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VALUE ANALYSIS OF WIND ENERGY SYSTEMS TO ELECTRIC UTILITIES

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NOTICE

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ABSTRACT

A method has been developed for determining the value of utility-operated wind energy systems to electric utilities. The analysis is performed by a package of computer models that interface with most conventional utility planning models. Weather data are converted to wind turbine output powers, which are used to modify the utility load representation. Execution of the utility planning models with both the original and modified load representation yields the gross and marginal value ($/rated kW) of the added wind energy systems. This value is then compared with cost estimates to determine if for economic reasons the wind energy systems should be included in future generation plans.

INTRODUCTION

The Solar Energy Research Institute (SERI) has developed a method for determining the value of utility-operated wind energy systems to electric utilities. The method is executed by computer models available from SERI. These models interface with most conventional electric utility planning models and thus allow the utility planner to include Wind Energy Conversion Systems (WECS) in future generation planning.

Currently, utility planning models cannot account for WECS or other intermittent solar technologies in future generation plans. The proposed method accounts for WECS by appropriately modifying the projected utility load (customer demand) that is input to these planning models. Briefly, wind data are converted to WECS power outputs, which are used to modify the utility load representation. The utility planning models are executed with both the modified load representation and the original unmodified load representation. Comparison of both of these results in a financial model determines the gross and marginal value ($/rated kW) of the added WECS. Key variables in determining these values include the wind resource and utility cost information.

This SERI methodology uses probabilistic techniques to represent the variability of the wind resource and to modify the utility load representation. Previous studies on WECS value analysis (1,2,3,4) either did not use probabilistic methods or failed to carry the probabilistic approach through the entire methodology.

METHODOLOGY

Figure 1 shows the relationship of all the computer models involved in the methodology. Five of the models are available from SERI (WTP, WEIBUL, ROSEW, ULMOD, and FINAM), and the two utility planning models (expansion and production cost) are available to most utilities.

These SERI models can perform the value analysis with either probabilistic or simple hourly techniques. If the hourly technique is chosen, the program WTP is used to initiate the analysis. If the probabilistic technique is selected, the program WEIBUL is used instead of WTP.

Weather Data

As Figure 1 shows, the value determination procedure begins with the processing of hourly weather data by computer programs WTP or WEIBUL to produce either hourly wind velocity data or wind probability distributions, respectively. Both programs accept SOLMET, TMY, TDF-14, and Aerospace weather data sources.

If the hourly technique is chosen, WTP (Weather Tape Preprocessor) converts the hourly weather data into the proper units and fills in any missing data by

