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**THE APPLICATION OF WIND POWER SYSTEMS TO THE SERVICE AREA
OF THE MINNESOTA POWER AND LIGHT COMPANY**

Final Report, July 1975—August 1976

**By
O. H. Lindquist
F. S. Malver**

Work Performed Under Contract No. EY-76-C-02-2618

**Honeywell Incorporated
Systems and Research Center
Minneapolis, Minnesota**

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Period July 1975 - August 1976

O. H. Lindquist
and
F. S. Malver

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PREPARED FOR THE UNITED STATES
ENERGY RESEARCH AND DEVELOPMENT
ADMINISTRATION
DIVISION OF SOLAR ENERGY
FEDERAL WIND ENERGY PROGRAM

ERDA CONTRACT NO. EY-76-C-02-2618.*000

Systems & Research Center
2600 RIDGWAY PARKWAY,
MINNEAPOLIS, MINNESOTA 55413

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ERDA PREFACE

The Federal Wind Energy Program was initiated in fiscal year 1974 as a modestly funded activity under the auspices of the National Science Foundation after nearly 30 years of relative inactivity in this country toward utilization of wind energy. The program has grown rapidly, and in January of 1975 was transferred from the National Science Foundation to the then newly formed Energy Research and Development Administration (ERDA).

To pursue the development of wind energy a number of parallel activities were initiated to address the many questions existing at the initiation of the program. These activities were developed to address certain areas by more than one project in order to provide comparative results and to furnish a measure of the level of uncertainty. Other projects were devised to be complementary and to investigate specific questions in more depth. This report represents the results of one of these projects.

Many uncertainties exist in the present level of understanding of the operation, performance, and economics of wind energy systems. Before a firm answer is obtained regarding the long-term potential economics and utilization of windpower, present estimates must be verified by the development, testing, and evaluation of modern, advanced wind turbines.

ABSTRACT

Honeywell, in a joint effort with Minnesota Power and Light Company (MP&L), Boeing Vertol Company, and Dr. C.G. Justus, Georgia Institute of Technology, has conducted a regional application study of wind energy systems.

Proof of economic viability is needed to justify the capital investment to build a practical Wind Energy Conversion System (WECS). The objectives of Honeywell's study have been to assess current WECS viability for a utility application and to define the attributes and performance requirements of a system capable of yielding a satisfactory return on investment to a utility company. Minnesota Power and Light Company, an investor-owned company with 853-MW owned capacity, has served as the case study subject utility.

An initial system definition was developed based on available wind information and near-term wind turbine generator (WTG) technology. The system was tailored to fit MP&L's forecasted generation needs and the company's existing transmission and distribution system. Honeywell developed a WECS simulation to convert wind data to wind energy available for input to the utility's grid. The simulation was used to evaluate the performance of preliminary design wind turbine generators developed for ERDA/NASA by the General Electric Company and Kaman Aerospace Corporation, and to evaluate the performance of a wind turbine optimized for the Northern Minnesota wind regime and developed by the Boeing Vertol Company under subcontract to Honeywell. Overall evaluation of WECS performance was conducted by MP&L using the company's production costing and financial planning models.

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INTRODUCTION

The study, "The Application of Wind Power Systems to the Service Area of the Minnesota Power and Light Company," was conducted by the Honeywell Systems and Research Center, assisted by representatives of the utilities industry, aerospace industry, state governmental agencies, and the academic community. Members of the study team were:

O. Herbert Lindquist, Honeywell Senior Staff Engineer
(Principal Investigator)
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C. G. Justus, Consultant, Georgia Institute of Technology

ACKNOWLEDGMENTS

This study was guided by Donald D. Teague, ERDA program manager. Both he and Louis V. Divone, Chief, Wind Energy Conversion Branch of ERDA, greatly assisted the effort and contributed much significant information necessary for the study. Valuable assistance and information were also made by the State of Minnesota Energy Agency and Environmental Quality Council, and the coordination center of the Mid-Continent Area Power Pool (MAPP).

CHRONOLOGY

The Minnesota Power and Light Company (MP&L) regional wind energy application study proposal was submitted to the National Science Foundation in July 1974. ERDA was subsequently created and assumed responsibility for the Federal Wind Energy Program. A contract for the MP&L study was awarded in June 1975. The main study effort commenced July 1, 1975 and concluded August 31, 1976. Preparation of this final report began after a program review held in Washington, D. C., September 2, 1976.

REPORT FORMAT AND PREPARATION

This report is published in two volumes. The first volume, Executive Summary, is designed to present a rapid overview of the reasons for the study, the approach taken, the problems addressed, and the principal findings and recommendations. The second volume contains the complete report, comprising the contents of the Executive Summary plus a detailed analysis, discussion, and supporting information.

SECTION I

Executive Summary

The decision to introduce a significant wind energy conversion system (WECS) into a utility requires that utility management conclude the system is technically feasible, economically viable, and environmentally acceptable. Utility planners need a method, compatible with their current planning methods, to evaluate these WECS technology issues. This study was directed toward 1) understanding this planning/decision process and 2) defining the technical, financial, and environmental issues which must be addressed before a large-scale application of WECS as an energy alternate.

STUDY OBJECTIVES

The overall objectives of this study were to assess current WECS viability for a utility application and to define the attributes and performance requirements of a system capable of yielding a satisfactory return on investment to a utility company. The specific objectives of the study were to do the following:

- Determine cost goals, performance, and user requirements for a specific, high-potential utility application
- Provide realistic data concerning fuel savings

- Assess the degree to which wind energy can be regarded as base generating capacity
- Identify installation, maintenance, and operational issues associated with WECS
- Establish an understanding of the methods, tools, and decision process a utility may employ in making WECS decisions
- Identify priority R&D needs.

Many of these objectives yielded results applicable only to the subject utility. The combination of regional wind characteristics, generation mix, and load characteristics emphasize the uniqueness of each specific utility case study.

THE MINNESOTA POWER AND LIGHT COMPANY

The Minnesota Power and Light Company (MP&L) is an investor-owned utility operating in the northeastern part of the State of Minnesota. Its service area (see Figure 1-1) is a combination of concentrated residential/industrial areas and sparsely settled rural areas.

Figure 1-1. Minnesota Power and Light Company: Transmission System and Service Area

A unique aspect of MP&L's operation is the Mesabi Iron Range and its concentration of mining and ore processing industries. These not only require large amounts of power, but also are an almost constant load, operating 24 hours a day the year around. As a result, MP&L has the highest load factor among utilities in the United States.

MP&L's high load factor was initially viewed an asset for a WECS application. When the wind blew MP&L could always use the energy. This reduced the need to match wind availability to the utility's load. It was discovered, however, that the high load factor carried with it a requirement for more base capacity (than for peaking capacity). This forced the wind energy to compete with more economical sources of base power.

Hydro power accounts for approximately 12 percent of the company's present capacity and will remain at this level, representing

a smaller percentage of future total capacity. The bulk of MP&L's present capacity is in four steam electric stations, having a total capacity of nearly 750 Mw. Since 1968, MP&L has purchased power from other utilities to meet its demand. This situation is expected to continue until new generation is installed in the 1980s.

Figure 1-2 summarizes the generating capabilities and current MP&L 10-year forecast of maximum demand. This data is the settling into which the study of WECS was introduced.

STUDY METHODOLOGY

The case study method was used to explore the relationship of current WECS technology (mid-1976) to a major utility, Minnesota Power and Light Company. The study was conducted as an actual planning exercise in which the utility's current financial goals, cost escalations, load forecasts, planning tools, and operating procedures were employed.

Minnesota Power and Light Company uses a standard set of computer planning programs. To use these programs, it was necessary to work closely with MP&L's technical, financial and management personnel familiar with practices and policies acceptable to the utility. The utility controlled the final power production and financial analysis and the assumptions which underlay the case study. MP&L viewed the study as part of their standard planning process and

Figure 1-2. Minnesota Power and Light Company: Net Generating Capabilities and Forecast of Maximum Demand (MW)

employed exactly the same criteria and methodology in later evaluating a conversion from oil to coal in a major generating facility.

The study's procedures and assumptions fall into the following major areas:

- Wind information
- Wind turbine generators
- System integration
- Utility evaluation
- Economic viability
- Environmental and societal issues

Each is discussed in the following paragraphs.

Wind Information

National Weather Service wind data from Fargo, Duluth, International Falls, and St. Cloud was selected as the data base for the MP&L area. Figure 1-3 shows monthly mean wind speeds for the four recording stations representing an average over the 10-year period 1965 to 1974.

Wind characterization was performed by Dr. C. G. Justus, Georgia Institute of Technology. His techniques involving the Wiebull probability distribution and power law height variation of wind speed were employed throughout the study. These methods were adapted and extended to address the issues associated with a distributed array of wind turbines.

Wind speed data was processed into frequency of occurrence monthly summaries, covering the 10-year period 1965 through 1974. Monthly wind summaries best matched the data interval requirements imposed by MP&L's system planning computer programs.

Wind Turbine Generators

Five wind turbine generator (WTG) options were included in the study: the General Electric 500 KW and 1500 KW units⁽¹⁾; the Kaman 500 KW and 1500 KW units⁽²⁾; and a Boeing Vertol 1125 KW design. The G. E. and Kaman units were considered as a baseline for current technology designs. Boeing Vertol defined a new wind turbine optimized for the region's 4.65 meter-per-second average wind speed (10.4 mph ten-year average measured at 20 feet anemometer height). Table 1-1 summarizes design parameters for these units.

-
- (1) General Electric Company, "Design Study of Wind Turbines 50 KW to 3000 KW for Electric Utility Applications, Analysis and Design," prepared for NASA Lewis Research Center, Contract NAS 3-19403, February 1976.
 - (2) Kaman Aerospace Corporation, "Design Study of Wind Turbines 50 KW to 3000 KW for Electric Utility Applications, Analysis and Design," prepared for NASA Lewis Research Center, Contract NAS 3-19404, February 1976.

Figure 1-3. Monthly Mean Wind Speeds at National Climatic Center Wind Data Sites for the 10-Year Period 1965-1974

Table 1-1. Summary of Alternate WTGs

		500 KW		1125 KW	1500 KW	
		GE	Kaman	Boeing*	GE	Kaman
Design mean wind speed at 30 feet	(MPH) (M/S)	12 5.4	12 5.4	11.1 5.0	18 8.1	18 8.1
Cut-in wind speed at 140 feet	(MPH) (M/S)	10.3 4.6	11.4 5.1	10.4 4.7	14.8 6.6	15.7 7.0
Rated wind speed at 140 feet	(MPH) (M/S)	21.0 9.4	26.2 11.7	23.3 10.4	29.3 13.1	32.6 14.6
Cut-out wind speed at 140 feet	(MPH) (M/S)	51.9 23.2	38.2 17.1	60.0 26.8	64.4 28.8	58.4 26.1
Rotor diameter	(Feet) (Meters)	183 55.8	150 45.6	265 80.6	190 57.9	180 54.8
Hub height	(Feet) (Meters)	140 42.6	140 42.6	185 82.7	140 42.6	140 42.6
Disk area	(Sq. Meters)	2445	1633	5102	2633	2359

* Boeing values for cut-in, rated, and cut-out wind speed are for 185 feet hub height, not 140 feet.

System Integration

An initial system definition was developed, based on available wind information and current technology wind turbine generators (WTG). The total system was tailored to fit MP&L's forecasted generation needs and the company's existing transmission and distribution system.

The system peak rating was set at 150 mw. The 150 mw rating was comfortably related to the combined capacity of MP&L's hydroelectric and oil-fired units so that wind energy could be stored using the hydro system or used to save oil. Five separated site locales of 30, 45, 45, 15 and 15 MW were selected on the basis of regional needs and convenient tie-in to distribution lines. Installation and interface requirements were addressed as part of the system integration.

Given the wind data at the four recording station sites and the wind turbine performance characteristics, it was necessary to transform the wind data to the turbine sites, determine the turbine outputs at the five turbine clusters, and then combine the five cluster outputs to establish total WECS array performance. Computer programs were developed to perform these operations. Array performance was expressed in monthly units compatible with the input requirements of MP&L's production costing model.

Utility Evaluation

MP&L evaluated the wind power system performance using its normal corporate planning tools. A production costing

program and a corporate financial program yielded a ten-year forecast of the utility's operation, both with and without WECS. This forecast was used to evaluate the economic viability of WECS.

Production costs are based upon the economic dispatch of generating units. To employ the utility's standard program, it was necessary to devise a means to accommodate the probabilistic dispatch of the WECS. This was achieved by introducing the WECS as an equivalent hydroelectric plant with appropriate power availability determined from WECS array analysis.

Fuel and interchange costs determined by the production costing model were inputs to the corporate financial model. The financial model generated a ten-year financial forecast using the utility's standard financial practices.

Either of two criteria could have been used to evaluate financial performance: the effect on earnings holding customer rates constant and the effect on rates holding earnings constant. The latter criterion was selected as more typical of the standard decision-making process.

Revenue requirement (i. e., customer rates) to hold earnings constant was therefore used to evaluate financial performance. The revenue requirement for a given year is the difference between the total income generated by the WECS system and the yearly cost of owning the system. A negative revenue requirement indicated the WECS was making money.

Use of the production costing model and corporate financial model, both with and without WECS, is represented in Figure 1-4. The accented lines show how WECS was introduced and the deltas (Δ_1 , Δ_2 , and Δ_3) show how its affects were measured. Δ_3 represents the revenue requirement.

Economic Viability

The criteria for WECS Economic Viability was defined that the revenue requirement must be zero or negative within one-half the equipment's anticipated life.

Environmental and Societal Issues

Minnesota Energy Agency and Minnesota Environmental Quality Council personnel provided information relating to environmental and societal factors for installing a

significant WECS installation into the MP&L area. Minnesota state regulations, power plant siting information and land use map information were evaluated. Discussions were held with MP&L, state personnel and the public with regard to environmental issues.

STUDY ASSUMPTIONS

Several assumptions were required to provide a basis for the hypothetical wind power system definition and to establish MP&L's utilization of WECS. These assumptions are summarized below.

Installation and System Integration

- 1) The power system peak rating was set at 150 megawatts. This capability

Figure 1-4. WECS Evaluation Technique

reflected current and projected utility needs. If installed in 1976, it would represent from 18 percent of MP&L's generating capability in 1977 to 9 percent in 1985.

- 2) Five turbine site locales were selected for the 150 MW wind power system as follows: Park Rapids - 30 MW, Hibbing - 45 MW, Virginia - 45 MW, Winton - 15 MW, and Sandstone - 15 MW. They were selected and apportioned primarily on the basis of known regional generation needs and availability of existing 14, 23, 34 or 46 KV distribution lines.
- 3) All WECS construction and installation was assumed to occur in 1976.
- 4) Current experience in the installation and maintenance of remotely located microwave communication equipment and semi-automatic hydroelectric stations could be applied to WECS.
- 5) MP&L conducted this study as an ongoing evaluation of their real operation. All current commitments, base capacity plans, fuel contracts, load estimates and financial plans were standard. Their current planning requires substantial base capacity increase. Variations in their base capacity plans were considered unrealistic and therefore the generation mix was not changed as WECS was added.
- 6) MP&L established that they would most likely operate the WECS as a fuel saver. The utility's high load factor, 83

percent, assured their ability to virtually always displace oil and energy purchases.

- 7) System response time was not considered an issue since MP&L could follow changes in WECS power on the order of tens of megawatts over several minutes. Such changes are typical of current taconite load variations.

Production Costing and Financial Evaluation

- 1) Use of MP&L's production costing and corporate financial models attempted to exploit the utility's standard planning tools. The utility's high load factor and the basic study emphasis on multi-year planning offset deficiencies in the production costing model's ability to perform detailed dispatch analysis.
- 2) The MP&L Corporate Financial Analysis was based upon MP&L standard financial factors summarized in Table 1-2.
- 3) Production Cost analysis was based upon MP&L Standard cost parameters summarized in Table 1-3.

RESULTS

Economic Viability

Based on the results obtained from these analyses, MP&L concluded that with present technology and the wind characteristics in

Table 1-2. Corporate Financial Model Assumptions

	Standard Practice
1. Capitalization Ratios	
Preferred Stock	15% @ 10%
Long-Term Debt	50% @ 9 1/4%
Common Equity	35% @ 14 1/2%
2. Revenues adjusted to maintain return on common equity at	14 1/2%
3. 15% of construction work in progress eligible for allowance for funds used during const. at	8%
4. Equipment book life (years)	30
5. Investment tax credit rate	10%
6. Property tax rate	4%
7. O&M	1.5%
O&M inflation rate	12%
8. Equipment tax life (years)	24
9. Book depreciation	St. Line
10. Tax depreciation	S. Y. D.
11. Salvage rate	0
12. Net fixed charge rate*(%)	15 - 20

*Depending on book life.

the MP&L service area, WECS is not currently economically viable.

This conclusion is based upon the information available in mid-1976 with respect to WECS technology and the introduction of WECS using the same financial planning assumptions as would apply to any current energy alternate. The basis for this decision is summarized in Table 1-4. This information indicates all WECS alternates failed to be economically viable, always requiring additional revenue to operate. MP&L's independent summary report and conclusions are found in Appendix H of the main volume final report.

An "Economic Baseline" WECS System can be defined which is economically viable.

The study investigated the sensitivity of factors involved in the financial analysis of economic viability. It was found that economic viability and utility return from WECS was extremely sensitive to financial factors. The sensitivity study was performed on the most cost effective Wind Turbine Generator (WTG), the Boeing 1125KW BV-1.

Results of the sensitivity study are summarized in Table 1-5. This analysis shows the relative influence of these financial factors.

The strong influence of non-WECS associated financial factors is illustrated by the following example.

Table 1-5 includes a financing variation relative to the baseline case wherein the interest rate on long-term debt was decreased by 1-3/4 percent, a value commensurate with a possible method of financing within current MP&L practices. Figure 1-5 indicates the more dramatic result of changing from conventional financing ratios to 100% long-term financing, holding all other baseline assumptions fixed. The annual revenue requirement is significantly decreased.

An "economic baseline" case was defined (Table 1-6) which was shown to be economically viable for MP&L (Figure 1-6). The economic baseline would not require any supportive revenue after four years of operation, and would have paid for itself in nine years. The result prompted MP&L to state:

Table 1-3. Production Cost Model Base Year and Final Year Assumptions

	1976 Values	1986 Values
1. Energy Content of Fuel		
Coal (MTBU/Ton)	17.0	17.0
Oil (MBTU/BBL)	6.34	6.34
2. Fuel Cost (\$/MBTU)		
Coal	0.45 to 0.61	0.97 to 1.32
Oil	1.87	4.04
3. Average Cost at Rating (\$/MWH)		
Coal	6.234 to 10.434	12.778 to 19.719
Oil	30.628 to 33.918	64.106 to 71.205
Purchases	4.0 to 19.0	4.0 to 32.390
4. Escalation Factors		
Fuel	8 %	8 %
Variable O&M	6 %	6 %
5. Present Worth At	10 %	10 %

Table 1-4. Application of WECS Equipment

	GE 500KW	GE 1500KW	Boeing 1125KW
Number of Units	300	100	135
Systems Costs (\$ thousands)	164,700	79,100	88,695
Dollars per Rated KW	1,098	528	584
MWH/YR	508,526	186,262	474,032
10-Year Cumulative Revenue Requirements (\$ thousands)	322,449	148,232	101,160
10th Year Revenue Requirements (\$ thousands)	29,688	12,500	6,250
10th Year Cost Savings Fuel Costs plus Purchased and Interchanged Power (\$ thousands)	9,127	4,077	8,677

Table 1-5. Economic Sensitivity Analysis for Boeing BV-1

	Cumulative 10 Year Revenue Requirement \$(1000)	% of Baseline	10th Year Revenue Requirement \$(1000)	% of Baseline
1. Baseline - (Expected Financial Structure and 30 Year Life)	101,160		6,250	
2. Baseline - (Life Expectancy)				
35 Year Life	92,763	- 9%	5,469	-12%
20 Year Life	128,114	+ 27%	7,813	+25%
3. Capital Costs - (Total Installation)				
-20%	54,285	- 46%	1,563	-75%
+20%	148,034	+ 46%	10,938	+75%
+50%	213,073	+110%	17,188	+175%
4. Tax Assumptions				
+10% Increase Inv. Tax Credit	80,261	- 21%	3,125	-50%
Relief from 4% Property Tax	69,138	- 32%	3,125	-50%
5. Interest Rates				
1.75% Reduction on \$37,000,000 Long Term Debt	87,097	- 14%	4,688	-25%
6. Operational and Maintenance Costs				
1% Capital Costs + 12% esc.	93,351	- 8%	4,688	-25%
1% Capital Costs + 7% esc.	89,225	- 12%	3,907	-37%
1 1/2% Capital Costs + 7% esc.	95,303	- 6%	4,688	-25%

Figure 1-5. Revenue Requirements Sensitivity to Capitalization Ratios

Table 1-6. Definition of an "Economic Baseline"

	BV-1 Baseline Case 1	"Economic Baseline" Case 2
Capital Cost	\$657,000/Unit	\$526,000/Unit
Depreciation	30 Year Life	35 Year Life
Property Taxes	4%	None
Investment Tax Credit	10%	20%
Operating Expense	1-1/2%, 12% Escalation	1%, 7% Escalation
Financing - Long Term Debt	\$37,000,000 @ 9-1/4%	\$37,000,000 @ 7-1/2%

Figure 1-6. Comparison of Revenue Requirements for BV-1 Baseline Versus "Economic Baseline".

"If the capital costs of WECS could be reduced by 25 percent to 30 percent and the technological risks can be minimized, such that the year in which energy cost savings equal or exceed the fixed cost of WECS occurs at an early point in the anticipated life of the wind facilities, then WECS could become a viable energy alternative. Under such economic conditions, MP&L would seriously consider the installation of WECS." (A. J. Sandbulte; V. P., MP&L)

Wind System size is key to economic viability in a given application. The case study identified that a 75-megawatt complex of 1.125-megawatt Boeing units designed to the wind regime of the utility was economically viable using MP&L's standard financial assumptions, whereas the desired 150-megawatt system was not. This result indicated that wind energy in the 75-megawatt system displaced proportionally more high-priced oil-generated energy whereas the larger 150-megawatt system energy displaced proportionally more low-priced energy with which it could not economically compete. Figure 1-7 relates the 75 MW System to the larger system and the "Economic Baseline".

The case study clearly shows the advantage of designing the WTG to the wind spectrum of the region, the benefit of a WTG designed for economy-of-size, and the sensitivity to capital costs.

The cumulative revenue requirements for 150 MW systems comprised of either the GE or Boeing units are shown in Figure 1-8. The higher capital costs of the 300 unit

GE500 system cannot be compensated for by its good wind conversion performance, and the low plant factor of the GE 1500 outweighs the lower capital cost of its 100 unit system. The BV-1, conceptually designed for the region, with economy-of-size, is the best WTG candidate.

Base Generation Capacity

MP&L could not accept WECS for base generation capacity.

Discussions were held with their regional planning group (MAPP) which indicated

Figure 1-7. Relation of 75 MW System to the Larger System and its Economic Baseline

Figure 1-8. Cumulative Revenue Requirements for Three Alternate WECS

capacity credit would not be approved. MP&L's hydro capability was fully rated and could not be increased by interaction with WECS.

Since any energy storage system would add additional costs to the WECS system, MP&L concluded WECS had to be justified solely on the basis of production cost savings.

System Considerations

No first-order system obstacle was identified that would prohibit WECS. MP&L was confident it could handle the problems of the transient behavior of WECS power within their system. WECS variations appeared within the variations which occurred

because of high power transients in the Taconite Industry. Hydro capacity and spinning reserve were adequate to handle the 150 MW baseline case.

Utility Planning and Decision Making

The installation, maintenance, and operational problems of a large WECS system are foreign to utility practice.

1) Production Cost Model

The MP&L production cost model, a model frequently used in utility planning, has serious limitation in general applications for evaluating the effectiveness of WECS. The use of the model for the economic evaluation of the simultaneously varying utility load and WECS power output present a transient analysis problem. MP&L felt that the assumptions related to the production cost model were very defensible due to the utility's high load factor, the availability and current use of hydropower (106 megawatts) to modulate hourly load variations, spinning reserve, and the new Duluth operations control center.

Analysis of the extreme effects on the MP&L model indicated a potential 10 percent variation in economic return estimates. This is considered adequate for this planning study. The model deficiencies would be much larger for a utility with severe peaking problems and a lower load factor. Appendix I of the main volume final report elaborates on these problems.

2) Sandbulte summarized MP&L reservations:

"A number of areas which must be considered include:

- Maintenance considerations. No actual maintenance costs are available so conventional operation maintenance costs were assumed.
- The logistics involved in erecting a large number of units in a short period of time must be considered.
- More detail in analyzing the integration of WECS into a utility's system is necessary.
- The environmental acceptance of large numbers of wind turbine generators including regulatory approval, licensing, zoning, possible microwave interference and other unforeseen circumstances must be evaluated."

Environmental and Societal Issues

Some potential environmental and societal problems may develop. A study of key environmental factors was conducted to identify the impact of the above constraints on siting WECS. A serious potential problem appears to exist in that over half of Minnesota may be excluded or constrained from WECS siting. (Figure 1-9.)

A significant body of Minnesota state regulation may be applied to a WECS installation. The dispersed nature and broad area coverage of WECS application would present a major obstacle to hardware implementation, if Minnesota law were strictly interpreted.

Figure 1-9. Minnesota Land Use Summary

Wind Information

The study found that the average winds for the entire region were slightly lower than anticipated. Using a one-sixth power law and expressing the wind speed at 9.1 meters (30 feet), the regional average was about 5.0 meters per second (between 11 and 12 MPH). Also, monthly wind levels were found to be more in-phase with the hydro system's reservoir levels rather than complementary thus reducing the potential for seasonal wind and hydro complementary interaction.

The eight-observations per day National Weather Service data tapes served as a good data source for first-level wind assessment within the region. The correlation between recording stations revealed trends and general relative wind potentials within the region. This first level of regional analysis combined with general topographical information can help assess and guide more refined wind data analysis and wind survey.

A lack of more refined wind measurement information will however delay a significant introduction of WECS into Minnesota. Of the available regional wind data reviewed, only five recording stations (four NWS stations and the Hibbing Airport) were found to provide usable data. Checks of other data taken for purposes such as pollution studies found all such data to be unreliable. Since significant localized wind variations can occur from year to year, as well as monthly and hourly, no immediate solution is apparent but to make conservative estimates from long-term National Weather Service data.

If MP&L decided to implement WECS, a wind data problem will then exist with respect to site selection and turbine placement. The commitment of millions of dollars worth of equipment will take place only when some method of ensuring the reasonable placement of wind turbine generators is available.

CONCLUSIONS AND RECOMMENDATIONS

The study indicates WECS could be accepted by MP&L if its installed costs were 25 to 30 percent less than the estimated cost of the Boeing 1125 WTG.

- 1) A wind Turbine Generator should be designed which is optimized for the MP&L region with an installed cost goal of \$400/rated kw (1976 dollars).
- 2) New models are needed for utility WECS planning, especially in production cost estimating.

Evaluation of the wind energy system presented very basic problems of methodology, criteria and acceptability to standard utility practices.

- 3) The installation, maintenance, and operational problems of a large WECS system are foreign to utility practice.

The installation of 100 generating plants in acceptable sites is a significant problem to utilities accustomed to large central plants. Realistic maintenance costs and personnel skills associated with WTG reliability estimates and maintenance provisions need to be developed for distributed systems.

Logistical plans and schedules for installing WECS turbines need to be defined so as to be able to schedule financial requirements and power production in planning studies.

A general method to optimize the system size of WECS for a given application should be developed.

Some method of reliably identifying and verifying good turbine sites is needed which does not require long-term data collection and reduction.

A more extensive set of findings and recommendations associated with each of the primary areas of the study is provided at the end of each major section of the main volume final report.

GENERAL APPLICATION OF THE STUDY

The issues, results, and conclusions from a specific case study have limitations for general application.

This study has dealt with the primary elements in a utility planning process, but when assessing other applications the limitations of the MP&L study must be considered. Specifically these limitations are as follows:

- The MP&L case study was based upon available long-term wind data in the utility area.

Application planning should have more accurate data for placing units in higher wind energy sites. Many potential areas, including selected MP&L sites, would produce higher energy than that postulated in this case study.

- MP&L has a very unique load factor and growth projection. MP&L has the highest load factor in the USA, is the fastest growing utility in the country and is continually forced to purchase power. These characteristics, along with existing hydro generation, place MP&L in a unique position to accept intermittent wind energy.
- The study was based on an analysis of production cost savings and long-range financial performance. This analysis was conducted using planning tools currently employed by MP&L. The MP&L production costing model and corporate financial model constrained the study and must be carefully reviewed for any other application.

- The case study placed economic and operating constraints applicable to MP&L on the WECS viability analysis to provide credibility to the utility. Other utilities may have more freedom so that a better tradeoff could be developed.

SECTION II

BACKGROUND AND UNDERLYING ISSUES

Honeywell, in a joint effort with Minnesota Power and Light Company, Boeing Vertol Company, and Dr. C. G. Justus, Georgia Institute of Technology, has conducted a regional application study of wind energy systems. The study has explored the economic viability, technical feasibility, and environmental acceptability of introducing a large-scale wind energy conversion system (WECS) into the operations of a specific northern Minnesota utility, the Minnesota Power and Light Company (MP&L), believed to represent a high-potential candidate user.

The effectiveness of large-scale wind energy systems is a function of the wind potential of a region, the particular application and its demand characteristics, the availability and cost of other energy sources, and the need for or availability of energy storage. Thus, the potential use of wind systems and their goals and requirements will vary in different regions and are more competitive in certain types of applications.

The purpose of this study has been to assess the potential and determine the cost goals, performance, and user requirements for a specific, high-potential utility application. The study has sought to identify what performance and financial conditions would be necessary to enable WECS to be economically viable, and to provide ERDA with realistic data concerning fuel savings, priority R&D needs, environmental impact problems, and methods of applying the system to a utility. However, it must be restated that WECS performance is sensitive to the wind characteristics of particular regions and sites (MP&L is not in a high wind area), and to the demand and operational characteristics of each utility. Given today's understanding of wind power systems, the results for one utility cannot necessarily be extrapolated to other utilities.

It has been a continuing challenge throughout the study to reconcile those characteristics unique to the region and MP&L with the objective of achieving study results that were applicable in a more generic sense and meaningful not only to MP&L but also to ERDA and the general user community. The case study approach and the aforementioned sensitivities of wind systems tended to deter generalizations. Constraints associated with MP&L, its operations and standard practices were not necessarily universal utility practices.

Several basic premises to the study are thus very important to understanding the approach taken and to deriving a proper interpretation of the study results:

1. The decision process of an investor-owned utility is first and foremost interested in the economics of a particular question. Thus, it was of major importance that a credible method be developed to assess the economic value of the wind power system. A method was sought that would be acceptable to a utility and that would employ commonly used utility planning techniques. The assessment method itself was intended to be a general product of the study applicable, with only minor modifications, to other utilities for conducting a first-level economic evaluation of WECS.
2. Because of the breadth of the overall subject, refinement of some technical issues was compromised to engineering judgment in the belief that absolute accuracies were less important than relative sensitivities. As we progressed further into the study, we were especially reluctant to pursue protracted analyses of wind data, the results of which would still have been highly uncertain and speculative. The same applies to cost data. The goal was to conduct a first-level economic evaluation recognizing that a positive outcome would subsequently lead to further study iterations refined in more depth.

3. A characteristic of MP&L that made it appear as a favorable setting for a wind system was its high load factor (83% in 1974, 76% in 1975), which was consistently the highest of the top 100 electric utilities reported in an annual Electric Light and Power survey. This high load factor, however, may have contrasted MP&L to the larger group of utilities that operate with a more normal peaking load characteristic. This, consequently, detracted from the general applicability of the study methodology. Assumptions considered reasonable in the MP&L case study may be challenged as to their validity to other utilities. In this light, we believe the general value of the MP&L results is to establish a performance level relative to which utilities with lower load factors can still relate. We can also identify within the study methodology those steps that would require modification for a utility with a more peaking load.
4. As a part of its original study proposal, Honeywell put forth the concept of an "economic baseline" which, by definition, would be economically viable in the MP&L system. This concept was proposed, recognizing the likelihood that current technology WECS would probably not compete with low-cost, low-sulphur coal plants within MP&L's current planning cycle. The economic baseline, with engineering goals and assumptions, was to be used to identify where current technology must be modified or where low-cost production must be introduced to make WECS competitive. The economic baseline concept is thus an "optimistic" concept and some of the assumptions associated with it are also intentionally optimistic. Optimism, as used in this context, is not intended to be misleading, but rather to help define absolute goals for WECS development.

SECTION III

MINNESOTA POWER AND LIGHT COMPANY AND THE REGION

MINNESOTA POWER AND LIGHT COMPANY

Minnesota Power and Light Company, which includes its subsidiary Superior Water, Light and Power Company, is a regional investor-owned company serving 15 counties in central and northeastern Minnesota and two counties in northwestern Wisconsin. With headquarters in Duluth, it provides both direct and indirect service to 189 communities. Indirect service is through municipally operated systems or rural cooperatives. MP&L's 26,000-square-mile service area (see Figure 3-1), with 6289 miles of transmission and distribution lines, combines concentrated residential and industrial loads with sparsely settled rural areas.

A unique aspect of MP&L's operation is the Mesabi Range and its concentration of mining and ore processing industries. These not only require large amounts of power, but also are an almost constant load, operating 24 hours a day the year around. As a result, MP&L consistently has one of the highest load factors in the United States. Presently, the iron mining industry uses approximately 300 MW, or about 35 percent of MP&L's generating capacity. These requirements are forecast to rise significantly (see Figure 3-2).

To meet increasing demands, MP&L will purchase power from a 400 MW plant being built near Center, North Dakota. A ± 250 KV, direct-current transmission line will bring this power to the MP&L area. The new plant and transmission line, scheduled for 1977, continues MP&L's commitment to fossil fuels as its basic energy source. Hydro power accounts for approximately 12 percent of the company's present capacity, and will remain at this level, representing a smaller percentage of the total capacity as the system expands.

The bulk of MP&L's present capacity is in four steam electric stations, having a total capacity of nearly 750 mw (See Table 3-1).

Since 1968, MP&L has purchased power from other utilities to meet its demand. This situation is expected to continue in spite of currently planned system expansion; i. e., the 500 MW Boswell No. 4 and 800 MW Brookston No. 1. The potential size of the Brookston unit was recently increased from 500 to 800 megawatts, anticipating that neighboring utilities may want to participate in this unit. Figure 3-3 illustrates MP&L's net generating capabilities and forecast of maximum demand. The utility's continuing dependence upon purchases, coupled with the very high system load factor forms the basis for this claimed high-potential WECS application. Even though the availability of wind power cannot be reliably predicted, the probability is high that MP&L will be able to use it whenever it is available.

Current Projects and Plans

MP&L currently expects to spend \$1 billion in the next 10 to 12 years to meet the electric power needs of Northern Minnesota's expanding economy. It forecasts a doubling in electric demand during the next five years, as shown in Figure 3-3. Duluth-Superior harbor projects, taconite industry expansion and growth in the forest product industries all contribute to this increasing demand.

Work on the Square Butte project is proceeding on schedule with completion set for 1977. The work includes a 400-megawatt, mine-mouth generating unit near Center, N. D. and a 456-mile, direct-current transmission line connecting the plant with the MP&L system near Duluth.

Conversion terminals are being built at the plant itself and at MP&L's Arrowhead substation in Duluth where the electricity will be transmitted into the company's system as alternating current for use by customers. The use of

Figure 3-1. Minnesota Power and Light Company Transmission System and Service Area

Table 3-1. MP&L System Electric Generating Capability

Steam Electric Stations	Kilowatts	Hydroelectric Stations	Kilowatts
M. L. Hibbard (Duluth) Oil-Gas	124, 500	Thomson (St. Louis River)	68, 000
Aurora (Aurora-Hoyt Lakes) Coal-Oil	110, 000	Blanchard (Mississippi River)	11, 800
Clay Boswell (Cohasset) Coal	490, 000	Fond du Lac (St. Louis River)	11, 800
Winslow (Superior Water, Light and Power Company) Oil-Gas	25, 000	Winton (Kawishiwi River)	4, 000
Total	749, 500	Little Falls (Mississippi River)	3, 300
		Knife Falls (St. Louis River)	1, 900
		Pillager (Crow Wing River)	1, 700
		Sylvan (Crow Wing River)	1, 700
		Scanlon (St. Louis River)	1, 400
		Total	105, 600

Overall Total System Capability = 855, 100 kilowatts

Figure 3-2. Growing Need for Power in Iron Ore Industry

Figure 3-3. Minnesota Power and Light Company:
Net Generating Capabilities and Forecast
of Maximum Demand (MW)

direct current means reduced line losses and physically smaller transmission fixtures, providing economic and environmental advantages. The "mine-mouth" generating concept is based on the premise that it will be more efficient to export power than to export coal, especially when the coal is moist and relatively low in heat content.

Under terms of the Square Butte project agreement, MP&L will be able to purchase 100 percent of the new generating unit's output for the first seven years and progressively lesser amounts after that to a minimum of 49 percent.

A 230-kilovolt transmission line to connect MP&L's system with that of Manitoba Hydro-Electric is under consideration and is scheduled for completion in the fall of 1976. The line is being built between Winnipeg, Canada, and the Shannon area near Hibbing. Approval by Canadian and U. S. governmental agencies is now pending, with final approval expected this year.

MP&L and Northern States Power Co. are seeking permits to build a 500-kilovolt transmission line which would run from the Twin Cities area to the Manitoba Hydro-Electric system near Winnipeg, passing through MP&L territory via Forbes on the Iron Range. The line, scheduled for completion in 1980, would connect the three electric systems and enhance the reliability of each by allowing for interchange of large quantities of electricity. It is anticipated the Twin Cities to Forbes section of the line will be completed by 1978.

MP&L also is going through the permit process for the proposed 500-megawatt addition to the Clay Boswell plant near Cohasset. The unit, which will burn low-sulphur Western coal, is scheduled for completion in 1980 and, provided the necessary permits are granted, construction will begin this year. Total cost has been estimated at about \$400 million, with more than \$100 million of that amount tabbed for environmental protection facilities.

Also, in the permit-seeking stage, is the large generating plant proposed for the Brookston area. MP&L forecasts a need for that plant in the 1982-1984 period.

MP&L's new energy control center is under construction in Duluth. The center will contain a highly modern central dispatch system, supervisory controls, data acquisition and generator controls. It also will have an extensive microwave system which will link the center with MP&L facilities throughout the service area. The center is expected to cost \$14 million and be completed in 1977.

Regional Power Pool

MP&L is an active member of the Mid-Continent Area Power Pool (MAPP). MAPP was organized in 1963 as the first regional power planning group, and it grew from a coordinating role into an operating pool for the Upper Midwest. The pool provides significant economic as well as reliability benefits through the advantages of large-scale operations while permitting its member utilities to retain local company ownership and control.

MAPP's membership includes 12 investor-owned electric companies, 11 municipal systems, eight rural electric generating and transmission cooperatives, two public power districts, and the federal Missouri Basin hydroelectric system. Its membership embraces every type of power supplier and serves an eight-state geographical area that includes much of the nation's "bread-basket" and vast coal and iron ore reserves. Figure 3-4 shows the area served by MAPP.

Figure 3-4. Eight-State Region Covered by Mid-Continent Area Power Pool

THE TACONITE INDUSTRY OF MP&L'S NORTHERN DIVISION

The Mesabi Range is a band formation of iron which includes an iron-bearing rock consisting of 20 to 30 percent iron. This is called "taconite." Located in MP&L's Northern Division, the Range is about 100 miles long, 1-1/2 to 3 miles wide, (see Figure 3-5) with the iron formation extending to depths of 600 feet. Nature enriched part of this iron formation into "natural ore," but after 30 years of mining, including the demands of two World Wars, most of the high-grade, natural ore has been used.

Figure 3-5. Mesabi Range

Much of the natural ore that remains has too little iron to permit its use in that form. But experts believe Minnesota has a 100-year supply of taconite, an extremely hard, dense material that can be processed into usable iron ore material.

Taconite mining operations require drilling, blasting and loading millions of tons of taconite. It is hauled from the mine to a processing plant in standard gauge, diesel-electric powered trains. The processing plants operate around the clock, producing the hard, marble-sized taconite pellets for shipment to the steel mills.

