data points in each band, and normalizing by both the width of the band and the total



(A) PROB. DENSITY FUNCTION. (B) CUMUL. PROB. FUNCTION. (C) LOAD DURATION CURVE.

FIGURE 2. REPRESENTATIONS OF LOAD ON ELECTRIC UTILITY SYSTEMS.

number of hours in the study period. The resulting histogram approximates Pr(L) numerically.

(b) The cumulative probability function, PR(L), is defined by:

$$PR(L) = Prob[\tilde{L} \leq L] \qquad [3.2]$$

where PR(L) is the probability that a random load $\tilde{L}$ is equal to or less than a load level of L. From Equations [3.1] and [3.2], it is evident that PR(L) can be obtained through integrations of the probability density function, Pr(L):

$$PR(L) = \int_0^L [Pr(\lambda)]\, d\lambda \qquad [3.3]$$

Conversely, Pr(L) can be obtained from the slopes of PR(L). The cumulative probability function is also known as the "complementary distribution function" and "inverted load duration curve."

(c) The load duration curve (LDC) is a rank ordering by magnitude of the utility load. It shows the value of the load versus the fraction of the time, τ, where a load equal to or greater than this value is observed:

$$\tau(L) = Prob[\tilde{L} \geq L]$$

$$= \int_L^{\infty} [Pr(\lambda)]\, d\lambda \qquad [3.4]$$

This is equivalent to the complement of the cumulative probability function, plotted with the abscissa and ordinate interchanged:

$$\tau(L) = 1 - PR(L) \qquad [3.5]$$

The LDC is the form used to represent the system load in the generation planning procedures of most electric utilities.

3.2. Characteristics of Load on Utility Considered

This section presents the characteristics of the load on the synthetic utility system analyzed in this work. Actual load data are utilized in order to make the analysis more realistic. The approach used in the projection of future loads assumes that the load growth is felt across the entire range of loads for the year. An average normalized LDC is thus obtained and used, in conjunction with a peak load model, to predict LDCs for the utility in future years.

3.2.1. Representations of System Load

Historical hourly load data were analyzed in order to establish the characteristics of the load on the model utility considered in this work. These hourly load data were obtained from a typical summer peaking utility system -- Public Service Company of Oklahoma (PSCO) Tulsa, Oklahoma.

The hourly load data for the years of 1974, 1975, 1980, and 1981 were utilized in this analysis. The LDCs for these years are presented in Figure 3. As shown in this figure, the shape of the utility LDC appears to remain relatively constant from year to year. Thus, the four LDCs were combined to obtain an average normalized LDC, as shown in Figures 4 and 5. This average normalized LDC was then used as the basis of forecasting load distributions for the utility for future years. The LDC for a particular year in the future was obtained by adjusting the average normalized LDC so that it portrays the expected annual peak load for that year.

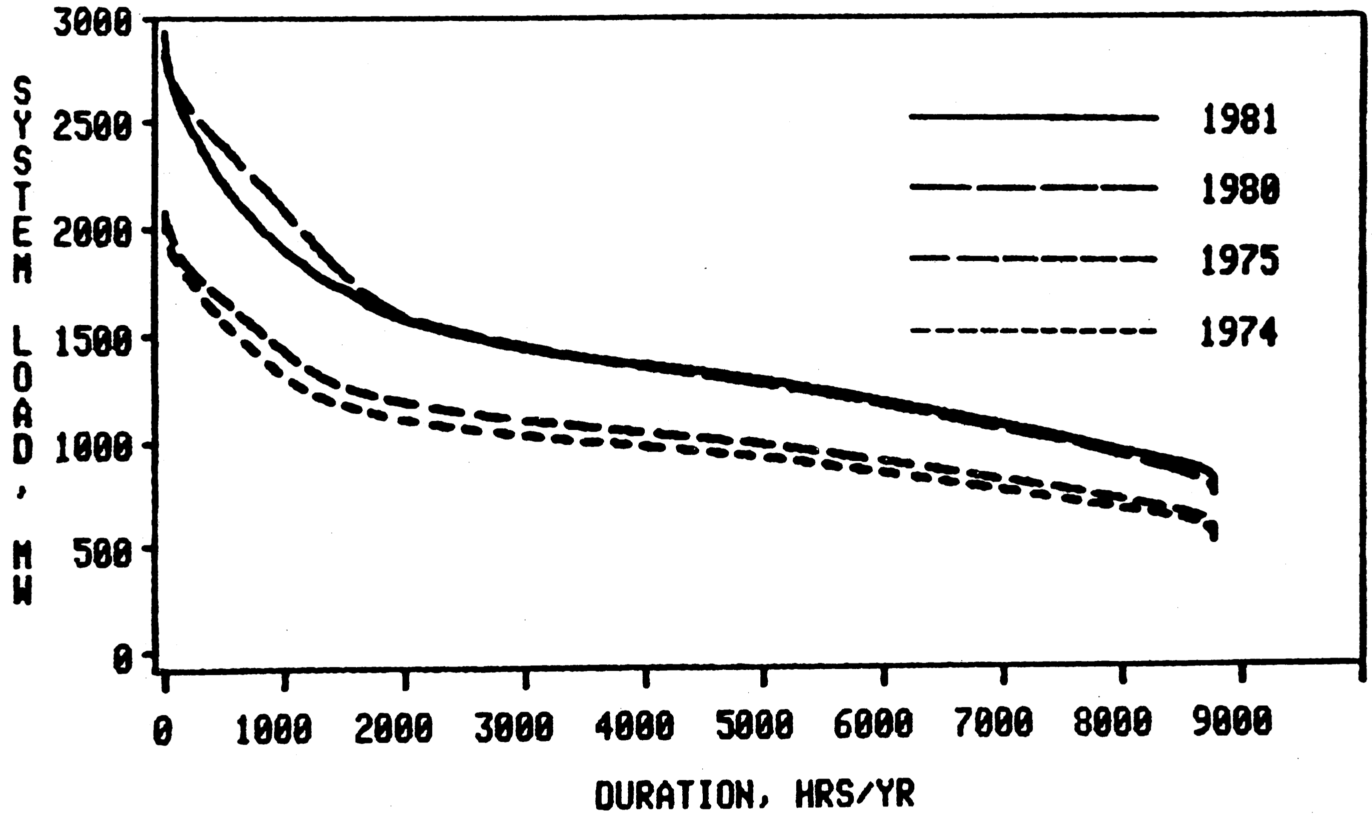


FIGURE 3. LOAD DURATION CURVES.

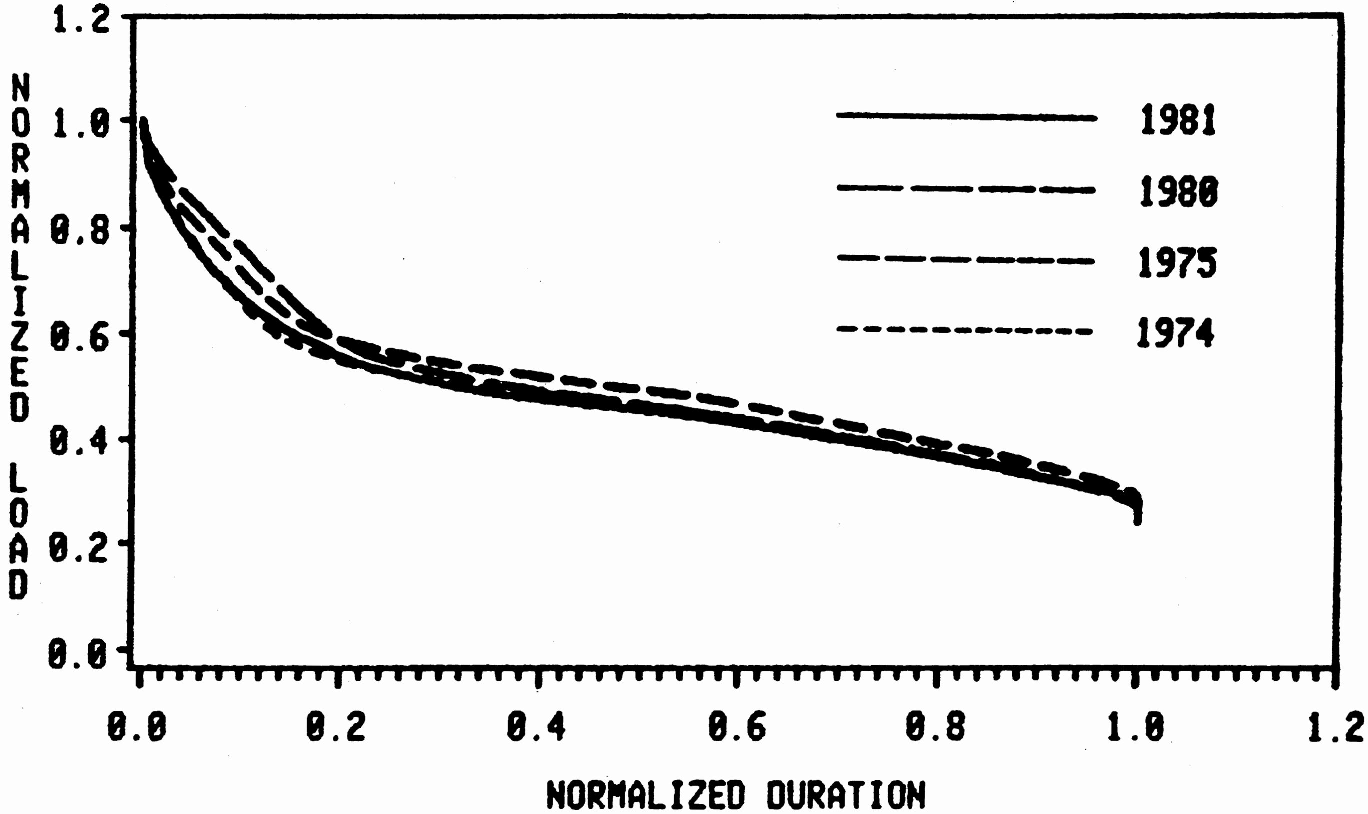


FIGURE 4. NORMALIZED LOAD DURATION CURVES.

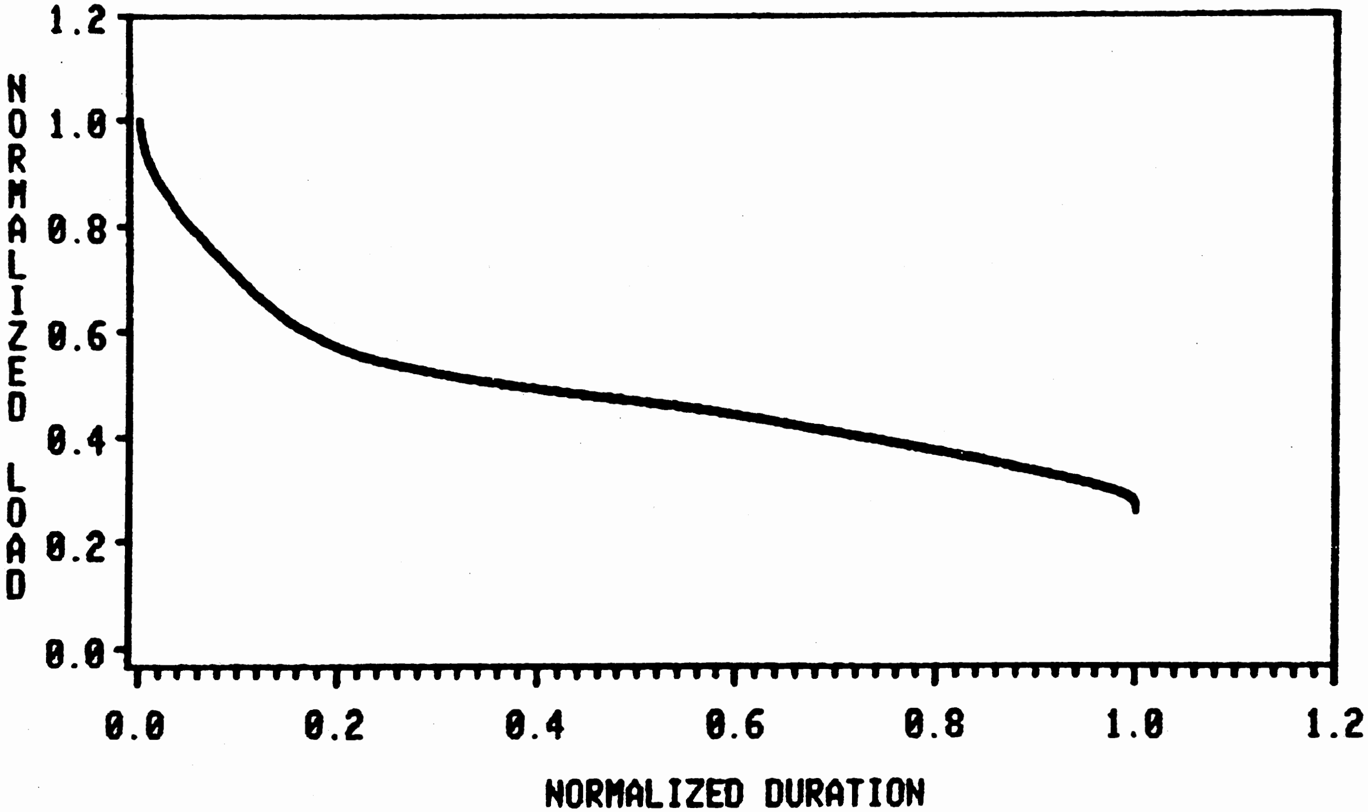


FIGURE 5. AVERAGE LOAD DURATION CURVE.

3.2.2. Prediction of Annual Peak Load

The peak load model used in this work was developed based upon an analysis of the annual peak loads of the PSCO utility system for the period 1960-1981. The values of these loads and the corresponding energy demands are given in Table I. Several empirical models were examined in this analysis. A third-order polynomial was found to best fit the observed data of the peak load. The value of the coefficient of determination, R^2, was found to be 0.994. The predictions of both the third-order polynomial and the exponential model, which is often used in modeling utility peak loads, are compared in Figure 6.

3.2.3. Projection of Future Load Distributions

The average normalized LDC was used, in conjunction with the developed peak load model, to obtain distributions of the expected loads on the utility for future years. The analysis carried out in this work concerns the year of 1990, the analysis year. The projected peak load for this year was found to be 4185 MW.

Figure 7 presents the expected 1990 load distribution in a load duration form, while Figure 8 shows the corresponding probability density information. The area under the curve shown in Figure 7 represents the annual energy requirements of the load in the analysis year. This curve is utilized in the following section to determine the capacity and energy generation of the various types of conventional equipment that are selected to meet the anticipated 1990 load requirements.

TABLE I.

PEAK LOAD AND ENERGY GENERATION

Year	Peak Load, MW	Energy Generation, MWH/Yr
1960	655	2,832,633
1961	686	2,966,482
1962	770	3,272,963
1963	863	3,669,915
1964	960	3,866,955
1965	1,000	4,230,753
1966	1,138	4,628,984
1967	1,166	4,828,516
1968	1,289	5,334,979
1969	1,453	5,966,485
1970	1,550	6,529,425
1971	1,610	6,824,378
1972	1,828	7,820,642
1973	1,843	8,201,793
1974	2,070	8,630,164
1975	2,071	9,203,598
1976	2,193	9,647,358
1977	2,405	10,581,144
1978	2,527	11,382,058
1979	2,456	11,309,572
1980	2,839	12,363,003
1981	2,930	12,120,032

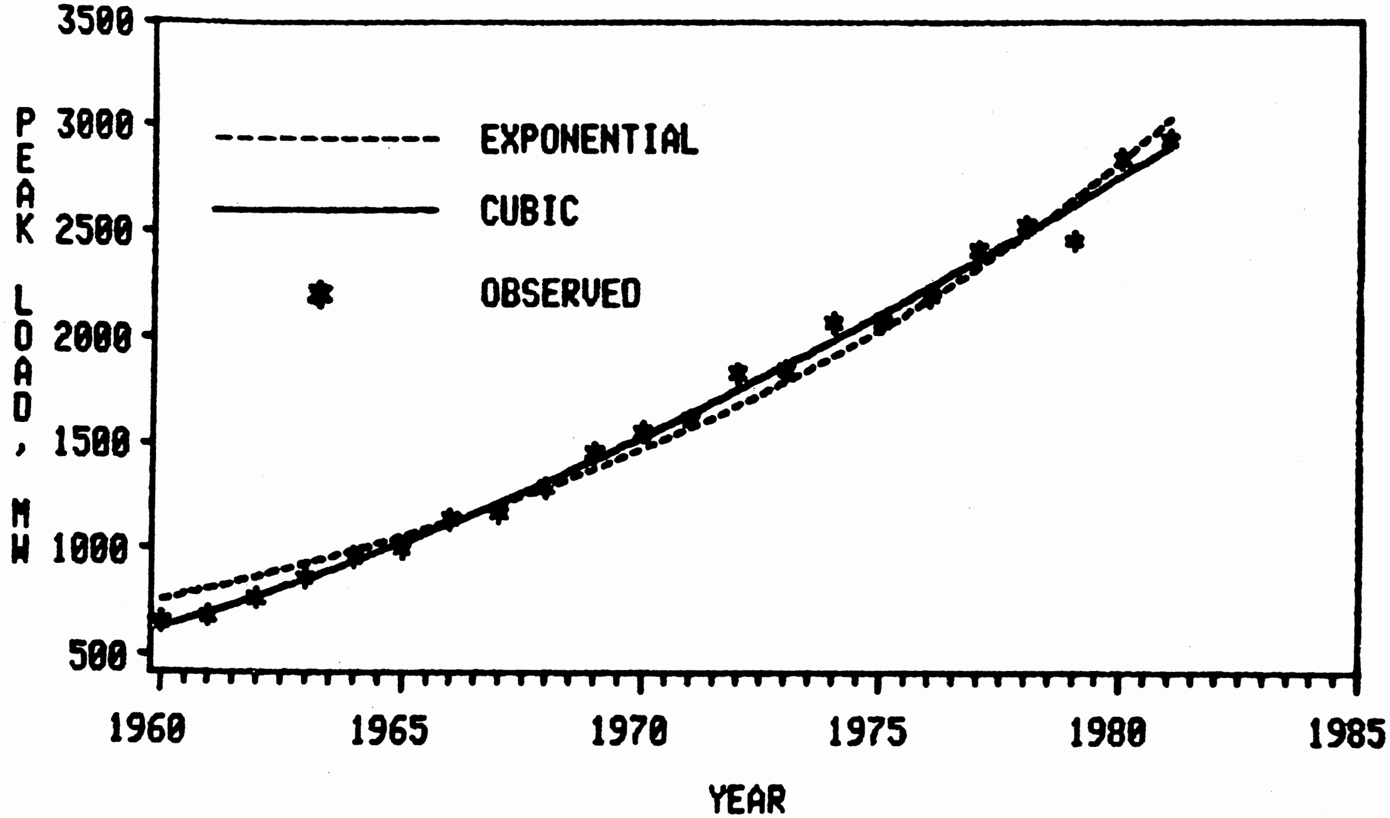


FIGURE 6. OBSERVED AND PREDICTED PEAK LOADS.

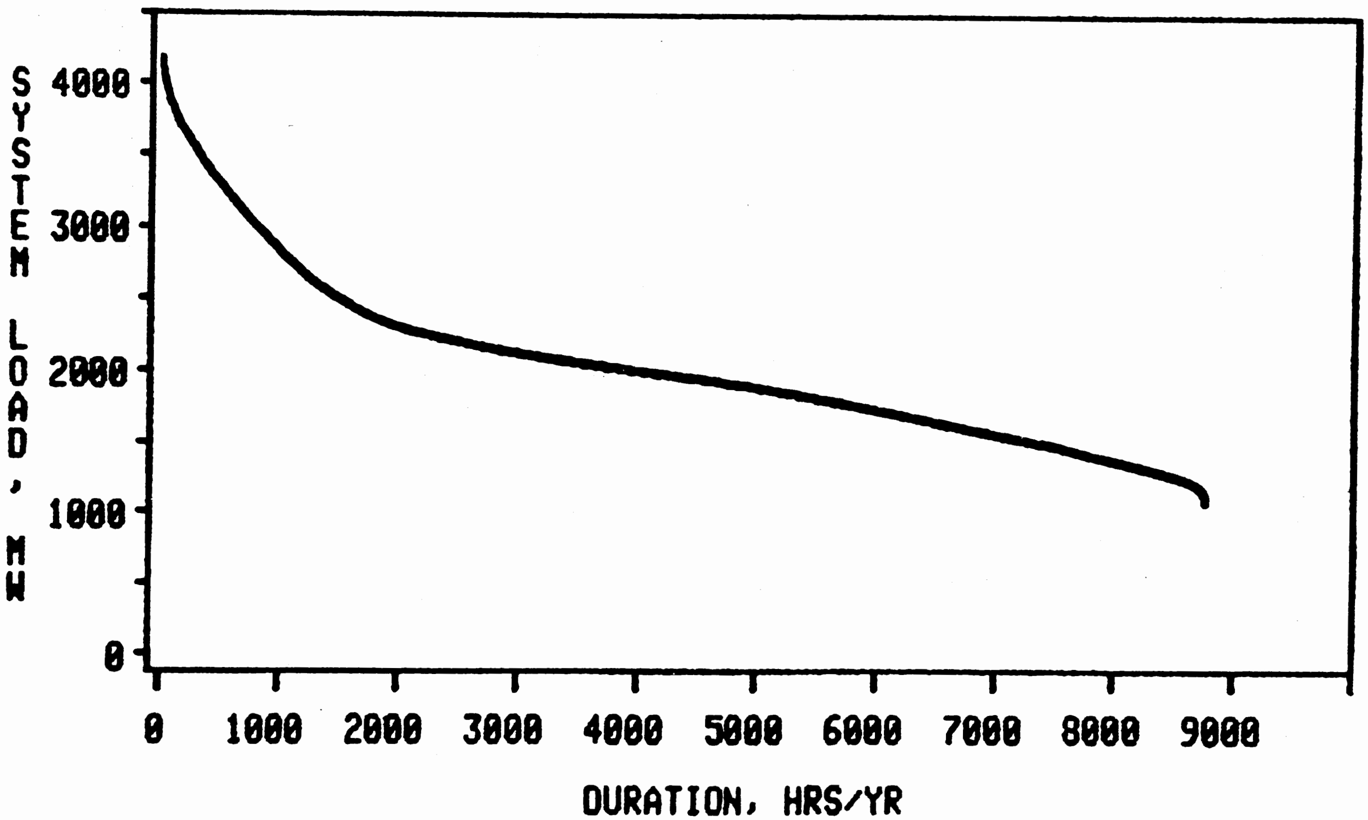


FIGURE 7. PREDICTED LOAD DURATION CURVE, FOR 1990.

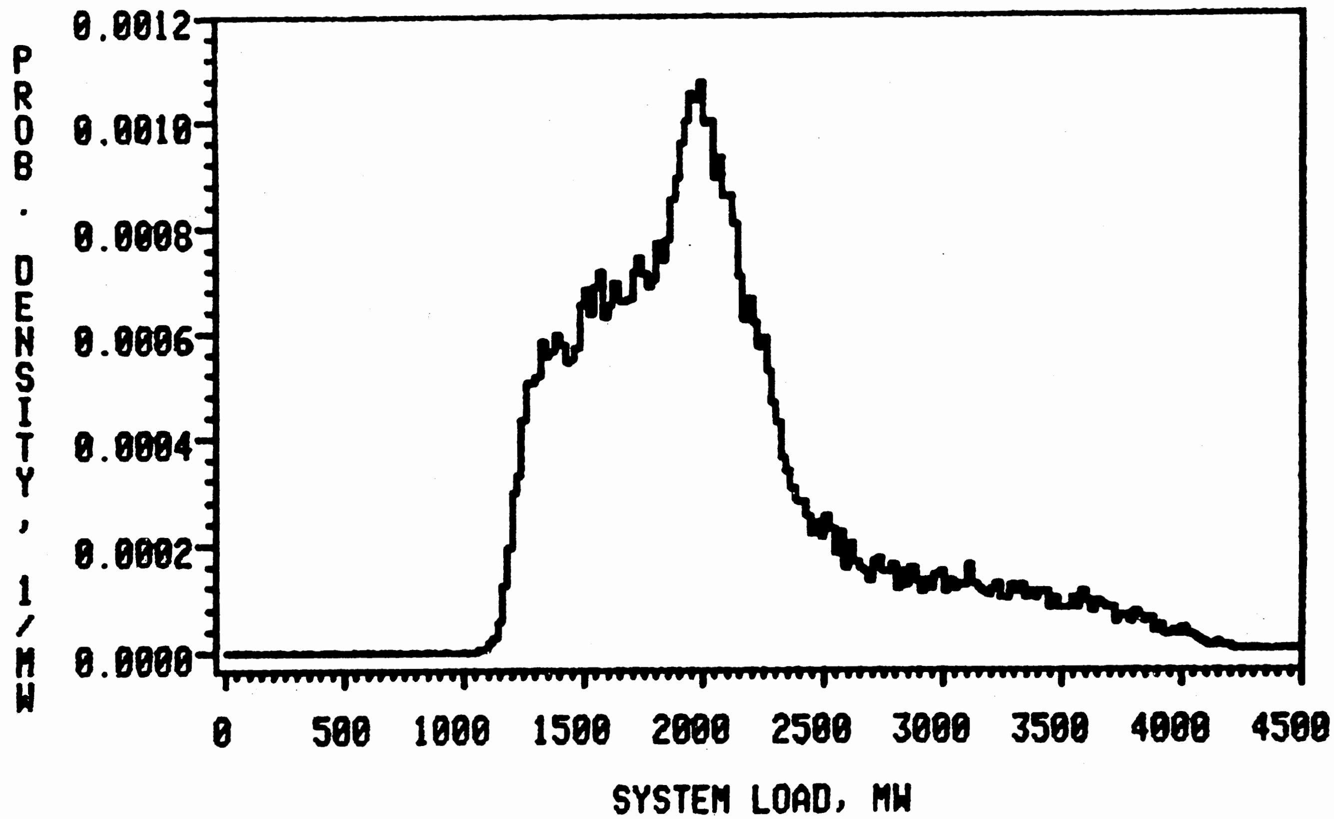


FIGURE 8. PROBABILITY DENSITIES OF PREDICTED LOAD.

