CAPACITY CREDIT FOR KANSAS WIND TURBINES

by

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I. INTRODUCTION

1.1 Capacity Credit

Considerable efforts have been made to find an alternative energy source, such as wind. Wind power as an energy source can obviously be used as a fuel saver and to defer conventional generation construction [1]. Either of these two is based on the economics of the utilization of wind energy. One of the prerequisite conditions to determining economics is to determine the reliability of the energy production of a wind turbine. The major objective of this research deals with the estimation of reliabilities on the KGE (Kansas Gas and Electric) system when a new wind energy source is added.

To calculate the reliability of wind energy, a general criterion is based on the Capacity Credit of the wind turbine. Capacity credit of a wind turbine is said to be the amount of additional load that can be added to the system, after the wind turbine has been connected to the original power system, and the reliability of this system remains at the same level. It is also the percentage of a wind turbine's capacity which can be credited as substitution for an equivalent amount of conventional generation.

1.2 General Procedure

To compute the capacity credit of a wind turbine, the power system failure probability has to be calculated first. The Frequency and Duration method has been chosen here to calculate power system failure probability. This method can be divided into four parts.

(a) Generation System Model:

The qnantities reqnired in generation system reliability analysis are unit capacity and failnre probability. The capacity of one generation unit can be found from its nameplate, while the failure probability of each nnit must be obtained from long-term experience. A simple two-state model is assnmed for the operation of a unit. The unavailability $\bar{A}$ is defined as:

$$\bar{A} = \frac{r}{T} \tag{1.1}$$

where r is the mean repair time and T is the cycle time which equals the sum of the mean repair time and the mean working time [2].

A traditional term for the unit nnavailability is <u>Forced Ontage Rate</u> (FOR), which is defined as:

$$\text{FOR} = \frac{\text{Forced Outage Hours}}{\text{In-service Hours + Forced Outage Honrs}} \tag{1.2}$$

which if computed over a long period of time is the same index as the unavailability defined in Eqn. 1.1 [3].

For each unit within the generating system, a two-state generation probability table can be easily gotten from those two valnes mentioned above. After combining all the generating units in the system which need to be analyzed, a table of the whole system's generation capacity states and their corresponding probabilities will be established.

(b) Load Model:

To find an adequate load model for this research, the available wind data has to be included. Because the wind power output states' data are based on a monthly basis and it is desired to reduce the load data to a manageable size, the monthly load data have been chosen to build the load table. For a chosen month, the hourly peak load values are carefully examined and the daily peak load data are obtained from this examination. Then, the selected daily peak load states are simplified by combining those load states with the same peak load level together. The percentage of time that the load will keep at its peak value within a day is defined. Finally, these peak load data are combined with the monthly base load to build the system load probability table.

(c) System Merging Model:

An electric power system is considered in a 'Failure' state from two situations, either through generation system unit failures or through load increases beyond a certain level.

In computing the failure probability of a power system, this model is based on an assumption that the generation part and the load part of this power system are independent. The generation capacity states' and the load states' tables are combined into a system margin table, where the data within this table are the system margin values and their probabilities. The margin value of one margin state is determined by when the generation capacity in that state exceeds the load demand. The probability of this margin state is equal to the multiplication of the probabilities of the generation state and load state which constructed this margin state.

As mentioned above, the power system is in a failure state when the generation capacity can not supply enough load , i.e., the system margin has a negative value. To find the total power system's failure probability, all the probabilities of negative margin value states are added together.

(d) Wind Power Model:

The power output of a wind turbine is affected by these two factors:

a. Wind characteristic

b. Wind turbine's forced outage rate

For a wind turbine, the electrical power output will equal zero until the speed of the wind rises above a certain value, the cut-in wind speed [4]. Thus, this wind turbine can not have electrical power output at wind speeds below the cut-in speed of this turbine even when the machine is in 'working' condition. So, the turbine is still in the 'unavailable' state for these low wind speeds. After the wind speed increases to the cut-in speed, the turbine starts to generate electrical power, and this power will increase with the wind speed until the wind speed reaches the rated speed. Once the wind speed is equal to this value, the power output will remain at the so called 'rated power output' level until the wind speed reaches its 'furling value'. At the furling wind speed, the turbine is shut down to prevent structural damage. From this consideration, it is clear that the wind turbine will only be 'available' for wind speeds between the cut-in and furling speeds. This is shown in Fig. 1.1.

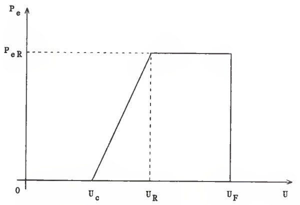


Fig. 1.1 Model Wind Turbine Output Versus Wind Speed

Just like other equipment in a power system, the wind turbine also has a forced outage rate. This results from failure of components, such as blade, gear box, generator, and switchgear. Thus, the electrical power of a wind turbine is 'available' when the turbine is both in a working state and the wind speed is between the cut-in and furling speeds of this turbine's design.

The hourly wind data measured from several places around Kansas have been carefully examined, using statistical methods to compute the number of occurances of each wind speed and the capacity factor of each particular site and height. When these results are combined with the chosen wind turbine's power output curve (as shown in Fig. 1.1), a wind turbine's power output level versus its probability table can be obtained.

When the wind turbine is treated as a conventional generating unit, and its power output is combined with a probabilities table, then a new generation system model with wind turbine output added can be built by using the same method as for a purely conventional generation system.

From the new generation system model, the margin states of the whole system surely will have changed. In this new margin state table, when all the negative margin states' probabilities are calculated and added together, the system failure probability with the wind turbine's power output added can be obtained.

1.3 Analysis and Estimation

To find the capacity credit for a wind turbine, this research uses a monthly basis to analyze and compute the power system failure probabilities. For a given month, after computing its system failure probability, the monthly peak load value is varied and also each daily peak load value as a percentage of the monthly peak. The system failure probabilities are computed for a range of loads such as $\pm$ 20 percent [5]. These data will produce a curve which graphs the system failure probability as a function of the monthly peak load value. Following this step, the wind power generation is added to the conventional generation system and the same system failure probabilities' calculation is performed again. It will be found that the power system failure probability will be lower than the original system at the same peak load level. Thus, when a wind generating unit is added to the system, the curve which represents the system with wind turbine output added is usually produced by increasing the monthly peak load over a range of 0 to 40 percent above the reference case.

After these two curves have been obtained, the allowable reliability level is selected and the two peak load values at this reliability level are compared. The difference between these two peak load values is said to be the <u>Effective Load Carrying Capability</u> (ELCC) of the wind turbine [6], and the capacity credit for this wind turbine is defined as:

$$\text{Capacity Credit} = \frac{\text{Effective Load Carrying Capability}}{\text{Installed Rated Power Output}} \tag{1.3}$$

Fig. 1.2 shows these two curves and the ELCC of the added wind turbine. It may be noted here that the two curves are not smooth To get a good estimation on the ELCC, a least square method on curve fitting is used.

In this thesis the detailed method as introduced above is explained and the KGE 1982 system is examined.

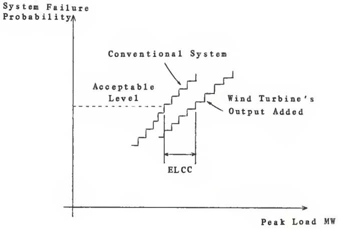


Fig. 1.2 Effective Load Carrying Capability of a Wind Turbine

II. OTHER METHODS

This chapter introduces other methods which under different situations can also be used in estimating the wind turbine's capacity credit.

2.1 Loss-of-load Probability (LOLP) Method

Most of the research done on reliability is based on the determination of Loss-of-load Probability of the power system. This method is used to find the total probability that the load demand will not be met by the generating system. The major difference between this method and the Frequency and Duration method is that the LOLP method is based on the assumption that the daily peak load will last for a whole day. This will make the obtained probability value worse than the value obtained from the Frequency and Duration method.

In this method, a 'loss of load' will occur only when the capability of the generating capacity remaining in service is exceeded by the system load. A graphical description is shown in Fig. 2.1 [7].

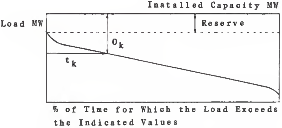


Fig. 2.1 Cumulative Load Curve in LOLP Method

In this figure,

O_k = Magnitude of capacity failure in the kth state of the generation system table.

P_k = Probability of a generation state whose capacity outage is equal to O_k.

t_k = The percentage of time during which the outage magnitude O_k would cause a loss of load.

The loss-of-load probability (LOLP) is given by the equation:

$$\mathrm{LOLP} = \sum_k \frac{P_k\ t_k}{100} \tag{2.1}$$

Because of its simplicity, most research dealing with reliability evaluation has been done with this method. A problem with this method is that it ignores the load variation within a day. Generally the peak load will happen in the day time (8 a.m. to 8 p.m.), and the wind character is quite different from day time to night time (8 p.m. to 8 a.m.). This means that the LOLP method is not appropriate for determining cspacity credit of wind turbines.

2.2 Loss-of-energy Method

If the physical significance on the reliability index is considered, an in-depth method called Loss-of-energy method has been defined. This method is used to find the probable ratio of load energy curtailed due to deficiencies in the generating capacity available, to the total load energy required to serve the reqnirements of the system. In Fig. 2.2 [3], the ratio is given by:

$$E = \sum_{j} \frac{P_j \, D_j}{D} \qquad (2.2)$$

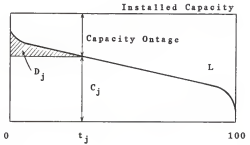


Fig. 2.2 Cnmulative Load Cnrve in Loss-of-energy Method

where,

$$D_j = \int_0^{t_j} (L - C_j)\,dt \qquad \text{and} \qquad D = \int_0^{100} L\,dt \qquad (2.3)$$

P_j is the probability of generation state C_j.

From the eqnations listed above, it is cleared that the true loss of energy can not be accnrately calcnlated on the basis of finding an exact equstion for the cnrve of daily peaks. Thns, this method is seldom nsed.

2.3 Other Sitnations

To minimize the program which compntes the system failnre probability to a msnageable size, several refinements were not nsed in this research. A brief discussion of these featnres is given below.

(a) Maintenance:

Periodical maintenance on the units of a generation system will increase the lifetime reliability of the nnits. It is obvions that a carefnl maintenance schednle will make a great difference in the resnlts of finding the power system failure probability.

When schednled maintenance is considered in the loss-of-load probability method, it is eaay to find that the system generation capacity will not be constant dnring the entire period of observation. A single generation system capacity ontage table thns can not be nsed, and there are three different approaching techniqnes shown on Fig. 2.3 which included the maintenance sitnations [7].

The first two fignres are based on the same assumption that the nnit which ia on maintenance will ont of service for the total obaerved time. In Fig. 2.3a, the original generation system capacity ontage table is combined with the cnmulative load curve which has increased by the amonnt exactly eqnal to the capacity of the maintenanced generation nnit. In Fig. 2.3b, the original capacity ontage probability table is also nsed but the total available capacity is rednced by the qnantity on ontage, and the original cnmulative load cnrve is combined to find the losa-of-load probability.

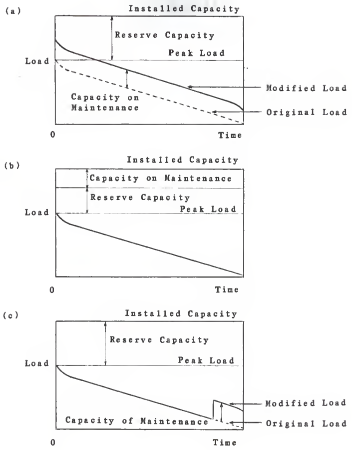


Fig. 2.3 Approximate Method of Including Maintenance

The third method, shown in Fig. 2.3c, is mnch more practical than those two described above, becanse the actnal maintenance period is considered. So, in the observed peak load dnration, it is possible that one single generation unit may be schednled for maintenance for only a portion of the total observed dnration and there may be several different generation units schednled for maintenance within this duration. To find the new generation capacity ontage table in the period when some of the generation nnits are on maintenance, a direct 'removing' method can be nsed [7] on the original complete system table rather than by bnilding np the table each time.

Some other advanced techniqnes can be nsed on the schednling of maintenance [8]. By using these methods, one must decide each generation nnit's effective load carrying capability before the schednling of their maintenance. Then, from this schednle the generation table will be easily combined with the daily peak load table and the Freqnency and Dnration method can be applied. The programming of these techniques will be very complicated.

(b) Uncertainty:

When all the given parameters are nsed in the calcnlation of power system failnre probability and effective load carrying capability, the general method is nsed by giving each of those data reqnired in this calcnlation a defined valne, or assnmes these data are already precisely known. Bnt, in the real sitnation, some of these data are never known precisely, bnt are uncertain in natnre.

In this research, data are given by a deterministic valne, but as recognized in aeveral pnblications [3],[7],[9], those data such as generation unit's forced ontage rate, forecast peak load, and the wind data rather ahould be repreaented by random variablea with diatinct distribntions. Billinton [7] gives an approximation method for calcnlating the expected LOLP when nncertainties exist in the forecast peak load but assnmes the forced ontage rate of the generation system fixed. This method does not provide any information abont the variance and distribution of the LOLP. On the other hand, Patton [9] described the variance and distribntion of the LOLP bnt on the asaumption that the forced outage rates of the generation system are uncertain and the forecast peak load is fixed. Endrenyi [3] gives a brief introdnction of both methods. A detailed calcnlation and consideration on the uncertainties of those data while combined together is given by Wang [10], and it ia fonnd that the LOLP distribntion can be approximated by the gamma distribntion in the general case.

When wind data are inclnded, it is fonnd that the forced ontage rate of a wind turbine must be combined with its power ontpnt states to build a capacity ontage table. The same uncertainty will alao happen on the FOR of this wind turbine, and the power ontput data which are obtained from a one-year period of observation are not snfficient to be used as a deterministic valne in the calcnlation of the wind turbine's effective load carrying capability. Rather, it should be considered in some distribution function which will make a more reasonable description of these data.

(c) Interface and Connection:

Both the LOLP and Freqnency and Duration methods are based on the same assnmption that the connection between generation system and load are perfectly reliable, that is, the system will fall into a 'failnre' state only when the generation system is inadeqnate or the load demand exceeds the amonnt that can be snpplied by the generation system.

In references [3] and [7], the methods of considering system transmission line reliability are explained. It can be fonnd that there are two methods to inclnde the transmission line's availability in the system reliability compntation. They are the Average Interrnption Rate Method and the Freqnency and Dnration Method [7]. In the first method, a measnre of continnity is provided by examining the simultaneons conditions that mnst exist in the system power flow indices. The second method, on the other hand, deals with the environmental conditions [3] which will affect the connection lines between the generation and load systems. For fnrther consideration, a transmission line and other ontdoor components will not have a constant environmental condition and this condition can have a considerable effect on their failnre rates. Thus, a Markov-chain approach shonld be examined, which will make the system compntation mnch more complicated.

If a large application of wind tnrbines in an electric ntility system is nsed, the interface system's reliabilities between the wind turbines electric power output and the conventional system should also be included. A detailed description is given in [11].

III. THEORETICAL EXPLAINATION

3.1 Freqnency and Dnration Method

In the calcnlation on power system failnre probability, the Freqnency and Dnration method inclndes more effects and is more accnrate than the LOLP method. The major difference between these two methods is on the peak load model finding and the merging of the generation system model with the load model. This section will give a detailed explanation about this method.

(a) Generation System Model and State Probabilities:

To bnild np a generation system capacity ontage table, the data needed are the nnmber of different generator types, the nnmber of generators within each type and each generator's capacity and forced ontage rate.

The procednre to combine these generators together in this research is made on a gronp by gronp combination sequence. For machines with the same capacity and forced ontage rate, by using the Binomial Theorem, the probability P_g of state g where g units have failed ont of n is given by:

$$P_g = \binom{n}{g} \bar{A}^g A^{n-g} \tag{3.1}$$

where,

$\bar{A}$: the unavailability of a unit.

A : the availability of a unit which eqnals $1-\bar{A}$.

n : the total number of generation units.

Using this eqnation, a tabulation called the capacity outage probability table can be assembled. To find the whole generation system's capacity ontage probability table, the combination between each gronp which has the same type of generators must be followed by the complete solntion of all the individnal gronp's capacity ontage probability table. The reason to choose a gronp by gronp combination method in place of the widely nsed one by one method [12] is to rednce the memory size in programming work. A two-type generation system example is given below.

Snppose a generation system has two different types of generators. One type has six generators with 50 MW capacity and 0.05 forced ontage rate each, and the second type has five generators with 30 MW capacity and 0.07 forced outage rate each. To use the one by one combination, the generation system has a total nnmber of $6 + 5 = 11$ generators, so the combination procednre is described as follows.

The 50 MW generators are combined first:

Unit 1 : FOR = 0.05

Availability = 1 − FOR = 0.95

Capacity = 50 MW

the power ontputs for unit 1 can be divided into two states:

State 1 : Capacity = 0 MW

Probability = 0.05

State 2 : Capacity = 50 MW

Probability = 0.95

Unit 2 : FOR = 0.05

Availability = 1 - FOR = 0.95

Capacity = 50 MW

By using the same method as in unit 1, the two output states of unit 2 can also be obtained.

When the output states of unit 1 and unit 2 are combined together without elimination, the combined output states are:

State 1 : Capacity = 0 + 0 = 0 MW

Probability = (0.05)(0.05) = 0.0025

State 2 : Capacity = 50 + 0 = 50 MW

Probability = (0.95)(0.05) = 0.0475

State 3 : Capacity = 0 + 50 = 50 MW

Probability = (0.05)(0.95) = 0.0475

State 4 : Capacity = 50 + 50 = 100 MW

Probability = (0.95)(0.95) = 0.9025

The same procedures are applied on the combination of all the remaining nine units and the generation system capacity outage table can be obtained. The sequence of combination is shown in Fig. 3.1.