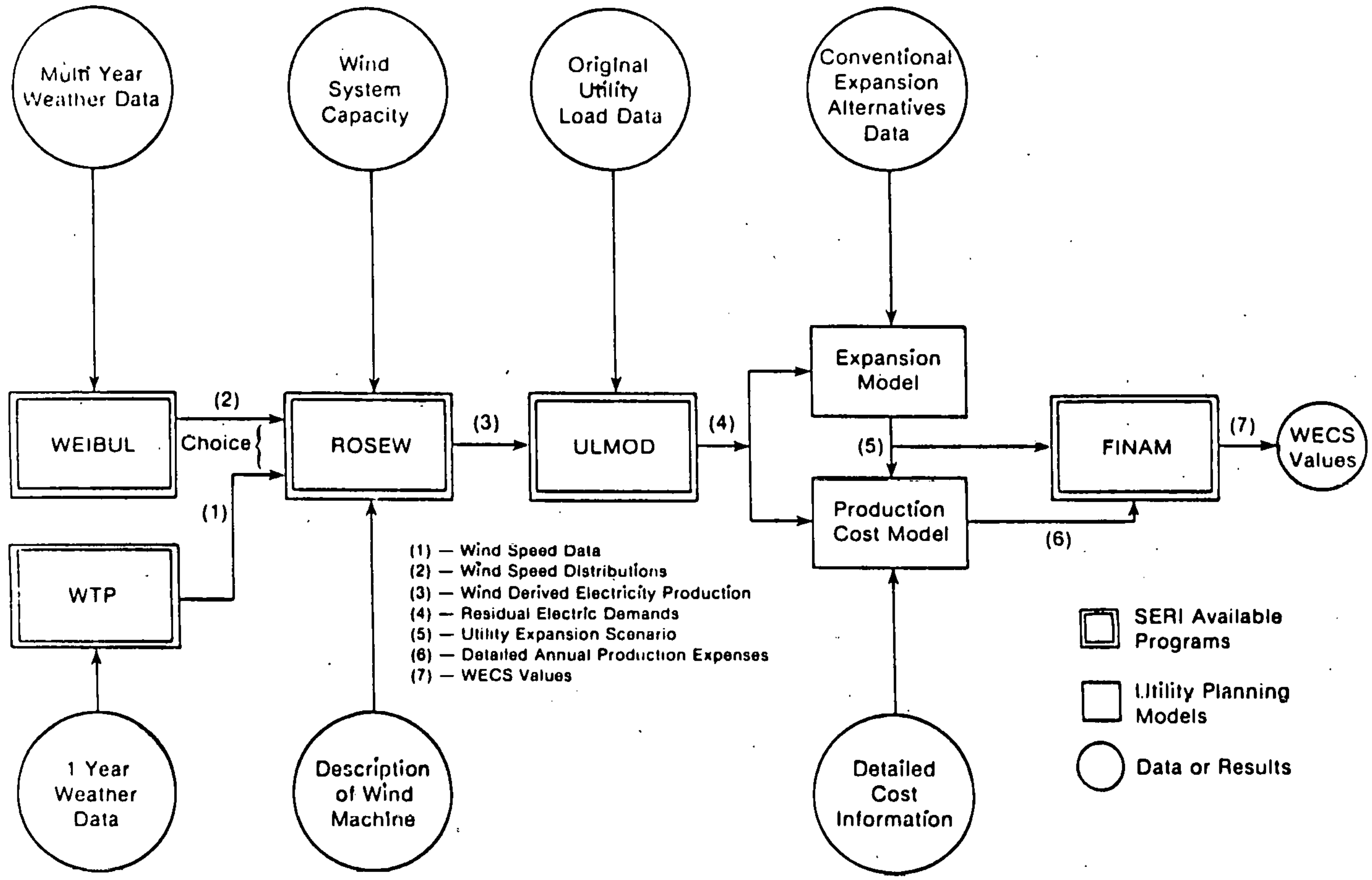

Figure 1 - Value Model Overview

interpolation. The single hourly wind speed from the weather tapes is an approximate one minute average value at the beginning of each hour. This value is assumed to be constant over the entire hour when wind power calculations are made; in fact, the wind speed can vary from zero to some maximum many times during the hour. Figure 2 illustrates these wind speed fluctuations that are not represented by this hourly modeling.

To more accurately represent the long-term variability of the wind resource, it is recommended that the program WEIBUL be used instead of WTP when more than one year of weather data is available. WEIBUL creates a probabilistic representation of the wind resource from as much hourly data for the site as can be obtained. The resulting Weibull distributions are created for each hour of a monthly typical day, thus 288 (12 typical days per year × 24 hourly distributions per day) Weibull distributions characterize the wind resource for a typical year at this site.

As illustrated in Figure 3, each Weibull distribution is described by a scale factor C and a dimensionless shape factor K. The scale factor has the same units as wind speed and is approximately 1.1 times the average wind speed. To calculate these parameters, the appropriate wind velocities are sorted into velocity intervals. From this distribution, either a linear least squares curve fit or a maximum likelihood curve fit can be used to determine the values of C and K. Figure 4 illustrates a maximum likelihood curve fit to wind speed observations. The Weibull curve is fitted only to points above a user input cut-in wind speed to obtain as accurate a curve fit as possible.

Several sources have pointed out the appropriateness of the Weibull distribution (5,6,7), and sample cases to date have confirmed this. The Weibull distribution is also superior to other probabilistic distributions owing to the scale factor, even though some curve fits (such as a high-order polynomial) could fit the wind data much more accurately. Since the scale factor is related to the average wind speed, judicious scaling of this factor can account for average wind speed differences at different sites. Thus if the same shape of the wind speed distribution can be assumed, then the Weibull distributions created for one site can be appropriately scaled up or down to another site with a higher or lower average wind velocity.

Since the power in a wind stream is proportional to the velocity cubed, the additional accuracy achieved in this Weibull probabilistic modeling could be important in the calculation of available wind energy. Also, the unpredictability of the wind velocity is important to reflect in electric utility studies for reliability considerations.

