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WIND ENERGY SYSTEMS APPLICATION TO REGIONAL UTILITIES

Executive Summary

June 1979

Work Performed Under Contract No. AC01-76ET20063

JBF Scientific Corporation
Wilmington, Massachusetts

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WIND ENERGY SYSTEMS
APPLICATION TO REGIONAL UTILITIES
EXECUTIVE SUMMARY

by

JBF Scientific Corporation
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Wilmington, MA 01887

Contract No. EX-76-C-01-2438

U.S. Energy Research & Development Administration
Operations, Division of Procurement
Washington, DC 20545

June, 1979

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ABSTRACT

This study developed a generic planning process that utilities can use to determine the feasibility of utilizing WECS (Wind Energy Conversion Systems) as part of their future mix of equipment. While this is primarily an economic process, other questions dealing with WECS availability, capacity credit, operating reserve, performance of WECS arrays, etc., had to be addressed. The approach was to establish the worth, or breakeven value, of WECS to the utility and to determine the impact that WECS additions would have on the utilities mix of conventional source.

The value of WECS was established by determining on an hour-by-hour basis, the wind power available and what portion of the load it satisfied.

The economic analysis was developed around the concept of maximizing the net present value of the savings due to WECS. This approach yields the maximum number of dollars that can be applied to purchase the WECS units and is commensurate with the utilities' desire to minimize operating costs. Finally, the results were presented as marginal savings, or the savings that would result from the addition of one more unit, at the penetration level of interest.

Earlier regional studies utilized WECS primarily in the marginal savings, or fuel saver, mode. That is, the optimum mix of conventional sources were selected by the utility to satisfy its load at minimum cost, assuming no WECS. The WECS were then added to the utility to essentially save fuel. In this study a second method was also investigated in which the wind was utilized to satisfy as much of the load as it could and then the mix of conventional sources was reoptimized within given construction and requirement schedules to satisfy the remaining load. This approach allows WECS to be integrated into the utility mix, in an optimum manner, rather than simply as a fuel saver. Both the fuel saver mode and this new reoptimized mix mode were investigated on this contract.

The planning process was applied to a utility in Southeastern Massachusetts (NEGEA) using a 500 KW WECS machine design. It was found that the results were similar for both the fuel saver and reoptimized mix modes up to peak load penetrations where the on-line WECS rated power was 15% of the expected yearly peak load. At higher penetrations the reoptimized mix mode had a higher breakeven value but the fuel saver mode saved more fuel.

Capacity displacement was a small component of the total value, approximately 10%. The major value is associated with fuel savings except at penetrations larger than 15%, at which time fixed cost savings are achieved by buying less baseload plants and more peaking units.

The first 500 KW WECS installation would be worth \$700/KW (35 mills/kWh to NEGEA (1978 dollars) assuming it began operation in 1985. Each additional unit would be worth less due to its displacing less valuable fuel.

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I. INTRODUCTION AND OBJECTIVES

Wind Energy Conversion Systems (WECS) can be used to convert wind energy into electrical energy. This energy source has appeal because of its simplicity, lack of pollution byproducts, and utilization of a renewable resource. Like other solar sources, WECS generation raises questions because of the intermittent and relatively unpredictable nature of the wind.

This study, begun in June of 1976, was intended to consider the WECS resource and technology from the perspective of an electric utility, and develop methods that would allow a utility planner to establish the value of wind systems as part of a utility's future mix of equipment.

The specific study objectives were to:

- . Develop a planning process for evaluation of Wind Energy Conversion Systems as an integral part of a Central Utility System mix.

The planning process should provide a utility planner with the analytical tools necessary to establish the economic value of a WECS to the utility.

- . Demonstrate the planning process by applying it to a specific utility.

A utility in Southeastern Massachusetts was selected and the analysis conducted for a number of WECS designs. The value of WECS, in \$/KW and mills/kWh, was determined for a number of penetration levels.

- . Investigate both capacity and energy displacement of conventional sources, due to the addition of WECS.

Fuel savings and capacity displacement (credit) were established by adding WECS to the utilities planned mix of conventional sources (marginal savings mode). A new mode was also investigated in which the WECS was optimally introduced into the conventional source mix selection process (reoptimized mix mode).

- . Identify key issues and requirements that would alter the relationships between conventional power technology and WECS.

The sensitivity of WECS value to the utility was investigated, for technical and economic parameters. Research and analysis needs were identified.

II. KEY FINDINGS

This study has led to the following principal conclusions:

- . The value of the first 500 KW WECS installation to NEGEA is \$700/KW (\$-1978) which has an energy value of 35 mills/kWh.

This value represents the maximum cost that NEGEA could incur for the WECS, transportation to the site, erection, land acquisition, and tie to the grid - and breakeven over the WECS assumed lifetime of 30 years. This value is based upon a 6%/year inflation and no escalation of fuel costs above inflation.

- . WECS value decreases for each unit added to the utility.

This decrease is primarily due to each additional unit having less costly fuel to displace.

- . If WECS are added to the utility's planned mix of equipment (marginal savings mode), approximately 90% of the value is obtained from fuel savings and 10% from capacity displacement.

Utility planners are reluctant to accept the capacity displacement concept, until it has been demonstrated, however.

- . If WECS are optimally integrated into the utility equipment mix selection process (reoptimized mix mode), the WECS value is obtained from fuel savings, capacity credit, and fixed cost saving due to a shift from baseload to peaking equipment.

For penetrations between 0 and 15% the value components are almost the same for the marginal savings mode and the reoptimized mix mode. Above 15%, the reoptimized mix mode generates significant up-front fixed cost savings, and larger total savings.

- . WECS added in the marginal savings mode (or fuel saver mode) maximize the fuel savings. WECS added in the reoptimized mix mode maximize the cost savings.