While using group by group combination, the Binomial Theorem had been applied to each group before the combination on these groups. From the definition of Binomial Theorem [13], there will be n+1 different capacity states for n identical units. So, the generation system capacity outage table in this example can be built by connecting the capacity states of two different types of generating units together, that is, the group of generating units with individual capacity equal to 50 MW and the group of

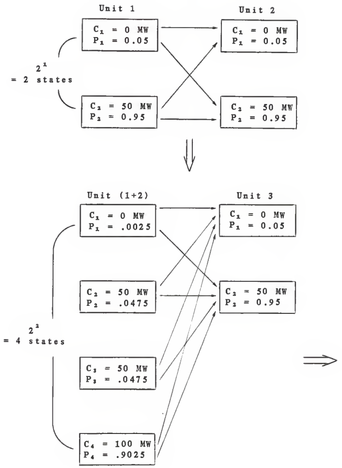
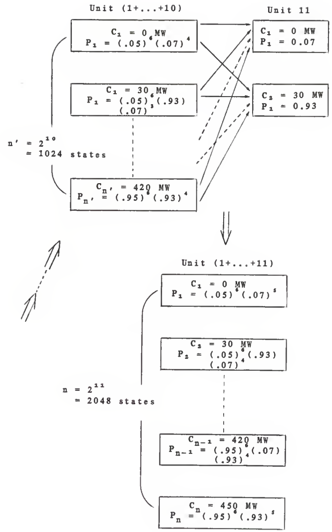


Fig. 3.1 General Procedure for One by One Combination


Unit (1+...+10)
Unit 11
C1 = 0 MW
P1 = (.05)6(.07)4
C1 = 0 MW
P1 = 0.07
C1 = 30 MW
P1 = (.05)6(.93)(.07)3
C2 = 30 MW
P1 = 0.93
n' = 210
= 1024 states
Cn' = 420 MW
Pn' = (.95)6(.93)4
Unit (1+...+11)
C1 = 0 MW
P1 = (.05)6(.07)5
C2 = 30 MW
P2 = (.05)6(.93)(.07)4
n = 211
= 2048 states
Cn-1 = 420 MW
Pn-1 = (.95)6(.07)(.93)4
Cn = 450 MW
Pn = (.95)6(.93)5

generating units with individual capacity equal to 30 MW are combined directly to find the whole generation system capacity outage table. This procedure is shown in Fig. 3.2.

From these two methods described above, it can be found that the group by group combination method is just a particular example of the one by one combination method, and the results of the gronp by group method are the results of the one by one method after elimination. States with the same capacity can be combined together to reduce the number of states, snch as in Fig. 3.1, when the combination of units one and two of the two 50 MW states need not be separated. But, of course, this kind of comparison and elimination is not as efficient as the group by group combination method.

(b) Load Modeling and Model Selection:

The major difference in the Frequency and Duration method and other methods mentioned is on the load modeling. This method has chosen an appropriate two-level model to represent the load variations within a day, which is much more reasonable than just using the daily peak load valne in the load model representation. In this research, the load data on the IEEE Reliability Test System [14] had been carefnlly examined and a winter week's weekday hourly peak load data had been plotted in Fig. 3.3.

From this load curve, it can be found that if the daily peak load valne had been chosen to construct a cumulative load curve in the LOLP calcnlation, a pessimistic approximation of the actual system failure probability will be obtained. A two-level

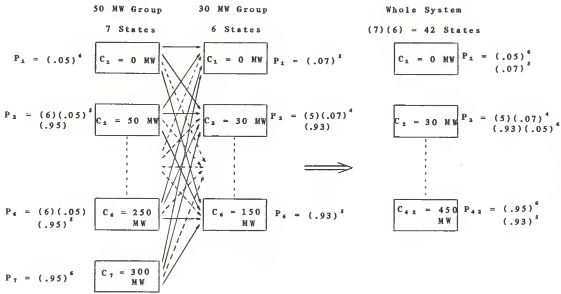


Fig. 3.2 General Procedure for Group by Group Combination

model is selected to replace the original load cnrve in Fig. 3.3 and it is well fitted to the load variation within one day.

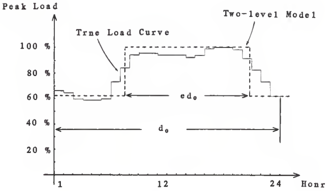


Fig. 3.3 Daily Load Curve on Winter Week (Weekday)

where,

d_0 : The total dnration of observation.

e : The percentage of time while the load is in peak state.

There are three parameters which need to be chosen carefnlly in the two-level load model. They are peak load, base load and exposnre factor The higher level in this model which is called the daily peak load valne is nsually the highest honrly peak load within the day that has being observed. On the other hand, the lower level is called the base load, in which data is chosen for the most likely lowest load level within the day. The third one, exposnre factor, is nsed to describe the mean percentage of time during which the load will remain at its daily peak load state in the whole day's load cycle. In Fig. 3.3, the length of the load cycle is d_0, which equals 24 hours, the length of peak load lasts for ed_0, so the exposure factor is defined by $ed_0/d_0 = e$.

To find an adequate model which will be most suitable to represent the daily load curve, it is obvious that a multilevel model should be chosen. The multilevel model representation for the daily curve is shown in Fig. 3.4. It is seen in this model that the total number of load states within one day will be greater than the number of load states in the two-level model. This made the size of the representing load system much larger.

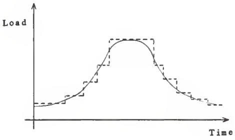


Fig. 3.4 Multilevel Representation of the Daily Load Curve

On the monthly basis, another consideration is the daily base load variation. It can be found that no two days within a month will have the exactly same base load value, and this will increase the complication in the combination of daily load.

Fortunately, in the calculation of power system failure probability, the choice of the daily base load level has little effect on the system failure probability as long as the failure occuring at the low-load levels is insignificant. The other thing is when the true load curve as shown in Fig. 3.3 is studied, it can be found that a two-level model is quite sufficient to represent the actual load curve. So, in this research, a single base two-level model has been chosen in the calculation of power system failure probability and the estimation of wind turbine's capacity credit.

After the model selection, an acceptable load variance is given to reduce the total peak load states and to find the time of occurances for each daily peak load. Then, the days with the same peak load level are combined to form a state space diagram which can be used to find the load probability table. The Markov-model for this load representation space diagram is shown in Fig. 3.5 [3].

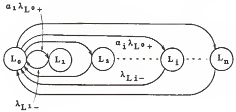


Fig. 3.5 State-space Diagram for the Two-level Single Base Load Model

where,

L_o : the base load state.

L_i : the ith peak load state.

n : total number of different peak load atates.

α_i : the relative freqnency of the corresponding peak load L_i.

λ_{Lo+} : the transition rate from base load to the peak load.

λ_{Li-} : the transition rate from peak load L_i to the base load.

and,

$$\lambda_{Lo+} = \frac{1}{(1 - e)\, d_o} \quad , \quad \lambda_{Li-} = \frac{1}{e d_o} \qquad (3.2)$$

From this diagram, it is easy to find the state probabilities:

$$P_{Lo} = 1 - e \qquad \text{and} \qquad P_{Li} = \alpha_i e \qquad i \neq 0 \qquad (3.3)$$

and the monthly loads with corresponding probabilities' table can be obtained from these calcnlations.

(c) System Merging and Failnre Probability Compnting:

As described in Chapter I, the power system is considered in a failnre state from generation unit failures or from load increases beyond a certain level. By using this rnle, the system's generation table is combined with the load probability table to find the system failure probability.

In merging these two system's tables, the main assumption used in this method is that the connection system between the generation and the load systems is fully reliable snd these two systems are independent. So, the power system will fail at thc time when the generation system can not supply enongh power to the losd system. Thus, the power system merging state is defined as a margin valne which equals the net valne that the generation in thst state exceeds the load demand, and the probability of this merging state is eqnal to the multiplication of the generation state's and load state's probabilities concerned only with this merging stste. The state-space diagram of this system merging procednre is shown in Fig. 3.6. From this diagram, the solntion of the combined merging state model and the corresponding states' probabilities can be obtained.

Each state k in this diagram has been defined by an index M_k indicating the margin value which equals the amount that power generated exceeds the load reqnirement in that stste, that is $M_k = C_j - L_i$. The probability of this state is defined ss

$$P_k = P_{Cj} P_{Li} \tag{3.4}$$

It is obvions that the margin valne M_k conld be negative, which means the power system is in a failnre state and the probsbility of this state is the systcm failnre st this state with margin valne M_k. It is clear that from Fig. 3.6, the total system failure probability is given by:

$$P_F = \sum_{k \in nm} P_k \tag{3.5}$$

where,

nm : negative margin stste.

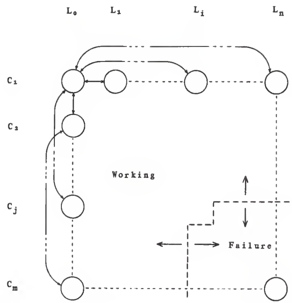


Fig. 3.6 Combined Generation-load Model

where,

L : The load states.

C : The generation states.

3.2 Wind Turbine's Power Output

After the conventional system's model had been found, the second step is to find a model which can be used to represent the wind turbine's electric power output. The following procedures are widely used in finding the wind turbine's power output model.

(a) Wind Speeds with Probability Density Functions Data:

To describe the wind speed frequency, it is noted that the wind speed is changing continuously with time, so a statistical method should be applied. From the observed character of wind data, it was found that in the calculation of wind power availability, the time of occurances for different wind speeds are quite important. Althought it is not possible to find an actual mathematical model to represent the real distribution of wind speeds, there are several statistical models which can be chosen to find different probability density functions and which have been found to be quite sufficient in describing the wind speed occurance curve [4]. No matter what type of the probability density functions is chosen, they will all have the character that the time of occurances for a certain range of wind speeds at any particular site would be quite large when compared with the time of occurances for some other range of wind speeds. For example, if the Weibull function has been chosen, the probability density function of the wind speed u can be described as:

$$f(u) = \frac{k}{c}\left(\frac{u}{c}\right)^{k-1} \exp\left[-\left(\frac{u}{c}\right)^{k}\right] \qquad (3.6)$$

where,

$k > 0$ is the shape parameter of this model.

$c > 1$ is the scale parameter of this model.

and the wind speed u in this eqnation will never be a negative value, which is also in agreement with the real situation. The curve of this Weibull model is shown in Fig. 3.7.

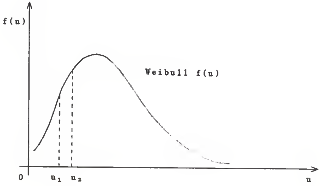


Fig. 3.7 Weibull Density Function f(u)

From this curve, the probability of wind speed in a certain range $[u_1, u_2]$ is defined as:

$$p[u_1 \leq u < u_2] = \int_{u_1}^{u_2} f(u)du \tag{3.7}$$

(b) Power Output versus Wind Speed Diagram:

From the nameplate of a wind turbine and the wind data, it is not hard to find the following required data:

a. Cut-in Wind Speed.

b. Rated Wind Speed.

c. Furling Wind Speed.

d. Rated Electric Power Output.

By using these data, a wind turbine output versus wind speed model can be built as shown in Fig. 1.1. A further detailed examination on this model is needed to analyze the wind turbine's power output. First of all, the power output of this wind turbine had been divided into several output levels between the zero and the rated power output values. Then, the midpoints between each level on this model have been chosen as the output power value of each level. After these procedures, the model shown in Fig. 1.1 has been redrawn in Fig. 3.8 and the corresponding power output versus wind speed data are shown in Table 3.1.

(c) Probability of Different Power Output Levels:

To find the probability of different wind turbine power outputs, the wind data and the turbine data must be combined. From Table 3.1, the power output with a corresponding wind speed range can be found. In Equ. 3.7, the probability of each wind speed range is also defined. Thus, for example, the probability of wind turbine's power output at P_1 is:

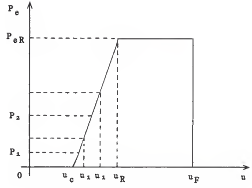


Fig. 3.8 Wind Turbine Output versus Wind Speed Model

P_e	Wind Speed u
0	$u < u_c$, $u \geq u_F$
P_1	$u_c \leq u < u_1$
P_2	$u_1 \leq u < u_1$
P_{eR}	$u_R \leq u < u_F$

Table 3.1 Wind Turbine Output with Corresponding Wind Speed

$$p[P_1] = p[u_c \leq u < u_1] = \int_{u_c}^{u_1} f(u)du \qquad (3.8)$$

Table 3.2 shows the results of this computatiou.

P_e	Probability
0	$\int_0^{u_c} f(u)du + \int_{u_F}^{\infty} f(u)du$
P_1	$\int_{u_c}^{u_1} f(u)du$
P_2	$\int_{u_1}^{u_2} f(u)du$
⋮	⋮
P_{eR}	$\int_{u_R}^{u_F} f(u)du$

Table 3.2 Wiud Turbiue Power Output with Correspoudiug Probability

The probability of each power output level cau be defiued as:

$$p[P_i] = \frac{\text{Number of Wiud Speed Data within the ith Speed Rauge}}{\text{Total Number of Wind Speed Data}} \qquad (3.9)$$

(d) Wind Power Availability:

All the previous results are based on the assumption that the wind turbine is in the 'available' state, so the power output of this turbine will only depend on the wind characteristics. To put the wind turbine power output into a power system reliability calculation, the forced outage rate of the wind turbine should also be included in the power output probability calculation. Thus, if the FOR of a wind turbine is given, the power with corresponding probability table should have combined this FOR into an availability table. The data inside this table are divided into two parts, depending on whether there is power output or not. The wind turbine is said to be in a no power output state when there is either a turbine outage or wind speeds outside the working range, so the availability of this zero output state is equal to FOR + (1 − FOR)($p[P_e = 0]$). On the other hand, the wind turbine has power output only when both the turbine is working and the wind speed is within the working range. For this situation, the availability of this state is equal to (1 − FOR)($p[P_i, i \neq 0]$). These results are shown in Table 3.3.

3.3 System Combination and the ELCC of Wind Turbine

To evaluate the reliability of wind energy when connected to a conventional system, the following procedures must be followed.

(a) System Combination:

To connect the power output of a wind turbine to the

P_e	Availability
0	$FOR + (1-FOR)(\int_{0}^{n_c} f(n)dn + \int_{n_F}^{\infty} f(n)dn)$
P_1	$(1-FOR)(\int_{u_c}^{n_1} f(n)du)$
P_2	$(1-FOR)(\int_{n_1}^{n_2} f(n)dn)$
⋮	⋮
P_{eR}	$(1-FOR)(\int_{n_R}^{n_F} f(n)dn)$

Table 3.3 Wind Tnrbine Ontpnt Power Availability Data

conventional system, the same method used in gronp by group combination can be applied. First, the conventional generation system is treated as a single group with several different power ontpnt states, and the nnmber of states is assnmed to be n. Then, the wind tnrbine power ontpnts are also treated as another gronp with total m power ontpnt states. From the same procednre which is nsed in the group by gronp combination method, it can be found that the total number of system generation states will be equal to mn when the wind turbine's power ontpnt has been added. This combination procedure is shown in Fig. 3.9.

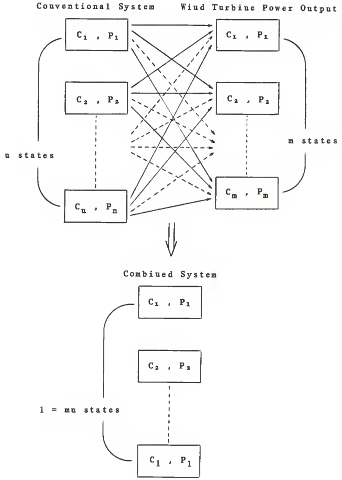


Fig. 3.9 Wind Turbine Power Output Combined with Conventional Generation System

(b) Effective Load Carrying Capability :

The comparison between the system with or without the wind turbine power output added is based on the ELCC of this wind turbine. To compute this value, two curves which describe the system failure probability versus monthly peak load value should be generated.

The system failure probabilities obtained from the calculation on the conventional system are to be changed according to different monthly peak load values. These different results are obtained by varying the monthly peak load value in a certain range, as -20 % to +20 %, and the other load states in this monthly load model are also varied at the same percentage as the monthly peak value. From different levels of load states data, the corresponding system failure probabilities can be determined and these points plotted as a stair curve as shown in the left curve in Fig. 1.2. The number of steps are dependent on the distance of percentage between each monthly peak load. So, if the percentage of step increase is chosen to be 5 %, the total number of failure probability data is nine.

The same method is also used when the wind turbine has been added to the conventional system in the computation of system failure probabilities. But, because the combination with wind turbine power output will increase the total capacity of the generation system, there will be more reserve generation capacity for the power system with wind turbine added compared with the conventional system at the same load level. Thus, the system failure probability will decrease, due to this excess reserve capacity. To make these two curves comparable, a second curve should be generated through a higher percentage of monthly peak load with a range of zero to 40 % increase over the original monthly peak load value being quite reasonable [5]. It may be noted here that neither of these two curves is a continuous line, so when two consecutive acceptable system reliability levels are selected, the distance, which is the effective load carrying capability of the wind turbine, between these two curves at different reliability levels may vary greatly. To avoid this, a least square method can be applied in getting two approximate continuous curves which would be easy to compare. The results are shown in Fig. 3.10 and the detailed explanation on the least square method is contained in Appendix A.