Wind Power Calculations

The results from WEIBUL are sent to the program

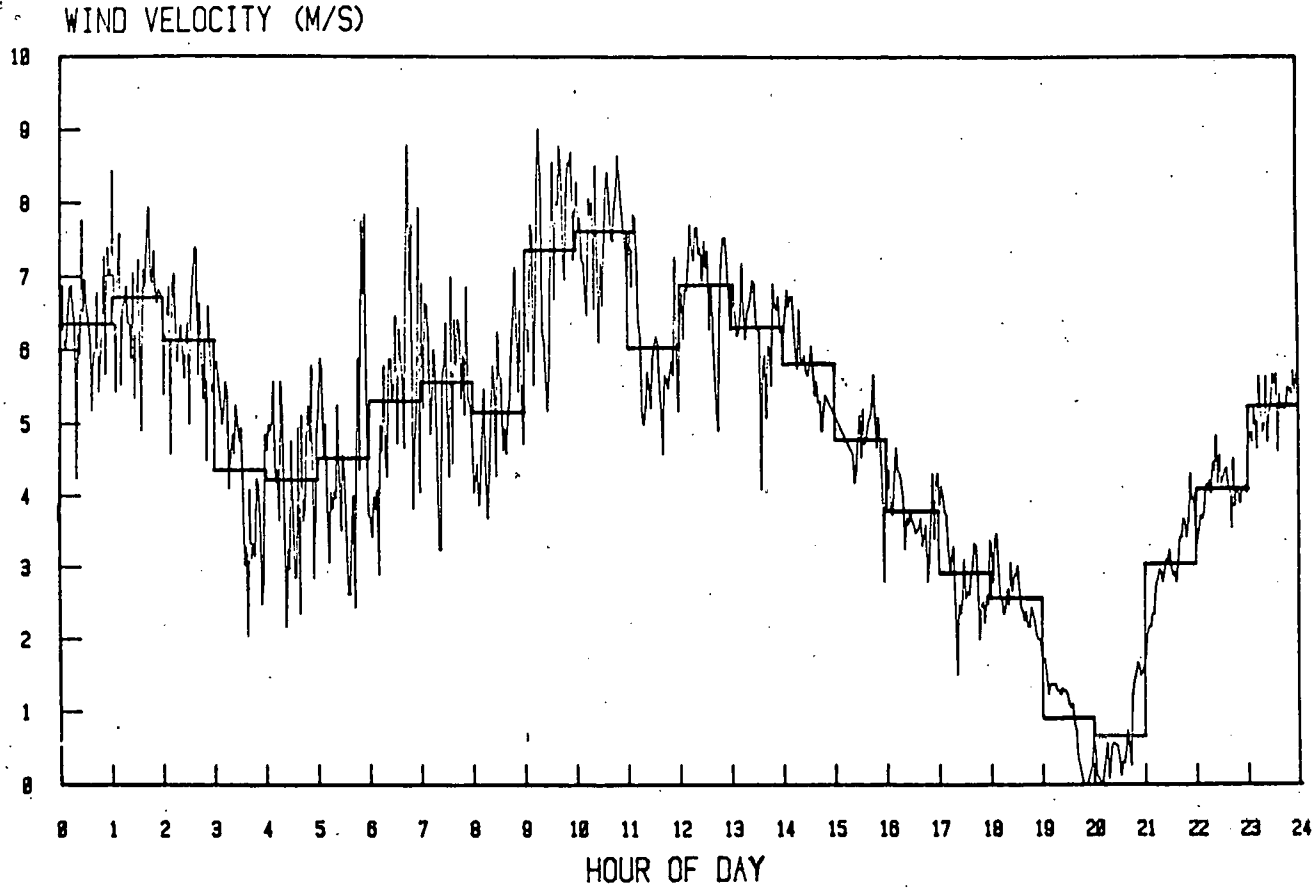

Figure 2 - Hourly Average Compared with Two-Minute Wind Data

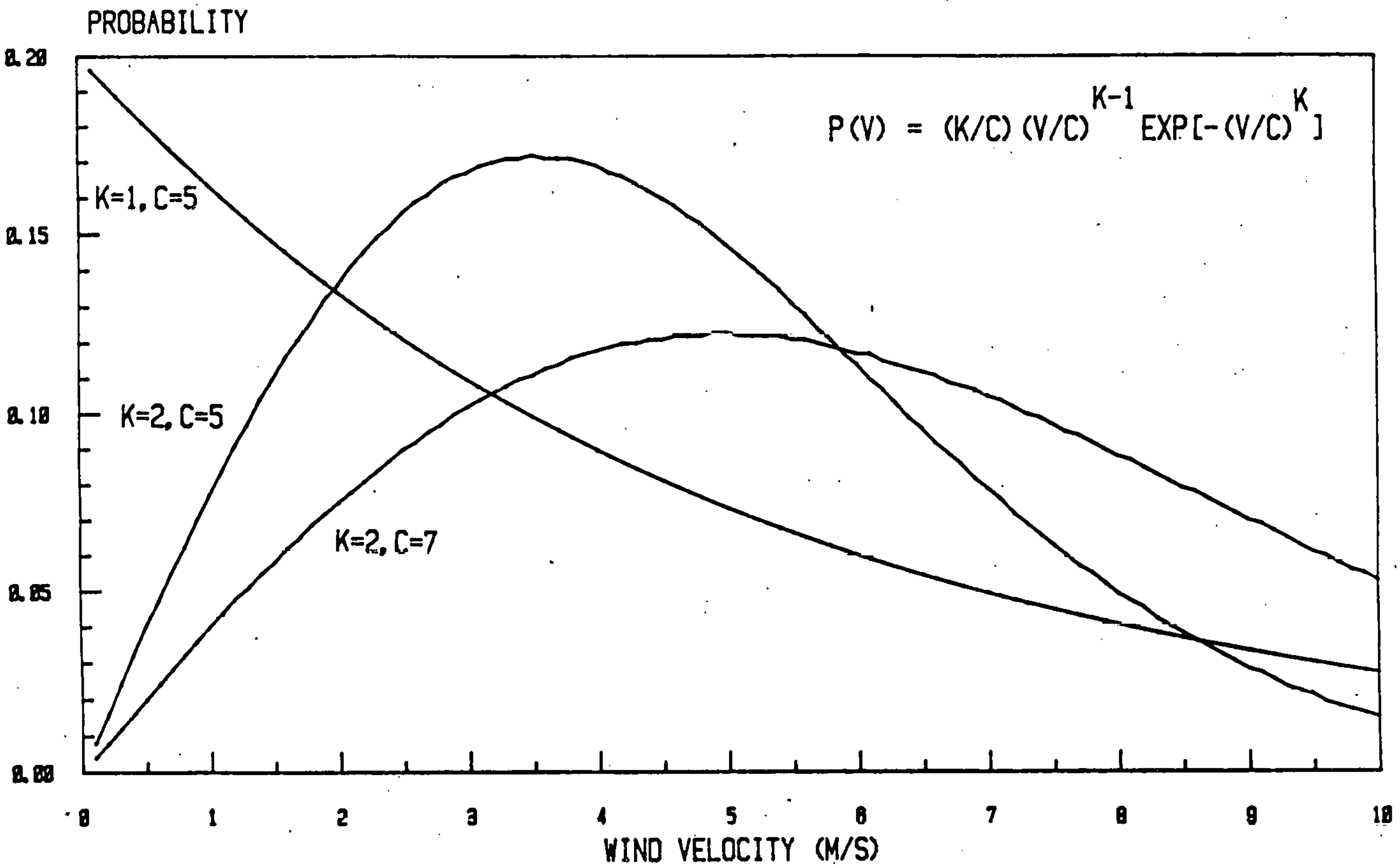

Figure 3 - WEIBUL Wind Distribution

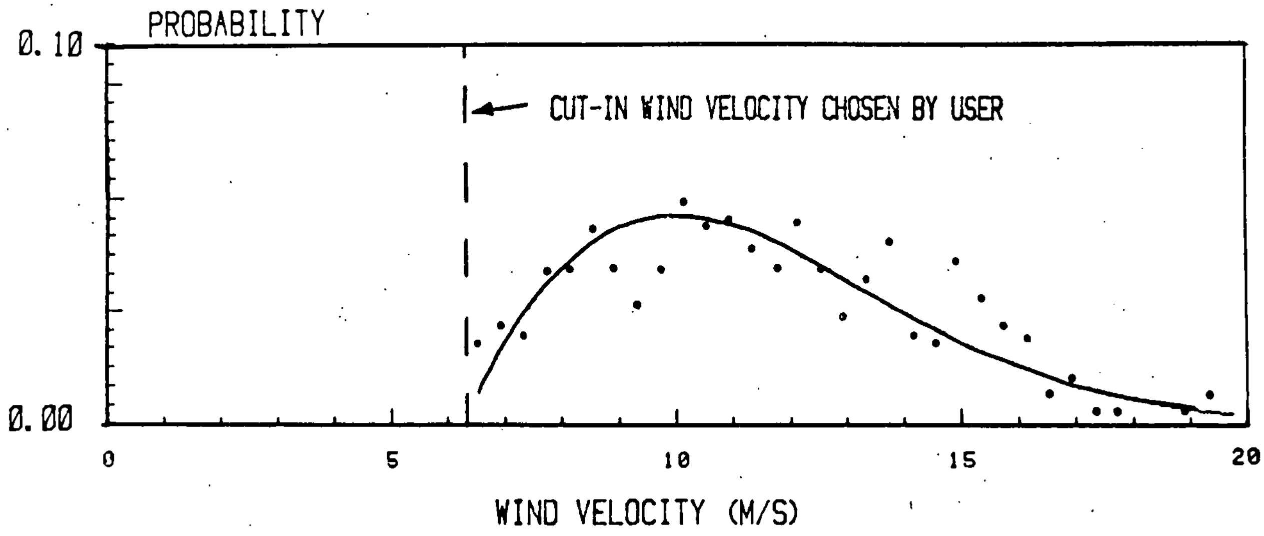

Figure 4 - WEIBUL Curve Fit

ROSEW (Representation of Solar Electric - Wind) to calculate the probabilities of different levels of WECS power output. The Weibull distributions are divided into sections as follows: below cut-in wind velocity, from rated through cut-out wind velocity, above cut-out wind velocity, and up to ten intervals between cut-in and rated wind velocity. Figure 5 illustrates these sections. The probability that the wind velocity is in any one of these sections can be easily calculated from the Weibull wind distribution. The accompanying representative WECS power output for each of these sections can be found in one of two ways. First, a velocity wind power table can be input to ROSEW, with a given wind velocity resulting in a corresponding power output. This table can be obtained from the performance history of an operating machine or another reliable source. Second, one can calculate the power from the wind power equation:

$$p = 1/2\ C_p \eta \rho V^3$$

where

C_p = Power coefficient (aerodynamic efficiency) as a function of machine tip speed ratio;

ρ = air density;

V = wind velocity; and

η = gearbox, generator, and transformer efficiency.

The first method is recommended if a verifiable velocity power curve is available.