3.3. Characteristics of Generating System and Determination of Generation Requirements and Costs for Utility Considered

The total cost of producing energy by an electric utility depends primarily upon the characteristics of the generating system selected for meeting the load requirements. Typically, the utility selects a mix of conventional generating equipment, with a total capacity large enough, to meet the expected load on the system and to satisfy its reliability requirements at a minimum cost. Complex and costly production costing models, both deterministic and probabilistic, are often used in order to select an optimum mix of equipment and to calculate the associated generation costs.

This section presents the general characteristics of the various types of conventional generating equipment that are selected to meet the 1990 load requirements of the utility under consideration. An approach is outlined for determining the capacity and energy generation of each type of equipment selected. This approach simulates the annual operation of the utility using load-duration and incremental-cost curves. These curves provide a simple basis for estimating the total annual costs associated with meeting the load requirements in the analysis year.

3.3.1. Characteristics of Generating Equipment

The generating system selected for the model utility analyzed in this work was assumed to have three types of conventional equipment: nuclear, oil-fired, and gas turbines for base-, intermediate-, and peak-load generation, respectively. Figure 9 shows the general

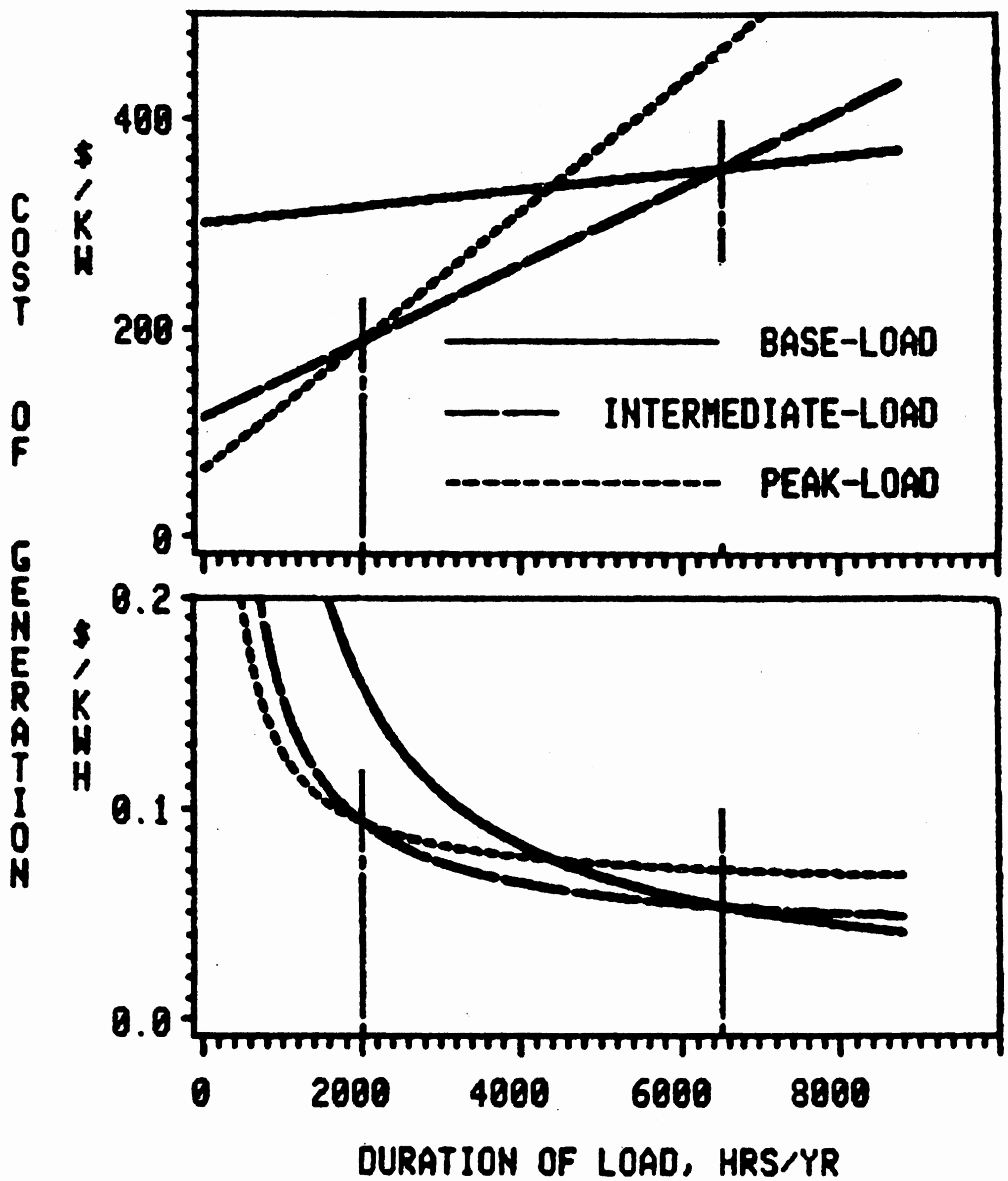


FIGURE 9. ANNUAL COST OF GENERATION FOR CONVENTIONAL EQUIPMENT.

characteristics of the fixed and variable costs of energy generation for each type of equipment. The fixed costs are incurred regardless of how much the units are used, while the variable costs are those that are incurred when units are dispatched. The total annual cost of generation from a unit is a function of both its capacity and the amount of annual energy it generates.

For the purpose of the analyses presented in this work, the yearly fixed costs were assumed to be 300, 115, and 65 $/KW for the nuclear, oil-fired, and gas turbine units, respectively. The variable costs, on the other hand, were assumed to be 8, 36.5, and 61.5 mills/KWH, respectively. No particular significance should be attached to the values of the cost parameters assumed in this analysis. In general, there is an inverse relationship between the fixed and the variable costs of a generating unit. That is, a unit with a low variable-cost energy would have a high fixed cost, and vice versa. Such an inverse relationship between the fixed and variable costs of a generating unit results in the equipment being economically compared based on their total annual costs for satisfying a given load distribution.

The most desirable situation would be to use each type of equipment for loads where it has the lowest total cost. For the cost parameters shown in Figure 9, the nuclear plant provides the lowest total cost of energy generation when operated for durations of more than 6490 hours per year. For operation time between 2000 and 6490 hours per year, the oil-fired plant is the least expensive. The gas turbines, however, yield the lowest total cost for operation time lasting up to 2000 hours per year. These characteristics provide a basis for selecting an optimum equipment mix for meeting the load requirements in a given year.

3.3.2. Determination of Generation Requirements and Production Costs of Optimum Equipment Mix

Given the load distribution presented in the form of a load duration curve, the most economical units are dispatched first to cover the base load, as shown in Figure 10. These units are then topped off with the more expensive units to meet the higher loads. This approach provides a simple method for determining the capacity and energy generation of each type of equipment for a given year.

For the 1990 load distribution, the capacity and annual energy generation for the three types of equipment are shown in Figure 10. The values of the capacity requirements were found to be 1642, 656, and 1887 MW for the base-, intermediate-, and peak-load equipment, respectively. The annual energy generation was found to be 13915.970, 2753.406, and 1238.438 GWH, respectively. These values were determined, through integration, from the appropriate areas under the 1990 LDC.

Given the values of the capacity and annual energy generation, the total annual costs can be determined, using the fixed and variable costs of the various types of equipment in the generating mix. For each type of equipment, the fixed-cost is multiplied by the capacity while the variable-cost is multiplied by the annual energy generation. The fixed and variable costs of all units are then summed up to determine the total annual costs of dispatch.

3.4. Closure

A synthetic utility system has been developed in order to demonstrate the methods and approaches introduced in this work. Historical hourly load data for the PSCO utility system were utilized to

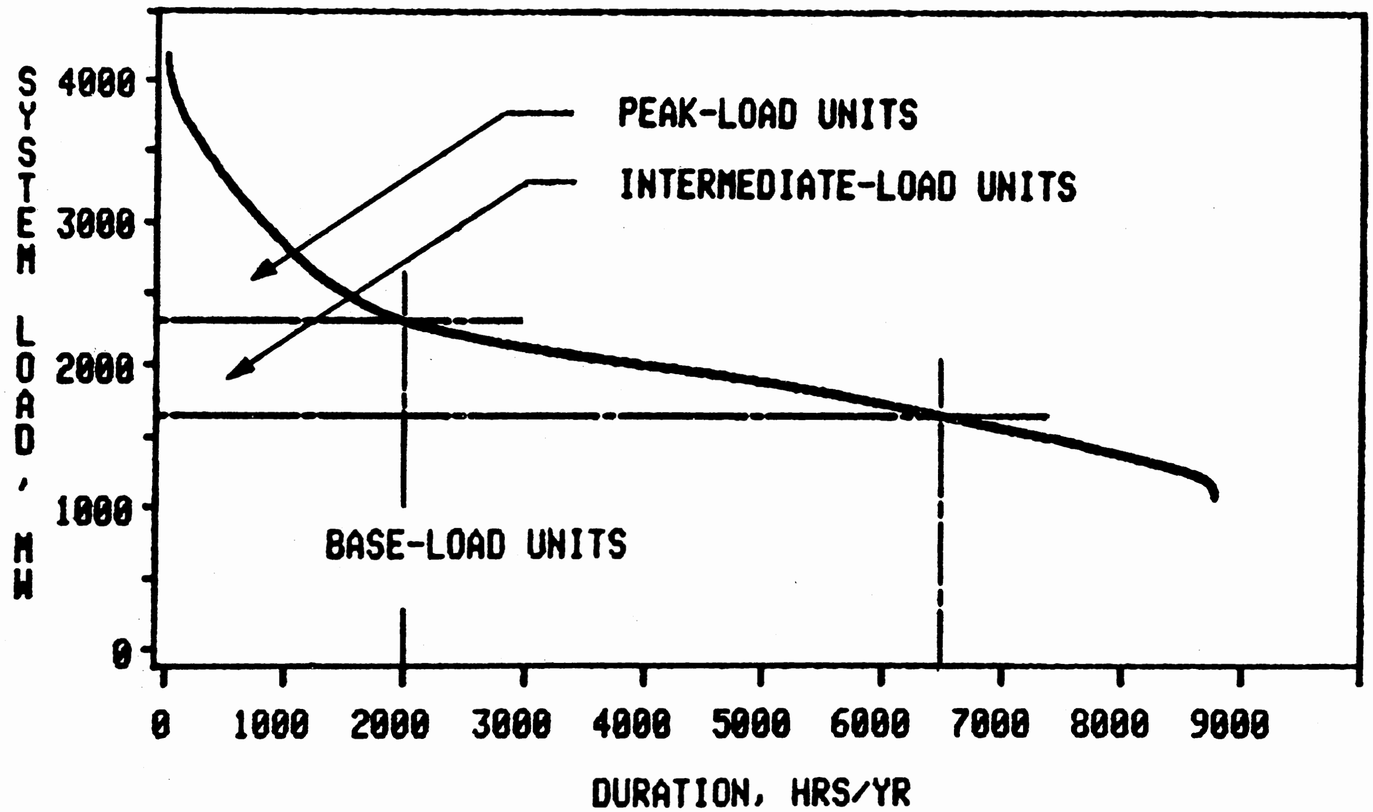


FIGURE 10. CAPACITY AND ENERGY REQUIREMENTS FOR OPTIMUM MIX OF CONVENTIONAL GENERATING EQUIPMENT.

obtain realistic load distributions for the developed utility. An average normalized LDC and a peak load model were utilized in the projection of anticipated LDCs for future years. The developed utility was assumed to have three types of conventional generating equipment: Nuclear, oil-fired, and gas turbines for base-, intermediate-, and peak-load generation, respectively. The LDC and screening-curve technique of the electric utility industry were utilized in the determination of the capacity and energy generation of the various equipment in the selected mix. This approach provides a simple basis for calculating the total annual costs of meeting a given load distribution.

The planning and production costing procedures of this work were based upon the assumption that the generation of each type of equipment in the utility mix could be represented by a continuous function, rather than step-wise commitment and dispatch. This approach is justifiable since, in a large utility system, the individual units make up a small fraction of the entire generating system.

CHAPTER IV

MODELING OF WIND POWER GENERATION

A primary application of wind electric generation is expected to be large clusters or arrays of megawatt-size Wind Turbine Generating Systems (WTGS) connected to the utility transmission network. An accurate prediction of the array power outputs and a proper evaluation of their impacts on the utility-wide capacity and load characteristics are vital in assessing the economic viability of such an investment.

This chapter concerns the development of a probabilistic approach for modeling the power output of an array of WTGS. The applicability of various probability models for describing the wind speed characteristics is examined in Section 4.1. Long-term records of observed data are utilized to obtain an accurate estimate of the characteristics of anticipated wind speeds at the recording site. In Section 4.2, the performance characteristics of a typical large horizontal-axis WTGS are discussed. A performance model is developed to approximate field-test power curves reported in the literature. The wind speed distribution model and the performance characteristic model of the WTGS are combined, in Section 4.3, in order to simulate and predict the power output from an array of WTGS. A summary of the main results, conclusions, and limitations of this approach is given in Section 4.4.

The array power output distributions generated in this chapter are used, in the following chapters, to modify predicted utility loads in order to assess impacts of WTGS on the load characteristics and on the capacity and energy requirements of the conventional generating sources in the utility. The reduction in the total generation costs of the conventional equipment due to the addition of wind power will dictate the value of WTGS to the electric utility.

4.1. Prediction of Wind Speed Distribution

One of the main requirements for predicting the power output from an array of WTGS is the determination of wind characteristics in the region where the units are expected to be installed. The most important wind characteristic for energy conversion is clearly the wind speed. The power available in the wind is proportional to the cube of the wind speed spatially integrated over the rotor-swept area of the wind system. An accurate determination of the characteristics of expected wind speeds at a candidate site is also required for the proper selection of wind turbine design(s).

Wind speed is site specific. It increases with the height following what is often referred to as the "power law". Further, it exhibits high variability, randomness, and diffuseness during both short and long intervals of time. The ideal approach for predicting the wind speed characteristics over the area of a WTGS array involves obtaining and analyzing historical wind speeds for all WTGS sites in the array. However, for the purpose of this work, the wind speeds at the various sites in the area of the array are assumed to be fairly uniform from site to site. Therefore, a single meteorological site, for which data were available, is used to represent the sites of all WTGS in the array.

4.1.1. Characteristics of Wind Speed

The purpose of obtaining and analyzing historical wind speed data is to make an estimate of the characteristics of future wind speeds. There is no assurance that any particular historical time span of data will be a good representation of the wind speed in a particular future year. However, evaluating historical wind speeds over a number of years gives an indication of the average distribution to be expected.

The data analyzed in this work were actual measurements of one-minute-average wind speed recorded at one-hour intervals. These measurements were carried out at a height of 10.67 meters above the ground using a cup anemometer on a meteorological site located near Tulsa, Oklahoma. These data were also made available by PSCO.

Wind speed data are analyzed in a number of different ways including average wind speed and standard deviation. The observed data are often represented in a compact form as a wind speed duration curve or a probability distribution of wind speed. The need for probabilistic representations arises from the inability to forecast the exact values of future wind speeds. Figure 11 shows typical distributions of hourly wind speeds observed at the Tulsa site. The data presented in this figure illustrate the year-to-year variation in the wind speed at this site. These variations demonstrate the need for obtaining and analyzing long-term records in order to accurately estimate the characteristics of future wind speeds at the recording location.

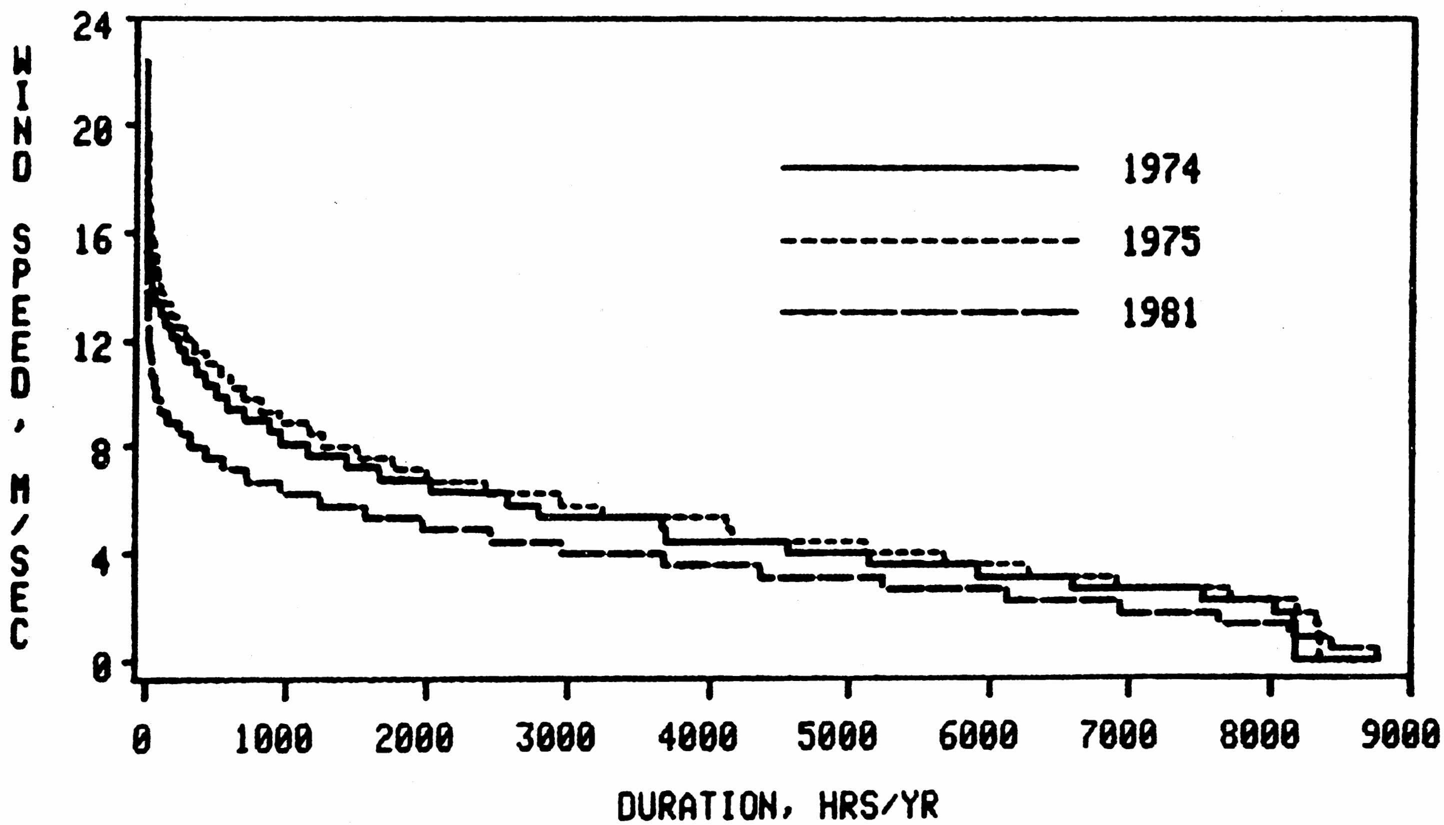


FIGURE 11. WIND-SPEED DURATION CURVES.

4.1.2. Probability Models for Wind Speed

Considerable work has been done in past decades to analyze and to construct reliable descriptions of the characteristics of wind speed and other random variables. Several different mathematical models have been proposed and compared with observed data. The Rayleigh, Weibull, and NASA probability distributions seem to have a distinct advantage over other mathematical models in modeling wind speed characteristics at many locations. The frequent use of these models in analyzing and representing wind speed data is largely due to their ability to combine long-term observations in a compact and consistent manner.

The most commonly used wind speed model is the Rayleigh distribution. This model is also known as the Chi-square distribution. The model is fairly easy to use since it requires only one parameter, namely, the mean wind speed at the site. This distribution is given by the following equations:

$$Pr_R(V) = \frac{\pi}{2} \frac{V}{(V_m)^2} \exp[-\frac{\pi}{4} (V/V_m)^2]$$

$$PR_R(V) = 1 - \exp[-\frac{\pi}{4} (V/V_m)^2] \qquad [4.1]$$

where:

$Pr_R(V)$ = probability density function

$PR_R(V)$ = cumulative probability function

V = wind speed

V_m = mean wind speed

The Weibull distribution represents an improvement over the

Rayleigh model, but it requires two parameters to be evaluated, namely, the mean and standard deviation of wind speed. This model is expressed by the following relations:

$$Pr_W(V) = \frac{K}{C}\left(\frac{V}{C}\right)^{K-1} \exp[-(V/C)^K]$$

$$PR_W(V) = 1 - \exp[-(V/C)^K]$$

$$\left(\frac{\sigma_V}{V_m}\right)^2 = \frac{\Gamma(1 + 2/K)}{\Gamma^2(1 + 1/K)} - 1 \qquad [4.2]$$

$$V_m = C\,\Gamma(1 + 1/K)$$

where:

C = scale factor

K = shape factor

σ_V = standard deviation

The Weibull shape factor is an indicator of the spread of wind speeds about the mean. The larger the value of K, the more peaked is the distribution. It should be noted that the Weibull distribution reduces to the Rayleigh distribution when $K = 2$ and $C = 2V_m/\sqrt{\pi}$.

The NASA distribution is a modification of the conventional one-parameter Rayleigh model. It was developed by NASA to provide a better fit to real-world wind conditions. This distribution is given by the following equations:

$$Pr_N(V) = \frac{\pi}{\beta}\,\frac{\alpha\,(V)^{\alpha-1}}{(V_m)^{\alpha}} \exp[-\frac{\pi}{\beta}(V/V_m)^{\alpha}]$$

$$[4.3]$$

$$PR_N(V) = 1 - \exp[-\frac{\pi}{\beta}(V/V_m)^{\alpha}]$$

The coefficients α and β, in the above equations, are selected to minimize the sum of the squares of deviations of the function from the observed data. This indicates that complete and long-term records of wind speed are required in order to evaluate the NASA model. It should also be noted that both the NASA and Rayleigh distributions give identical results when $\alpha = 2$ and $\beta = 4$.

4.1.3. Evaluation of Wind Speed Models

The three probability models represented by Equations [4.1], [4.2], and [4.3] were considered in this analysis. These models were evaluated using wind speed data observed at the Tulsa site. Four years of one-minute-average hourly observations were used for this purpose. This type of hourly observations has been shown to provide accurate probabilistic descriptions of the characteristics of wind speeds at most locations.

The observed data were analyzed to determine the parameters of the three models considered. The mean and standard deviation of these data were found to be 4.57 and 2.74 m/sec, respectively. The parameters C and K of the Weibull probability distribution were then determined using Equations [4.2]. The values of these parameters were found to be 5.12 m/sec and 1.72, respectively.

The hourly observations were also analyzed to calculate the wind speed probability densities. The resulting data were then used, in conjunction with Equations [4.3], to evaluate the parameters α and β of the NASA probability distribution. The values of these parameters were found to be 2.08 and 3.70, respectively.

The applicability of the three probability models for describing the wind speed characteristics was next examined. Figures 12 through 15 compare the observed distribution and the predictions of the Rayleigh, Weibull, and NASA models. The values of the coefficient of determination, R^2, were also calculated. These values were found to be 0.839, 0.808, and 0.843 for the Rayleigh, Weibull, and NASA probability distributions, respectively.