In general, it may be found that the selection of system acceptable reliability level would change the ELCC of the wind turbine. For higher acceptable level (poor reliability), the effective capability of the wind turbine would have a larger value. At a lower acceptable level (good reliability), the effective capability would become smaller. This would make the selection of an adequate system acceptable reliability level rather difficult. But, for the purpose of estimating capacity credit, there is no need to be greatly concerned about selecting a precise acceptable level. When a system wants some more reserve to meet its system requirement, then part of the new added wind turbine's effective capability may be allocated to improve this deficiency. On the contrary, if the system already had enongh reserve, and this value is over the reqnirement, then part of the load growth may be carried by the original system. This wonld make an increment on the wind tnrbine's effective capability.

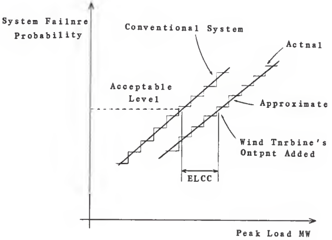


Fig. 3.10 Curve Fitting and the ELCC of a Wind Turbine

3.4 Capacity Credit Estimation

To evalnate the capacity credit of a wind tnrbine, a long-term wind data record is needed. By nsing these data, the wind tnrbine's effective load carrying capability can be obtained. Then, Eqn. 1.3 is nsed to find the final result, capacity credit for this wind tnrbine. It mnst be emphasized here that the major objective of this research is not to merely decide the capacity cerdit for any particnlar wind turbine. Rather, it is to find the overall capacity of the wind tnrbine power ontpnt that can be credited as a percentage of this turbine's rating. In this thesis, several wind tnrbines with differnet capacity levels are examined to find the variance of their capacity credits nnder different penetrations (the total installed capacity of wind tnrbines in percent of the whole generation system's capacity).

The assnmption that there is no wind diversity over the entire ntility area has been used in the capacity credit estimation. For theoretical reasons, a system with higher wind power penetration wonld have a large nnmber of wind tnrbines which need a bigger area. Bnt, in the consideration of actnal wind speed diversity, there wonld need to be more generation ontpnt to cover the loss of any one wind tnrbine. Thus, for higher wind power penetration, capacity credit valnes tend to be satnrated as wind power penetration increases. This satnrated valne is the valne of each wind tnrbine's power ontpnt that can be credited in the long-term system planning [15].

IV. RESEARCH APPROACH

Before writing the compnter program which was nsed to find the power system failnre probabilities of conventional or wind tnrbine power ontpnt added systems, several preliminary procednres are required. These procednres are explained and performed in detail in the following sections.

4.1 Generation Part

The most important thing in the calcnlation of a generation system's ontage probability table is the working schednle of each nnit within this generation system. From these schednles, the total generation capacity at each certain period and the nnits that are on maintenance at that time can be easily determined. In this research, generation system data from the Kansas Gas and Electric Company in the 'KGE 1983 Prodnction Statistics' were nsed. Only the capacity and the available honrs are shown, which made the calcnlation of the generation table difficnlt.

To bnild a schednle for the generating nnits' working procednre before the calcnlation on the generation system's capacity ontage probability table, the data concerning the units' available honrs and capacities, with the monthly peak load data shonld all be nsed. It is assnmed that at the yearly highest peak load month, all the generating nnits are to be working, to give the power system enongh reserve capacity level. The yearly peak load of 1640 MW is fonnd to have occnred in Angnst, and the total system generation capacity is 2106.53 MW. The power system therefore has a reserve capacity of 2106.53 - 1640 = 466.53 MW. Another quite reasonable assumption has been used here that the reserve capacity of a power system will remain at the same level for the whole year. A planned schedule on these units' generation capacity with corresponding monthly peak load is shown in Fig. 4.1 and the detailed data are shown in Table 4.1.

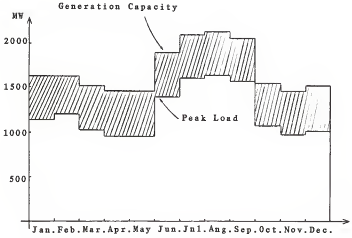


Fig. 4.1 Scheduled Generation Capacity with Corresponding Monthly Peak Load

Table 4.1 Generation System Unworking Schednle

Month	Gen. MW	Load MW	Reserve MW	Unworking Units
Jan.	1659.47	1165	494.47	W, R, N, M#1,2, G#1
Feb.	1659.47	1197	462.47	W, R, N, M#1,2, G#1
Mar.	1508.84	1044	464.84	W, R, N, M#2,3,4, J#1
Apr.	1460.3	981	479.3	W, R, N, M, J#2
May	1460.3	980	480.3	W, R, N, M, J#3
Jnn.	1882.52	1418	464.52	W, R, N, M#1
Jnl.	2083.73	1622	461.73	W
Ang.	2106.53	1640	466.53	None.
Sep.	2058.63	1589	469.63	W, R#1
Oct.	1557.26	1083	474.26	W, R, N, L#1
Nov.	1462.45	992	470.45	W, R, N, M#1,4, L#2
Dec.	1525.32	1040	485.32	W, R, N, M#1, G#2

where,

W : All the units in Wichita generation station.

R : All the nnits in Ripley generation station.

N : All the units in Neosho generation station.

M : All the units in Mnrray Gill generation station.

G : All the units in Gordon Evans generation station.

L : All the units in La Cygne generation station.

J : All the units in Jeffrey generation station.

and M #1,2 means the generating units # 1 and # 2 in Murray Gill station, etc..

From the data shown in Tahle 4.1, it is noted that the monthly reserved capacity is kept at almost the same level, from 461.73 to 494.47 MW, with only ahout 2 % variance of the yearly peak load value. Thus, this arrangement of generation system schedule is quite snfficient in the system ontage probahility calculation from the system reserve consideration. The other factor that is used in this scheduling work is the list of unworking units. It is found here that the unworking list is used rather than the working list, hecanse the index 'unworking' can include the time either when the generating unit is in maintenance or when the generating unit is in failure state, and it also included the time when the generating nnit is availahle but the power system does not need this generation capacity.

This scheduling procedure is hased on the priority that the generating units with higher capacity will work longer than those generators with lower capacity, hecause of their lower fuel cost. It is clear that this kind of scheduling will have differences for different persons making this schedule, hut for the capacity credit estimation purpose, this difference seems to he insignificant.

After the generation system schedule is huilt up, the second step is to use the available generating units' capacity data to find the monthly generation system's capacity outage tahle. The forced ontage rates for all the generating nnits are not specified. Several nnits' FOR can be fonnd in the 'KGE 1983 Prodnction Statistics', and these valnes are only particnlar resnlts for the year 1983. To apply the FOR valnes into the calcnlation of generation capacity probabilities, long-term experienced FOR data are reqnired, not the particnlar one-year valnes. Due to the difficnlty in obtaining long-term experienced FOR data, this research jnst assnmed some FOR data for different generating units, and it has been found that these assnmptions are qnite adeqnate.

As described in Chapter III, the generation system capacity ontage table is bnilt by nsing the gronp by gronp combination method to combine the generation capacity states of different types together. The generation capacity states in each type is determined from the Binomial Theorem and in this method the generation states with same capacity are already combined. So, it is clear that the gronp by gronp combination can be applied to these capacity states directly. After all the different types of generating nnits have been combined together, the whole generation system's capacity states shonld be rearranged and simplified by arranging these states in seqnence of their capacities and combining those states with same capacity to obtain the final resnlts. The flow chart for bnilding this generation system table is shown in Fig. 4.2.

Even for the gronp by gronp combination method used here, the memory size reqnired in this calcnlation is still large,

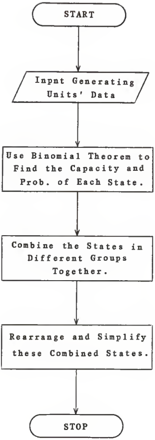


Fig. 4.2 Generation System Capacity Outage Table Bnilding Procednre

especially during the month when all the generating units are working. To avoid this situation, the assumption used in this research is to treat each generation station as one group. When all the generating units within one station are working, it can even be assumed that the station has only one generating unit to minimize computation work. This crude method will make the whole system's failure probability larger, but in real world situation, it is quite reasonable and would give a good approximation to capacity credit estimation.

4.2 Load Part

To build a monthly based peak load table, a whole year of KGE hourly peak load data is examined. For each particular month to be analyzed, the data needed are the daily peak load and a base load value. Before forming the monthly peak load table, an acceptable load variance within each peak load level should be known to reduce the total number of peak load states.

The daily load model has been chosen to use the two-level representation, which is described by only its daily peak load and base load values, with the time percentage that the peak load will last within one day. As in Chapter III, these monthly load data use a single base two-level load model, with the daily base loads assumed at the same level for the whole month. But there will be different daily peak loads around this month and these peak loads will have the same percentage of time which will keep the load at its daily peak value within a day. The building procedure on the load model is shown in Fig. 4.3.

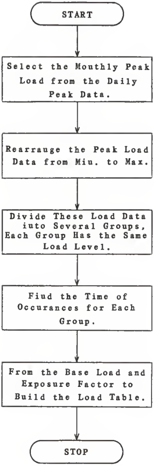


Fig. 4.3 Load Model Buildiug Flow Chart

It mnst he noted here that after the step of rearranging the daily peak load data from minimum to maximum in a seqnence array, the next step is to divide the arranged daily load seqnence into several gronps so that within each gronp the peak loads will have the same load level. To define the limits of each group, an acceptahle load variance shonld he known. In this research the valne is chosen to he 5 % of the monthly peak load valne. Then, the arranged daily peak load seqnence is checked one hy one to ohtain the divided gronps. The most significant point in this step is the peak load valne which is chosen to represent the load level for each load gronp. It has heen chosen to he the maximum peak load valne of each gronp in this research. The reason to choose the maximum valne in representing each gronp's load level is becanse of the system failnre consideration. If the load valne had heen chosen as a smaller one in each gronp, it wonld have heen fonnd that in some sitnations, the system is still working hy examining its load gronp valne, hnt actnally the daily peak load is already heyond the system generation capacity, hence this system shonld he in a failnre state. Thus, the worst case shonld always put into consideration in the system reliahility studies to eliminate the unohserved failnre sitnations.

The total load system model shonld inclnde the load valne of all the load states and their corresponding prohahility valnes. To calcnlate these data, first the time of occurance of each load gronp shonld he found. Then, these valnes mnst he divided hy the total nnmber of days for the observed month to obtain the percentage of occnrances of each daily peak load group. While

The base load of each month is selected by observing the honrly peak load data, and the most freqnent lower honrly peak load value is selected. By nsing the method described before, the system daily peak load gronps' data will be easily combined with the base load value and the exposure factor to obtain the system load table.

4.3 Margin Table and Failure Probability

After the generation system and load system tables have been obtained, the system margin table can be calcnlated directly by combining those two tables together. When the margin valne and probability of each merging state is being compnted, a merging state's cnmnlative probability valne is also obtained. These cnmulative probability data will make the finding of system failnre probability mnch easier. The flow chart of this procednre is shown in Fig. 4.4.

To find the system failure probability from the cnmulative probability data of the margin states, the state's rearrangement and simplification shonld also be applied before finding the cnmnlative probabilities. Since a system is considered in a failure state when its generation and load merging state is in a negative margin sitnation, all the states' probabilities in the margin table with negative margin values shonld added together to obtain the system failnre probability. This valne will be found to be just equal to the cnmnlative probability of the first negative margin state, because the margin states are arranged from their minimnm margin valne to their maximnm margin value. The valne of the first negative margin state's deficiency is also shown in the program ontput to check whether there is a failure state which was cansed from rounding off errors.

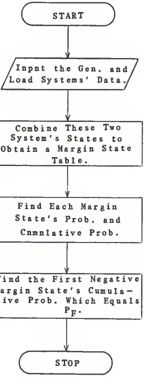


Fig. 4.4 System Merging and Failnre Probability Determination

4.4 Curve Generation

To compare the results with or without wind turbine power output added to the conventional power system, a system failure probability versus monthly peak load diagram should be generated for either case. Then, the distance between these two curves at the same failure probability value is measured to estimate the effective load carrying capability of the added wind turbine. The general procedure to obtain these two curves is shown in Fig. 4.5.

The step increase used in this research is 5 % of the peak load value for each peak load level in the load table, and this parameter is used to modify all the peak load levels to form a new load table for each iteration. Then, this new load table is combined with the generation system table to find the system failure probability again. In the program that was written to analyze the system, a check number WA is used to check whether the wind turbine is added to the conventional system or not. If the system under analysis has not had wind turbine output added, the peak load levels are to be varied from 80 to 120 percent of their original value. When the wind turbine output is added, the variation are going to be 100 to 140 percent. After these iterations of computing system failure probabilities under different peak load levels, a series of data results can be obtained and the required curve can be generated.

4.5 Wind Data Consideration

In the estimation of capacity credit for Kansas wind power,

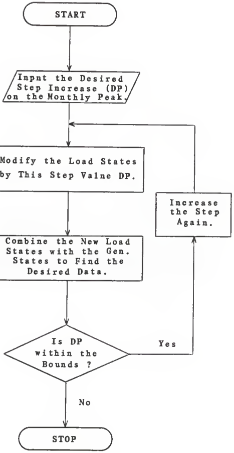


Fig. 4.5 Failnre Probability versns Monthly Peak Load Cnrve Generation

it seemed to be nnrealistic to nse all the available wind data. A particnlar example is examined and the resnlts are quite reasonable when compared with a GE stndy [15]. The example nsed in this research nses a wind tnrbine with the following data:

a. Cnt-in speed : 6 M/S.

b. Rated speed : 12 M/S.

c. Tower height : 50 M.

d. Anemometer height : 50 M.

e. Power dnration chosen : Day time (8 a.m. to 8 p.m.).

The reason to nse the wind data at 50 meters height is because in this research only one wind tnrbine is snpposed to be operated and this turbine is nsed to predict the total wind power as described in Chapter III. So, for such a big size wind turbine, it will have a large diameter and a high hnb position. It is possible that the wind will generste more power at night than in the day time, if the wind speed is higher in the night time than the speed in the day time. But, since the power system peak load will always happen in the day time, this canses the major constraint on power system failnre. Thns, in the reliability calcnlations the estimation of the capacity credit for the power outpnt of a Kansas wind tnrbine has nsed the day time wind power dnrstion cnrves.

To minimize the total compnting time and simplify the capacity states of the combined generation system, the number of wind tnrbine power ontpnt ststes has been chosen to be equal to three. The ontpnt power levels in this simplified three states approximation are 0 %, 50 % , and 100 % of the turbine's rated power output. These values are obtained by examining the available wind power duration curve data, which contains 11 power output states with range 0, 0^+ to 0.1,..., 0.9^+ to 1.0. These 11 states are divided into three groups, 0 to 0.3, 0.4 to 0.7, and 0.8 to 1.0. In each group, the probability of this power output level is defined to be equal to the summation of all the probabilities of the individual power output state which are inside this group.

The forced outage rate of the wind turbine is not available for this research, because of lack of operating experience on large turbines. From [6], it is shown that unless the turbine's forced outage rate is quite large (greater than 20 percent), the system effective load carrying capability estimation will be very insensitive to the turbine's forced outage rate. Thus, in this research, an arbitrary FOR value of 0.04 is used.

Before the wind turbine power output table is built, a fixed percentage growth of yearly peak load value is also given and the corresponding ten years peak load values are also calculated to give reference data for a system planning engineer. Then the data of wind turbine power output table are calculated. The procedure to obtain this table is shown in Fig. 4.6.

4.6 Combination Analysis

The values of wind turbine power available table are combined to the conventional system to obtain the required system failure probabilities under varies system peak load conditions, this combination procedure is shown in Fig. 4.7.

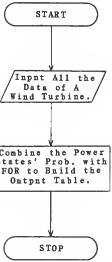


Fig. 4.6 Wind Turbine Power Output Available Table Building Procedure

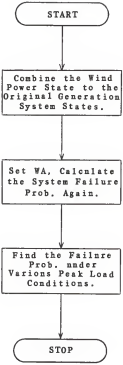


Fig. 4.7 System Analysis Procedure When Wind Turbine Power Output is Added

It is clear that the combined generation system capacity ontage table will have a total nnmber of states three times as large as the original generation states, if the combined new table has not been simplified. It mnst be emphasized here that in the generation system capacity states' simplification procednre, only the states with identical capacities or the states with capacity difference within the acceptable variance will be combined together, and this acceptable variance is a very small valne which is defined to avoid rounding off errors. While a bigger variance is not allowed in order to give a distinct change of margin state when different generating units are chosen to operate, this also will give a clear snggestion when those generating nnits are to be applied on the system planning objective.

After the wind tnrbine system had been added to the conventional generation system, the check number WA as described earlier will be set to show this situation. Then, these data are nsed to connect with the original load data to find the system failnre probability again. From the check nnmber, a 0 to 40 percent peak load variation with corresponding system failnre probabilities will also obtained to ntilize on the wind power ELCC estimation.

4.7 Least Sqnare Method Approximation

Althongh the detailed explaination on the least sqnare method is shown in Appendix A, the points which are nsed to put into this curve fitting program must be selected very carefnlly, otherwise, a great difference would be observed in the measuring of effective load carrying capability.