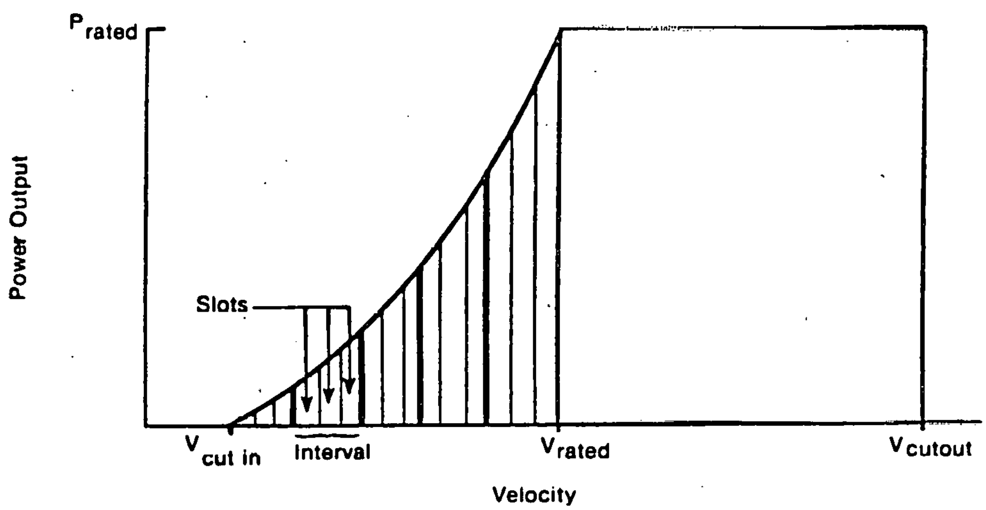

Figure 5 - Wind Turbine Power Curve

For each velocity interval that was created between cut-in and rated wind velocities, a representative wind velocity is needed to estimate the electrical power output for this interval. The average velocity for the interval could be used, but this ignores the cubic relationship between velocity and power. To account for the cubic relationship, the following procedure is used: each interval is divided into a number of slots, with the probability of the wind occuring in each slot being calculated from the Weibull distribution. Using this probability data, one determines the "power-probability weighted" wind speed:

$$V_{int} = \sqrt[3]{\frac{\sum_{s=1}^{n} (P_s * \overline{V}_s^3)}{P_{int}}}$$

where

V_{int} = interval "power-probability weighted" wind speed;

n = number of slots per intervals;

$\overline{V}_s$ = average velocity per slot;

P_s = probability of wind in slot; and

P_{int} = probability of wind being in interval.

This wind speed represents the interval more accurately than the interval mean wind speed in power calculations.

The WECS power calculated so far ignores the possibility that some component of the WECS or its accompanying electrical system may fail and prevent any electrical generation. The forced outage rate of the WECS is the probability that such a failure would occur during the time that the WECS is available for operation and not down for maintenance. The preferred method of forced outage treatment is to appropriately adjust the probabilities of WECS electrical output.

The results of ROSEW using Weibull distributions consist of power-probability pairs (WECS electric power output and associated probability of occurrence) for zero power output, rated power output, and each power output for the intervals between cut-in and rated wind speeds. If WTP has been used to process the weather data instead of WEIBUL, then ROSEW calculates a single WECS power output for each hour of the year. Either way, this ROSEW output is input to the program ULMOD (Utility Load Modification).

Load Modification

ULMOD can account for WECS electricity production in utility planning models by reducing the forcasted utility loads by the amount of intermittent generation. Since both utility loads and wind resources are diurnal, the load must be reduced hourly by using either all days of each month or a typical week each month. This simple reduction in hourly loads is an acceptable modeling procedure because of the extremely low variable cost of electricity production from the WECS. The utility will always accept this low variable cost energy, except possibly in a case when significant WECS capacity could bring this new reduced residual load below the minimum allowable base load for hydro or large coal or nuclear units. This rare situation might require either the dumping of excess WECS generation or agreements with neighboring utilities to purchase this excess energy.

The power-probability pairs (for each hour of a typical day each month) that result from a Weibull execution of ROSEW are used by ULMOD to reflect the WECS electrical output. This is done by subtracting the WECS hourly output distribution from the appropriate hourly utility load. The result is a distribution of residual loads for each original utility load, each residual with an associated probability of occurrence. This intermediate result may be used in a variety of ways. If desired, each hour's distribution of residual loads may be probability weighted into a single hourly residual load. This would be equivalent to subtracting the expected or average hourly WECS output from the utility load, and the probability information is lost. This type of result is called the Expected Residuals.

The preferred treatment is to use all the hourly residual distributions for each month to create a set of hourly residual loads which may be used by any of a number of utility planning models (loss of load probability, production cost, or expansion planning). Since these models can typically use only one load value per hour, the several residual load values per hour must be somehow consolidated. Also, it is usually important to maintain the chronology of the utility loads. ULMOD handles these points in the following manner: First, all the residual load distributions (one distribution per hour) for a month are ordered by decending residual loads, with each residual's associated probability being retained. This step removes the chronological order of the residuals. The next step is to reduce this number of residual points until it equals the number of hours in the month. This is done by starting at the highest value of the decending order residual loads and accumulating the probability of this load and enough of the following load's probabilities to yield a total probability of 1.0. These loads in this group are probability weighted to yield a single load. This accumulation procedure is repeated for all the residuals equal to the number of hours in the month (there will be no points left over). These results are called Accumulated Residuals.

To recover the chronological information lost in the sorting process, the Expected Residuals are determined, as mentioned earlier, and also sorted into decending order. This time the associated day and hour of occurrence is retained. The day and hour of the largest Expected Residual is assumed to correspond to the largest Accumulated Residual. By continuing for all points, the Estimated Chronological Accumulated Residuals are determined.