At high penetrations, the first mode saves more oil and the second mode results in more dollar savings that can be used to purchase the WECS. Up to about 15% penetration, however, the results are similar for either mode. Both modes save fuel over the case using only conventional generating equipment.

- . WECS value to NEGEA is enhanced by its large component of oil-fired equipment.

NEGEA's plans call for reducing their oil-fired component to 68% by 1985, by adding more nuclear capacity. In 1977 NEGEA's mix was 83% oil fired.

- . Potential sites in Southeastern Massachusetts were identified for 593 large WECS.

The availability of the potential sites was not established on this study.

- The value of WECS to a utility can be established by augmenting existing utility planning methods.

Augmentation is necessary in the determination of system reliability, the handling of load data, and the determination of hourly power output to accommodate the stochastic nature of the wind resource.

- The value of WECS to a utility varies with the utilities equipment mix, its wind resource, and its load shape.

NEGEA's large component of oil-fired equipment, its good wind resource, and good correlation between its wind and load diurnal shapes generates a good WECS value for coastal New England.

- A WECS value analysis can be run for a utility, using one WECS machine design, and the results expanded to include other WECS designs, without rerunning the entire analysis.

Each machine, however, must have its capacity factor determined using the same hourly wind speed data as used for the initial machine. Comparisons are made, based upon the value for a constant annual energy output for each machine of interest.

III. PROJECT TEAM

The project team for this study is shown in Figure 1. JBF Scientific Corporation was the prime contractor. The Georgia Institute of Technology provided assistance in the areas shown. NEGEA, the utility providing service to Southeastern Massachusetts, provided extensive data and assistance to aid in characterizing the utility and its loads.

IV. APPROACH

The methodology used to establish the value of WECS to a utility is shown in Figure 2. Standard utility methods exist for taking historical load data, conventional generating equipment, and reliability goals and calculating the fixed and variable costs associated with meeting the projected load. The added requirement for WECS consists of using hourly wind data, and a specified WECS to establish hourly wind power expected. This hourly wind power is then used to satisfy as much of the load as it can and the remaining load satisfied with conventional sources. The reliability analysis must also be modified to allow inclusion of a stochastic source (WECS).

FIGURE 1. PROJECT TEAM

FIGURE 2. UTILITY PLANNING MODEL

The approach used is to first calculate the conventional source fixed and variable costs, to meet the load and reliability requirements, with no WECS. WECS are then added, at the desired penetration, and the conventional source fixed and variable costs again determined. The costs will be less since some of the load had been satisfied by the WECS. The WECS will have also satisfied some of the reliability requirements, reducing the reserve margin requirement for conventional sources. This saving is called capacity cost savings. The total "savings" in fixed and variable costs are then used to establish how much the utility could spend for the WECS and break even over its lifetime. This is the marginal value or fuel saver mode.

A second approach developed on this contract involves optimally integrating the WECS into the equipment mix selection process - the reoptimized mix mode. In this mode, the analysis is similar except that for each WECS penetration analysis, the optimum mix of conventional sources is re-established after using the WECS power as a negative load. The WECS power modifies the hourly loads that the utility uses to select its optimum mix of conventional sources. In the reoptimized mix mode, for penetrations greater than 15%, there is a significant shift away from future baseload equipment acquisitions toward more peaking units. The WECS value in this latter mode comes from fuel savings and capacity credit (as in the marginal savings mode) but also from capital cost savings related to the shift from baseload to peaking equipment.

As shown in Figure 2, conventional source savings are obtained in variable costs (basically fuel savings) and fixed costs (capacity credit and mix changes away from baseload), when WECS are introduced. There are also costs that must be charged against the WECS, due to siting and grid interface requirements and additional operating reserve requirements due to the uncertainty in wind speed predictions. When all of the savings and costs are combined, the result is the savings that can be used to offset the cost of purchasing and operating the WECS, that is, the value of WECS to the utility.

The final step in the generic planning process is to compare the calculated WECS value to a manufacturer's schedule of WECS costs, to establish the maximum (if any) WECS penetration that is economically viable.

V. WIND SYSTEM INVESTIGATION

Wind Speed

An economic analysis of stochastic systems (WECS) requires an hourly (or three-hourly) determination of the power that can be extracted from the wind. Wind data was obtained for a five year period, starting in 1970, for the eleven stations shown in Figure 3. The data was used to develop average wind speed contours, based upon distance from the shore, height above sea level and terrain roughness. Figure 4 shows that the annual average wind speed is similar (approximately 5 m/s) in the entire Cape Cod service area of NEGEA. This minimizes the number of WECS designs that the utility need purchase and operate. A 6 m/s contour was found in the beach areas but this was eliminated because of site unavailability.

FIGURE 3. METEOROLOGICAL SITES IN SOUTHEASTERN MASSACHUSETTS

FIGURE 4. WIND SPEED CONTOURS IN THE NEGEA CAPE COD SERVICE REGION (REFERENCE HEIGHT=10 METERS)

WECS Power Output

Based upon the 5 m/s annual wind speed, and the machine designs available in 1976, a 500 KW design was selected for the NEGEA analysis (1). The machine's design speed was 5.4 m/s. Figure 5 shows the machine characteristics.

Power output can be calculated using a method where the WECS performance characteristic is analytically described with a polynomial and the hourly wind speed converted to hourly power by deterministically applying it to the polynomial. A second method of calculating wind power is a probabilistic approach using the Weibull distribution approach. This latter methodology was used for the NEGEA analysis, using the Falmouth, Mass. hourly wind data as a representative site in a WECS array. A deterministic analysis was also conducted, for the year 1975, and similar results obtained.