MP&L'S WESTERN DIVISION

In contrast to the rugged, forested terrain of the Northern Division, MP&L's Western Division contains more gently rolling farmland, rural communities, some light commercial industry, and many resort and recreational areas.

MP&L'S CENTRAL DIVISION

MP&L's Central Division combines characteristics of the other two divisions. The northern half of the division, adjoining the north shore of Lake Superior, again contains rugged, forested terrain. The southern half contains more gentle geography and more farmland. Between these two regions are the major northern Minnesota city of Duluth (population about 100,000 and MP&L's base of operations) and the Duluth Port, one of the largest and busiest inland ports in the world. Heavy industry and commerce ship products through this port.

REGIONAL WEATHER AND WIND SUMMARY

Weather is similar from the Red River Valley in Minnesota's west across to central Wisconsin, being marked by the general wet-warm season and dry-cold season that characterizes interior North America. Differences do exist, however, even between places 50 miles apart, although they may be imperceptible at first glance. Although all areas in Minnesota share certain climatic characteristics with each other, locations at the extreme portions of the state do have characteristics shared with places far from Minnesota.

Southwestern Minnesota has characteristics of the central high plains; the northwest has characteristics of the subarctic; the northeast has characteristics of the upper Great Lakes; and the southeast has characteristics of the lower midwest.

The region's winds are summarized in Table 3-2. Mean wind speeds are given for four National Weather Service Recording stations (Duluth, St. Cloud, Fargo, and International Falls) that bordered MP&L's service area. The mean wind speeds were computed from data recorded over the five-year period 1/67 to 12/71.

Also included in Table 3-2 is the mean wind speed at Hibbing, Minnesota. This value was determined from data recorded at the Hibbing Airport from 1964 to 1973. Hibbing data was independently obtained to establish a data checkpoint located at about the center of MP&L's service area.

Table 3-2. Mean Wind Speeds

	Mean Wind Speeds			Anemometer Height		Station Elevation	Fastest Wind
	Knots	MPH	Meter Sec	Meter	Feet	Feet	MPH
Fargo	10.3	11.9	5.3	6.1	20	896	115
Duluth	9.2	10.6	4.7	6.4	21	1428	75
International Falls	8.0	9.2	4.1	6.1	20	1179	52
St. Cloud	8.8	10.1	4.5	14.0	46	1028	53
Hibbing	8.2	9.5	4.3	9.1	30	1350	

St. Cloud --

St. Cloud is located in the Mississippi Valley on rolling hills. The weather station is located at the airport in Sherburne County. Elevation averages around 1000 feet.

Fargo --

Fargo is located on the Red River at nearly 47 degrees north. The terrain is generally flat, but the valley slopes upward to the east and west. Elevation is 910 feet.

International Falls --

International Falls is located along the Rainy River on the Ontario border. The surrounding country is largely forested and slightly rolling. Elevation is 1125 feet.

Duluth --

Duluth is located on the north shore of Lake Superior. The city is built on the side of a sharply-sloping hill along the lake. Elevation varies from 602 feet along the lake to over 1400 feet above at the crest of the hill. The weather station is located over the crest of the hill at 1428 feet.

Hibbing --

Hibbing is located on the Mesabi Range. On the hills it is at an elevation of 1500 feet. The weather station is at the airport, about 10 miles to the south-east, on flat meadowland at 1350 feet.

Figure 3-6 locates these weather recording stations relative to the MP&L service area and shows wind roses for each station.

The monthly and annual variability of the region's winds are plotted in the following figures:

1. Figure 3-7 shows the monthly mean wind speeds at each of the NWS sites. Each monthly data point represents an average over the ten months (i. e. , 10 Januarys, 10 Februarys, 10 Marches, etc.) that occurred during the 10-year period of 1/65 to 12/74.

Figure 3-6. Regional Wind Roses

Figure 3-7. Monthly Mean Wind Speeds at National Climatic Center Wind Data Sites for the 10-year Period 1965-1974

The figure includes a monthly average (X's) over the three stations having 20-foot-high anemometers. Also plotted as a single point to the right of the twelfth month is a 10-year annual average for each of the recording stations (4.1 to 5.23 mps (2.5 MPH) spread) and the 3-site 10-year average, 4.65 mps (10.4 MPH).

2. Figure 3-8 shows the annual wind distribution for each of the four NWS sites in the form of five-year wind summaries. One must be cautioned against interpreting this data as continuously plotted probability distributions. The data points represent the total number of occurrences of velocities within the particular speed categories.
3. Figure 3-9 is a cumulative plot of the data presented in Figure 3-8. The median wind speeds for each of the stations can be determined from these plots.

FINDINGS AND RECOMMENDATIONS

1. The average winds for the entire region were slightly lower than anticipated. Using a one-sixth power law and expressing the wind speed at 9.1 meters (30 feet), the regional average was about 5.0 meters per second (between 11 and 12 MPH).

Recommendation: In search of localized, higher wind speeds, wind data should be recorded along the continental divide (i. e., the Mesabi Range) and on the western side of MP&L's service area approaching towards Fargo. Potential speed increases in the vicinity of lakes could also be sought.

Figure 3-8. Annual Wind Distribution Provided by the National Climatic Center for the 5-year Period 1/67-12/71

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Figure 3-9. Cumulative Annual Wind Distribution Provided by the National Climatic Center for the 5-Year Period 1/67-12/71

2. National Weather Service data tapes are a good source for first-level wind assessment within a region. The correlation between recording stations can reveal trends and general relative wind potentials within the region. This first-level of regional analysis combined with general topographical information can help assess and guide the need for a more refined wind data analysis and wind survey.

Recommendation: First-level wind analysis techniques (such as the weighted-nearest-neighbor interpolation method discussed in the next section) that facilitate the use of existing NWS or other reliable and available wind data should be

1. Sought through funded research by the Federal Wind Program Office
2. Validated and certified by that office
3. Given broad general visibility by that office so as to make these accepted techniques widely available to the general user community.

SECTION IV

STUDY METHODOLOGY AND WIND ENERGY CONVERSION ANALYSIS

Five major work elements formed the basic technical approach for the application study (see Figure 4-1). The regional wind data and utility load data at the beginning of the study and the standard practices of the utility at the end of the study established overall study constraints. The issues associated with wind energy conversion, system integration, and WECS viability were pursued within these constraints.

Figure 4-1. WECS Program Technical Approach

INITIAL ASSUMPTIONS

Several initial assumptions were required to provide a basis for the hypothetical wind power system definition:

1. The power system peak rating was set at 150 megawatts. This capability reflected current and projected utility needs (see Figure 3-3). If installed in 1976, it would represent from 18 percent in 1977 to 9 percent in 1985 of MP&L's currently forecasted owned generating capability. The 150-MW WECS peak rating was also comfortably related to the sum total of MP&L's 106-MW hydroelectric and 150-MW oil-fired capacity so that wind energy could be stored using the hydro system or used to conserve on oil usage.
2. Five turbine sites were selected for the 150-MW wind power system: Park Rapids - 30 MW; Hibbing - 45 MW; Virginia - 45 MW; Winton - 15 MW; and Sandstone - 15 MW. They were selected and apportioned primarily on the basis of known regional generating needs and existing 14-, 23-, 34-, or 46-KV distribution lines. Their locations are circled on the MP&L system map (Figure 4-2).
3. MP&L established that they would most likely operate the WECS as a fuel saver. Operating with an 83 percent utility load factor (the nation's highest), MP&L virtually always requires energy to serve its system load.

WIND CHARACTERIZATION AND REGIONAL POTENTIAL

The National Weather Service (NWS) wind data from Fargo, Duluth, International Falls and St. Cloud was selected as the most reliable and readily available data base for the northern Minnesota region. The four recording stations situated on the periphery of MP&L's service area are indicated on the MP&L system map (Figure 4-2). Effectively bounding the study region, these four recording stations were believed to establish a sound basis for subsequent analyses. A spot check using wind data recorded at the Hibbing airport from 1964 to 1973, reasonably matched the NWS wind data and validated its use.

The wind data was obtained in two forms from the National Climatic Center:

1. Monthly and annual wind distributions at each of the recording stations for the five year period, 1/67 - 12/71
2. Data tapes containing 8-observations-per-day readings at each of the recording stations for the 10-year period, 1/65 - 12/74

The data tapes were required because the five-year summaries compressed all five year's worth of data into one representative year such that no particular month during the five-year interval could be recovered. Having the NWS data tapes provided more flexibility in the types of analyses that could be conducted.

Wind Data Conversion

To conduct the WECS economic analysis using MP&L's standard system planning computer programs, it was necessary to determine WECS performance on a monthly basis to satisfy the input requirements for these programs. It was also believed that a more meaningful, generalized WECS performance analysis would result from some statistical compression of the 10-year, 8-observations-per-day NWS wind data. These two considerations strongly influenced the decision to use monthly wind summaries as a basis for the analysis.

A third factor contributing to the use of monthly wind summaries arose from the study objective to address the distributed nature of a large WECS installation. This required that the wind data from the four NWS recording sites be transformed to the five areas, each containing several turbine sites.

Monthly wind summaries provided a convenient basis for making the recording site to turbine site wind data transformation and for determining the overall WECS array performance. Monthly net capability was the performance measure established by MAPP for the uniform rating of generating equipment.

The following sequence describes how the wind data was processed for use in the study:

1. Convert wind data to monthly wind summaries --

The wind speed data from each NWS data tape was binned (sorted by speed) into three-knot speed intervals for each month of the 10-year period. This established monthly wind summaries (i. e. , frequency of occurrence wind distributions) similar to that shown in Figure 4-3. The relative frequency of occurrence of winds within specific speed classes can be used to describe the monthly distribution of the wind at a particular site.

2. Fit each monthly summary by a Weibull probability distribution --

The Weibull probability distribution is of the form

$$p(V) = \left(\frac{k}{c}\right) \left(\frac{V}{c}\right)^{k-1} \exp \left[- \left(\frac{V}{c}\right)^k \right] \quad (4-1)$$

where

V = wind speed

c = a constant related to the mean wind speed

k = a dimensionless constant shape factor
related to the measure of variance (the
larger k, the smaller the variance).

Figure 4-3. Monthly Wind Summary: Duluth, Minnesota, April 1971

The two parameters, c and k , that determine the distribution can be evaluated by a least-squares straight line fit to

$$Y_i = a + b X_i, \quad (4-2)$$

where

$$Y_i = \ln \{ -\ln [1 - P(V_i)] \} \quad (4-3)$$

$$X_i = \ln V_i \quad (4-4)$$

$$c = \exp(-a/b) \quad (4-5)$$

$$k = b \quad (4-6)$$

and $P(V_i)$ is the Weibull cumulative distribution given by

$$\begin{aligned} P(V_i) &= \int_0^{V_i} p(v) dv \\ &= 1 - \exp \left[- \left(\frac{V_i}{c} \right)^K \right]. \end{aligned} \quad (4-7)$$

The least-squares fit of a and b to the straight line represented by equation (4-2) is found by the values of a and b which minimize

$$\epsilon = \sum \{ \ln [-\ln (1 - P(V_i))] - a - b \ln V_i \}^2. \quad (4-8)$$

Equations (4-1) - (4-8) yield monthly c and k values for each wind data site for winds at the height of the recording anemometer. These c and k values must next be adjusted to hub height.

3. Height adjustment of the Weibull parameters --

The height adjustment for c is made using

$$\frac{C_2}{C_1} = \left(\frac{h_2}{h_1} \right)^x \quad (4-9)$$

where

h_1 and h_2 are in meters and

$$x = (0.37 - 0.0881 \ln c_1) / [1 - 0.0881 \ln (h_1/10)] \quad (4-10)$$

The shape factor ratio is evaluated by

$$\frac{k_2}{k_1} = [1 - 0.0881 \ln (h_1/10)] / [1 - 0.0881 \ln (h_2/10)] \quad (4-11)$$

The derivation of equations (4-9) - (4-11) is provided in Reference (1).

4. Transformation of c and k to Turbine Site --

The hub height values of c and k at the wind data sites must next be transformed to the turbine sites. A transformation was derived that combined c 's and k 's by a "weighted nearest neighbor" technique.

The weighted nearest neighbor transformation was developed as an engineering approximation to the problem of interpolating wind speed data between known recording stations and completely ignores local topographical effects. For the relatively flat, gentle rolling terrain of northern Minnesota, this transformation was considered reasonable, producing a conservative estimate of interpolated wind speed because it does not over-weigh high wind areas.

$$C_{Ti} = \sum_{j=1}^N D_{ij} C_j \quad (4-12)$$

$$k_{Ti} = \sum_{j=1}^N D_{ij} k_j, \quad (4-13)$$

where

C_{Ti} = transformed value of c_j 's to the i^{th} turbine site

k_{Ti} = transformed value of k_j 's to the i^{th} turbine site

N = number of wind data sites

$$D_{ij} = \frac{1}{d_{ij} \left[\frac{1}{d_{i1}} + \frac{1}{d_{i2}} + \dots + \frac{1}{d_{ij}} + \dots + \frac{1}{d_{iN}} \right]} \quad (4-14)$$

d_{ij} = distance between the i^{th} turbine site and the j^{th} wind data site.

Wind data recorded at the Hibbing airport over the 10-year period 1964-1973 was used to test the weighted nearest neighbor transformation. The mean wind speed for Hibbing determined from the Hibbing data was 4.25 meters per second (9.5 MPH). The transformation yielded a mean windspeed of 4.45 mps (9.95 MPH) using the 20-foot means at Fargo, International Falls, Duluth, and St. Cloud.

Appendix A elaborates on this transformation and provides a sample computation. A tabular summary of mean wind speeds calculated at the WTG area sites using this transformation is also included in Appendix A.

WTG Energy Conversion

Monthly values for the Weibull probability distribution c and k parameters were determined at each area turbine site for the 10-year period 1965-1974. The turbine site winds were then used to evaluate turbine site outputs.

As much output information as possible was obtained for each WTG site. This benefitted the final step of combining site outputs into total WECS system output. Output computations included

1. $\bar{P}$ = monthly mean output power
2. F_p = capacity factor, the ratio of the average output power to the rated power, $\bar{P}/P_r$
3. $\bar{V}$ = mean wind speed
4. f = energy pattern factor, the ratio of the average available power to the power available in the mean wind
5. P_m = available power in the mean wind
6. E = monthly energy output, (hours per month $\times \bar{P}$)
7. E_{sp} = monthly specific energy output
8. T = number of hours per month that turbines would run

Appendix B contains derivations and equations for the above parameters. This appendix was extracted from Reference (2) the Benefit-Cost Methodology Study prepared by Dr. Justus, et al. for NASA. Note that the WTG power output characteristic curve was a required input for the WTG energy conversion computations.

WIND TURBINE GENERATORS

Five wind turbine options were included in the study: the General Electric 500 KW and 1500KW units Reference (3); the Kaman 500 KW and 1500 KW units Reference (4); and a Boeing Vertol 1125 KW design Reference (5). The G. E. and Kaman units were considered current-technology designs, from which a baseline system performance was established. Boeing Vertol defined an advanced technology wind turbine optimized for the region's 4.65-meter-per-second average wind speed (10.4 mph ten-year average measured at 20 feet anemometer height). Table 4-1 summarizes design parameters for these units.

Table 4-1. Summary of Alternate WTGs

		500 KW		1125 KW	1500 KW	
		GE	Kaman	Boeing*	GE	Kaman
Cut-in wind speed at 140 feet	(MPH)	10.3	11.4	10.4	14.8	15.7
	(M/S)	4.6	5.1	4.7	6.6	7.0
Rated wind speed at 140 feet	(MPH)	21.0	26.2	23.3	29.3	32.6
	(M/S)	9.4	11.7	10.4	13.1	14.6
Cut-out wind speed at 140 feet	(MPH)	51.9	38.2	60.0	64.4	58.4
	(M/S)	23.2	17.1	26.8	28.8	26.1
Rotor diameter	(Feet)	183	150	265	190	180
	(Meters)	55.8	45.6	80.6	57.9	54.8
Hub height	(Feet)	140	140	185	140	140
	(Meters)	42.6	42.6	82.7	42.6	42.6
Disk area	(Sq. Meters)	2445	1633	5102	2633	2359
Design mean wind speed at 30 feet	(MPH)	12	12	11.1	18	18
	(M/S)	5.37	5.37	5.0	8.05	8.05
Number of blades		2	2	1	2	2
Rotor speed	(RPM)	29	32.3	24.7	40	34.4
Rotor solidity	(%)	3	3	1.5	3	3

* Boeing values for cut-in, rated, and cut-out wind speed are for 185 feet hub height not 140 feet.

Within the advanced technology design effort, Boeing Vertol developed both one-bladed and two-bladed conceptual designs, the BV-1 and BV-2. The BV-1 and BV-2 both have 265-foot rotor diameters, 185-foot hub heights, and peak ratings of 1125 KW. The designs were sufficiently similar so that only the BV-1 was used for system evaluation. The following design summary describes the key characteristics of the BV-1. Reference (3), which was included as an attachment in this study's third report, provides a complete discussion of both Boeing designs.

System evaluation was initially conducted using all five candidate WTG's. After the relative performance was established, only the most viable candidate was retained. As one would expect, the Boeing unit, optimized for the northern Minnesota wind regime, performed best.

BV-1 Design Characteristics

The advanced-technology wind turbine generator selected from the results of this study is the Boeing Model BV-1 (Figure 4-4) whose characteristics and performance are shown in Table 4-2 and Figure 4-5.

The unique characteristic of this design is its counterbalanced, single-blade, 265-foot-diameter rotor which performs exceedingly well, has good maintainability and gust characteristics, and has low capital and operating costs.

Some of the most advanced features are:

- The built in 'delta-three' hinge arrangement of the teeter axis of the rotor, which automatically compensates for rotor gust loadings and will reduce tower and rotor fatigue loads.
- The articulated (teetering) hub external to the blade structure, which lowers capital and maintenance costs.

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Figure 4-4. Boeing Model BV-1 WTG General Arrangement

Table 4-2. Characteristics of 1125 KW Models BV-1 and BV-2
(for Duluth 200 ft. Wind Spectra)

Item	BV-1 (One Blade)	BV-2 (Two Blades)
1. Average Wind, MPH*	16.9	16.9
2. Maximum Efficiency Velocity, MPH*	17.6	16.8
3. Rated Wind Velocity, MPH*	23.3	23.3
4. Rated Watts/Sq. Ft.	20.4	20.4
5. KW Output	1125	1125
6. Efficiency (Machine)	0.33	0.33
7. Rotor Diameter, Ft.	265	265
8. HP Output (Rotor)	1600	1620
9. Mean Blade Lift Coefficient	1.0	1.0
10. Max. Efficiency Tip Speed to Wind Ratio	13.3	9.4
11. Rotor Solidity	0.015	0.030
12. Mean Rotor Blade Chord, Ft.	6.25	6.25
13. Rotor Tip Speed, Ft/Sec.	343	231
14. Rotor RPM	24.7	16.6
15. Generator RPM	1,200	1,200
16. Step Up Ratio	48.5	72.1
17. Input Torque (Rotor), Ft/Lb	338,000	501,000
18. Hub Height, Ft.	185	185
19. Rotor Drag, Lb (Limit)	77,200	70,000
20. KW. Hr/Yr	4,164,000	4,423,000
21. Capacity Factor	0.43	0.45
22. Blade Type	Reinf. Thermoplastic D-Spar + T. E. Box	
23. Hub Type	Teeter - δ_3	Teeter - δ_3
24. Gear Box Type	Planetary	Planetary
25. Generator Type	Induction	
26. Tower Type	Welded Steel Shell	
27. Controls	Electro-Mechanical	
28. Installed Cost, \$	568,000	643,000
29. Installed Unit Cost, \$/KW (Rated)	504	616
30. Cost of Electricity, ¢/KW. Hr	2.71	3.17

* At Hub

Figure 4-5. Performance of Wind Turbine Model BV-1 at Rated Power of 1125 KW

- Selected rotor characteristics which maximize electrical energy output per year by efficiently converting wind energy especially for the low-wind velocities below rated power.
- Blade material of common, low-cost fiberglass impregnated with formable thermoplastic material, which allows an automated, low-labor-cost fabrication.
- Soft-in-torsion shafting, which permits achieving high power by minimizing the alternating torque harmonics resulting from rotor and wind loads.
- Proven tower construction formed from steel plates and welded into a semi-cantilever conical shell with dynamic characteristics minimizing the interaction with rotor vibratory loads, and a cost-effective shell construction for longer dimensions to reach higher wind velocities.*
- An advanced planetary gear drive, which improves efficiency, and reduces the weight and cost.

The general data on configuration, fabrication methods and material selection for the respective subsystems are shown in Table 4-3.

WTG Cost Estimates

WTG cost estimates were an important factor in the system evaluation. Since each of the manufacturer's was unique in the treatment of costs, their individual estimates have been reproduced in Tables 4-4 - 4-6.

* Note that tower "shadowing" is a potential problem requiring further study.

Table 4-3. Boeing Model BV-1 W. T. G. General Data

Subsystem	Material/Hardware	Configuration	Fabrication Method
Blade	Glass and Thermoplastic	D-Spar	Forming
Hub	Corrosion Rest. Steel	Casting	Machining
Pitch Controls	Electr. Actuator	Hub Mounted	N. A.
Transmission	High Quality Steel	Planetary	Commercial/Aircraft
Generator	---	Induction	---
Nacelle	Composite - Steel	Shell + Beams	Wet Layup and Welding
Tower	Steel Plate	Shell	Forming and Welding

Table 4-4. G. E. WTG Cost Estimates
100 Units

System Task	500 kW, WTG	1500 kW, WTG
Program Management	2,000	2,000
Final Design	1,500	1,500
Systems Integration	2,500	2,500
Equipment Costs		
Rotor	154,000	185,000
Transmission	100,000	162,000
Electrical	37,400	60,700
Controls	13,600	13,600
Tower (concrete)	39,300	55,900
Bedplate/Pintle	19,100	36,400
Subtotal	363,400	513,600
Assembly Costs		
Nacelle	8,600	8,600
Site Delivery	5,600	9,300
Erection	14,700	14,700
System Check-Out	2,500	2,500
Subtotal	31,400	35,100
Site Costs		
Land	1,500	1,500
Control Building	3,500	3,500
Total Direct Labor and Material	405,800	559,700
Gross Operating Margin	60,870	83,955
Total Cost	466,670	643,655

Table 4-5. Kaman WTG Cost Estimates

Steel Truss Tower 1000 Units		
	Cost Per Unit, \$	
	500 KW WTG Estimated from Preliminary Design	1500 KW WTG Estimated from Preliminary Design
System Integration	14,400	25,100
Rotor Subsystem	110,000	194,900
Blades	(76,600)	(122,000)
Hub and Other	(33,400)	(72,900)
Drive Subsystem	78,000	181,000
Electrical Subsystem	43,800	64,800
Control Subsystem	31,400	31,400
Structure Subsystem	97,400	134,600
Total WGS Unit Cost	375,000	631,800
Other Capital Costs	75,670	89,000
Direct Capital Cost, \$	450,670	720,800
Direct Capital Cost, \$/KW	901	481
Estimated Energy Cost, ¢/KW-Hr	7.1	2.7

Table 4-6. Boeing Vertol WTG Cost Estimates

Component (1)	Model BV-1		Model BV-2	
	Induction	Synchronous	Induction	Synchronous
Rotor Subsystem (Including Pitch Controls)	105,500		179,000	
Rotor Shaft and Bearings	11,900		11,900	
Step Up Transmission ⁽²⁾	155,000		195,000	
High Speed Shaft, Brake, Clutch, Couplings	11,900		11,900	
Generator - 1125 KW	23,500	58,000	23,500	58,000
Capacitors (4)	3,560	- - -	3,560	- - -
Generator Controls, Indicators, Protective Equipment				
Electrical Controls, Wiring, Switchgear and Transformer	47,000		47,000	
Mechanical Controls (5)	8,700		8,700	
Nacelle - Structure and Interior Equipment	31,300		31,300	
Turntable - Structure, Drive Train, Controls	23,000		23,000	
Tower - Structure and Foundation (3)	103,500		103,500	
Subtotal	516,160	554,800	630,560	669,300
Erection and Assembly 10%	51,616	55,480	63,056	66,930
Total	567,776	605,280	693,616	736,230

Table 4-6 summarizes the capital costs including erection and assembly and special plant and tooling costs for the 1125 KW Model BV-1 based on a production of 1000 units in five years.

- (1) Includes blade plant and tooling amortization, and non-recurring engineering costs.
- (2) Advanced Planetary.
- (3) Cantilever shell type by Bruce-Lake Company.
- (4) Proportional to rated power.
- (5) 15 percent of synchronous generator.

A later section covering interface and installation issues identifies additional costs that were added to the manufacturer's cost estimates. These costs were mainly for interfacing the multi-unit system with the utility grid. Table 4-7 summarizes these additions on a per-unit basis. The costs in Table 4-7 were used for the wind system evaluation.

Table 4-7. WECS per Unit Costs

	500 KW		1125 KW	1500 KW	
	G. E.	Kaman	Boeing	G. E.	Kaman
Unit Prices from Design Studies	466,670	450,670	567,776	643,655	720,800
Additional Interface	65,883	52,314	60,516	130,750	66,080
Additional Installation	16,870	16,870	28,270	16,870	16,870
Total Dollars	549,423	519,854	656,562	791,275	803,750
Dollars per Rated KW	1,098	1,039	584	528	536

PRELIMINARY WTG ENERGY CONVERSION COMPARISONS

Early in the study, preliminary WTG energy conversion comparisons were performed to establish the relative performance between the five units. Preliminary design characteristics and costs including a 1000KW preliminary Boeing WTG design were employed in these comparisons. WTG performance was evaluated at the turbine sites.

The power theoretically available in the wind is

$$\text{Theo. Avail. Power} = \frac{1}{2} \rho V^3 A,$$

where

- ρ = air density
- V = wind speed
- A = projected disk area.

The actual wind power extracted by the wind turbine generator is represented by the mean available power, $\bar{P}$, where

$$\bar{P} = \int_{V_{CI}}^{V_{CO}} P(v)p(v)dv$$

and

- V_{CI} = WTG cut-in wind speed
- V_{CO} = WTG cut-out wind speed
- $P(v)$ = WTG power output versus wind speed characteristic
- $p(v)$ = probability distribution of the wind.

The theoretically available power and the mean available power (along with the performance parameters previously sighted under WTG energy conversion) were computed for the General Electric and KAMAN 500 KW and 1.5 MW wind turbine generators and for the preliminary Boeing 1000 KW WTG. These data were computed on a monthly basis for the 10-year period, 1/65-12/74. Figures 4-6 and 4-7 and Tables 4-8 and 4-9 are typical results. The tabulated results are for a maximum and minimum capacitor factor year. MP&L's 1975 energy costs for the Hibbard and Boswell oil-and coal-fired units are included for comparison.

Figure 4-8 summarizes the monthly maximum and minimum capacitor factor for each of the WTG's covering the entire 10-year period and all five turbine sites. The spread between the maximum and minimum capacity factor values for a particular month covers all values that occurred over the 10-year period.

Figure 4-6. Annual Energy Output at Virginia, Minnesota
 4.8mps (10.7MPH) Calculated 10-Year Average
 Mean Wind at 30 Feet

Figure 4-7. Specific Energy (E_s) for Virginia, Minnesota, 1973
 4.3mps (9.6MPH) Calculated 1973 Mean Wind Speed

Table 4-8. 1970 WTG Performance at Virginia, Minnesota
(Maximum Capacity Factor Year)
5.05mps (11.3MPH) Calculated 1970 Mean Wind Speed

	500		1000	1500	
	GE	KAMAN	BOEING	GE	KAMAN
MEAN AVAILABLE POWER (KW)	213	130	335	251	171
THEOR. AVAILABLE POWER (KW)	741	495	1546	798	715
EFFICIENCY (%)	29	26	22	32	24
SPECIFIC ENERGY (KW-HR/KW PER YEAR)	3729	2275	2939	1469	1000
TOTAL ENERGY OUTPUT (KW-HR/YR)	1864661	1137701	2938577	2203088	1499201
CAPACITY FACTOR	.43	.26	.34	.17	.11
WTG CAPITAL COST (\$)	486800	420500	561450	673950	747000
COST PER RATED KILOWATT (\$/KW)	974	841	561	449	498
COST PER MEAN AVAIL. KILOWATT (\$/KW)	2285	3235	1676	2685	4368
CARRYING CHARGE RATE PLUS O&M	20%	20%	20%	20%	20%
ENERGY COST (¢/KW-HR)	5.2	7.4	3.8	6.1	10.0
HIBBARD - #6 OIL ENERGY COST 2.8 ¢/KW-HR					
BOSWELL - COAL ENERGY COST .58 ¢/KW-HR					

Table 4-9. 1973 WTG Performance at Virginia, Minnesota
(Minimum Capacity Factor Year)
4. 3mps (9.6MPH) Calculated 1973 Wind Speed

	500		1000	1500	
	GE	KAMAN	BOEING	GE	KAMAN
MEAN AVAILABLE POWER (KW)	179	102	281	183	120
THEOR. AVAILABLE POWER(KW)	583	389	1216	627	562
EFFICIENCY (%)	31	26	23	29	21
SPECIFIC ENERGY (KW-HR/KW PER YEAR)	3145	1791	2465	1070	699
TOTAL ENERGY OUTPUT (KW-HR)	1572296	895475	2464680	1604819	1047801
CAPACITY FACTOR	.36	.20	.28	.12	.08
WTG CAPITAL COST (\$)	486800	420500	561450	673950	747000
COST PER RATED KILOWATT (\$/KW)	974	841	561	449	498
COST PER MEAN AVAIL. KILOWATT (\$/KW)	2720	4123	1998	3683	6225
CARRYING CHARGE RATE PLUS O&M	20%	20%	20%	20%	20%
ENERGY COST (¢/KW-HR)	6.2	9.4	4.6	8.4	14.3
HIBBARD - #6 OIL ENERGY COST 2.8 ¢/KW-HR					
BOSWELL - COAL ENERGY COST .58 ¢/KW-HR

Figure 4-8. Monthly Maximum and Minimum Capacity Factor Covering 10 Years and 5 Turbine Sites; i. e. each vertical spread represents 10 monthly values at each of the 5 turbine sites, 50 values in all.

Relative performance between the WTGs was consistently (1) Boeing, (2) General Electric, and (3) Kaman. To reduce the number of computer runs that would be required, the Kaman units were dropped from further analysis after a preliminary array analysis discussed in the next section. This decision was not intended as a reflection on the quality of Kaman's design, but only to facilitate the subsequent analysis by reducing the number of units that must be dealt with.

WECS ARRAY ANALYSIS

The WECS array is the aggregate of the individual WTG's. For a large system application involving many wind turbines distributed over a utility's service area, there are several potential configurations and alternatives for connection to the utility's grid. While these various configurations are relevant to system design and operations, the approach taken for economic performance evaluation within the MP&L study required that one overall measure of monthly wind system performance be defined. It was necessary that this measure of monthly WECS performance satisfy the input requirements of the MP&L production costing model (PCM).

The WECS array analysis was directed at satisfying the PCM input requirements. It combined the outputs from the five area turbine sites defined on page 4-2 into a monthly representation of the overall WECS array power and energy available to the utility. The resulting monthly array output power distributions contained the necessary information to describe WECS power capability (including median value), power availability, and array diversity benefit. The measure of the probabilistic availability of the array's output provided a basis for assessing WECS (without storage) ability to furnish base, intermediate, or peaking capability.

Array diversity benefit was a function of the wind correlation between the area turbine sites. The distance between the area turbine sites ranged from 25 to 170 miles (about 40 to 274Km). All the individual WTG's located within a 5 mile (8Km) radius at an "area turbine site" such as Virginia were assumed to be excited by the same monthly wind distribution for that area site; ie, 100% correlated monthly wind excitation.

The assessment of wind capacity credit involves determining the reliability that a particular power output level can be achieved from a single unit or an array of units. Rigorously pursued, this assessment requires an elaborate statistical analysis of hourly time series data. Dr. Justus approached this issue on two levels: one, a limited but rigorous analysis; and the other, a more generalized and simplified computational technique. The rigorous approach was used to validate the more general method.

The technique for array analysis was developed by Dr. Justus. Reference 6 provides a thorough discussion of this technique.

Figures 4-9 through 4-13 are representative of the array analysis results. They show 10-year averaged cumulative probability distributions for the WTGs operating both as an individual unit and as an array of units. Figure 4-9 is interpreted as follows:

1. Operating as a single unit 100 percent correlated over all WTG sites, the G. E. 500-KW WTG would average (50 percent probability) 140 KW, or 28 percent capacity factor. This is less than the 36 percent capacity factor in Table 4-9 due to the influence of the lower velocity wind sites.
2. Operating in a 40 percent correlated array, the G. E. 500 KW WTG would average 189 KW per generator or 37.8 percent capacity factor.
3. Operating in a zero correlation array, the G. E. 500-KW WTG would average 195 KW per generator or 39 percent capacity factor.
4. Individual units would be idle (zero power output) 26 percent of the time and would produce a rated 500 KW of power 16 percent of the time.

Figure 4-9. Array Analysis Output Power Distribution:
GE 500 KW

Figure 4-10. Array Analysis Output Power Distribution:
GE 1500 KW

Figure 4-11. Array Analysis Output Power Distribution:
Kaman 500 KW

Figure 4-12. Array Analysis Output Power Distribution:
Kaman 1500 KW

Figure 4-13. Array Analysis Output Power Distribution:
Boeing 1000 KW

5. The 40 percent correlated array would be idle 6 percent of the time and all array units would simultaneously reach rated power 1 percent of the time.
6. The zero correlation array would be idle 1.7 percent of the time and all array units would simultaneously reach rated power 0.06 percent of the time.
7. The 40 percent correlated array would produce 80 KW or more per unit about 80 percent of the time. Therefore, if 80 percent reliability is adequate, the GE 500-KW WTG array could be counted on for 80 KW of power per unit, without storage. However, if 80 KW per unit is desired with higher than 80 percent reliability, some form of storage would be required.

Figures 4-10 through 4-13 present similar results for the GE 1.5 MW, Kaman 500 KW and 1.5 MW, and Boeing 1000 KW WTGs, respectively.

Figure 4-14 shows three monthly array power duration curves computed for the Boeing Vertol BV-1 turbine. A 40-percent site correlation (wind diversity factor) was assumed, based upon the distances between area turbine sites (25 to 170 miles) and prior work of Dr. Justus (see Reference 6). The three curves plotted in Figure 4-14 were the minimum (August), average (December), and maximum (April) monthly duration curves. Curves for the other nine months fell in between those shown.

Array performance, to be compatible with the input requirements of MP&L's production costing model, was expressed by the following set of monthly parameters determined from the above mentioned curves:

- Minimum and maximum megawatt output
- Megawatt-hours energy produced
- Three-level equivalent array power duration curves

Figure 4-14. Array Power Duration Curves for BV-1
(10-year average, minimum and maximum)

Tables 4-10 and 4-11 tabulate this set of monthly parameters for the BV-1 turbine.

Average Megawatt-hours

The megawatt-hours for each of the ten Januarys during the period 1965-1974 were used to compute an average 43,909 MWH January. Similar calculations were made for the other eleven months shown in Table 4-10. The average annual array energy for the 10-year period was 474,032 MWH.

Minimum Megawatt Output -- For normal wind system performance it was conservatively assumed that the turbine array would have zero accredited capability, i. e., zero minimum output available on demand.

Maximum Megawatt Output -- The monthly maximum output was set equal to the 135-unit turbine array peak capability, i. e., for the BV-1:

$$1.125 \text{ MW} \times 135 \text{ units} = 151.875 \text{ MW}$$

Three-Level Equivalent Array Power Duration Curve -- Figure 4-15 illustrates the significance of the values in Table 4-11 using January as an example. Note that the area under the curve has been normalized by the average megawatt-hours and hence must equal unity, i. e., for January:

$$[0.0 \times 0.05 + 1.036 \times (0.99 - 0.05) + 2.57 \times (1.0 - 0.99)] = 1.0$$

Table 4-10. Boeing 1125 KW Array Monthly Average over 10 Years

Month	Megawatt Hours (Average)	Minimum MW Output*	Maximum MW Output*
1	43,909	0	151.8
2	37,948	0	151.8
3	42,639	0	151.8
4	48,232	0	151.8
5	46,517	0	151.8
6	36,168	0	151.8
7	32,928	0	151.8
8	29,452	0	151.8
9	33,264	0	151.8
10	43,239	0	151.8
11	40,123	0	151.8
12	39,613	0	151.8
Total	474,032		

Table 4-11. Unit Type = Boeing 1125 KW

Month	Energy in P. U. of Ave.			Cum. Prob. of Energy or Less		
	Min	Ave	Max	Min	Ave	Max
1	0	1.036	2.57	0.05	0.99	1
2	0	1.046	2.69	0.06	0.99	1
3	0	1.047	2.65	0.06	0.99	1
4	0	1.025	2.27	0.04	0.99	1
5	0	1.038	2.43	0.05	0.99	1
6	0	1.087	3.02	0.08	1.00	1
7	0	1.111	3.43	0.10	1.00	1
8	0	1.136	3.84	0.12	1.00	1
9	0	1.099	3.28	0.09	1.00	1
10	0	1.047	2.61	0.06	0.99	1
11	0	1.064	2.73	0.06	1.00	1
12	0	1.075	2.85	0.07	1.00	1

*The "minimum" output is equivalent to hydro run-of-river and the maximum output is the WECS peak capability.

Figure 4-15. Three-Level Equivalent January Array Power Duration Curve for BV-1 Array

COMPUTER PROGRAM FOR WECS PERFORMANCE ANALYSIS

The previous sections have described a sequence of computations required to transform the wind data from a number of recording stations to a set of parameters descriptive of WECS performance and compatible with the input requirements of MP&L's production costing model. Specifically, given the NWS wind data at the four recording stations and the wind turbine design characteristics, the wind data was compressed into monthly Weibull probability distributions, transformed first in elevation to hub height and then to the turbine sites, combined with the wind turbine characteristic to establish turbine performance, and finally the unit outputs were combined to represent the total WECS array.

This sequence of computations was programmed into a set of subroutines. These subroutines combined to form the WECS analysis program flow diagrammed in Figure 4-16. A sample program output for the 135 unit/BV-1 system is provided in Appendix C.

WTG PARAMETRIC MODEL

Within the WECS performance analysis computer program, a general representation of the wind turbine generators was made through their power-output-versus-wind-velocity operating curve, as characterized by the cut-in, rated, and cut-out design velocities. These curves existed for specific turbine designs which have been optimized to specific wind regimes.

To conduct parametric analyses, a more general WTG representation was sought that would be capable of including the wind regime variability. This was accomplished through adapting a method developed by Peter G. Sulzer,

Figure 4-16. WECS Performance Analysis Program

"A Direct Method for Selecting Wind-Turbine Generator Parameters for Maximum Energy Output (Ref. 7). * Based upon Mr. Sulzer's work, a computer program was prepared which enabled the variation of key WTG and wind characteristics. Primary inputs are an assumed wind velocity duration curve obtained from binning NWS data tapes and an assumed wind turbine power coefficient curve. The input wind velocity duration curve must be computed for an assumed WTG hub height. **

The program's operation was tested by using it to verify the BV-1 power output characteristic. The operating cut-in, rated, and cut-out wind speeds checked within one mile per hour. The program is viewed as a potential "generic" evaluation tool for utility (or other user) analysis.

FINDINGS AND RECOMMENDATIONS

1. Wind characterization is a vital element of any wind power system study. The modeling and analysis techniques employed in a study must be appropriate to the study objectives. For this case study emphasizing an assessment of WECS economic viability, the methods of Dr. C. G. Justus were found to be well suited to the task. In particular, the monthly determination of WECS performance fulfilled the needs of a utility's first-level planning.

Recommendations: Acceptable, simple-if-possible, wind characterization and analysis methods should be sought and encouraged to facilitate the WECS analysis and application assessment. When appropriate, these methods should be developed with the user and application in mind so that the measures and parameters are pertinent. "Plant capacity factor," for example, is a very meaningful parameter to a utility planner.

* A copy of Mr. Sulzer's paper is provided in Appendix D.

**Mr. Sulzer's method could be extended to look at the effect of hub height variation by repeating his entire process for an input set of assumed hub heights. Initially at each loop through the program the wind velocity duration curve would have to be recomputed at the new hub height.