The added accuracy obtained by use of the Accumulated Residual loads is especially important near the peak demand of the utility due to the importance of these hours in reliability considerations. Further background and details of these residual load manipulations are explained thoroughly in Refs. 8, 9, and 11.

If the Weibull method was not chosen and single hourly WECS powers were sent to ULMOD, then these powers are simply subtracted from the forecasted load.

ULMOD can also accommodate utility load forecasting uncertainty, a very important consideration in utility planning. Reference 10 contains an in-depth discussion of load forecasting uncertainty in relation to solar generation variability. ULMOD accommodates the load uncertainty by allowing up to five input amounts by which the forecasted loads might vary from the forecasted mean and a probability that each variation will occur. Each of these five values represents an interval of MW loads (such as segments of a Gaussian distribution), each interval having a probability of occurrence. Usually one of these intervals will be centered around the mean forecast (zero MW variance).

Utility Planning Models

Next, the monthly load representations that have been determined by ULMOD are sent to the utility planning models - an expansion model and/or a production cost model. Both models are commonly used among the electric utility industry and are not available from SERI.

The expansion model is an automated technique for optimally developing a schedule of conventional generating unit additions. An expansion scenario is usually considered optimal if there is no other feasible scenario with a lower cumulative present worth of utility revenue requirements during the planning horizon. Typical input parameters include descriptions of each current and future generation type, financial parameters, utility load shapes, future energy and peak requirements, and the minimum amount of capacity in excess of the expected peak demand (reserve margin). The result of an expansion planning model includes a year-by-year schedule of conventional unit additions and possibly estimates of the operation of available generation capacity with associated costs and fuel usage. Due to the approximations usually required to keep the expansion problem within reasonable computer time limits, the operation estimates produced are usually less precise than those available with a detailed production cost model.

Typical utility production cost models (PCM) estimate specific monthly operating expanses of the utility system for one or more years. Input data required include descriptions of each generating unit, fuel costs, load descriptions, and description of electricity sales or purchases to other utilities. PCMs usually consider the system's required spinning reserve and approximate the scheduling of each generating unit's planned maintenance. Potential equipment failures (forced outages) are usually accounted for by either capacity deration or probabilistic techniques. The latter method is usually preferred. The probabilistic PCMs also give two reliability measures that are gaining popularity: the amount of expected unserved energy and the expected number of hours of capacity deficiencies. Both measures are related to the traditional loss of load probability results.

The value of WECS to the utility that is to be found contains two components. The operations component of WECS value consists of savings of fuel, operations, and maintenance costs to the utility due to the addition of WECS. The capacity component of WECS value consists of savings to the utility due to conventional capacity that will not be required in the future due to the addition of WECS. This second component is often referred to as WECS capacity credit or load carrying capability.

Determination of the operations component of value consists of comparing the utility's conventional operating costs before and after the addition of WECS to the utility system. Thus, execution of an expansion or production cost model for a base case with zero WECS generation (unmodified load shape), and a change case for each WECS penetration scenario (modified load shapes from ULMOD) is required. The difference in the total operating costs between the base and change case divided by the WEC rated capacity gives the operating component of value in $/rated kW.

If it is felt that the year-to-year production cost estimates of the expansion model are sufficiently accurate, then the use of a detailed production cost model may be avoided. Whether this is possible depends on the expansion model used, the desired precision of the results, and the complexity of the generating system. Several test comparisons of the expansion model cost estimates with those of the detailed production cost model are advisable.

The capacity component of value is found by using the expansion model for both the base and change cases. Comparison of these results will indicate the amount of conventional capacity (in MW) that is not required due to the WECS capacity assumed. In obtaining this capacity credit, one must give attention to the utility system's reliability index (such as loss of load probability) for both the base and change case by use of a probabilistic production cost model or a loss of load probability (LOLP) model. Only when the reliability index is the same for the base and change case can a capacity credit for the WECS be indicated. Once this capacity credit has been found, simple application of the displaced conventional generating unit's total installed cost will yield a capacity component of WECS value ($/rated kW).