Figure 6 shows the average capacity factor for the 500 KW WECS, for each phase. The year was divided into 13 equal four-week phases and the figure shows the average capacity factor, for each phase, for each hour of the day. Capacity factor, or wind power output, is shown to peak in the winter and reach a minimum in the summer. It also peaks in the late afternoon and shows a minimum in the late evening and early morning hours. As will be shown, this wind power-time profile correlates well with the diurnal and seasonal load shapes. There was little correlation, however, between the wind and the load, on an hourly basis.

While the basic analysis was conducted for NEGEA using the 500 KW design, a family of other designs was postulated and examined to verify the hypothesis that the results of a value analysis for one machine design can be reasonably extrapolated to other designs. Table 1 shows the cut-in, and rated wind speeds for four machine designs. The ratio of these two parameters is similar. A ratio of 2.04 was assumed as a constant and 10 machine designs postulated, as shown in Table 2. Using the Falmouth wind data, the capacity factor for each machine design was calculated, as shown in Table 2. The value analysis was also run for each of the 10 machines and the results will be presented later in this report.

Thus, while a full life cycle value analysis was only run for the 500 KW machine, the results can be interpreted for 10 machine designs, spanning the design characteristics of many of the present, and future, horizontal axis machines.

(1) General Electric Company, Design Study of Wind Turbines 50 KW to 3000 KW for Electric Utility Applications Analysis and Design, ERDA/NASA-19403-76/2, February 1976.

Table 1. Characteristics of Specific Machines at Hub Height

<u>Machine</u>	<u>$V_{\text{cut-in}}$ (m/s)</u>	<u>V_{rated} (m/s)</u>	<u>$V_{\text{rated}} / V_{\text{cut-in}}$</u>
GE 500-KW	4.57	9.42	2.06
Mod OA	4.3	10.2	2.37
Mod 1	7.1	14.5	2.04
Mod 2	6.3	12.7	2.02

Table 2. WECS Performance Parameters at Hub Height of 50 Meters

<u>Assumed $V_{\text{cut-in}}$ (m/s)</u>	<u>Calculated V_{rated} (m/s)</u>	<u>Calculated C_p</u>
2.65	5.42	.71
3.13	6.42	.64
3.63	7.42	.57
4.12	8.42	.50
4.61	9.42	.4435
5.10	10.42	.39
5.59	11.42	.34
6.08	12.42	.31
6.57	13.42	.27
7.06	14.42	.24

FIGURE 5. POWER VS WIND SPEED FOR GE 500 - kW WECS

FIGURE 6. AVERAGE CAPACITY FACTORS BY HOUR OF THE DAY AND PHASE OF THE YEAR

Siting and Grid Interface Considerations

A siting methodology was developed that could be used by a utility to select potential WECS sites. It involved:

- . identifying preferred geographical areas,
- . defining WECS land requirements and restrictions,
- . eliminating technically unacceptable sites,
- . evaluating legal/social/environmental factors,
- . defining and estimating utility interface costs, and
- . selecting the actual sites.

Using the wind contour map, Figure 4, it became apparent that annual mean wind speeds were similar over the region of interest, so any available site would be acceptable based upon wind speed considerations. Thus, for this utility case there were no preferred sites. This might not be the case, however, for utilities that have high, medium and low wind regime regions.

The next step was to define WECS land requirements. The approach used was to assume that the area required would be circular with a radius of one WECS vertical height, including the rotor. It was further assumed that the tower footprint would be purchased and the remaining land obtained through an easement. For the 500 KW machine the area required was 4.7 acres. Land costs were estimated by NEGEA to be approximately \$3400 per acre (\$1978).

A series of site restrictions were also defined covering RF interference, noise, aircraft clearance zones, public land, aerodynamic interface, soil structure, area seismic properties, topography, migratory birds, etc.

Technically unacceptable sites were then eliminated, resulting in 593 potential WECS sites being identified. These were grouped into four subfarms as shown in Figure 7. It should be emphasized that the number of sites that could actually be purchased by the utility was not investigated.

The next step in the process would be to consider legal/social/environmental factors, as possible site restrictions. These were not considered on this study.

Grid Interface Requirements

The requirements for grid interface were examined, as shown in Figure 8. It was assumed that the WECS output voltage would be 4 KV and this would be stepped up to 23 KV via pad mounted transformers. The 23 KV would then be raised to 115 KV, in a substation, and then tied to NEGEA's grid.

Table 3 presents a summary of the siting and interface costs, indicating that the siting and interface costs are estimated to be approximately \$98/KW (\$1978) for the 500 KW machine.

FIGURE 7. WECS FARMS IN THE NEGEV REGION

FIGURE 8. TYPICAL SCHEMATIC FOR CONNECTING WECS TO NEGEV POWER GRID

Table 3. WECS Siting and Interface Cost* Summary
(\$/Site in 1976 Dollars)

Transmission Lines		12,900
Local Transformers		2,200
Substation		2,700
Miscellaneous		
Title Search Fees		2,500
Survey Plot Plan		5,500
Negotiating Agent		500
Access Road		1,500
Clearing Property		2,500
Environmental Impact Statement		1,500
Wind Measurements (593 Sites)		4,200
Land:		
Easement	684	
Purchase	6,656	
Total		<hr/>
Total Cost Per Site		43,400
Dollars/kW		\$ 87 (1976\$)
		\$ 98 (1978\$)
		\$137 (1984\$)

*To convert to 1978 dollars, multiply by 1.12.

VI. UTILITY CHARACTERIZATION

NEGEA was selected for the utility analysis, representing a coastal New England utility serving a region with good winds. The year 1985 was selected as the year in which it would be assumed that WECS would become operational on its grid.

Table 4 shows NEGEA's mix of equipment in 1977 and its projected mix for 1985.