2. At the outset of this study when plans were being made and computational techniques selected, there was a very limited established methodology from which to choose. This study sought, as one objective, to develop an "end-to-end" set of computations for converting wind data to usable utility inputs that would provide an acceptable, general methodology satisfactory for utility planning and sufficiently flexible to allow refinement. Most of the steps in the computational sequence are believed to be adequate. The exception, where improvements could be made, is in that three-level energy availability probability description.

Recommendation: Acceptable, standard computational techniques should be sought and given wide visibility when approved. The techniques assembled for this study are submitted as candidates for this type of general acceptance. Weak links in the computational chain should be identified, and refined or replaced.

3. The elevation adjustment of wind data is a critical step in wind data analysis.

Recommendation: The Wind Program Office should encourage further modeling work in this area, but should simultaneously identify for near-term studies an accepted technique that can be used for common practice to achieve comparable study results.

4. A theoretical analysis of wind conversion computations that included integrating the wind shear effect vertically over the turbine disk area was compared to analysis techniques that employ only hub-height wind speeds. The two techniques were within 1.2 percent of each other, thus justifying the general use of the simpler hub height computation.

Recommendation: The validity of hub height wind-energy conversion computations should be recognized and their use encouraged.

5. Design descriptions of current and advanced technology WTGs were difficult to compare.

Recommendation: A standard, minimum set of WTG parameters should be established to facilitate performance and cost comparisons. The design parameters included in Table 4-1, plus some appropriate costs, are recommended.

SECTION V

SYSTEM EVALUATION

An important element of this study was that the utility evaluate the wind power system's performance using its normal forecasting and planning tools. For MP&L, these tools were a production costing model (PCM) and corporate financial model (CFM). Figure 5-1 shows the relationship between these two models and their joint relationship to the existing utility structure, its load forecast, and the planned expansions. The accented lines in the figure indicate how WECS was introduced and how its resultant performance was measured.

The production costing model computes the costs of fuel, purchases, and fixed and variable O&M, all required as inputs to the corporate financial model. When WECS was added to the MP&L system, each of these parameters decreased, reflecting a savings in production costs. This decrease, excluding O&M associated with WECS, is represented as Δ_1 in Figure 5-1. This parameter has been referred to in this report as "production cost savings."

The capital structure of the utility was, of course, changed by adding WECS. CFM accounts, such as construction, in-service plant, depreciation and amortization, property taxes, other operating expenses (to include WECS O&M), and financing all had to be modified. In Figure 5-1, Δ_2 designates the composite of these modifications.

Either of two criteria could be used to evaluate financial performance: the effect on earnings, holding rates constant; and the effect on rates, holding earnings constant. The latter criterion, which examines revenue requirements, was selected as more typical of the standard decision-making process. In Figure 5-1, Δ_3 represents the change in revenue requirements

Figure 5-1. WECS Evaluation Technique

resulting from introducing WECS. The Δ_3 revenue requirement was needed to hold the capitalization ratios and returns fixed.

Together, the PCM and CFM were used to generate a 10-year forecast of MP&L's operations, both with and without WECS. These forecasts were used to evaluate the economic viability of WECS. The Δ_1 represented the savings or equivalent worth of wind energy to the utility. The Δ_3 represented the equivalent cost of WECS to the utility and its customers.

To begin assessing WECS economic viability, the approach was more macroscopic than microscopic. Performance was evaluated over monthly intervals rather than for a shorter period of time. MP&L typically conducted its planning on a monthly basis and recommended that this study do the same.

PRODUCTION COSTING MODEL (PCM)

Producing costing is based upon the economic dispatch of generating units. The production costing model takes a load model input and computes the expected production costs. It considers such factors as random forced outages, scheduled outages, interchange purchases and sales, long-term commitments, the probabilistic nature of hydroelectric energy availability, and the economic loading of thermal units. MP&L's production costing program was developed by Power Technologies, Inc. of Schenectady, New York. (Details of this program are in Appendix E and Reference 8.)

The model currently recognizes the following forms of generation:

1. Hydroelectric (105.6 MW rated capacity)
2. Firm interchange purchases
3. Economy interchange purchases
4. Steam electric (749.5 MW rated capacity)
5. Participation interchange purchases
6. Emergency interchange purchases

To use MP&L's production costing model, it was necessary that the program recognize the probabilistic availability of wind energy. It was specifically necessary to accommodate the probabilistic dispatch of wind energy in conjunction with the program's economic loading logic without requiring major changes to the program. This was accomplished by treating WECS as an equivalent hydroelectric plant but with energy availability determined from the WECS array analysis.

Water power like wind power is probabilistic in nature. Hence, utility practices associated with hydro characterization furnished clues for wind characterization. Where reference was made to a median hydro year, a median wind year could be equally meaningful.

There was sufficient flexibility built into the production costing model that wind energy could be broken down into additional non-hydro components and entered into the PCM as a combination of the above generation types. The approach initially taken, however, was to treat wind energy as an equivalent hydroelectric source with its energy availability determined from the WECS array analysis. Subsequent analysis could include a wind component treated as economy energy.

The initial treatment of wind as a special hydro source enabled a direct assessment of wind energy, albeit an assessment assuming optimistic energy dispatch. For MP&L, the degree of optimism of wind energy dispatch was tempered by the utility's high load factor, its purchase posture, its requirement to operate the oil-fired Hibbard peaking units for grid stability, and its ability to back up the wind system with some limited modulation of hydro units. This assessment was sought to establish the emphasis of subsequent analysis. If this optimistic dispatch achieved or nearly achieved economic viability, then subsequent analyses would have been directed at refining the analysis. If, however, the optimistic utilization of current-technology WECS was not close to achieving economic viability, then the subsequent analysis would emphasize identifying R&D needs, cost goals, performance and user requirements through a yet-to-be-determined set of assumptions, which, by definition, would be economically viable and thus establish an economic baseline of performance. Figure 5-2 illustrates these two different emphases. It will be shown that the initial assessment resulted in directing the study into the economic baseline approach.

PCM Input and Base Year Assumptions

A sample PCM input summary is provided in Appendix F. Table 5-1 lists pertinent base year assumptions that appear in the input summary and that were used throughout the study. Final year values, using the annual eight percent fuel escalation factor, are also shown in Table 5-1.

Table 5-1. Production Cost Model Base Year and Final Year Assumptions

	1976 Values	1986 Values
1. Energy Content of Fuel		
Coal (MTBU/Ton)	17.0	17.0
Oil (MBTU/BBL)	6.34	6.34
2. Fuel Cost (\$/MBTU)		
Coal	0.45 to 0.61	0.97 to 1.32
Oil	1.87	4.04
3. Average Cost at Rating (\$/MWH)		
Coal	6.234 to 10.434	12.778 to 19.719
Oil	30.628 to 33.918	64.106 to 71.205
Purchases	4.0 to 19.0	4.0 to 32.390
4. Escalation Factors		
Fuel	8 %	8 %
Variable O&M	6 %	6 %
5. Present Worth At	10 %	10 %

Figure 5-2. Current Technology Concept Refinement versus Advanced Technology Economic Baseline: Alternate Directions for Study Emphasis

Sample PCM Load Duration Curve Modification

To better understand how the production costing model works and how the aforementioned assumption to introduce wind energy as an equivalent hydro source influenced the PCM results, it is instructive to trace the model's dispatch process through the sequence of load modifications that occur during a specific month. For illustration, January, 1977, will be used.

After the methodology has been explained, a detailed discussion of results and their sensitivity to wind availability will be provided. At that point, the generic implications of these specific case studies will be explored.

1. The Original Load Duration Curve -- The solid line in Figure 5-3 represents MP&L's January load duration curve. This general curve is part of the PCM's input data and is used for each January during the forecast period. The peak value can be changed annually to reflect the utility forecasted load growth. For MP&L, the January peak was varied from 732 megawatts in 1976 to 1829 megawatts in 1986. The January 1977 peak load was 974 MW.

The load duration curve indicates the number of hours in the period (in this case a month) during which the load was greater than or equal to a particular level. It is an accumulative plot. Figure 5-3 indicates, for example, that MP&L's January, 1977 load will be greater than, or equal to 800 MW for 365 hours out of the month.

The area under the load duration curve is equivalent to the energy that must be delivered to the load. The utility serves this load through the economic dispatch of its owned or interchanged generating capability. The PCM performs and evaluates this process by effectively filling the area under the load duration curve through the economic commitment of the generating units.

2. Load Modified by St. Louis River Hydro -- Dispatch of the hydroelectric energy from units in the St. Louis River system produces the first modification to the original load. The net result is to lower the original load curve (Figure 5-3). Allocation of this energy (29,000 MWH) is controlled by the following parameters:

- Minimum Megawatt Output -- This parameter defines a run-of-river, base hydro component (31 MW for this example)
- Maximum Megawatt Output -- This parameter defines a controllable, peak-shaving hydro component (44 MW - 31 MW = 13 MW for this example)

Figure 5-3. MP&L January Load Duration Curve Modifications

- Average Megawatt Energy -- This parameter defines the amount of energy to be dispatched (29,000 MWH for this example)
- Minimum, Average and Maximum Energy in Per Unit of Average Energy -- These are three of the six parameters required to define the energy availability in terms of a three-point probability distribution (0.82, 1.11, and 0.0 for this example)
- Minimum, Average, and Maximum Cumulative Probability of Available Energy or Less -- These are the other three parameters required to define the energy availability (0.37, 1.0, and 0.0 for this example).

Note that

$$0.82 \times 0.37 + 1.11 (1.0 - 0.37) = 1.0^*$$

3. Load Modified by Mississippi Hydro -- This second load modification represents the dispatch of the hydroelectric energy produced by units in the Mississippi River system. It is a small, 6-MW, 4300-MWH, run-of-river component barely discernible in Figure 5-3.

4. Load Modified by Purchases -- The load is next modified by purchases, in this case representing off-peak surplus energy from neighboring, pool-member systems (lowest curve in Figure 5-3).

This load modification sequence establishes the resultant load that is next modified by the wind component.

*See the discussion on page 4-35.

Wind Energy Contribution to Load Duration Curve Modification

Since wind energy was entered into the production costing model like hydro, parameters similar to those describing hydro were required to describe wind energy. The array analysis previously discussed, was designed to calculate these parameters, thus establishing a measure of wind energy availability. Table 5-2 summarizes the set of parameters used to describe the advanced technology baseline, Case 1, and also tabulates six other cases that were used for sensitivity analysis of the availability parameters relative to the baseline, Case 1. Figures 5-4 through 5-7 show the modified load duration curves associated with Cases 1 - 6. Case 7, the 2-times nominal system, was eliminated from consideration by MP&L. Results are discussed on pages 112 - 117.

It is extremely important to a proper understanding of this study that this element of the technical approach be clearly understood. The optimistic dispatch valuation of wind energy's peaking capability resulting from treating the wind as hydro establishes a very meaningful upper bound to the overall contribution wind energy can make to any utility. The degree of optimism totally depends upon the specific utility. MP&L, under its particular operating conditions, advised and supported this approach. Their specific high load factor situation will be looked at in more detail. For other utilities, the value of the wind's energy contribution can be readily degraded to account for load matching, and this subject will also be further discussed.

For an initial assessment of WECS's economic viability within MP&L, the assumption that WECS was equivalent to hydropower quickly established whether wind energy had sufficient potential to merit a refined, more in-depth examination. It was this premise that is embodied within Figure 5-2.

Treating wind as hydro implies that the wind is virtually available on demand, contingent upon the three-point energy availability probability distribution. For a hypothetical utility with a 100 percent load factor (i. e., the utility would always be operating on peak), it would be valid to assume that the wind energy

Table 5-2. Production Costing Wind Energy Parameter Variations
for BV-1 Operating as a Fuel Saver for January*

Case	Min. MW Demand	Max. MW OUTPUT	Ave. MWH OUTPUT	Energy in Per Unit of Ave.			Cum. Prob. of Energy or Less			A (\$)	B (\$)	C (%)	D (Mills/KWH)
				Min.	Ave.	Max.	Min.	Ave.	Max.				
1.	0	151.8	43909	0	1.036	2.57	0.05	0.99	1.0		524,000		11.9
2.	5	151.8	43909	0.11	1.01	1.86	0.2	0.8	1.0	+ 17,000		3.2%	
3.	30	151.8	43909	0.5	1.0	2.0	0.4	0.8	1.0	+ 18,500		3.5%	
4.	50	151.8	43909	0.5	1.0	2.0	0.4	0.8	1.0	+ 19,000		3.6%	
5.	0	151.8	43909	0	0.984	2.57	0	0.99	1.0	- 34,000		-6.5%	
6.	0	76.5	22119	0	1.036	2.57	0.05	0.99	1.0		309,000		14.0
7.	0	306	88476	0	1.036	2.57	0.05	0.99	1.0		867,000		9.8

A: Increase in January production costs over Case 1

B: Savings in January production costs for Case 1 (advanced technology baseline) due to adding WECS

C: A/B; percent sensitivity of Cases 2 - 6 relative to Case 1 savings

D: B/Ave. MWH Energy; production cost savings due to WECS expressed in mills per kilowatt-hour

* Note these results are for one month only.

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Figure 5-4. Modified January Load Duration Curves for Production Costing WECS Parameter Variations (Cases 1 & 5)

Figure 5-5. Modified January Load Duration Curves for Production Costing WECS Parameter Variations (Case 2)

Figure 5-6. Modified January Load Duration Curves for Production Costing WECS Parameter Variations (Case 3 and 4)

Figure 5-7. Modified January Duration Curve for 76.5 MW Wind Energy System

would be available on demand, since the demand would exist whenever the wind blew. The validity of treating wind as hydro decreases as the utility's load factor decreases. (Note that the generation mix of a high load factor utility will likely contain more low cost base power plants, thus placing wind power at a competitive disadvantage.)

As a first approximation, one might consider introducing a penalty factor inversely related to the utility's load factor. An 80 percent load factor would imply a penalty factor of 1.25; 50 percent load factor would imply a penalty factor of 2; etc. This simple and direct method suggests a potential shortcut to a more rigorous statistical analysis attempting to measure the correlation of wind energy availability to peak loads.

The simple concept of a penalty factor can be refined by accounting further for the utility's actual operating practices. For MP&L, there were four operating conditions that could support a near-unity penalty factor:

1. MP&L has a load factor in the range of 75 to 80 percent
2. It is virtually always purchasing energy, some of which is high priced and can be cancelled on short notice
3. It operates the oil-fired Hibbard plant 24 hours per day
4. It has controllable hydro which can be modulated within limits to back up the wind energy

MP&L is also in the process of introducing an automatic dispatch system. There is a likelihood that the wind's value could be benefited under the continuous supervision of such a system.

PCM Thermal Unit Commitment and Economic Dispatch

After the load duration curve has been modified by the hydro, interchange purchases, and wind, the production costing model dispatches the thermal

units to satisfy the remaining load. (Appendix D is a detailed description of how this is done.)

A unit commitment priority list can be a part of the PCM input. Appendix F contains such a list. The list includes each of the utility's units, participation purchases, and emergency interchange ties. Those units with minimum downtimes of 168 hours are designated as must-run units.

Under the control of the PCM's dispatch logic and the constraints of the commitment priority list, the wind produces energy displacement across all appropriate units and purchases. This total system impact is indicated in Table 5-3 which summarizes the individual plant's capacity factors and energy purchases, both with and without the wind. Each plant capacity factor represents the total number of units in that plant. For example, the Hibbard plant is composed of four units, one of which is a must-run unit.

The Current Value of Production Cost Savings

The PCM computes the annual costs of fuel, energy purchases, and O&M assuming currently forecast escalation rates (i. e. 8 percent - fuel and 6 percent - O&M). As the PCM progresses in time, each year's economic dispatch is influenced by the relative values of the projected costs associated with each unit. Since these relationships vary in time, a 10-year forecast based upon frozen relationships would have no significance.

To compute current value production cost savings for the entire 10-year forecast period, the PCM was run as MP&L standardly uses it with the assumed 6 percent O&M and 8 percent fuel escalation rates. All the resultant cost components were separately adjusted back to the base year, thus removing the escalations and expressing all costs in December, 1975 or January, 1976 dollars. (These results are summarized in Figure 5-8.) The average annual savings in production costs for the 10-year period was \$5,972, 500, the equivalent of (dividing by 474033 MWH) 12.6 mills/KWH.

Table 5-3. Summary of Plant Capacity Factors With and Without Wind Energy

	Aurora	Boswell	Hibbard	Winslow	Brookston	Purchased Energy
1976 Plant Capacity (MW)	110	490	115	25		(MWH)
No. Units in Plant	2	3	4	2	1	
C.F. Without Wind	0.50	0.78	0.14	0.08		925,700
C.F. With Wind	0.34	0.77	0.08	0.03		727,700
1977 C.F. WOW	0.49	0.71	0.16	0.10		1,034,600
C.F. WW	0.39	0.67	0.11	0.06		852,700
1978 C.F. WOW	0.50	0.67	0.19	0.13		878,300
C.F. WW	0.36	0.65	0.14	0.09		694,600
1979 C.F. WOW	0.64	0.77	0.15	0.10		946,600
C.F. WW	0.57	0.76	0.11	0.07		606,600
1980 Plant Capacity	110	490	115	25		
C.F. WOW	0.42	0.40	0.13	0.07		600,800
C.F. WW	0.39	0.38	0.10	0.05		399,700
1981 C.F. WOW	0.30	0.68	0.15	0.09		303,800
C.F. WW	0.24	0.65	0.13	0.07		195,400
1982 C.F. WOW	0.41	0.72	0.16	0.11		458,163
C.F. WW	0.32	0.70	0.13	0.08		311,400
1983 C.F. WOW	0.51	0.73	0.18	0.12		701,000
C.F. WW	0.41	0.71	0.14	0.09		483,700
1984 Plant Capacity	110	490	115	25	800	
C.F. WOW	0.51	0.73	0.15	0.10	0.12	704,272
C.F. WW	0.41	0.71	0.12	0.07	0.12	482,600
1985 C.F. WOW	0.22	0.74	0.10	0.05	0.66	149,700
C.F. WW	0.19	0.74	0.08	0.04	0.62	88,970
1986 C.F. WOW	0.23	0.76	0.11	0.06	0.68	190,100
C.F. WW	0.19	0.75	0.09	0.05	0.64	115,900

Note in Figure 5-8 that in those years immediately following the addition of new base capacity units (1980 and 1985), there is a decrease in the savings component associated with interchange purchases. This suggests that MP&L forecasts a cutback in purchases in those years with the new units, 500-MW Boswell No. 4 in 1980 and 800-MW Brookston unit in 1984, replacing the need for some of the purchases. This results in a decrease in the potential savings associated with WECS because the new units themselves displace some of the more expensive purchases and the overall utility is operating at a lower average cost per kilowatt-hour produced. The effective value of WECS to the utility thus decreases as the result of these new units being brought on-line.

Production Cost Model Parameter Variations and Findings

Table 5-2 summarized a set of parameter variations that were run using the production costing model. These variations were performed (1) to better understand the PCM's output, (2) to establish the sensitivity of some of the parameters, and (3) to facilitate a generalization of these results.

Findings of PCM Studies --

1. MP&L's production costs were virtually insensitive to changes in the WECS base capacity (i. e. , minimum output), as shown by a comparison of Cases 2 - 4.
2. A very small change in the wind energy probability distribution in the direction of increased availability produced a relatively large (6.5 percent in Case 5) increase in production cost savings. MP&L's system costs are sensitive to on-peak displacement of high-priced energy, but one could not justify more on-peak wind energy availability than was already assumed.

- TOTAL ANNUAL SAVINGS
- FUEL SAVINGS
- ◇ PURCHASE SAVINGS
- △ O&M SAVINGS EXCLUDING WECS

Figure 5-8. Production Cost Savings for BV-1
Operating as a Fuel Saver

3. Cases 6 and 7 evaluated the performance of wind power systems one-half and twice the peak rated capacity of the baseline 151.8 MW system. The smaller system turned out to be economically better matched to MP&L's system. Table 5-2, Column D, shows the savings in production costs that would have occurred in January, 1976, if the WECS had been operating in that year. (For the study scenario, it was assumed that the wind system was installed in 1976 and not actually operating in that year.) These production cost savings represent the value of wind energy to the utility. This value is expressed as mills-per-KWH equivalent energy cost, which is computed by dividing the total savings in January (Column B) by the average megawatt-hours of wind energy produced in January.

The relationships between Cases 1, 6, and 7 are linear. This indicates that changes in the size of the wind system have a small-perturbation linear effect on the PCM performance. The larger WECS system displaces more low-cost energy, resulting in a lower mills-per-KWH net worth, 9.8 mills versus 14.0 mills.

This result shows that the wind systems should be properly sized to the utility system. For a wind energy system operating as a fuel saver, the size must be established in relation to the wind energy's ability to displace higher cost fuels or energy purchases. WECS's peak rated power is not, of itself, a meaningful parameter for sizing; e.g., the original MP&L system was sized to be 150 MW.

The wind system's energy capability must be described probabilistically to yield a correct size relationship. It is clear that if, in the limit, WECS could be selectively assigned, on demand, to displace energy from specific units, then the wind system's size would equal the size required to displace only the energy that cost more than the wind energy.

For MP&L, the 152-MW and 306-MW systems were too large, displacing a larger amount of low-cost fuel.

4. As fuel costs and energy purchase costs increase, the break-even size of WECS may shift to where more units could be justified. This time-dependent relationship could be well suited to the modularity of wind systems and to the installation sequence that might typically occur for a large WECS system.
5. Installation of new base capacity units decreases interchange purchases and lowers the break-even cost and size relationship (Figure 5-9). Savings in production costs are plotted for the 76.5, 151.8, and 306 MW systems. The savings result from fuel, purchased energy, and variable O&M associated with the thermal units. Each point in the figure represents the present investment worth of production costs without wind, minus the present investment worth of production costs with wind, the quantity divided by the total annual wind energy produced, 474,000 MWH per year for the 151.8 MW system. The present investment worth is expressed in 1976 dollars by taking the actual forecasted production cost in a particular year and adjusting this cost back to 1976, assuming a 10 percent interest rate compounded annually.

Figure 5-9. MP&L Production Cost Savings or BV-1 Operating as Fuel Saver

Figure 5-9 can be interpreted as a present-worth forecast of the savings in annual production costs resulting from WECS. It shows that the value of WECS-induced savings decreases in 1980 when the 500-MW Boswell No. 4 unit comes on-line. These equivalent mills-per-KWH savings decrease again in 1985 when the full impact of the planned 800-MW Brookston unit is encountered.

FIXED POINT SYSTEM ANALYSIS

It is probably the nature of economic studies in general, and a study of fuel savings in particular, that the results are highly dependent upon the dynamics of the system being studied and very sensitive to assumed escalation and inflation rates. From the perspective of a case study, it was especially meaningful to evaluate WECS's economic viability for MP&L using the utility's current operations forecast and its standard planning tools, all of which recognize and account for the time-varying aspects of the problem.

Prior to discussing the "dynamic" analysis, this section presents a static or fixed-point system analysis. It is aimed at establishing a current economic assessment of WECS's viability as expressed in 1976 dollars (FY-75) and using zero escalation and inflation rates.

Fixed-point analysis is especially useful when comparing equivalent capital investment; for example, the tradeoff between alternate new power plants. As long as the alternates are treated similarly, their impact can be assessed equally.

The economic assessment of a fuel saver presents a unique problem when the fuel saving device is not given any capacity credit. Without capacity credit, investment in the new unit has no firm value and the unit's worth must be

entirely based on the value of fuel savings. While the investment can validly be assumed fixed, the recovery of that investment through fuel savings cannot be treated as fixed. The fixed point economic assessment establishes meaningful current relative values and statically forecast break-even points. It, however, oversimplifies the issue of investment recovery through fuel savings.

Current investment in a fuel-saving device may best be viewed as a hedge against rising fuel and purchased power costs. Even a fixed-point economic assessment of such an investment must consider the effect of cost projections for fuel.

Relative System Performance of Current and Advanced Technology WTG Designs

Table 5-4 presents a fixed-point performance summary using the savings in production costs experienced in 1977 and expressed in 1976 (FY-75) dollars. The relative system performance for the current technology is compared with advanced technology WTG designs in Table 5-4.

It is important to recognize that the G. E. 1500-KW unit was not designed to operate in Northern Minnesota's approximate 12-mph (at 30 feet) wind regimes. Also, the array performance reflects wind data from a combination of recording stations, not just the winds from the highest potential recording station.

Development of the capital costs appearing in Table 5-4 is given in Section VII.

The objectives of the fixed-point analysis is to compare the cost of wind energy to the "savings" that the wind energy produced by displacing fuel, purchases, and other O&M costs. (The production cost savings were determined earlier in this section). Table 5-4 includes two different (although related) measures of production cost savings. Both are for 1977 production costs expressed in 1976 dollars. Their difference is the following:

Table 5-4. Fixed Point Performance Summary for 1977*
Production Expressed in 1976 Dollars

	G. E. 500 KW	Boeing 1125 KW			G. E. 1500 KW
Wind Regime Designed For (MPS at 9.14 Meters) (MPH at 30 feet)	5.37 12		5.37 12		8.05 18
No. Units in System	300	68	135	272	100
System Peak Rating (MW)	150	76.5	151.8	306	150
Array Average Annual Energy (MWH)	508,526	238,834	474,032	955,336	186,262
Array Mean Available Power (MW)	58	27.3	54.1	109	21.3
Annual Array Capacity Factor	0.39	0.36	0.36	0.36	0.14
Capital Cost					
\$1000 Per Unit	549		657		791
\$ Per Rated KW	1098		584		528
\$ Per Mean Available KW	2830		1638		3714
Total System \$M	165.0	44.7	88.7	178.7	79.1
Cost of Energy (Mills/KWH)					
15% Fixed Charge Rate	49	28	28	28	64
20% Fixed Charge Rate	65	37	37	37	85
Present Worthed Production Cost Savings					
\$M	5.93	3.1	5.59	9.73	2.49
Mills/KWH	11.7	12.0	11.8	10.3	13.4
Zero Escalation Production Cost Savings					
\$M			6.18		
Mills/KWH			13.0		

*Note these results are determined from one year's performance.

1. Present Worthed Production Cost Savings -- Production costs are computed both with and without WECS using an 8 percent annual escalation rate on fuel and some purchases, and using a 6 percent annual escalation rate on variable O&M. The total production cost of a specific year is then "present worthed" back to the base year of the study period using a 10 percent interest rate, compounded annually. This is a standard computation included in MP&L's production cost model (see Figure 5-9).

2. Zero Escalation Production Cost Savings -- To facilitate comparing results from this study with other study results, it was necessary to determine production cost savings unencumbered by any assumed escalation or inflation rates. There was a problem getting a meaningful evaluation for this special case in that some of MP&L's long-term purchase commitments are not escalated while short-term purchases are escalated. To treat both types of commitments alike would misrepresent their economic dispatch and economic relationship.

To solve this problem, the aforementioned 6 percent and 8 percent escalation factors were left in the production costing, but all the resultant component costs were annually recomputed removing the appropriate escalation rates. The net result was a zero escalation production cost with the proper dispatch weights (see Figure 5-8).

The fixed-point analysis can be summarized as follows:

1. Using the present-worthed production cost savings, the G. E. 500-KW/300 unit system would have produced energy costing approximately 4.2 to 5.5 times more than it saved, depending on the fixed-change rate.

2. Similarly the G.E. 1500-KW/100-unit system, not designed for the northern Minnesota wind regime, would have produced energy costing approximately 4.8 to 6.3 times more than it saved, again depending on the fixed-charge rate.
3. Using the present-worth production cost savings, the system of Boeing's 1125-KW units would have produced energy costing approximately 2.4 to 3.1 times more than it saved.
4. Using the zero escalation figures, the wind energy would have cost approximately 2.2 to 2.8 times more than it saved.
5. The 10 percent interest rate slightly penalizes the present-worth cost, but at the second year of the forecast period the influence of the escalation rates is relatively small, the effect of compounding not yet having built up.
6. These relative production cost savings were the best that could have been achieved by any of the wind systems as the WECS was dispatched in like manner to hydro within the production costing model.
7. The factors given in the above statements could equivalently be stated as the factors by which the equipment capital costs exceeded the break-even capital costs.

Relative WEG Performance for Current and Advanced Technology
Turbine Designs, Using only Fargo Wind Data

During the course of this study several fixed-point analyses have been performed at various stages of the effort. (Preliminary fixed-point results were previously presented in Tables 4-7 and 4-8.) Table 5-5 summarizes a similar analysis that used only the Fargo wind data and was performed before additional

capital costs were included for system interface and installation. The table shows the performance for the windiest and least windy years during the 10-year wind recording period.

Table 5-5. WTG Performance at Fargo - 1967 Max - 1965 Min

	Maximum Capacity Factor-Year '67			Minimum Capacity Factor-Year '65		
	GE 500 kw	GE 1500 kw	Boeing 1125 kw	GE 500 kw	GE 1500 kw	Boeing 1125 kw
Mean Available Power (kw)	277	383	581	225	284	470
Theoretical Available Power (kw)	1054	1135	2575	823	887	2019
Efficiency (%)	27	34	23	28	32	24
Specific Energy (kw-hr/hr)/rated kw	4836	2228	4521	3936	1656	3661
Total Energy Output per Unit (kw-hr/yr)	2419920	3343338	5085828	1970472	2489964	4118665
Capacity Factor	.55	.26	.52	.45	.20	.42
WTG Capital Cost (\$)	466670	643655	567776	466670	643655	567776
Cost per Rated KW (\$/kw)	933	429	505	933	429	505
Cost per Mean Ave. KW (\$/kw)	1685	1680	977	2074	2266	1208
Fixed Charge Rate	20%	20%	20%	20%	20%	20%
Energy Cost (\$/kw-hr)	3.9	3.9	2.2	4.7	5.2	2.8
Annual Mean Wind Speed at 20 Ft. Anemometer Height	5.6 mps (12.5 MPH)			4.9 mps (11.0 MPH)		

Recognizing the lower capital costs and assumed Fargo winds, these energy costs can be compared to those in Table 5-4. While still not achieving break-even performance with the savings in production costs, the 22 mill/KWH BV-1 Fargo results are within a factor of two of the 13 mill/KWH production cost savings. It is also important to note that the 22 to 28 mill Fargo energy costs are lower than the average cost at rating for oil-fired units shown in Table 5-1 for 1976 and subsequent years.

MP&L CORPORATE FINANCIAL MODEL

The MP&L corporate model is one for a standard electric utility. It was developed for MP&L by Power Technologies, Inc.

The program was written to accept, as input, manually prepared revenue, expense, and capital expenditure forecasts. It calculates:

1. Changes to various accounts, including the calculation of book and tax depreciation
2. Cash flows and the need for external financing
3. Income taxes

The program is capable of handling a 10-year forecast and produces standard corporate annual reports.

The program is composed of seven subprograms which are chained together. (A detailed description of the set of programs is provided in Appendix G and Reference 9.)

The financial model has logic to simulate financial decisions and can, if the accounting model indicates a need for cash, predict the impact of the short-term financing needed. The ability of the model to arrange both short-term and long-term financing in accordance with predetermined criteria gives it the ability to move through time, executing stated management financial policies. Figure 5-10 provides a flow diagram of the Financial Model Program.

The criterion imposed on the corporate financial model for examining the revenue requirements induced by WECS was to hold the return on common equity fixed at 14.5 percent and to maintain capitalization ratios fixed at 35 percent common, 15 percent preferred, and 50 percent long-term debt.

Figure 5-10. Corporate Financial Model

Common equity is the sum of common stock and retained earnings. Table 5-6 summarizes all the CFM assumptions that represented standard MP&L practices. A few of the parameter variations that were run in conjunction with the CFM are also shown in Table 5-6. A complete list of the cases that were studied is provided in Table 5-7.

Inputs to the Financial Model

Several specific inputs were required to enter WECS into the corporate financial model. Some of these parameters were given in Table 5-6. The following list summarizes these inputs:

1. Production plant capital investment
2. Property taxes to be capitalized
3. Rate of interest during construction
4. Monthly expenses excluding property taxes to be capitalized
5. Production plant transfer to in-service plant
6. Annual property tax accrual
7. Adjusted monthly expenses
8. Modified purchased and interchanged power expenses
9. Operating expense
10. Maintenance expense
11. Monthly investment tax credit
12. Financing: Used standard rates and compensating balances

The adjusted fuel expenses and modified purchased and interchanged power expenses are the key parameters provided by the production cost model. They enter the corporate financial model as a dynamic excitation. Because this

Table 5-6. Corporate Financial Model Assumptions

	Standard Practice	Parameter Variations
1. Capitalization Ratios Preferred Stock Long-Term Debt Common Equity	15% @ 10% 50% @ 9 1/4% 35% @ 14 1/2%	@ 7.5
2. Revenues adjusted to maintain return on common equity at	14 1/2%	
3. 15% of construction work in progress eligible for allowance for funds used during const. at	8%	
4. Equipment book life (years)	30	20, 35
5. Investment tax credit rate	10%	20%
6. Property tax rate	4%	0%
7. O&M O&M inflation rate	1.5% 12% **	1% 12%, 7%
8. Equipment tax life (years)	24	
9. Book depreciation	St. Line	
10. Tax depreciation	S. Y. D.	
11. Salvage rate	0	
12. Net fixed charge rate*(%)	15 - 20	

*Depending on book life.

**Note that the annual escalation rate for corporate O&M is 12% rather than the 6% used only for production costing.

Table 5-7. Summary of Case Variations

Case	Description
1.	MP&L standard forecast without WECS
2.	MP&L standard forecast with 1125KW advanced technology WECS
3.	Case 2 with system capital cost decreased 20%.
4.	Case 2 with system capital cost increased 20%.
5.	Case 2 with system capital cost increased 50%.
6.	Case 2 with WECS O&M at 1.5% capital cost and 7% annual escalation.
7.	Case 2 with WECS O&M at 1.0% capital cost and 12% annual escalation.
8.	Case 2 with WECS O&M at 1.0% capital cost and 7% annual escalation.
9.	Case 2 with 35 year equipment book life.
10.	Case 2 with 20 year equipment book life.
12.	Case 2 with WECS long-term debt financed through municipal revenue bonds at 7.5% interest (1.75% less than standard rate).
13.	Case 2 with investment tax credit increased to 20% from 10%.
14.	Case 2 with 0% property tax on WECS rather than standard 4%.
15.	Case 2 with all beneficial factors.
16.	Assumed 30 MW minimum WECS demand capability.
17.	Approximate 1/2 sized (68 unit) advanced technology WECS.
18.	300 unit G. E. 500 KW system.
19.	100 unit G. E. 1500 KW system.
20.	Artificial test case assuming \$6M savings in 1977 escalated 6% annually.
21.	Artificial test case assuming \$10M savings in 1977 escalated 10% annually.

excitation is important to understanding the corporate model's response, it has been plotted in Figure 5-11 for the advanced technology baseline case. The figure shows the incremental combined savings in fuel and purchased and interchanged expenses resulting from WECS, the O&M costs that were assigned to WECS (1.5 percent capital cost with 12 percent annual escalation), and the resulting net production cost savings from these specific components.

Figure 5-11 differs from the earlier discussed Figure 5-8 in that Figure 5-11 contains the 8 percent PCM fuel cost escalation factor. Also the O&M cost shown in Figure 5-11 is only the O&M cost for WECS.

Revenue Requirements Method

Fixed-point economic analysis has been previously presented and discussed. The analysis of revenue requirements is an alternate economic analysis that explores in more depth the time-varying dynamics of the problem of WECS economic viability.

"Revenue requirements" refers to those additional revenues that are required to satisfy certain corporate financial policies or constraints. They are the Δ_3 in Figure 5-1. For this specific case study, they were the additional revenues required to maintain a 14.5 percent return on common equity and capitalization ratios of 35 percent common, 15 percent preferred, and 50 percent long-term debt.

The impact of any corporate decision can be measured by this technique and it is common practice throughout the utility industry. It reveals the impact of a decision in terms of dollars that must ultimately come from the utility's rate-paying customers. A positive revenue requirement would imply the need to adjust customer rates upward. "Revenue requirement" is sometimes also referred to as "rate adjustment." It is a composite requirement, however, and does not show how specific customer rates will be affected.

Figure 5-11. PCM Outputs and CFM Inputs for Advanced Technology Baseline Case (2-1)

The revenue requirement method was applied in this study to isolate the impact of WECS. A baseline was established using MP&L's current 10-year forecast. This forecast was then reexamined, with WECS added to the utility's operations. Revenue requirements for both cases were determined, and the difference (Δ_3 in Figure 5-1) isolated the net result of introducing wind energy.

For MP&L we were primarily looking at WECS as a fuel saver and as a means to trim expensive energy purchases. The net Δ_3 provided a measure of the "cost" of these savings. Economic viability required that a net savings must be realized in a period of time safely within the predicted lifetime of the equipment. MP&L interpreted a safe time period to be about one-half the equipment life. The criteria for WECS economic viability was thus established that the revenue requirement, Δ_3 , must be zero or negative within one-half the equipment's anticipated life.

Results of Revenue Requirements Analysis

Table 5-8 and the subsequent figures summarize the results obtained for the several cases that were studied. The figures are plots of the data in Table 5-8.

The general similarity among those cases that are variations of the base case (2-1) reflects the similarity of the CFM's revenue requirement response to the WECS performance shown in Figure 5-11. The relative performance between these cases reflects the sensitivity to the parameter that was varied. The advanced technology baseline case (2-1) is included on all the figures for purposes of comparison.

Table 5-8. Annual Revenue Requirement for WECS
(\$1000)

Case	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	Total	% of Baseline
(2-1)	5,850	15,234	12,890	10,937	12,109	10,156	8,203	6,250	6,250	7,031	6,250	101,160	
(3-1)	4,678	10,937	8,593	6,250	7,812	5,468	3,516	1,562	1,562	2,344	1,563	54,285	-46.0
(4-1)	7,021	19,531	17,187	14,843	16,796	14,453	12,891	10,937	10,937	12,500	10,934	148,034	46.0
(5-1)	8,779	25,781	23,437	21,484	23,046	21,093	19,141	17,187	17,187	18,750	17,188	213,073	110.6
(6-1)	5,850	15,234	12,890	10,547	12,109	9,375	7,422	5,469	5,469	6,250	4,688	95,303	-5.8
(7-1)	5,850	14,844	12,500	10,156	11,328	9,375	7,422	5,469	5,469	6,250	4,688	93,351	-7.7
(8-1)	5,850	14,844	12,500	10,156	11,328	9,375	7,422	4,687	4,687	5,469	3,907	90,225	-10.8
(9-1)	5,264	14,062	12,109	9,765	11,328	9,375	7,422	5,469	5,469	7,031	5,469	92,763	-8.3
(10-1)	7,412	18,359	16,615	13,671	15,234	12,500	10,547	8,594	8,594	9,375	7,813	128,114	26.6
(12-1)	5,459	14,062	11,718	9,375	10,937	8,593	6,641	4,687	4,687	6,250	4,688	87,097	-13.9
(13-1)	3,310	13,672	11,718	9,375	10,546	8,593	6,641	3,906	3,906	5,469	3,125	80,261	-20.7
(14-1)	5,850	11,719	9,765	7,422	8,984	7,031	5,078	3,125	3,125	3,906	3,125	69,130	-31.7
(15-1)	2,139	5,859	3,515	1,172	2,734	--	(1,953)	(4,688)	(4,688)	(3,906)	(6,250)	(6,066)	-106.0
(16-1)	5,850	15,234	12,500	10,156	12,499	10,156	8,203	6,250	6,250	7,031	6,250	100,379	-0.8
(17-1)	2,920	7,422	5,468	3,515	4,688	2,343	781	(781)	(781)	(781)	(2,343)	22,450	-77.8
(18-1)	10,732	32,812	32,031	31,250	33,203	31,250	30,078	28,125	28,906	30,468	29,688	318,543	214.9
(19-1)	5,264	16,016	15,625	15,625	16,406	14,062	13,672	12,500	13,281	13,281	12,500	148,232	46.5
(20-1)	5,850	14,844	13,281	11,718	11,328	8,593	7,422	6,250	6,250	5,469	4,688	95,693	-5.4
(21-1)	5,850	10,937	8,593	6,250	5,078	1,562	(390)	(2,344)	(3,906)	(6,250)	(8,593)	16,787	-83.4

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These results are based upon the assumptions in Table 5-6, the case variations in Table 5-7 and the baseline production cost data shown in Figure 5-11.