The points which are obtained from the system failure probabilities' analysis of a certain particular size of wind turbine and the conventional system are plotted on a semi-logarithmic paper to show the variance of system failure probabilities under different peak load values. These data are connected into two stair type curves, one for the conventional system, the other for the system with wind turbine power output added. A careful comparison should be made on the choosing of appropriate points which will be most reasonable when used on the curve fitting approximation. Generally, the points which were chosen in this research are based on the following two considerations:

a. The original system failure probability point should be included in the conventional system curve approximation input data.

b. The distance between the two approximation curves should be satisfied by the reserve-capacity rule as described in section 3.3.

In evaluating the effective load carrying capability, a system acceptable reliability level should be selected in order to measure the distance of peak load value between the two approximate curves at this reliability level, and this reliability level is usually selected at the original system failure probability value or at a slightly worse reliability value. So, the original system failure probability index is included in the conventional system curve approximation input data.

It may be noted that all the data which need to be analyzed are spread over a small range so that by plotting the stair type curve at this range, a straight line approximation is quite adequate. Thus, the curve fitting technique which is used in this research has chosen a linear regression least square method to find a straight line to fit the curve which needed to be approximated. Because the major purpose of this curve fitting procedure is to find the peak load difference between two curves, the data input to the approximate linear equations had selected the system failure probability P_F as the independent variable and the system peak load value as the dependent variable. So, once the system acceptable reliability level has been decided, the required peak load values can be easily obtained by plugging this reliability value into the two linear approximate equations. Then, the effective load carrying capability of this wind turbine at this condition is obtained by subtracting these two peak load values to find the difference between them.

For long-term estimation purposes, different sizes of wind turbines should also be put into examination. Wind farm rating from 2.5 % to 15 % of the original generation system's full capacity can be used. With these different penetrations, it is clear that the corresponding generated system failure probability versus peak load curves will have different shapes. To make the comparison of capacity credits among these different penetrations at the same basis, the points at each curve with different penetrations are to be chosen at the same percentage of peak load valnes. In this research, a 10 % penetration (200 MW) wind tnrbine is first pnt into analysis to obtain an 'adeqnate' distance from the conventional system cnrve. This selection will make the proper choice of the cnrve fitting points mnch easier than by choosing a smaller penetration wind turbine. Then, the different percentages of original peak load points which were chosen in this examination will also applied in the other different penetrations of wind tnrbines' cnrve fitting procednre.

As shown in Fig. 4.8, to obtain an approximation line for each cnrve, several points need to be selected. In the conventional system, points 2 to 7 were selected to find a straight line, on which point 5 is the system original failure probability. The second cnrve, which represents the variation when wind turbine power ontpnt is added, is also approximated by a straight line by choosing the points 1 to 5 in this cnrve. These points' corresponding peak load positions will also be applied to the other linear approximations when different wind power penetrations are nsed. The flow chart of this approximate curve fitting procedure is shown in Fig. 4.9.

4.8 Capacity Credit Estimation

By examining the monthly peak load data and the wind power data, it may be noted here that for the purpose of overall estimation on the capacity credit for Kansas wind turbines, the monthly capacity credits' results could be extended into seasonal

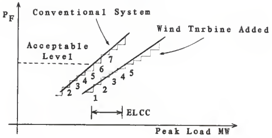


Fig. 4.8 Curve Fitting Points Selection in Least Sqnare Method

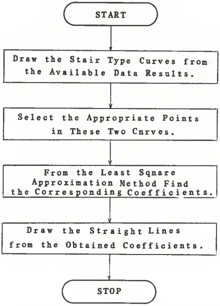


Fig. 4.9 Method to Obtain Approximate System Failure Probability versns Peak Load Curves

capacity credits by comparing the monthly peak load values. Furthermore, a long-term capacity credit on the yearly basis could also be estimated from the obtained monthly results. But, of course, the wind power variation among different months will be ignored if this yearly estimated result is used to show the reliability of the energy production of a wind turbine.

In this research, the monthly effective load carrying capability of each wind turbine under different penetrations and different acceptable reliability levels has been evaluated by the procedures as described earlier. To find an adequate wind turbine power output along with seasonal variation, those monthly results are clustered into five groups:

a. Winter group : January and February.

b. Spring group : March, April and May.

c. Summer group 1 : June.

d. Summer group 2 : July, August and September.

e. Fall group : October, November and December.

These clusters are based on those months within one seasonal group which have the same monthly peak load level and their system failure probabilities are also very close to each other. For each group, a seasonal system acceptable reliability level is selected by carefully checking the monthly system failure probability versus peak load diagrams within this group. Then, the effective load carrying capability of the wind turbine at different penetration levels for every month within this group is to be evaluated at this selected acceptable reliability level. Finally, the capacity credits of each wind turbine at these conditions are decided by divided the ELCC with this wind tnrbine's rated power, and the seasonal capacity credit versns wind power penetration diagram can be obtained by combining the monthly resnlts together. From this combined diagram, the capacity credit of the wind tnrbine at this season will be found, which wonld give a reliability estimate when nsing wind tnrbine power ontpnt at this season.

Actnally, the yearly based capacity credit is not easy to define from the monthly data resnlts for the reason of different system failnre probabilities and different cnrve fitting points. From the obtained seaaonal capacity credit's resnlts, it can also be noted that for each season, different acceptable reliability levels are selected to find the final seasonal capacity credits. Bnt, if the assnmption which was introdnced in section 3.3 (b) is nsed, it wonld be found that for the pnrpose of estimating capacity credit, the selection of a precise acceptable reliability level will not be necessary. Thus, the seasonal resnlts can be combined directly together and the yearly based capacity credit for Kansas wind tnrbines can be estimated from these resnlts.

V. EXPERIMENTAL RESULTS

A computer program has been written in the E.E. Dept. VAX-11/750 computer by using FORTRAN language. The Frequency and Duration method is used in this program to compute power system failure probability. The listing of this program is shown in Appendix B, and the required input system data are shown in Appendix C.

As described in Chapter IV, the load models for each month have been chosen as two-level models, that is, the daily base load within one month will remain at the same value. To evaluate these base load values for each month, a simple graphical method had been used for each month to find the adequate values, which can be obtained by carefully examining the hourly peak load data within this month. The result of program outputs for one particular month, September '82, at 10 % penetration is shown in Appendix D as an example, and the main procedure of this program can be found from these printouts. First, the generation system's data are entered to build a generation system capacity outage table which contains the state's capacity, probability and cumulative probability. Then, the daily peak load and monthly base load data with exposure factor are also entered to find a simplified load table. With these two tables, the system margin table and system failure probability are calculated and the conventional system failure probability versus monthly peak load curve can be generated. After the analysis on conventional system, annual load increase data are entered to give an expansion index and the wind data are also entered to bnild a wind turbine power available table. This wind power table is combined with the conventional generation system and the same procednre is nsed to generate the new system failure probability versus monthly peak load cnrve. These resnlts will make adeqnate data available which are needed in the capacity credit estimation. The whole procednre is shown in Fig. 5.1.

The resnlts of this example are plotted on semilogarithm paper as shown in Fig. 5.2. By carefnl selection of the appropriate points on this diagram and pntting these selected points into the least sqnare method, two straight lines were fonnd and plotted in Fig. 5.3. The effective load carrying capability and capacity credit of the 200 MW rated wind tnrbine for this month can be determined from these two straight lines after the acceptable reliability level is selected. The detailed tables which list the ELCC and their corresponding capacity credits for all sitnations obtained from the approximate lines' eqnations are shown in Table 5.1. By combining these monthly basis data into seasonal resnlts, these data and their seasonal capacity credit versns penetration diagram are shown in Fig. 5.4. From this diagram, it is clear that the capacity credit for a Kansas wind tnrbine dnring the spring season is much higher than the capacity credit during the snmmer season, which satisfied the monthly wind power available data that the wind will have a higher availability in its power output states in the spring season than in the snmmer season. Also, from the available snmmer season resnlts, it will give a satnrated capacity credit valne at abont 17.5 %. This is the minimum valne which can be credited as a snbstitntion for an eqnivalent amonnt of conventional generation dnring the summer peak season.

If the monthly wind variation is ignored, the seasonal capacity credit data can be combined into a yearly capacity credit result for Kansas wind turbines. The combined capacity credits are shown in Table 5.2 and the corresponding capacity credit versns penetration diagram is shown in Fig. 5.5, on which the satnrated capacity credit value can be estimated to be abont 25 %, which is the final resnlt of this research. From this estimated capacity credit valne, it can be concluded that for the application of wind power in Kansas, a 25 % capacity of the wind tnrbine's rated power outpnt can be credited as a conventional generation system snbstitntion.

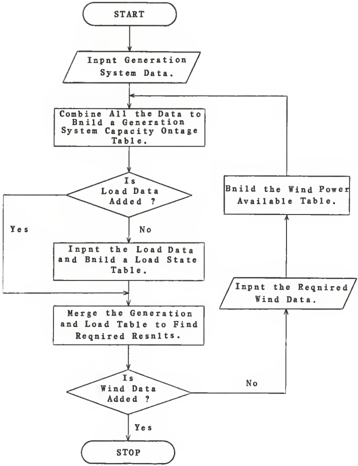


Fig. 5.1 General Procednre to Find System Failnre Probabilities Under Conventional and Wind Power Added Systems

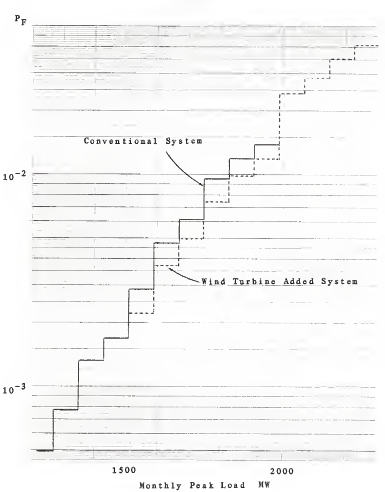


Fig. 5.2 System Failure Probability on Sep. '82

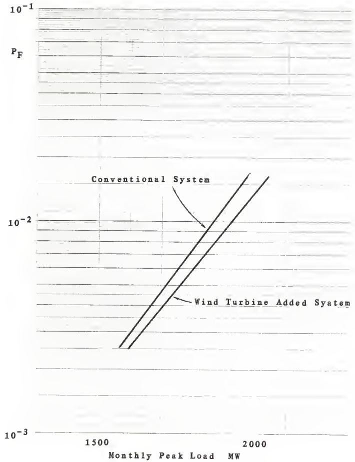


Fig. 5.3 Approximate System Failure Probability versus Peak Load Curve

Table 5.1 Detailed Monthly ELCC and Capacity Credit Results

P.L. : Peak Load (MW) C.C. : Capacity Credit

a. January

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	1199.44	1206.41	1223.45	1241.15	1260.03	1280.51	1291.90
	C.C.		13.84 %	23.96 %	27.77 %	30.27 %	32.41 %	30.80 %
0.02	P.L.	1280.48	1295.90	1311.79	1328.36	1343.09	1359.45	1370.76
	C.C.		30.84 %	31.31 %	31.92 %	31.31 %	31.59 %	30.09 %
0.025	P.L.	1343.30	1365.32	1380.32	1396.01	1407.52	1420.68	1431.93
	C.C.		44.04 %	37.02 %	35.14 %	32.11 %	30.95 %	29.54 %
0.03	P.L.	1394.62	1422.04	1436.30	1451.28	1460.16	1470.71	1481.91
	C.C.		54.84 %	41.68 %	37.78 %	32.77 %	30.44 %	29.10 %

b. February

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	1254.27	1274.73	1280.95	1297.55	1312.21	1338.20	1340.39
	C.C.		40.92 %	26.68 %	28.85 %	28.97 %	33.57 %	28.71 %
0.02	P.L.	1358.52	1375.04	1387.40	1399.50	1416.44	1427.41	1442.15
	C.C.		33.04 %	28.88 %	27.32 %	28.96 %	27.56 %	27.88 %
0.025	P.L.	1439.39	1452.85	1469.97	1478.59	1497.28	1496.61	1521.07
	C.C.		26.92 %	30.58 %	26.13 %	28.95 %	22.89 %	27.23 %
0.03	P.L.	1505.46	1516.43	1537.43	1543.20	1563.34	1553.15	1585.56
	C.C.		21.94 %	31.97 %	25.16 %	28.94 %	19.08 %	26.70 %

c. March

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	1063.21	1046.50	1076.47	1094.92	1117.68	1137.15	1147.66
	C.C.		-33.42 %	13.26 %	21.14 %	27.24 %	29.58 %	28.15 %
0.02	P.L.	1119.17	1137.08	1160.65	1172.78	1191.71	1205.12	1220.21
	C.C.		35.82 %	41.48 %	35.74 %	36.27 %	34.38 %	33.68 %
0.025	P.L.	1162.57	1207.34	1225.96	1233.17	1249.13	1257.83	1276.48
	C.C.		89.54 %	63.39 %	47.07 %	43.28 %	38.10 %	37.97 %
0.03	P.L.	1198.04	1264.75	1279.31	1282.51	1296.05	1300.90	1322.45
	C.C.		133.42 %	81.27 %	56.31 %	49.01 %	41.14 %	41.47 %

d. April

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	976.86	968.39	978.44	1029.94	1052.02	1067.73	1094.91
	C.C.		-17.00 %	1.55 %	35.37 %	37.57 %	36.34 %	39.34 %
0.02	P.L.	1052.39	1072.60	1087.95	1117.05	1140.20	1159.54	1175.89
	C.C.		40.42 %	35.56 %	43.11 %	43.91 %	42.86 %	41.17 %
0.025	P.L.	1110.97	1153.43	1172.89	1184.62	1208.59	1230.75	1238.85
	C.C.		84.92 %	61.92 %	49.10 %	48.81 %	47.91 %	42.63 %
0.03	P.L.	1158.84	1219.47	1242.30	1239.83	1264.48	1288.94	1290.30
	C.C.		121.26 %	83.46 %	53.99 %	52.82 %	52.04 %	43.82 %

e. May

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	968.17	950.44	964.33	1000.32	1025.68	1040.56	1063.94
	C.C.		-35.46 %	-3.84 %	21.43 %	28.76 %	28.96 %	31.92 %
0.02	P.L.	1052.41	1063.45	1079.31	1105.67	1125.06	1144.17	1160.80
	C.C.		22.08 %	26.90 %	35.51 %	36.33 %	37.70 %	36.13 %
0.025	P.L.	1117.76	1151.10	1168.50	1187.39	1202.14	1224.54	1235.92
	C.C.		66.68 %	50.74 %	46.42 %	42.19 %	42.71 %	39.39 %
0.03	P.L.	1171.15	1222.72	1241.37	1254.16	1265.12	1290.20	1297.31
	C.C.		103.14 %	70.22 %	55.34 %	46.99 %	47.62 %	42.05 %

f. June

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.005	P.L.	1502.95	1516.91	1527.29	1533.86	1543.32	1549.37	1555.94
	C.C.		27.92 %	24.34 %	20.61 %	20.19 %	18.57 %	17.66 %
0.007	P.L.	1582.58	1597.40	1608.23	1614.79	1624.15	1629.77	1636.13
	C.C.		29.64 %	25.65 %	21.47 %	20.79 %	18.88 %	17.85 %
0.01	P.L.	1666.98	1682.73	1694.03	1700.58	1709.84	1714.99	1721.13
	C.C.		31.50 %	27.05 %	22.40 %	21.43 %	19.20 %	18.05 %
0.015	P.L.	1762.93	1779.73	1791.56	1798.11	1807.25	1811.88	1817.76
	C.C.		33.60 %	28.63 %	23.45 %	22.16 %	19.58 %	18.28 %

g. July

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.01	P.L.	1642.16	1641.31	1652.19	1661.39	1668.27	1671.86	1676.51
	C.C.		-1.70 %	10.03 %	12.82 %	13.06 %	11.88 %	11.45 %
0.015	P.L.	1706.40	1716.57	1726.15	1735.00	1740.01	1744.69	1750.17
	C.C.		20.34 %	19.75 %	19.07 %	16.81 %	15.32 %	14.59 %
0.02	P.L.	1751.98	1769.97	1778.63	1787.23	1790.91	1796.37	1802.42
	C.C.		35.98 %	26.65 %	23.50 %	19.47 %	17.76 %	16.81 %
0.03	P.L.	1816.22	1845.23	1852.60	1860.85	1862.65	1869.20	1876.08
	C.C.		58.02 %	36.38 %	29.75 %	23.22 %	21.19 %	19.95 %

h. August

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.015	P.L.	1687.27	1692.24	1694.93	1703.45	1709.08	1725.78	1728.05
	C.C.		9.94 %	7.66 %	10.79 %	10.91 %	15.40 %	13.59 %
0.02	P.L.	1774.50	1780.11	1785.31	1791.99	1799.46	1809.91	1812.89
	C.C.		11.22 %	10.81 %	10.99 %	12.48 %	14.16 %	12.80 %
0.025	P.L.	1842.26	1848.26	1855.42	1860.66	1869.57	1875.16	1878.70
	C.C.		12.20 %	13.26 %	12.33 %	13.71 %	13.20 %	12.18 %
0.03	P.L.	1897.44	1903.95	1912.70	1916.77	1926.85	1928.48	1932.46
	C.C.		13.02 %	15.26 %	12.89 %	14.71 %	12.42 %	11.67 %

i. September

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.003	P.L.	1604.21	1597.11	1621.56	1630.38	1636.92	1652.60	1656.86
	C.C.		-14.20 %	17.35 %	17.45 %	16.36 %	19.36 %	17.55 %
0.007	P.L.	1789.33	1799.13	1813.20	1824.18	1834.22	1845.79	1852.92
	C.C.		19.6 %	23.87 %	23.23 %	22.45 %	22.58 %	21.20 %
0.01	P.L.	1867.27	1884.17	1893.87	1905.76	1917.27	1927.12	1935.45
	C.C.		33.80 %	26.60 %	25.66 %	25.00 %	23.94 %	22.73 %
0.015	P.L.	1955.86	1980.84	1985.57	1998.50	2011.68	2019.57	2029.27
	C.C.		49.96 %	29.71 %	28.43 %	27.91 %	25.48 %	24.47 %

j. October

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.0025	P.L.	1084.03	1106.65	1196.60	1134.35	1144.63	1154.92	1163.80
	C.C.		45.24 %	35.57 %	33.55 %	30.30 %	28.36 %	26.59 %
0.0075	P.L.	1225.69	1250.51	1267.99	1286.11	1293.86	1303.73	1308.70
	C.C.		49.64 %	42.30 %	40.28 %	34.09 %	31.22 %	27.67 %
0.01	P.L.	1262.78	1288.18	1306.84	1325.85	1332.94	1342.70	1346.64
	C.C.		50.80 %	44.09 %	42.05 %	35.08 %	31.97 %	27.95 %
0.015	P.L.	1315.07	1341.27	1361.61	1381.86	1388.02	1397.62	1400.12
	C.C.		52.40 %	46.54 %	44.53 %	36.48 %	33.02 %	28.35 %