In 1977 17% of NEGEA's capacity was nuclear and the remainder oil fired. They plan on adding almost 100% nuclear between 1977 and 1985. In 1985 approximately 32% of their capacity is planned to be nuclear. These additions will drive their mix toward more optimum economics for the generation costs of energy.

The diurnal load shapes for NEGEA, as shown in Figure 9, peak in the afternoon and early evening hours. NEGEA had a 1977 peak load of 554 MW and expects a peak load of 903 MW in 1985. Their total installed capacity to meet this peak, and reliability requirements, will be 1111 MW in 1985.

For purposes of the WECS value analysis, each four-week phase of the year was divided into the four diurnal load shape types shown in Figure 9. Comparison of Figures 1 and 9 show the good wind-load correlation found on a diurnal basis. There was poor correlation, however, between hourly winds and hourly loads, based upon the five years of data.

The single year analysis methodology is shown in Figure 10. Historical load data was used to establish the 1976 diurnal load shapes. These were then extrapolated to 1985 using the ratio of the 1976 peak load to the 1985 peak load. This is a standard methodology for NEGEA. The optimum economic mix of conventional sources was established for no WECS installed - the marginal savings mode (also called the fuel saver mode). The optimum mix was also determined with various levels of WECS on-line, after using the WECS power output as a negative load - the reoptimized mix mode. The single year conventional source production costs were then established (annual costs), assuming that the WECS had been added at no cost.

Table 5 shows the NEGEA equipment mix for both modes of operation. The 0-WECS mix is, by definition, the optimum mix in the marginal savings mode. It is important to emphasize that the reoptimized mix mode, as shown in the table, results in a shift toward more peaking, and less baseload, equipment. This translates into a fixed cost saving which will be shown to be significant.

The annual costs were calculated for the mixes shown in Table 5 and the 1985 NEGEA diurnal load shapes. A representative load duration curve is shown in Figure 11 to indicate where the variable cost savings come from. Most of the variable cost savings are obtained from peaking and intermediate fuel savings.

The 1985 diurnal load shapes and winds were utilized to establish the remaining loads that conventional sources would have to meet and the results are shown in Figure 12, plotted as load duration curves. Note that as the

Table 4. NEGEA Current and Planned Future Mix

Fuel Type	1977 Capacity		Addition Capacity Planned for 1985		Total Capacity 1985	
	MW	% of Total	MW	% of Total	MW	% of Total
Nuclear	151	17	208	99.5	359	32
#6 Fuel	596	66	1	0.5	597	54
#2 Fuel	155	17	-	-	155	14
	902		209		1111	

Table 5. 1985 Optimum Conventional Equipment Mix* for the Marginal Savings** and Reoptimized Mix Modes

		Plant Capacity (MW) for Various Percent WECS on-line levels					
Plant No.	Name	0&2-1/2	5&10	20	40	80	120
1	Conn. Yankee	26	26	26	26	26	26
2	Mass. Yankee	8	8	8	8	8	8
3	Vt. Yankee	12	12	12	12	12	12
4	Me. Yankee	31	31	31	31	31	31
5	Pilgrim 1	74	74	74	74	74	74
6	Seabrook 1	35	35	35	25	--	--
7	Seabrook 2	35	35	35	25	--	--
8	Pilgrim 2	18	18	18	--	--	--
9	Nepco 1	50	50	50	--	--	--
10	Other Nuclear	70	66	25	--	--	--
11	Canal 1	143	143	143	143	143	143
12	Canal 2	292	292	292	292	292	292
13	Wyman 4	8	8	8	8	8	8
14	Other Intermediate	1	1	2	8	24	2
15	Cannon 1 & 2	61	61	61	61	61	61
16	Kend./Blkstn	73	73	73	73	73	73
17	New Bedford GT	85	85	85	85	85	85
18	C&V Diesels	22	22	22	22	22	22
19	Kendall GT	48	48	48	48	48	48
20	Blackstone 1	16	16	16	16	16	16
21	Blackstone 2	3	3	3	3	3	3
22	Other Gas Turbine	0	4	44	151	185	207

*Total Capacity equals 1111 MW

**The Optimum Mix for the Marginal Savings Mode is the 0-WECS Mix

FIGURE 9. HISTORICAL DIURNAL LOAD SHAPES FOR PHASE 1, BASED UPON 5 YEARS OF LOAD DATA, SCALED TO THE 1975 PEAK

FIGURE 10. PRODUCTION COST MODEL FOR CALCULATING IMPACT OF WECS ON UTILITY SINGLE YEAR OPERATING COSTS

$$\begin{aligned}
 A_P, A_I, A_B &= \text{ENERGY PROVIDED BY WECS} \\
 \bar{C}_P, \bar{C}_I, \bar{C}_B &= \text{AVERAGE INCREMENTAL COST OF ENERGY} \\
 A_P \bar{C}_P + A_I \bar{C}_I + A_B \bar{C}_B &= \text{VARIABLE SAVINGS}
 \end{aligned}$$

FIGURE 11. REPRESENTATIVE VARIABLE COST SAVINGS FOR A WECS PENETRATION INTO A UTILITY GRID.

FIGURE 12. NEGEA NET LOAD DURATION CURVES EXPRESSED AS A PERCENTAGE OF THE 1985 PEAK LOAD (902 MW)

percentage of WECS on-line increases, the remaining load to be met by conventional sources changes character in a manner such that the reoptimized mix shifts toward less baseload and more peaking equipment. This results in a major change in the conventional source mix the utility would purchase for generating electricity at a minimum cost.

This section of the generic planning approach yields the optimum equipment mix and the production costs associated with operating that mix for the first year for which the plan is being developed. The outputs are the fixed and variable costs for conventional sources in the first year of analysis. The next section discusses capacity credit and then the single year analysis is expanded into a life cycle analysis to determine the conventional source cost savings that can be attributed to the WECS..