From an engineering standpoint, it can be concluded that the predictions of the three probability models compare well with the observed values, although discrepancies exist. The one-parameter Rayleigh distribution did not describe the observed data as well as the other two models. The NASA distribution, on the other hand, provided the best overall fit, particularly near the mean wind speed. The Weibull distribution, however, was found to best fit the observed data over the range of operating wind speeds for most wind turbine designs (above 3.0 m/sec). This model was, therefore, selected for the purpose of the analysis presented in the following sections. It should be noted that the Weibull distribution is fully determined by specifying the mean and standard deviation of wind speed at the location of interest.

4.2. Performance Characteristics of Wind Turbines

The technology of modern wind turbine systems has been under development since the early 1970s. Significant advances have been made in the development of large (nominally rated at least 100 KW) horizontal-axis WTGS which are oriented primarily toward utility applications. Several designs have been built and are in operation on a number of utility grids throughout the country.

The selection of optimum WTGS designs for a specific utility

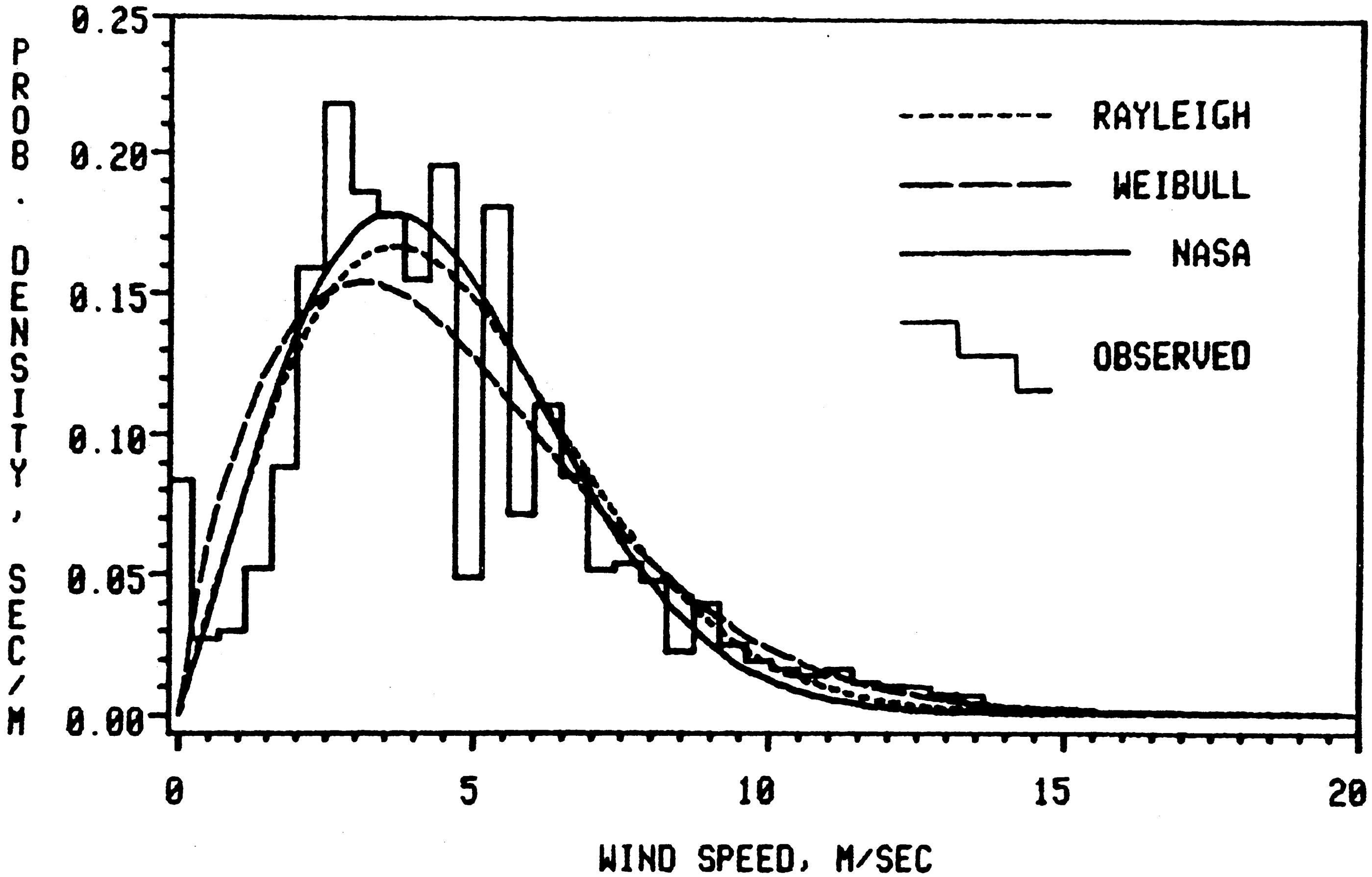


FIGURE 12. OBSERVED AND PREDICTED PROBABILITY DENSITIES OF WIND SPEED.

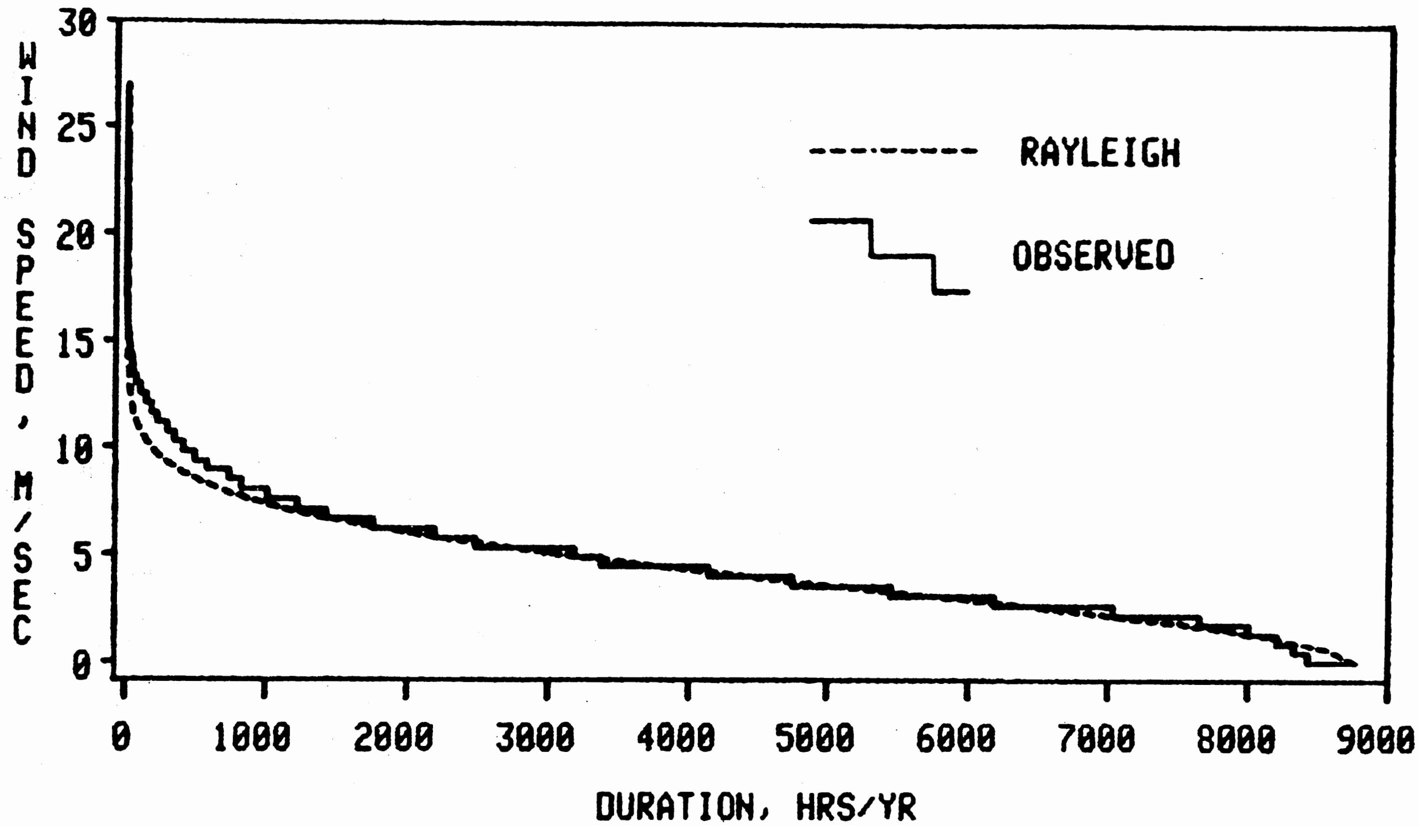


FIGURE 13. OBSERVED DURATION CURVE OF WIND SPEED AND PREDICTION OF RAYLEIGH MODEL.

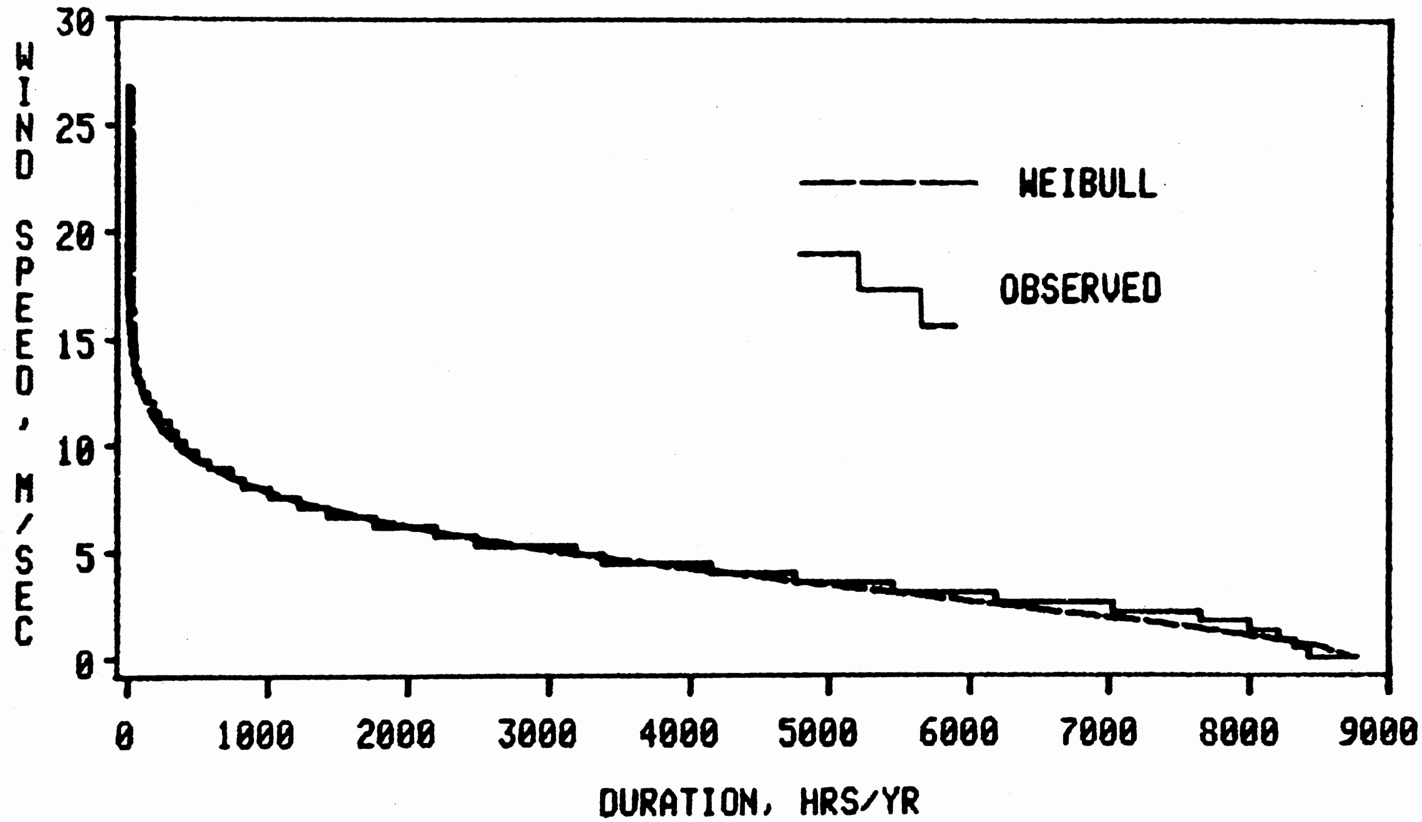


FIGURE 14. OBSERVED DURATION CURVE OF WIND SPEED AND PREDICTION OF WEIBULL MODEL.

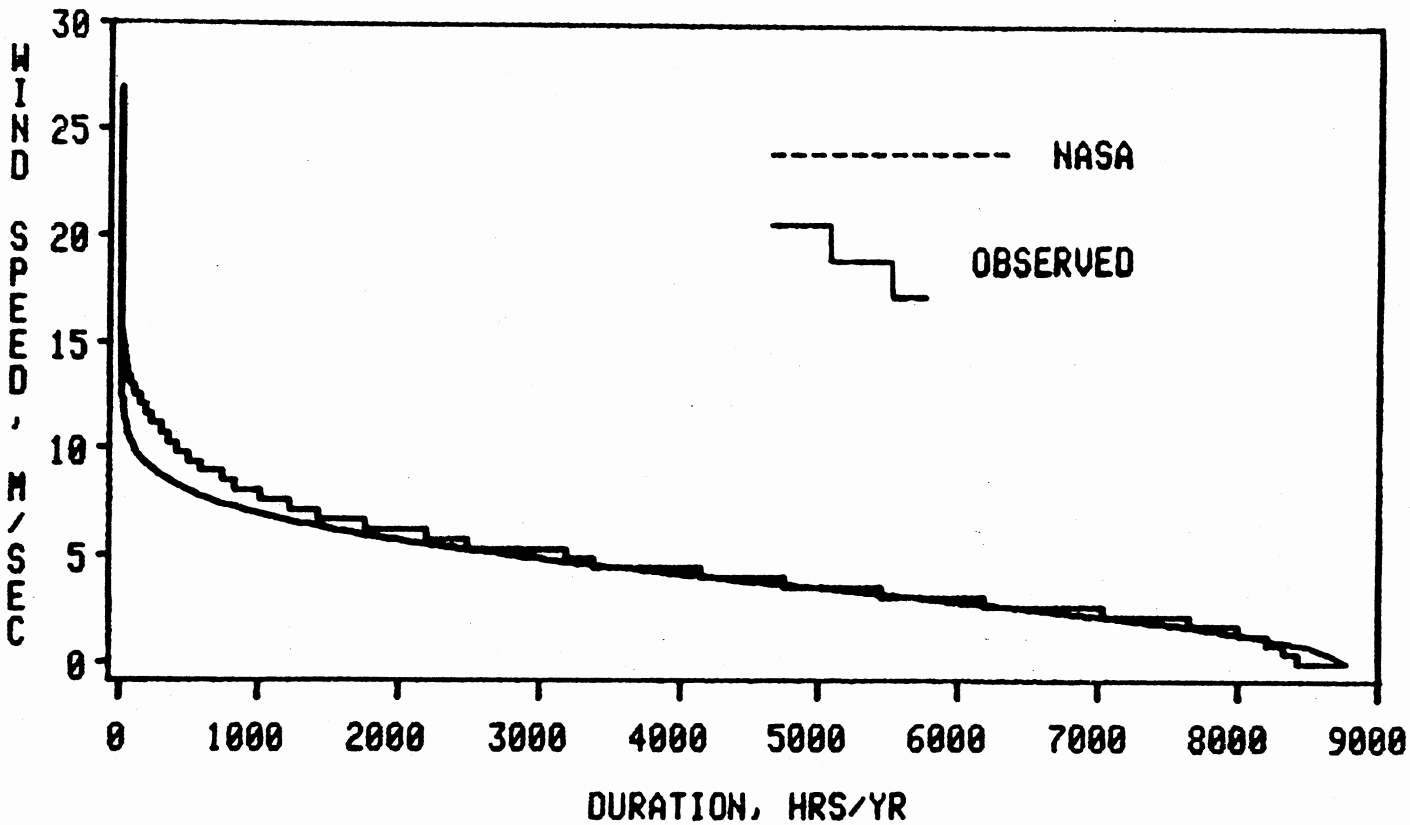


FIGURE 15. OBSERVED DURATION CURVE OF WIND SPEED AND PREDICTION OF NASA MODEL.

application is usually based on the performance characteristics and overall cost of available WTGS and on the characteristics of anticipated wind environment where the units are expected to be installed. A thorough analysis of each WTGS option may be required in order to determine the design(s) with the best overall cost advantage to the utility. However, for the purpose of this work, a typical large WTGS design, the 2.5-MW DOE/NASA MOD-2 wind turbine system, was selected for application in the model utility under consideration.

The MOD-2 WTGS was designed and built by the Boeing Engineering and Construction Company for the Department of Energy (DOE) under the direction of the Lewis Research Center of the National Aeronautics and Space Administration (NASA). This wind turbine design, a two-bladed WTGS, has the following basic characteristics:

Hub Height	= 61.0 m
Rotor Diameter	= 91.4 m
Performance Characteristics at 9.14 m:	
Rated Power, P_{rat}	= 2.5 MW
Cut-in Wind Speed, V_{in}	= 3.8 m/sec
Rated Wind Speed, V_{rat}	= 9.0 m/sec
Cut-out Wind Speed, V_{out}	= 19.2 m/sec

The actual power generated by a WTGS in a given wind environment is a function of its operational and performance characteristics. For the MOD-2 wind turbine, the power output response function was assumed to take a standard form, where power is zero below V_{in}, rises in a smooth fashion from zero at V_{in} to P_{rat} at V_{rat}, and remains constant at P_{rat} for wind speeds between V_{rat} and V_{out}, the furling speed above which zero power is produced. In mathematical terms, the instantaneous power output of the wind turbine was expressed as a function of the wind speed by the following equations:

$$P(V) = \begin{cases} 0 & V \leq V_{in} \\ a + bV + cV^2 & V_{in} \leq V \leq V_{rat} \\ P_{rat} & V_{rat} \leq V \leq V_{out} \\ 0 & V > V_{out} \end{cases} \quad [4.4]$$

where:

$P(V)$ = power output

The parameters a, b, and c of the power output response to wind speeds between V_{in} and V_{rat} were determined such that the turbine cuts in at V_{in}, generates 0.91 MW at a wind speed of 6.44 m/sec, and reaches the rated power at V_{rat}. This function was found to approximate the actual response of the wind turbine, based upon field-test power curves reported in the literature. It should be noted that the 6.44-m/sec speed is the average value of V_{in} and V_{rat}, and that the 0.91-MW power was determined assuming that P is directly proportional to V^3.

The performance curve of the MOD-2 WTGS, in terms of power output versus wind speed, is shown graphically in Figure 16. This curve is used in the following section in order to predict and simulate the power output performance of the WTGS array.

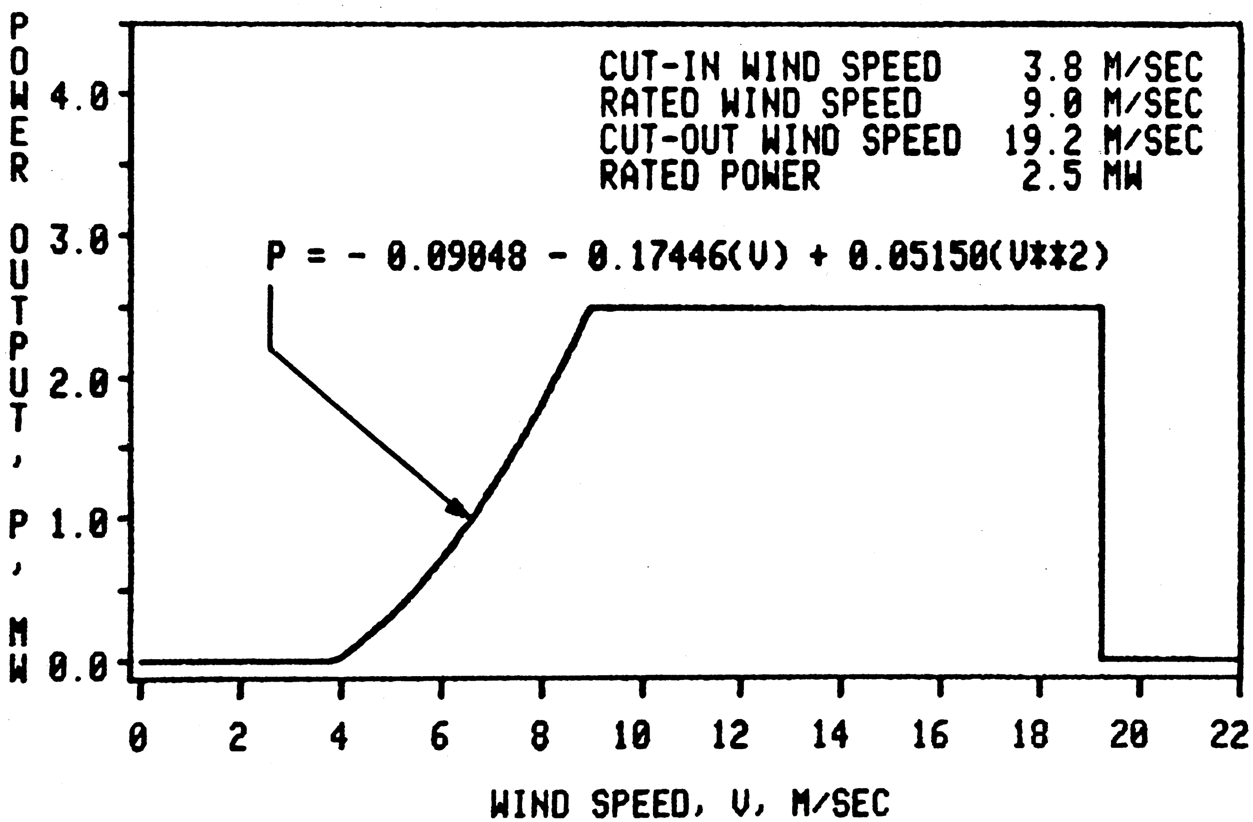


FIGURE 16. POWER OUTPUT CHARACTERISTICS OF NASA MOD-2 WTGS.

4.3. Simulation of Array Power-Output Performance

The economic benefits of WTGS to an electric utility system are largely determined by the amount of energy the wind turbines produce and the distribution of that energy relative to the utility load. For an array of WTGS, the power output depends primarily upon the distribution of wind speed at the turbine hub height, correlation between wind speeds at the various WTGS sites in the array, and the operational and performance characteristics of the array units. In general, the total power output from a large WTGS array is less variable in percentage than the power output from a single WTGS because of diversities in wind speeds.

For the purpose of this work, it was assumed that the wind speeds were uniform over the area of the array and that all WTGS units in the array were identical. That is, all wind turbines in the array were assumed to generate the same power at any instant. The power output from an array is then just that of a single WTGS multiplied by the number of wind turbines in the array.

The distribution of the power output of the MOD-2 wind turbine system was derived from the performance characteristics defined by Equations [4.4] and the wind speed distribution given by Equations [4.2], the Weibull probability model. Figure 17 presents the output distribution in a power duration form, while Figure 18 gives the corresponding cumulative probability information. It should be noted that the power output versus wind speed characteristics of the WTGS were specified at approximately the same height where the anemometer data were taken.

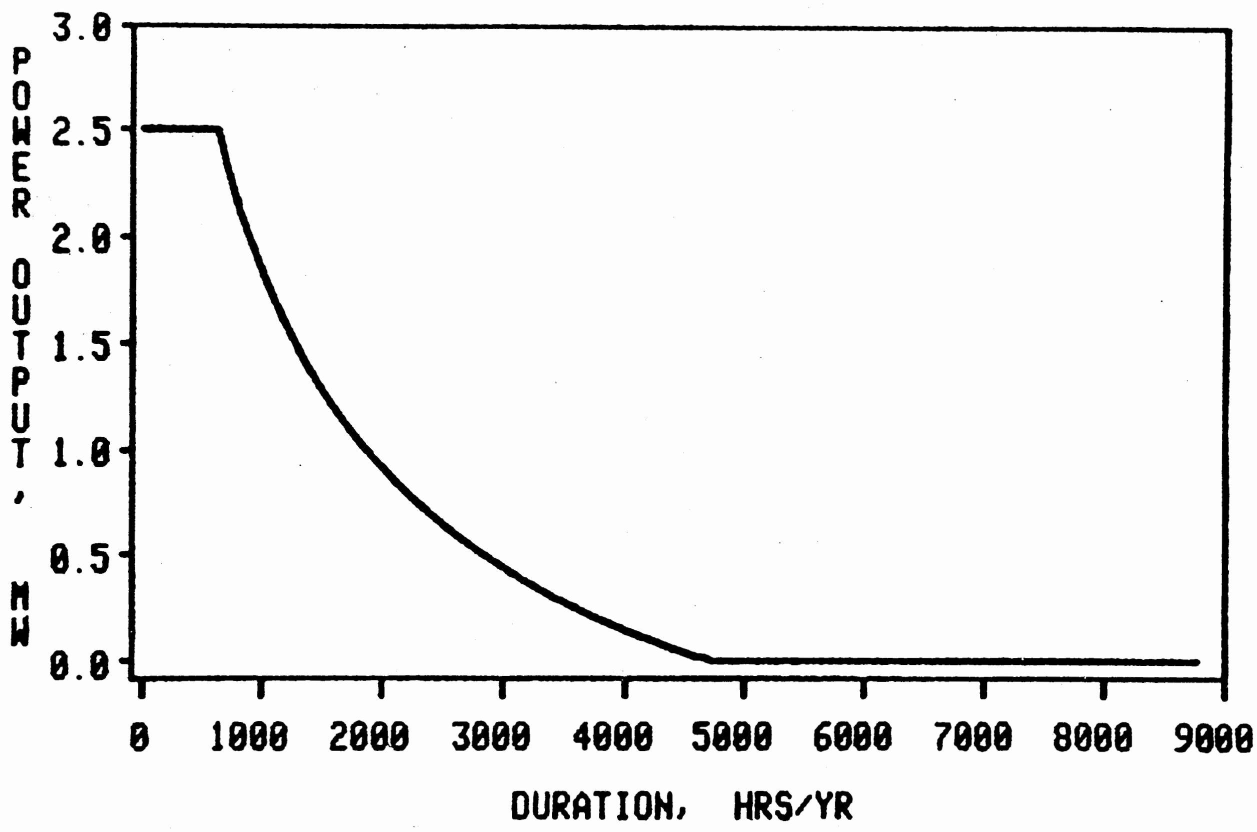


FIGURE 17. POWER DURATION CURVE FOR NASA MOD-2 WTGS.