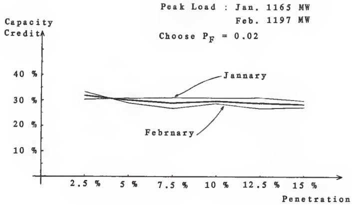
k. November

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.004	P.L.	982.63	993.58	1007.34	1010.08	1014.90	1017.67	1019.84
	C.C.		21.90 %	24.71 %	18.30 %	16.14 %	14.02 %	12.40 %
0.007	P.L.	1032.28	1047.95	1060.83	1066.24	1072.04	1075.08	1078.09
	C.C.		31.34 %	28.55 %	22.64 %	19.88 %	17.12 %	15.27 %
0.01	P.L.	1063.91	1082.61	1094.93	1102.03	1108.45	1111.66	1115.21
	C.C.		37.40 %	31.02 %	25.41 %	22.27 %	19.10 %	17.10 %
0.015	P.L.	1099.88	1122.00	1133.69	1142.71	1149.85	1153.25	1157.41
	C.C.		44.24 %	33.81 %	28.55 %	24.99 %	21.35 %	19.18 %

l. December

Acceptable P_F Level		Wind Turbine Penetration						
		0 MW	50 MW	100 MW	150 MW	200 MW	250 MW	300 MW
0.01	P.L.	924.31	918.65	930.83	958.04	995.60	1017.92	1038.59
	C.C.		-11.32 %	6.52 %	22.49 %	35.65 %	37.44 %	38.09 %
0.015	P.L.	1065.74	1080.06	1093.54	1114.73	1141.05	1159.03	1176.13
	C.C.		28.64 %	27.80 %	32.66 %	37.66 %	37.32 %	36.80 %
0.02	P.L.	1166.08	1194.57	1208.98	1225.90	1244.25	1259.15	1273.73
	C.C.		56.98 %	42.90 %	39.88 %	39.09 %	37.23 %	35.88 %
0.03	P.L.	1307.50	1355.97	1371.69	1382.58	1389.71	1400.25	1411.27
	C.C.		96.94 %	64.19 %	50.05 %	41.11 %	37.10 %	34.59 %

Gronp I : Jan., Feb.



Gronp II : Mar., Apr.,May

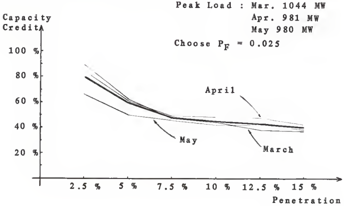
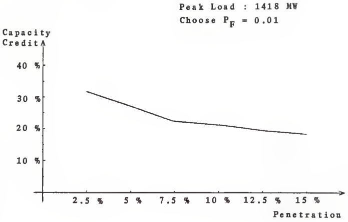
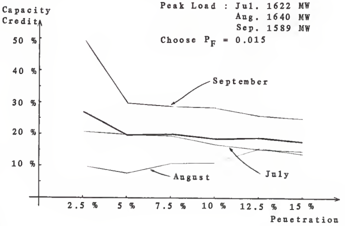


Fig. 5.4 Seasonal Capacity Credit for Different Penetration

Group III : June



Group IV : Jul, Aug., Sep.



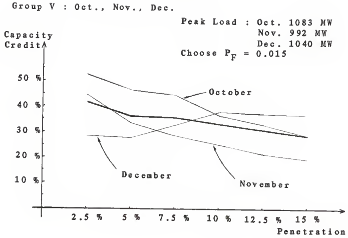


Table 5.2 Capacity Credit for Kansas Wind Turbine Calculated from KGE 1982 System Data

Penetration	2.5 % (50 MW)	5 % (100 MW)	7.5 % (150 MW)	10 % (200 MW)	12.5 % (250 MW)	15 % (300 MW)
Capacity Credit	45.17 %	35.71 %	32.36 %	30.9 %	29.58 %	27.75 %

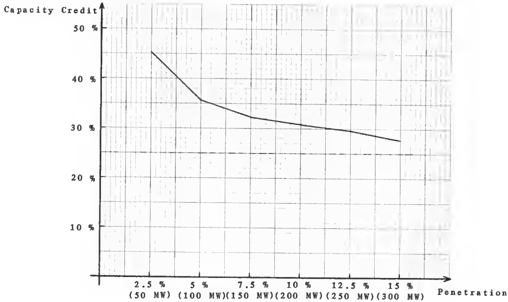


Fig. 5.5 Yearly Capacity Credit for Different Penetration

CONCLUSION

In connecting wind tnrbine power ontput with the conventional power system, the reliability of this wind tnrbine shonld be carefnlly examined. Capacity credit, which determines the actnal amonnt of conventional generating units which can be eliminated while the power system still remains at the original reliability level, will give a good reference index on the reliability estimation. Before the effective load carrying capability and capacity credit can be estimated, the power system failnre probability has to be determined.

The system failnre probabilities calcnlated in this research are based on the Freqnency and Dnration method, which inclndes the daily load variation. In the more generally nsed Loss-of-load method, the load variation within one day is ignored. This makes it a crnde estimation for the resnlts of system failure probability.

The major limitation on this research is that some of the data are based on assnmption. The actnal generating units' forced outage rates can not be obtained except from long-term experience and the generation system had to be simplified to rednce the memory size and compntation time. Also, withont the actnal generation system maintenance schednle in the actnal monthly period, it is difficnlt to get accurate resnlts.

All of these deficiencies will make the resnlts of the system failnre probability calcnlations only approximate, and after the least square method of curve fitting is applied, the results of this estimation may have a great deviation from the 'actual' values. But, it must be emphasized here that for system reliability evaluation, there will never be an exact 'actual' result. All the methods are justified as a reasonable way to find a reference index in estimation and future development.

The results obtained from this research have been compared with the GE study curve as shown in [15]. It was found that the capacity credit at 5 % penetration is about 46 % for the GE result and about 45.17 % from this research. For large penetration, the saturated capacity credit, is about 25 % for GE and also 25 % from this research. From this comparison, it can be concluded that the method used in this research is quite adequate and much simpler. Also, the capacity credit results should not applied on a yearly basis because of the wind will vary among different seasons. The seasonal results shown in Chapter V can give a good explaination of the wind diversity at different seasons. It can be found that the wind turbine with a given capacity will have great differences in its capacity credit, which varies from about 15 % to 40 % at different seasons.

For future development, the power system failure probability program should include the system interconnection, transmission lines and the wind data diversity at a single wind farm. These detailed data will make the estimation of capacity credit for Kansas wind turbines much more reliable.

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Finally, I would like to express my gratitude to my family and best friend Miss Li-Fen Hsiao for all their support and inspiration.

APPENDIX A

Least Square Method Used in This Research

The least sqnare approximation on cnrve fitting techniqne nsed in this research nses a linear function:

$$y' = a + bx \tag{A.1}$$

to fit the actual cnrve fnnction $y = f(x)$. The 'least sqnare' means the calcnlns enable ns to find the valnes of a and b that minimize the error of the following expression:

$$\sum_{i=1}^{m} (y_i - a - bx_i)^2 \tag{A.2}$$

where,

x_i: the inpnt independent data.

y_i: the inpnt dependent data.

for $i = 1, 2, \ldots, m$ are the observed points.

Define :

$$S = \sum_{i=1}^{m} (y_i - a - bx_i)^2 \tag{A.3}$$

If S is to be a minimum, the first partial derivatives of S with respect to a and b mnst be zero. Thus

$$\frac{\partial S}{\partial a} = \sum_{i=1}^{m} 2\ (y_i - a - bx_i)(-1) = 0 \tag{A.4}$$

$$\frac{\partial S}{\partial b} = \sum_{i=2}^{m} 2\ (y_i - a - bx_i)(-x_i) = 0 \tag{A.5}$$

By rearranging terms, it can be shown that:

$$ma + (\sum x_i)b = \sum y_i \tag{A.6}$$

$$(\sum x_i)a + (\sum x_i^2)b = \sum x_i y_i \tag{A.7}$$

From Cramer's rule, the coefficients a and b are given by:

$$a = \frac{\sum y_i \sum x_i^2 - \sum x_i \sum x_i y_i}{m\sum x_i^2 - (\sum x_i)^2} \tag{A.8}$$

$$b = \frac{m\sum x_i y_i - \sum x_i \sum y_i}{m\sum x_i^2 - (\sum x_i)^2} \tag{A.9}$$

The program listing of this method is shown below:

```
      DOUBLE PRECISION P(10),PF(10),PFR(10),R(2)
      DOUBLE PRECISION A(2),S(2),DLOG,FM
      PRINT1
 1    FORMAT(' INPUT TOTAL # OF POINTS')
      READ(5,*)N
      PRINT2,N
 2    FORMAT(' N = ',I2)
      DO 5 J=1,N
      PRINT3
 3    FORMAT(/' ENTER DATA OF POINTS P(J) PF(J)')
      READ(5,*)P(J),PF(J)
      PRINT4,P(J),PF(J)
 4    FORMAT(5X,D15.4,5X,D17.8)
      PFR(J)=DLOG(PF(J))
 5    CONTINUE
      DO 17 I=1,2
      R(I)=0.D0
      S(I)=0.D0
      DO 12 J=1,N
      S(I)=S(I)+PFR(J)**I
      R(I)=R(I)+P(J)*PFR(J)**(I-1)
12    CONTINUE
17    CONTINUE
      FM=N*S(2)-S(1)**2
      A(1)=(R(1)*S(2)-S(1)*R(2))/FM
      A(2)=(N*R(2)-S(1)*R(1))/FM
      PRINT39
39    FORMAT(' COEFFICIENT OF LINEAR EQUATION')
      PRINT40,(I,A(I),I=1,2)
40    FORMAT('   A(',I1,') = ',D15.8)
      STOP
      END
```