Relative performance varying capital cost -20 percent, +20 percent, and +50 percent is shown in Figure 5-12. The general relationship is linear as seen in the figure and in the "total" and "percent of baseline" columns in Table 5-8. It is doubtful that the advanced technology baseline case would have satisfied the MP&L criteria for economic viability by the 15th year of operation (one-half of the 30-year equipment life); but with a 20 percent reduction in capital costs the 151.8 MW system is very close to being acceptable using standard baseline assumptions. The 76.5-MW system, Case (17-1), whose energy output is better matched to displacing MP&L's higher cost fuels and purchases, does satisfy the viability criteria under baseline assumptions.

Also shown in Figure 5-12 is Case (15-1) which combines all the beneficial assumptions studied individually. These included -20 percent cost, a 35-year equipment life, O&M at 1 percent, escalated 7 percent annually, long-term debt financed at 7.5 percent interest, zero property tax, and a 20 percent investment tax credit for fuel conserving devices. This case clearly achieved economic viability.

Figure 5-13 shows the relative performance of the 20-year life cases to the baseline of a 30-year life figure.

Figure 5-14 shows the relative performance between three of the four O&M variations. Case (7-1) was omitted because it tended to confuse the figure.

Case (7-1) is shown in Figure 5-15, along with two incentive-type variations. Case (14-1) represents the elimination of WECS property tax. Case (13-1) represents a 10 percent increase in investment tax credits. Case (12-1), representing long-term debt financed at 7.5 percent interest, was omitted from this figure, but it falls between Case (7-1) and Case (13-1).

Figure 5-12. Case Summaries of Revenue Requirements (Chart 1)

Figure 5-13. Case Summaries of Revenue Requirements (Chart 2)

Figure 5-14. Case Summaries of Revenue Requirements (Chart 3)

Figure 5-15. Case Summaries of Revenue Requirements (Chart 4)

Figure 5-16. Case Summaries of Revenue Requirements (Chart 5)

Case (16-1) in Figure 5-16 shows the net effect that resulted from the production cost model's dispatch logic when the wind system was assigned a 30-megawatt minimum demand capability. The PCM dispatch logic assigned the firm wind capacity to displace some lower cost fuel. The net change in revenue requirement is within 1 percent of the baseline case indicating a virtual insensitivity to WECS's minimum demand.

Figure 5-17 shows the relative revenue requirements between the 300-unit/G. E. 500-KW system, the 100-unit/G. E. 1500-KW system, and the advanced technology 135-unit/Boeing 1125-KW system. The equivalent mills-per-KWH energy costs can be computed by dividing the annual revenue requirement by the total annual wind energy produced by the respective WECS system. The high energy costs associated with the system of 1500-KW units again reflects that this unit was not designed for a 12-mph wind regime. The high energy cost associated with the system of 500-KW units reflects that the units are of a high capital intensity.

In Figure 5-18, cases (20-1) and (21-1) were run as artificial test cases to check the general behavior of the financial model and the revenue requirements methodology. For these cases, it was arbitrarily assumed that the advanced technology baseline system produced six and 10-million dollars in production cost savings, respectively, in the first year of operation, and increased this savings in subsequent years by six percent and 10 percent, respectively. These arbitrary savings replaced the normal input savings shown in Figure 5-11. The effects of the relative magnitudes of the assumed savings and their rates of increase are clearly shown in Figure 5-18. These results can also be interpreted as indicative of the effect of $\pm 2\%$ variations in the nominal 8% fuel escalation rate.

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Figure 5-17. Relative Revenue Requirements Between G.E. 500 KW, G.E. 1500 KW and Boeing 1125 KW WECS

Figure 5-18. Test Cases of Revenue Requirements Method

Figure 5-19 has been included because it illustrates the influence that financial assumptions exert on WECS economic viability. The preliminary results shown in this figure were subsequently updated and refined into Case (2-1).

The curve labled "100 percent long-term debt" was one of the first results obtained for this study from the CFM. To get a "feel" for the problem, all of the WECS financing was put into long-term debt. The resulting capitalization ratios were outside allowable limits, necessitating more careful financing. The second curve resulted when standard 35-15-50 percent financing ratios were use.

These results demonstrate the significant influence of financial assumptions on economic viability. While the sensitivity to financing will vary among utilities, this dimension of the WECS problem could, in some cases, override technical performance issues.

FINDINGS AND RECOMMENDATIONS

1. Current technology wind turbine designs by G.E. and Kaman do not achieve economic viability in northern Minnesota's 11-12 MPH wind regime. Costs are too high by factors of four to seven.

Conditions can be defined within which an advanced technology design could be economically viable. These conditions relate to

- 1) System characteristics designed for economy-of-size
- 2) Capital costs decreased about 25 percent from BV-1 cost estimates
- 3) Financing and financial incentives

Figure 5-19. Revenue Requirements Sensitivity to Financing Ratios

Recommendation: An advanced-technology wind turbine generator should be developed that, through economy-of-size, would be viable for plains states operation. It should operate within a reasonable spectrum of low wind speeds, ranging around 12 MPH.

2. Fixed-point financial analysis is not adequate for evaluating fuel savings. The time-varying aspects of utility planning should not be ignored.

Recommendation: The revenue-requirements method should be adopted for general use in evaluating the economics of WECS operation as a fuel saver.

3. The economic viability of WECS was dramatically affected by financial considerations and economic forecasting parameters.

Recommendation: In addition to technical advancements, creative financing, excluding incentives, should be explored. An example of creative financing might be to spread the WECS installation and associated construction costs over several years, keeping it at a sufficiently low level in any one year so that the utility has more flexibility in financing, and the installation is paced to rising fuel costs.

4. The size of the overall wind system was an important factor in achieving economic viability.

Recommendation: Simple computational methods should be developed to optimize the wind system size for economic energy displacement.

5. The probability of wind energy availability and its match to the utility's load was given a first-level treatment in this study. The assumptions and techniques employed were restricted to high load factor situations.

Recommendations: Acceptable analytical techniques should be developed for treating the lower load factor case. A simplified approach, whose validity should be explored, would aim at using the product of the WTG's plant capacity factor and the utility's load factor to yield a measure of on-peak energy availability.

SECTION VI

SYSTEM OPERATIONS AND MAINTENANCE

SYSTEM OPERATIONS -- DAY-TO-DAY

How to introduce WECS into MP&L's daily operations was approached through the job functions of two MP&L system operators: the energy coordinator, and the dispatcher.

The energy coordinator plans and schedules the generator unit commitments for the next day. Monday through Thursday (on Friday the commitments are made for the weekend plus Monday) by 3 p. m. the major energy supply decisions have been made through midnight of the following day. These commitments include:

1. Generation unit schedules
2. Firm purchases and sales
3. Scheduled outage purchase
4. Major economy energy purchases or sales
5. Wheeling schedules

At 3 p. m. , the next day's operating schedule (Figure 6-1) is given to the dispatcher. Each day the dispatcher assigns units on an hour-to-hour basis. This daily operating sequence is illustrated in Figure 6-2.

If a WECS were available, the energy coordinator might perform the following sequence:

[illegible]

Figure 6-1. Minnesota Power and Light Operation Schedule

1. Make up a preliminary operating schedule for the next day
2. Review weather forecasts to assess the probability of available wind energy
3. Modify the preliminary schedule to include the predicted wind energy; adjust scheduled outage purchases or sales, and/or oil peaking unit requirements
4. Submit the schedule to the dispatcher

Figure 6-2. MP&L Daily Operations

The dispatcher would, in turn, operate as follows:

1. If the wind power is available and equal to the amount predicted, the dispatcher would follow the original schedule
2. If the wind power is less than that predicted, the dispatcher would purchase additional capacity and energy, or adjust the generator schedule
3. If the wind power is greater than that predicted, the dispatch would back down some units or trim any economy purchases or sales.

This dispatcher logic is diagrammed in Figure 6-3.

Figure 6-3. Dispatcher Logic

The probabilistic nature of the wind adds an element of chance to the energy coordinator's job. His schedule predictions will be influenced by many things, one of which may be the season. He may be more willing to gamble during the summer when MP&L's peak demand is down: there is more flexibility in scheduling the hydro, and fuel is less expensive. However, he still may gamble conservatively during the summer, aware that interchange purchases might be expensive when the surrounding suppliers are encountering their summer peaks.

The risk in predicting the weather is already present in the energy coordinator's unit commitment task. Load forecasting is an integral part of unit commitment planning, and weather forecasting is an important element of load forecasting. It is common utility practice to consider weather parameters such as illumination, temperature, relative humidity, and wind. The relative importance of these parameters varies among utilities, but for MP&L the relationship between winter winds and heating can be significant.

To better predict winds would enhance the value of wind power. If it were possible to provide a tighter loop around weather reporting stations and the function of the energy coordinator, it might be possible to reduce the risk of not committing a unit or scheduling reservoir usage. MP&L, for example, would like to have more flexibility in scheduling their hydro generation, and WECS could provide this flexibility. With experience, an energy coordinator might be willing to take more risk in scheduling units, assuming the potential cost savings merits the risk.

MP&L currently schedules their reservoirs and hydroelectric energy production as shown in Figures 6-4 and 6-5. During the spring, there is an abundance of water from melting snow and spring rains. The hydro can be operated near its peak capability and the reservoirs simultaneously filled. Hydro generation is cut back during the summer to conserve water for peaking energy and to maintain the reservoir levels as high as possible during the dryer summer months. A scheduled flow is then planned through the winter months to maintain a tunnel under the ice and to gradually lower the reservoir levels so as to use the stored water and have the reservoirs ready to accept the spring run-off.

The average monthly wind energy is determined from the 10-year National Weather Service wind data for the region. This information is used throughout this study and is plotted in Figure 6-4 for comparison with the normal hydroelectric energy production. The two curves show somewhat similar periodicity. During the summer when the hydroelectric energy is conserved, the average wind speed is typically reduced. In the spring, when the water is plentiful, the winds also typically pick up.

Monthly data can only roughly indicate the potential for complementary wind-water interaction. Within the normal daily and hourly utility operating cycle there could still be enhanced operating flexibility.

6-6

Figure 6-4. Hydro Scheduling

Figure 6-5. Average Monthly Wind Energy and Hydroelectric Energy Production

SYSTEM OPERATIONS -- HOURLY

A wind power system operationally acceptable to a utility must be capable of operating as a completely autonomous system within the framework of normal hourly operations. In this context, MP&L likened a wind turbine generator to a remotely located, semi-automatic hydroelectric station. On an hour-to-hour basis, the dispatcher would primarily monitor the WECS output. His actions would be in accordance with the previously discussed dispatch logic.

The requirement for autonomous hourly operation suggests two perspectives for treating WECS, depending upon whether one is in the commitment planning or hourly operating phase of the utility's operating cycle. Figure 6-6 illustrates these two WECS perspectives. For planning unit commitments, WECS could be viewed as a generating source. Hence, power from conventional units plus WECS power must equal the forecasted system load. During normal daily operations, WECS might be viewed as a negative load. Hence, conventional units must supply power from WECS. The wind energy conversion system would be embedded within the system load, and the dispatcher would perform his normal function of serving the load without specifically attending to WECS output.

For many utilities the dispatching function is itself automated through automatic supervisory control and data acquisition (SCADA) systems. MP&L is currently constructing a new energy control center that will operate through a SCADA and automatic generation control (AGC) system. The negative load concept of WECS should be totally compatible with automatic dispatching and offers the potential for tighter overall system control and more optimal economic utilization of WECS.

WECS AS GENERATION FOR UNIT COMMITMENT PLANNING

WECS AS NEGATIVE LOAD FOR DAILY OPERATIONS

Figure 6-6. WECS Viewed as Generation and Negative Load

Much remains to be learned about WECS performance before utility operating issues can be properly addressed. WECS demonstration programs will help provide some of the necessary insights. To the extent that system operations could be hypothesized for MP&L, no technical problems could be identified that would have precluded WECS as a technically feasible energy alternative.

THE CORRELATION OF WIND AVAILABILITY TO LOAD

Within the hour-to-hour operations of a utility, the actual availability of wind energy remains a major concern. Viewing WECS as a negative load tends to overlook this very basic issue, although it does offer a very logical approach to operating with WECS embedded within the utility system. For MP&L, the issue was minimized by the utility's high load factor and other operating constraints previously discussed.

Figure 6-7 shows a typical 24-hour MP&L system load diagram. Of course, it reflects the system's high load factor. Also, however, it reflects a diurnal load characteristic consistent with the diurnal characteristic associated with the wind. Although wind analysis was not conducted to establish the probable hourly availability of the wind, it is reasonable to assume that high winds would tend to occur more frequently during on-peak daylight hours and low winds would tend to occur more frequently during off-peak nighttime hours if there is a diurnal wind cycle.

ON-SITE MAINTENANCE INSPECTION

The operations view of WECS as a virtually autonomous system carriers over into the area of maintenance. MP&L again approached this subject through analogy to a remotely located, unmanned, semi-automatic hydroelectric station.

MP&L's normal practice is to have a field engineer routinely visit each of these unmanned hydroelectric stations once per week. He may stay less than one hour, but his main job is to ensure that everything looks and sounds normal. This is done in spite of station monitoring and communications.

Wind turbines will also have self-monitoring and communications gear to relay status and performance information to a regional control center and/or a central control center. MP&L's new energy control center will have a capability for monitoring critical equipment parts as often as 2-second scan intervals. MP&L felt, however, that one-per-week on-site checks would still be advisable. This would especially be true initially until there is experience with and confidence in the equipment.

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SYSTEM LOAD DIAGRAM FOR TUESDAY, MARCH 26, 1976

Figure 6-7. Typical 24-hour MP&L System Load Diagram

Assuming a weekly on-site inspection averaging about one hour per unit including the drive between units, one man could visit about six units per day. (Note the need for an elevator or hoist to relieve this man's work load.) Table 6-1 reflects these assumptions in an estimate of the number of men that would be required in the case of each alternate wind system to perform just this one job. For the 135-unit/1125-KW system, the equivalent of 4.6 full-time men would be required.

It is pure conjecture at this point to estimate what actual maintenance experience will be. Goals should be for the WTG's to require no more than two minor scheduled maintenances per year, and preferably just one. Not more than one major maintenance every three or four years would also be desirable. It would be logical, if possible, to schedule WTG maintenance during calms. Note, however, that if a minor maintenance schedule takes one day, then the 135-unit system would require the equivalent of 135 days. If two maintenance schedules are required per year, this is equivalent to 270 days, which is slightly more than the number of week-days per year. Similarly, if a major maintenance effort took one week, then the 135-unit system would require the equivalent of 135 weeks, or about 2.6 years.

All of these estimates are intended to place in context some of the problems facing a major WECS installation. These problems are not insurmountable but they do present challenges. They also imply a significant commitment to WECS by a utility.

In the absence of actual data upon which to base maintenance estimates, MP&L recommended using 1.5 percent of plant at a 12 percent annual escalation, which represents their standard practice based on operating experience with generating equipment. A reasonable goal used in the economic baseline model was 1 percent of plant, escalated annually at 7 percent.

Table 6-1. Manpower Estimates for Weekly On-Site Checkout

Candidate WTG		Park Rapids	Hibbing	Virginia	Winton	Sandstone	Total
500 KW	No. Units	60	90	90	30	30	300
	No. Checkout Days	10	15	15	5	5	50
	No. Men	2	3	3	1	1	10
1500 KW	No. Units	20	30	30	10	10	100
	No. Checkout Days	3 1/3	5	5	1 2/3	1 2/3	16 2/3
	No. Men	2/3	1	1	1/3	1/3	3 1/3
1125 KW	No. Units	27	42	42	12	12	135
	No. Checkout Days	4.5	7	7	2	2	22.5
	No. Men	1.0	1.4	1.4	0.4	0.4	4.6

Ruggedness, reliability, and low maintenance are, of course, standard requirements that would be expected of wind turbines. Both the current and advanced technology WTG's have been designed to achieve these objectives, and ambitious goals have been set for all these units.

For the large, horizontal-axis wind turbines, there are unique characteristics that could be objectionable to utilities. The large blades, high towers, and elevated equipment could all present significant problems.

It remains for actual hardware testing to prove equipment quality, reliability and maintainability. Equipment standards for WTG's would be expected to meet or exceed normal utility requirements.

FINDINGS AND RECOMMENDATIONS

The manner in which WECS (without storage) would fit into a utility's operations has been explored from the utility's perspective. This has yielded the following findings and recommendations:

1. Two distinct views of WECS have emerged, depending upon whether one is in the generation-planning phase or hourly energy-dispatch phase of operation. The key to planning unit commitment is forecasting the availability of wind with sufficient confidence to withhold a conventional unit or not commit to a purchase.

Recommendation: Wind forecasting should be studied to determine the accuracy to which wind availability and velocity can be forecast. Development of wind speed sensing systems should be considered to provide more extensive and accurate wind forecasting for WECS users.

2. Viewing wind turbines as negative load fits the fuel saving concept of wind turbines as providing supplemental energy. The negative load concept also infers a wind system sized to be compatible with spinning reserve requirements. This view is also consistent with the overall prediction that wind energy can someday supply five to ten percent of the nation's energy needs.

The negative-load concept is a very unfavorable one to those who view a larger role for wind energy. It does, however, respond to the utility's need to displace expensive purchases and fuels without creating a new set of equally undesirable problems.

Recommendation: The negative-load concept should be further analyzed to quantify and give more tangible substance to this concept. General relationships should be sought in terms of utility system size and load structure.

3. The complementary interaction of wind energy with hydro is highly desirable. Macroscopic (monthly) data, however, suggests that wind and water availability may be more in-phase rather than complementary.

Recommendation: Hourly wind and hydro records should be analyzed to assess the short-term potential for complementary interaction.

4. There is reason to believe that the diurnal characteristic of the wind (if it exists) may favorably bias the correlation between wind availability and high-load level for typical utilities with standard higher daylight loads.

Recommendation: This hypothesis should be analyzed.

5. The concept of a highly reliable, easily assembled and maintained, rugged, totally automatic wind turbine with extensive performance monitoring, fault detection, and fail-safe design is generally espoused by all potential WTG manufacturers. Nevertheless, a large distributed WECS system will present unique new problems for a utility. While some O&M problems such as fuel handling would be nonexistent for WECS, other problems will undoubtedly emerge.

Recommendation: Problems uniquely rising from the large-array WECS should be examined in more depth. Case studies and typical scenarios should be further pursued to identify problems that could affect WECS design, performance, operation, and maintenance.

SECTION VII STORAGE ASSESSMENT

From the outset of this study, MP&L was most interested in applying WECS as a fuel saver, and the utility's high load factor virtually eliminated the need for dedicated energy storage. This need was further mitigated by MP&L's around-the-clock operation of its oil-fired Hibbard plant and its short-term ability to modulate, within limits, some of its hydro. Thus it was concluded that MP&L did not need dedicated energy storage and that there was sufficient flexibility within their current system to facilitate this situation in conjunction with WECS operations. The wind system was originally sized with this constraint considered.

The use of WECS to displace planned capacity was also not a valid issue within MP&L's current planning, which must respond to the rapid growth forecasted for the region. MP&L's forecasted power deficit and needs for large amounts of firm capacity had fixed their currently planned expansions at 500MW in 1980 and an additional 800MW by 1985. The 800-MW plant was sized to allow the joint participation of other utilities within the MAPP region. These expansion plans were too firm for MP&L to realistically consider using WECS for displacing capacity in these large amounts.

The assessment of storage was conducted within the above constraints. Several issues were of general interest:

1. What array capacity, if any, could be derived from geographic separation of the individual units?
2. How would array reliability increase with storage?

3. How does storage affect WECS accreditation?
4. What general conclusions could be drawn concerning storage?

ARRAY CAPACITY

The method for determining array capacity was discussed in Section IV. From Figure 4-14 of that section, an 80 percent array reliability (i. e., 20 percent outages due to lack of wind) accompanied a 60KW/unit August minimum array output (at a 40 percent correlation factor for the BV-1), a 130-KW December average array output, and a 240-KW April maximum array output. For the 135-unit BV-1 array, this would imply minimum, average and maximum array outputs of 8.1MW, 17.6MW, and 32.4MW respectively.

To assess the additional reliability which could be achieved by storage, the array power output return times were evaluated for selected values of return power (Ref. 6). The return time, $t_R(P)$, for a given return power, P , is defined as the time required for the array power output to return above the level P after once going below that value. Return powers were expressed as power-per-generator. Thus, for an array of n generators, the array return power would be n times P .

All return times over four sample months were evaluated for $P = 100\text{KW}$. These results are presented in Tables 7-1 and 7-2 and Figure 7-1. Figure 7-1 is a plot of the average return time probability distributions from Table 7-1. Table 7-2 gives average and maximum observed return times for the 100-KW per generator array power output level.

If a storage system is designed to provide P KW per array generator for t_S hours (i. e., for n generators, the total storage in KW-hours is nPt_S), and if an array power return time $t_R(P)$ is found to have, say, a 90 percent

Table 7-1. Return Time for Array Power Below 100KW

WTG	T(HRS)	JAN '73	JULY '73	JAN. '74	JULY '74	TOTAL	CUM'TIVE (%)
GE 500	0-4	8	13	9	6	36	.387
	4-8	1	2	7	4	14	.538
	8-16	3	12	8	7	30	.860
	32	5	1	3	2	11	.978
	64	0	1	0	0	1	.988
	128	1	0	0	0	1	1.000
	256	0	0	0	0	0	1.000
		18	29	27	19	93	
GE 1500	4	7	12	8	12	39	.333
	8	7	5	5	8	25	.547
	16	3	10	10	9	32	.821
	32	5	4	3	4	16	.957
	64	1	1	1	0	3	.983
	128	1	0	1	0	2	1.000
	256	0	0	0	0	0	1.000
		24	32	28	33	117	
KAMAN- 500	4	5	8	6	11	30	.275
	8	2	2	4	4	12	.385
	16	4	14	12	10	40	.752
	32	7	3	2	4	16	.899
	64	2	2	1	3	8	.972
	128	1	1	1	0	3	1.000
	256	0	0	0	0	0	1.000
		21	30	26	32	109	
KAMAN 1500	4	16	7	4	11	28	.246
	8	6	3	4	9	22	.435
	16	2	14	9	11	36	
	32	8	7	2	1	18	.912
	64	2	1	2	3	8	.982
	128	1	0	1	0	2	1.000
	256	0	0	0	0	0	1.000
		25	32	22	35	114	
BOEING 1000	4	8	11	9	9	37	.420
	8	2	4	8	1	15	.591
	16	4	8	10	7	29	.920
	32	3	2	0	1	6	.989
	64	0	0	0	0	0	.989
	128	1	0	0	0	1	1.000
	256	0	0	0	0	0	1.000
		18	25	27	18	88	

Table 7-2. Return Time for Array Power Below 100KW Per Generator

	<u>AVERAGE</u>					
	JAN'73	JUL '73	JAN. '74	JULY '74	AVG.	MAX.
GE 500	69	36	21	21	37	69
GE 1500	87	45	69	24	56	87
KAMAN 500	108	66	87	42	76	108
KAMAN 1500	102	48	96	42	72	102
BOEING 1000	66	27	15	21	32	66

	<u>MAXIMUM</u>				
	JAN'73	JUL '73	JAN. '74	JULY '74	AVERAGE
GE 500	14.0	8.4	8.4	9.0	10.0
GE 1500	13.9	10.2	11.8	8.4	11.1
KAMAN 500	20.0	13.6	13.6	11.6	14.7
KAMAN 1500	16.8	12.8	15.8	9.9	13.8
BOEING 1000	12.3	7.7	7.2	7.7	8.7

cumulative probability, then 90 percent of the time when the array output power goes below nP the available KW hours of storage would not be exhausted before the array power returns above nP again (assuming the storage started fully charged with nPt_S KW hours). Thus, a 90 percent cumulative probability for $t_R(P) = t_S$ means roughly that the storage time t_S will provide array power, P , per array generator with a reliability of 90 percent. For a more accurate assessment of reliability achieved by various storage levels, a time series simulation of the storage status (i. e., amount of KW hours available) must be performed. This is because a long period of time when storage is required could begin with the storage is already partially exhausted, instead of being fully charged. This analysis assumes that the velocity stays above the 100 KW level long enough to recharge the storage. If this storage were not dedicated to WECS, there would be other alternatives to keeping it fully charged.

Figure 7-1. Return Time Probability

Figure 7-1 indicates that 80 percent array reliability with storage required 13 hours, 15 hours, and 16 hours for the Boeing 1000KW, G. E. 500KW and G. E. 1500KW WTGs respectively, assuming a 100-KW return power output level. This 100-KW level compares reasonably with the 60-KW August minimum and 130-KW December average array output at 80 percent reliability. For the 135-unit BV-1 array, the 100-KW return power implies 13.5MW for the entire array.

There is much uncertainty in costs associated with storage. For computational purposes, estimates from Reference (10) were used; i. e., \$40/KW + \$15/KWH. Therefore, using these estimates, the 13-hour storage requirement would have a capital cost of

$$\$40/\text{KW} + 13 \times \$15/\text{KWH} = \$235/\text{KW}.$$

WECS ACCREDITATION

The issue of WECS accreditation is germane to storage. Conversely, storage is often regarded as a necessity for wind power accreditation.

Early in the study, at a MAPP planning meeting, MP&L raised the question of how WECS accreditation might be treated. The power pool has regulations and procedures for the uniform rating of generating equipment. Their response was based upon achieving an 80 percent availability, which approximates the standard 20 percent forced outage rate of an equivalent (say, 100MW) coal-fired unit. Figure 7-2 illustrates this MAPP response and the potential severity of the accreditation problem.

The Mid-Continent Area Reliability Coordination Agreement (MARCA) procedure for the uniform rating of generating equipment shed further light on the problem of WECS accreditation. The procedure emphasizes that "generating capability must be accounted for in a uniform manner which

assumes the use of consistently attainable values." Monthly Net Capability (MNC) ratings are established as the common basis for accounting. "The Monthly Net Capability is the net power output which can be obtained for the period specified on a monthly adjusted basis with all equipment in service under average conditions of operation and with equipment in an average state of maintenance."

A PRELIMINARY VIEW FROM MAPP

80% IS APPROXIMATELY THE FORCED OUTAGE RATE
OF A 100 MEGAWATT COAL FIRED UNIT.

Figure 7-2. WECS Accreditation

Among the guidelines for establishing capability are the following:

1. "The MNC rating shall be that available regularly to satisfy the daily load patterns and shall be available for four continuous hours or more."

2. "The MNC will be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others. The MNC will be determined as a group for commonheader sections of steam plants or multiple-unit hydro plants and each unit assigned a rating by apportioning the combined capability among the units."
3. "The MNC established for hydroelectric plants, including pumped hydro, will be determined by taking into consideration the reservoir storage program and will be based on median hydro conditions."

These statements from the MARCA uniform rating regulations provide insight into the rating process and the challenges confronting WECS accreditation. It is likely that special consideration will have to be given to WECS to determine an appropriate rating technique.

GENERAL DISCUSSION

The importance of WECS power accreditation is diminished when the wind system is being operated mainly as a fuel saver. One of the parametric variations examined for the advanced technology baseline system, Case 16, showed that when a 30-MW minimum demand capability was assigned to the system, the dispatch logic of the production cost model used the resulting energy to displace lower cost fuels. Although this result is strictly the product of the PCM's dispatch logic which equated the magnitude of capacity credit with minimum "run-of-river" wind output and correspondingly shifted the distribution of wind energy to more off-peak hours, it emphasizes that it is peak energy displacement and not base capacity displacement that is important to fuel savings operation. Storage could be employed to ensure WECS minimum output, however, the benefit of doing this would be to ensure peak energy fuel savings.

Array diversity, without storage, was examined to establish what minimum capability, if any, could be assigned to the array. The monthly array power levels and associated probabilities discussed earlier in this section represent these array capacities. The array's reliability to deliver power could be further improved through storage. The return-time analysis indicated that 13 hours of storage was required to provide a 80 percent reliability based upon a 100-KW minimum capability and a preliminary 1000-KW Boeing WTC design.

A lack of substantive storage cost information made it very difficult to convert these storage requirements to capital costs. We have seen storage capital costs ranging from \$40/KW + \$15/KWH to \$100+/KW + \$50/KWH. It is clear from the financial analysis that additional capital costs for a fuel-saving application would move WECS farther away from economic viability. Hence, no realistic cost goal can be identified for storage associated with pure fuel savings.

MP&L currently anticipates capital costs for their 1980 and 1984 plant expansions to be approximately \$800/KW and \$1000/KW, respectively. Given a moderate inflation, currently estimated WECS capital costs could probably compete with these coal-fired unit costs. The problems are that advanced technology units with proven performance levels will not be available during this time; and the amounts of power are too large within their system for MP&L to consider WECS as a valid alternative for base capacity.

FINDINGS AND RECOMMENDATIONS

1. For the specific case of MP&L, storage dedicated to the wind power system is neither necessary nor economically viable at this time. The utility has a sufficiently constant load and generation flexibility to accept wind energy without storage. Capital costs ranging from \$235/KW

to more than \$750/KW, as previously discussed, for 13 hours of storage drive WECS farther from being economically viable, and the resulting additional capacity would not be sufficient to eliminate MP&L's near-term deficits.

Were MP&L facing a lower demand growth rate (as may occur beyond 1985, or as may be more representative now of other utilities) the potential for WECS with storage would increase. The likelihood remains that non-dedicated storage created by existing intrinsic system flexibility would still be the first approach to implementation, followed by new forms of non-dedicated auxiliary system storage and then dedicated storage.

Recommendation: Analysis of medium and low load factor cases should be undertaken to broaden the basis for storage assessment. A compendium of existing, near-term, and long-term bulk electric storage for utility applications should be compiled, including performance and cost projections to facilitate this storage assessment. This compendium should consider dedicated and non-dedicated WECS storage alternatives.

2. The need for dedicated short-term storage to smooth out WECS transients was not explored in this case study. (Short-term herein implies not more than 15 to 30 minutes of storage capability.)

Recommendation: The need for short-term dedicated storage should be investigated in conjunction with WECS transient analysis and utility interface studies.

3. Establishing regulations for WECS accreditation will present unique problems. Whether each unit must be considered separately may depend on how the units are interconnected and tied into the utility grid.

Recommendation: Guidelines for establishing WECS accreditation should be studied in joint effort with utility representatives.

4. In recent years utilities have more and more been coordinating their operations on a regional basis, as through the MAPP pool and MARCA reliability council. Pool operations can affect both the regulations imposed on WECS and the overall potential for WECS within a region. For example, grid storage may be available on a regional basis and load leveling accomplished on a regional basis. The benefit of economies-of-scale for introducing large generating facilities within a region has been achieved through joint participation construction projects.

Recommendation: The regional influence of power pool cooperation should be examined to determine its positive and negative impacts on WECS. Both operational and economic issues should be investigated.

SECTION VIII

SITING, INSTALLATION, AND INTERFACE ISSUES

The details of siting, installing and interfacing a large-scale wind power system will again be examined through the case study approach.

SITE SELECTION CONSIDERATIONS

Selecting a site or sites for wind turbine generators is analogous to selecting sites for conventional power stations. A significant difference, however, is the spacial separation requirement of wind power systems. Many small parcels of land distributed over a large regional area are required for a large-scale utility application. Each parcel must satisfy the many concerns and conditions associated with acceptable WTG sites. With the wind varying not only from location to location, but also within the time domain, the site selection process will require large amounts of site-specific data.

General mission studies using existing wind data have identified geographic areas throughout the United States where there is a high wind potential. These macroscopic studies, however, cannot be used to select specific sites where the wind varies significantly due to localized effects. The next step must be to select sites within these potential areas and to assess both the wind and the many other issues related to a specific locale.

A general study was conducted to define the primary problems associated with specific site selection.

The approach to developing a site selection process is to specifically select an area for a specified generating capacity. During the process, documentation of the parameters addressed was sufficient to include in the results an appreciation of a site survey specification defining the requirements, formats and accuracy of data. Most of the initial issues were addressed to ensure an understanding of the interrelationship:

- Utility influence
- Land employment
- Wind generator system constraints
- Environmental factors

A specific area within MP&L's Western Division was selected based upon present wind assessment studies. Along with the constraints imposed upon the site by the baseline wind generator system and the land use restrictions, the interface with the utility network was determined. A set of selection criteria was established and a set of potential sites selected. An aerial survey was conducted of the sites selected.

Specific Site Selection for WTGs in the MP&L Service Area

The proposed areas for installing up to 150 MW of wind turbine generators (WTGs) were analyzed. These areas, which are shown in Figure 4-2 were recommended by MP&L from a utility standpoint. One area (Park Rapids) was used as a case study of a two-level site selection process by determining first-level characteristics of possible areas and then, by use of a weighted ranking and scoring of these characteristics, selecting a specific area. The specific area was then analyzed and sites designated for the WTGs. These specific locations were described using a similar set of characteristics. Topographic maps were obtained for all the remaining, tentatively

selected site areas. By a similar process, all WTG specific site locations may be selected. An aerial survey was conducted of the general and specific site areas. This information supported the technical feasibility of introducing WECS into MP&L service.

Based upon the sites shown in Figure 4-2 and the process shown in Figure 8-1, maps were obtained to gather information about these specific areas. The two basic maps were 1) a land-use map for the State of Minnesota from the State Planning Agency; and 2) topographic maps from the Minnesota Geological Survey. The land-use map categorizes each 40 acres of land within the state into nine primary use classes (see Table 8-1). These classes are then used for characterizing the potential site area. The topographic maps obtained are the most detailed available: either 7-1/2' (scale 1:24,000) or 15' (scale 1:62,500). These maps are used to determine the location of land contours, roads, buildings, and power lines, for the potential site area. Another source of information were the one-line schematic switching diagrams obtained from MP&L. These diagrams indicate the possible locations of company-owned substations, transmissions line voltages and possible tie-in points to the electrical network.

The specific area analyzed as a case study was around Park Rapids, which is within the Western Division of MP&L and has no power generation within it. One 115-KV high-voltage power substation is located at Badoura, and company-owned substations are located at Akeley, Nevis, Dorset, Park Rapids (2), Hubbard and Menagha within the area. The characteristics of the potential site areas around each of the substations was determined using the previously mentioned sources. The characteristics are those which will influence the choice of sites and include land aspects, utility interfaces and impact on the public. Table 8-2 lists nine detail characteristics, and the information on the seven site areas concerning those characteristics. Characteristics were weighted according to which would increase efficiency and reduce cost/kilowatt-hour. Table 8-3 shows the weighted scores for those areas, with the number 1 rank being an area near the Menagha substation.

8-4

Figure 8-1. Site Selection Process

Table 8-1. Land Use Classes

Forested	A forty in which the dominant use consists of trees. To be considered forested, a forty must contain a scattering of trees whose crowns cover at least 10 percent of the land area.
Cultivated	A forty in which the dominant use consists of land which has been recently tilled or harvested mechanically.
Pasture and Open	A forty on non-forested land not used for any identifiable purpose. Examples are grazing land or abandoned farm land.
Water	A forty in which the dominant land use is open and permanent water.
Marsh	A forty in which the dominant land use consists of non-forested, shallow permanently wet, vegetated areas.
Urban Residential	A forty containing five or more residential dwellings, and no commercial buildings.
Urban Residential or Mixed Residential Development	A forty containing at least one commercial, industrial or institutional development and may or may not contain residential development.
Extractive	A forty in which the dominant land use consists of the extraction of minerals, including ancillary facilities. Examples are mines, tailing piles and gravel pits.
Transportation	A forty in which the dominant land use consists of facilities for the conveyance of people or materials.

Table 8-2. Potential Site Area Characteristics

Area Characteristics	Badoura	Akeley	Nevis	Dorset	Park Rapids	Hubbard	Menagha	
• Wind Information Possibly Available	No	No	? Landing Field	? Lookout Tower	? Municipal Airport	No	No	
• Topography Info								
- Elevation	1450-1500	1400-1460	1450-1505	1450-1510	1430-1450	1410-1420	1420-1530	
- Type	Flat	Marsh/Forest	Lakes/Hilly	Hilly	Flat	Flat	Rolling	
• Transmission Line Voltage Level	34KV	34KV	34KV	34KV	34KV	34KV	12.5 KV	
• Distance to Substation	4	3	1 to 2	1 to 2	4	4	9	
• Existing Tie-In Point	?	No	No	No	?	No	Yes	
• Land Use	Cult/ Forest	Cult/ Forest	Forest/ Urban	Cult/ Forest and Urban	Cult/ Transp.	Cult	Pasture/ Cult/Forest	(Forested Cultivated Pasture/Open Urban Transportation (Airport)
• Land Ownership	?	?	?	?	?	?	?	
• Population Density	15 Farms	10 Farms	Higher	High	2 Farms/MI	24 Farms	2 Farms/MI	
• Potential Site Area Size - MI ²	8	6	5	7	12	13	12	
• Access								
- Roads in Area	15 mi.	7 mi.	9 mi.	14 mi.	Section Roads	Section Roads	20 mi.	

Table 8-3. Potential Site Area Characteristics

Area Characteristics		Badoura	Akeley	Nevis	Dorset	Park Rapids	Hubbard	Menagha
● Wind Information Possibly Available	<u>Weight</u> 2	<u>SC/WT-SC</u> 0/0	0/0	3/6	4/8	5/10	0/0	0/0
● Topograph Info - Elevation - Type	10	5/50	3/30	1/10	7/70	5/50	5/50	10/100
● Transmission Line Voltage Level	6	5/30	5/30	5/30	5/30	5/30	5/30	10/60
● Distance to Substation	5	5/25	7/35	10/50	10/50	5/25	5/25	2/10
● Existing Tie-In Point	5	5/25	1/5	1/5	1/5	5/25	1/5	10/50
● Land Use	5	6/30	6/30	1/5	2/10	4/20	8/40	10/50
● Land Ownership	2	?	?	?	?	?	?	?
● Population Density	4	9/36	10/40	5/20	2/8	7/28	8/32	7/28
● Potential Site Area Size	8	3/56	5/40	4/32	5/40	9/72	10/80	9/72
Total Wt. Score		252	210	158	216	260	262	370
Rank		4	6	7	5	3	2	1

After the ranking of the potential areas, the Menagha area was further analyzed to select the specific location for 20 WTGs. Promising sites were selected mainly by land elevation, with the locations selected being on the crest of the rolling hills in the area. The 20 specific sites are shown in Figure 8-2 and further described in Table 8-4.

Other Site Areas -- Maps were obtained for Hinckley, Winton/Ely, Virginia/Eveleth and Hibbing/Nashwauk. These areas are described below, along with the judgement of whether desirable WTG sites would be available.

Hinckley -- South edge of central division of MP&L. The transmission lines are mainly 23 KV, with substations at Hinckley, Freisland, Lone Pine, Sandstone (2), Groningen, Finlayson and Rutledge. Elevation is between 1030 and 1140 feet above mean sea level (MSL). The area is rolling, with 20- to 40-foot hills. Forest and marsh levels are interspersed with cultivated areas. Areas which would be potential sites from up to 10 WTG's are north of Hinckley, adjacent to Friesland. The areas are between Groningen and Sandstone and north of Finlayson. This area would not present a difficult situation for WTG installations.

Winton/Ely -- This is at the northern most point of the northern division of MP&L, and contains a four-MW hydroelectric plant between Garden Lake and Fall Lake. Substations with 46-KV transmission lines are at the St. Croix and Kainz Logging Company. The topography is moderately hilly and appears to have heavy forested areas. Lakes and marsh land are interspersed between the hills. Elevation ranges from around 1400 feet MSL to peaks of hills up to 1550 feet MSL. The area contains few section roads and access to the areas appears limited. One possible approach in this area would be to expand the right-of-way for the present 46-KV transmission line between the Winton hydroelectric plant and the Virginia HV substation. The transmission line does pass over some higher ground and appears to have some cleared ground. To place 10 WTGs in this area does not appear to be readily feasible without a significant forest clearing and construction of access roads.