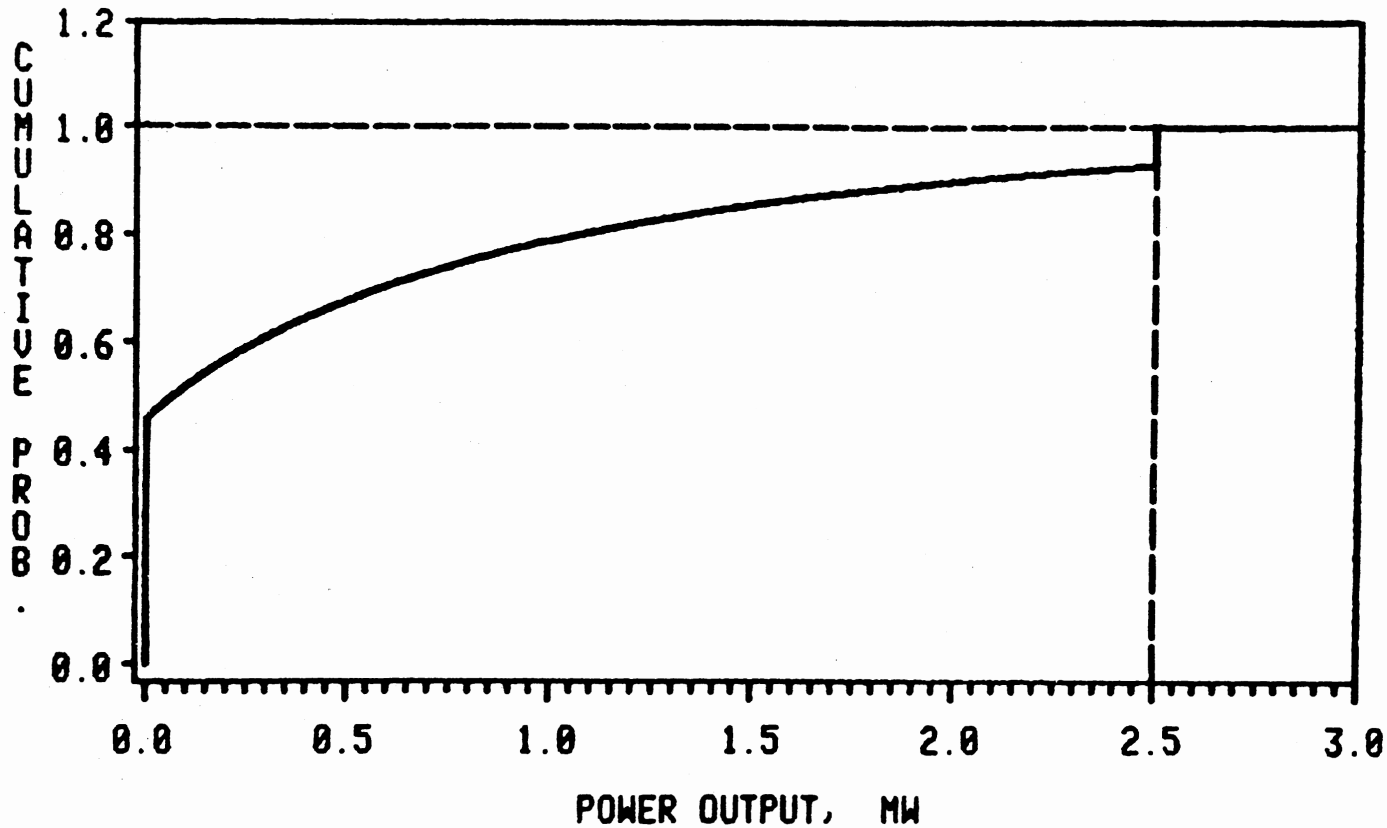


FIGURE 18. CUMULATIVE PROBABILITY DISTRIBUTION OF WTGS POWER OUTPUT.

The mean power output of the WTGS, P_m, was estimated through numerical integration based on the following equation:

$$P_m = \int_{V_{in}}^{V_{out}} [Pr_w(\lambda)][P(\lambda)]\, d\lambda \qquad [4.5]$$

The expected value of P_m was found to be 534.75 KW. This gives an annual energy production of 4683.7 MWH and a capacity factor of 21.39%.

The probability density for various levels of power output, Pr(P), was evaluated by the following expressions:

(a) The probability of a zero power output:

$$\begin{aligned}[Pr(0)]\, dP &= Prob[0 \leq \tilde{P} \leq dP] \\ &= 1 + PR_W(V_{in}) - PR_W(V_{out}) \\ &= 1 + \exp[-(V_{out}/C)^K] \\ &\quad - \exp[-(V_{in}/C)^K] \qquad [4.6]\end{aligned}$$

(b) The probability of power output between P_i and P_j:

$$\begin{aligned}[Pr(P)](P_j - P_i) &= Prob[P_i \leq \tilde{P} \leq P_j] \\ &= PR_W(V_j) - PR_W(V_i) \\ &= \exp[-(V_i/C)^K] \\ &\quad - \exp[-(V_j/C)^K] \qquad [4.7]\end{aligned}$$

(c) The probability of a rated power output:

$$[Pr(P_{rat})]\ dP = Prob[P_{rat} \leq \tilde{P} \leq (P_{rat} + dP)]$$

$$= PR_W(V_{out}) - PR_W(V_{rat})$$

$$= \exp[-(V_{rat}/C)^K]$$

$$- \exp[-(V_{out}/C)^K] \qquad [4.8]$$

The values of V_i and V_j in Equation [4.7] were determined by the quadratic response of Equations [4.4], from the corresponding power levels of P_i and P_j, respectively. It should be noted that the power outputs in the above equations can represent the generation of a single WTGS exposed to the given wind speed, or equivalently the generation of a set of identical turbines experiencing the same wind regime. The probability density functions for the power outputs from several WTGS arrays with various power ratings are shown in Figure 19.

4.4. Closure

The foregoing provides the basic methods and procedures used in this work for modeling the power generation from wind system arrays. The Weibull probability distribution was utilized for predicting the distribution of anticipated wind speeds in the area of the array. This distribution was found to have a distinct advantage over other commonly used probability models in accurately predicting the characteristics of wind speeds in the operating range of most WTGS designs. The Weibull wind speed distribution model and the performance characteristic model of the MOD-2 WTGS were combined in order to simulate and predict the distribution of the power outputs from the array.

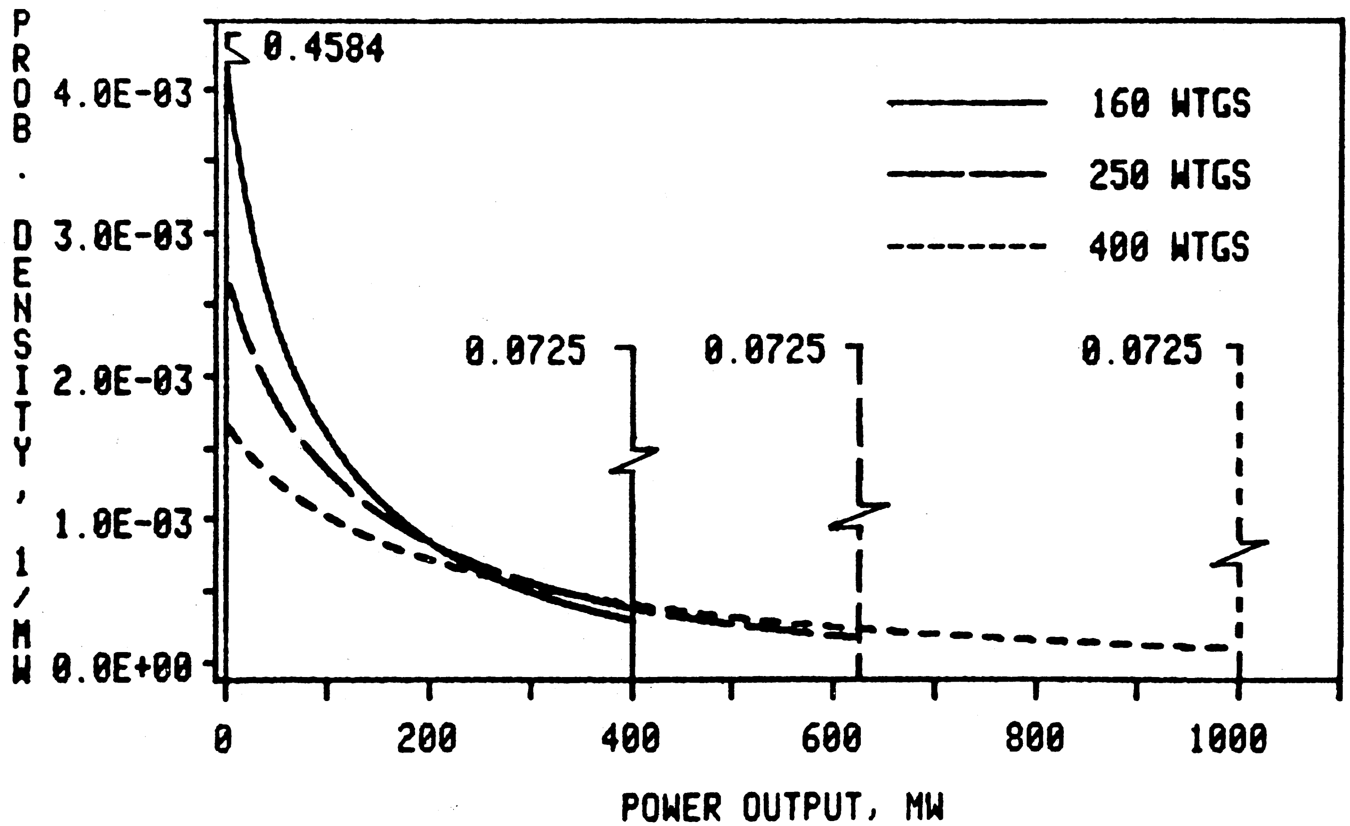


FIGURE 19. PROBABILITY DENSITY FUNCTION FOR POWER OUTPUTS OF SEVERAL ARRAYS OF WTGS.

The modeling approach of this work assumed that the array is composed of identical WTGS units experiencing the same wind regime. The effects of wind speed variations between WTGS sites and diversity in WTGS designs must be considered in order to correctly simulate and predict the power output performance of more realistic WTGS arrays.

CHAPTER V

SIMULATION METHODS FOR ELECTRIC UTILITY SYSTEMS WITH WTGS

The feasibility of utilizing WTGS as a component in the generation mixes of electric utility systems primarily depends on economic factors. Typically, a utility selects a mix of conventional equipment, with a total capacity large enough to meet the expected load on the system and to satisfy its reliability requirements at a minimum cost. When WTGS are included in the equipment mix, the generation requirements and costs associated with the conventional units decrease. The conventional units, in this case, must supply only the requirements of the original load less the net generation from the WTGS. The difference in the conventional generation costs between the with- and the without-WTGS cases is the savings resulting from the inclusion of WTGS into the equipment mix. These savings determine, to a great extent, the value of WTGS to the adopting utility.

For planning purposes, however, the power output from WTGS cannot be accurately predicted for any future moment in time. Only the probability distribution of WTGS power outputs can be forecasted. Furthermore, the utility, in general, has no control over the level of wind power generation at any time. Unlike conventional generating equipment, WTGS cannot be dispatched at will and, thus, cannot be represented directly in the planning procedures of electric utility systems.

A simple approach for operating an electric utility with a large WTGS array is to treat the power output from the array as a "negative load" with respect to the conventional part of the utility system. That is, the array power outputs are used to satisfy a portion of the load that the utility would experience without WTGS present. The resulting modified load can then be analyzed to determine the savings in the generation requirements and costs associated with the conventional equipment, due to the addition of WTGS. This approach is desirable in two respects. First, the energy production by the array is maximized since the power system absorbs wind-generated power whenever it is available. Second, no modification of the utility's operating control system is necessary since no control is exerted over the array power output.

The following sections describe the basic methods and approaches developed for evaluating the economic and operational impacts of wind power generation on electric utility systems. These methods and approaches are based upon the negative load operating concept. Furthermore, the load-duration and incremental-cost techniques presented in Chapter 3 are used to simulate the annual operation of the utility. Section 5.1 concerns the application of the convolution integration approach in the prediction of the modified-load distribution. The results of the load modification for both this approach and the traditional hourly data method are also compared in this section. The analyses presented in Section 5.2 concern WTGS impacts on the capacity and energy generation of the conventional equipment in the utility mix. Both the short- and long-term operation modes are discussed in this section. The impact of adding WTGS to the equipment mix on the conventional generation costs is also discussed in this section. A summary of the overall simulation approach, including its validity and limitations, is given in Section 5.3.

5.1. Modification of System Load

To simulate the impact of WTGS on the operations of an electric utility system, the original load on the utility must be modified to reflect the part of the load being satisfied by the power output from the WTGS. The modified load is traditionally generated by subtracting the power output from the original load on an hour-by-hour basis. Several years of input data are usually required in order to obtain an accurate estimate of the characteristics of the modified load.

The load modification approach utilized in this work is based on the convolution integration for the probability density of the sum of two independent random variables. This approach works with probability distributions rather than hourly data of wind speed and utility load. The applicability of this approach in predicting impacts of wind power generation on the system load is examined in this section. The results of the load modification for this approach and the hourly data method are also compared in this section.

5.1.1. Convolution Integration Method

The characteristics of the modified load, L', depend, to a great extent, on the nature of the original load, L, and the power output, P, and on the degree of correlation between them. If P is independent of L, the probability density of L', Pr(L'), can be computed from the probability density functions of both L, Pr(L), and P, Pr(P), by the following equations:

$$Pr(L') = \int_{-\infty}^{\infty} [Pr(L = \lambda)][Pr(-P = L' - \lambda)]\, d\lambda$$

$$= \int_{L'}^{L' + P_{max}} [Pr(L = \lambda)][Pr(P = \lambda - L')] d\lambda \qquad [5.1]$$

$$= \int_{0}^{P_{max}} [Pr(P = \lambda)][Pr(L = \lambda + L')] d\lambda$$

$$L' = L - P$$

where:

$$(L_{min} - P_{max}) \leqq L' \leqq L_{max}$$

This equation is the familiar convolution integral for the probability density of the sum of two independent random variables. It should be noted that, in Equations [5.1], the WTGS power output is treated as a negative load. A graphical representation of this integration approach is shown in Figure 20.

The validity of the assumption of statistical independence between the power output from WTGS and the original load on the utility was tested in this work. For the four years of data considered in this analysis, the value of the correlation coefficient between the original load and the wind speed, on an annual basis, was found to range from 0.022 to 0.139. The corresponding correlation between the original load on the system and the power output from the WTGS was essentially zero. The value of the correlation coefficient was found to range from 0.003 to 0.075.

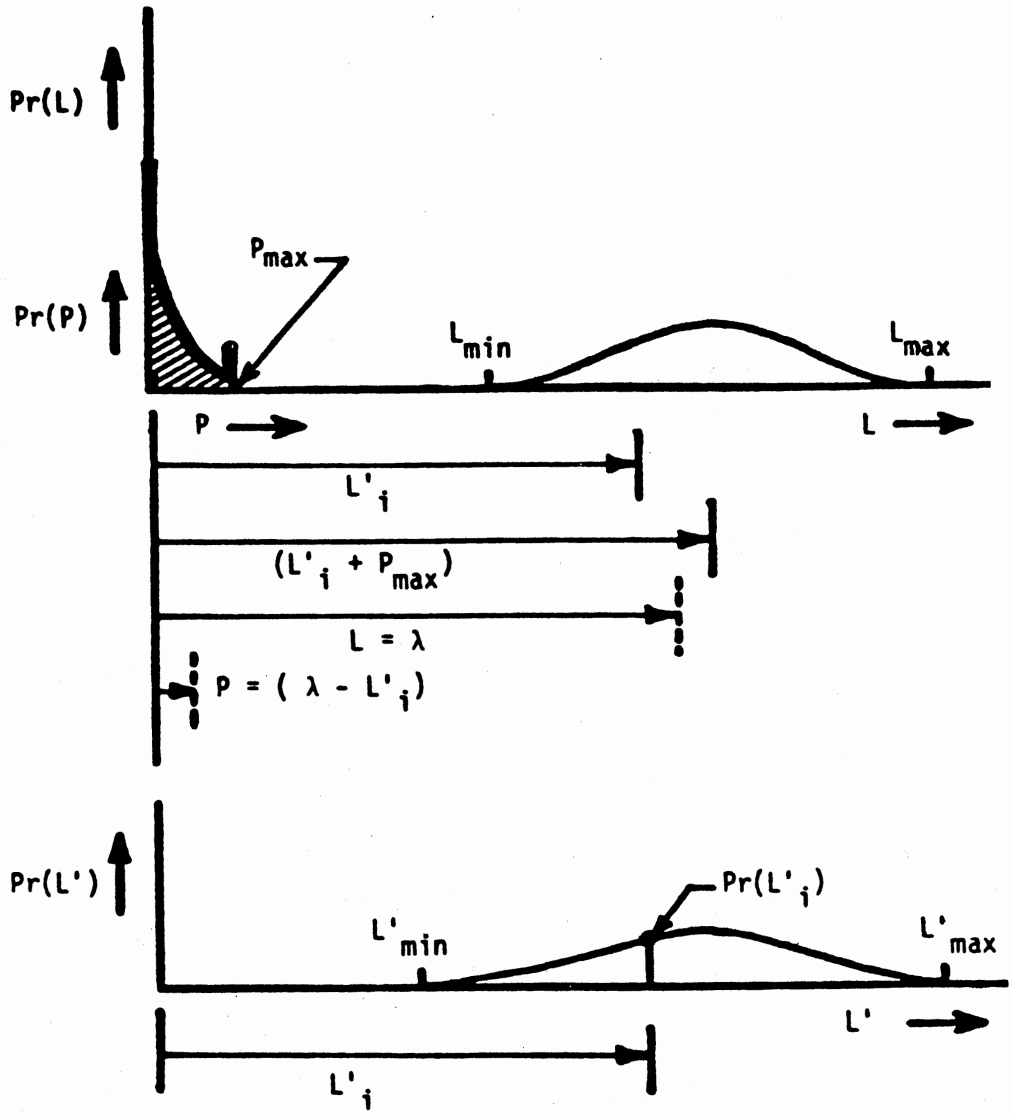


FIGURE 20. GRAPHICAL REPRESENTATION OF CONVOLUTION INTEGRATION.

Other investigators have also reported similar results for many areas in the country, as well as for other areas throughout the world. These results suggest that the lack of significant correlations between wind speeds (or WTGS power outputs) and utility loads may be typical. Therefore, it is justifiable to use the convolution integration approach in predicting the distribution of the modified load from the probability distributions of wind speeds and utility loads.

5.1.2. Comparison Between Convolution Integration and Hourly Data Methods

The results of the load modification for both the convolution integration and the hour-by-hour methods were examined in this work. Three cases of correlation between wind speed and utility load were considered in this analysis. The hourly data for the year of 1975 were utilized for this purpose. The observed wind speed and original load were found to be statistically independent of each other. The value of the correlation coefficient was approximately equal to zero (0.022). Positive and negative correlation cases were obtained by sorting the hourly loads in descending order and their associated hourly wind speeds in descending and ascending orders, respectively. The resulting correlation coefficients were found to be 0.991 and -0.885, respectively.

The MOD-2 performance characteristic model was next used to convert the hourly wind speeds into hourly power outputs. Figure 21 presents the results in a power-output duration form, while Figure 22 shows the corresponding probability density function. The correlation of the power output with the original load was found to be 0.925, 0.003, and

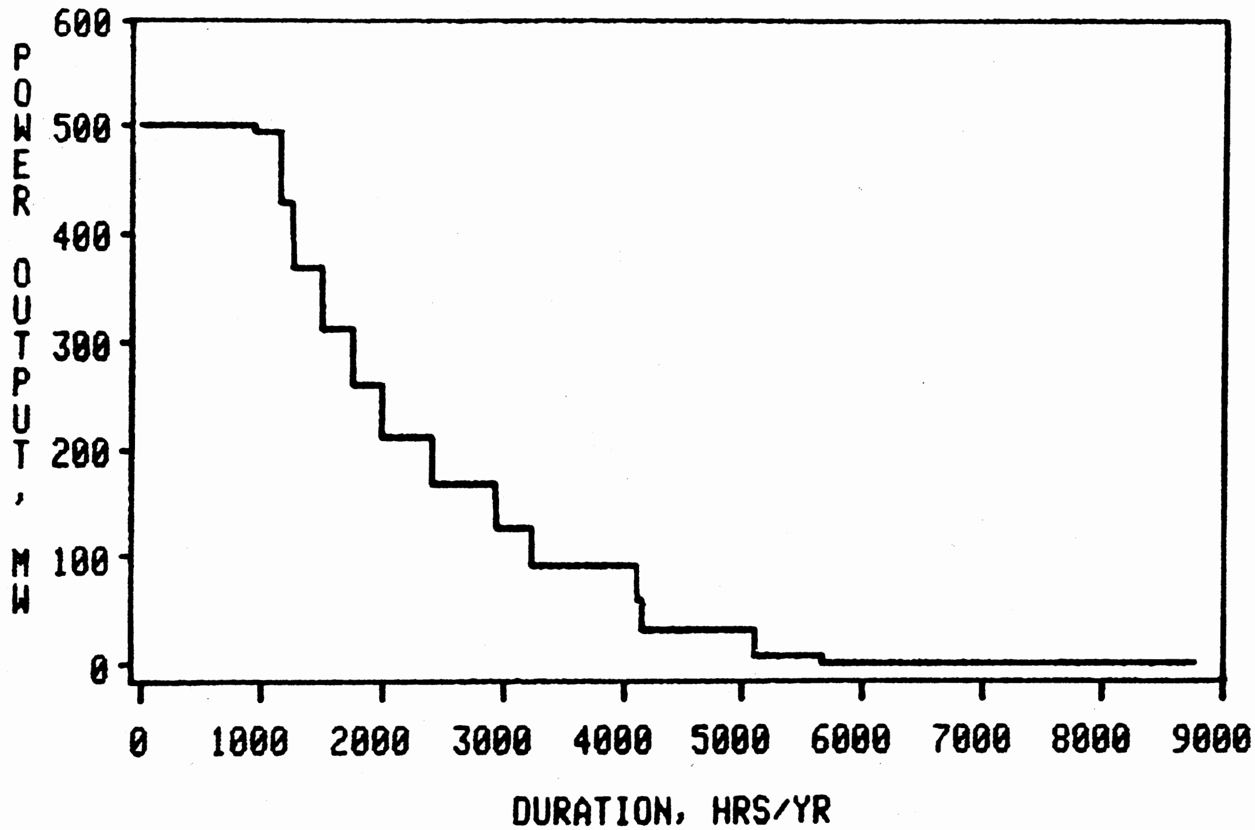


FIGURE 21. POWER-OUTPUT DURATION CURVE FOR ARRAY OF 200 MOD-2 WTGS, FOR 1975.