VII. CAPACITY COST SAVINGS AND OPERATING RESERVE ANALYSIS

Capacity Cost Savings

In order to ensure a high probability of satisfying their load, utilities install a power-generating reserve margin (the difference between the peak hourly load and the installed capacity). The amount that the utility reserve margin can be reduced after the installation of WECS while still maintaining the same reliability is called the WECS capacity cost savings. This represents fixed costs that the utility will not have to incur.

One criteria that is often used to evaluate the reliability of a utility generating system is the Loss of Load Probability (LOLP). The annual LOLP has the character of the probable number of times during the year that the load will be lost. By specifying a maximum acceptable value for the annual LOLP, the utility planner can determine the system reserve that should be available for specific operating conditions and also the total installed capacity (i.e., reserve margin) that the utility should have.

When WECS capacity is added to a utility's generating mix (nuclear, hydro, fossil, etc.) without a corresponding reduction in the capacity of the conventional generating equipment, the utility's LOLP will decrease (that is, reliability will improve). This is due to two factors. First, WECS power output, even though of a stochastic nature, reduces a utility's need for conventional generating sources to satisfy its load demand. Secondly, the addition of WECS to a utility and subsequent mix reoptimization, causes a change in the optimal mix of conventional equipment; the mix is shifted toward more peaking capacity and less baseload capacity. Since peaking units (e.g., gas turbines) have relatively small power outputs (hence, require a large number of units for a given power level) they make less of a contribution to the LOLP than intermediate or baseload units.

Since NEGEA is part of the New England Power Pool, its LOLP is higher than it would be for a stand-alone utility. The annual LOLP used by NEGEA, for 1985, would be 18.99 events per year. Figure 13 shows the results of calculating the LOLP with 40% WECS on-line and indicates that 134 MW of peaking units could be removed due to the 360 MW represented by the 40% WECS. Table 6 shows the credited capacity that was calculated for NEGEA at various levels of WECS on-line.

FIGURE 13. CREDITED CAPACITY OF 40% ON-LINE WECS

Table 6. Credited Capacity of WECS

On-Line WECS (%)	On-Line WECS (MW)	Credited Capacity Fuel Saver Mode		Credited Capacity Reoptimized Mix Mode	
		(MW)	(%)*	(MW)	(%)*
2.5	22.5	12	53	12	53
5	45	22	49	23	51
10	90	42	47	44	49
20	180	71	39	93	52
40	360	107	30	134	37
80	720	150	21	177	25
120	1080	176	16	208	19

*percentage of on-line WECS rated power available as credited capacity

The table indicates that, for small penetrations, about 50% of the WECS rated capacity can be taken as credit toward the reserve margin requirements. However, NEGEA would take the credit by removing peaking units from the expansion plan thus the capital cost per kilowatt would be small. As an example, the capacity cost savings, expressed as a percentage of the total fixed and variable cost savings due to WECS, is about 20%.

Figure 14 shows the decrease in capacity cost savings as the penetration increases. Major mix changes take place between 50 and 150 MW, for the NEGEA case. At low and high penetrations of WECS, both methods yield approximately the same capacity cost savings. For penetrations between 50 and 300 MW, however, the reoptimized mix mode generates a higher capacity cost savings. As will be shown in the next section, capacity cost savings are a component of the total savings (value) that can be attributed to WECS, and is a fixed cost savings.

WECS capacity credit, and the savings it represents, is a controversial issue with utilities at this time and the concept, as well as the methodology, requires additional examination before it will receive widespread acceptance.

FIGURE 14. MARGINAL CAPACITY CREDIT

Operating Reserve

Each day a utility must commit generating units that will be available to satisfy its load requirements. The capacity of the units committed must be large enough to handle both normal load fluctuations and the forced outage of generating units.

The addition of a WECS to a utility grid introduces additional uncertainty since there is uncertainty in any estimate of what the wind conditions will be in the next 24 hours. This uncertainty in WECS power output, when combined with the uncertainty of estimating the load, results in a requirement for additional operating reserve, as compared to the no-WECS case. The costs incurred in providing this additional operating reserve, called WOR(X) in this report, must be charged against the value of the WECS in the economic analysis.

The technique adopted for estimating the amount of WECS induced operating reserve was to first use the National Weather Service's (NWS) wind speed forecasts to estimate the uncertainty in predicting wind speeds. These results were then used to estimate the uncertainty in predicting available WECS power.

The uncertainty in predicting WECS power was then combined with the uncertainty in load prediction, as shown in Figure 15. The difference between the maximum expected load variation before and after the addition of a WECS in the equipment mix is the additional operating reserve (WOR(X)) required by the utility. This technique is shown in Figure 15 and the results are listed in Table 7. It was found that WOR(X) represents a small (negative) component of the WECS value.

VIII. WECS ECONOMIC ASSESSMENT

The next step in the generic planning process is to establish the present value of the stream of savings that can be credited to the WECS over its lifetime. These are then combined with the siting and interface costs and the marginal value of WECS established as a function of penetration.

Figure 16 shows the methodology. In Figure 16A the annual savings, at some penetration level of interest, are shown to grow over time, primarily due to fuel price increases and inflation. The sum of the annual savings are then brought back and expressed as a present value. If this process is repeated for a number of penetration levels and the data plotted, the present value is obtained as a function of penetration (Figure 16B). This curve is then differentiated to obtain the marginal present value, as shown in Figure 16C. The marginal present value represents the savings due to adding one additional WECS, at the penetration level selected. Finally, the siting, interface, and all other WECS costs are taken into account and the remaining savings plotted as a function of penetration, as shown in Figure 16D. This figure shows the value of a WECS unit, transportation to the site, and erection. It also shows a hypothetical schedule of WECS costs, from a manufacturer, to show how a utility could establish the optimum penetration. For the case shown, units beyond a penetration of X^* would have less value than the quoted unit price hence X^* represents the optimum penetration, from an economic point of view. There may be other reasons, however, for reducing the penetration, such as grid stability or lack of sites.