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Figure 8-2. WTG Sites - Menahga, Minnesota

Table 8-4. Specific Location Characteristics - Menagha Area

Site No.*	Elevation		Land Use	Distance to Buildings (feet)	Distance to Closest WTG (feet)	Direction to WTG Degrees	Distance to Forest (feet)	Distance to Access Road (feet)	Type of Road		Remarks
	Feet	Feet/Mi							Improved	Unimproved	
1	1540	30	Forest	2500	4-4000	150	0	2400		X	Wooded
2	1530	30	Forest	6000	4-3000	20	0	1500	X		Wooded
3	1510	20	Cult	1500	5-3500	170	750-W	1500	X		Farm - flat
4	1540	40	Forest	2000	7-3000	90	10	1800		X	Wooded
5	1540	40	Forest	2000	3/8-3500	350/60	0	2000	X		East edge of farm?
6	1540	30	Cult	1000	1-3500	280	100-E	1000		X	East edge of farm?
7	1530	60	Cult	2000	4-3000	270	100-E	800		X	East edge of farm/buildings
8	1510	15	Cult	100	10-2500	60	100-S	100	X		South edge of farm/buildings
9	1530	40	Cult	3000	11-2600	150	600-E		X		Large
10	1490	30	Cult	1700	12-2400	130	400-W	500	X		Flat
11	1520	60	Cult	2000	9-2600	330	600-S	1000	X		Knoll
12	1507	30	Cult	400	10-2400	260	400-S	200	X		At farm
13	1520	70	Forest	1000	15-2800	30	0	1000/800	X	X	Wooded knoll
14	1490	40	Cult	3500	17-4400	30	100-E	100	X		East edge of farm
15	1500	40	Cult	200	16-2000	10	100-N	100	X		North edge of farm
16	1500	40	Cult	1500	15-2000	190	600-E	600	X		Knoll
17	1490	40	Forest	2500	19-4200	60	0	100	X		Wooded
18	1490	60	Cult	1000	16-5000	260	200-N	800	X		Wooded
19	1510	90	Forest	1500	20-3800	90	0	1500	X		High peak
20	1490	70	Forest	2000	19-3800	270	90	1000		X	High peak

*Refer to map (Figure 8-2) for site location.

Virginia/Eveleth -- This area is also in the Northern Division of MP&L and is characterized by the 115-KV substation at Virginia with company-owned substations at Eveleth Rural Lakes, Thunderbird South, Inland Steel and the Plant and Mine at McKinley. These are either 33- or 46-KV substations.

The distinguishing topographical feature is the hills of the Laurentian Divide. Mountain peaks in the area are between 1850 and 1875 feet high, with the predominate peak being Pike Mountain at 1930 feet MSL. Pine Mountain has an access road and a lookout tower at its crest. The local ground elevation varies from 1375 feet south of Eveleth to the 1875-foot peaks through the Laurentian Divide north and east of Virginia, with the area north of Laurentian Divide being about 1500 feet about MSL. The area appears to be heavily wooded, except south of Eveleth. Depending upon the direction of the prevailing winds (or conversely, the blockage by the Laurentian Divide) the area south of Eveleth could have potential WTG site locations. High-voltage transmission lines run along the Laurentian Divide from the north and east into the Virginia area, and could possibly be expanded for WTG sites.

Hibbing/Nashwauk -- This area is also part of the Northern Division of MP&L. There are two high-voltage power substations, one at Hibbing and one at Nashwauk. Company-owned substations also are at Chisholm, Leetonia and East Stevenson, with the transmission lines being 23 KV and 115 KV. A number of taps exist to local mines and industry, including some of a 13-KV distribution. The area is mostly distinguished by numerous open-pit iron mines, mine dumps and tailing ponds. A municipal airport east of Hibbing is 1350 feet above MSL.

The topography is distinguished by the continuation of the Laurentian Divide, which peaks at from 1750 to 1775 feet. This divides the area in half, with the southern elevation being about 1350 to 1400 feet, and the northern side of the Divide being about 1450 to 1500 feet. The area is mainly wooded, except around the airport and area north of Chisholm and an area north of Nashwauk. These three areas would be candidate locations for WTGs.

Aerial Survey

Since the first approach to site selection data was confined to maps and verbal information, a flight survey was conducted of the area. The flight survey had the objectives of observing and photographing the area and specific sites chosen by the above process. (See Figures 8-3 through 8-8). (Numerous other colored photographs were taken and are available upon request; however, their contrast was such that reproducing them herein would be unsatisfactory.) The flight survey also was conducted to gain a perspective on the nature and extent of the Laurentian Divide, a most promising area for higher wind sites. The flight survey confirmed the general appropriateness of the preliminary siting study. There is a need for a defined systematic approach to introducing a large number of wind turbines into an area. The first-ranked Menagha area proved to be a rolling farmland area which contained many potential sites. The area appeared to be rich farmland, however, and no wind data could be obtained which directly measured its wind regime. The Laurentian Divide had a most interesting set of high hills which rose from the surrounding forested lands. Again, no applicable wind information was available to describe wind energy on the prevailing windward side of the hills.

INSTALLATION AND INTERFACE

WECS installation, utility interfaces, and general system engineering issues were addressed by conceptually working through the implementation of the assumed MP&L WECS configuration. This called for the installation of a peak-rated, 150-MW wind-power system distributed between five locations. A slight departure from the 150-MW system occurred when the Boeing Vertol effort converged on a WTG with a 1125-KW peak rating. An integer number of Boeing units would not give a system peak rating of 150 MW. For this case, a 135-unit system was selected with a resulting $135 \times 1125 \text{ KW} = 151.8$ megawatts peak capability.

Figure 8-3. Looking Northeast towards Park Rapids

Figure 8-4. Nashwauk: 12 Miles Southwest of Hibbing

Figure 8-5. Akeley: 1.5 Miles Southeast

Figure 8-6. Lookout Tower at Dorset

Figure 8-7. Menahga: Site 18 (View 1)

Figure 8-8. Menahga: Site 18 (View 2)

The five area turbine sites were in the vicinity of Park Rapids, Hibbing, Virginia, Winton, and Sandstone, Minnesota. Three alternative MP&L 150-MW peak-rated installations were considered: 300 units with a 500-KW peak rating; 135 units with a 1125-KW peak rating, and 100 units with a 150-KW peak rating. Table 8-5 summarizes the number of units and the peak capability at each of the five areas for the three candidate WTG ratings.

Table 8-5. Number of Units and Peak Capability at Each of the Five Areas

Candidate WTG		Park Rapids	Hibbing	Virginia	Winton	Sandstone	Total
500 KW	No. of Units	60	90	90	30	30	300
	Megawatts	30	45	45	15	15	150
1500 KW	No. of Units	20	30	30	10	10	100
	Megawatts	30	45	45	15	15	150
1125 KW	No. of Units	27	42	42	12	12	135
	Megawatts	30.4	47.2	47.2	13.5	13.5	151.8

MP&L had existing 14-, 23-, 34-, or 46-KV distribution lines in each of these areas, and could forecast the local need for additional power. The wind turbines were allocated to contribute to satisfying these areas' needs, while still staying within the capability of the existing area's distribution systems.

To satisfy installation and interface differences between the 500-, 1125-, and 1500-KW units, five modular cluster configurations were laid out. They consisted of 30/500-KW units, 14/1125-KW units, 27/1125-KW units, 10/1500-KW units, and 20/1500-KW units. The five cluster configurations and their interface modules are shown in Figures 8-9 and 8-10.

Figure 8-9. Array Cluster Configurations

A) 15 MW ARRAY WITH 30/500 KW UNITS

B) 15 AND 30 MW ARRAYS WITH 1500 KW UNITS

C) 13.5 AND 30.4 MW ARRAYS WITH 1125 KW UNITS

Figure 8-10. Interconnect Module

The previously discussed site selection considerations showed that actual installations will be shaped to fit local geographies, jurisdictions, proximities to substations and distribution lines. It is doubtful that an actual installation would necessarily have the regular geometries shown in Figure 8-9. These geometric modular clusters were merely assumed as a basis for costing the installation and interfaces.

A detailed discussion of the system interface, installation, and associated costs follows. Table 8-6 summarizes the resultant WECS per unit costs that were employed throughout the study. They are based on 1975 WTG cost estimates expressed in 1975 dollars and representing units assumed to be ordered in 1975 for installation in 1976.

Table 8-6. WECS Per Unit Costs

	500 KW		1125 KW	1500 KW	
	G. E.	Kaman	Boeing	G. E.	Kaman
Unit Prices from Design Studies (\$)	467,000	451,000	568,000	644,000	721,000
Additional Interface (\$)	66,000	52,000	61,000	130,000	66,000
Additional Installation (\$)	17,000	17,000	28,000	17,000	17,000
Total Dollars	550,000	520,000	657,000	791,000	804,000
Dollars per Rated KW	1,098	1,039	584	528	536

The cost estimates used were clearly rough-order-of-magnitude (ROM) numbers. The intent was to obtain generic, not specific, installation and interface estimates, and to gain insight into the relative significance of the cost components.

Because of the general "softness" of these cost estimates, no attempt was made to correct for the disparity in assumed production quantities and rates between the three WTG manufacturers. General Electric quoted prices on the basis of 100 units to be delivered and installed within three years. Kaman assumed a 1000-unit production level, and Boeing assumed 1000 units at the rate of 200 per year. In the end, it was assumed that the cost estimates shown in Table 8-6 were within ± 20 percent and, accordingly, -20 percent, +20 percent, and +50 percent cost variations were included in the study's financial evaluation parameter variations.

WTG Substation and Distribution Costs

The estimated costs for the electrical substation and distribution system were based on the general array configurations and interface modules shown in Figures 8-9 and 8-10. The energy-gathering facilities, including circuit breakers, distribution lines, transformers, protective relaying, and communications requirements were developed as modules so that several combinations of energy parks or farms could be priced. An in-depth study of relaying and communications circuits was not conducted, but prices of typical relaying packages were estimated.

There are two basic WECS installation configurations: (1) clustered WTGs combined through dedicated feeders to dedicated interfaces with the utility grid; and (2) isolated WTGs tied directly into the utility's distribution system. The selection and cost tradeoffs are highly dependent upon the particular utility, its loads, and the density of the utility's distribution system. For MP&L, a number of dedicated feeders tied into the distribution system at major substations was preferred.

Cost estimates were made for the five aforementioned WTG configurations: three approximate 15-MW parks or arrays, using 500-KW, 1125-KW, and 1500-KW units; and two approximate 30-MW arrays, using 1125-KW and 1500-KW units. All WTG clusters or arrays were assumed to be located 3.5 miles from a major substation where an oil circuit breaker could be installed for each 15 MW generated on a separate feeder. The 3.5-mile feeder length was chosen to allow some degree of flexibility in selecting acceptable park areas. Feeder voltages of 23 KV, 34.5 KV, or 45 KV were considered. These voltages will influence the line costs, depending upon which voltage is selected.

ROMs were provided by MP&L based upon 1976 values. Line costs included right-of-way acquisition, clearing, chemical treatment, and construction using 795-kc mil ACSR (aluminum conductor-steel reinforced) with an overhead shield wire.

I. 15-MW Array - 30/500 KW Units (Figure 8-9) -- This is one of a multitude of possible configurations. In most cases, two generating units are switched with each 4-KV circuit breaker. Standard 3750/4500-KVA OA/FA (oil air cooled/forced air cooled) transformers are specified. Assume a minimum of 10-rotor diameters between each WTG, or approximately 0.5 mile of separation.

Substations

4	3750/4500-KVA OA/FA transformers
16	4-KV breakers
4	Lots of power wiring, foundations, etc.

Total

\$ 900,000

Exits and Feeders

26	1/2 mile feeders 350 Kc mil aluminum underground @ \$12,300 per 1/2 mile at 2.4 KV	\$ 320,000
1	34-KV breaker at main switching station	50,000
7	Miles of 34 KV overhead feeder @ \$40,000 per mile including right-of way acquisition, clearing, chemical treatment, and line construction using 795 kc mil ACSR with overhead shield wire	280,000
	Total	\$ 650,000

WTG Protective Relaying and Communications

30	Lots at \$10,000 per unit	\$ 300,000
	Subtotal	1,850,000
	18% omissions, contingencies and overhead	333,000
	Total	\$2,183,000
		= \$145/KW

II. 15-MW Array - 10/1500 KW Units (Figure 8-9) --Substation

3	3750/4500-KVA transformers	
1	1500 KVA transformer	
7	4-KV breakers	
4	Lots power wiring, foundations, etc.	
	Total	\$ 780,000

Exits and Feeders

6	1/2 mile feeders	\$ 75,000
1	34-KV breaker	50,000
5	Miles 34-KV circuit	200,000
Total		<u>\$ 325,000</u>

WTG Protective Relaying and Communications

10	Lots at \$10,000 per unit	100,000
Subtotal		1,205,000
10% omissions, contingencies, and overhead		216,000
Total		<u>\$1,421,900</u>

III. 30-MW Array - 20/1500 KW Units (Figure 8-9) --Substation

6	3750/4500-KVA transformers	
1	3000-KVA transformer	
13	4-KV breakers	
7	Lots power wiring, foundations, etc.	
Total		<u>\$1,500,000</u>

Exits and Feeders

13	1/2 mile feeders	\$ 160,000
2	34-KV breakers	100,000
2	Miles 34-KV single circuit	80,000
4.5	Miles 34-KV double circuit	270,000
Total		<u>\$ 610,000</u>

WTG Protective Relaying and Communications

20	Lots at \$10, 000 per unit	\$ 200, 000
	Subtotal	2, 310, 000
	18% omissions, contingencies, and overhead	415, 800
	Total	<u>\$2, 725, 800</u>
		= \$91/KW

IV. 13.5-MW Array - 12/1125 KW Units (Figure 8-9) --Substation

3	3750/4500 KVA transformers	
6	4-KV breakers	
3	Lots power wiring, foundations, etc.	
	Total	<u>\$ 600, 000</u>

Exits and Feeders

9	1/2-mile feeders	\$ 110, 000
1	34-KV breaker	50, 000
4.5	Miles 34-KV circuit	180, 000
	Total	<u>\$ 340, 700</u>

WTG Protective Relaying and Communications

12	Lots at \$10, 000 per unit	\$ 120, 000
	Subtotal	1, 060, 700
	18% omissions, contingencies, and overhead	191, 000
	Total	<u>\$1, 251, 700</u>
		= \$93/KW

V. 30. 4-MW Array - 27/1125 KW Units (Figure 8-9) --Substation

7	3750/4500 KVA transformers	
14	4-KV	
7	Lots power wiring, foundations, etc.	
Total		\$1,400,000

Exits and Feeders

20	1/2 mile feeders	246,000
2	34-KV breakers	100,000
2	Miles 34-KV single circuit	80,000
5	Miles 34-KV double circuit	300,000
Total		\$ 726,000

WTG Protective Relaying and Communications

27	Lots at \$10,000 per unit	\$ 270,000
Subtotal		\$2,396,000
18% omissions, contingencies, and overhead		431,000
Total		\$2,827,300
		= \$93/KW

Site Preparation and WTG Erection

Desirable WTG sites will probably be near main feeder lines, preferably on elevated country that is well drained. If adequate drainage is not present, the land can be tiled to keep water levels or water tables within reasonable limits. Drainage is especially important for the road network since the road bed must be able to carry loads approaching 30 tons. Since most of the land in northern Minnesota is of gravel and rock, there will be adequate supplies for road construction.

It may be preferable to acquire land in one-square-mile sections, which means that the perimeter will coincide with county or township roads. More likely, the land will be purchased in four-acre plots with easements between various plots for feeder lines. Another approach would be to purchase small tracts near a township road where the utility has easements for power lines and stretch out the wind turbines along the road. The visibility of wind generators may be significant so as many trees as possible should be left standing to obscure the installation, assuming wind blockage is not a factor.

MP&L helped establish land costs by providing the values of parcels recently obtained for a system of microwave towers. Table 8-7 summarizes these values thought to be representative of what might be incurred for wind turbine sites. Based upon these values, a price of \$500 per acre was used for land acquisition and \$150 per acre for power line easements. Easements are cleared areas 100 feet wide. Each WTG was assumed to require four acres and 1/2 mile of feeder easement.

Land Costs

4 acres:	\$2000
1/2 mile easement:	<u>900</u>
	\$2900 per WTG

Land Clearing and Site Preparation -- Land in northern Minnesota is generally wooded, may have some standing water and probably some rock outcroppings. Site preparation will involve clearing the four acre sites or a comparable area if the land is in one parcel. Trees will be cut and stumps removed as well as will be the rock outcroppings if they are in a road area. The land will first be surveyed to establish boundaries, roads, fencing and easements. At the same time, soil samples will be taken at the wind generator sites and where all roads for the facility would be constructed. If soil tests indicate that the water level or sub-soil structure would increase the cost of installation,

Table 8-7. Minnesota Land Values in Vicinity of Candidate WTG Sites

Location	Site Size	\$ Cost	\$ Per Acre
1. St. Louis County near Virginia	300 ft x 300 ft	10,000	4760
2. Lake County NW of Two Harbors	40 acres	6,500	163
3. Cass County near Remer	300 ft x 300 ft	3,000	1428
4. Wadena County	600 ft x 600 ft	1,500	176
5. Cass County	40 acres	5,200	130
6. Aitkin County	40 acres	4,500	113
7. Crow Wing County	400 ft x 400 ft	650	171
8. Transmission Line Right-of-Way in St. Louis County near Virginia	6.35 acres (130 ft x 2128)	7,500	1181
9. Leased Substation Site near Virginia	450 ft x 450 ft (5.14 acres)	1,500 per year	292 per year

NOTE: 1 acre = 43,560 sq ft = (208.7 ft)²

40 acres = 1/16 sq mile = (1320 ft)²

alternate locations will be suggested. Soil readings can also indicate potential gravel pits to be used in the road construction. Soil readings will also indicate the necessity for piling, road culverts, type of tower footings and the amount of road fill. After all soil readings have been taken, the survey crew will finalize all stakes for wind generator footing excavations, road grading stakes, culverts, road grades, fencing lines and easement limits. To facilitate 30-ton loads, all roads should have a coarse gravel base six inches thick and not to exceed a 15 percent slope. Ditches should not exceed a 3-to-1 slope from the shoulder with a 2-to-1 slope on the back slope. An 18-inch clay culvert is recommended in areas where cross drainage is required. In areas where water levels may be a problem, drainage tile should be used.

Roads are assumed to have a 30-foot crowned gravel top with 10-foot ditches on either side. It is assumed that it takes one cubic yard of dirt for each lineal foot of road bed.

A natural-soil road of this type can be built with a standard 12-foot blade grader with a back sloping attachment. The first cut usually removes the sod from the shoulders and ditches which is then used for fill along the edges of the road. The center of the roadway must be kept free of sod since it tends to weaken the road. In work of this type the amount of earth that is moved is about 5000 cubic yards per mile and requires an average of three days for completion. For the center section, heavier equipment may be necessary and it is estimated that 8000 cubic yards of dirt per mile must be moved. This will take a heavy duty grader about five days per mile.

After grading, the road is covered with six inches of pit run gravel (pebbles under 1 inch) and then bladed. This is about 3000 cubic yards per mile and should be not more than \$4/yd delivered. This also takes an average of two days to grade and compact the gravel for each mile of road. It is assumed that no fill will be necessary.

Each of the wind generator sites must be enclosed by a security fence to minimize vandalism and provide safety. A six-foot-high chain link fence, 60 feet on each side, is recommended for each tower. This is close enough to the tower and still should not interfere with unloading trucks and operating cranes around the tower. A locked gate, near the access road, is located at the front of the tower and instrumentation building. A graveled road extends in a wide circle around the tower to accommodate truck and crane traffic. The fencing was estimated at \$10 per foot, which includes concrete, hole digging, labor and materials.

Land Clearing and Site Preparation Costs
(4 acres and 1/2 mile per unit)

12 hours grading at \$35/hr:	\$ 420
500 yards gravel at \$4/yard:	2,000
8 hours final grading at \$25/hr:	200
Fencing at \$10 per foot:	2,400
Soil testing:	700
Surveying:	2,000
Easement clearing at \$1075/acre:	6,450
Site clearing at \$700/acre:	2,800
Road:	4,200
Culvert (two per WTG):	700
	<hr/> \$21,870

Site Footings -- All of the footings for the various types of towers seem to cost around the same, with the only variance being the size. Footings that have been suggested for the towers include piling, piling with rock anchors and the typical mass concrete footing. For the purposes of this study assume a truss-type tower with mass concrete footings. All of the concrete will be mixed on-site, since gravel and sand is probably nearby.

Part of the surveying costs in the previous estimate included setting stakes for the concrete footings. Also, since some equipment will be necessary for the footings, a gravel road has been finished to the area.

The footings are needed primarily for the upset load rather than for the bearing load. Even under the most adverse conditions, where the subsoil is soft clay, the bearing capacity of one footing is 324 tons. If conditions are

worse than the soft clay, a piling with rock anchors may be required. The cost of this approach is slightly less than the mass concrete by about 15 percent. However, for this estimate, assume a mass concrete footing with a 28-day cure. This seems to be a standard curing time, but if the schedule does not permit it, a minimum of two weeks should be used.

A standard paving concrete mixer handles one cubic yard per mix, and with a five-minute mix can turn out a cubic yard every 30 minutes. The 1976 price of Portland cement is \$3.75 per 90-pound bag (1 cubic foot) and the price for clean sand or gravel is around \$4 per cubic yard, delivered. One man on a front-loading cat can handle 30 cubic yards per hour and charges \$25 per hour. The forms for the footing would take two men 20 hours and would include a slab for associated equipment and a small control house near the base of the tower.

The curing of the concrete over a two-week period should be obtained with moist burlap, or two inches of straw, or two inches of wet earth over the top surface. It would be ideal to pour the lower portion of the stepped concrete block first and then pour the smaller unit after two days. This simplifies the forms also, since the bracing becomes quite a problem for a mass this size. Spalls and small rocks can be used in the mixture since the objective is to provide a large weight to counteract the upsetting moment.

A typical 100-cubic-yard mix of concrete would have the following ingredients:

Cement:	534 bags
Sand:	54 cubic yards
Coarse aggregate:	74 cubic yards
Water:	2670 gallons

Plywood, greased on one side, can be used for forms with 2 inch by 4 inch boards as the bracing in the holes. If the forms are constructed one at a time, the same forms can be used about four times. It would be expedient to build the lower part of the footings for each site first. After two days of curing, the upper portion of the footings can then be completed. A typical footing is shown below:

For the 1500-KW installation, each tower will cost the following:

- 70 yd³ per footing; 280 yd³ total:

Building forms (40 hr; \$8/hr): \$320

160 sheets (4 x 8 3/4 plywood) }
2198 board feet (2 x 4 bracing) } Can be used for 4 sites

Take 1/4 the cost of

Plywood: \$320
Bracing: \$110

- Excavation -- excavate one large hole and then backfill around footings, which means a 55-ft square hole, 9 feet deep; 1000 yd³:

4 days (\$25/hr): \$800

Backfill (2 days): \$400

From a previous statement, two men can mix two cubic yards of concrete per hour, with another two men hauling it to the forms. Each pier takes 70 cubic yards, or a total of 280 yards:

A total of 140 hours for four men at \$8 per hour:

Labor: \$4480

The cement is \$3.75 per bag and has a volume of 1 cubic foot. Sand and gravel are \$4/yd and water is 10¢ per gallon (since we assume it has to be trucked in).

Cement (1500 sacks):	\$5625
Sand and gravel (359 yd):	1436
Water (7476 gallons):	<u>748</u>
	\$7809

The total cost for excavating, building the forms, and mixing at the site is:

\$14,239.

Then, add a 40 percent contractors fee to include profit and use of equipment, insurance and other incidentals:

Total Cost: \$19,934.60.

This amounts to about \$71 per yard poured.

For the 1125-KW unit, the footings take 278 yd of concrete versus 290 for the 1500-KW unit, so it is safe to use the same cost figure.

For the 500-KW station, the footings use 160 yd versus 290 yd for the 1500-KW site. The same numbers are used for building the forms, material and the ratio of concrete and labor associated with it. This subtotal was:

Mixing labor:	\$ 4,480
Materials:	<u>7,809</u>
	\$12,289

By the ratio of 160/290, this becomes \$6720.

Adding forms, excavating, backfill, and form building totals \$1950.

Concrete:	\$ 6,720
Labor and Materials:	<u>1,950</u>
	\$ 8,670

Adding 40 percent to get the total cost of a 500-KW tower footing = \$12,138.

Tower Erection -- The height of the 1500-KW unit's tower (140 feet) should be no problem for a heavy-lift crane since they can handle 200 tons and have a vertical reach of 190 feet. It would be advantageous to have a smaller crane to unload the trucks, handle the forms, move concrete and transfer steel during the assembly.

Two main types of towers have been suggested for the generators: the tensioned steel concrete tower, and the steel-truss structure. The steel-truss structure can be assembled on the site, as well as the concrete tower.

However, the concrete sections are 10 feet high and 24 feet in diameter and weigh 15 tons. These sections are bolted together through 12 shoulder fittings on the periphery. Each of these bolts must be torqued and "miked" to ensure that the sections are under the proper tension. They work on the principle that the pre-tensioned steel keeps the concrete (which is weak in tension) under a compressive load under all loading conditions. Because of the size and the difficulty in erection, the concrete tower will not be priced.

The material will be brought to the site in around 10 truck loads, with the first three loads containing the structural steel. These are followed by a truck containing the structural steel. These are followed by a truck containing one blade, then the hub, another blade, and then the shaft and bearings. Finally, the factory-assembled nacelle with brake, gear box, generator, electrical cable and other miscellaneous is delivered. There must be an order in the delivery since about one acre of the central site will be used for the tower, access road and material storage. Material and components cannot be readily stored since the site is open and the ground is probably too soft for heavy equipment. It is proposed that 8- and 16-foot railroad ties be used for cribbing and temporary equipment platforms. The blades are heavy (up to 35,000 pounds each) and should be supported on three cribs of railroad ties laid down as in a log cabin. Since the blade is of semi-monocoque construction (stressed skin construction -- the load is carried in the outer layer), it must be adequately supported. Each of the railroad tie supports is around 8 feet square on top, and should be topped with a cushioned pad to distribute the load. If the top row of supports are railroad ties abutting each other, the top surface can then be layered with styrofoam sheets. A layer of sheets about 12 inches thick should be sufficient to allow the heavy weight of the blade to mold a conformal surface so that the load is not concentrated.

The pier that holds the hub portion must be adjustable to accommodate the alignment with the blades. This can be done with heavy duty jacks bearing on the railroad ties to raise or lower the hub as necessary. After the blades

have been assembled to the hub, the entire assembly can then be hoisted to the top of the tower.

The steel truss tower designs have 12-inch "H" section beams for the outer legs and double-angle "T" section members for diagonal bracing. The outer members and bracing are all selected on the basis of an effective column length, since the critical load is buckling. Both the 500-KW and 1500-KW tower used a taper on the outer supporting legs with a thick section near the base and a lighter section near the top. Essentially, three sections are used with a 12-inch H beam at the bottom for the 1500-KW tower and a 8-inch H beam for the 500-KW tower.

A typical tower has over 124 individual steel sections with some of the diagonals preassembled, each of which must be fit into place. It would save time to preassemble sections and then lift them into place, but, because of the weight of the tower, it would be hard to hoist the tower without bending some of the members. For this reason, the trussed tower should be assembled by bolting or welding in bays and then hoisting these into place.

It is difficult to break down the assembly into small enough parts so that a close estimate can be made but, from a statistical view, the tower has close to 172 joints. It is safe to say that each joint may take an elapsed time of 15 minutes. On this basis, it would take six men a period of 40 hours to erect the tower. This is in addition to the crane, which, with an operator, costs \$300 per day. The sixth day is spent in erecting the steps and/or hoist, while the seventh day is spent on the platform and railing. The assembly and placement of the propeller will take about three days. Installation and connection of electrical modules could take about four days, mechanical checkout two days and the final system electrical/dynamic tests could take two days. In 18 working days, the installation should be ready to go on line. It may be possible to shorten this by having one crew work on the propeller assembly, while the others are working on the tower, but only two days can be saved.

The dynamic check cannot be accelerated since it depends on getting enough wind to go through start-up and shut-down. These checks are also time consuming, so there is no real "cushion" in the estimates.

A second crane has been assumed in the numbers to help unload trucks, move units around for preassembly, and to assist in erecting the tower. This second crane is smaller and is priced at \$200 per day, with operator.

There is not enough difference in tower height between the 500-KW and 1500-KW units to save any labor. Other than material, the erection costs should run about the same.

10 days of 190-ft crane at \$300 per day:	\$ 3,000
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10 days of 100-ft crane at \$200 per day:	2,000
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18 days 6-man crew 864 hours at \$10/hr:	8,640
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Total Labor	<u>\$13,640</u>
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Add 40% insurance,
contractor and profit (\$5456): \$19,096

Summary of Site Preparation and WTG Erection Costs

Land

4-acre site at \$500/acre:	\$ 2,000
100-ft wide 1/2 mile easement @ \$150/acre:	<u>900</u>
	\$ 2,900

<u>Land Clearing and Site Preparation:</u>	\$21,870
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Site Footings

500-KW	1125-KW	1500-KW
\$12,000	\$20,000	\$20,000

WTG Erection, Assembly and Checkout:Totals

500-KW
\$55,866

1125-KW
\$63,866

1500-KW
\$63,866

SYSTEM COST ADJUSTMENTS FOR THE CURRENT AND ADVANCED TECHNOLOGY WECS

Wind power system installation and interface costs were developed as one part of the overall assessment of WECS system integration. Before the installation and interface costs could be used, however, the Kaman, General Electric and Boeing Vertol WTG designs had to be reviewed to determine which costs had been included and which costs excluded from those design studies. Kaman, G. E. , and Boeing were all somewhat different in these details. Table 8-6 summarizes the final cost adjustments that amended the manufacturer's quoted price. The basis for these adjustments are further explained in the following paragraphs.

General Electric WTG Designs

The G. E. unit costs were the easiest to adjust in that the designs were defined only to bring the power to the base of the tower. Other than main contractor and automatic transfer switching, G. E. left the utility interface to be defined for the particular application and utility requirements. The designs did, however, include some protective relaying and communications equipment. To accommodate this inclusion, the original estimate of \$10,000 per unit was reduced to \$5000 per interconnected module of units.

- 15-MW Array -- 30/500-KW Units:

Originally \$300,000 at \$10,000 per unit

Became \$ 80,000 at \$ 5,000 x 16 modules

- 15-MW Array -- 10/1500-KW Units:

Originally \$100,000 at \$10,000 per unit

Became \$ 35,000 at \$ 5,000 x 7 modules

- 30-MW Array -- 20/1500-KW Units:

Originally \$200,000 at \$10,000 per unit

Became \$ 65,000 at \$ 5,000 x 13 modules

General Electric also included costs for site acquisition, clearing, preparation, footings, and WTG erection. Only the costs of easements and associated land development (\$17,000) were added to General Electric's original cost estimate.

Kaman WTG Designs

The Kaman design cost estimates were more difficult to adjust because Kaman included more of the utility interface in their system definition. This should not be interpreted as criticism of the Kaman design. It appeared, however, that Kaman had carried out their design with the assumption that each unit would be separately tied directly into the utility's distribution system. The Kaman interface costs were amended per unit as follows:

- 15-MW Array - 30/500-KW Units

1/2 mile 34-KV line to main feeder	\$20,000
Additional utility relaying, communications, and data acquisition	12,000
1/30 breaker and associated equipment at major substation	1,667
1/30 of 8 miles main feeder	<u>10,667</u>
	\$44,334
+ 18% omission, contingencies, etc.	<u>7,980</u>
Total Additional Interface	\$52,314

- 15-MW Array - 10/1500-KW Units

1/2-mile 34-KV line to main feeder	\$20,000
Additional utility relaying, communications, and data acquisition	12,000
1/10 breaker and associated equipment at major substation	5,000
1/10 of 5.5 miles main feeder	<u>22,000</u>
	\$59,000
+ 18% omissions, contingencies, etc.	<u>10,620</u>
Total Additional Interface	\$69,620

● 30-MW Array - 20/1500-KW Units

1/2-mile 34-KV line to main feeder	\$20,000
Additional utility relaying, communications, and data acquisition	12,000
1/20 of 2 breakers, etc.	5,000
1/20 of 2 miles single circuit and 5 miles double circuit main feeder	19,000
	<u>\$56,000</u>
+ 18% omissions, contingencies, etc.	10,080
Total Additional Interface	<u>\$66,080*</u>

*Arbitrarily used for costing.

Additional installation costs were treated in like manner to General Electric's by adding \$17,000.

Boeing Vertol WTG Design

Boeing's WTG design included \$47,000 for electrical equipment, a portion of which was for unit protection and relaying. As with the Kaman design, it was not possible to make a direct cost adjustment to the desired MP&L interface configuration. Adjustments similar to those employed for the Kaman design were thus assumed.

● 30. 4-MW Array - 27/1125-KW Units

1/2-mile 34-KV line to main feeder	\$20,000
Additional utility relaying, communications, and data acquisition	12,000
1/27 of 2 breakers, etc.	3,704
1/27 of 2.5 miles single circuit and 5.5 miles double circuit main feeder	<u>15,926</u>
	\$51,630
+ 18% omissions, contingencies, etc.	<u>9,293</u>
Total Additional Interface	\$60,923*

*The 12-unit array costs virtually the same.

Costs for land, site preparation, and a control building were not included in Boeing's unit cost. \$28,000 was added to cover these additional installation expenses.

FINDINGS AND RECOMMENDATIONS

1. For a large wind power system involving a significant number of wind turbines, the overall site selection process could be quite involved and take several years. The process would include:
 - a. General planning to identify candidate sites subject to utility, regional, and turbine constraints
 - b. Wind speed measurements to assess the site's wind potential
 - c. A legal process to acquire the necessary land and permits

Depending upon the outcome of unyet faced social issues that will be discussed in Section IX, it is impossible to predict how lengthy this process will be.

Recommendation: The issues associated with site selection should be thoroughly understood so that the process can be quickly expedited. Wind measurement techniques should be developed to also help expedite the process. A goal should be set that this process not take as long as the current power plant siting process.

2. Estimates of realizable per-unit installation rates are summarized in Table 8-8. They suggest that a rapid installation and on-line availability of significant amounts of wind power may be difficult. In addition to the WTG installation, time will be required for site selection, possible permits, licenses, impact statements and zoning procedures, site acquisition, site/easement preparation, soil testing, surveying, possible access road construction, foundation construction, and feeder line construction. All these activities would precede or parallel the actual WTG on-site installation. There ultimately could be little difference between the time currently required for environmental impact statements, construction permits and clearances for conventional power stations, and the time required for wind survey, monitoring, and site selection for a wind power system.

Table 8-8. Installation Estimates

Task	Boeing		Honeywell	
	Days	Men	Days	Men
Tower Erection	2.0	6	6.0	6
Nacelle	1.0	6	1.0	6
Rotor	0.5	4	3.0	6
Electrical Modules	2.0	4	2.0	6
Cabling and Hook-up	2.0	4	2.0	6
Mechanical Checkout	1.0	2	2.0	6
Electrical Checkout	1.0	3	2.0	6
Total	9.5		18.0	

Inherent modularity is an attribute of a large WECS installation that must be exploited. The system is composed of many individual WTGs that can also be modular in construction. A more rapid installation and a quick return on investment is a definite WECS benefit compared to the five- to ten-year construction time for conventional thermal electric and nuclear power plants. However, the logistics and timing associated with WECS installations will be critical to realizing this benefit. At an assumed installation rate of one per month, 25 crews working simultaneously for 12 months could install the 300 units in one year. Five crews would take five years; etc. Both the Boeing Vertol and Honeywell estimates of realizable per-unit installation rates could be optimistic, depending upon local conditions such as terrain and climate.

Recommendation: The detailed logistics of installing a large WECS installation should be carefully examined. An installation rate slower than one unit per month appears unacceptable.

3. The pace of WECS installation and system expansion over a period of years must be keyed to the escalation rate of the utility's most expensive fuels and purchases. The case study demonstrated that MP&L could benefit more from the 76-MW wind system than from the 151.8-MW system, as the former was better matched to displacing more expensive fuels and purchases.

Recommendation: Installation rates should be further addressed in the context of projected escalation and inflation rates. These rates may be a key to optimizing WECS installation rates.

4. The WECS interface with the utility grid, initially thought to present no special problems, was found to be more subtle and require more study. The potential for many configuration alternatives, coupled with the requirements for unit protection, grid security, overall reliability and

grid stability made it clear that a more detailed analysis was required. Normal WECS performance which by nature could be quite variable, must be separable from abnormal, system fault performance. To accommodate and correctly monitor WECS performance, the interface protective relaying and communications cannot be treated lightly.

Recommendation: MP&L recommended more work in this area. At some point, this work should involve actual or simulated WECS transient performance data.

5. The advantages and disadvantages of a dedicated feeder interfacing with the utility grid at a major substation versus an individual unit directly tied to the grid appeared totally dependent upon the specific utility and specific application.

Recommendation: There appears to be a general rule that it is beneficial to place power generation as close as possible to the load. Simple analytical techniques to help size, define, and resolve these interface alternatives would benefit WECS planning.

6. For the five interface configurations that were costed, there was a clear capital cost benefit (i. e. , lower \$/KW) associated with the larger 1125- and 1500-KW units. Costs were not significantly different when large and small arrays involving the same units were compared. The 15-MW and 30-MW arrays using the 1500-KW units did, however, demonstrate a potential for some savings through array component sharing.

Recommendation: Economies-of-scale should be applied to system interface alternatives. Innovative array component sharing may help reduce overall interface costs and help introduce economies-of-scale.

SECTION IX ENVIRONMENTAL AND SOCIETAL FACTORS IN SITING A WIND ENERGY SYSTEM

The case study approach is a means of identifying significant Environmental and Societal factors associated with installing a significant WECS system in an area. This aspect was greatly aided by the Minnesota Energy Agency and Minnesota Environmental Quality Council. The following information was reviewed:

- Minnesota state regulations
- Power plant siting information developed by the Environmental Quality Council
- Minnesota land-use maps

Discussions were held with MP&L and state personnel directly involved with the environmental impact of power plant siting.

A general siting of the five locations for groups of WECS for MP&L was undertaken. One area, Park Rapids, was studied in more detail to examine the specifics of siting at a unit level.

MINNESOTA STATE REGULATIONS

Minnesota has taken a progressive governmental position regarding environmental protection as related to its energy problem. It is embodied in the Environmental Policy Act:

Chapter 412 -

Section 2. (116D.02) DECLARATION OF STATE ENVIRONMENTAL POLICY, Subdivision 1. The legislature, recognizing the profound impact of man's activity on the interrelations of all components of the natural environment, particularly the profound influences of population growth, high density urbanization, industrial expansion, resources exploitation, and new and expanding technological advances and recognizing further the critical importance of restoring and maintaining environmental quality to the overall welfare and development of man, declares that it is the continuing policy of the state government, in cooperation with federal and local governments, and other concerned public and private organizations, to use all practicable means and measures, including financial and technical assistance, in a manner calculated to foster and promote the general welfare, to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of the state's people.

In keeping with this policy, Minnesota has created laws, regulations, and agencies to cope with current problems. The process is also characterized by a high degree of public participation by groups and individuals interested in preserving the good life. The application of WECS to this situation in a favorable climate is not a foregone matter as many legal and regulating problems can be used to inhibit a major installation. Since no opposition or negative forces have been found, this possibility of opposition may be academic. In any regard, WECS will need to pass some institutional and public milestones prior to introduction. The following is a review of applicable state regulations.

New rules and regulations govern power plant siting and transmission line routing in the state of Minnesota. These regulations, developed by the Minnesota Environmental Quality Council (MEQC), are:

- MEQC 71 Authority, Purpose, Definitions
- MEQC 72 Responsibilities of Utilities

- MEQC 73 Procedural Aspects of Power Plant Siting and Transmission Routing
- MEQC 74 Substantive Aspects of the Power Plant Siting Process
- MEQC 75 Public Participation

These regulations implement Minnesota Statutes., Sec. 116C.51 to 116C.69.

It was assumed that these rules and regulations would be further developed for WECS, but would retain the general spirit and intent of present law. Minnesota is characterized by strong public participation and significant involvement in environmental aspects of power plant sitings. The current policy applies to "large" electric power facilities and would include WECS if it meets the legal definition of "large," which is:

MEQC 73

"Large electric power generating plant means electric power generating equipment and associated facilities designed for or capable of operating at a capacity of 50,000 kilowatts or more, including, but not limited to, fossil fuel, nuclear fuel, pumped storage and hydroelectric plants."

In the case study, MP&L distributed the WECS power to five sites, all of which were "small" to avoid the necessity of battling with the regulations. If WECS were considered a large facility, a large set of regulations would apply including:

- a) Submission of data $\left\{ \begin{array}{l} \text{Minn. Energy Agency Certificate of Need} \\ \text{Data to meet Minn. Plant Siting Act} \end{array} \right.$
- b) A 15-year facility forecast
- c) A five-year facility development plan
- d) Payment of an assessment to help finance the state agencies' studies, i. e., environment, general criteria, and baseline studies. (This fee would approach \$50,000 in the case study.)