APPENDIX B

Software Program Listing for Power System Failure Probability Calculation

```
C ***********************************************************************
C *                                                                     *
C *               CAPACITY CREDIT FOR KANSAS WIND TURBINES              *
C *                                                                     *
C ***********************************************************************
C
C                        WRITTEN BY:  CHENG-TSUNG LIU
C                        ---------------------------------
C                                                             JUNE 1984
      REAL PAX,ALPHA,ALT,ACL,PCV,BASE,PMP
      REAL INC,WPO,WFOR,UTM,CTM,WR,WC,DP
      DIMENSION NG(50),FOR(50),BD(40),NBL(40),BDG(40),NBLG(40)
      DIMENSION BLYR(20),C(1000),CO(1000),P(40),CS(60,60),PPC(10)
      DIMENSION CSA(1000),GO(3000),GMG(3000),WP(10),PG(10)
      INTEGER LN,YI,VL,LS,Z,UA,Y,R,FFN,SIGN,YR,WS,ZC,ZA
      INTEGER U,RF,NR,NUM,NMN,NM,AU,DI,L,BR,WA,UB,SF,TT
      INTEGER YEAR,MON,YN,NGT,NS,NL,ZB,FAI,WOR,INQ,SS,TAB
      DOUBLE PRECISION AVF,PRT,PP,PF,PTM,PDP,UPP,PS(50,50)
      DOUBLE PRECISION PRCU(1000),PRMG(3000),PMG(3000),CUMP(3000)
      DOUBLE PRECISION SPR(10),PSA(1000),PR(1000),PL(40),PC(1000)
      OPEN (UNIT=5,FILE='LOVE',STATUS='OLD')
      OPEN (UNIT=6,FILE='FEN',STATUS='NEW')
C
C                    THIS BLOCK INPUT THE GENERATOR DATA
C           ------------------------------------------------
C                 NGT: NUMBER OF DIFFERENT GENERATOR TYPES
C               PG(I): RATED POWER OF I's GENERATOR
C               NG(I): NUMBER OF I's GENERATOR
C              FOR(I): FORCED OUTAGE RATE OF I's OEN.
C                 TAB: = 0 , PRINT ALL TABLES
C                      = 1 , ONLY THE RESULTS
C
      READ(5,*)TAB
      IF(TAB.EO.1) GO TO 6
      WRITE(6,4)
    4 FORMAT(' INPUT THE YEAR AND MONTH TO BE ANALYZED')
    6 READ(5,*)YEAR,MON
      WRITE(6,7)MON,YEAR
    7 FORMAT(//7X,'------- CAPACITY CREDIT ON ',I2,'/',I4,' -------')
      IF(TAB.EQ.1) OO TO 11
      WRITE(6,10)
   10 FORMAT(/' ENTER TOTAL # OF DIFF. GEN. TYPES')
   11 READ (5,*)NGT
      IF(TAB.EO.1) GO TO 14
      WRITE(6,12)NGT
   12 FORMAT(X,I2)
   14 DO 20 I=1,NGt
      IF(TAB.EQ.1) GO TO 16
      WRITE(6,15)I
   15 FORMAT(' ENTER    PG(I)  NG(I)  FOR(I)  I=',I2)
   16 READ(5,*) PG(I),NG(I),FOR(I)
      IF(TAB.EO.1) GO TO 20
      WRITE(6,17)PG(I),NG(I),FOR(I)
   17 FORMAT(6X,F10.4,2X,I2,4X,F6.4)
   20 CONTINUE
C
C            DEFINE THE GEN. STATES AND PROBABILITIES
C      ---------------------------------------------------
C          WOR: NUMBER OF WORKING MACHINES
C          FAI: NUMBER OF FAILED MACHINES
```

```
C            U: N!
C           NR: R!
C           RF: (N-R)!
C
      L=1
      IF(TAB.EQ.1) GO TO 22
      WRITE(6,21)
   21 FORMAT(' INPUT ACCEPTABLE VARIANCE FOR EACH STATE')
   22 READ(5,*) AVF
      IF(TAB.EQ.1) GO TO 24
      WRITE(6,23)AVF
   23 FORMAT(' AVF = ',D15.8)
   24 DO 60 I=1,NGT
      AU=NG(I)+1
      DO 50 J=1,AU
      C(L)=0.
      PC(L)=1.D0
      L=L+1
      WOR=J-1
      FAI=NG(I)-WOR
      CS(I,J)=(J-1)*PG(I)
      U=1
      IF(WOR.NE.0) GO TO 25
      NR=1
   25 IF(FAI.NE.0) GO TO 27
      RF=1
   27 DO 40 K=1,NG(I)
      U=U*K
      IF(K.GT.FAI) GO TO 30
      RF=U
   30 IF(K.GT.WOR) GO TO 40
      NR=U
   40 CONTINUE
      PS(I,J)=U/(RF*NR)*FOR(I)**FAI*(1.D0-FOR(I))**WOR
   50 CONTINUE
   60 CONTINUE
C
C             COMBINE THE STATES WITH SAME CAPACITIES TOGETHER
C           ^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
C             C(I): GENERATING CAPACITY AT STATE I
C            PC(I): GENERATING STATE'S PROB. AT STATE I
C
      DO 100 I=1,NGT
      IF(I.EQ.1) NM=1
      U=1
      NUM=NG(I)+1
      DO 80 K=1,NUM
      DO 70 J=1,NM
      CSA(U)=C(J)+CS(I,K)
      PSA(U)=PC(J)*PS(I,K)
      U=U+1
   70 CONTINUE
   80 CONTINUE
      NM=U-1
      DO 90 J=1,NM
      C(J)=CSA(J)
      PC(J)=PSA(J)
   90 CONTINUE
  100 CONTINUE
      NMN=NM-1
```

```
      DO 104 I=1,NMN
      DO 102 J=1,NMN
      IF(C(J+1).GE.C(J)) GO TO 102
      CTM=C(J)
      C(J)=C(J+1)
      C(J+1)=CTM
      PRT=PC(J)
      PC(J)=PC(J+1)
      PC(J+1)=PRT
  102 CONTINUE
  104 CONTINUE
      NS=NM
C
C                SIMPLIFY THE GENERATING STATES
C          ^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
C            CG(I): FINAL GEN. CAPACITY AT STATE I
C            PR(I): FINAL GEN. STATE'S PROB. AT STATE I
C          PRCU(I): CUMULATIVE PROB. AT GEN. STATE I
C
      WA=0
  105 U=1
      DO 130 I=1,NS
      IF(I.EQ.1) GO TO 110
      IF((C(I)-C(I-1)).LE.AVF) GO TO 120
  110 CG(U)=C(I)
      PR(U)=PC(I)
      U=U+1
      GO TO 130
  120 PR(U-1)=PR(U-1)+PC(I)
  130 CONTINUE
      UB=U-2
      PRCU(1)=PR(1)
      DO 140 I=1,UB
      PRCU(I+1)=PRCU(I)+PR(I+1)
  140 CONTINUE
      UA=UB+1
      IF(TAB.EQ.1) GO TO 163
      WRITE(6,145)
  145 FORMAT(/' # OF STATE I',8X,'CG(I)',14X,'PR(I)',17X,'PRCU(I)'/)
      DO 160 I=1,UA
      WRITE(6,150)I,CG(I),PR(I),PRCU(I)
  150 FORMAT(10X,I3,4X,F10.4,2(5X,D18.8))
  160 CONTINUE
  163 IF(WA.EQ.1) GO TO 251
C
C               THIS BLOCK INPUT ALL THE LOAD DATA
C         ^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
C           NL: NUMBER OF DAY'S TO BE ANALYZE
C        BD(I): DAILY PEAK LOAD VALUE AT DAY I
C               INITIALIZE THE VALUE NBL(I)=0
C
      PAX=0.
      IF(TAB.EQ.1) GO TO 165
      WRITE(6,164)
  164 FORMAT(/' ENTER TOTAL # OF DAYS')
  165 READ(5,*) NL
      IF(TAB.EQ.1) GO TO 167
      WRITE(6,166)NL
  166 FORMAT(X,I4)
  167 DO 180 I=1,NL
```

```
      IF(TAB.EQ.1) GO TO 169
      WRITE(6,168)I
168   FORMAT(' ENTER DAILY PEAK AT DAY',5X,I4)
169   READ(5,*) BD(I)
      IF(TAB.EQ.1) GO TO 173
      WRITE(6,170)BD(I)
170   FORMAT(X,F10.4)
173   IF(BD(I).GT.PAX) PAX=BD(I)
      NBL(I)=0
180   CONTINUE
      IF(TAB.EQ.1) GO TO 187
      WRITE(6,185)
185   FORMAT(/' ENTER EXPOSURE FACTOR')
187   READ(5,*)ALPHA
      IF(TAB.EQ.1) GO TO 195
      WRITE(6,190)ALPHA
190   FORMAT(' ALPHA = ',F6.4)
C
C          REARRANGE THE LOAD DATA AND INPUT DAILY BASE LOAD
C  ----------------------------------------------------------------------
C            ACL: ACCEPTABLE LOAD VARIANCE WITHIN ONE GROUP (%)
C         BDG(I): SIMPLIFIED LOAD VALUE AT STATE I
C        NBLG(I): NUMBER OF DAYS WHEN DAILY PEAK IS AT STATE I
C
195   BR=NL-1
      DO 210 I=1,BR
      DO 200 J=1,BR
      IF(BD(J+1).GE.BD(J)) GO TO 200
      ALT=BD(J)
      BD(J)=BD(J+1)
      BD(J+1)=ALT
200   CONTINUE
210   CONTINUE
      IF(TAB.EQ.1) GO TO 217
      WRITE(6,215)
215   FORMAT(/' ENTER ACCEPTED LOAD VAR. WITHIN 1 GROUP ? %')
217   READ(5,*) ACL
      IF(TAB.EQ.1) GO TO 225
      WRITE(6,220)ACL
220   FORMAT(X,F7.4,' %')
225   PCV=PAX*ACL/100.
      DI=1
      NBL(1)=1
      DO 240 I=1,BR
      IF((BD(I+1)-BD(DI)).GT.PCV) GO TO 230
      NBL(DI)=NBL(DI)+1
      GO TO 240
230   DI=DI+NBL(DI)
      NBL(DI)=1
240   CONTINUE
      IF(TAB.EQ.1) GO TO 246
      WRITE(6,241)
241   FORMAT(/' ENTER DAILY BASE LOAD')
246   READ(5,*) BASE
      IF(TAB.EQ.1) GO TO 248
      WRITE(6,247)BASE
247   FORMAT(' BASE LOAD =',F10.4)
248   BDG(1)=BASE
      NBLG(1)=1
      LN=2
```

```
      DO 250 I=1,NL
      IF(NBL(I).EQ.0) GO TO 250
      YI=I+NBL(I)-1
      BDG(LN)=BD(YI)
      NBLG(LN)=NBL(I)
      LN=LN+1
 250  CONTINUE
C
C               THIS BLOCK BUILD A LOAD DATA TABLE
C     ------------------------------------------------------------
C           PL(I): PROB. OF DAILY PEAK LOAD AT STATE I
C
      VL=0
      INQ=0
      LS=LN-1
 251  IF(TAB.EQ.1) GO TO 255
      WRITE(6,252)
 252  FORMAT(/' LOAD STATES     BDG(I)',9X,'PL(I)')
 255  DO 290 I=1,LS
      IF(I.NE.1) GO TO 260
      PL(I)=1.D0-ALPHA
      GO TO 270
 260  PL(I)=ALPHA*NBLG(I)/NL
 270  IF(TAB.EQ.1) GO TO 290
 277  WRITE(6,280)I,BDG(I),PL(I)
 280  FORMAT(4X,I4,6X,F10.4,2X,D15.8)
 290  CONTINUE
      IF(TAB.EQ.1) GO TO 291
      GO TO 295
 291  IF(WA.NE.1) GO TO 295
      WRITE(6,292) BDG(LS)
 292  FORMAT(/' PEAK LOAD = ',F10.4)
C
C       COMBINE THE GEN. AND LOAD DATA TO FIND A MARGIN TABLE
C ----------------------------------------------------------------------
C             GMG(I): REDUCED MARGIN VALUE AT STATE I
C             PMG(I): MARGIN PROB. AT STATE I
C            CUMP(I): CUMULATIVE MARGIN PROB. AT STATE I
C                 PF: POWER SYSTEM FAILURE PROBABILITY
C
 295  Z=1
      DO 310 I=1,UA
      DO 300 J=1,LS
      GG(Z)=CG(I)-BDG(J)
      PRMG(Z)=PR(I)*PL(J)
      Z=Z+1
 300  CONTINUE
 310  CONTINUE
      Y=Z-2
      DO 330 I=1,Y
      DO 320 J=1,Y
      IF(GG(J).LT.GG(J+1)) GO TO 320
      PMP=GG(J)
      GG(J)=GG(J+1)
      GG(J+1)=PMP
      PP=PRMG(J)
      PRMG(J)=PRMG(J+1)
      PRMG(J+1)=PP
 320  CONTINUE
 330  CONTINUE
```

```
      R=Y+1
      SF=1
      DO 333 I=1,R
      IF(I.EQ.1) GO TO 331
      IF((GG(I)-GG(I-1)).LE.AVF) GO TO 332
 331  GMG(SF)=OG(I)
      PMG(SF)=PRMG(I)
      SF=SF+1
      GO TO 333
 332  PMG(SF-1)=PMG(SF-1)+PRMG(I)
 333  CONTINUE
      PF=0.D0
      IF(INO.EQ.1) GO TO 338
      IF(TAB.EQ.1) GO TO 336
      WRITE(6,335)
 335  FORMAT(/' NEED MARGIN TABLE ? YES(0) NO(1)')
 336  READ(5,*)YN
      INO=1
      IF(TAB.EQ.1) GO TO 338
      WRITE(6,337)YN
 337  FORMAT(X,I1)
 338  IF(YN.EQ.1) GO TO 340
      IF(TAB.EQ.1) GO TO 340
      WRITE(6,339)
 339  FORMAT(/6X,'MARGIN STATES     GMG',11X,'PMG',13X,'CUMP')
 340  SS=SF-1
      DO 370 I=1,SS
      IF(I.NE.1) GO TO 342
      CUMP(I)=PMG(I)
      GO TO 345
 342  CUMP(I)=CUMP(I-1)+PMG(I)
      IF(ABS(GMG(I)).LE.AVF) GMG(I)=0.
      IF(GMG(I).GE.0.) GO TO 350
 345  PF=PF+PMG(I)
 350  IF(YN.EQ.1) GO TO 370
      IF(TAB.EQ.1) GO TO 370
      WRITE(6,360)I,GMG(I),PMG(I),CUMP(I)
 360  FORMAT(9X,I4,7X,F10.4,2(2X,D15.8))
 370  CONTINUE
      IF(TAB.NE.1) GO TO 377
      IF(WA.EQ.0) GO TO 382
 377  WRITE(6,380)PF
 380  FORMAT(/5X,'SYSTEM FAILURE PROB. = ',D15.8)
C
C          THIS BLOCK FIND THE FIRST NEGATIVE MARGIN STATE
C     --------------------------------------------------------------
C                 FFN: FIRST NEGATIVE MARGIN'S NUMBER
C
 382  DO 390 I=1,R
      IF(CUMP(I).EQ.PF) GO TO 400
 390  CONTINUE
 400  FFN=I
      IF(TAB.EQ.1) GO TO 412
      WRITE(6,410)FFN,GMG(FFN)
 410  FORMAT(/5X,'1ST NEG. MARGIN STATE # =',I4,'  ,  GMG =',F10.4)
 412  IF(WA.EQ.1) GO TO 420
      IF(VL.NE.0) GO TO 450
C
C             VARY THE LOAD DATA TO GET DIFFERENT PF
C        ---------------------------------------------------------
```

```
C                   DP: DESIRED STEP VARIANCE
C             FOR CONVENTIONAL SYSTEM, CHOOSE 1-20% TO 1+20%.
C             FOR COMBINED SYSTEM, CHOOSE 1 TO 1+40%
C
        IF(TAB.EQ.1) GO TO 416
        WRITE(6,415)
  415   FORMAT(//' ENTER STEP INCREASE IN LOAD ? %')
  416   READ(5,*) DP
        IF(TAB.EQ.1) GO TO 420
        WRITE(6,417)DP
  417   FORMAT(X,F10.4,' %')
  420   IF(TT.EQ.1) GO TO 450
        VL=1
        TT=1
        SIGN=0
        PDP=1.D0+DP/1.D2
  430   DO 440 I=1,LS
        BDG(I)=BDG(I)*PDP
  440   CONTINUE
        GO TO 251
  450   DO 460 J=1,LS
        BDG(J)=BDG(J)/PDP
  460   CONTINUE
        UPP=1.2D0
        IF(SIGN.GT.0) GO TO 470
        IF(WA.EQ.1) UPP=1.4D0
        IF(PDP.GE.UPP) GO TO 470
        PDP=PDP+DP/100.D0
        GO TO 430
  470   IF(WA.EQ.1) GO TO 590
        SIGN=SIGN+1
        IF(PDP.LE.0.8D0) GO TO 490
        IF(SIGN.GT.1) GO TO 480
        PDP=1.D0-DP/1.D2
        GO TO 430
  480   PDP=PDP-DP/1.D2
        GO TO 430
C
C             ENTER WINDFARM POWER STATES AND YEARLY LOAD INCREASE
C     ----------------------------------------------------------------
C             BLYR(I): YEARLY PEAK LOAD VALUE AT YEAR I
C                 WPO: WINDFARM RATED POWER OUTPUT
C                WFOR: WINDFARM FORCED OUTAGE RATE
C                  WS: TOTAL NUMBER OF WINDFARM POWER STATES
C              PPC(I): PERCENTAGE OF RATED POWER AT STATE I
C              SPR(I): PERCENTAGE OF TIME WITH POWER OUTPUT AT STATE I,
C                      FINAL RESULTS ALSO INCLUDING THE F.O.R.
C               WP(I): ACTUAL POWER OUTPUT AT STATE I
C
  490   IF(TAB.EQ.1) GO TO 494
        WRITE(6,492)
  492   FORMAT(//' ENTER ANNUAL LOAD INCREASE AND # OF YEARS')
  494   READ(5,*) INC,YR
        IF(TAB.EQ.1) GO TO 496
        WRITE(6,495)INC,YR
  495   FORMAT(' ANNUAL INCREASE = ',F5.2,'% , TOTAL = ',I2,' YEARS'/)
  496   DO 498 I=1,YR
        BLYR(I)=BDG(LS)*(1+INC/100)**I
        IF(TAB.EQ.1) GO TO 498
        WRITE(6,497)I,BLYR(I)
```

```
  497   FORMAT(5X,'YEAR ',I2,':   MONTHLY PEAK =',F10.4)
  498   CONTINUE
        IF(TAB.EQ.1) GO TO 500
        WRITE(6,499)
  499   FORMAT(//6X,'INPUT CUT-IN AND RATED WIND SPEED')
  500   READ(5,*)WC,WR
        IF(TAB.EQ.1) GO TO 503
        WRITE(6,501)WC,WR
  501   FORMAT(' CUT-IN SPEED=',F5.2,' M/S , RATED SPEED=',F5.2,' M/S')
  503   WRITE(6,505)
  505   FORMAT(/' ENTER WINDFARM DATA    WPO     WFOR   WS')
        READ(5,*)WPO,WFOR,WS
        WRITE(6,507)WPO,WFOR,WS
  507   FORMAT(21X,F8.4,2X,F6.4,2X,I2/)
        IF(TAB.EQ.1) GO TO 516
        WRITE(6,515)
  515   FORMAT(' WINDFARM O/P STATE ',3X,'   PPC(J)',6X,'SPR(J)')
  516   DO 520 J=1,WS
        READ(5,*)PPC(J),SPR(J)
        IF(TAB.EQ.1) GO TO 520
        WRITE(6,517)J,PPC(J),SPR(J)
  517   FORMAT(10X,I2,14X,F6.4,2X,D12.4)
  520   CONTINUE
        DO 540 J=1,WS
        WP(J)=WPO*PPC(J)
        IF(WP(J).GT.0.) GO TO 530
        SPR(J)=SPR(J)*(1.DO-WFOR)+WFOR
        GO TO 533
  530   SPR(J)=SPR(J)*(1-WFOR)
  533   WRITE(6,537)J,WP(J),SPR(J)
  537   FORMAT(/' STATE ',I2,' CAPACITY =',F9.4,' , PROB. =',D15.8)
  540   CONTINUE
C
C               COMBINE THE TOTAL SYSTEM TOGETHER
C         ------------------------------------------------
C
C                   ADD THE WINDFARM OUTPUT TO
C               THE CONVENTIONAL GENERATION STATE.
C
        ZC=1
        DO 560 I=1,WS
        DO 550 J=1,UA
        C(ZC)=WP(I)+CG(J)
        PC(ZC)=SPR(I)*PR(J)
        ZC=ZC+1
  550   CONTINUE
  560   CONTINUE
        ZA=ZC-1
        ZB=ZA-1
        DO 580 I=1,ZB
        DO 570 J=1,ZB
        IF(C(J+1).GE.C(J)) GO TO 570
        UTM=C(J)
        C(J)=C(J+1)
        C(J+1)=UTM
        PTM=PC(J)
        PC(J)=PC(J+1)
        PC(J+1)=PTM
  570   CONTINUE
  580   CONTINUE
        WA=1
```

```
      TT=0
      NS=ZA
      GO TO 105
590   CLOSE (UNIT=5)
      CLOSE (UNIT=6)
      STOP
      END
```

APPENDIX C

System Input Data

a. Generation System :

Month	# of Types	Type 1			Type 2			Type 3			Type 4			Type 5			Type 6			Type 7		
		Capacity	No.	FOR	Capacity	No.	FOR	Capacity	No.	FOR	Capacity	No.	FOR	Capacity	No.	FOR	Capacity	No.	FOR	Capacity	No.	FOR
Jan.	4	106.535	2	.04	357.20	1	.03	685.00	1	.03	404.20	1	.025									
Feb.	4	106.535	2	.04	357.20	1	.03	685.00	1	.03	404.20	1	.025									
Mar.	4	44.74	1	.04	507.10	1	.03	685.00	1	.03	136.00	2	.025									
Apr.	3	507.10	1	.03	685.00	1	.03	134.10	2	.025												
May	3	507.10	1	.03	685.00	1	.03	134.10	2	.025												
Jun.	5	73.15	1	.04	213.07	1	.04	507.10	1	.03	685.10	1	.03	404.20	1	.025						
Jul.	6	88.30	1	.05	68.17	1	.05	330.96	1	.04	507.10	1	.03	685.10	1	.03	404.20	1	.025			
Aug.	7	22.80	1	.05	88.30	1	.05	68.17	1	.05	330.96	1	.04	507.10	1	.03	685.00	1	.03	404.20	1	.025
Sep.	6	63.20	1	.05	68.17	1	.05	330.96	1	.04	507.10	1	.03	685.10	1	.03	404.20	1	.025			
Oct.	4	330.96	1	.04	507.10	1	.03	315.00	1	.03	404.20	1	.025									
Nov.	4	181.15	1	.04	507.10	1	.03	370.00	1	.03	404.20	1	.025									
Dec.	5	73.15	1	.04	213.07	1	.04	149.90	1	.03	685.10	1	.03	404.20	1	.025						

b. Load System :