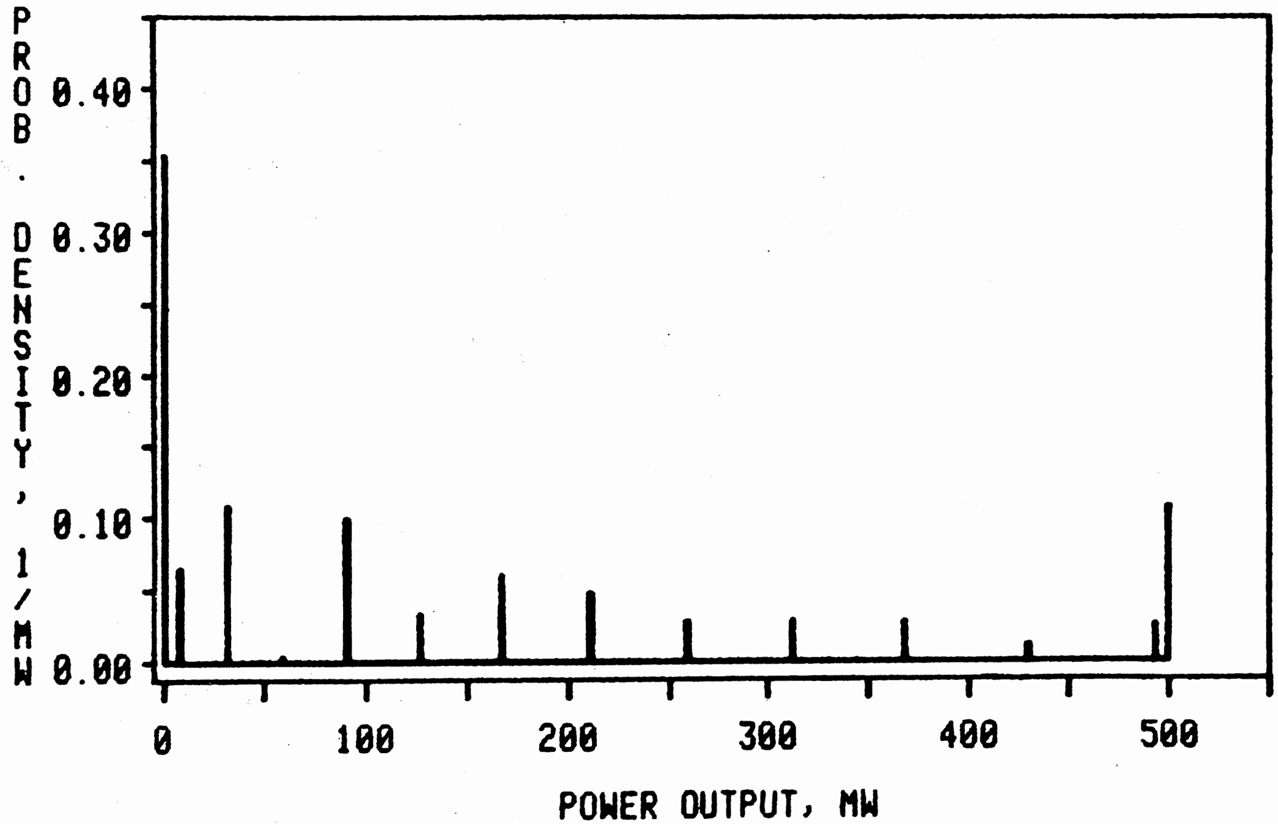


FIGURE 22. PROBABILITY DENSITY FUNCTION FOR POWER OUTPUT FROM ARRAY OF 200 WTGS, FOR 1975.

-0.744 for the corresponding cases of 0.991, 0.022, and -0.885 wind-speed/utility-load correlation, respectively.

For each correlation case, the hourly power outputs were then subtracted from the corresponding hourly loads in order to obtain the distribution of the modified load. Additionally, the probability density function of the power output was convolved with the probability density function of the original load to obtain the modified loads and corresponding probabilities, the load modification results for the convolution integration method.

The results of the load modification for both the convolution integration and the traditional hour-by-hour methods are presented in Figures 23 through 29. For the uncorrelated case, the two methods gave essentially the same results, as shown in Figures 23, 24, and 25. However, for both the positive and negative correlations, the results differed significantly. In the case of positive correlation, the convolution integration method overestimated the peak-load requirements and underestimated the requirements of the base load (Figures 26 and 27). A reversed impact on the load requirements was observed to occur for the negative correlation case, as shown in Figures 28 and 29.

While the results of the load modification are exact for the hourly data method, the convolution integration method only estimates the modified load probabilities. Because of the assumption of statistical independence between the WTGS power output and the original load, the later method produces the same probability estimates irrespective of the degree of correlation between the input variables. Thus, as shown in Figures 24, 26, and 28, the modified LDC obtained by this method will always show the same characteristic increase of negative slope relative

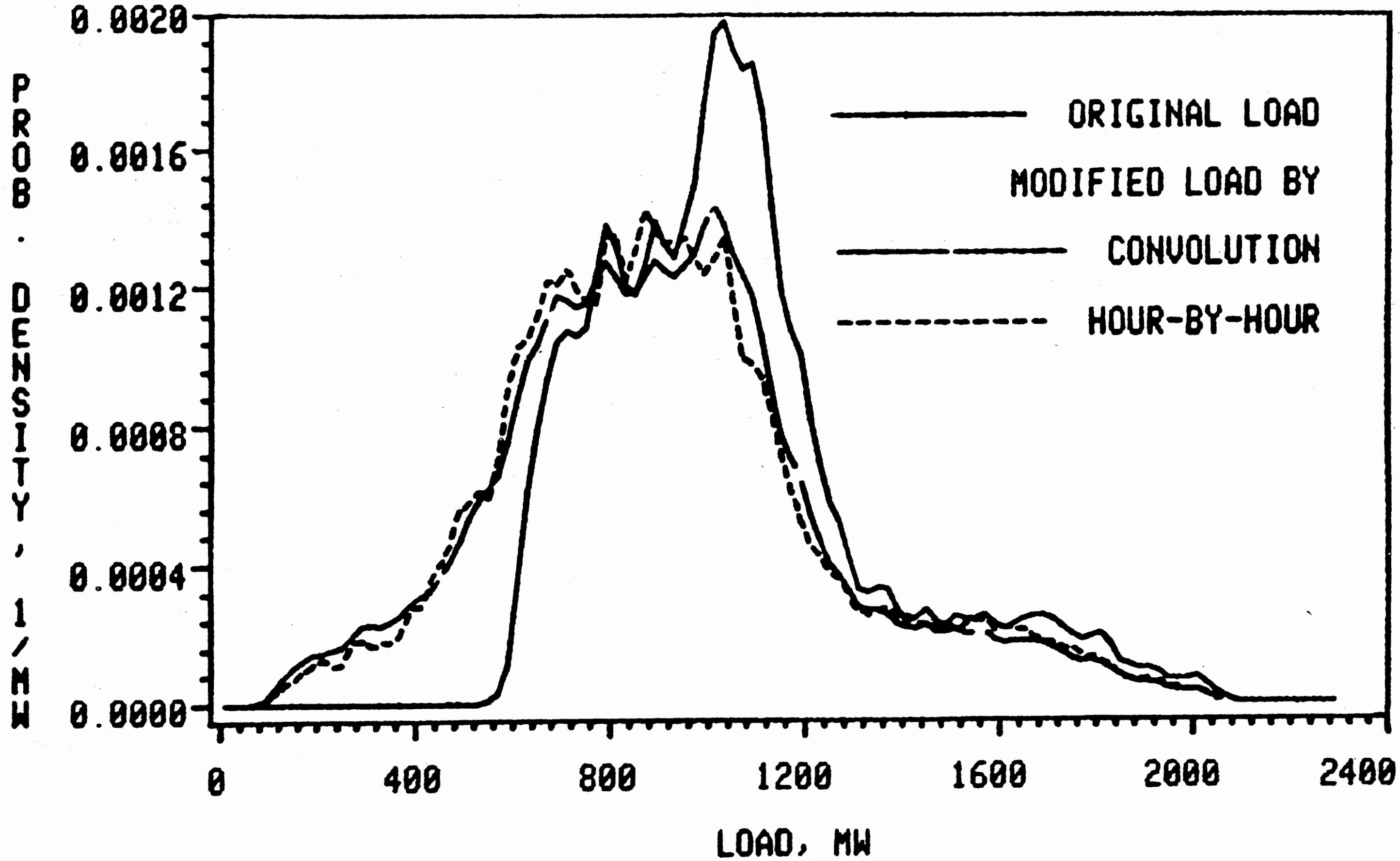


FIGURE 23. EFFECT OF MODIFICATION METHOD ON PROBABILITY DENSITY OF MODIFIED LOAD, FOR 0.00% CORRELATION BETWEEN P AND L.

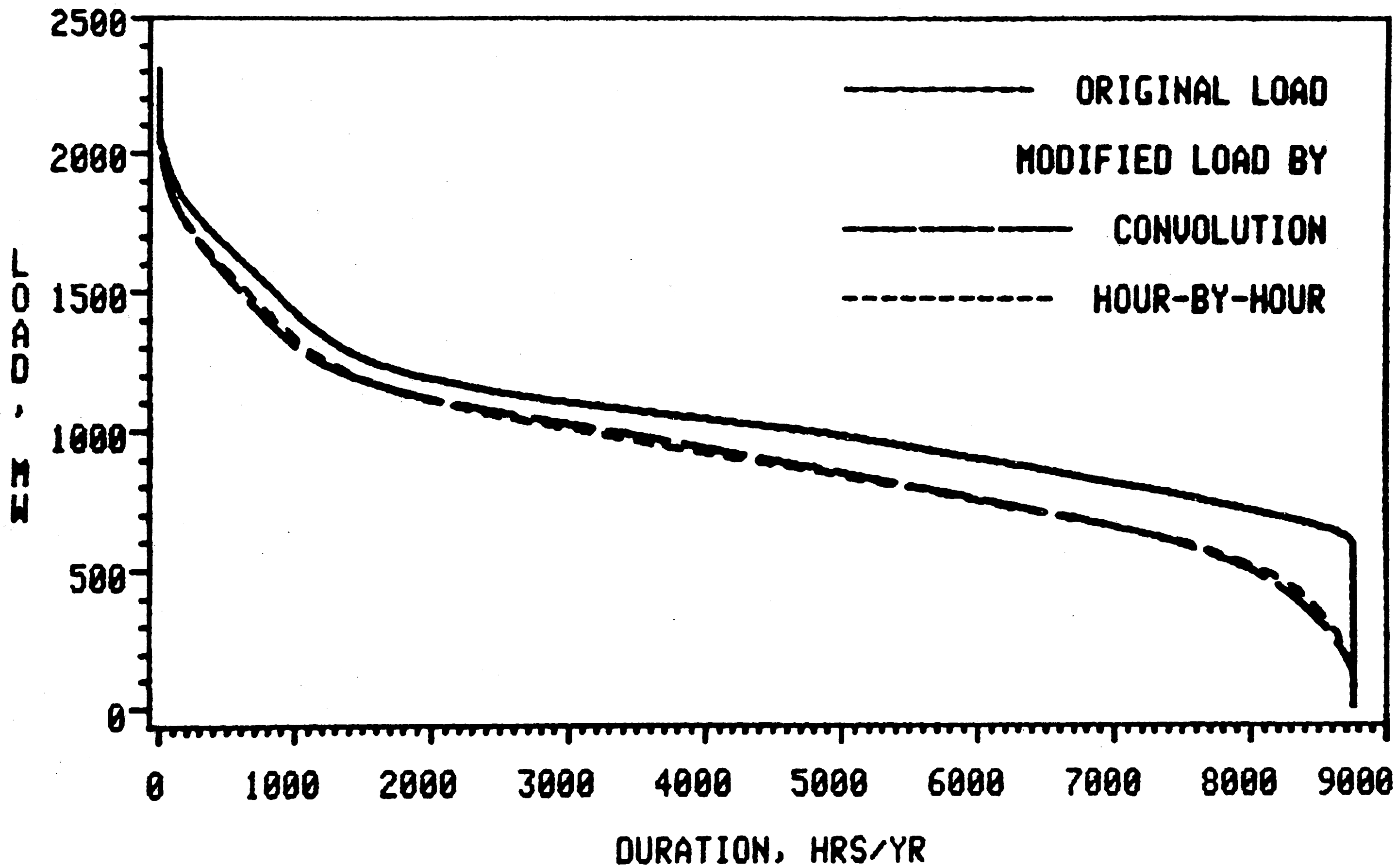


FIGURE 24. MODIFIED LDCs OBTAINED BY BOTH CONVOLUTION INTEGRATION AND HOUR-BY-HOUR METHODS, FOR 0.00% CORRELATION BETWEEN P AND L.

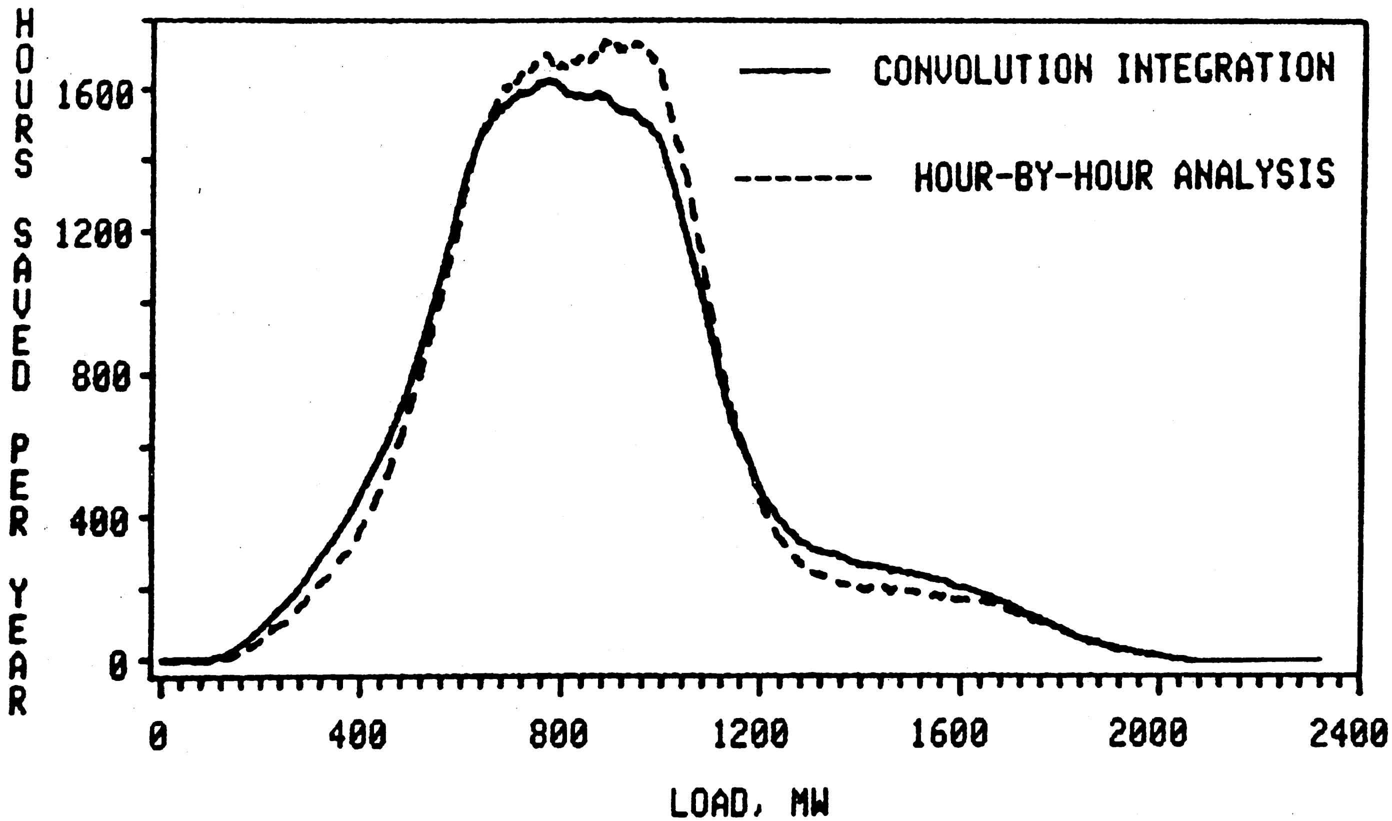


FIGURE 25. EFFECT OF LOAD MODIFICATION METHOD ON ENERGY DISPLACEMENT, FOR 0.00% CORRELATION BETWEEN P AND L.

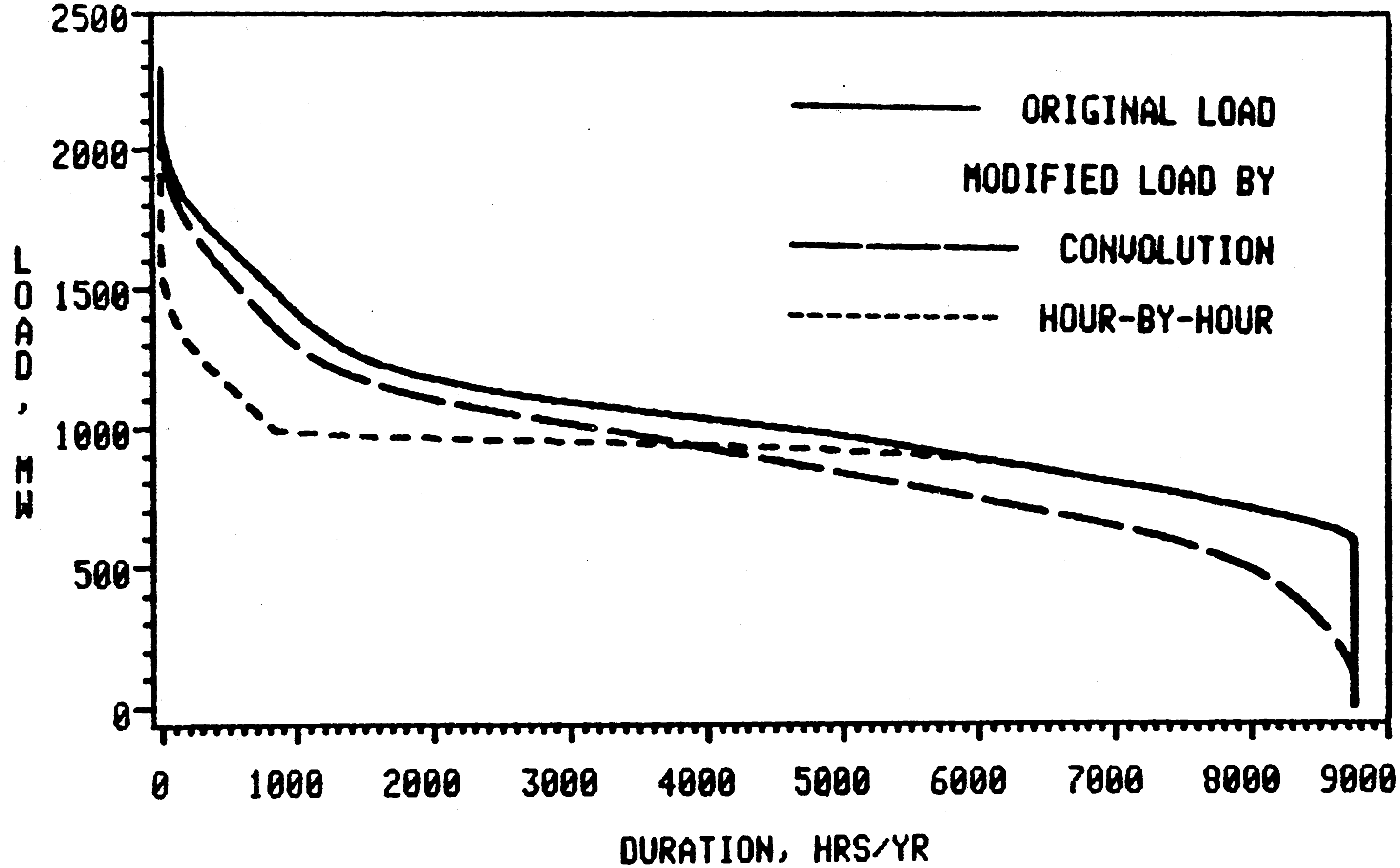


FIGURE 26. MODIFIED LDCs OBTAINED BY BOTH CONVOLUTION INTEGRATION AND HOUR-BY-HOUR METHODS, FOR +93% CORRELATION BETWEEN P AND L.

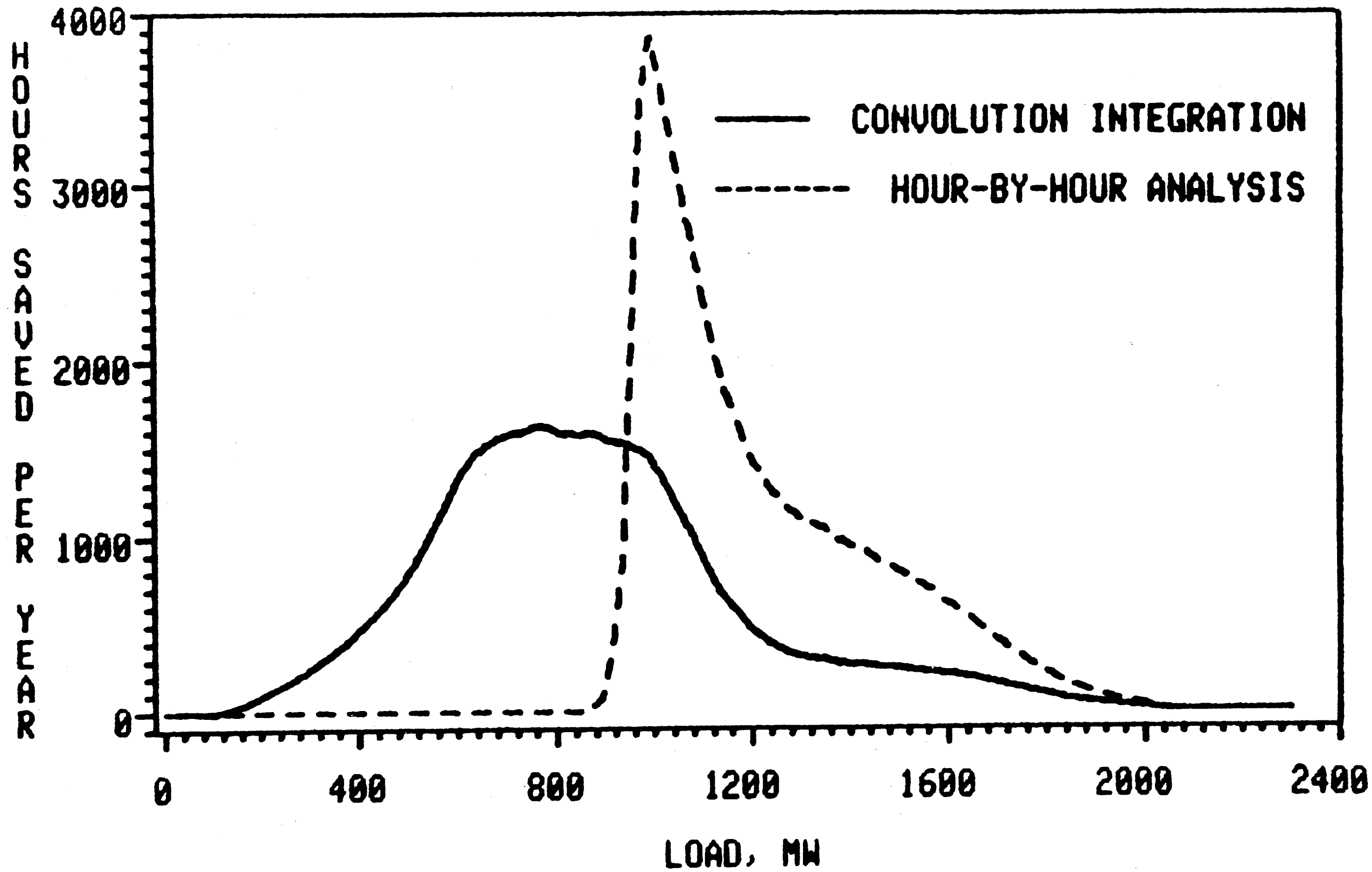


FIGURE 27. EFFECT OF LOAD MODIFICATION METHOD ON ENERGY DISPLACEMENT, FOR +93% CORRELATION BETWEEN P AND L.