- e) Public hearings would have to take place in each county associated with the program

(MEQC 73) "Transmission line additions or modifications under 1.6 Kilometers in length may be exempted from these regulations by council action."

Minnesota utilities have experienced, and are experiencing, difficulty in obtaining the right to construct new transmission lines (Figure 9-1). New d-c lines are currently being held up by organized opposition. The dispersed WECS locations developed in the Park Rapids site could face local opposition.

MEQC 74 (B) (1) The Facility Development Plan shall contain the following information:

- (1) "Identification of the location, generating capacity (over one megawatt), type, fuel"

This regulation clearly identifies WECS facilities and controls them. The need to identify alternate sites and line locations is especially dangerous to WECS which is forced to use wind "hot spots" to be economically competitive.

MEQC 74 also contains site selection criteria and exclusion criteria for both power plant and transmission line criteria. Twelve criteria exist for power plant siting, and more for transmission line selection. These will be further discussed below under "Power Plant Siting."

MEQC 74 (page 17)

The site application must contain the following:

- (1) Size and type of the plant
- (2) The preferred site

2 utilities ask route for new power line

By Dave Kuhn
Staff Writer

Another controversial power-line routing process has begun with the application of two utilities for a permit to construct a 345-kilo-volt AC transmission line from Wright County to near Mankato.

The application to the Minnesota Environmental Quality Council (EQC) this week by United Power Association (UPA), Elk River, and Co-operative Power Association (CPA), Edina, will start a six-month series of public information meetings and public hearings, ending with a decision by the EQC.

Last May the EQC designated a corridor approximately 20 miles wide through Wright, Carver, Sibley, Scott, Le Sueur and Blue Earth counties. The proposed line is an extension of the high-voltage transmission line across central Minnesota that has resulted in acrimony and legal battles.

More recently, residents of those counties organized to fight the line, calling their group Protect Our Land and Environment. The group then affiliated with Counties United for Rural Environment, an umbrella organization that has played a major role in opposing the central Minnesota line.

According to state law, the EQC must choose a route within the corridor that was designated in May.

The route proposed by the utilities is about 76 miles long, with an estimated cost of \$7.7 million. It would connect a substation between Delano and Buffalo with a substation near Mankato.

John Hynes, of the EQC's power plant siting staff, said Thursday that copies of the application and maps of the corridor, showing the preferred and alternate routes of the utilities, are being prepared. They should be available early next week at public libraries and at county planning offices in the affected area, he said.

The EQC staff or citizens groups probably will propose other routes for consideration, Hynes said.

UPA-CPA said there would be about six wooden H-frame structures per mile. Each would be about 89 feet tall.

A decision is expected within a week on a motion for a temporary injunction halting activity related to construction of a high-voltage transmission line in Meeker County.

Judge John Lindstrom Thursday heard oral arguments in Meeker County District Court on the motion sought by Counties United for Rural Environment. A temporary restraining order issued Oct. 4 remains in effect until Judge Lindstrom announces his decision.

Confrontations between farmers opposed to the power line and surveyors resulted in three arrests and one injury before the restraining order was issued.

- (3) At least one alternate site
- (4) The engineering design concepts for the plant
- (5) An engineering analysis of each of the proposed sites
- (6) An environmental analysis of each of the proposed sites
- (7) A cost analysis of the plant to be constructed on each of the proposed sites

There is a similar list of eight specific information requirements for a corridor application, which appears to be a more likely requirement. To develop a satisfactory position, the utility typically spends 1 to 1-1/2 years and \$50 to 100 thousand dollars.

The Minnesota Environmental Quality Council must then act according to Minnesota Statute, Sec. 116C.01.

Summary of Minnesota State Regulations

A significant body of Minnesota state regulations can easily be applied to a WECS installation. The dispersed nature of and broad area coverage of WECS applications would present a major obstacle to hardware implementation, if Minnesota law were strictly interpreted, which is a likely event in a state with active citizen participation. The nature of the interaction of the state regulation, the MEQC, and affected citizens is illustrated by the aforementioned newspaper report.

The laws and regulations have been designed to strictly control large nuclear and fossil plant construction. They impose an unknown obstacle and threat to a major installation of WECS. This is a significant potential problem.

MP&L interpreted that a 50-megawatt site was not within the state's "large" plant regulation. This is a system design restriction and an untested assumption with respect to state regulations.

ENVIRONMENTAL QUALITY

Consideration has been given as to how WECS will relate to the environment of the case study utility and to the policy or regulation related to environmental impact. Minnesota has a very structured interaction to policy or regulation which includes citizens' participation. State regulations for the primary issues related to power plant siting, and transmission line routing have already been discussed. Additional procedures and regulations regarding environmental impact are applicable. They take the form of the environmental impact statement process, the critical areas planning process, and environmental standards for subdivision of land. The state position in this matter is controlled by the Environmental Quality Council, which has the overall responsibility for protecting the environment.

Membership on the EQC consists of 12 persons:

- The heads of seven state agencies: Agriculture, Energy, Health, Highways, Natural Resources, Pollution Control, and State Planning
- A representative of the Governor's office
- Four citizens selected from the Citizens' Advisory Committee

The EQC also has a Citizens' Advisory Committee to assure citizen participation in the activities and decisions of the EQC. Its 11 members are appointed by the Governor.

The council derives its function from the Environmental Policy Act; Chapter 412 Section 2 (116D.02) Declaration of State Environmental Policy.

The implications of WECS to the formal policy and regulation environment is currently under study by a task force on energy alternates directed by the Minnesota Energy Agency. The committee on Wind Energy is headed by the principal investigator of this study. The general impression is that an atmosphere of positive cooperation and constructive participation exists toward WECS. All public contacts in the state have resulted in a neutral or supportive reaction.

A review of environmental impact implications has been performed to identify the problems associated with introducing WECS into the case study area. A comprehensive description of the total relationship of any power plant to the Minnesota environment has been developed by the Environmental Quality Council (Table 9-1). The results of applying these criteria to nuclear and fossil plants siting was completed in 1975¹. The environmental factors considered in the 1975 study can be related to WECS. The following is a general discussion of the environmental impact areas.

Generally, environmental control relates to exclusion and constraints. Exclusion prohibits the construction of power generation plants and avoidance areas which guide the defining of the priorities of remaining areas. Avoidance areas can be graded by environmental constraints which have been prioritized for fossil fuel plants into "constraint weights" (Table 9-2). The first full application of environmental exclusion and constraints for siting resulted in a very restrictive composite map in which all current major power plants are located in prohibitive areas.

¹"Minnesota Environmental Quality Council Power Plant Siting Program," Inventory 1975 Candidate Areas for Large Electric Power Generating Plants (LEPGP), April 25, 1975.

Table 9-1. Information Processing Diagram

Table 9-2. Fossil Fuel Environmental Constraint Weights

<u>Weights</u>	
6.0	Scenic Timber
5.8	Buffer Zones for Visual and Audible Impingement on Recreation Areas - 2 mile
*	Bald Eagle Nesting Range
*	Federal Waterfowl Production Areas
5.1	Exceptional Game Habitat
*	Rare Flora
5.0	Agricultural Lands of High Productivity
*	Lakes
*	Areas Tributary to BWCA or Voyageurs N. P.
*	Prairie Marshes
4.8	Prairie Remnant
4.4	Iron Deposits
4.2	Copper-Nickel Deposits
*	Areas Tributary to National or State Wild, Scenic, and Recreational Rivers
*	Wild Rice Marshes (Artificial)
3.9	Areas of Greatest Local Relief
3.6	Indian Reservations
3.4	Forest Lands of High Productivity
*	Timber Wolf Range (Common)
3.3	Other Scientific and Natural Areas
*	Prairie Chicken Range
*	Peregrine Falcon Range
3.1	Buffer Zones for Visual and Audible Impingement on Recreation Areas - 2.1 - 5 mile
2.9	National Forests
2.8	Glacial Features
2.7	Areas Tributary to Trout Streams
2.7	Agricultural Lands of Medium Productivity
*	State Forests
1.6	Forest Lands of Medium Productivity
1.2	Military Reservations

Environmental Factors

The following environmental factors have been reviewed for applicability to WECS installations.

1) Exclusion Criteria - (MEQC 74) --

- (aa) "No LEPGP shall be sited in violation of any federal or state law or regulation. No area shall be considered in which a LEPGP is not licensable by all appropriate state and federal government agencies." Applicable to an unknown extent due to the lack of definition of legal aspects of WECS.
- (bb) "The following land areas shall be excluded: national parks; national historic sites and landmarks; national historic districts; national monuments; national wilderness areas; national wildlife refuges; national, wild, scenic, and recreational riverways; state wild, scenic, and recreational rivers and their land use districts; state parks, Nature Conservancy preserves; state scientific and natural areas; state wilderness areas; and any area designated a LEPGP exclusion area by the Council." Fully applicable and eliminates many potential site areas.
- (cc) Not Applicable (Use of water supply)
- (dd) Not Applicable (Water drainage)
- (ee) Not Applicable (Water transport)

2) Exclusion Criteria - State Regulations: Lakes and Airports -- WECS cannot be constructed on the surfaces of lakes or in the vicinity of major airports.

3) Exclusion Criteria - State Regulation: Air Quality -- Not Applicable.

4) Avoidance Areas --

Avoidance Areas -- designated trout streams and state wildlife management areas. WECS may be excluded under current practice, but would seem to have little impact on the functions being protected.

Avoidance Area -- State Historic Sites and Districts
Minor or no applicability.

Avoidance Area -- Recreational Areas and Rivers
Approval will be needed to encroach on these environmental areas.

Avoidance Area -- County and Metropolitan Parks
Little Applicability.

Avoidance Area -- Drainage Basins
Not applicable.

5) Environmental Constraints --

Environmental Constraints -- Population

Large Indian Reservations exist in MP&L's service area, which probably cannot be considered for WECS installation. Over two million acres of land are involved. The Red Lake Reservation of 573,725 acres is a closed reservation, having its own legal code, law enforcement and judiciary.

Environmental Constraint -- Rare, unique or unusual land forms

WECS would encroach upon a state preference to retain rare, unique or important land forms.

Environmental Constraint -- Rare, unusual, unique vegetative types

This is an area related to scenic timbre, rare flora, prairie remnants and national forests. It is not clear how WECS would be restricted by this environmental concern.

Environmental Constraint -- Exceptional wildlife habitat

The Project 80 Inventory of 1970 identified areas to be preserved as those containing prairie chickens, ducks and geese, bald eagles nesting, moose, sandhill cranes, and heron rookeries. Only 1,000 acres are reserved for federally protected waterfowl but over 100,000 acres are reserved for other elements in this classification. This classification also includes trout streams and their tributaries. It is doubtful that WECS would affect any of the habitats of any exceptional wildlife.

Environmental Constraint - Public Recreational Areas

The EQC would like to minimize visual and audible disruptions to recreation. This eliminates a great deal of North Minnesota for WECS installations.

Environmental Constraint -- Valuable and Productive Land

Iron and copper-nickel deposits occupy the Laurentian Divide area, which is the primary site source for WECS in the taconite area. It may be necessary to consider WECS as having mobile installations to avoid conflict in this area.

Other lower priority environmental constraints which probably have no WECS relationship:

- Soil of high potential forest productivity
- Soil areas of agricultural productivity
- Artificial wild rice paddies
- Fuel delivery opportunities

The total impact of key environmental factors has been studied to identify the affect of the above constraints on siting WECS. Figure 9-2 summarizes the findings of the survey. A serious problem appears to be that over one-half of the area appears to be excluded or constrained from WECS siting. Note the isopleths on this figure. They were obtained from a Sandia Report. For the State of Minnesota as a whole, the western side of the state has the fortunate combination of a relatively high wind potential and unrestricted land.

FINDINGS AND RECOMMENDATION

The environmental and social factors of siting a wind energy system are highly dependent on the statutes and local ordinances of a particular locale. While generic studies may help identify some of the general issues, the case-study approach provides much more substantive insight into the problem.

This study revealed that for the State of Minnesota the laws have been specifically written for large power plants (50 MW or greater) and high voltage transmission lines (200 KV or greater). Below these levels, however, there is much room for interpretation. While there is little precedence for wind energy, per se, there is reason to believe that the current spirit of public participation and involvement will draw attention to many WECS issues before they are resolved.

Figure 9-2. Minnesota Wind Energy Summary

Recommendation: Wind energy R&D should be a highly visible activity. The public should be kept informed and encouraged to react to the prospect of a significant number of wind turbines for a particular area. To this end, the case study approach could be carried through to the county and local levels for a few specific studies.

In parallel with these recommended case studies, answers must still be sought for the many environmental questions that undoubtedly will continue to be raised.

SECTION X
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APPENDIX A

WIND DATA SITE TO WIND TURBINE SITE TRANSFORMATION

Figure A1 shows a regional grid made by simply placing graph paper over a map of northern Minnesota.

Wind Data Sites

1. Fargo
2. International Falls
3. Duluth
4. St. Cloud
5. Cohasset
6. Aurora/Hoyt Lakes

Turbine Sites

1. Park Rapids
2. Hibbing
3. Virginia
4. Winton
5. Sandstone

In the following sample computation the wind data from Cohasset and Aurora will not be used. The transformation of c's at the wind data sites to the Park Rapids turbine site would be as follows:

$$C_{t1} = D_{11}C_1 + D_{12}C_2 + D_{13}C_3 + D_{14}C_4 \quad (A1)$$

$$D_{11} = \frac{1}{d_{11} \left[\frac{1}{d_{11}} + \frac{1}{d_{12}} + \frac{1}{d_{13}} + \frac{1}{d_{14}} \right]} = .352 \quad (A2)$$

For purposes of programming use the form

$$D_{11} = \frac{d_{12}d_{13}d_{14}}{d_{12}d_{13}d_{14} + d_{11}d_{13}d_{14} + d_{11}d_{12}d_{14} + d_{11}d_{12}d_{13}} \quad (A3)$$

$$\text{Let } D = d_{12}d_{13}d_{14} + d_{11}d_{13}d_{14} + d_{11}d_{12}d_{14} + d_{11}d_{12}d_{13} \quad (A4)$$

Figure A-1. REGIONAL GRID FOR WIND TRANSFORMATION

Then

$$C_{t1} = \left(\frac{d_{12}d_{13}d_{14}}{D} \right) C_{11} + \left(\frac{d_{11}d_{13}d_{14}}{D} \right) C_{12} + \left(\frac{d_{11}d_{12}d_{14}}{D} \right) C_{13} + \left(\frac{d_{11}d_{12}d_{13}}{D} \right) C_{14} \quad (A5)$$

Using the d_{ij} values shown in Figure A1,

$$C_{t1} = .352C_{11} + .194C_{12} + .194C_{13} + .26C_{14} \quad (A6)$$

Note that $.352 + .194 + .194 + .26 = 1.0$ (A7)

i.e., the sum of the weights equals unity.

Using this weighted nearest neighbor transformation, the mean wind speeds appearing in Table 3-2 for the wind data sites Fargo, International Falls, Duluth, and St. Cloud (St. Cloud data adjusted to 20 feet anemometer height using one-sixth power law) were transformed to the WTG area sites. The resulting calculated mean winds speeds are tabulated in Table A-1.

Table A-1. Calculated Mean Wind Speeds at WTG Area Sites

WTG Area Sites	Calculated Mean Wind Speeds			Assumed Anemometer Height		Site Elevation Range
	Knots	MPH	$\frac{\text{Meter}}{\text{Sec}}$	Meters	Feet	
Park Rapids	8.9	10.3	4.6	6.1	20	1400 - 1530
Hibbing	8.7	10.0	4.5	6.1	20	1350 - 1775
Virginia	8.7	10.0	4.5	6.1	20	1375 - 1930
Ely/Winton	8.7	10.0	4.5	6.1	20	1400 - 1550
Sandstone	8.5	9.9	4.4	6.1	20	1030 - 1140

APPENDIX B

A METHOD FOR EVALUATING OUTPUT WIND POWER
CHARACTERISTICS FROM INPUT WIND STATISTICS

Dr. C. G. Justus

The method discussed here is based on certain assumptions with regard to the wind frequency distribution and the wind generator operating characteristics. These assumptions are: 1) The wind frequency distribution $p(V)$, which gives the fraction of time over the year (or other time interval) during which the wind speed has a value V (within certain small limits dV), is a Weibull distribution, characterized by two parameters, the scale parameter c and the shape parameter k . 2) The wind generator has a given value of cut-in speed V_0 , rated speed V_1 , and feathering speed V_2 and rated power P_r , which uniquely determine the output power as described by equation (B-1), given below.

The variable (instantaneous) output power $P(V)$ as a function of the instantaneous wind speed V is, from assumption 2, given by

$$P(V) = \begin{cases} 0 & V < V_0 \\ A + BV + CV^2 & V_0 \leq V < V_1 \\ P_r & V_1 \leq V < V_2 \\ 0 & V > V_2 \end{cases} \quad (B1)$$

where the coefficients A , B , and C are determined by the two conditions

$$P(V_0) = A + BV_0 + CV_0^2 = 0 \quad (B2)$$

$$P(V_1) = A + BV_1 + CV_1^2 = P_r \quad (B3)$$

and the assumption that

$$P(V_c) = A + BV_c + CV_c^2 = P_c \quad (B4)$$

where the wind speed V_c is defined as $V_c = (V_o + V_1)/2$ and the power value P_c is taken to be

$$P_c = P_r (V_c/V_1)^3 \quad (B5)$$

From the conditions (B-2) through (B-4), the values of A, B, and C are determined to be

$$B = [P_r(V_c^2 - V_o^2) - P_c(V_1^2 - V_o^2)]/D \quad (B6)$$

$$C = [P_c(V_1 - V_o) - P_r(V_c - V_o)]/D \quad (B7)$$

$$A = -BV_o - CV_o^2 \quad (B8)$$

where D is given by

$$D = (V_1 - V_o)(V_c^2 - V_o^2) - (V_c - V_o)(V_1^2 - V_o^2) \quad (B9)$$

Figure B.1 shows the design turbine power curve for the NASA Plumbrook unit (Puthoff and Sirocky, 1974), which has the characteristics $V_o = 3.6$ m/s (8 mph), $V_1 = 8.0$ m/s (18 mph), $V_2 = 26.8$ m/s (60 mph), $P_r = 100$ kW (generator output). The dashed curve in Figure B-1 is the approximation to the actual curve, by equation (B-1). The approximate curve is seen to be identical with the actual curve above the speed V of about 12 mph. This form of output curve is obviously a simplified

Figure B-1. OPERATING CHARACTERISTICS (TURBINE POWER VERSUS WIND SPEED) FOR NASA'S PLUMBROOK UNIT. CUT-IN SPEED V_0 IS 3.6 m/s (8 mph). RATED SPEED V_1 IS 8.0 m/s (18 mph). RATED POWER (AT THE GENERATOR OUTPUT) IS 100kW.

parameterization of an actual output curve from a real wind generator system, but should be accurate for the present design purposes.

The monthly average output power $\bar{P}$ can be evaluated by integrating $P(V)$, from equation (B-1), weighted by the probability $p(V)$ for observing the speed V . Thus $\bar{P}$ is given by

$$\bar{P} = \int_0^{\infty} P(V) p(V) dV = \int_{V_0}^{V_1} (A + BV + CV^2) p(V) dV \quad (B10)$$

$$+ \int_{V_{1r}}^{V_2} P_1 p(V) dV$$

where, from assumption 1, above, the probability distribution $p(V)$ is given by

$$p(V)dV = (k/c) (V/c)^{k-1} \exp -(V/c)^k dV \quad (B11)$$

Through a change of variables $x = (V/c)^k$, $x_0 = (V_0/c)^k$, $x_1 = (V_1/c)^k$, and $x_2 = (V_2/c)^k$, equation (B-10) becomes

$$\bar{P} = AP_{01} + Bc \int_{x_0}^{x_1} x^{1/k} e^{-x} dx + Cc^2 \int_{x_0}^{x_1} x^{2/k} e^{-x} dx + P_{12} \quad (B-12)$$

where P_{01} and P_{12} are the cumulative probabilities

$$P_{01} = \int_{V_0}^{V_1} p(V) dV = e^{-x_0} - e^{-x_1} \quad (B-13)$$

$$P_{12} = \int_{V_1}^{V_2} p(V) dV = e^{-x_1} - e^{-x_2} \quad (B-14)$$

The integrals in (B-12) must be evaluated by series approximation

$$\int_{x_0}^{x_1} x^{n/k} e^{-x} dx = \{ x^{n/k} \left[x(1 + n/k)^{-1}/0! - x^2(2 + n/k)^{-1}/1! + x^3(3 + n/k)^{-1}/2! - x^4(4 + n/k)^{-1}/3! + \dots \right] \} \Big|_{x_0}^{x_1} \quad (B-15)$$

where n takes on the values of 1 or 2 for the integrals appearing in (B-12).

From the average output power $\bar{P}$, evaluated by (B-12), various factors of interest can be easily evaluated. The plant factor F_p , the ratio of the average output power to the rated power is given by

$$F_p = \bar{P}/P_r \quad (B-16)$$

The energy pattern factor f is defined as the ratio of the average available power to the power available in the mean wind, or numerically, in terms of the plant factor F , the energy pattern factor is given by

$$f = (V_1^3 / \bar{V}^3) F_p = \frac{\bar{P}}{P_m} \quad (B-17)$$

where $\bar{V}$ is the mean wind speed, either evaluated directly from the wind data, or estimated from the previously determined Weibull parameters by the relation

$$\bar{V} = \int_0^{\infty} V_p(V) dV = c \int_0^{\infty} x^{1/k} e^{-x} dx = (c/k) \Gamma(1/k) \quad (B-18)$$

The available power P_m in the mean wind is defined by

$$P_m = P_r (\bar{V}/V_1)^3 \quad (B-19)$$

Thus P_m is the available power in the mean wind assuming the same system efficiency at $\bar{V}$ as it has at the rated speed V_1 . The annual specific energy output in kW hours per rated kW, $\bar{E}$, is given by

$$\bar{E} = 8766 \bar{P} / P_r = 8766 F_p \quad (B-20)$$

and, of course, the actual annual energy output E , in kW hours would be

$$E = 8766 \bar{P} \quad (B-21)$$

A computer program has been written which takes input values of cut-in wind speed (V_0), rated wind speed (V_1), feathering wind speed (V_2), rated power (P_r), and for each input value of wind frequency scale parameter (c) and shape parameter (k) calculates, via the above equations, output values for the following: plant factor (F_p), arithmetic mean wind speed ($\bar{V}$), available power in the mean wind (P_m), average available power ($\bar{P}$), energy pattern factor (f), the annual specific energy output in kW hours per rated kW ($\bar{E}$), and the annual energy output in kW hours (E). The program uses an efficient method for computing an accurate numerical approximation to the series

expansion of the integral in equation (B-15).

Figure B.2 shows a plot of plant factor values computed by this program for a wind generator having the operating characteristics of the NASA Plumbrook unit ($V_0 = 8$ mph, $V_1 = 18$ mph). Qualitatively the results in Figure B.2 may be explained as follows: at high mean wind speeds (high c values) a small variance (high k value) is desirable to limit the wind speeds to only high values near the (high) mean (where the output will be at or near the rated output); at low mean wind speeds (low c values) a large variance (low k value) is desirable to allow some possibility of high wind speeds occurring.

Figure B-2 PARAMETRIC VARIATION OF PLANT FACTOR F_p
 (RATIO OF AVERAGE OUTPUT POWER TO RATED
 POWER) VERSUS WEIBULL SCALE FACTOR c AND
 SHAPE FACTOR k

APPENDIX C

SAMPLE WECS ANALYSIS PROGRAM OUTPUT

This appendix contains a sample output listing from the WECS array analysis program. The sets of output are defined below:

I. Monthly turbine site outputs per unit:

1. C: Hub height Weibull velocity coefficient (meters per second)
2. k: Hub height Weibull shape parameter (dimensionless)
3. VBAR: Mean hub height wind speed (meters per second)
4. PBAR: Mean output power (kilowatts)
5. PMEAN: Available power in the mean wind (kilowatts)
6. ENPAT: Energy pattern factor ($PBAR \div PMEAN$)
7. THEPOW: Theoretical power in the wind (kilowatts)
8. EFFIC: Percent power extraction efficiency
 $(PBAR \div THEPOW)$
9. EBAR: Specific energy output, denoted in text as E_{sp}
 $(E \div \text{Rated Power} \dots \text{KWH per rated KW})$
10. E: Total energy output (KWH)
11. PF: Plant capacity factor ($E \div E_{max}$)

12. SIGMA: Standard deviation of monthly plant capacity factor from annual mean ($\text{SQRT } |PF^2 - PF_{\text{MEAN}}^2|$)
13. TOP: Total hours of operation

Sets of data are computed for each area turbine site: Park Rapids, Hibbing, Virginia, Winton, and Sandstone.

II. Monthly Array Outputs

The cumulative percent probability of array power output (per unit) for 100 percent, 40 percent, and zero array diversity (correlation) factor.

- III. Monthly array output distributions for 40 percent array diversity factor wherein each monthly distribution is an average over the 10-year period.
- IV. Monthly array mean powers averaged over the 10-year period, P_{ARRAY} (KW per unit).
- V. Monthly array energy output averaged over the 10-year period, E_{ARRAY} (MWH).

BOEING 1125KW UNIT

CUTIN(M/S)	RATED(M/S)	FEAING(M/S)	POWER(KW)	AREA(SM)
4.6	10.5	26.8	1125.0	5102.0

0.0	29.4	50.6	252.1	318.4	827.7	1068.0	1125.0	1125.0	1125.0
-----	------	------	-------	-------	-------	--------	--------	--------	--------

KW POWER INTERVALS
FOR ARRAY ANALYSIS

ARRAY AVERAGE (10 YEARS)

C	K
7.774	2.646

I. MONTHLY TURBINE SITE OUTPUTS PER UNIT

***** PARK RAPIDS *****														
C.	K	VBAR	PBAR	PMEAN	ENPAT	THEPOW	EFFIC	EBAR	E	PF	SIGMA	TOP	YEAR	MO
7.98	2.55	7.1	422.34	345.29	1.223	1727.98	24.44	279.31	314221.0	0.375	0.361	581.8	1965	1 JAN
8.62	2.56	7.7	494.69	435.69	1.135	2174.79	22.75	295.50	332434.2	0.440	0.380	549.8	1965	2 FEB
8.15	2.49	7.2	441.46	367.12	1.203	1866.15	23.66	291.95	328448.7	0.392	0.369	585.0	1965	3 MAR
8.12	2.79	7.2	440.28	367.55	1.198	1732.38	25.41	281.78	317001.9	0.391	0.355	586.7	1965	4 APRIL
9.04	2.96	8.1	553.19	510.63	1.083	2321.13	23.83	365.84	411571.3	0.492	0.373	650.1	1965	5 MAY
7.94	2.68	7.1	417.19	341.20	1.223	1651.08	25.27	267.00	300377.2	0.371	0.353	570.7	1965	6 JUNE
7.40	2.56	6.6	353.43	275.49	1.283	1374.60	25.71	233.74	262954.8	0.314	0.334	553.2	1965	7 JULY
6.61	2.27	5.9	269.89	194.77	1.386	1065.68	25.33	178.49	200801.3	0.240	0.307	479.2	1965	8 AUGUST
7.54	2.56	6.7	370.92	292.07	1.270	1456.67	25.46	237.39	267064.0	0.330	0.342	543.2	1965	9 SEPT
8.53	2.67	7.6	487.25	424.00	1.149	2052.40	23.74	322.23	362510.7	0.433	0.373	614.3	1965	10 OCT
8.35	2.42	7.4	462.94	394.43	1.174	2051.31	22.57	296.28	333313.4	0.411	0.379	568.3	1965	11 NOV
9.01	2.97	8.0	549.92	505.71	1.087	2296.88	23.94	363.68	409139.3	0.489	0.372	649.5	1965	12 DEC
8.11	2.62	7.2	438.63	371.16	1.201	1814.26	24.34	3413.19	3839838.0	0.390	0.358	6931.8	1965	13 AVERAGE OR TOTAL
8.37	2.73	7.4	468.96	400.60	1.171	1912.06	24.53	310.14	348907.6	0.417	0.366	612.2	1966	1
7.93	2.76	7.1	416.02	341.19	1.219	1617.38	25.72	248.50	279564.7	0.370	0.349	538.0	1966	2
9.19	2.46	8.2	549.89	526.27	1.045	2702.09	20.35	363.66	409119.9	0.489	0.393	620.0	1966	3
9.17	2.86	8.2	563.91	530.22	1.064	2458.68	22.94	360.90	406015.9	0.501	0.378	626.8	1966	4
8.83	2.77	7.9	522.71	471.10	1.110	2231.39	23.43	345.68	388895.6	0.465	0.376	631.0	1966	5
8.20	2.82	7.3	450.39	379.12	1.188	1773.56	25.39	288.25	324280.1	0.400	0.357	592.2	1966	6
7.51	2.65	6.7	364.88	288.46	1.265	1404.83	25.97	241.31	271473.1	0.324	0.335	566.2	1966	7
6.83	2.43	6.1	289.30	216.12	1.339	1119.50	25.84	191.32	215237.5	0.257	0.309	507.6	1966	8
7.09	2.37	6.3	321.36	241.04	1.333	1274.23	25.22	205.67	231379.2	0.286	0.329	502.7	1966	9
8.77	2.61	7.8	512.56	460.06	1.114	2263.88	22.64	338.97	381342.5	0.456	0.381	618.1	1966	10
7.94	2.67	7.1	418.02	342.05	1.222	1656.11	25.24	267.53	300973.0	0.372	0.353	570.8	1966	11
7.56	2.51	6.7	373.18	293.13	1.273	1482.85	25.17	246.79	277643.5	0.332	0.345	558.0	1966	12
8.12	2.64	7.2	437.60	374.11	1.195	1824.71	24.37	3408.74	3834832.6	0.389	0.356	6943.6	1966	13

9.04	2.79	8.0	547.20	506.85	1.080	2389.92	22.90	361.88	407113.7	0.486	0.379	639.0	1967	1
8.72	2.76	7.8	510.23	453.76	1.124	2152.55	23.70	304.77	342871.3	0.454	0.374	566.2	1967	2
8.92	3.06	8.0	542.36	493.00	1.100	2201.69	24.63	358.68	403512.4	0.482	0.367	652.3	1967	3
9.63	2.99	8.6	618.24	616.97	1.002	2792.02	22.14	395.67	445133.7	0.550	0.378	645.0	1967	4
8.76	2.71	7.8	513.95	459.92	1.117	2209.38	23.26	339.89	382377.7	0.457	0.377	624.7	1967	5
7.57	2.48	6.7	374.71	293.91	1.275	1501.45	24.96	239.81	269789.8	0.333	0.347	537.9	1967	6
7.34	2.52	6.5	346.66	268.14	1.293	1353.79	25.61	229.26	257915.5	0.308	0.333	546.2	1967	7
7.37	2.70	6.6	347.76	274.11	1.269	1318.62	26.37	229.99	258734.8	0.309	0.325	562.6	1967	8
7.73	2.66	6.9	392.19	315.18	1.244	1529.71	25.64	251.00	282379.9	0.349	0.345	560.2	1967	9
8.66	2.71	7.7	502.81	444.31	1.132	2130.10	23.60	332.52	374089.0	0.447	0.374	621.8	1967	10
8.79	3.02	7.9	525.32	470.51	1.116	2117.95	24.80	336.20	378230.5	0.467	0.366	624.9	1967	11
8.52	2.85	7.6	489.75	425.96	1.150	1979.77	24.74	323.89	364375.1	0.435	0.365	626.4	1967	12
8.42	2.77	7.5	475.93	418.55	1.159	1973.08	24.36	3703.58	4166523.5	0.423	0.361	7207.2	1967	13

8.50	2.83	7.6	486.13	421.54	1.153	1969.56	24.68	321.49	361678.0	0.432	0.366	623.8	1968	1
8.53	2.60	7.6	485.24	422.08	1.150	2079.93	23.33	300.20	337725.0	0.431	0.375	549.9	1968	2
8.85	2.76	7.9	524.92	474.34	1.107	2248.41	23.35	347.15	390538.6	0.467	0.376	631.4	1968	3
9.39	2.98	8.4	593.23	573.18	1.035	2596.54	22.85	379.67	427126.2	0.527	0.376	639.3	1968	4
8.50	2.65	7.6	483.38	419.13	1.153	2039.18	23.70	319.68	359635.3	0.430	0.373	611.6	1968	5
7.66	2.62	6.8	384.30	306.37	1.254	1505.42	25.53	245.95	276698.3	0.342	0.344	553.3	1968	6
7.77	2.55	6.9	397.60	318.62	1.248	1593.72	24.95	262.95	295813.3	0.353	0.352	571.9	1968	7
7.60	2.53	6.7	377.43	297.72	1.268	1498.31	25.19	249.61	280808.7	0.335	0.346	561.5	1968	8
7.38	2.60	6.6	350.65	274.15	1.279	1351.10	25.95	224.42	252468.2	0.312	0.331	537.9	1968	9
8.18	2.63	7.3	446.31	373.35	1.195	1826.36	24.44	295.16	332057.2	0.397	0.364	597.3	1968	10
7.84	2.72	7.0	405.19	329.30	1.230	1577.45	25.69	259.32	291740.3	0.360	0.347	569.3	1968	11
8.41	2.38	7.5	468.82	402.84	1.164	2122.94	22.08	310.04	348798.8	0.417	0.382	586.3	1968	12
8.22	2.65	7.3	450.27	384.38	1.186	1867.41	24.31	3515.63	3955087.9	0.400	0.361	7033.5	1968	13

8.50	2.73	7.6	484.94	420.53	1.153	2006.94	24.16	320.70	360792.3	0.431	0.370	617.4	1969	1
7.04	2.36	6.2	316.36	236.37	1.338	1253.34	25.24	188.97	212594.6	0.281	0.327	466.0	1969	2
7.51	2.50	6.7	367.87	287.76	1.278	1459.22	25.21	243.29	273697.9	0.327	0.343	554.9	1969	3

8.32	2.64	7.4	462.27	392.49	1.178	1916.79	24.12	295.85	332832.1	0.411	0.368	584.0	1969	4
8.48	2.90	7.6	485.14	420.10	1.155	1933.47	25.09	320.84	360941.9	0.431	0.362	628.0	1969	5
8.12	2.62	7.2	438.62	364.33	1.204	1789.15	24.52	280.71	315804.0	0.390	0.363	574.3	1969	6
7.12	2.51	6.3	321.33	245.53	1.309	1241.13	25.89	212.51	239072.4	0.286	0.322	533.1	1969	7
7.90	2.53	7.0	413.04	334.77	1.234	1684.89	24.51	273.16	307300.0	0.367	0.359	576.5	1969	8
7.65	2.70	6.8	382.12	306.01	1.249	1471.94	25.96	244.55	275124.2	0.340	0.339	559.0	1969	9
8.10	2.93	7.2	437.74	366.25	1.195	1676.17	26.12	289.49	325680.1	0.389	0.348	614.8	1969	10
8.30	2.92	7.4	463.70	394.80	1.175	1810.82	25.61	296.77	333865.2	0.412	0.356	602.4	1969	11
7.33	2.62	6.5	343.49	268.04	1.282	1316.56	26.09	227.16	255558.3	0.305	0.327	553.5	1969	12
7.86	2.66	7.0	409.72	336.42	1.229	1630.04	25.21	3194.01	3593263.1	0.364	0.349	6863.7	1969	13

7.76	2.82	6.9	395.32	321.26	1.231	1504.07	26.28	261.44	294117.4	0.351	0.338	591.9	1970	1
8.71	2.75	7.8	509.68	453.14	1.125	2153.75	23.66	304.45	342502.9	0.453	0.374	565.6	1970	2
7.59	2.52	6.7	376.84	296.98	1.269	1497.61	25.16	249.22	280367.4	0.335	0.346	560.6	1970	3
9.45	3.08	8.5	604.06	586.84	1.029	2611.33	23.13	386.60	434922.7	0.537	0.373	645.9	1970	4
9.30	3.16	8.3	590.06	560.75	1.052	2461.64	23.97	390.23	439003.5	0.524	0.369	667.9	1970	5
8.26	2.81	7.4	456.87	386.43	1.182	1812.82	25.20	292.40	328945.2	0.406	0.359	593.5	1970	6
7.66	2.54	6.8	384.85	305.42	1.260	1531.02	25.14	254.51	286328.7	0.342	0.348	565.9	1970	7
7.03	2.37	6.2	314.28	235.11	1.337	1239.64	25.35	207.84	233823.7	0.279	0.325	516.4	1970	8
8.06	2.82	7.2	432.95	359.86	1.203	1684.92	25.70	277.09	311725.6	0.385	0.351	586.2	1970	9
8.64	2.88	7.7	503.71	443.57	1.136	2049.69	24.57	333.12	374758.2	0.448	0.367	632.2	1970	10
7.99	2.43	7.1	423.07	345.10	1.226	1788.02	23.66	270.77	304612.5	0.376	0.367	554.2	1970	11
7.87	2.45	7.0	410.41	330.89	1.240	1705.71	24.06	271.42	305344.3	0.365	0.362	568.8	1970	12
8.19	2.72	7.3	450.17	385.45	1.191	1836.68	24.66	3499.07	3936452.1	0.400	0.357	7049.1	1970	13

8.03	2.85	7.2	428.89	355.88	1.205	1655.89	25.90	283.64	319094.9	0.381	0.349	606.3	1971	1
8.45	2.69	7.5	478.06	412.03	1.160	1986.81	24.06	285.56	321254.1	0.425	0.370	553.1	1971	2
8.27	2.97	7.4	459.80	390.65	1.177	1775.58	25.90	304.08	342091.2	0.409	0.353	624.1	1971	3
9.08	2.85	8.1	553.64	514.63	1.076	2392.88	23.14	354.33	398618.7	0.492	0.377	623.5	1971	4
8.12	2.89	7.2	440.73	369.00	1.194	1702.96	25.88	291.47	327899.5	0.392	0.351	613.0	1971	5
6.59	2.28	5.8	268.04	193.68	1.384	1056.01	25.38	171.54	192987.7	0.238	0.305	463.6	1971	6
7.40	2.46	6.6	355.44	274.84	1.293	1410.63	25.20	235.07	264449.4	0.316	0.340	545.5	1971	7