The single analysis was run for NEGEA and the components are shown in Figure 17 for both the reoptimized mix and marginal savings (fuel saver) modes.

FIGURE 15. GENERIC METHOD OF CALCULATING WIND OPERATING RESERVE MARGIN (WOR)

Table 7. WECS Operating Reserve (WOR) Required

Parameter (MW)	On-Line WECS, % of Annual Peak Load					
	2.5	5.0	10.	20.	40.	80.
Maximum Expected Deviation in Wind power Estimation, $3\sigma_W$	18	36	72	143	286	572
Maximum Expected Deviation in Load Forecast, $3\sigma_L$	420	420	420	420	420	420
Maximum Total System Load Deviation, $3\sigma_T$	420	422	526	444	508	710
Maximum Net Expected Excursion (WOR)	0.4	1.5	6.0	2.4	88	290
Cost of WOR (\$ Millions 1985)	.01	.03	.08	.33	1.22	4.01

FIGURE 16. OVERVIEW OF THE ECONOMIC METHODOLOGY

FIGURE 17. RELATIVE MAGNITUDE OF THE COMPONENTS OF NEGEA'S 1985 SINGLE YEAR SAVINGS FOR THE FUEL SAVER AND REOPTIMIZED MIX MODES

There are really two "fixed" and two "variable" cost components. In the figure fuel and WOR (Wind Operating Reserve) values are shown. The sum of these represent the total variable cost savings. Note that WOR has a negative value (more operating reserve is required when a stochastic source is introduced into the mix). The fixed cost savings consist of a capacity credit and, in the case of the reoptimized mix, a fixed cost saving associated with the shift in mix away from baseload toward more peaking equipment. The figure shows that, for small penetrations (10%), the fixed cost savings due to the mix change are small.

Large penetrations (40%), however, yield a substantial mix change hence the total fixed cost savings from the mix change and capacity credit are actually larger than the fuel savings. This is a critical finding of the study. At medium-to-large WECS penetrations, there is a large up-front fixed cost saving - the WECS actually displaces future baseload capacity expansion. It is critical to recognize that the shift toward peaking units is not a priori bad. That is, there is nothing wrong with owning peaking units (for reliability), but only with operating them. In the reoptimized mix mode, the utility would purchase more oil fired equipment than in the fuel saver mode, but there is still large savings of oil due to the WECS.

Figures 18 and 19 show how the NEGEA mix would vary in 1985, as a function of WECS penetration, for the two modes of operation. The marginal savings mode would result in a fuel cost saving and a capacity credit. Figure 18 shows that NEGEA would take that capacity credit by reducing the number of peaking units purchased. In the reoptimized mix mode, however, the mix (Figure 19) would show capacity credit being taken, reducing the number of peaking units initially. At a penetration level of about 15%, however, the mix shift toward baseload overcomes the capacity credit component and the net result is an increase in peaking units and substantial decrease in new baseload. The net result, or penetrations beyond 30%, is for NEGEA to have about the same number of peaking units as originally planned but a very significant reduction in baseload additions. It is important to recognize that each penetration level represents an optimum economic mix. That is, the most economic mix for NEGEA in 1985 would be the same number of peaking and intermediate units that they would obtain with no WECS but a replacement of the baseload with WECS.

Figure 20 shows the 1978 WECS installation value that was established on this study. It shows that the first unit has an installation value of \$700/KW (or 35 mills/KWh). At 40% penetration the next WECS would have a value of about \$500/KW. The negative value slope is caused by each WECS unit having less valuable fuel to displace. The assumptions used in the analysis are shown in Table 8. The 1978 dollars can be changed to other years using a 1.06/year factor (6% inflation was assumed).

A sensitivity analysis was conducted to establish the sensitivity of the value calculation to the assumptions in Table 8 and the results are shown in Figure 21 for 40% penetration. The base case assumptions in Table 8 are represented by the 0 on the X and Y axis. To use the Figure, assume a percentage change on the X-axis and the resultant percentage change in the WECS

FIGURE 18. VARIATION IN CONVENTIONAL SOURCE EQUIPMENT MIX AS A FUNCTION OF ON-LINE WECS RATED CAPACITY

FIGURE 19. VARIATION IN CONVENTIONAL SOURCE EQUIPMENT MIX AS A FUNCTION OF ON-LINE WECS RATED CAPACITY

FIGURE 20. 1978 WECS INSTALLATION BREAK-EVEN VALUE FOR THE WECS, TRANSPORTATION TO THE SITE, ERECTION, SITE ACQUISITION AND TIE TO THE GRID

FIGURE 21. SENSITIVITY OF THE UNIT VALUE, $CI(X)$, TO THE ASSUMPTIONS IN THE ECONOMIC ANALYSIS, FOR THE FIRST WECS UNIT INSTALLED