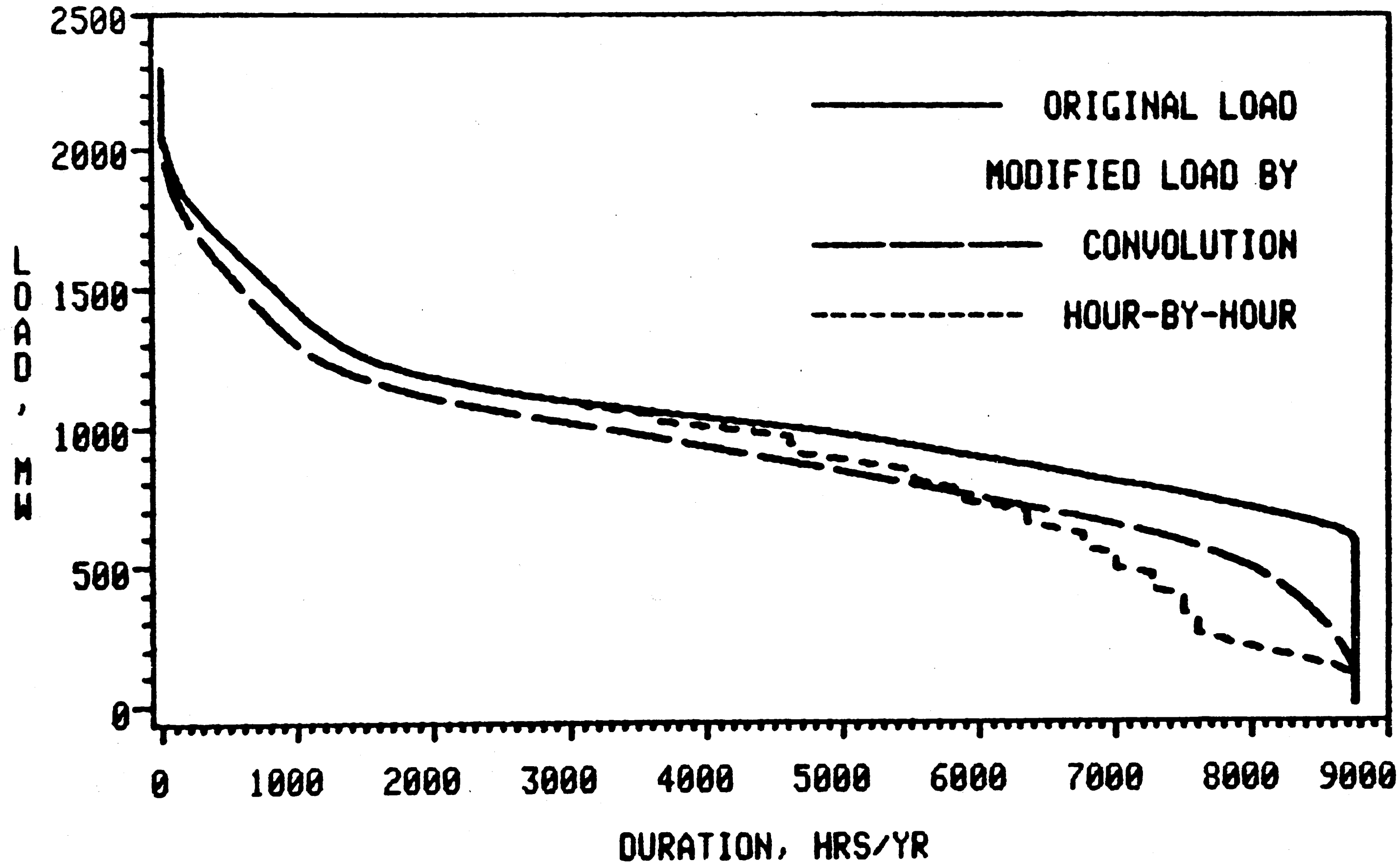


FIGURE 28. MODIFIED LDCs OBTAINED BY BOTH CONVOLUTION INTEGRATION AND HOUR-BY-HOUR METHODS, FOR -74% CORRELATION BETWEEN P AND L.

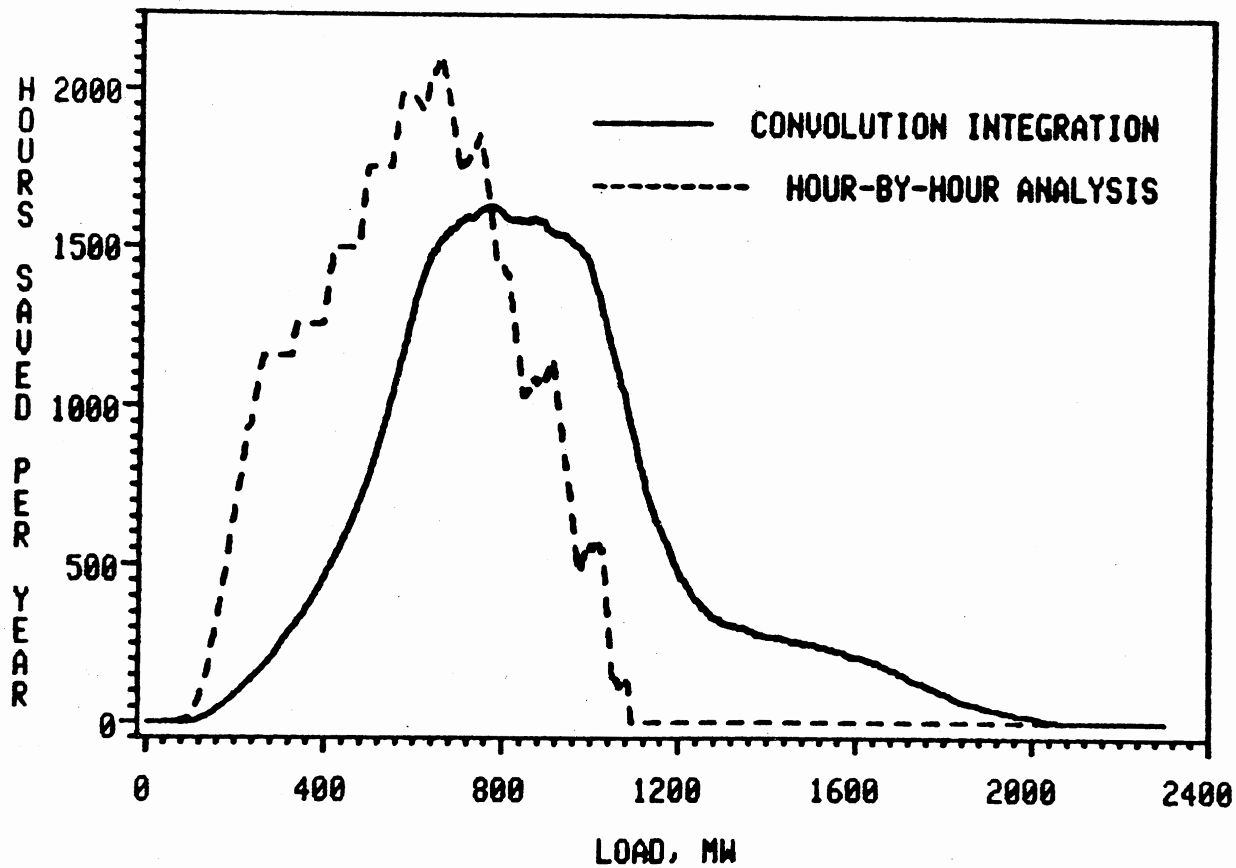


FIGURE 29. EFFECT OF LOAD MODIFICATION METHOD ON ENERGY DISPLACEMENT, FOR -74% CORRELATION BETWEEN P AND L.

to the original LDC. Furthermore, in the convolution integration method, the value of the peak load remains constant at the original level, and only the probability of the peak load is decreased.

The above results and discussions indicate that, where the independence assumption holds, both the convolution integration and the hourly data methods produce nearly identical results. Because a more accurate estimate of the modified load is likely to be obtained using several years rather than one year of input data, the probabilistic modeling and the convolution integration technique represent a more efficient simulation, as compared to the hourly data method. With the hourly data method, the computational time is proportional to the number of years of input data. However, in the convolution integration approach, the time involved in the computational work hardly changes from that where a single year of data is used. Moreover, when the Weibull and the Rayleigh wind-speed probability models are used, the hourly data are no longer needed.

5.2. Impacts of WTGS on Generation Requirements and Costs of Conventional Equipment

This section describes the methods used in this work for evaluating WTGS impacts on the generation requirements and production costs associated with the conventional equipment in the utility mix. These methods concern both the short- and long-term operation modes. The short-term mode involves adding WTGS to the conventional equipment mix that the utility needs for meeting the original-load requirements. In the long-term, however, the mix of conventional generating equipment can be reoptimized to reflect the addition of WTGS. The savings in the conventional generation costs, resulting from the inclusion of WTGS into the equipment mix, can be used to establish the value of WTGS to the adopting utility.

The "capacity-credit" and "operating-reserve requirements" associated with the installation of WTGS were not evaluated in this work. A review of the results obtained from several major studies indicated that the capacity-credit savings and operating-reserve costs are small compared to the total savings that are incurred due to the addition of WTGS. Furthermore, they are offsetting since one is a credit and the other is a debit.

5.2.1. Short-Term Operation Mode

This approach is often referred to as the "fuel saver mode". It involves adding WTGS to the optimum mix of conventional equipment, that is the equipment mix selected to satisfy the original-load requirements. The main value of WTGS, in this case, is derived from the reduction in the energy generation of the conventional equipment. Because of the lack of significant correlation between WTGS power outputs and utility loads, the energy reduction occurs in the generation requirements of all types of conventional equipment.

The savings in the generation costs associated with the conventional equipment, due to the addition of WTGS, depend upon both the energy reduction and the variable costs for each type of equipment. Using the approach shown in Figure 30, it is possible to obtain an estimate of the relative contribution to the savings from WTGS. The areas shown in this figure between the original and modified LDCs represent the energy displaced by the WTGS from the three types of

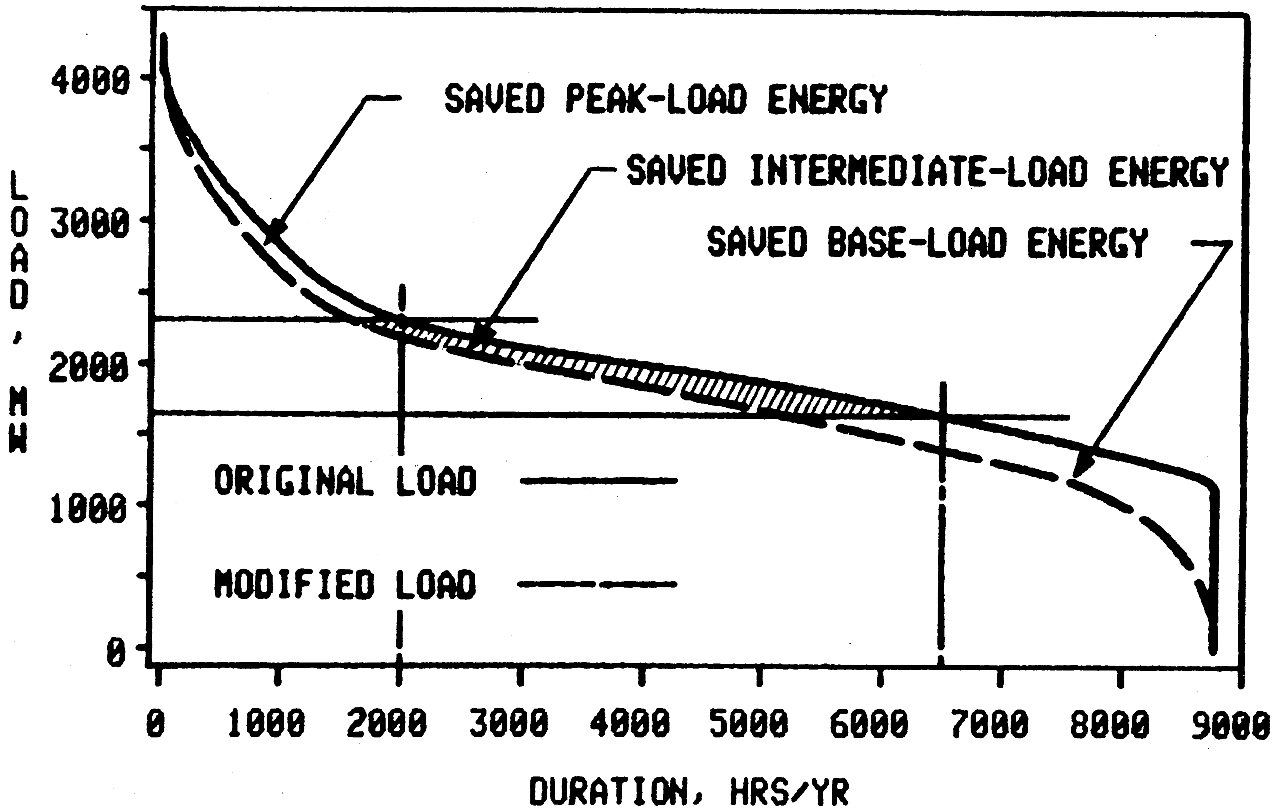


FIGURE 30. IMPACT OF WTGS ON GENERATION REQUIREMENTS OF CONVENTIONAL EQUIPMENT, FOR SHORT-TERM OPERATION MODE.

equipment in the conventional generation mix. If these energy savings are multiplied by the appropriate variable costs, the total annual savings in the conventional generation costs due to the addition of WTGS are obtained.

5.2.2. Long-Term Operation Mode

This approach is also known as the "reoptimized mix mode". It involves adding WTGS to satisfy as much of the utility load as in the short-term operation mode. The advantage here is that the mix of conventional equipment is reoptimized based upon the requirements of the modified load, as shown in Figure 31. Although the total capacity of the conventional equipment mix remains unchanged, the reoptimized mix exhibits an increase in the capacity requirements of both the peak- and intermediate-load equipment and a corresponding decrease in the capacity of the base-load equipment, as compared to the optimum equipment mix of the original load.

The change in the capacity of the various types of conventional equipment in the generation mix results in fixed-cost savings not enjoyed in the short-term operation mode. The variable-cost savings, however, are much less, in the long-term mode than in the short-term mode. This is due to the fact that, in the long-term mode, most of the energy reduction occurs in the generation requirements of the base-load equipment, the low-variable cost type of equipment. It should also be noted that the increase in the capacity of the fast-responding peak-load equipment increases the value of the capacity credit associated with the installation of WTGS.

The approach described in Chapter 3 was utilized to estimate the

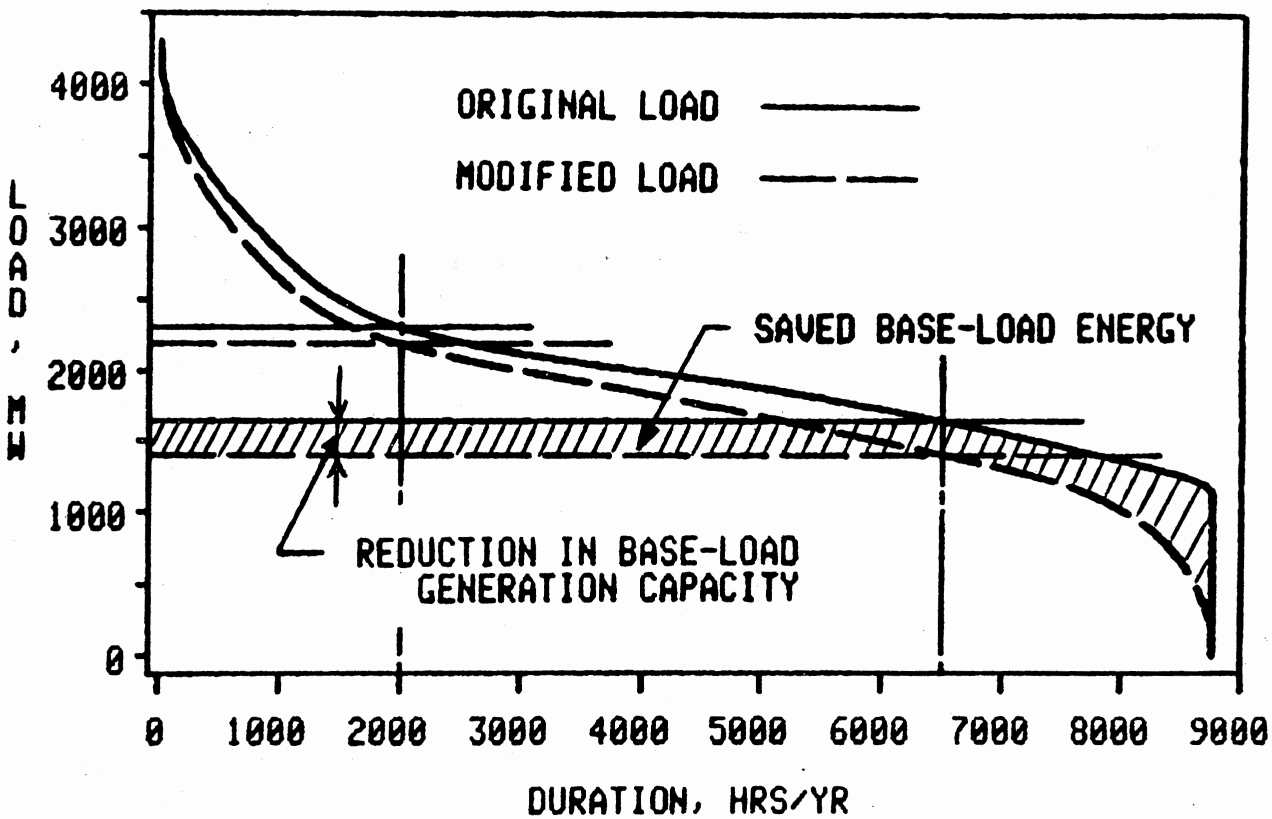


FIGURE 31. IMPACT OF WTGS ON GENERATION REQUIREMENTS OF CONVENTIONAL EQUIPMENT, FOR LONG-TERM OPERATION MODE.

capacity and annual energy generation of the three types of conventional equipment in the utility mix, for both the with- and the without-WTGS cases. The resulting changes in the generation requirements of the conventional equipment were then multiplied by the appropriate cost parameters and summed up to determine the annual cost savings achieved by adding WTGS.

5.3. Closure

The foregoing sections present and discuss the basic methods and procedures of the overall simulation approach developed for evaluating the economic and operational impacts of WTGS on electric utility systems. In this approach, the original load on the utility is first modified to reflect the power output from the WTGS. The original- and modified-load distributions are then analyzed in order to evaluate WTGS impacts on the generation requirements of the conventional equipment and on the overall operation of the electric utility. The savings in the conventional generation costs, due to the inclusion of WTGS into the equipment mix, determine, to a great extent, the value of WTGS to the adopting utility.

The procedure adopted for the load modification was developed based on the convolution integration for the probability density of the sum of two independent random variables. For many areas, the lack of significant correlations between the wind speed (or WTGS power output) and utility load appears to be typical. The correlation coefficients obtained in this work and the work of other investigators were judged to be insignificant. For this typical case of uncorrelated input variables, both the convolution integration approach and the traditional hourly-data method were found to produce nearly identical results. The probabilistic representations of the input variables and the convolution integration technique, however, result in considerable savings in computational effort and cost over the hour-by-hour analysis since many years of input data can be summarized in one distribution.

Once the modified-load distribution is obtained, the impacts of WTGS on the utility operations are easily seen. In the short-term operation mode, the utility must utilize the conventional equipment that are already in place. The addition of WTGS to the utility, in this case, results mainly in a reduction in the energy generation from the various types of conventional equipment. This reduction is readily estimated from the appropriate areas between the original and modified LDCs. The estimated values of the energy reduction are then multiplied by the associated variable costs and summed up to evaluate the savings in the conventional generation costs resulting from the addition of WTGS.

The procedure used to evaluate WTGS impacts, for the long-term operation mode, involves reoptimizing the mix of conventional equipment based on the distribution of the resulting modified load. The result of this is a change in both the capacity and energy generation of the various types of conventional equipment. Although the total capacity of the conventional equipment remains unchanged, the steeper modified LDC causes an increase in the capacity of both the peak- and intermediate-load equipment and a corresponding decrease in the capacity of the base-load equipment. The change in the capacity and energy generation of the conventional equipment is readily estimated by comparing the generation requirements of the optimum mix under both the original and modified

LDCs. The savings, in this case, consist mainly of a fixed-cost component due to the shift in the capacity and a variable-cost component resulting from the reduction in the energy generation of the conventional equipment.

It should be noted that the capacity credit and operating reserve requirements associated with WTGS were not evaluated in this work. The results from several major studies indicated that the capacity-credit savings and operating-reserve costs are insignificant compared to the total savings in the conventional generation costs.

The methods and procedures developed in this work were applied to the model utility described in Chapter 3. The results of this application are presented and discussed in the following chapter.

CHAPTER VI

APPLICATIONS AND DISCUSSIONS

The overall simulation approach developed in this work was applied to the model utility system described in Chapter 3. The WTGS power output distributions generated in Chapter 4 were used to modify the original load on the utility. The convolution integration technique presented in Chapter 5 was utilized for this purpose. Different levels of on-line WTGS, in the range up to 23.89 percent, were considered in this analysis. These levels represent the values of the rated power of on-line WTGS expressed as a percentage of the annual peak load. Figures 32 and 33 present the results of the load modification for two levels of on-line WTGS.

The impacts of WTGS on the capacity and energy requirements of the conventional generating equipment were next examined. Both the short- and long-term operation modes of Chapter 5 were considered in this work. The short-term mode involved adding WTGS to the mix of conventional equipment that was optimized for the original load. In the long-term mode, for each level of on-line WTGS, the original load was modified and the mix of conventional equipment was then reoptimized.

The results obtained from this application are presented in Tables II through IV and in Figures 34 through 42. These results concern the annual operation of the utility in the year of 1990, the analysis year.

TABLE II.

IMPACTS OF WTGS FOR SHORT-TERM OPERATION MODE.

No. of WTGS On-Line	Percent WTGS On-Line	Reduction in Energy Generation, MWH:			Savings in Variable Costs, $ Million:			
		Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	TOTAL
80	4.7790	114671.585	183335.205	76691.964	0.917	6.692	4.717	12.326
160	9.5579	269327.085	339490.398	140584.270	2.155	12.391	8.646	23.192
250	14.9343	497446.336	472081.314	201413.894	3.980	17.231	12.387	33.598
320	19.1159	705263.034	551555.420	241987.175	5.642	20.132	14.882	40.656
400	23.8949	964385.338	627315.197	281806.818	7.715	22.897	17.331	47.943

TABLE III.

IMPACTS OF WTGS FOR LONG-TERM OPERATION MODE: 1. ENERGY REQUIREMENTS AND VARIABLE COSTS.

No. of WTGS On-Line	Percent WTGS On-Line	Reduction in Energy Generation, MWH:			Savings in Variable Costs, $ Million:			
		Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	TOTAL
80	4.7790	388072.016	-26277.386	12904.124	3.105	-0.959	0.794	2.939
160	9.5579	833803.042	-115548.266	31146.976	6.670	-4.218	1.915	4.368
250	14.9343	1390155.585	-271209.430	51995.388	11.121	-9.899	3.198	4.420
320	19.1159	1832127.892	-397180.117	63857.853	14.657	-14.497	3.927	4.087
400	23.8949	2331615.622	-536308.891	78200.623	18.653	-19.575	4.809	3.887

TABLE IV.

IMPACTS OF WTGS FOR LONG-TERM OPERATION MODE: 2. CAPACITY REQUIREMENTS AND FIXED COSTS.