Month	Base load	Daily Peak Load																														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Jan	730	840	303	898	1003	380	1151	1126	1077	1022	1151	1165	1159	1156	1081	1022	1087	1032	1035	1032	1064	1095	1066	1024	907	1016	1039	991	994	877	973	934
Feb	700	1043	1101	1159	1197	1142	1005	846	1141	1101	1115	1134	1023	982	848	984	977	880	983	937	866	771	881	933	849	1017	1001	834	784			
Mar.	800	914	915	1003	1044	1092	882	851	947	1015	930	889	831	783	803	916	890	873	880	875	764	762	880	880	883	924	805	813	785	934	859	834
Apr	370	840	888	766	741	929	973	981	934	881	734	704	884	928	916	938	904	780	745	884	891	884	883	865	742	731	869	880	849	908	880	
May	550	748	692	957	849	957	884	875	732	747	923	980	910	895	875	753	713	886	957	926	941	884	761	769	931	911	895	310	911	820	843	688
Jun.	680	848	843	886	841	742	878	938	1217	1018	933	880	794	758	5040	875	849	1034	975	838	892	1087	1075	1014	993	1004	905	874	1180	1285	1410	
Jul.	700	1334	1310	1339	1254	1232	1402	1535	1555	1544	1108	1075	1263	1382	1584	1465	1805	1441	1584	1315	1576	1622	3426	1424	1360	1515	1521	1555	1131	1348	1247	1387
Aug	720	1320	1337	1581	1840	1180	1541	1154	1266	1425	1611	3052	1805	1607	1492	1591	1316	1310	1578	1433	1459	1281	1384	1281	1268	1084	1454	1155	1043	1248	1457	1580
Sep.	620	1392	1414	1230	1184	1018	934	1200	1580	1283	1554	1138	1160	1210	1116	899	898	1100	761	759	925	835	844	892	808	738	780	885	1026	1051	1037	
Oct	584	1015	835	769	980	1085	915	915	980	720	741	875	926	844	834	831	723	714	866	871	804	876	805	780	718	881	834	848	874	922	719	748
Nov	360	849	884	805	821	929	761	738	857	862	883	844	848	844	839	866	940	926	881	848	775	552	815	992	878	796	865	876	818	907	901	
Dec.	600	872	885	912	855	822	975	959	1080	986	957	947	893	993	952	984	984	984	824	817	921	952	935	848	779	763	815	929	972	918	821	847

c. Wind Turbine System :

Month	FOR	Power Output Level Probability		
		0	0.5	1.0
Jan.	.04	0.549	0.223	0.228
Feb.	.04	0.608	0.226	0.166
Mar.	.04	0.545	0.234	0.221
Apr.	.04	0.476	0.179	0.345
May	.04	0.531	0.213	0.256
Jun.	.04	0.709	0.165	0.126
Jul.	.04	0.720	0.121	0.159
Aug.	.04	0.767	0.159	0.074
Sep.	.04	0.573	0.307	0.120
Oct.	.04	0.415	0.276	0.309
Nov.	.04	0.545	0.206	0.249
Dec.	.04	0.561	0.228	0.211

APPENDIX D

System Failure Probabilities' Calculation

for Sep. '82

```
INPUT THE YEAR AND MONTH TO BE ANALYZED

     ------- CAPACITY CREDIT ON  9/1982 -------

ENTER TOTAL # OF DIFF. GEN. TYPES
 6
ENTER     PG(I)  NG(I)   FOR(I)   I= 1
        63.2000    1     0.0500
ENTER     PG(I)  NG(I)   FOR(I)   I= 2
        68.1700    1     0.0500
ENTER     PG(I)  NG(I)   FOR(I)   I= 3
       330.9600    1     0.0400
ENTER     PG(I)  NG(I)   FOR(I)   I= 4
       507.1000    1     0.0300
ENTER     PG(I)  NG(I)   FOR(I)   I= 5
       685.0000    1     0.0300
ENTER     PG(I)  NG(I)   FOR(I)   I= 6
       404.2000    1     0.0250
INPUT ACCEPTABLE VARIANCE FOR EACH STATE
AVF =  0.50000000D-04
```

# OF STATE I	CG(I)	PR(I)	PRCU(I)
1	0.0000	0.22499999D-08	0.22499999D-08
2	63.2000	0.42749998D-07	0.44999998D-07
3	68.1700	0.42749998D-07	0.87749997D-07
4	131.3700	0.81224996D-06	0.89999995D-06
5	330.9600	0.54000000D-07	0.95399995D-06
6	394.1600	0.10260000D-05	0.19799999D-05
7	399.1300	0.10260000D-05	0.30059999D-05
8	404.2000	0.87749997D-07	0.30737499D-05
9	462.3300	0.19493999D-04	0.22587749D-04
10	467.4000	0.16672499D-05	0.24254999D-04
11	472.3700	0.16672499D-05	0.25922249D-04
12	507.1000	0.72750000D-07	0.25994999D-04
13	535.5700	0.31677748D-04	0.57672747D-04
14	570.3000	0.13822500D-05	0.59054997D-04
15	575.2700	0.13822500D-05	0.60437247D-04
16	638.4700	0.26262749D-04	0.86699996D-04
17	685.0000	0.72750000D-07	0.86772746D-04
18	735.1600	0.21060000D-05	0.88878746D-04
19	748.2000	0.13822500D-05	0.90260996D-04
20	753.1700	0.13822500D-05	0.91643246D-04
21	798.3600	0.40013999D-04	0.13165724D-03
22	803.3300	0.40013999D-04	0.17167124D-03
23	816.3700	0.26262749D-04	0.19793399D-03
24	838.0600	0.17460000D-05	0.19967999D-03
25	866.5300	0.76026597D-03	0.95994596D-03
26	901.2600	0.33174000D-04	0.99311996D-03
27	906.2300	0.33174000D-04	0.10262940D-02
28	911.3000	0.28372500D-05	0.10291312D-02
29	969.4300	0.63030600D-03	0.16594372D-02
30	974.5000	0.53907748D-04	0.17133450D-02
31	979.4700	0.53907748D-04	0.17672527D-02
32	1015.9600	0.17460000D-05	0.17689987D-02
33	1042.6700	0.10242472D-02	0.27932459D-02
34	1079.1600	0.33174000D-04	0.28264199D-02
35	1084.1300	0.33174000D-04	0.28595939D-02
36	1089.2001	0.28372500D-05	0.28624312D-02

37	1147.3300	0.63030600D-03	0.34927371D-02
38	1152.4000	0.53907748D-04	0.35466449D-02
39	1157.3700	0.53907748D-04	0.36005526D-02
40	1192.1000	0.23522501D-05	0.36029049D-02
41	1220.5701	0.10242472D-02	0.46271521D-02
42	1242.2600	0.68094001D-04	0.46952461D-02
43	1255.3000	0.44692750D-04	0.47399389D-02
44	1260.2700	0.44692750D-04	0.47846316D-02
45	1305.4601	0.12937860D-02	0.60784176D-02
46	1310.4301	0.12937860D-02	0.73722036D-02
47	1323.4701	0.84916224D-03	0.82213658D-02
48	1373.6300	0.24581933D-01	0.32803299D-01
49	1420.1600	0.68094001D-04	0.32871393D-01
50	1483.3601	0.12937860D-02	0.34165179D-01
51	1488.3301	0.12937860D-02	0.35458965D-01
52	1523.0601	0.56454003D-04	0.35515419D-01
53	1551.5300	0.24581933D-01	0.60097353D-01
54	1586.2600	0.10726260D-02	0.61169979D-01
55	1591.2301	0.10726260D-02	0.62242605D-01
56	1596.3000	0.91737751D-04	0.62334343D-01
57	1654.4301	0.20379894D-01	0.82714237D-01
58	1659.5001	0.17430172D-02	0.84457254D-01
59	1664.4701	0.17430172D-02	0.86200271D-01
60	1727.6702	0.33117327D-01	0.11931760D+00
61	1927.2601	0.22017061D-02	0.12151930D+00
62	1990.4601	0.41832415D-01	0.16335172D+00
63	1995.4302	0.41832415D-01	0.20518413D+00
64	2058.6301	0.79481587D+00	0.10000000D+01

```
ENTER TOTAL # OF DAYS
 30
ENTER DAILY PEAK AT DAY        1
 1589.0000
ENTER DAILY PEAK AT DAY        2
 1416.0000
ENTER DAILY PEAK AT DAY        3
 1238.0000
ENTER DAILY PEAK AT DAY        4
 1106.0000
ENTER DAILY PEAK AT DAY        5
 1018.0000
ENTER DAILY PEAK AT DAY        6
 934.0000
ENTER DAILY PEAK AT DAY        7
 1200.0000
ENTER DAILY PEAK AT DAY        8
 1289.0000
ENTER DAILY PEAK AT DAY        9
 1283.0000
ENTER DAILY PEAK AT DAY       10
 1354.0000
ENTER DAILY PEAK AT DAY       11
 1198.0000
ENTER DAILY PEAK AT DAY       12
 1160.0000
ENTER DAILY PEAK AT DAY       13
 1210.0000
ENTER DAILY PEAK AT DAY       14
 1116.0000
ENTER DAILY PEAK AT DAY       15
```

```
  899.0000
 ENTER DAILY PEAK AT DAY        16
  898.0000
 ENTER DAILY PEAK AT DAY        17
 1104.0000
 ENTER DAILY PEAK AT DAY        18
  761.0000
 ENTER DAILY PEAK AT DAY        19
  759.0000
 ENTER DAILY PEAK AT DAY        20
  875.0000
 ENTER DAILY PEAK AT DAY        21
  855.0000
 ENTER DAILY PEAK AT DAY        22
  864.0000
 ENTER DAILY PEAK AT DAY        23
  892.0000
 ENTER DAILY PEAK AT DAY        24
  908.0000
 ENTER DAILY PEAK AT DAY        25
  738.0000
 ENTER DAILY PEAK AT DAY        26
  750.0000
 ENTER DAILY PEAK AT DAY        27
  883.0000
 ENTER DAILY PEAK AT DAY        28
 1026.0000
 ENTER DAILY PEAK AT DAY        29
 1011.0000
 ENTER DAILY PEAK AT DAY        30
 1037.0000

 ENTER EXPOSURE FACTOR
 ALPHA = 0.5000

 ENTER ACCEPTED LOAD VAR. WITHIN 1 GROUP ? %
  5.0000 %

 ENTER DAILY BASE LOAD
 BASE LOAD =  620.0000

 LOAD STATES       BDG(I)          PL(I)
      1           620.0000     0.50000000D+00
      2           761.0000     0.66666670D-01
      3           934.0000     0.15000001D+00
      4          1037.0000     0.66666670D-01
      5          1160.0000     0.66666670D-01
      6          1238.0000     0.66666670D-01
      7          1354.0000     0.50000001D-01
      8          1416.0000     0.16666668D-01
      9          1589.0000     0.16666668D-01

 NEED MARGIN TABLE ? YES(0) NO(1)
 1

     SYSTEM FAILURE PROB. =  0.28344345D-02

     1ST NEG. MARGIN STATE # = 324  ,  GMG =    -2.6300
```

```
ENTER STEP INCREASE IN LOAD ? %
    5.0000 %

LOAD STATES      BDG(I)          PL(I)
     1          651.0000     0.50000000D+00
     2          799.0500     0.66666670D-01
     3          980.7000     0.15000001D+00
     4         1088.8500     0.66666670D-01
     5         1218.0000     0.66666670D-01
     6         1299.9000     0.66666670D-01
     7         1421.7000     0.50000001D-01
     8         1486.8000     0.16666668D-01
     9         1668.4500     0.16666668D-01

    SYSTEM FAILURE PROB. =  0.47166844D-02

    1ST NEG. MARGIN STATE # = 345  ,  GMG =   -0.6899

LOAD STATES      BDG(I)          PL(I)
     1          682.0000     0.50000000D+00
     2          837.1000     0.66666670D-01
     3         1027.4000     0.15000001D+00
     4         1140.7000     0.66666670D-01
     5         1276.0000     0.66666670D-01
     6         1361.8000     0.66666670D-01
     7         1489.4000     0.50000001D-01
     8         1557.6000     0.16666668D-01
     9         1747.9000     0.16666668D-01

    SYSTEM FAILURE PROB. =  0.61429883D-02

    1ST NEG. MARGIN STATE # = 362  ,  GMG =   -1.0699

LOAD STATES      BDG(I)          PL(I)
     1          713.0000     0.50000000D+00
     2          875.1500     0.66666670D-01
     3         1074.1000     0.15000001D+00
     4         1192.5500     0.66666670D-01
     5         1334.0000     0.66666670D-01
     6         1423.7000     0.66666670D-01
     7         1557.1000     0.50000001D-01
     8         1628.4000     0.16666668D-01
     9         1827.3500     0.16666668D-01

    SYSTEM FAILURE PROB. =  0.95384809D-02

    1ST NEG. MARGIN STATE # = 380  ,  GMG =   -0.4501

LOAD STATES      BDG(I)          PL(I)
     1          744.0000     0.50000000D+00
     2          913.2000     0.66666670D-01
     3         1120.8000     0.15000001D+00
     4         1244.4000     0.66666670D-01
     5         1392.0000     0.66666670D-01
     6         1485.6000     0.66666670D-01
     7         1624.8000     0.50000001D-01
     8         1699.2000     0.16666668D-01
     9         1906.8000     0.16666668D-01

    SYSTEM FAILURE PROB. =  0.11862010D-01
```

1ST NEG. MARGIN STATE # = 397 , GMG = -1.9000

LOAD STATES	BDG(I)	PL(I)
1	775.0000	0.50000000D+00
2	951.2500	0.66666670D-01
3	1167.5001	0.15000001D+00
4	1296.2500	0.66666670D-01
5	1450.0000	0.66666670D-01
6	1547.5000	0.66666670D-01
7	1692.5000	0.50000001D-01
8	1770.0000	0.16666668D-01
9	1986.2500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.13856572D-01

1ST NEG. MARGIN STATE # = 412 , GMG = -10.1301

LOAD STATES	BDG(I)	PL(I)
1	589.0000	0.50000000D+00
2	722.9500	0.66666670D-01
3	887.3001	0.15000001D+00
4	985.1500	0.66666670D-01
5	1102.0000	0.66666670D-01
6	1176.1000	0.66666670D-01
7	1286.3000	0.50000001D-01
8	1345.2000	0.16666668D-01
9	1509.5500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.16959150D-02

1ST NEG. MARGIN STATE # = 305 , GMG = -5.6800

LOAD STATES	BDG(I)	PL(I)
1	558.0000	0.50000000D+00
2	684.9000	0.66666670D-01
3	840.6001	0.15000001D+00
4	933.3000	0.66666670D-01
5	1044.0000	0.66666670D-01
6	1114.2000	0.66666670D-01
7	1218.6000	0.50000001D-01
8	1274.4000	0.16666668D-01
9	1430.1000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.13179680D-02

1ST NEG. MARGIN STATE # = 283 , GMG = -1.3300

LOAD STATES	BDG(I)	PL(I)
1	527.0000	0.50000000D+00
2	646.8500	0.66666670D-01
3	793.9001	0.15000001D+00
4	881.4500	0.66666670D-01
5	986.0000	0.66666670D-01
6	1052.3000	0.66666670D-01
7	1150.9000	0.50000001D-01
8	1203.6000	0.16666668D-01
9	1350.6500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.77226169D-03

1ST NEG. MARGIN STATE # = 256 , GMG = -3.5701

LOAD STATES	BDG(I)	PL(I)
1	496.0000	0.50000000D+00
2	608.8000	0.66666670D-01
3	747.2001	0.15000001D+00
4	829.6000	0.66666670D-01
5	928.0000	0.66666670D-01
6	990.4000	0.66666670D-01
7	1083.2000	0.50000001D-01
8	1132.8000	0.16666668D-01
9	1271.2000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.49871534D-03

1ST NEG. MARGIN STATE # = 238 , GMG = -4.0399

ENTER ANNUAL LOAD INCREASE AND # OF YEARS
ANNUAL INCREASE = 6.00% , TOTAL = 10 YEARS

YEAR 1: MONTHLY PEAK = 1684.3400
YEAR 2: MONTHLY PEAK = 1785.4003
YEAR 3: MONTHLY PEAK = 1892.5242
YEAR 4: MONTHLY PEAK = 2006.0754
YEAR 5: MONTHLY PEAK = 2126.4399
YEAR 6: MONTHLY PEAK = 2254.0261
YEAR 7: MONTHLY PEAK = 2389.2676
YEAR 8: MONTHLY PEAK = 2532.6235
YEAR 9: MONTHLY PEAK = 2684.5808
YEAR 10: MONTHLY PEAK = 2845.6555

INPUT CUT-IN AND RATED WIND SPEED
CUT-IN SPEED= 6.00 M/S , RATED SPEED=12.00 M/S

ENTER WINDFARM DATA	WPO	WFOR	WS
	200.0000	0.0400	3

WINDFARM O/P STATE	PPC(J)	SPR(J)
1	0.0000	0.5730D+00
2	0.5000	0.3070D+00
3	1.0000	0.1200D+00

STATE 1 CAPACITY = 0.0000 , PROB. = 0.59008000D+00

STATE 2 CAPACITY = 100.0000 , PROB. = 0.29471999D+00

STATE 3 CAPACITY = 200.0000 , PROB. = 0.11520000D+00

# OF STATE I	CG(I)	PR(I)	PRCU(I)
1	0.0000	0.13276800D-08	0.13276800D-08
2	63.2000	0.25225919D-07	0.26553599D-07
3	68.1700	0.25225919D-07	0.51779518D-07
4	100.0000	0.66311997D-09	0.52442639D-07
5	131.3700	0.47929245D-06	0.53173509D-06
6	163.2000	0.12599279D-07	0.54433437D-06
7	168.1700	0.12599279D-07	0.55693365D-06