Table 8. NEGEA Analysis Scenario

<u>PARAMETER</u>	<u>NOMINAL VALUE</u>
<u>General Economic Conditions</u>	
Long-run average annual rate of growth of total savings	0.06**
Long-run average annual rate of growth of operation maintenance costs (conventional equipment)	0.06
Average annual rate of growth of interfacing equipment and land cost prior to the date at which they are actually incurred	0.05
Long-run average annual rate of growth of "other taxes" (primarily property taxes)	0.00
Long-run average annual rate of appreciation for land values after the utility develops it	0.00
Inflation rate (1976-1985)	0.05
<u>Utility Description</u>	
Cost of capital based on the long-run debt-equity structure of the utility	0.0917*
Effective income tax rate. The marginal rate after any adjustments peculiar to the utility	0.5138*
<u>WECS Description</u>	
Availability	0.9
Ratio of purchased land cost to total land cost including easements needed for a WECS	0.093
The rated capacity of a WECS unit in kilowatts	500
WECS operating life in years	3
Ratio of annual insurance premiums to acquisition cost	.0025
Ratio of first year operation and maintenance cost to the capitalized cost of owned WECS assets	.030
First year's property taxes expressed as a proportion of the capitalized cost of owned WECS assets	.020
<u>Scenario Description</u>	
The first year of WECS operation	1985
The year in which land cost estimates are compiled	1976
The year in which interfacing cost estimates are made	1976
The present year	1977
The year in which land is acquired	1983
The year in which WECS are purchased	1984
*These two parameters are different than in the JPL report [1], where they are 0.08 and 0.40	
**This implies that fuel prices and inflation are the same (no growth in fuel prices above inflation).	

value is shown on the Y-axis. As an example, WECS life was assumed to be 30 years. If this were changed to 20 years (a 33% decrease), the value of the Y-axis decreases by approximately 30%. That is, the installation value of \$700/KW for a 30 year life would only be \$490/KW for a 20 year life. Vertical lines show more sensitivity than horizontal lines. Thus the graph shows that cost of capital, tax rate and growth in savings (inflation and fuel price increases) have more leverage than does O&M percentage changes. It should be noted that the graph in Figure 21 assumed that each variable was independent and that the change would only be applied to the WECS. It was found that a decrease in the tax rate, or cost of capital, if applied to all of the equipment in the utility's mix, had little effect because the mix optimization process would minimize its impact. Thus, incentives, if applied to utilities, would have much more impact on the value of WECS if only applied to the WECS and not all of the mix.

Finally, a methodology was investigated for extrapolating the results of the 500 KW machine results to other WECS designs without rerunning the analysis. The hypothesis adopted was that the fixed and variable cost savings are primarily determined by the WECS energy generated and the value could be similar for many designs as long as they produced the same amount of energy. A single year analysis was conducted for the 10 machine designs shown in Table 2 and the results are shown in Figure 22. The X-axis shows capacity factor and represents the 10 machines in Table 2. What the figure shows is that, for all 10 machines, if the number of machines added are such that the annual energy output is the same, the single year savings are almost identical for each machine group added. Thus, if two 500 KW machines are to be compared, and one had a capacity factor twice the other (would generate twice the energy), it would only take half as many of the high capacity factor machines and since the value of the energy would be the same, twice as much could be spent on the high capacity factor machine and still breakeven.

FIGURE 22. AVAILABLE FUNDS IN THE ANALYSIS YEAR AS A FUNCTION OF VARIOUS MACHINE CAPACITY FACTORS, FOR WECS ARRAYS THAT PRODUCE THE SAME AMOUNT OF TOTAL ENERGY

Thus a generic methodology can be developed to extrapolate the results to other machine designs. However, we recommend that the analysis be repeated for each machine design of interest, especially during the period when few designs are available.

IX. SUMMARY

A generic planning process has been developed for introducing stochastic sources (WECS) into the utility planning process. The plan has been exercised on a utility in New England that has good winds and a large fraction of its conventional mix oil-fired. The analysis was done for the more conventional marginal savings, or fuel savings, mode as well as a new mode in which the wind power is treated as a negative load and the utility reoptimized its own mix around the remaining load.

WECS have been shown to have a value of about \$700/KW (35 mills/kWh) in 1978 dollars for a complete installation, including land and grid intertie. This number is somewhat conservative since the analysis was done in 1977 assuming a 6% inflation and no escalation of fuel (oil) above inflation. It was found that most of the value (80% of the dollar savings) comes from fuel in the fuel saver mode, but that more than half the savings in the reoptimized mix mode come from capacity displacement combining a capacity credit and a shift away from baseload toward peaking units. It was found that the utilities contacted are hesitant to take a capacity credit and would not use the reoptimized mix mode, thus only a fraction of the potential value of WECS can be achieved in the near term, unless additional work is done in this area.

The study suggests that more work is necessary in the following areas:

- . examination of other utilities to see how generic the results of this study are,
- . a need to develop a more acceptable capacity credit concept so that it can be accepted by the utilities,
- . a comprehensive look at the reoptimized mix mode since it ultimately results in the highest value for WECS and/or the lowest energy cost to society.

GLOSSARY

Annual Peak Load	The maximum integrated load over any hour in the year (MW).
Annualized Fixed Costs	The constant value of annual costs which is charged to a generating unit over its expected lifetime. This covers the fixed costs and fixed operating costs, taking into account the cost of capital and taxes.
Availability Factor	<p>The ratio of time a unit is ready for or in service to the total time interval under consideration. For some of the computations in this study, the scheduled time maintenance for a unit reflects unavailability of that unit; that is,</p> $\text{Availability factor} = \frac{\text{AH} - (\text{FOH})}{\text{AH}}$
Available Hours (AH)	<p>The number of hours annually during which a unit is available; that is,</p> $\text{AH} = \text{SH} + \text{RSH}.$
Average On-Line WECS Capacity	The name plate rating (MW) of the average number of WECS units which are available to produce power, i.e., the WECS penetration (MW) multiplied by the average annual availability (assumed to be 0.9 for this study).
Base Load	The minimum load in a stated period of time (MW).
Base Load Plant (Unit)	A power plant which is normally operated 24 hours per day.
Capacity	The load for which a generating unit is rated (MW).
Capacity Credit	Value in MW, of conventional sources that are displaced by WECS due to maintaining the same level of system reliability.
Capacity Factor	<p>The ratio of the average annual load placed on a utility's generating equipment to the equipment's rated capacity. For WECS, the capacity factor is:</p> $\frac{(\text{annual energy output})}{(\text{rated power})(8760)}$

Source: Edison Electric Institute and Federal Power Commission.