6.99	2.52	6.2	304.42	231.49	1.315	1167.68	26.07	201.32	226485.8	0.271	0.313	524.8	1971	8
7.31	2.52	6.5	343.35	265.32	1.294	1336.87	25.68	219.75	247214.2	0.305	0.332	527.7	1971	9
7.95	2.51	7.1	418.56	340.65	1.229	1724.55	24.27	276.81	311408.0	0.372	0.362	577.1	1971	10
8.18	2.48	7.3	444.73	371.05	1.199	1893.23	23.49	284.63	320204.7	0.395	0.371	566.3	1971	11
7.89	2.91	7.0	410.90	338.23	1.215	1555.28	26.42	271.74	305712.9	0.365	0.340	603.9	1971	12
7.85	2.66	7.0	408.88	338.12	1.228	1638.20	25.12	3179.93	3577421.1	0.363	0.347	6828.9	1971	13
9.00	2.93	8.0	546.77	502.12	1.089	2298.51	23.79	361.60	406798.7	0.486	0.373	646.6	1972	1
7.83	2.52	7.0	405.47	326.54	1.242	1644.69	24.65	250.85	282204.2	0.360	0.356	517.7	1972	2
7.90	2.59	7.0	412.88	335.41	1.231	1659.53	24.88	273.05	307181.9	0.367	0.356	581.4	1972	3
7.81	2.78	7.0	401.66	326.75	1.229	1543.96	26.01	257.06	289193.1	0.357	0.343	572.2	1972	4
6.94	2.30	6.1	306.12	225.68	1.356	1220.01	25.09	202.45	227755.8	0.272	0.325	504.6	1972	5
7.06	2.48	6.3	314.52	238.67	1.318	1217.96	25.82	201.29	226451.7	0.280	0.320	509.5	1972	6
5.95	2.22	5.3	199.98	142.12	1.407	791.36	25.27	132.25	148783.6	0.178	0.262	423.0	1972	7
6.26	2.19	5.5	235.43	165.76	1.420	933.16	25.23	155.70	175160.6	0.209	0.289	447.6	1972	8
7.55	2.52	6.7	371.91	292.03	1.274	1474.55	25.22	238.02	267775.7	0.331	0.344	540.0	1972	9
7.58	2.61	6.7	374.04	296.22	1.263	1457.61	25.66	247.36	278283.0	0.332	0.340	566.9	1972	10
6.82	2.52	6.1	284.50	215.52	1.320	1085.87	26.20	182.08	204837.4	0.253	0.302	497.3	1972	11
7.13	2.30	6.3	328.13	244.97	1.339	1326.08	24.74	217.00	244125.2	0.292	0.336	516.4	1972	12
7.32	2.50	6.5	348.45	275.98	1.291	1387.77	25.21	2718.71	3058550.9	0.310	0.329	6323.1	1972	13
7.06	2.38	6.3	317.01	237.63	1.334	1250.99	25.34	209.65	235854.9	0.282	0.326	518.3	1973	1
7.50	2.60	6.7	364.96	287.38	1.270	1416.88	25.76	218.00	245251.3	0.324	0.337	507.8	1973	2
7.05	2.59	6.3	310.35	238.72	1.300	1180.52	26.29	205.24	230896.9	0.276	0.312	534.6	1973	3
8.36	2.93	7.5	471.36	403.70	1.168	1846.40	25.53	301.67	339381.3	0.419	0.357	605.5	1973	4
7.90	2.74	7.0	412.36	336.99	1.224	1607.31	25.66	272.71	306798.1	0.367	0.349	592.4	1973	5
7.45	2.62	6.6	358.49	281.81	1.272	1382.38	25.93	229.43	258113.3	0.319	0.333	542.8	1973	6
6.99	2.40	6.2	308.47	230.86	1.336	1208.46	25.53	204.00	229503.4	0.274	0.321	515.3	1973	7
6.22	2.25	5.5	227.97	162.84	1.400	895.72	25.45	150.76	169610.2	0.203	0.281	448.7	1973	8
6.85	2.51	6.1	288.89	218.41	1.323	1106.00	26.12	184.89	208003.8	0.257	0.305	498.1	1973	9
7.62	2.64	6.8	379.49	302.09	1.256	1476.26	25.71	250.97	282341.1	0.337	0.341	571.4	1973	10
7.48	2.74	6.7	360.71	286.91	1.257	1366.02	26.41	230.85	259710.2	0.321	0.328	553.5	1973	11

7.90 2.64

7.55	2.60	6.7	371.46	293.55	1.265	1447.56	25.66	245.66	276364.3	0.330	0.340	565.1	1973	12
7.34	2.58	6.5	347.63	273.41	1.284	1348.71	25.78	2703.85	3041828.8	0.309	0.328	6453.5	1973	13
7.13	2.40	6.3	325.56	245.85	1.324	1284.67	25.34	215.30	242215.5	0.289	0.329	525.1	1974	1
7.30	2.44	6.5	344.09	263.78	1.304	1360.90	25.28	205.54	231229.6	0.306	0.336	486.3	1974	2
8.25	2.81	7.3	455.54	384.93	1.183	1804.14	25.25	301.27	338923.7	0.405	0.358	613.1	1974	3
8.16	2.78	7.3	444.29	371.97	1.194	1755.01	25.32	284.34	319886.7	0.395	0.357	587.7	1974	4
7.92	2.65	7.0	415.49	339.07	1.225	1649.99	25.18	274.78	309123.1	0.369	0.354	587.3	1974	5
7.40	2.53	6.6	354.26	275.54	1.286	1385.54	25.57	226.73	255070.4	0.315	0.336	533.3	1974	6
7.40	2.55	6.6	353.20	275.08	1.284	1375.43	25.68	233.58	262782.9	0.314	0.335	552.4	1974	7
7.56	2.67	6.7	371.25	294.93	1.259	1429.17	25.98	245.52	276208.8	0.330	0.336	570.6	1974	8
7.40	2.56	6.6	353.04	275.11	1.283	1372.92	25.71	225.94	254185.7	0.314	0.334	535.1	1974	9
7.52	2.44	6.7	369.87	288.39	1.283	1488.02	24.86	244.61	275187.0	0.329	0.347	550.7	1974	10
8.01	2.75	7.1	426.48	352.05	1.211	1674.96	25.46	272.94	307063.0	0.379	0.353	579.1	1974	11
7.02	2.52	6.2	308.79	235.24	1.313	1185.36	26.05	204.21	229736.3	0.274	0.315	527.5	1974	12
7.59	2.59	6.7	376.82	300.16	1.263	1480.51	25.47	2934.77	3301612.6	0.335	0.341	6648.3	1974	13

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C K YBAR PBAR PMEAN ENPAT THEPOW EFFIC EBAR E PF SIGMA TOP YEAR MO

8.30	2.68	7.4	460.19	389.96	1.180	1886.52	24.39	304.34	342377.7	0.409	0.366	605.4	1965	1
8.71	2.59	7.7	505.49	450.22	1.123	2224.72	22.72	301.95	339690.5	0.449	0.380	555.3	1965	2
7.71	2.45	6.8	391.77	310.88	1.260	1599.22	24.50	259.09	291474.1	0.348	0.355	561.4	1965	3
8.07	2.77	7.2	433.97	360.38	1.204	1707.58	25.41	277.74	312456.7	0.386	0.354	582.9	1965	4
8.83	2.92	7.9	527.83	475.30	1.111	2178.17	24.23	349.07	392702.7	0.469	0.370	641.3	1965	5
7.84	2.64	7.0	405.47	328.38	1.235	1601.60	25.32	259.50	291937.8	0.360	0.351	563.9	1965	6
7.41	2.61	6.6	354.37	277.61	1.277	1367.37	25.92	234.36	263653.0	0.315	0.332	557.7	1965	7
6.36	2.23	5.6	244.36	173.60	1.408	965.31	25.31	161.60	181803.0	0.217	0.293	457.5	1965	8
7.53	2.60	6.7	368.14	290.25	1.268	1433.28	25.68	235.61	265057.4	0.327	0.339	545.0	1965	9
8.42	2.72	7.5	475.00	408.07	1.164	1954.34	24.30	314.13	353400.6	0.422	0.368	613.2	1965	10
8.36	2.51	7.4	464.89	396.26	1.173	2004.12	23.20	297.53	334722.3	0.413	0.375	575.8	1965	11
9.04	3.06	8.1	556.51	513.03	1.085	2290.22	24.30	368.04	414046.1	0.495	0.369	655.9	1965	12
8.05	2.65	7.2	432.33	364.49	1.207	1767.70	24.61	3362.95	3783322.0	0.384	0.354	6915.3	1965	13

8.38	2.76	7.5	471.66	403.86	1.168	1913.88	24.64	311.92	350912.3	0.419	0.365	615.1	1966	1
8.01	2.74	7.1	426.13	351.63	1.212	1674.55	25.45	254.54	286356.9	0.379	0.353	540.1	1966	2
9.31	2.65	8.3	569.81	550.38	1.035	2683.79	21.23	376.83	423939.2	0.506	0.388	637.2	1966	3
8.95	2.73	8.0	535.40	490.61	1.091	2342.55	22.86	342.66	385490.6	0.476	0.380	612.1	1966	4
8.72	2.80	7.8	511.27	454.51	1.125	2134.73	23.95	338.12	380388.0	0.454	0.372	629.9	1966	5
8.08	2.86	7.2	435.78	363.32	1.199	1687.69	25.82	278.90	313760.6	0.387	0.351	589.6	1966	6
7.46	2.67	6.6	358.53	283.02	1.267	1372.13	26.13	237.11	266747.5	0.319	0.331	564.8	1966	7
6.86	2.46	6.1	291.04	218.47	1.332	1122.28	25.93	192.48	216535.7	0.259	0.309	511.3	1966	8
6.99	2.41	6.2	308.51	231.47	1.333	1204.92	25.60	197.45	222125.8	0.274	0.320	500.4	1966	9
8.64	2.70	7.7	500.57	441.47	1.134	2123.75	23.57	331.04	372422.1	0.445	0.375	620.2	1966	10
7.80	2.62	6.9	401.45	323.79	1.240	1589.65	25.25	256.93	289044.3	0.357	0.350	560.4	1966	11
7.58	2.61	6.7	374.92	297.17	1.262	1460.52	25.67	247.94	278937.0	0.333	0.340	567.6	1966	12
8.07	2.67	7.2	432.09	367.47	1.200	1775.87	24.68	3365.92	3786660.0	0.384	0.353	6948.8	1966	13

9.00	2.86	8.0	545.17	501.64	1.087	2329.78	23.40	360.54	405604.9	0.485	0.376	642.4	1967	1
8.16	2.70	7.3	444.82	371.95	1.196	1790.86	24.84	265.70	298915.8	0.395	0.361	543.2	1967	2
8.58	2.99	7.7	498.35	436.09	1.143	1973.90	25.25	329.57	370771.6	0.443	0.362	636.8	1967	3
9.22	2.88	8.2	570.07	539.35	1.057	2491.55	22.88	364.84	410449.3	0.507	0.378	629.2	1967	4
8.62	2.75	7.7	499.47	439.34	1.137	2088.56	23.91	330.31	371604.3	0.444	0.372	623.0	1967	5
7.42	2.40	6.6	359.00	276.83	1.297	1446.06	24.83	229.76	258478.3	0.319	0.344	524.6	1967	6
6.90	2.34	6.1	300.61	222.24	1.353	1186.30	25.34	198.80	223655.5	0.267	0.320	505.1	1967	7
6.82	2.53	6.1	284.62	215.82	1.319	1085.57	26.22	188.23	211756.8	0.253	0.302	514.5	1967	8
7.12	2.47	6.3	321.69	244.57	1.315	1251.15	25.71	205.88	231614.3	0.286	0.324	512.5	1967	9
8.35	2.62	7.4	465.82	396.92	1.174	1945.67	23.94	308.06	346572.2	0.414	0.370	603.6	1967	10
8.47	3.06	7.6	486.28	421.42	1.154	1882.06	25.84	311.22	350125.2	0.432	0.356	617.0	1967	11
8.29	2.83	7.4	461.57	391.97	1.178	1830.15	25.22	305.25	343411.0	0.410	0.359	616.3	1967	12
8.08	2.70	7.2	436.46	371.51	1.201	1775.13	24.78	3398.19	3822959.3	0.388	0.352	6968.2	1967	13
7.93	2.68	7.1	416.77	340.81	1.223	1647.38	25.30	275.63	310078.2	0.370	0.353	589.9	1968	1
8.31	2.63	7.4	460.79	390.69	1.179	1912.35	24.10	285.07	320708.2	0.410	0.368	544.0	1968	2
8.37	2.76	7.4	469.35	401.06	1.170	1902.30	24.67	310.40	349199.3	0.417	0.365	614.1	1968	3
9.11	2.97	8.1	561.44	522.88	1.074	2374.94	23.64	359.32	404240.2	0.499	0.373	631.4	1968	4
8.21	2.71	7.3	450.83	378.95	1.190	1820.87	24.76	298.15	335420.4	0.401	0.362	604.1	1968	5
7.72	2.79	6.9	390.43	315.84	1.236	1489.40	26.21	249.87	281107.8	0.347	0.338	568.6	1968	6
7.66	2.55	6.8	384.88	305.62	1.259	1528.36	25.18	254.54	286352.7	0.342	0.348	566.6	1968	7
7.44	2.52	6.6	359.03	279.81	1.283	1410.14	25.46	237.44	267115.7	0.319	0.338	552.7	1968	8
7.19	2.59	6.4	327.69	253.53	1.293	1252.49	26.16	209.72	235936.2	0.291	0.321	526.3	1968	9
7.82	2.61	6.9	403.02	325.28	1.239	1600.51	25.18	266.53	299845.7	0.358	0.351	579.1	1968	10
7.55	2.64	6.7	371.04	294.05	1.262	1435.54	25.85	237.47	267151.9	0.330	0.338	549.8	1968	11
8.10	2.36	7.2	435.22	359.33	1.211	1901.07	22.89	287.82	323802.6	0.387	0.373	572.2	1968	12
7.95	2.65	7.1	419.21	347.32	1.218	1689.61	24.95	3271.96	3680959.0	0.373	0.352	6898.7	1968	13
8.20	2.82	7.3	449.68	378.28	1.189	1771.91	25.38	297.39	334562.2	0.400	0.357	611.4	1969	1
6.86	2.42	6.1	292.93	218.60	1.340	1137.09	25.76	174.98	196847.5	0.260	0.312	459.2	1969	2
7.29	2.46	6.5	341.95	262.27	1.304	1346.38	25.40	226.14	254410.4	0.304	0.334	538.8	1969	3

7.98	2.55	7.1	422.64	345.67	1.223	1727.77	24.46	270.49	304300.4	0.376	0.361	563.5	1969	4
8.40	2.98	7.5	476.09	409.32	1.163	1856.89	25.64	314.85	354211.1	0.423	0.357	629.7	1969	5
7.97	2.63	7.1	421.21	344.90	1.221	1690.25	24.92	269.58	303272.9	0.374	0.357	568.5	1969	6
6.98	2.43	6.2	306.29	230.21	1.330	1191.42	25.71	202.56	227880.1	0.272	0.318	517.6	1969	7
7.63	2.48	6.8	382.41	301.72	1.267	1539.83	24.83	252.90	284515.8	0.340	0.350	559.5	1969	8
7.42	2.75	6.6	352.54	279.63	1.261	1330.22	26.50	225.63	253828.4	0.313	0.325	550.3	1969	9
7.98	2.93	7.1	423.08	350.93	1.206	1606.02	26.34	279.80	314770.3	0.376	0.343	609.8	1969	10
8.12	2.94	7.2	440.99	369.81	1.192	1689.81	26.10	282.23	317510.3	0.392	0.349	596.5	1969	11
7.22	2.55	6.4	332.20	256.11	1.297	1280.96	25.93	219.69	247154.8	0.295	0.325	542.1	1969	12
7.67	2.66	6.8	386.83	312.25	1.249	1514.05	25.58	3016.23	3393264.0	0.344	0.341	6746.9	1969	13

7.59	2.87	6.8	372.52	300.84	1.238	1392.17	26.76	246.36	277158.4	0.331	0.327	586.9	1970	1
8.59	2.88	7.7	498.49	436.88	1.141	2020.50	24.67	297.76	334983.9	0.443	0.366	569.5	1970	2
7.42	2.46	6.6	358.01	277.27	1.291	1423.38	25.15	236.76	266359.2	0.318	0.341	546.6	1970	3
9.38	3.07	8.4	595.12	572.56	1.039	2554.28	23.30	380.88	428487.0	0.529	0.373	643.4	1970	4
9.46	3.31	8.5	614.47	594.41	1.034	2551.67	24.08	406.37	457169.1	0.546	0.366	678.7	1970	5
8.28	2.92	7.4	460.27	390.92	1.177	1791.29	25.69	294.57	331392.0	0.409	0.355	601.6	1970	6
7.56	2.66	6.7	371.91	295.29	1.259	1435.02	25.92	245.95	276698.0	0.331	0.337	569.9	1970	7
7.00	2.46	6.2	308.57	233.01	1.324	1196.01	25.80	204.07	229573.3	0.274	0.318	521.4	1970	8
8.14	2.91	7.3	442.89	371.53	1.192	1708.11	25.93	283.45	318877.9	0.394	0.351	595.2	1970	9
8.63	2.98	7.7	505.01	444.47	1.136	2013.59	25.08	333.98	375729.8	0.449	0.363	638.4	1970	10
7.85	2.47	7.0	408.01	328.48	1.242	1683.49	24.24	261.12	293764.9	0.363	0.360	551.0	1970	11
7.91	2.51	7.0	414.57	336.25	1.233	1700.60	24.38	274.17	308437.8	0.369	0.360	575.7	1970	12
8.15	2.79	7.3	445.82	381.82	1.192	1789.18	25.08	3465.45	3898631.4	0.396	0.351	7078.4	1970	13

8.26	3.07	7.4	459.25	390.80	1.175	1743.01	26.35	303.71	341678.4	0.408	0.348	630.2	1971	1
8.62	2.80	7.7	500.39	440.00	1.137	2067.82	24.20	298.90	336263.9	0.445	0.370	565.9	1971	2
8.22	3.07	7.3	454.19	385.34	1.179	1717.80	26.44	300.37	337919.3	0.404	0.346	628.8	1971	3
9.01	2.98	8.0	549.79	505.35	1.088	2291.95	23.99	351.87	395851.7	0.489	0.372	628.9	1971	4
8.19	3.02	7.3	449.85	380.18	1.183	1710.36	26.30	297.50	334691.3	0.400	0.347	624.4	1971	5
6.62	2.32	5.9	269.34	196.33	1.372	1054.10	25.55	172.38	193923.8	0.239	0.304	468.8	1971	6
7.25	2.43	6.4	338.49	258.31	1.310	1337.67	25.30	223.86	251837.6	0.301	0.334	534.5	1971	7

6.45	2.34	5.7	248.44	181.06	1.372	966.62	25.70	164.30	184840.2	0.221	0.290	472.3	1971	8
6.92	2.43	6.1	299.56	224.40	1.335	1163.46	25.75	191.72	215682.4	0.266	0.315	496.7	1971	9
7.74	2.39	6.9	345.31	313.65	1.260	1644.82	24.03	261.43	294109.8	0.351	0.359	557.7	1971	10
8.07	2.53	7.2	433.37	357.70	1.212	1800.23	24.07	277.36	312027.7	0.385	0.365	565.7	1971	11
7.62	2.79	6.8	376.97	303.04	1.244	1428.03	26.40	249.30	280464.6	0.335	0.333	582.4	1971	12
7.75	2.68	6.9	397.91	328.01	1.239	1577.16	25.34	3092.70	3479290.7	0.354	0.340	6756.2	1971	13

8.99	2.97	8.0	547.15	501.62	1.091	2277.24	24.03	361.85	407076.0	0.486	0.371	649.0	1972	1
7.59	2.53	6.7	376.61	297.02	1.268	1492.46	25.23	232.99	262117.3	0.335	0.345	507.2	1972	2
7.69	2.56	6.8	388.89	309.80	1.255	1546.62	25.14	257.19	289337.3	0.346	0.349	568.8	1972	3
7.74	2.60	6.9	393.65	315.37	1.248	1557.74	25.27	251.93	283425.7	0.350	0.349	555.5	1972	4
6.92	2.29	6.1	303.94	223.48	1.360	1212.39	25.07	201.01	226133.6	0.270	0.324	502.4	1972	5
6.97	2.44	6.2	305.16	229.57	1.329	1184.71	25.76	195.30	219714.0	0.271	0.317	501.2	1972	6
6.03	2.20	5.3	210.30	148.29	1.418	832.36	25.27	139.08	156461.8	0.187	0.271	429.2	1972	7
6.17	2.23	5.5	223.50	158.51	1.410	881.29	25.36	147.81	166285.8	0.199	0.279	442.2	1972	8
7.49	2.55	6.6	364.15	285.36	1.276	1426.80	25.52	233.06	262189.2	0.324	0.339	539.5	1972	9
7.79	2.72	6.9	399.80	323.89	1.234	1550.08	25.79	264.40	297449.6	0.355	0.345	586.4	1972	10
6.78	2.52	6.0	279.31	211.49	1.321	1065.12	26.22	178.76	201100.9	0.248	0.299	494.4	1972	11
6.95	2.21	6.2	310.63	226.64	1.371	1266.11	24.53	205.43	231108.5	0.276	0.332	498.2	1972	12
7.26	2.49	6.4	341.92	269.25	1.298	1357.74	25.27	2668.80	3002399.8	0.304	0.327	6273.9	1972	13

6.98	2.48	6.2	304.65	230.39	1.322	1175.51	25.92	201.48	226662.2	0.271	0.315	521.2	1973	1
7.20	2.65	6.4	326.62	254.09	1.285	1239.12	26.36	195.10	219487.8	0.290	0.318	494.7	1973	2
6.90	2.60	6.1	291.50	223.56	1.304	1104.03	25.40	192.78	216874.7	0.259	0.302	524.7	1973	3
8.03	2.86	7.2	429.27	356.42	1.204	1654.33	25.95	274.73	309071.9	0.382	0.348	587.7	1973	4
7.66	2.64	6.8	383.73	306.40	1.252	1494.35	25.68	253.77	285492.1	0.341	0.343	573.8	1973	5
7.17	2.58	6.4	324.70	250.50	1.296	1242.54	26.13	207.81	233786.1	0.289	0.320	523.6	1973	6
6.78	2.38	6.0	284.62	210.59	1.352	1108.36	25.68	188.23	211754.2	0.253	0.309	499.9	1973	7
5.85	2.15	5.2	193.58	134.97	1.434	772.52	25.06	128.02	144022.9	0.172	0.261	409.8	1973	8
6.83	2.50	6.1	286.89	216.70	1.324	1098.36	26.12	183.61	206560.0	0.255	0.304	496.7	1973	9
7.45	2.54	6.6	359.94	281.15	1.280	1409.27	25.54	238.04	267797.5	0.320	0.338	554.8	1973	10
7.60	2.87	6.8	374.40	302.48	1.238	1400.86	26.73	239.62	269569.5	0.333	0.328	568.5	1973	11

7.26	2.64	6.5	335.00	261.31	1.282	1274.53	26.28	221.55	249238.5	0.298	0.322	551.8	1973	12
7.14	2.58	6.3	324.57	252.38	1.298	1247.82	25.99	2524.73	2840317.3	0.289	0.317	6307.2	1973	13
7.19	2.46	6.4	330.68	252.02	1.312	1294.89	25.54	218.69	246022.7	0.294	0.329	532.9	1974	1
7.11	2.49	6.3	319.53	243.44	1.313	1236.71	25.84	190.86	214722.6	0.284	0.322	479.3	1974	2
8.16	2.83	7.3	444.94	373.04	1.193	1743.86	25.51	294.25	331033.7	0.396	0.355	610.4	1974	3
8.06	2.76	7.2	432.38	358.59	1.206	1700.89	25.42	276.72	311310.5	0.384	0.354	582.1	1974	4
7.80	2.67	6.9	400.19	323.40	1.237	1566.64	25.54	264.66	297742.1	0.356	0.347	582.7	1974	5
7.26	2.55	6.4	336.77	260.08	1.295	1301.78	25.87	215.54	242477.7	0.299	0.327	526.6	1974	6
7.38	2.50	6.6	352.48	273.20	1.290	1384.11	25.47	233.11	262246.8	0.313	0.337	548.0	1974	7
7.42	2.67	6.6	354.48	279.38	1.269	1353.70	26.19	234.43	263736.0	0.315	0.329	563.2	1974	8
7.13	2.56	6.3	321.35	247.02	1.301	1231.92	26.09	205.66	231370.8	0.286	0.319	520.2	1974	9
7.43	2.52	6.6	357.84	278.59	1.284	1405.55	25.46	236.65	266234.0	0.318	0.338	551.8	1974	10
8.21	2.93	7.3	452.25	382.01	1.184	1747.76	25.88	289.44	325623.4	0.402	0.352	599.6	1974	11
7.19	2.73	6.4	323.81	254.20	1.274	1214.41	26.66	214.14	240912.6	0.288	0.312	553.6	1974	12
7.53	2.64	6.7	368.89	293.75	1.263	1431.85	25.79	2874.16	3233433.0	0.328	0.335	6650.2	1974	13

7.77 2.65

C K VBAR PBAR PMEAN ENPAT THEPOW EFFIC EBAR E PF SIGMA TOP YEAR MO

8.33	2.69	7.4	464.14	394.75	1.176	1903.83	24.38	306.95	345322.6	0.413	0.366	607.6	1965	1
8.72	2.60	7.7	505.94	450.80	1.122	2225.65	22.73	302.22	339993.6	0.450	0.380	555.6	1965	2
7.66	2.45	6.8	386.40	305.18	1.266	1572.86	24.57	255.54	287482.7	0.343	0.353	558.5	1965	3
8.06	2.76	7.2	432.46	358.70	1.206	1700.88	25.43	276.78	311373.9	0.384	0.354	582.2	1965	4
8.80	2.93	7.9	524.26	470.36	1.115	2154.24	24.34	346.71	390048.4	0.466	0.369	640.5	1965	5
7.82	2.64	6.9	402.97	325.74	1.237	1590.07	25.34	257.90	290141.8	0.358	0.350	562.7	1965	6
7.40	2.61	6.6	352.56	276.08	1.277	1358.07	25.96	233.16	262303.9	0.313	0.331	557.3	1965	7
6.33	2.23	5.6	241.32	171.34	1.408	952.89	25.33	159.59	179543.2	0.215	0.291	455.2	1965	8
7.53	2.60	6.7	368.95	291.14	1.267	1435.75	25.70	236.13	265641.5	0.328	0.339	545.7	1965	9
8.41	2.72	7.5	473.91	406.71	1.165	1947.57	24.33	313.41	352589.1	0.421	0.368	612.9	1965	10
8.38	2.52	7.4	467.48	399.53	1.170	2014.87	23.20	299.19	336586.3	0.416	0.375	577.4	1965	11
9.07	3.08	8.1	560.07	517.82	1.082	2305.36	24.29	370.39	416690.7	0.498	0.369	657.4	1965	12
8.04	2.65	7.2	431.71	364.01	1.208	1763.50	24.63	3357.97	3777717.7	0.384	0.354	6913.2	1965	13
8.41	2.77	7.5	475.16	408.13	1.164	1931.18	24.60	314.24	353517.6	0.422	0.366	616.7	1966	1
8.04	2.75	7.2	429.53	355.36	1.209	1690.54	25.41	256.58	288647.3	0.382	0.354	541.5	1966	2
9.33	2.66	8.3	572.06	553.65	1.033	2691.50	21.25	378.32	425615.0	0.509	0.387	638.6	1966	3
8.95	2.72	8.0	534.80	489.93	1.092	2343.55	22.82	342.27	385058.3	0.475	0.380	611.5	1966	4
8.72	2.82	7.8	512.58	456.07	1.124	2135.42	24.00	333.99	381360.3	0.456	0.372	631.1	1966	5
8.09	2.87	7.2	436.52	364.24	1.198	1688.17	25.86	279.37	314292.6	0.388	0.350	590.6	1966	6
7.46	2.68	6.6	359.31	284.05	1.265	1372.82	26.17	237.62	267323.0	0.319	0.331	566.2	1966	7
6.88	2.47	6.1	293.79	221.29	1.328	1130.83	25.98	194.29	218578.2	0.261	0.309	514.6	1966	8
7.00	2.43	6.2	309.04	232.31	1.330	1204.70	25.65	197.78	222506.0	0.275	0.320	501.8	1966	9
8.66	2.72	7.7	502.58	443.91	1.132	2124.79	23.65	332.37	373920.2	0.447	0.374	622.1	1966	10
7.81	2.62	6.9	402.30	324.70	1.239	1593.29	25.25	257.47	289654.9	0.358	0.351	560.9	1966	11
7.62	2.64	6.8	378.62	301.23	1.257	1472.31	25.72	250.39	281690.5	0.337	0.341	571.0	1966	12
8.08	2.68	7.2	433.86	369.57	1.198	1781.59	24.70	3379.70	3802164.0	0.386	0.353	6966.6	1966	13

9.03	2.87	8.0	548.48	506.29	1.083	2345.84	23.38	362.73	408072.2	0.488	0.376	643.9	1967	1
8.13	2.69	7.2	440.92	367.49	1.200	1770.51	24.90	263.38	296297.9	0.392	0.360	541.8	1967	2
8.54	2.98	7.6	493.43	430.05	1.147	1948.01	25.33	326.32	367110.2	0.439	0.361	635.2	1967	3
9.17	2.87	8.2	564.30	530.79	1.063	2460.71	22.93	361.15	406294.8	0.502	0.378	626.9	1967	4
8.63	2.76	7.7	500.33	440.34	1.136	2087.52	23.97	330.88	372242.5	0.445	0.372	624.1	1967	5
7.42	2.40	6.6	358.70	276.36	1.298	1447.03	24.79	229.57	258266.8	0.319	0.345	523.8	1967	6
6.88	2.32	6.1	298.51	219.95	1.357	1180.29	25.29	197.42	222092.5	0.265	0.320	502.3	1967	7
6.81	2.53	6.0	282.86	214.56	1.318	1078.12	26.24	187.07	210449.1	0.251	0.300	513.8	1967	8
7.10	2.47	6.3	319.11	242.22	1.317	1240.59	25.72	204.23	229758.6	0.284	0.323	510.8	1967	9
8.36	2.63	7.4	466.65	397.93	1.173	1947.48	23.96	308.61	347184.8	0.415	0.370	604.4	1967	10
8.45	3.07	7.6	484.15	418.93	1.156	1868.49	25.91	309.86	348590.7	0.430	0.355	616.8	1967	11
8.29	2.84	7.4	461.78	392.24	1.177	1828.79	25.25	305.39	343565.6	0.410	0.359	616.8	1967	12
8.07	2.70	7.2	434.94	369.76	1.202	1766.95	24.81	3386.60	3809925.9	0.387	0.351	6960.5	1967	13
7.91	2.68	7.0	413.55	337.33	1.226	1632.29	25.34	273.49	307679.4	0.368	0.352	588.3	1968	1
8.31	2.64	7.4	461.61	391.69	1.179	1914.02	24.12	285.59	321283.3	0.410	0.368	544.7	1968	2
8.34	2.76	7.4	466.75	397.93	1.173	1885.71	24.75	308.68	347264.3	0.415	0.364	613.5	1968	3
9.10	2.97	8.1	560.27	521.19	1.075	2368.60	23.65	358.57	403392.6	0.498	0.373	630.9	1968	4
8.21	2.71	7.3	449.90	377.90	1.191	1813.24	24.81	297.54	334729.0	0.400	0.362	604.2	1968	5
7.76	2.81	6.9	394.51	320.37	1.231	1501.61	26.27	252.49	284049.4	0.351	0.338	572.1	1968	6
7.67	2.56	6.8	385.50	306.35	1.258	1529.76	25.20	254.94	286809.5	0.343	0.348	567.3	1968	7
7.44	2.53	6.6	359.34	280.19	1.282	1410.71	25.47	237.64	267350.2	0.319	0.338	553.1	1968	8
7.19	2.61	6.4	327.31	253.52	1.291	1248.92	26.21	209.48	235664.3	0.291	0.320	527.1	1968	9
7.80	2.61	6.9	400.95	323.17	1.241	1589.02	25.23	265.16	298303.9	0.356	0.350	578.4	1968	10
7.55	2.64	6.7	370.28	293.28	1.263	1432.47	25.85	236.98	266600.4	0.329	0.337	549.3	1968	11
8.09	2.37	7.2	434.65	358.64	1.212	1895.70	22.93	287.45	323383.1	0.386	0.373	572.2	1968	12
7.95	2.66	7.1	418.72	346.80	1.218	1685.17	24.99	3268.01	3676509.3	0.372	0.352	6901.2	1968	13
8.20	2.83	7.3	450.42	379.20	1.188	1771.44	25.43	297.88	335113.1	0.400	0.356	612.4	1969	1
6.86	2.43	6.1	293.09	219.09	1.338	1135.98	25.80	175.07	196958.3	0.261	0.312	460.2	1969	2
7.28	2.46	6.5	341.58	261.84	1.305	1345.59	25.39	225.90	254138.0	0.304	0.334	538.3	1969	3

7.98	2.55	7.1	422.86	345.91	1.222	1729.28	24.45	270.63	304459.2	0.376	0.361	563.5	1969	4
8.42	2.99	7.5	478.94	412.69	1.161	1865.49	25.67	316.74	356328.1	0.426	0.357	631.7	1969	5
7.98	2.64	7.1	422.15	346.07	1.220	1690.48	24.97	270.17	303946.8	0.375	0.356	569.8	1969	6
6.99	2.43	6.2	307.90	231.47	1.330	1199.02	25.68	203.63	229078.6	0.274	0.319	518.2	1969	7
7.65	2.49	6.8	383.74	303.18	1.266	1544.53	24.64	253.78	285499.2	0.341	0.350	560.6	1969	8
7.42	2.76	6.6	352.82	280.24	1.259	1328.83	26.55	225.80	254027.9	0.314	0.324	551.5	1969	9
8.00	2.94	7.1	425.18	353.27	1.204	1612.94	26.36	281.19	316335.9	0.378	0.343	611.3	1969	10
8.12	2.94	7.2	441.12	369.99	1.192	1689.57	26.11	282.32	317608.5	0.392	0.348	596.7	1969	11
7.25	2.55	6.4	335.43	259.09	1.295	1294.31	25.92	221.83	249560.9	0.298	0.326	544.1	1969	12
7.68	2.67	6.8	387.94	313.50	1.248	1517.29	25.60	3024.94	3403054.4	0.345	0.341	6758.5	1969	13

7.62	2.90	6.8	375.67	304.25	1.235	1401.40	26.81	248.44	279494.9	0.334	0.327	589.9	1970	1
8.63	2.91	7.7	502.89	442.29	1.137	2032.95	24.74	300.39	337943.4	0.447	0.366	572.2	1970	2
7.44	2.46	6.6	360.25	279.38	1.289	1434.74	25.11	238.24	268025.4	0.320	0.342	547.6	1970	3
9.41	3.08	8.4	598.51	577.79	1.036	2573.65	23.26	383.04	430923.9	0.532	0.373	644.5	1970	4
9.51	3.34	8.5	621.03	604.07	1.028	2583.00	24.04	410.70	462042.8	0.552	0.365	680.9	1970	5
8.31	2.95	7.4	464.31	395.64	1.174	1804.77	25.73	297.16	334305.0	0.413	0.355	604.2	1970	6
7.58	2.68	6.7	373.78	297.57	1.256	1438.21	25.99	247.19	278088.6	0.332	0.337	572.5	1970	7
7.03	2.48	6.2	311.31	236.10	1.319	1203.15	25.87	205.88	231611.0	0.277	0.318	525.2	1970	8
8.18	2.93	7.3	447.88	377.19	1.187	1726.16	25.95	286.64	322473.0	0.398	0.351	598.2	1970	9
8.63	2.99	7.7	505.71	445.28	1.136	2012.69	25.13	334.44	376249.7	0.450	0.363	639.3	1970	10
7.86	2.47	7.0	408.46	329.03	1.241	1684.33	24.25	261.41	294091.1	0.363	0.360	551.5	1970	11
7.95	2.52	7.1	418.53	340.76	1.228	1718.33	24.36	276.79	311388.2	0.372	0.361	578.2	1970	12
8.18	2.81	7.3	449.03	385.78	1.189	1801.11	25.10	3490.34	3926637.0	0.399	0.351	7104.2	1970	13

8.32	3.11	7.4	467.31	399.93	1.168	1772.69	26.36	309.04	347675.6	0.415	0.349	634.6	1971	1
8.67	2.82	7.7	506.42	447.76	1.131	2095.20	24.17	302.50	340317.4	0.450	0.370	568.6	1971	2
8.24	3.09	7.4	457.27	388.81	1.176	1728.34	26.46	302.40	340205.6	0.406	0.347	630.7	1971	3
9.02	3.00	8.1	552.24	508.46	1.086	2297.93	24.03	353.44	397615.6	0.491	0.371	630.4	1971	4
8.21	3.04	7.3	453.45	384.26	1.180	1722.34	26.33	299.88	337369.0	0.403	0.348	626.8	1971	5
6.66	2.34	5.9	272.83	199.64	1.367	1066.16	25.59	174.61	196437.2	0.243	0.305	472.5	1971	6
7.24	2.43	6.4	336.66	256.63	1.312	1329.17	25.33	222.64	250473.3	0.299	0.333	533.5	1971	7

6.40	2.32	5.7	243.62	176.84	1.378	949.60	25.66	161.11	181252.9	0.217	0.288	467.2	1971	8
6.87	2.42	6.1	294.40	219.89	1.339	1142.90	25.76	188.42	211969.3	0.262	0.313	493.1	1971	9
7.73	2.38	6.8	394.07	312.15	1.262	1642.55	23.99	260.61	293186.1	0.350	0.359	556.2	1971	10
8.08	2.53	7.2	434.48	359.03	1.210	1803.22	24.09	278.07	312828.0	0.386	0.365	566.7	1971	11
7.61	2.78	6.8	376.66	302.62	1.245	1428.00	26.38	249.10	280238.4	0.335	0.333	581.8	1971	12
7.75	2.69	6.9	399.12	329.67	1.238	1581.51	25.35	3101.84	3489568.4	0.355	0.340	6762.0	1971	13
9.01	2.98	8.0	550.69	506.56	1.087	2295.88	23.99	364.19	409712.4	0.490	0.372	650.3	1972	1
7.59	2.54	6.7	376.82	297.36	1.267	1491.73	25.26	233.13	262267.0	0.335	0.345	507.7	1972	2
7.72	2.56	6.9	391.94	313.04	1.252	1559.64	25.13	259.20	291604.1	0.348	0.350	570.7	1972	3
7.76	2.58	6.9	396.27	317.81	1.247	1575.64	25.15	253.62	285317.6	0.352	0.350	555.5	1972	4
6.95	2.30	6.2	307.15	226.54	1.356	1224.94	25.07	203.13	228521.1	0.273	0.325	505.1	1972	5
6.99	2.45	6.2	307.70	231.98	1.326	1193.99	25.77	196.93	221540.8	0.274	0.318	503.3	1972	6
6.07	2.21	5.4	213.62	150.98	1.415	844.28	25.30	141.27	158931.9	0.190	0.273	432.9	1972	7
6.19	2.24	5.5	225.20	160.37	1.404	886.19	25.41	148.93	167548.6	0.200	0.280	445.3	1972	8
7.50	2.56	6.7	365.33	286.71	1.274	1429.76	25.55	233.81	263034.2	0.325	0.339	540.8	1972	9
7.85	2.74	7.0	406.06	330.63	1.228	1574.00	25.80	268.54	302105.6	0.361	0.346	590.5	1972	10
6.80	2.53	6.0	281.77	213.58	1.319	1074.25	26.23	180.33	202871.8	0.250	0.300	496.3	1972	11
6.96	2.21	6.2	312.05	227.71	1.370	1274.84	24.48	206.37	232167.7	0.277	0.333	498.4	1972	12
7.28	2.49	6.5	344.55	271.94	1.296	1368.76	25.26	2689.44	3025622.8	0.306	0.328	6296.9	1972	13
7.01	2.49	6.2	307.58	233.32	1.318	1185.27	25.95	203.41	228840.9	0.273	0.316	524.2	1973	1
7.20	2.65	6.4	326.73	254.47	1.284	1237.93	26.39	195.16	219560.0	0.290	0.317	495.5	1973	2
6.91	2.60	6.1	292.33	224.40	1.303	1106.59	26.42	193.32	217490.0	0.260	0.302	525.7	1973	3
8.03	2.86	7.2	428.61	355.78	1.205	1649.97	25.98	274.31	308598.9	0.381	0.348	587.7	1973	4
7.65	2.64	6.8	383.27	305.77	1.253	1494.69	25.64	253.47	285155.0	0.341	0.343	572.9	1973	5
7.17	2.59	6.4	324.42	250.44	1.295	1240.25	26.16	207.63	233584.1	0.288	0.320	524.0	1973	6
6.78	2.39	6.0	285.22	211.40	1.349	1109.32	25.71	188.63	212205.1	0.254	0.309	501.2	1973	7
5.85	2.16	5.2	193.43	135.07	1.432	771.58	25.07	127.92	143911.6	0.172	0.261	410.2	1973	8
6.87	2.51	6.1	290.47	219.98	1.320	1111.08	26.14	185.90	209137.8	0.258	0.306	499.8	1973	9
7.48	2.55	6.6	363.15	284.37	1.277	1422.47	25.53	240.16	270183.3	0.323	0.339	556.9	1973	10
7.66	2.90	6.8	381.44	309.60	1.232	1426.06	26.75	244.12	274634.6	0.339	0.329	573.1	1973	11