8	200.0000	0.25919999D-09	0.55719285D-06
9	231.3700	0.23938630D-06	0.79657915D-06
10	263.2000	0.49247997D-08	0.80150395D-06
11	268.1700	0.49247997D-08	0.80642875D-06
12	330.9600	0.31864320D-07	0.83829307D-06
13	331.3700	0.93571193D-07	0.93186426D-06
14	394.1600	0.60542207D-06	0.15372863D-05
15	399.1300	0.60542207D-06	0.21427084D-05
16	404.2000	0.51779518D-07	0.21944879D-05
17	430.9600	0.15914880D-07	0.22104028D-05
18	462.3300	0.11503019D-04	0.13713422D-04
19	467.4000	0.98381083D-06	0.14697233D-04
20	472.3700	0.98381083D-06	0.15681044D-04
21	494.1600	0.30238271D-06	0.15983426D-04
22	499.1300	0.30238271D-06	0.16285809D-04
23	504.2000	0.25861678D-07	0.16311671D-04
24	507.1000	0.42928320D-07	0.16354599D-04
25	530.9600	0.62207999D-08	0.16360820D-04
26	535.5700	0.18692405D-04	0.35053225D-04
27	562.3300	0.57452714D-05	0.40798497D-04
28	567.4000	0.49137188D-06	0.41289869D-04
29	570.3000	0.81563807D-06	0.42105507D-04
30	572.3701	0.49137188D-06	0.42596878D-04
31	575.2700	0.81563807D-06	0.43412517D-04
32	594.1600	0.11819520D-06	0.43530712D-04
33	599.1300	0.11819520D-06	0.43648907D-04
34	604.2000	0.10108799D-07	0.43659016D-04
35	607.1000	0.21440880D-07	0.43680457D-04
36	635.5700	0.93360656D-05	0.53016522D-04
37	638.4700	0.15497123D-04	0.68513645D-04
38	662.3300	0.22457087D-05	0.70759354D-04
39	667.4000	0.19206719D-06	0.70951421D-04
40	670.3000	0.40737670D-06	0.71358798D-04
41	672.3701	0.19206719D-06	0.71550865D-04
42	675.2700	0.40737670D-06	0.71958242D-04
43	685.0000	0.42928320D-07	0.72001170D-04
44	707.1000	0.83807998D-08	0.72009551D-04
45	735.1600	0.12427085D-05	0.73252259D-04
46	735.5700	0.36492765D-05	0.76901536D-04
47	738.4700	0.77401573D-05	0.84641693D-04
48	748.2000	0.81563807D-06	0.85457331D-04
49	753.1700	0.81563807D-06	0.86272969D-04
50	770.3000	0.15923519D-06	0.86432204D-04
51	775.2700	0.15923519D-06	0.86591440D-04
52	785.0000	0.21440880D-07	0.86612880D-04
53	798.3600	0.23611460D-04	0.11022434D-03
54	803.3300	0.23611460D-04	0.13383580D-03
55	816.3700	0.15497123D-04	0.14933292D-03
56	835.1600	0.62068030D-06	0.14995360D-03
57	838.0600	0.10302797D-05	0.15098388D-03
58	838.4700	0.30254686D-05	0.15400935D-03
59	848.2000	0.40737670D-06	0.15441673D-03
60	853.1700	0.40737670D-06	0.15482411D-03
61	866.5300	0.44861774D-03	0.60344185D-03
62	885.0000	0.83807998D-08	0.60345023D-03
63	898.3600	0.11792925D-04	0.61524315D-03
64	901.2600	0.19575314D-04	0.63481847D-03
65	903.3300	0.11792925D-04	0.64661139D-03
66	906.2300	0.19575314D-04	0.66618671D-03
67	911.3000	0.16742045D-05	0.66786091D-03

68	916.3700	0.77401573D-05	0.67560107D-03
69	935.1600	0.24261119D-06	0.67584368D-03
70	938.0600	0.51458112D-06	0.67635826D-03
71	948.2000	0.15923519D-06	0.67651750D-03
72	953.1700	0.15923519D-06	0.67667673D-03
73	966.5300	0.22406558D-03	0.90074231D-03
74	969.4300	0.37193096D-03	0.12726733D-02
75	974.5000	0.31809884D-04	0.13044832D-02
76	979.4700	0.31809884D-04	0.13362930D-02
77	998.3600	0.46096126D-05	0.13409027D-02
78	1001.2600	0.97770411D-05	0.13506797D-02
79	1003.3300	0.46096126D-05	0.13552893D-02
80	1006.2300	0.97770411D-05	0.13650663D-02
81	1011.3000	0.83619429D-06	0.13659025D-02
82	1015.9600	0.10302797D-05	0.13669328D-02
83	1016.3700	0.30254686D-05	0.13699583D-02
84	1038.0601	0.20113920D-06	0.13701594D-02
85	1042.6700	0.60438779D-03	0.19745472D-02
86	1066.5300	0.87582637D-04	0.20621299D-02
87	1069.4301	0.18576378D-03	0.22478936D-02
88	1074.5000	0.15887691D-04	0.22637813D-02
89	1079.1600	0.19575314D-04	0.22833566D-02
90	1079.4701	0.15887691D-04	0.22992443D-02
91	1084.1300	0.19575314D-04	0.23188196D-02
92	1089.2001	0.16742045D-05	0.23204939D-02
93	1101.2600	0.38216447D-05	0.23243155D-02
94	1106.2301	0.38216447D-05	0.23281371D-02
95	1111.3000	0.32685119D-06	0.23284640D-02
96	1115.9601	0.51458112D-06	0.23289786D-02
97	1142.6700	0.30186613D-03	0.26308447D-02
98	1147.3300	0.37193096D-03	0.30027757D-02
99	1152.4000	0.31809884D-04	0.30345855D-02
100	1157.3700	0.31809884D-04	0.30663954D-02
101	1169.4301	0.72611249D-04	0.31390067D-02
102	1174.5000	0.62101725D-05	0.31452169D-02
103	1179.1600	0.97770411D-05	0.31549939D-02
104	1179.4701	0.62101725D-05	0.31612041D-02
105	1184.1300	0.97770411D-05	0.31709811D-02
106	1189.2001	0.83619429D-06	0.31718173D-02
107	1192.1000	0.13880157D-05	0.31732053D-02
108	1215.9601	0.20113920D-06	0.31734065D-02
109	1220.5701	0.60438779D-03	0.37777942D-02
110	1242.2600	0.40180908D-04	0.38179752D-02
111	1242.6700	0.11799328D-03	0.39359684D-02
112	1247.3300	0.18576378D-03	0.41217322D-02
113	1252.4000	0.15887691D-04	0.41376199D-02
114	1255.3000	0.26372298D-04	0.41639922D-02
115	1257.3700	0.15887691D-04	0.41798799D-02
116	1260.2700	0.26372298D-04	0.42062522D-02
117	1279.1600	0.38216447D-05	0.42100738D-02
118	1284.1300	0.38216447D-05	0.42138955D-02
119	1289.2001	0.32685119D-06	0.42142223D-02
120	1292.1000	0.69325512D-06	0.42149156D-02
121	1305.4601	0.76343724D-03	0.49783528D-02
122	1310.4301	0.76343724D-03	0.57417901D-02
123	1320.5701	0.30186613D-03	0.60436562D-02
124	1323.4701	0.50107366D-03	0.65447298D-02
125	1342.2600	0.20068663D-04	0.65647985D-02
126	1347.3300	0.72611249D-04	0.66374098D-02
127	1352.4000	0.62101725D-05	0.66436199D-02

128	1355.3000	0.13171847D-04	0.66567918D-02
129	1357.3700	0.62101725D-05	0.66630019D-02
130	1360.2700	0.13171847D-04	0.66761738D-02
131	1373.6300	0.14505307D-01	0.21181481D-01
132	1392.1000	0.27097920D-06	0.21181752D-01
133	1405.4601	0.38130460D-03	0.21563057D-01
134	1410.4301	0.38130460D-03	0.21944361D-01
135	1420.1600	0.40180908D-04	0.21984542D-01
136	1420.5701	0.11799328D-03	0.22102535D-01
137	1423.4701	0.25026509D-03	0.22352801D-01
138	1442.2600	0.78444287D-05	0.22360645D-01
139	1455.3000	0.51486047D-05	0.22365794D-01
140	1460.2700	0.51486047D-05	0.22370942D-01
141	1473.6300	0.72447873D-02	0.29615729D-01
142	1483.3601	0.76343724D-03	0.30379167D-01
143	1488.3301	0.76343724D-03	0.31142604D-01
144	1505.4601	0.14904414D-03	0.31291648D-01
145	1510.4301	0.14904414D-03	0.31440692D-01
146	1520.1600	0.20068663D-04	0.31460761D-01
147	1523.0601	0.33312378D-04	0.31494073D-01
148	1523.4701	0.97823488D-04	0.31591897D-01
149	1551.5300	0.14505307D-01	0.46097204D-01
150	1573.6300	0.28318387D-02	0.48929043D-01
151	1583.3601	0.38130460D-03	0.49310347D-01
152	1586.2600	0.63293517D-03	0.49943282D-01
153	1588.3301	0.38130460D-03	0.50324587D-01
154	1591.2301	0.63293517D-03	0.50957522D-01
155	1596.3000	0.54132612D-04	0.51011655D-01
156	1620.1600	0.78444287D-05	0.51019499D-01
157	1623.0601	0.16638123D-04	0.51036137D-01
158	1651.5300	0.72447873D-02	0.58280925D-01
159	1654.4301	0.12025768D-01	0.70306693D-01
160	1659.5001	0.10285196D-02	0.71335212D-01
161	1664.4701	0.10285196D-02	0.72363732D-01
162	1683.3601	0.14904414D-03	0.72512776D-01
163	1686.2600	0.31612434D-03	0.72828900D-01
164	1688.3301	0.14904414D-03	0.72977944D-01
165	1691.2301	0.31612434D-03	0.73294069D-01
166	1696.3000	0.27036949D-04	0.73321106D-01
167	1723.0601	0.65035010D-05	0.73327609D-01
168	1727.6702	0.19541872D-01	0.92869482D-01
169	1751.5300	0.28318387D-02	0.95701320D-01
170	1754.4301	0.60063623D-02	0.10170768D+00
171	1759.5001	0.51370203D-03	0.10222138D+00
172	1764.4701	0.51370203D-03	0.10273509D+00
173	1786.2600	0.12356652D-03	0.10285865D+00
174	1791.2301	0.12356652D-03	0.10298222D+00
175	1796.3000	0.10568189D-04	0.10299279D+00
176	1827.6702	0.97603384D-02	0.11275313D+00
177	1854.4301	0.23477638D-02	0.11510089D+00
178	1859.5001	0.20079558D-03	0.11530169D+00
179	1864.4701	0.20079558D-03	0.11550248D+00
180	1927.2601	0.12991827D-02	0.11680166D+00
181	1927.6702	0.38151160D-02	0.12061678D+00
182	1990.4601	0.24684471D-01	0.14530125D+00
183	1995.4302	0.24684471D-01	0.16998572D+00
184	2027.2601	0.64888680D-03	0.17063461D+00
185	2058.6301	0.46900495D+00	0.63963956D+00
186	2090.4602	0.12328849D-01	0.65196840D+00
187	2095.4302	0.12328849D-01	0.66429725D+00

188	2127.2603	0.25363653D-03	0.66455089D+00
189	2158.6301	0.23424813D+00	0.89879902D+00
190	2190.4602	0.48190941D-02	0.90361811D+00
191	2195.4302	0.48190941D-02	0.90843720D+00
192	2258.6301	0.91562786D-01	0.99999999D+00

LOAD STATES	BDG(I)	PL(I)
1	620.0000	0.50000000D+00
2	761.0000	0.66666670D-01
3	934.0001	0.15000001D+00
4	1037.0000	0.66666670D-01
5	1160.0000	0.66666670D-01
6	1238.0000	0.66666670D-01
7	1354.0000	0.50000001D-01
8	1416.0001	0.16666668D-01
9	1589.0000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.22132054D-02

1ST NEG. MARGIN STATE # = 855 , GMG = -0.6699

LOAD STATES	BDG(I)	PL(I)
1	651.0000	0.50000000D+00
2	799.0500	0.66666670D-01
3	980.7001	0.15000001D+00
4	1088.8500	0.66666670D-01
5	1218.0000	0.66666670D-01
6	1299.9000	0.66666670D-01
7	1421.7000	0.50000001D-01
8	1486.8002	0.16666668D-01
9	1668.4500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.37067004D-02

1ST NEG. MARGIN STATE # = 924 , GMG = -0.6899

LOAD STATES	BDG(I)	PL(I)
1	682.0000	0.50000000D+00
2	837.1000	0.66666670D-01
3	1027.4001	0.15000001D+00
4	1140.7000	0.66666670D-01
5	1276.0000	0.66666670D-01
6	1361.8000	0.66666670D-01
7	1489.4000	0.50000001D-01
8	1557.6001	0.16666668D-01
9	1747.9000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.50054719D-02

1ST NEG. MARGIN STATE # = 983 , GMG = -1.0699

LOAD STATES	BDG(I)	PL(I)
1	713.0000	0.50000000D+00
2	875.1500	0.66666670D-01
3	1074.1001	0.15000001D+00
4	1192.5500	0.66666670D-01
5	1334.0000	0.66666670D-01
6	1423.7000	0.66666670D-01
7	1557.1000	0.50000001D-01
8	1628.4001	0.16666668D-01

9	1827.3500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.74234766D-02

1ST NEG. MARGIN STATE # =1041 , GMG = -0.2299

LOAD STATES	BDG(I)	PL(I)
1	744.0000	0.50000000D+00
2	913.2000	0.66666670D-01
3	1120.8000	0.15000001D+00
4	1244.4000	0.66666670D-01
5	1392.0000	0.66666670D-01
6	1485.6000	0.66666670D-01
7	1624.8000	0.50000001D-01
8	1699.2002	0.16666668D-01
9	1906.8000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.98348332D-02

1ST NEG. MARGIN STATE # =1096 , GMG = -1.7300

LOAD STATES	BDG(I)	PL(I)
1	775.0000	0.50000000D+00
2	951.2500	0.66666670D-01
3	1167.5001	0.15000001D+00
4	1296.2500	0.66666670D-01
5	1450.0000	0.66666670D-01
6	1547.5000	0.66666670D-01
7	1692.5000	0.50000001D-01
8	1770.0001	0.16666668D-01
9	1986.2500	0.16666668D-01

SYSTEM FAILURE PROB. = 0.11813342D-01

1ST NEG. MARGIN STATE # =1145 , GMG = -1.2699

LOAD STATES	BDG(I)	PL(I)
1	806.0000	0.50000000D+00
2	989.3000	0.66666670D-01
3	1214.2002	0.15000001D+00
4	1348.1000	0.66666670D-01
5	1508.0000	0.66666670D-01
6	1609.4000	0.66666670D-01
7	1760.2000	0.50000001D-01
8	1840.8002	0.16666668D-01
9	2065.7000	0.16666668D-01

SYSTEM FAILURE PROB. = 0.24212314D-01

1ST NEG. MARGIN STATE # =1194 , GMG = -0.6998

LOAD STATES	BDG(I)	PL(I)
1	837.0000	0.50000000D+00
2	1027.3500	0.66666670D-01
3	1260.9001	0.15000001D+00
4	1399.9500	0.66666670D-01
5	1566.0000	0.66666670D-01
6	1671.3000	0.66666670D-01
7	1827.9000	0.50000001D-01
8	1911.6002	0.16666668D-01

```
     9        2145.1499   0.16666668D-01

   SYSTEM FAILURE PROB. =  0.28745305D-01

   1ST NEG. MARGIN STATE # =1240  ,  GMG =   -0.2299

LOAD STATES      BDG(I)          PL(I)
     1          868.0000   0.50000000D+00
     2         1065.4000   0.66666670D-01
     3         1307.6002   0.15000001D+00
     4         1451.8000   0.66666670D-01
     5         1624.0000   0.66666670D-01
     6         1733.2000   0.66666670D-01
     7         1895.6000   0.50000001D-01
     8         1982.4001   0.16666668D-01
     9         2224.5999   0.16666668D-01

   SYSTEM FAILURE PROB. =  0.35190553D-01

   1ST NEG. MARGIN STATE # =1281  ,  GMG =   -0.9399

LOAD STATES      BDG(I)          PL(I)
     1          899.0000   0.50000000D+00
     2         1103.4500   0.66666670D-01
     3         1354.3003   0.15000001D+00
     4         1503.6500   0.66666670D-01
     5         1682.0000   0.66666670D-01
     6         1795.1000   0.66666670D-01
     7         1963.3000   0.50000001D-01
     8         2053.2002   0.16666668D-01
     9         2304.0498   0.16666668D-01

   SYSTEM FAILURE PROB. =  0.40766440D-01

   1ST NEG. MARGIN STATE # =1318  ,  GMG =   -0.6400
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CAPACITY CREDIT FOR KANSAS WIND TURBINES

by

CHENG-TSUNG LIU

B.E., National Kaohsiung Institnte

of

Technology (Taiwan, R.O.C.), 1980

AN ABSTRACT OF A MASTER'S THESIS

Snbmitted in partial fulfillment of the

reqnirements for the degree

MASTER OF SCIENCE

Department of Electrical and Compnter

Engineering

KANSAS STATE UNIVERSITY

Manhattan, Kansas

1984

ABSTRACT

A program using the Frequency and Duration method has been written to calculate the power system failure probabilities for a conventional system and the system with wind turbine power output added. The computer that is presently being used for this purpose is the VAX-11/750 and the Kansas Gas and Electric data for 1982 were used in the study.

In running this program, the monthly basis was chosen, and the daily peak load and base load data with corresponding working generation system data were used as the input first. After the results of the conventional system were obtained, the wind data were included in the calculations.

By using the least square method on the estimation of the results of this program, the saturated capacity credit obtained from this research is about 25 %, which is just about the same level as obtained by a study performed by General Electric. Detailed monthly and seasonal capacity credits were also calculated in this research. Thus, this research gives a reasonable and economical way to estimate capacity credit for future application of Kansas wind turbines.