No. of WTGS On-Line	Percent WTGS On-Line	Reduction in Capacity, MW:			Savings in Variable Costs, $ Million:			
		Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	Base-Load Equipment	Intermediate-Load Equipment	Peak-Load Equipment	TOTAL
80	4.7790	43	-10	-33	12.900	-1.150	-2.145	9.605
160	9.5579	91	-33	-58	27.300	-3.795	-3.770	19.735
250	14.9343	148	-67	-81	44.400	-7.705	-5.265	31.430
320	19.1159	190	-92	-98	57.000	-10.580	-6.370	40.050
400	23.8949	234	-120	-114	70.200	-13.800	-7.410	48.990

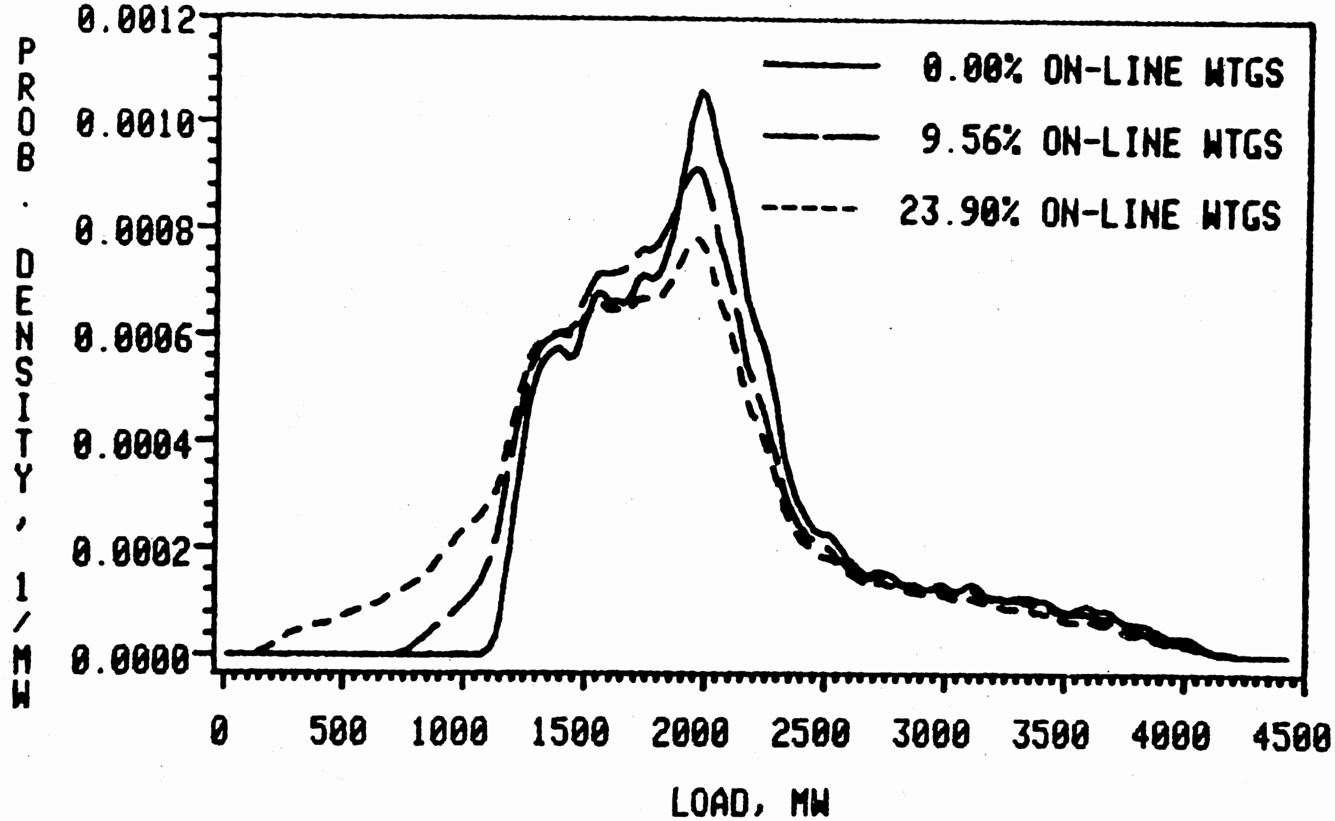


FIGURE 32. PROBABILITY DENSITIES OF ORIGINAL AND MODIFIED LOADS.

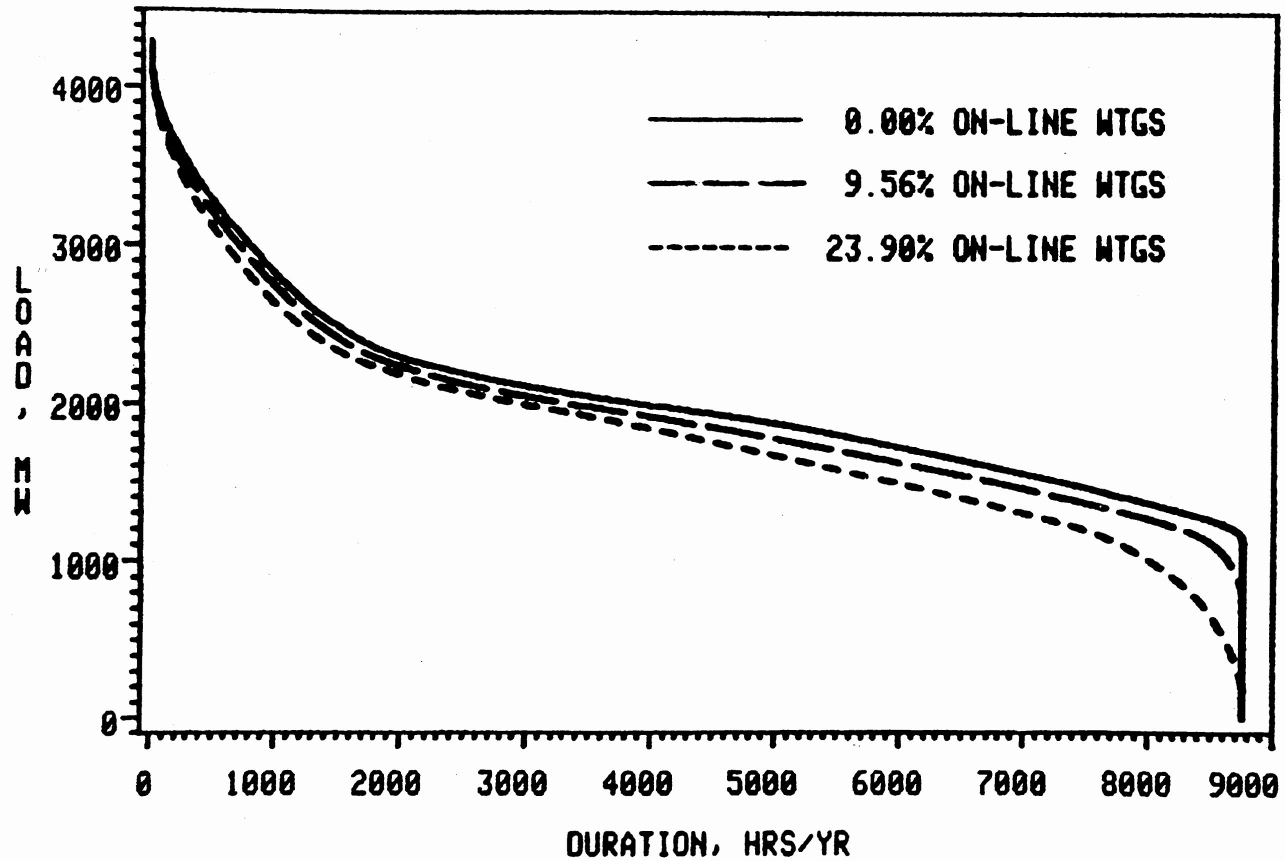


FIGURE 33. ORIGINAL- AND MODIFIED-LOAD DURATION CURVES.

6.1. Short-Term Operation Mode

This approach involves adding WTGS to the optimum mix of conventional equipment and, in most cases, results in a reduction in the energy generation from the various types of equipment. It should be noted that there is no change in the fixed costs associated with the conventional equipment. That is, the total difference in the conventional generation costs, due to the inclusion of WTGS into the equipment mix, comes mainly from the savings in the variable costs, which are, for the most part, fuel costs.

Figure 34 presents the results, for the short-term analysis, in terms of reductions in the energy generation, for the three types of conventional equipment in the assumed generating mix. These reductions were observed to increase as the level of WTGS on-line was increased in the utility. Because of the lack of significant correlation between the wind speed and utility load, the increase in the energy savings occurred at a decreasing rate for both the peak- and intermediate-load generation and at an increasing rate for the base-load generation. The corresponding savings in the variable costs are shown in Figure 35.

The smallest amount of energy reduction was found to occur in the generation requirements of the peak-load equipment, the highest variable-cost type of equipment. For all WTGS on-line levels considered, the contribution of this reduction to the total savings in energy generation and in production costs was found to remain fairly constant at about 18 and 36 percent, respectively.

The reduction in the energy generation of the intermediate-load equipment was found to be the largest, for WTGS on-line levels in the range up to about 13.5 percent. For levels beyond 13.5 percent,

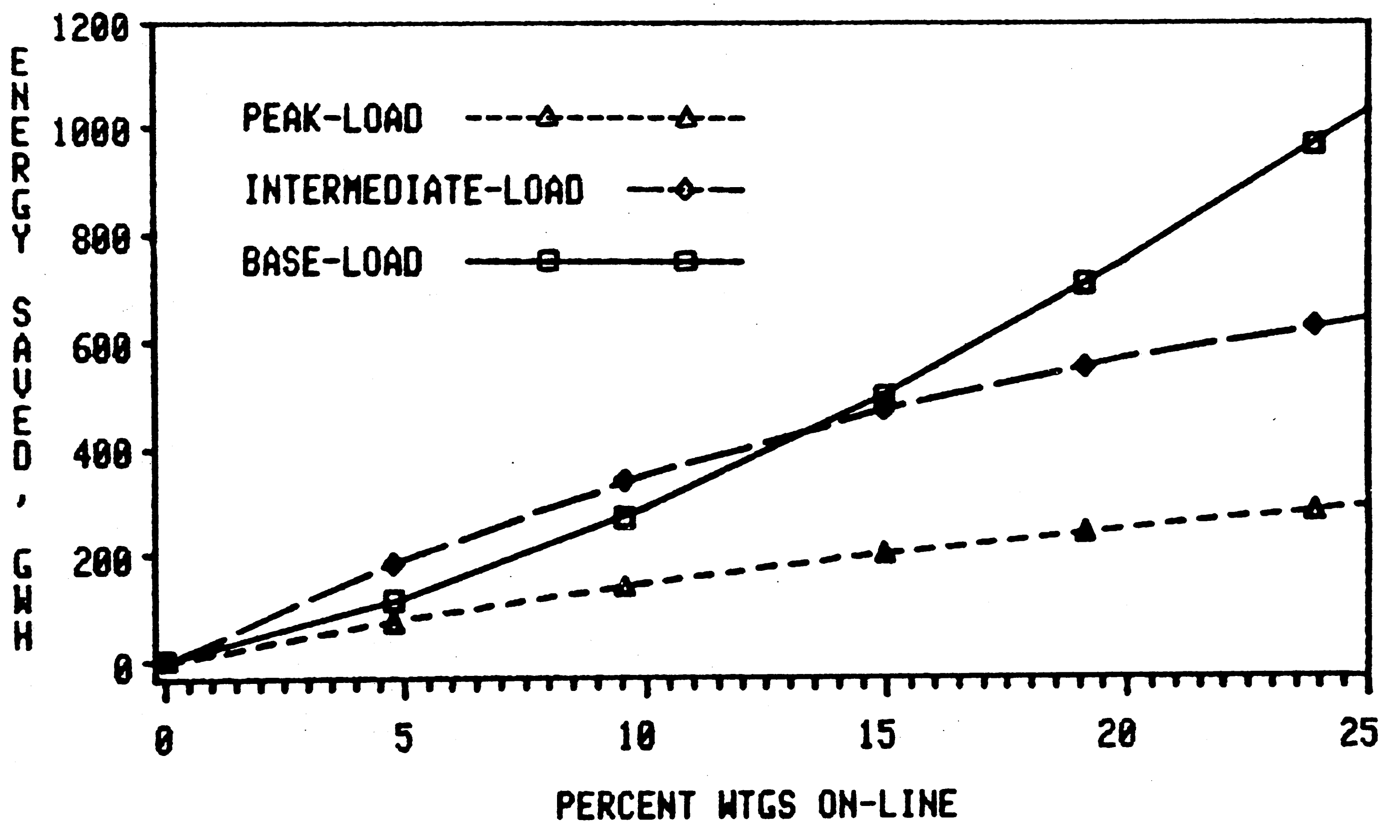


FIGURE 34. SHORT-TERM REDUCTIONS IN ENERGY GENERATION, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

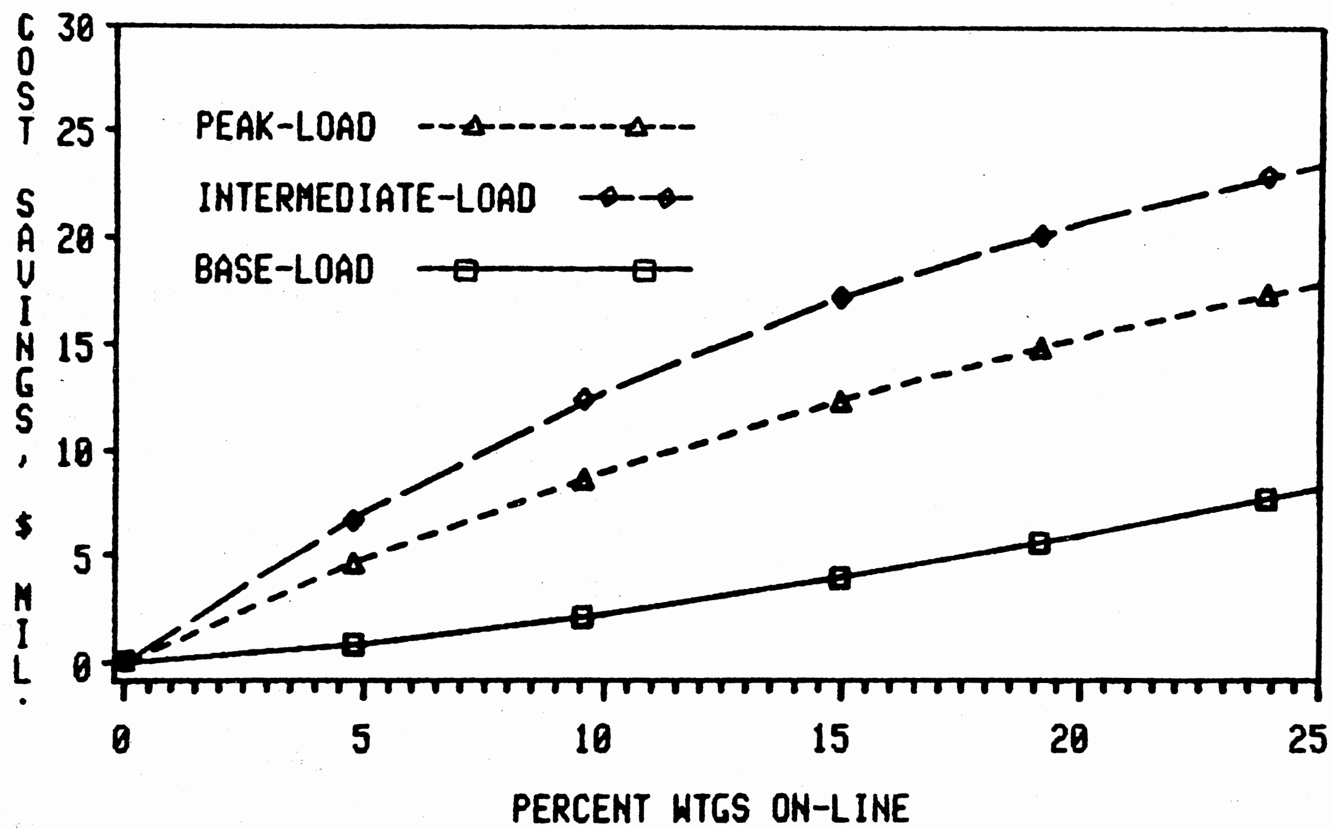


FIGURE 35. SHORT-TERM SAVINGS IN PRODUCTION COSTS, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

however, the greatest amount of energy reduction occurred in the generation requirements of the base-load equipment, the type of conventional equipment with the lowest variable costs. At about 23.89 percent level of WTGS on-line, the reduction in the energy generation of this type of equipment reached about 51.47 percent of the total energy displacement. However, the corresponding contribution of this reduction to the total savings in the conventional generation costs was only about 16.30 percent.

As a result, most of the total savings in the costs associated with the conventional equipment was due to the reduction in the energy generation of both the peak- and intermediate-load equipment. Furthermore, as shown in Figure 36, the total savings in the conventional generation costs were observed to increase at a decreasing rate as the level of WTGS on-line was increased in the utility.

6.2. Long-Term Operation Mode

This approach allows WTGS to be integrated into the equipment mix in an optimum manner, rather than simply as a fuel saver. It involves reoptimizing the mix of conventional equipment after the WTGS power outputs are considered. The savings in the conventional generation costs, in this case, consist mainly of a variable-cost component due to the reduction in the energy generation and a fixed-cost component resulting from the shift in the capacity of the equipment mix.

The amount of reduction in the energy generation from the conventional equipment is presented in Figure 37. For the low variable-cost base-load equipment, the reduction in the energy generation was found to increase from 103.6 to 124.5 percent of the total energy

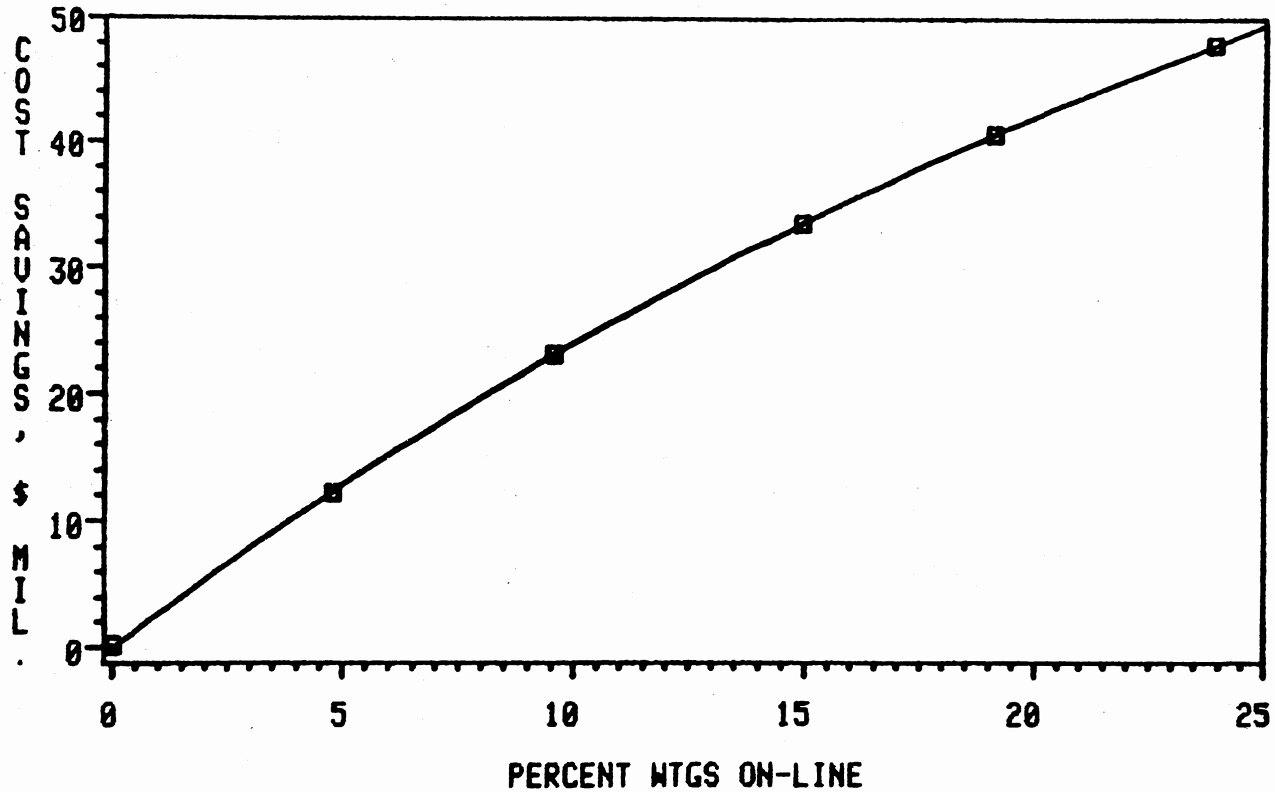


FIGURE 36. TOTAL SAVINGS IN PRODUCTION COSTS OF CONVENTIONAL EQUIPMENT, IN SHORT-TERM ANALYSIS.

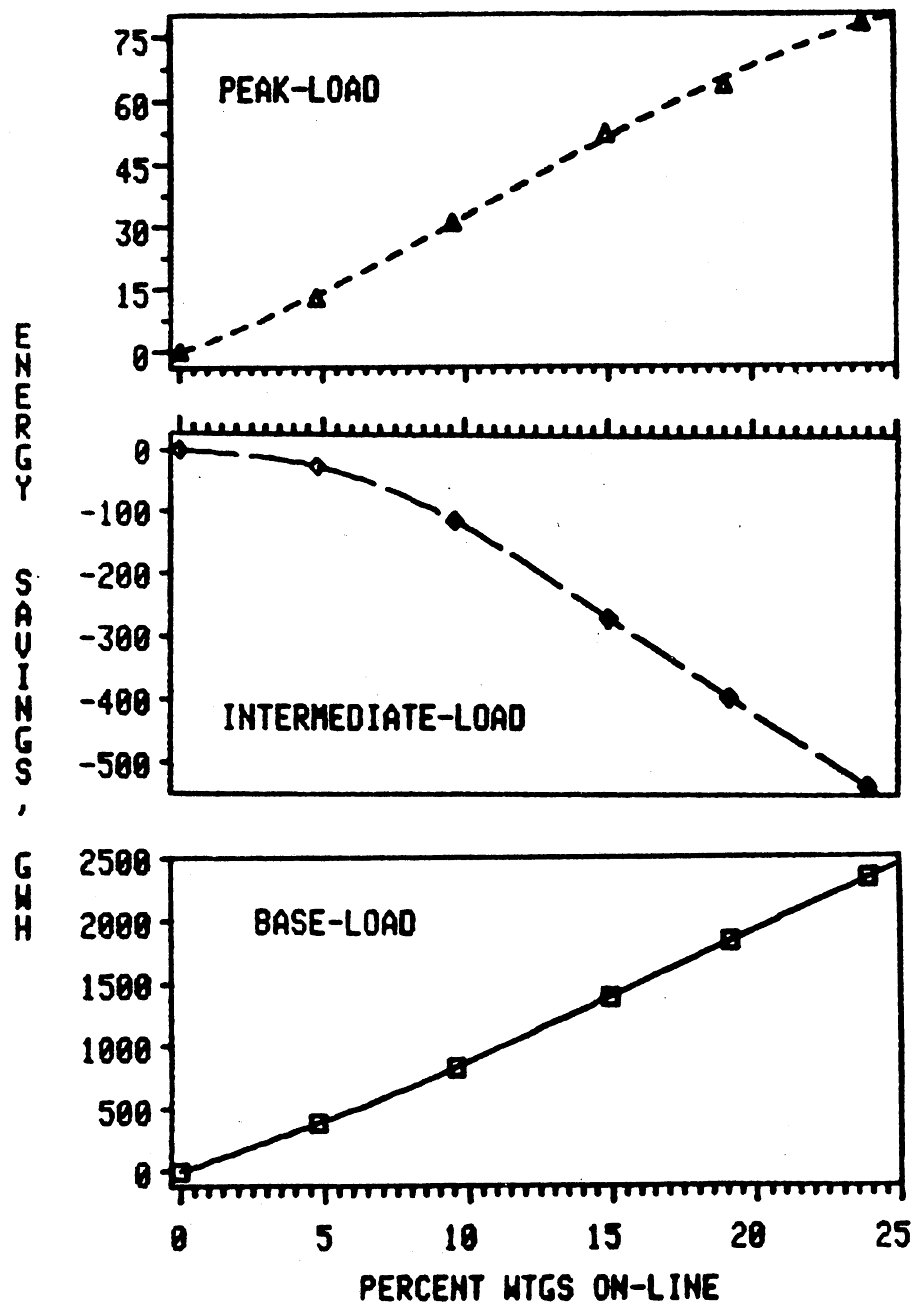


FIGURE 37. LONG-TERM REDUCTIONS IN ENERGY GENERATION, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

reduction as the percent WTGS on-line was increased from 4.78 to 23.89 percent, respectively. An amount of only about 4 percent of the total reduction was found to occur in the energy generation of the peak-load equipment, for all WTGS on-line levels considered. These results amount to a corresponding increase in the energy generation of the intermediate-load equipment, as indicated by the negative values for the energy savings shown in Figure 37.

The savings in the variable costs associated with the conventional equipment are presented in Figures 38 and 41. As shown in Figure 41, the total amount of these savings was found to increase to a maximum value of only about $4.5 million as the percent of WTGS on-line was increased to a level of about 12.5 percent. For levels beyond 12.5 percent, the total variable-cost savings showed a slight decrease from the maximum value due to the increase in the magnitude of the shift in the capacity away from the base- toward the intermediate-load equipment. The amount of the savings obtained at 23.89 percent level of on-line WTGS was only about $3.887 million, as compared to the estimated variable-cost savings of approximately $47.943 million for the short-term operation mode.