Note: Terms used in this report are not necessarily totally consistent with definitions used by others. In addition, some terms were defined, of necessity, by the report authors.

Capital Recovery Factor	The uniform annual payment, as a fraction of the original principal, necessary to fully amortize a loan over a specified period. It is a function of two variables; the relevant interest rate (cost of capital) and the specified amortization period (investment lifetime).
Conventional Source	Power generating equipment currently in utility mix
Day Group	A 24 hour period that is symbolic of similar 24 hour periods (i.e., Saturday, Sunday, etc.).
Demand	The rate at which electric energy is delivered by a generating unit or system, expressed in megawatts, at a given instant of time or averaged over a designated period of time (integrated demand, usually over a one-hour time period).
Diurnal Load Curve or Shape (DLS)	The curve of load versus time of occurrence presented in chronological sequence over a one day period.
Dumped Power	Power generated by unit(s) that cannot be stored or conserved and which is in excess of the utility's needs. Dumped power is considered to have no economic value to the utility.
Fixed Costs	Costs associated with a power source that are incurred regardless of the energy it produces (capital costs).
Fixed Operating Costs	Costs other than those associated with investment in plant, which do not vary with changes in operation or utilization of plant.
Forced Outage	The occurrence of a generating unit failure which requires that the unit be immediately removed from service.
Forced Outage Hours (FOH)	Hours per annum during which a unit was unavailable due to a forced outage.
Forced Outage Rates (FOR)	The fraction of time that a generating unit is in "non-scheduled outage" status, that is, $\text{FOR} = \frac{(\text{Hours of Non-Scheduled Outage Per Annum})}{8760 - (\text{Hours of Scheduled Outage Per Annum})}$
Fuel Costs	The additional costs of producing power above the annualized fixed costs. For gas turbines, fuel costs will include a small cost to cover maintenance which is a function of power and/or hours of operation. Fuel costs are also referred to as: dispatch costs, production costs, incremental costs, and incremental energy costs.

Fuel Saver Mode	When the addition of WECS is solely to save fuel and consequently no attempt is made to reoptimize the utility mix of conventional sources.
Load Duration Curve (LDC)	A curve of load power quantities plotted in descending order of magnitude as a function of time intervals (one hour) for a specified period (one year).
Loss of Load Probability (LOLP)	The probability of not satisfying the load, with generation, over a defined time period which would require disconnecting some customers. It is expressed as the number of events over a given time and is a measure of general system reliability.
Operating Availability	The proportion of time in a year which the unit is available = $AH/8760$.
Operating Reserve	On-line capacity in excess of load which is used to follow changes in load.
Optimum WECS Penetration Level	WECS penetration level at which marginal WECS cost equals marginal WECS savings and the total net present value of total WECS costs are less than the total net present value of total WECS available funds.
Peak Load	The maximum load in a stated period of time (MW).
Peak Load Plant (Unit)	A power plant which is normally operated to provide power only during maximum load periods.
Phase	A period of time typically consisting of 28 days. There are 13 phases that comprise a year.
Reoptimized Mix	When the mix of conventional sources is reoptimized to minimize utility costs after WECS are added to the mix.
Reserve Margin	The installed generating system capacity in excess of annual peak load which is needed as a standby to insure an adequate standard of service.
Reserve Shutdown Hours (RSH)	Reserve shutdown duration in hours per annum.
Scheduled Outage	The shutdown of a generating unit for inspection or maintenance, in accordance with a predefined schedule.
Service Hours (SH)	Hours per annum that a unit was actually operated with breakers closed to the station bus.

Spinning Reserve	On-line and/or short start-up time capacity in excess of load and all operating reserves which is ready to take the load if an on-line unit should fail.
Variable Costs	Costs associated with a power source that are a function of the energy it produces (mainly fuel costs).
WECS	Wind Energy Conversion System - a generic term.
WECS Capacity Credit	The installed capacity of conventional generating units (non-WECS) which can be deleted when WECS is installed while maintaining the same level of system reliability (LOLP).
WECS Cut-In Wind Speed	Wind speed at which a WECS unit first starts to produce power.
WECS Cut-Out Wind Speed	Wind speed at which WECS unit will be "feathered" and shut down to protect unit from possible damage.
WECS Design Wind Speed	Site mean wind speed for which the WECS has been optimized based on cost of energy.
WECS Farms	Zones where an array of WECS is to be installed.
WECS Installation	Total capitalized WECS investment including the unit itself, transportation to the site, erecting, land purchased (or leased or obtained through easement), the cost of site land clearance and transmission electrical interface equipment (wiring, step up transformer, etc.).
WECS On-Line Levels	The amount of WECS capacity on-line, expressed as a percentage of the utility annual peak load or in MW. The difference between WECS penetration and WECS on-line levels is the availability factor for WECS.
WECS Operating Reserve (WOR)	On-line conventional capacity in excess of load and operating reserve which is required to adjust for changes in WECS power resulting from the variability in wind speed.
WECS Penetration	The amount of WECS installed capacity expressed as either "percent" or "megawatts" WECS penetration (percent) is the installed WECS capacity expressed as a percentage of utility annual peak load.

WECS Rated Power

Maximum WECS output power.

WECS Rated Wind Speed

Wind speed at which WECS rated power is reached.

WECS Unit

Tower and WECS machinery located on top of the tower. Costs associated with the WECS unit also include transportation and erection, including foundations.