Financial Model

As the last step in the WECS value determination, FINAM performs the previously described economic comparison between the base case (no WECS generation) and each of the change cases. Some utilities may prefer to use their own corporate model instead of FINAM to perform the necessary calculations. All calculations in FINAM are based on present worth economics. A maximum of ten change cases can be analyzed simultaneously. The results of FINAM are the gross and marginal present value in $/rated kW for the WECS capacity of each change case. FINAM can also perform a wide variety of sensitivity studies to determine the impact of certain economic parameters on the results.

Use of Results

The WECS marginal value results produced from FINAM are extremely useful to the utility planner. By using the equation of the marginal value curve produced from FINAM, one can determine the maximum amount of WECS that can be economically justified for addition to the utility by finding the point on the marginal value curve that equals the installed cost for the WECS being considered (see Figure 6). The installed cost of the WECS must include the present worth total of all costs associated with the WECS over its operating lifetime.

Because most wind machines are rated at different wind speeds, a comparison between different wind machine's values ($/rated kW) is not valid. Only an inspection of a specific wind machine's marginal value compared with installed cost will indicate its economic performance for this specific utility system.

Sample Results

Work to date with wind data obtained every two minutes has shown successful Weibull curve fits, with annual WECS capacity factors using the Weibull distribution being within one percent of the actual capacity factor.

Analysis of a large, predominantly oil-fired utility has been performed in parallel with two subcontractors possessing different methodologies and computer models. Comparison of results have verified the intended performance of the computer models WEIBUL, ROSEW, ULMOD, and FINAM. A total value for MOD-2 wind turbines was determined to be $1644/kW assuming a 5% penetration (5% of peak demand), a site with a 31% annual MOD-2 capacity factor, and reasonable economic assumptions. Results obtained by the subcontractor methodologies varied from this result by about 2%, with the differences accounted for by methodological differences in the load modification and production costing sections.

Future Activities

SERI plans to include the effect of spatial diversity of the wind resource in the wind model to better represent the aggregate performance of many wind turbines. Once this is included, the problem of finding a utility's "avoided cost" of small distributed wind machines could be effectively handled. This determination of avoided cost is currently of great interest to utilities due to legislative action (PURPA 210). Operational realities of wind turbines such as control startup times and blade orientation will also be included in the wind model when more definite information on these factors is available. Other future efforts will be to extend the analysis capability to photovoltaic and solar thermal systems. SERI is also considering modifications to ULMOD that will include storage dedicated to the solar generation system.

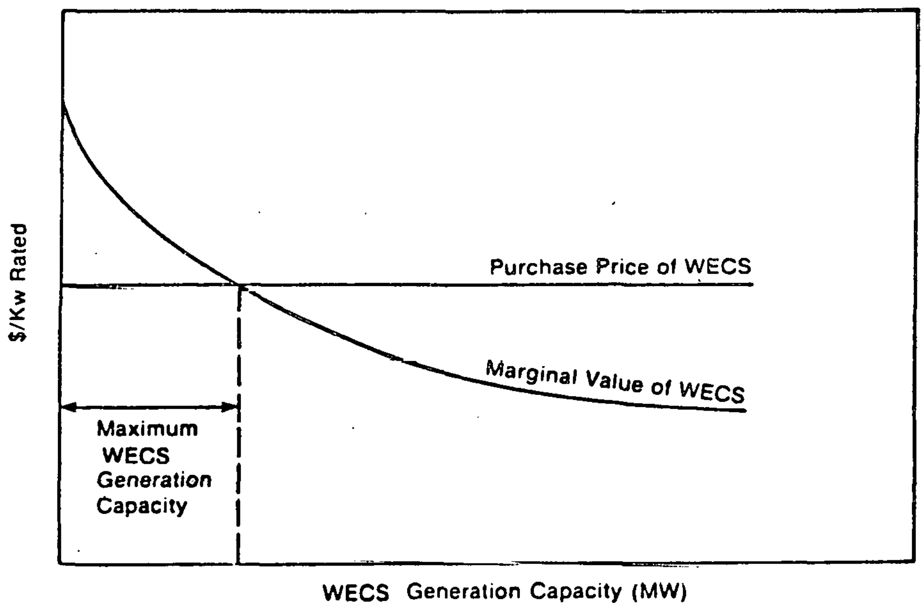

Figure 6 - WECS Marginal Value Cost Comparison

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