The main component of the total savings in the conventional generation costs, for the long-term operation mode, came in the form of fixed-cost savings due to the shift in the capacity of the conventional equipment. As discussed earlier, the addition of WTGS to the utility and subsequent mix reoptimization causes a change in the optimum mix of conventional equipment. Although the total capacity requirements of the mix remains unchanged, the new optimum mix is shifted toward more capacity for both the peak- and intermediate-load equipment and a

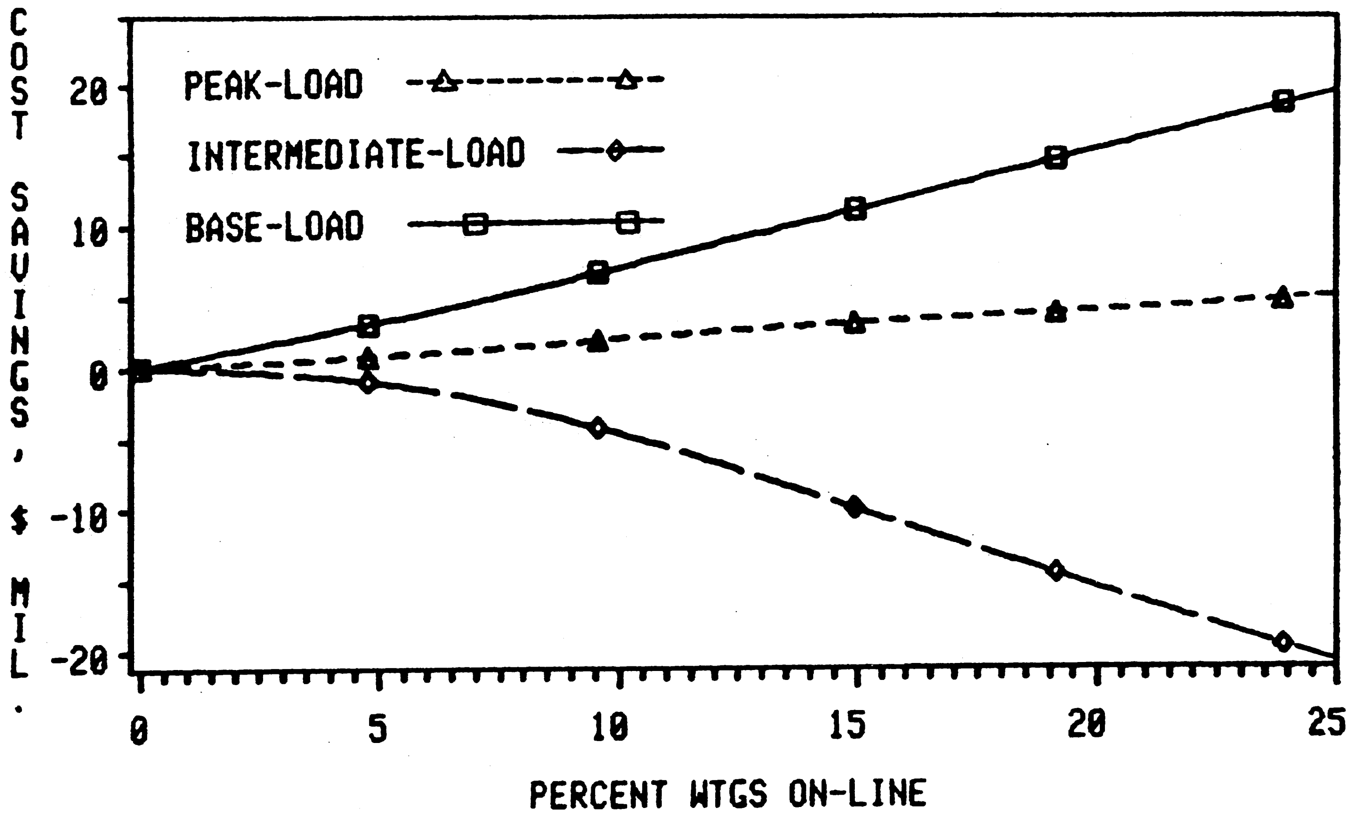


FIGURE 38. LONG-TERM SAVINGS IN PRODUCTION COSTS DUE TO REDUCTIONS IN ENERGY GENERATION, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

correspondingly less capacity for the base-load equipment, the highest fixed-cost type of equipment. This shift becomes more pronounced as the level of on-line WTGS is increased in the generation mix.

Figure 39 presents the amount of change in the capacity requirements for the three types of conventional equipment. The magnitude of the shift in the conventional capacity was found to be higher toward the peak- than toward the intermediate-load equipment, for levels of WTGS on-line up to about 21.5 percent. On the other hand, the increase in the capacity of peak-load equipment, expressed as a percentage of the decrease in the capacity of base-load equipment (or expressed as a percentage of the installed WTGS capacity), was found to decrease as the level of WTGS on-line was increased in the utility. The result of this would be a decrease in the capacity credit resulting from the mix change, expressed as a ratio of the installed WTGS capacity, as more units of WTGS are included into the generation mix.

The savings in the fixed costs associated with the various types of conventional equipment are shown in Figure 40. The reduction in the capacity of the expensive base-load equipment produced substantial savings in the fixed costs. The total amount of the fixed-cost savings was found to increase to a value of about $48.99 million as the level of WTGS on-line was increased to 23.89 percent, as shown in Figure 41.

The total savings in the conventional generation costs (fixed and variable costs) were found to be higher for the long-term operation mode than for the short-term one, as shown in Figure 42. The difference in the total savings between the two modes, expressed as a percentage of the total savings for the short-term, was found to be nearly proportional to the level of WTGS on-line. This difference was observed

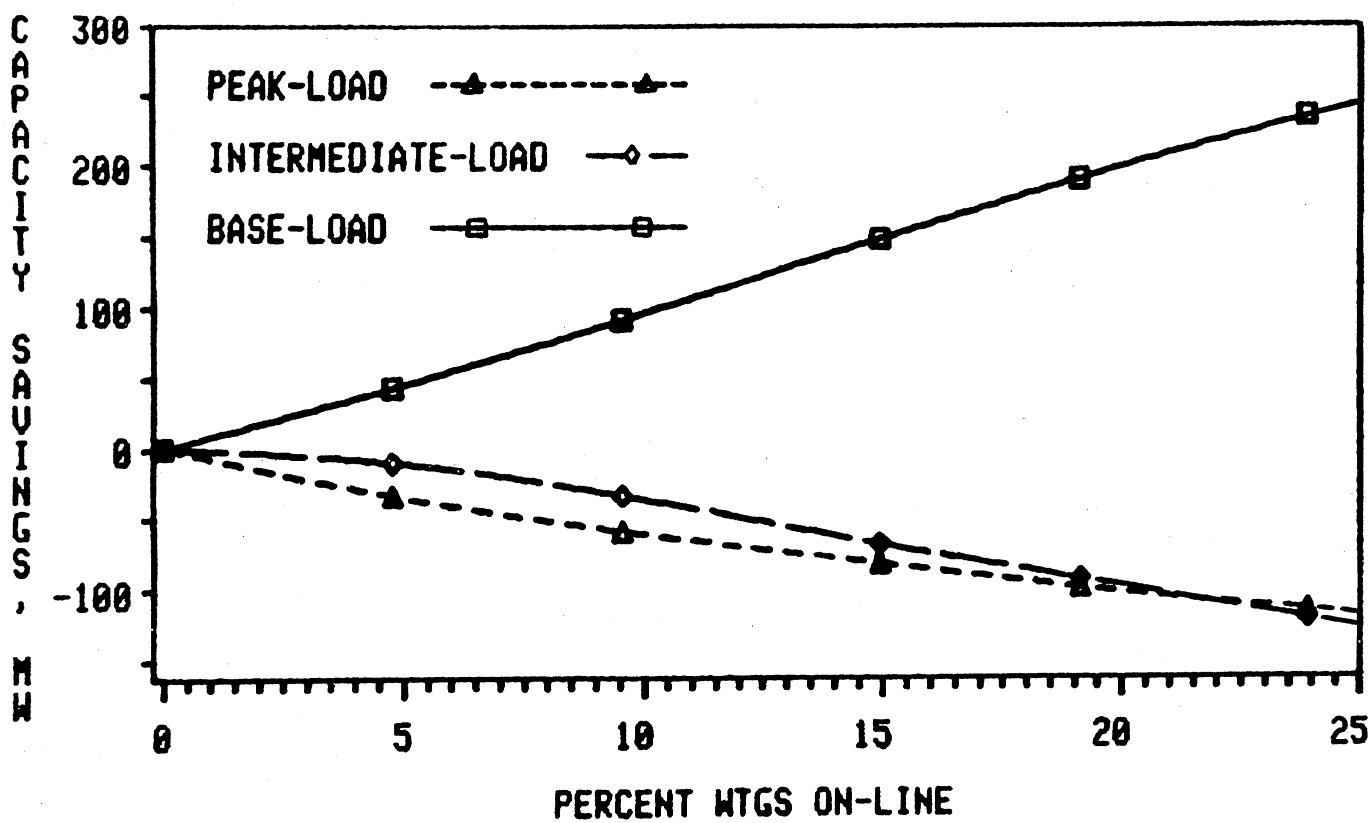


FIGURE 39. LONG-TERM CHANGES IN CAPACITY, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

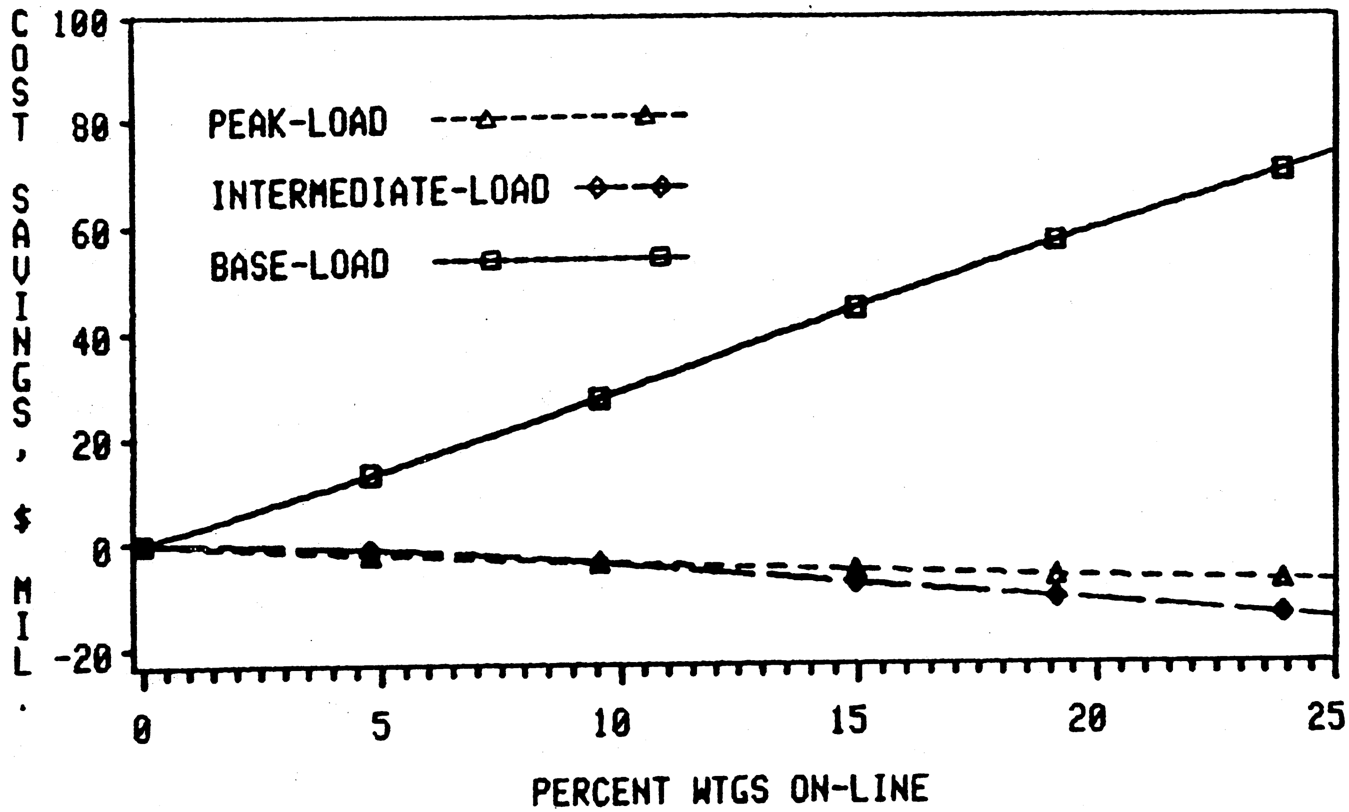


FIGURE 40. LONG-TERM SAVINGS IN PRODUCTION COSTS DUE TO CHANGES IN CAPACITY, FOR VARIOUS TYPES OF CONVENTIONAL EQUIPMENT.

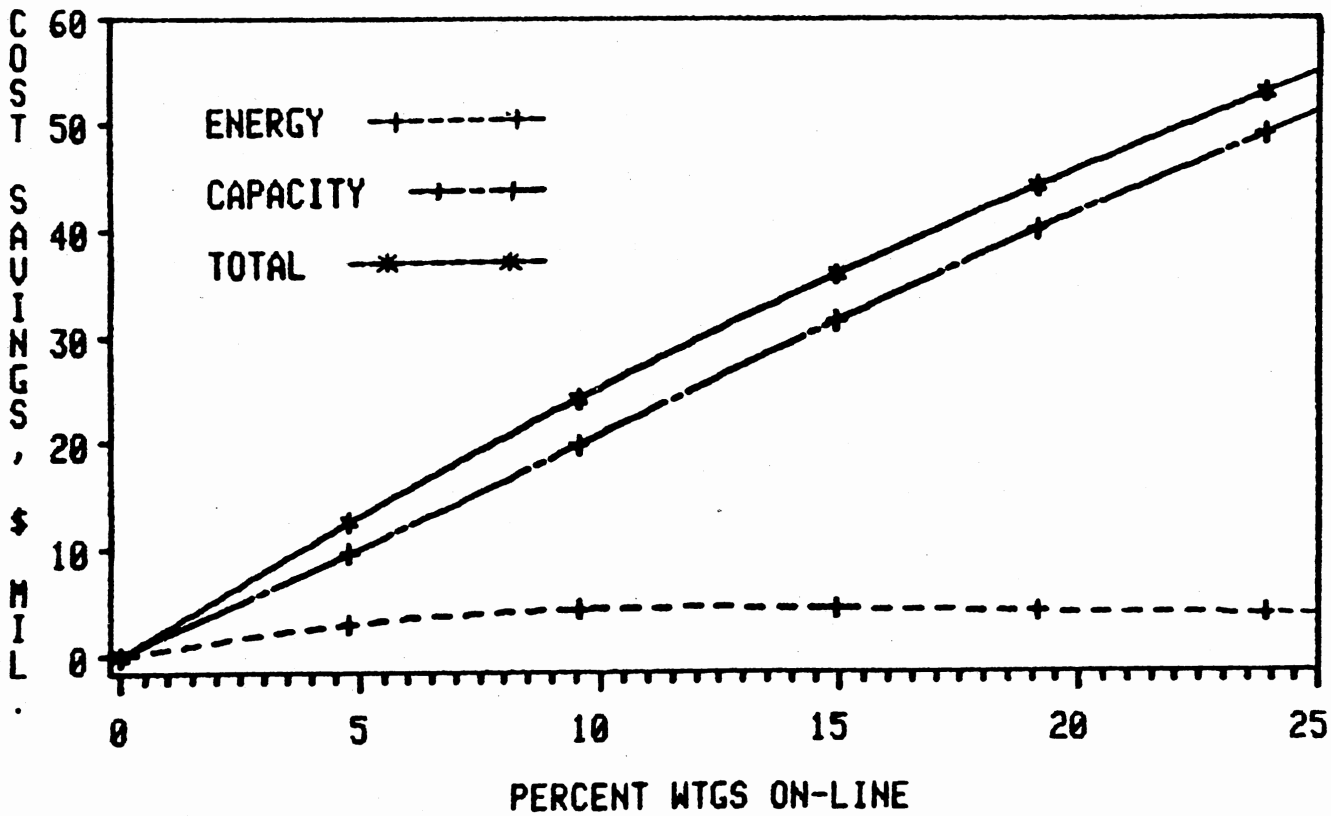


FIGURE 41. TOTAL SAVINGS IN PRODUCTION COSTS OF CONVENTIONAL EQUIPMENT, IN LONG-TERM ANALYSIS.

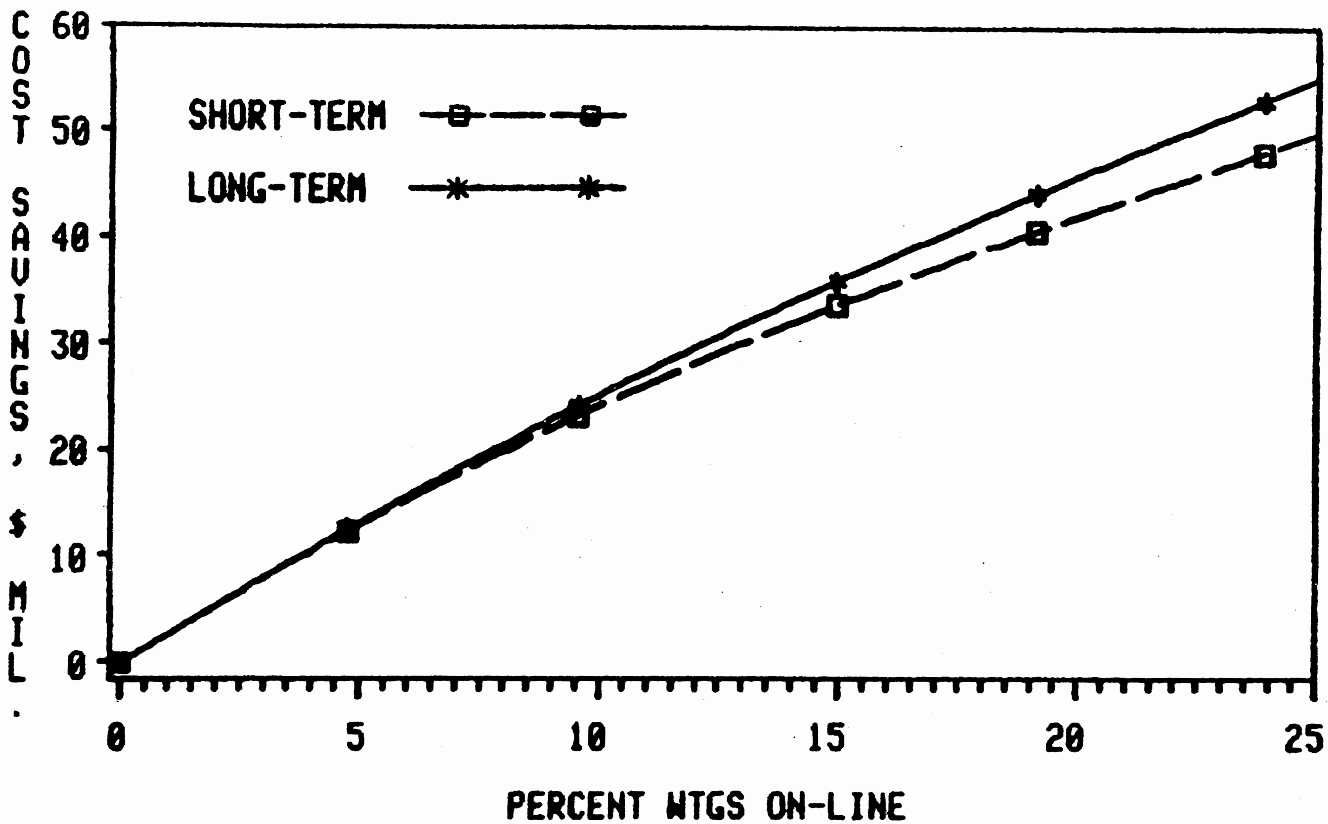


FIGURE 42. COMPARISON BETWEEN TOTAL SAVINGS IN PRODUCTION COSTS OF CONVENTIONAL EQUIPMENT FOR SHORT- AND LONG-TERM ANALYSES.

to increase to about 10.3 percent as the level of WTGS on-line was increased to 23.89 percent. Furthermore, the total savings in the conventional generation costs for the long-term approach, as for the short-term, were found to increase at a decreasing rate as the percent of WTGS on-line was increased in the utility mix.

6.3. Closure

The overall simulation approach developed in this work was applied to the model utility for the analysis year of 1990. Both the short- and long-term operation modes were considered in this analysis. The results of this work were found to show the same basic features and trends as those obtained from detailed simulations in several major studies.

In the short-term operation mode, the addition of WTGS to the utility resulted in large portions of the total energy reduction occurring in the generation from both the base- and intermediate-load equipment and a relatively small portion from the peak-load equipment. The savings in the annual costs resulting from these reductions were found to be the largest for the intermediate-load type and the smallest for the base-load type of equipment.

The addition of WTGS to the utility and subsequent mix reoptimization resulted in a shift in the conventional capacity toward more requirements for both the peak- and intermediate-load equipment and correspondingly less requirements for the base-load equipment. The reduction in the capacity of the expensive base-load equipment produced substantial savings in the fixed costs, the kind of cost savings not enjoyed in the short-term mode. The variable-costs savings, however, were much less for the long-term than for the short-term, due to the shift in the loading from the base- to the intermediate-load equipment.

The total savings in the conventional generation costs were found to be higher for the long-term than for the short-term operation mode. The difference in the savings, expressed as a percentage of the total savings for the short-term, was found to be directly proportional to the level of on-line WTGS. Furthermore, in both modes of operation, the savings in the conventional generation costs attributable to the WTGS were observed to increase at a decreasing rate as the percentage of WTGS on-line was increased in the utility.

CHAPTER VII

SUMMARY AND CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER STUDIES

7.1. Summary and Conclusions

The overall objective of this work was to develop a general methodology for making a systematic and credible evaluation of the operational and economic impacts of wind power on electric utility systems. The methodology developed was based on treating wind-generated power as a "negative load" with respect to the conventional part of the utility system. Probabilistic models were employed to describe the expected load on the utility and the output of the wind turbine generators. The convolution integration approach was utilized in predicting the characteristics of the modified load distribution. A load-duration approach was developed to assess the impact on the capacity and energy requirements and on the costs associated with the conventional equipment.

Two modes of operation were considered in this analysis, the short- and long-term modes. The short-term analysis involved adding WTGS to the optimum mix of equipment that was selected to satisfy the original load. In the long-term analysis, WTGS were added to cancel out as much of the load as in the short-term mode, and then the mix of conventional equipment was reoptimized to satisfy the remaining load. The capacity credit associated with wind power and the change in the spinning reserve requirements were not evaluated in this analysis. It is important to realize that the peak value of the modified load remains unchanged, and only the duration of the peak is decreased.

Based on the results and discussions presented in this work, the following conclusions may be drawn:

1. The low correlation coefficients between wind speed and utility loads appear to be typical for many areas. This indicates that wind power and original load on the utility can, in most cases, be considered as statistically independent variables. In these cases, it is preferable to obtain the modified-load duration curve by convolution integration, of wind power and original load distributions, rather than by the traditional hour-by-hour simulation. The advantage of the probabilistic modeling and the convolution integration approach is that many years of input data can be summarized in one distribution, which results in a more efficient simulation.
2. Wind turbine generators are of a more economic value in the long-term approach than in the short-term; that is, the utility can operate at a lower cost when the mix of conventional equipment is reoptimized based on the remaining load on the system. The shift in the optimum mix away from the more expensive base-load equipment results in the largest contribution to the total cost savings and is undoubtedly more significant than any reduction in the total conventional capacity of the utility.

7.2. Recommendations for Further Studies

Based on the analyses and discussions presented in this work, it is recommended that the following research be undertaken:

(a) Develop procedures for determining the WTGS capacity credit and impact on the operating reserve requirements of the utility system.

(b) Develop a procedure to account for variations in the wind speed among the various WTGS sites in the array.

(c) Examine the sensitivity of the WTGS impact results to changes in the various parameters of the wind speed, WTGS, and the utility load and generation mix.

(d) Compare the results of this work with those of the traditional hourly simulations for an actual utility case.

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VITA

Yahya Ibrahim Sharaf-Eldeen

Candidate for the Degree of

Doctor of Philosophy

Thesis: SIMULATION METHODS FOR GENERATION PLANNING OF ELECTRIC UTILITY SYSTEMS WITH INTERMITTENT POWER SOURCES

Major Field: Mechanical Engineering

Biographical:

Personal Data: Born in Zizinia, Ariamoon, Behera, Egypt, on April 1, 1946, the son of Mr. Ibrahim Youssef Sharaf-Eldeen and Naghia Mohammed Maree.

Education: Attended primary school in Ariamoon and secondary school in Elmahmoudia, Behera, Egypt; received the Bachelor and Master of Science degrees in Agricultural Egineering from Alexandria University, Alexandria, Egypt, in 1967 and 1973; received the Doctor of Philosophy degree from The Ohio State University, Columbus, Ohio, 1979, with a major in Agricultural Engineering, completed requirements for the Doctor of Philosophy degree at Oklahoma State University, Stillwater, Oklahoma, with a major in Mechanical Engineering, July, 1987.

Professional Experience: Instructor, 1967-1973, and Lecturer, 1973-1975, College of Engineering, Alexandria University, Alexandria, Egypt; Teaching/Research Associate in Mathematics and Agricultural Engineering, 1975-1979, The Ohio State University, Columbus, Ohio; Teaching/Research Associate, 1980-1982, and Lecturer, 1982-1987, School of Mechanical and Aerospace Engineering, Oklahoma State University.

Professional Organizations: Phi Kappa Phi, Pi Tau Sigma, Tau Beta Pi, Alpha Epsilon, Golden Key, AIAA, ASME, ASEE, and ASAE.