7.27 2.66
7.25 2.48

7.57	2.65	6.7	373.47	298.56	1.258	1449.86	25.79	2909.95	3273695.4	0.332	0.336	6687.7	1974	13
7.27	2.77	6.5	333.55	263.65	1.265	1247.66	26.73	220.59	248161.5	0.296	0.315	561.7	1974	12
8.29	2.96	7.4	462.98	394.22	1.174	1792.58	25.83	296.31	333345.3	0.412	0.354	604.8	1974	11
7.46	2.53	6.6	361.09	281.96	1.281	1417.72	25.47	238.80	268652.3	0.321	0.339	554.3	1974	10
7.15	2.57	6.3	322.91	248.64	1.299	1236.87	26.11	206.66	232496.7	0.287	0.320	521.8	1974	9
7.44	2.68	6.6	356.23	281.11	1.267	1360.28	26.19	235.59	265037.1	0.317	0.330	564.4	1974	8
7.43	2.51	6.6	357.40	278.09	1.285	1404.49	25.45	236.36	265908.3	0.318	0.338	551.2	1974	7
7.28	2.56	6.5	339.26	262.73	1.291	1309.50	25.91	217.13	244265.9	0.302	0.328	529.1	1974	6
7.82	2.68	7.0	403.72	327.12	1.234	1582.06	25.52	266.99	300364.5	0.359	0.348	584.6	1974	5
8.09	2.76	7.2	436.15	362.76	1.202	1719.42	25.37	279.13	314026.9	0.388	0.355	583.6	1974	4
8.19	2.83	7.3	449.39	378.06	1.189	1765.22	25.46	297.20	334348.3	0.399	0.356	612.3	1974	3
7.13	2.51	6.3	321.57	245.68	1.309	1242.52	25.88	192.09	216097.2	0.286	0.322	481.5	1974	2
7.25	2.48	6.4	337.35	258.67	1.304	1319.96	25.56	223.10	250991.3	0.300	0.331	538.4	1974	1
7.16	2.58	6.4	326.04	253.92	1.296	1252.60	26.01	2536.18	2853203.9	0.290	0.318	6324.5	1973	13
7.27	2.66	6.5	335.89	262.45	1.280	1276.03	26.32	222.14	249902.8	0.299	0.321	553.3	1973	12

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 C K VBAR PBAR PMEAN ENPAT THEPOW EFFIC EBAR E PF SIGMA TOP YEAR MO

8.32	2.69	7.4	462.78	393.09	1.177	1897.07	24.39	306.05	344305.2	0.411	0.366	607.0	1965	1
8.74	2.60	7.8	508.55	454.56	1.119	2244.69	22.66	303.77	341744.6	0.452	0.381	556.3	1965	2
7.69	2.45	6.8	389.32	308.34	1.263	1585.91	24.55	257.47	289657.7	0.346	0.354	560.4	1965	3
8.10	2.76	7.2	436.95	363.57	1.202	1726.15	25.31	279.65	314605.4	0.388	0.356	583.4	1965	4
8.86	2.91	7.9	530.30	478.91	1.107	2198.89	24.12	350.70	394542.9	0.471	0.371	641.5	1965	5
7.86	2.64	7.0	408.34	331.26	1.233	1618.91	25.22	261.34	294006.7	0.363	0.352	564.4	1965	6
7.45	2.61	6.6	358.99	281.99	1.273	1387.26	25.88	237.41	267086.4	0.319	0.334	560.2	1965	7
6.37	2.22	5.6	245.94	174.70	1.408	972.11	25.30	162.65	182976.9	0.219	0.294	458.4	1965	8
7.51	2.59	6.7	366.24	288.36	1.270	1425.34	25.69	234.39	263691.7	0.326	0.338	543.9	1965	9
8.42	2.73	7.5	475.21	408.28	1.164	1948.27	24.39	314.27	353554.7	0.422	0.367	614.3	1965	10
8.34	2.53	7.4	463.74	394.68	1.175	1987.18	23.34	296.79	333891.7	0.412	0.374	576.5	1965	11
9.02	3.07	8.1	553.70	508.84	1.088	2269.14	24.40	366.18	411954.9	0.492	0.368	655.5	1965	12
8.06	2.65	7.2	433.34	365.55	1.207	1771.74	24.60	3370.68	3792018.8	0.385	0.355	6921.7	1965	13
8.35	2.76	7.4	467.19	398.45	1.173	1890.78	24.71	308.97	347591.2	0.415	0.364	613.3	1966	1
7.99	2.73	7.1	423.70	348.81	1.215	1667.82	25.40	253.09	284726.4	0.377	0.353	538.2	1966	2
9.31	2.66	8.3	570.55	550.67	1.036	2673.42	21.34	377.32	424486.0	0.507	0.387	638.4	1966	3
8.91	2.72	7.9	530.65	483.96	1.096	2319.69	22.88	339.62	382071.5	0.472	0.379	609.9	1966	4
8.69	2.79	7.7	507.87	450.10	1.128	2121.07	23.94	335.87	377852.2	0.451	0.372	628.0	1966	5
8.06	2.85	7.2	432.95	360.22	1.202	1675.63	25.84	277.09	311726.9	0.385	0.350	588.2	1966	6
7.44	2.66	6.6	356.19	280.60	1.269	1363.97	26.11	235.56	265003.1	0.317	0.331	562.9	1966	7
6.83	2.44	6.1	288.90	216.08	1.337	1116.48	25.88	191.06	214939.0	0.257	0.309	508.2	1966	8
6.97	2.41	6.2	306.07	229.29	1.335	1194.90	25.61	195.88	220368.5	0.272	0.319	498.7	1966	9
8.60	2.70	7.6	495.69	434.97	1.140	2095.10	23.66	327.82	368793.1	0.441	0.374	618.3	1966	10
7.77	2.61	6.9	398.04	320.08	1.244	1576.00	25.26	254.75	286591.1	0.354	0.350	558.2	1966	11
7.55	2.60	6.7	370.78	292.89	1.266	1444.50	25.67	245.21	275863.1	0.330	0.339	564.7	1966	12
8.04	2.66	7.1	429.05	363.84	1.203	1761.61	24.69	3342.23	3760012.2	0.381	0.352	6927.0	1966	13

8.96	2.86	8.0	540.31	494.42	1.093	2295.57	23.54	357.32	401988.5	0.480	0.375	641.1	1967	1
8.11	2.69	7.2	437.67	363.81	1.203	1752.92	24.97	261.43	294111.6	0.389	0.359	540.7	1967	2
8.60	2.98	7.7	501.14	439.59	1.140	1990.81	25.17	331.42	372849.9	0.445	0.362	637.4	1967	3
9.21	2.89	8.2	569.54	538.38	1.058	2485.53	22.91	364.51	410071.3	0.506	0.378	629.2	1967	4
8.58	2.74	7.6	493.63	431.77	1.143	2059.01	23.97	326.46	367263.4	0.439	0.371	620.4	1967	5
7.40	2.40	6.6	356.42	274.27	1.300	1434.08	24.85	228.11	256624.2	0.317	0.343	523.1	1967	6
6.84	2.32	6.1	294.04	216.01	1.361	1161.73	25.31	194.46	218768.4	0.261	0.318	499.1	1967	7
6.71	2.49	6.0	272.49	204.94	1.330	1042.74	26.13	180.21	202731.0	0.242	0.297	503.3	1967	8
7.03	2.44	6.2	312.18	235.40	1.326	1215.82	25.68	199.79	224766.2	0.277	0.321	504.7	1967	9
8.27	2.59	7.3	456.40	385.34	1.184	1904.18	23.97	301.84	339564.6	0.406	0.369	598.1	1967	10
8.42	3.05	7.5	479.81	413.85	1.159	1851.28	25.92	307.08	345465.1	0.427	0.354	614.7	1967	11
8.26	2.83	7.4	456.98	386.65	1.182	1806.51	25.30	302.21	339990.9	0.406	0.358	614.6	1967	12
8.03	2.69	7.1	430.88	365.37	1.207	1750.01	24.81	3354.84	3774195.1	0.383	0.350	6926.4	1967	13
7.87	2.65	7.0	408.98	332.14	1.231	1617.67	25.28	270.47	304282.1	0.364	0.352	584.5	1968	1
8.25	2.62	7.3	454.23	382.72	1.187	1879.96	24.16	281.02	316145.1	0.404	0.367	541.0	1968	2
8.30	2.75	7.4	460.89	390.91	1.179	1859.26	24.79	304.80	342902.7	0.410	0.363	610.5	1968	3
9.07	2.97	8.1	556.75	515.69	1.080	2340.28	23.79	356.32	400861.4	0.495	0.373	630.4	1968	4
8.19	2.71	7.3	447.43	375.04	1.193	1799.93	24.86	295.90	332289.3	0.398	0.361	603.2	1968	5
7.71	2.80	6.9	389.28	314.91	1.236	1482.08	26.27	249.14	280281.2	0.346	0.337	568.8	1968	6
7.63	2.55	6.8	381.65	302.29	1.263	1513.73	25.21	252.40	283950.7	0.339	0.347	564.8	1968	7
7.42	2.52	6.6	356.89	277.74	1.285	1400.55	25.48	236.02	265524.3	0.317	0.338	551.5	1968	8
7.17	2.58	6.4	324.87	250.75	1.296	1242.59	26.14	207.91	233903.1	0.289	0.320	524.0	1968	9
7.78	2.60	6.9	399.14	321.16	1.243	1582.63	25.22	263.97	296962.2	0.355	0.350	577.0	1968	10
7.52	2.63	6.7	366.96	289.91	1.266	1419.47	25.85	234.86	264213.3	0.326	0.337	547.1	1968	11
8.05	2.36	7.1	429.56	352.42	1.219	1870.37	22.97	284.09	319595.6	0.382	0.372	569.1	1968	12
7.91	2.64	7.0	414.72	342.14	1.223	1667.38	25.00	3236.90	3641511.1	0.365	0.351	6872.1	1968	13
8.15	2.81	7.3	444.11	371.98	1.194	1745.39	25.44	293.71	330421.0	0.395	0.355	608.9	1969	1
6.82	2.41	6.0	288.73	215.04	1.343	1120.16	25.78	172.47	194027.2	0.257	0.310	456.6	1969	2
7.27	2.46	6.4	339.60	260.07	1.306	1335.98	25.42	224.59	252665.3	0.302	0.333	537.5	1969	3

7.91	2.53	7.0	414.91	336.90	1.232	1692.66	24.51	265.54	298731.9	0.369	0.359	559.1	1969	4
8.36	2.96	7.5	470.67	402.99	1.168	1832.49	25.68	311.27	350177.2	0.418	0.356	627.3	1969	5
7.92	2.61	7.0	414.87	337.80	1.228	1663.25	24.94	265.52	298709.4	0.369	0.356	564.8	1969	6
6.93	2.42	6.1	301.39	225.69	1.335	1172.63	25.70	199.32	224231.9	0.268	0.316	513.6	1969	7
7.56	2.46	6.7	374.57	293.52	1.276	1504.73	24.89	247.72	278681.4	0.333	0.348	554.7	1969	8
7.39	2.74	6.6	348.91	276.18	1.263	1316.32	26.51	223.30	251216.5	0.310	0.323	548.0	1969	9
7.94	2.92	7.1	417.64	345.23	1.210	1583.16	26.38	276.20	310723.4	0.371	0.342	607.2	1969	10
8.09	2.93	7.2	437.22	365.68	1.196	1674.03	26.12	279.82	314796.1	0.389	0.348	594.7	1969	11
7.18	2.53	6.4	327.01	251.12	1.302	1261.33	25.93	216.26	243293.1	0.291	0.323	538.1	1969	12
7.63	2.65	6.8	381.64	306.85	1.254	1491.84	25.61	2975.71	3347674.3	0.339	0.339	6710.6	1969	13
7.53	2.85	6.7	365.42	293.83	1.244	1366.10	26.75	241.66	271871.5	0.325	0.325	582.3	1970	1
8.55	2.86	7.6	492.36	429.21	1.147	1992.40	24.71	294.10	330865.0	0.438	0.366	566.9	1970	2
7.38	2.45	6.5	353.04	272.27	1.297	1402.47	25.17	233.48	262663.9	0.314	0.340	543.3	1970	3
9.33	3.05	8.3	588.70	562.86	1.046	2519.47	23.37	376.77	423866.0	0.523	0.373	641.2	1970	4
9.44	3.30	8.5	611.87	590.67	1.036	2540.37	24.09	404.65	455230.8	0.544	0.366	677.7	1970	5
8.25	2.91	7.4	457.26	387.47	1.180	1778.94	25.70	292.65	329230.1	0.406	0.354	600.1	1970	6
7.53	2.65	6.7	368.18	291.62	1.263	1419.23	25.94	243.49	273924.3	0.327	0.336	567.8	1970	7
6.97	2.44	6.2	305.39	229.77	1.329	1185.65	25.76	201.97	227211.2	0.271	0.317	518.0	1970	8
8.12	2.89	7.2	440.00	368.26	1.195	1698.27	25.91	281.60	316801.3	0.391	0.350	593.3	1970	9
8.65	2.99	7.7	508.07	448.29	1.133	2027.48	25.06	336.01	378006.6	0.452	0.363	639.7	1970	10
7.82	2.47	6.9	404.03	324.17	1.246	1660.79	24.33	258.58	290904.9	0.359	0.359	549.5	1970	11
7.88	2.52	7.0	411.34	332.78	1.236	1680.34	24.48	272.04	306040.2	0.366	0.359	574.9	1970	12
8.12	2.78	7.2	442.14	377.60	1.196	1772.63	25.11	3436.99	3866615.8	0.393	0.351	7054.7	1970	13
8.21	3.06	7.3	453.31	384.26	1.180	1717.12	26.40	299.79	337260.7	0.403	0.347	627.7	1971	1
8.60	2.79	7.7	497.67	436.53	1.140	2056.15	24.20	297.28	334434.9	0.442	0.370	564.6	1971	2
8.19	3.07	7.3	450.93	381.82	1.181	1702.79	26.48	298.22	335493.0	0.401	0.346	627.7	1971	3
8.99	2.99	8.0	548.38	503.07	1.090	2277.57	24.08	350.96	394833.4	0.487	0.371	629.0	1971	4
8.18	3.02	7.3	449.42	379.69	1.184	1708.80	26.30	297.22	334369.5	0.399	0.347	624.1	1971	5
6.56	2.30	5.8	262.62	190.46	1.379	1028.94	25.52	168.08	189086.4	0.233	0.300	462.8	1971	6
7.26	2.42	6.4	340.27	259.62	1.311	1349.09	25.22	225.03	253160.4	0.302	0.335	534.4	1971	7

6.43	2.33	5.7	247.29	180.00	1.374	962.70	25.69	163.54	183981.2	0.220	0.289	470.9	1971	8
6.92	2.42	6.1	300.10	224.71	1.335	1166.51	25.73	192.06	216068.4	0.267	0.315	496.6	1971	9
7.73	2.38	6.9	394.28	312.40	1.262	1642.99	24.00	260.75	293342.3	0.350	0.359	556.4	1971	10
8.05	2.53	7.1	430.27	354.12	1.215	1781.64	24.15	275.37	309793.4	0.382	0.364	564.6	1971	11
7.60	2.79	6.8	375.13	301.30	1.245	1420.08	26.42	248.09	279099.9	0.333	0.332	581.6	1971	12
7.73	2.68	6.9	395.81	325.67	1.241	1567.87	25.35	3076.38	3460923.7	0.352	0.340	6740.5	1971	13
8.96	2.97	8.0	544.06	497.27	1.094	2258.99	26.08	359.81	404782.3	0.484	0.371	648.0	1972	1
7.56	2.53	6.7	372.62	293.00	1.272	1474.34	25.27	230.53	259344.6	0.331	0.344	505.2	1972	2
7.65	2.54	6.8	384.11	304.72	1.261	1526.53	25.16	254.03	285778.8	0.341	0.348	565.8	1972	3
7.72	2.58	6.9	391.95	313.40	1.251	1553.26	25.23	250.85	282200.7	0.348	0.349	553.9	1972	4
6.93	2.29	6.1	305.60	224.85	1.359	1220.42	25.04	202.10	227363.7	0.272	0.325	503.2	1972	5
6.99	2.44	6.2	307.32	231.19	1.329	1195.20	25.71	196.69	221271.5	0.273	0.319	501.8	1972	6
6.06	2.20	5.4	213.31	150.22	1.420	844.38	25.26	141.07	158700.9	0.190	0.273	431.2	1972	7
6.19	2.22	5.5	225.75	159.92	1.412	890.68	25.35	149.30	167959.0	0.201	0.281	443.4	1972	8
7.54	2.56	6.7	370.31	291.46	1.271	1453.89	25.47	237.00	266620.6	0.329	0.341	542.9	1972	9
7.83	2.73	7.0	404.52	328.74	1.230	1571.86	25.73	267.52	300960.0	0.360	0.346	588.6	1972	10
6.79	2.53	6.0	281.04	213.09	1.319	1071.04	26.24	179.86	202345.3	0.250	0.299	496.1	1972	11
6.96	2.21	6.2	311.60	227.39	1.370	1271.79	24.50	206.07	231828.8	0.277	0.332	498.5	1972	12
7.27	2.48	6.4	342.68	269.60	1.299	1361.03	25.26	2674.81	3009156.1	0.305	0.327	6278.3	1972	13
6.98	2.49	6.2	304.54	230.54	1.321	1173.71	25.95	201.40	226578.3	0.271	0.315	521.8	1973	1
7.19	2.65	6.4	326.17	253.75	1.285	1236.95	26.37	194.83	219183.5	0.290	0.317	494.7	1973	2
6.92	2.60	6.1	293.65	225.43	1.303	1111.90	26.41	194.20	218475.9	0.261	0.303	526.4	1973	3
8.02	2.84	7.1	428.22	355.11	1.206	1653.87	25.89	274.06	308316.2	0.381	0.349	586.3	1973	4
7.67	2.65	6.8	385.23	307.93	1.251	1500.95	25.67	254.77	286613.2	0.342	0.343	574.6	1973	5
7.20	2.58	6.4	328.74	254.01	1.294	1259.66	26.10	210.39	236690.7	0.292	0.322	525.6	1973	6
6.79	2.37	6.0	286.05	211.49	1.353	1115.70	25.64	189.18	212824.8	0.254	0.310	500.1	1973	7
5.83	2.14	5.2	192.27	133.57	1.440	768.58	25.02	127.16	143051.6	0.171	0.261	407.2	1973	8
6.86	2.50	6.1	290.26	219.45	1.323	1111.74	26.11	185.76	208983.8	0.258	0.306	498.7	1973	9
7.45	2.53	6.6	359.98	280.83	1.282	1413.33	25.47	238.07	267824.6	0.320	0.339	553.5	1973	10
7.62	2.88	6.8	376.38	304.43	1.236	1408.36	26.72	240.89	270996.0	0.335	0.328	569.6	1973	11

7.25	2.64	6.4	333.12	259.54	1.284	1267.46	26.28	220.31	247843.1	0.296	0.321	550.5	1973	12
7.15	2.57	6.3	325.38	253.01	1.298	1251.85	25.97	2531.01	2847381.8	0.289	0.318	6309.0	1973	13
7.20	2.45	6.4	331.41	252.49	1.313	1299.70	25.50	219.17	246566.0	0.295	0.330	532.7	1974	1
7.09	2.49	6.3	317.78	241.92	1.314	1229.25	25.85	189.82	213550.8	0.282	0.321	478.4	1974	2
8.15	2.83	7.3	443.71	371.75	1.194	1735.16	25.57	293.44	330123.0	0.394	0.354	610.4	1974	3
8.05	2.76	7.2	431.63	357.76	1.206	1697.77	25.42	276.25	310776.5	0.384	0.354	581.7	1974	4
7.78	2.67	6.9	398.80	322.02	1.238	1559.14	25.58	263.74	296705.3	0.354	0.347	582.3	1974	5
7.27	2.54	6.4	337.77	260.72	1.295	1308.05	25.82	216.17	243193.4	0.300	0.328	526.3	1974	6
7.38	2.49	6.6	352.86	273.20	1.292	1389.61	25.39	233.36	262531.5	0.314	0.337	546.9	1974	7
7.45	2.68	6.6	357.87	282.74	1.266	1366.44	26.19	236.67	266257.1	0.318	0.330	565.6	1974	8
7.14	2.56	6.3	322.28	247.90	1.300	1235.37	26.09	206.26	232038.8	0.286	0.320	520.9	1974	9
7.43	2.53	6.6	357.86	278.82	1.283	1403.29	25.50	236.66	266245.9	0.318	0.338	552.5	1974	10
8.19	2.94	7.3	449.87	379.41	1.186	1734.63	25.93	287.92	323904.7	0.400	0.351	599.1	1974	11
7.15	2.72	6.4	319.15	250.03	1.276	1197.08	26.66	211.07	237449.6	0.284	0.310	550.5	1974	12
7.52	2.64	6.7	368.42	293.23	1.264	1429.63	25.79	2870.53	3229342.6	0.327	0.335	6647.4	1974	13

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***** SANDSTONE *****														
C	K	VBAR	PBAR	PMEAN	ENPAT	THEPOW	EFFIC	EBAR	E	PF	SIGMA	TOP	YEAR	MO
8.19	2.63	7.3	447.72	374.99	1.194	1835.56	24.39	296.09	333102.3	0.398	0.365	597.6	1965	1
8.57	2.59	7.6	489.69	428.30	1.143	2120.38	23.09	292.51	329073.4	0.435	0.377	550.2	1965	2
7.81	2.46	6.9	403.23	323.20	1.248	1659.25	24.30	266.67	300005.9	0.358	0.359	566.9	1965	3
7.93	2.83	7.1	416.94	343.20	1.215	1601.70	26.03	266.84	300194.3	0.371	0.346	581.7	1965	4
8.70	2.93	7.8	512.14	454.13	1.128	2079.52	24.63	338.70	381035.3	0.455	0.367	637.2	1965	5
7.73	2.70	6.9	392.20	315.88	1.242	1519.58	25.81	251.01	282381.8	0.349	0.343	563.0	1965	6
7.26	2.58	6.4	335.74	260.11	1.291	1290.23	26.02	222.04	249792.0	0.298	0.325	546.5	1965	7
6.23	2.20	5.5	231.90	163.38	1.419	918.16	25.26	153.36	172533.1	0.206	0.286	445.5	1965	8
7.57	2.62	6.7	372.80	295.26	1.263	1448.98	25.73	238.59	268414.4	0.331	0.339	548.9	1965	9
8.38	2.64	7.4	469.60	401.58	1.169	1959.37	23.97	310.56	349384.7	0.417	0.370	606.2	1965	10
8.27	2.40	7.3	454.08	382.98	1.186	2001.56	22.69	290.61	326934.3	0.404	0.377	563.9	1965	11
9.05	2.99	8.1	554.71	512.33	1.083	2319.69	23.91	366.85	412703.1	0.493	0.372	651.6	1965	12
7.97	2.63	7.1	423.40	354.61	1.215	1729.50	24.65	3293.83	3705554.7	0.376	0.352	6859.2	1965	13
8.44	2.78	7.5	478.83	412.63	1.160	1946.76	24.60	316.67	356251.6	0.426	0.366	618.7	1966	1
8.01	2.81	7.1	426.34	352.74	1.209	1653.33	25.79	254.67	286500.9	0.379	0.350	544.7	1966	2
9.29	2.60	8.3	566.46	546.83	1.036	2694.39	21.02	374.62	421447.6	0.504	0.389	634.0	1966	3
9.04	2.78	8.1	547.22	507.05	1.079	2393.70	22.86	350.22	393995.5	0.486	0.379	618.1	1966	4
8.73	2.84	7.8	513.99	457.72	1.123	2134.71	24.08	339.92	382410.5	0.457	0.371	632.6	1966	5
8.08	2.85	7.2	435.51	362.99	1.200	1687.45	25.81	278.72	313565.4	0.387	0.351	589.3	1966	6
7.49	2.66	6.7	363.19	287.10	1.265	1395.02	26.03	240.19	270209.9	0.323	0.333	566.1	1966	7
6.82	2.48	6.1	286.26	215.54	1.328	1098.58	26.06	189.31	212976.8	0.254	0.305	511.0	1966	8
6.99	2.39	6.2	309.05	231.04	1.338	1213.12	25.48	197.79	222515.3	0.275	0.322	498.1	1966	9
8.71	2.66	7.7	507.36	451.58	1.124	2195.40	23.11	335.53	377474.4	0.451	0.378	619.5	1966	10
7.82	2.63	6.9	403.06	325.60	1.238	1594.80	25.27	257.96	290200.5	0.358	0.350	561.7	1966	11
7.61	2.65	6.8	377.26	300.11	1.257	1463.51	25.78	249.50	280682.0	0.335	0.340	571.1	1966	12
8.09	2.68	7.2	434.54	370.91	1.196	1789.25	24.66	3385.09	3808230.5	0.386	0.353	6965.1	1966	13

9.07	2.83	8.1	551.61	512.38	1.077	2395.81	23.02	364.80	410397.4	0.490	0.378	642.4	1967	1	3
8.31	2.68	7.4	462.24	392.45	1.178	1899.36	24.34	276.11	310628.0	0.411	0.367	547.3	1967	2	2
8.37	2.97	7.5	472.10	404.66	1.167	1838.71	25.68	312.21	351238.8	0.420	0.356	628.0	1967	3	1
9.23	2.89	8.2	571.90	541.85	1.055	2497.33	22.90	366.02	411769.6	0.508	0.378	630.2	1967	4	3
8.80	2.80	7.8	521.06	468.14	1.113	2202.21	23.66	344.59	387665.6	0.463	0.374	632.3	1967	5	4
7.47	2.41	6.6	364.93	282.82	1.290	1473.12	24.77	233.55	262746.8	0.324	0.346	528.1	1967	6	5
7.13	2.45	6.3	323.80	245.65	1.318	1266.04	25.58	214.14	240904.2	0.288	0.326	528.4	1967	7	6
7.23	2.62	6.4	330.97	257.20	1.287	1261.27	26.24	218.88	246243.1	0.294	0.321	548.0	1967	8	7
7.34	2.54	6.5	346.28	268.50	1.290	1345.78	25.73	221.62	249325.1	0.308	0.332	530.6	1967	9	8
8.57	2.71	7.6	492.55	430.61	1.144	2066.07	23.84	325.74	366457.6	0.438	0.372	618.4	1967	10	9
8.66	3.12	7.7	511.21	451.48	1.132	1997.75	25.59	327.17	368070.0	0.454	0.359	626.3	1967	11	10
8.33	2.78	7.4	464.91	395.74	1.175	1870.23	24.86	307.46	345894.4	0.413	0.363	613.7	1967	12	11
8.21	2.73	7.3	451.13	387.62	1.185	1842.81	24.68	3512.30	3951340.6	0.401	0.356	7073.7	1967	13	12
8.06	2.79	7.2	432.26	358.83	1.205	1689.50	25.59	285.87	321603.5	0.384	0.352	603.7	1968	1	13
8.44	2.70	7.5	477.73	411.54	1.161	1977.61	24.16	295.55	332497.7	0.425	0.369	553.8	1968	2	14
8.58	2.82	7.6	495.68	433.74	1.143	2032.63	24.39	327.81	368784.3	0.441	0.368	625.9	1968	3	15
9.22	2.95	8.2	572.74	541.21	1.058	2469.33	23.19	366.55	412369.8	0.509	0.376	632.9	1968	4	16
8.20	2.67	7.3	449.29	377.00	1.192	1826.85	24.59	297.13	334270.8	0.399	0.363	601.1	1968	5	17
7.57	2.67	6.7	372.17	295.69	1.259	1434.60	25.94	238.19	267962.7	0.331	0.337	552.2	1968	6	18
7.71	2.54	6.8	390.85	311.56	1.254	1560.73	25.04	258.48	290795.3	0.347	0.350	568.7	1968	7	19
7.39	2.50	6.6	353.33	273.99	1.290	1388.02	25.46	233.67	262875.4	0.314	0.337	548.4	1968	8	20
7.20	2.58	6.4	328.37	253.76	1.294	1257.62	26.11	210.16	236426.0	0.292	0.322	525.7	1968	9	21
7.83	2.61	7.0	404.21	326.48	1.238	1607.63	25.14	267.32	300733.6	0.359	0.352	579.3	1968	10	22
7.58	2.66	6.7	373.31	296.72	1.258	1440.50	25.92	238.92	268782.5	0.332	0.337	552.4	1968	11	23
8.21	2.40	7.3	447.36	374.42	1.195	1957.67	22.85	295.86	332837.9	0.398	0.375	580.0	1968	12	24
8.00	2.66	7.1	424.77	354.58	1.212	1720.22	24.86	3315.50	3729939.6	0.378	0.353	6924.1	1968	13	25
8.18	2.86	7.3	447.27	375.89	1.190	1745.63	25.62	295.79	332769.2	0.398	0.354	613.2	1969	1	26
6.91	2.43	6.1	298.66	223.64	1.335	1159.75	25.75	178.40	200702.3	0.265	0.315	463.1	1969	2	27
7.24	2.46	6.4	335.92	256.89	1.308	1317.51	25.50	222.15	249923.4	0.299	0.331	536.1	1969	3	28

8.12	2.61	7.2	438.72	364.38	1.204	1794.66	24.45	280.78	315876.0	0.390	0.363	573.5	1969	4
8.46	2.99	7.5	483.60	418.19	1.156	1893.29	25.54	319.82	359799.6	0.430	0.358	632.5	1969	5
8.15	2.66	7.2	443.28	369.98	1.198	1795.73	24.68	283.70	319158.9	0.394	0.362	579.2	1969	6
7.06	2.47	6.3	314.79	238.61	1.319	1221.00	25.78	208.18	234201.6	0.280	0.321	525.8	1969	7
7.78	2.49	6.9	399.04	319.20	1.250	1622.85	24.59	263.90	296889.1	0.355	0.356	567.8	1969	8
7.37	2.74	6.6	346.42	273.98	1.264	1305.76	26.53	221.71	249421.7	0.308	0.322	546.9	1969	9
8.05	2.91	7.2	431.22	359.09	1.201	1650.32	26.13	285.18	320825.9	0.383	0.347	611.2	1969	10
8.15	3.00	7.3	444.44	374.18	1.188	1689.17	26.31	284.44	319995.7	0.395	0.347	601.5	1969	11
7.23	2.56	6.4	332.90	256.95	1.296	1282.41	25.96	220.15	247674.0	0.296	0.325	543.1	1969	12
7.72	2.68	6.9	393.02	319.25	1.242	1539.84	25.57	3064.21	3447237.2	0.349	0.342	6794.0	1969	13
7.62	2.91	6.8	376.16	305.01	1.233	1401.15	26.85	248.77	279863.8	0.334	0.327	591.1	1970	1
8.57	2.89	7.6	495.69	433.25	1.144	1999.34	24.79	296.09	333103.1	0.441	0.365	569.3	1970	2
7.42	2.49	6.6	357.47	277.52	1.288	1411.70	25.32	236.40	265954.7	0.318	0.339	549.1	1970	3
9.45	3.12	8.5	605.91	588.08	1.030	2598.63	23.32	387.78	436257.1	0.539	0.372	648.0	1970	4
9.37	3.33	8.4	604.64	577.96	1.046	2473.95	24.44	399.87	449855.8	0.537	0.364	677.6	1970	5
8.22	2.92	7.3	452.65	382.38	1.184	1752.60	25.83	289.70	325911.4	0.402	0.353	599.2	1970	6
7.55	2.64	6.7	370.64	293.58	1.262	1434.58	25.84	245.12	275754.7	0.329	0.338	567.6	1970	7
6.97	2.47	6.2	303.88	229.58	1.324	1173.17	25.90	200.97	226088.1	0.270	0.315	520.3	1970	8
8.06	2.92	7.2	433.38	361.50	1.199	1658.06	26.14	277.36	312033.4	0.385	0.347	592.8	1970	9
8.41	2.92	7.5	477.29	410.64	1.162	1883.85	25.34	315.65	355101.0	0.424	0.360	626.6	1970	10
7.94	2.46	7.0	418.20	339.78	1.231	1743.78	23.98	267.65	301104.9	0.372	0.364	554.7	1970	11
7.87	2.45	7.0	410.06	330.53	1.241	1703.22	24.08	271.19	305087.9	0.365	0.362	568.7	1970	12
8.12	2.79	7.2	442.16	377.48	1.195	1769.50	25.15	3436.55	3866115.8	0.393	0.350	7064.9	1970	13
8.34	3.08	7.5	469.65	402.38	1.167	1791.81	26.21	310.59	349418.2	0.417	0.351	633.8	1971	1
8.56	2.83	7.6	493.96	431.44	1.145	2015.90	24.50	295.06	331941.6	0.439	0.367	565.6	1971	2
8.16	3.06	7.3	446.99	377.55	1.184	1685.77	26.52	295.61	332561.6	0.397	0.345	626.1	1971	3
8.91	2.88	7.9	535.59	487.14	1.099	2253.35	23.77	342.78	385624.8	0.476	0.373	620.2	1971	4
8.06	3.00	7.2	432.63	361.78	1.196	1633.06	26.49	286.11	321877.0	0.385	0.343	617.7	1971	5
6.85	2.37	6.1	293.17	217.17	1.350	1146.80	25.56	187.63	211080.1	0.261	0.314	487.7	1971	6
7.13	2.49	6.3	322.57	245.86	1.312	1251.51	25.77	213.33	239994.5	0.287	0.324	531.6	1971	7

6.40	2.33	5.7	243.18	176.87	1.375	946.78	25.68	160.82	180922.4	0.216	0.287	467.8	1971	8
6.87	2.42	6.1	294.45	220.08	1.338	1142.31	25.78	188.44	212000.4	0.262	0.312	493.5	1971	9
7.69	2.43	6.8	389.96	308.52	1.264	1600.28	24.37	257.89	290131.5	0.347	0.356	558.3	1971	10
8.09	2.51	7.2	435.38	359.93	1.210	1822.36	23.89	278.64	313472.2	0.387	0.367	564.9	1971	11
7.47	2.73	6.6	358.96	284.87	1.260	1362.01	26.36	237.40	267069.6	0.319	0.328	569.7	1971	12
7.71	2.68	6.9	393.04	322.80	1.242	1554.33	25.41	3054.31	3436094.0	0.349	0.339	6736.8	1971	13
8.93	2.97	8.0	540.97	492.80	1.098	2237.72	24.17	357.76	402478.5	0.481	0.370	647.3	1972	1
7.57	2.53	6.7	374.54	294.95	1.270	1482.79	25.26	231.72	260679.6	0.333	0.344	506.2	1972	2
7.57	2.55	6.7	374.52	295.43	1.268	1475.94	25.38	247.68	278644.9	0.333	0.343	562.4	1972	3
7.59	2.62	6.7	376.23	298.54	1.260	1465.64	25.67	240.79	270887.0	0.334	0.341	550.2	1972	4
6.52	2.21	5.8	263.09	187.37	1.404	1046.45	25.14	173.99	195740.9	0.234	0.305	469.0	1972	5
6.55	2.37	5.8	258.69	190.11	1.361	1002.89	25.79	165.56	186258.1	0.230	0.294	467.3	1972	6
5.62	2.13	5.0	171.98	119.91	1.434	693.44	24.80	113.74	127953.2	0.153	0.245	387.4	1972	7
5.73	2.16	5.1	181.34	127.16	1.426	726.26	24.97	119.93	134916.4	0.161	0.251	399.5	1972	8
6.93	2.44	6.1	300.82	225.94	1.331	1166.16	25.80	192.53	216592.2	0.267	0.315	498.8	1972	9
7.30	2.62	6.5	339.89	264.89	1.283	1300.37	26.14	224.78	252876.6	0.302	0.325	552.0	1972	10
6.42	2.44	5.7	241.25	179.51	1.344	928.43	25.98	154.40	173700.7	0.214	0.280	462.0	1972	11
6.61	2.19	5.9	273.62	194.86	1.404	1097.25	24.94	180.95	203570.0	0.243	0.313	473.6	1972	12
6.95	2.44	6.2	308.08	239.29	1.324	1218.61	25.34	2403.82	2704298.1	0.274	0.311	5975.9	1972	13
6.65	2.40	5.9	268.65	198.87	1.351	1038.74	25.86	177.67	199875.7	0.239	0.299	492.4	1973	1
6.88	2.60	6.1	289.05	221.57	1.305	1094.58	26.41	172.66	194241.8	0.257	0.301	472.6	1973	2
6.53	2.52	5.8	249.61	188.76	1.322	952.19	26.21	165.08	185712.0	0.222	0.281	491.6	1973	3
7.79	2.87	6.9	398.52	325.42	1.225	1506.18	26.46	255.05	286934.1	0.354	0.337	577.8	1973	4
7.35	2.61	6.5	346.78	270.73	1.281	1333.12	26.01	229.34	258006.5	0.308	0.329	554.3	1973	5
6.63	2.48	5.9	263.17	197.41	1.333	1007.62	26.12	168.43	189479.2	0.234	0.292	480.4	1973	6
6.41	2.34	5.7	244.44	178.12	1.372	950.76	25.71	161.66	181862.2	0.217	0.287	469.6	1973	7
5.60	2.11	5.0	171.11	118.35	1.446	691.50	24.74	113.16	127303.6	0.152	0.245	383.9	1973	8
6.32	2.38	5.6	231.48	170.51	1.358	896.27	25.83	148.15	166663.3	0.206	0.276	450.2	1973	9
7.05	2.49	6.3	313.10	237.74	1.317	1210.11	25.87	207.06	232942.9	0.278	0.319	526.6	1973	10
7.13	2.74	6.3	316.68	248.51	1.274	1184.88	26.73	202.68	228012.2	0.281	0.308	533.0	1973	11

II. MONTHLY ARRAY OUTPUTS

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
65	1	19.25	22.33	24.49	42.65	47.78	75.80	83.60	92.07	96.73	98.95	100.0	453.0	205.2
		4.95	6.06	7.36	25.79	32.64	91.14	98.42	99.38	99.53	99.81	40.0		
		1.39	2.02	2.56	17.11	25.79	96.78	99.81	99.93	99.93	99.93	0.		
65	2	17.57	20.35	22.30	38.83	43.58	70.69	78.87	88.49	94.48	97.84	100.0	502.3	213.5
		4.01	4.95	6.06	19.77	29.12	87.49	97.44	98.61	98.93	99.38	40.0		
		1.07	1.39	1.58	12.51	19.77	93.94	99.53	99.81	99.81	99.81	0.		
65	3	23.98	27.40	29.76	48.60	53.65	79.52	86.26	93.37	97.21	99.06	100.0	400.8	200.4
		7.36	8.86	10.57	32.64	42.08	95.05	99.18	99.65	99.81	99.90	40.0		
		2.02	3.22	4.01	22.67	32.64	98.42	99.95	99.98	99.98	99.98	0.		
65	4	18.98	22.18	24.43	43.61	49.05	78.30	86.04	93.94	97.84	99.44	100.0	433.5	198.9
		4.95	6.06	7.36	25.79	36.32	92.64	98.93	99.65	99.81	99.90	40.0		
		1.58	2.02	2.56	17.11	29.12	97.44	99.90	99.97	99.97	99.97	0.		
65	5	13.64	16.18	18.00	34.47	39.48	69.62	78.93	89.59	95.71	98.68	100.0	530.6	208.0
		2.56	3.22	4.01	17.11	22.67	85.31	96.78	98.61	99.18	99.53	40.0		
		0.62	0.82	1.07	8.86	14.69	92.64	99.38	99.74	99.74	99.74	0.		
65	6	21.55	24.95	27.32	46.88	52.26	80.15	87.26	94.44	97.97	99.45	100.0	406.1	196.9
		6.06	7.36	8.86	29.12	42.08	95.05	99.18	99.74	99.81	99.93	40.0		
		2.02	2.56	3.22	22.67	32.64	98.42	99.95	99.98	99.98	99.98	0.		
65	7	25.28	29.06	31.68	52.48	57.97	84.48	90.58	96.27	98.78	99.71	100.0	352.4	186.6
		7.36	10.57	12.51	42.08	49.86	97.44	99.74	99.90	99.95	99.98	40.0		
		3.22	4.01	4.95	29.12	44.04	99.38	99.99	100.00	100.00	100.00	0.		
65	8	38.15	42.49	45.38	65.87	70.64	90.61	94.50	97.88	99.30	99.82	100.0	247.6	165.4
		14.69	19.77	22.67	55.96	67.36	99.53	99.98	100.00	100.00	100.00	40.0		
		7.36	8.86	12.51	51.09	67.36	99.98	100.00	100.00	100.00	100.00	0.		
65	9	24.29	27.95	30.48	50.81	56.24	83.05	89.45	95.63	98.49	99.61	100.0	369.2	190.5
		7.36	8.86	10.57	36.32	46.17	96.78	99.65	99.86	99.93	99.97	40.0		
		2.56	4.01	4.95	25.79	42.08	99.18	99.98	100.00	100.00	100.00	0.		
65	10	17.64	20.56	22.62	40.26	45.34	73.83	82.03	91.13	96.27	98.78	100.0	476.6	207.1
		4.01	4.95	6.06	22.67	29.12	89.43	97.98	98.93	99.53	99.74	40.0		
		1.07	1.58	2.02	14.69	22.67	95.05	99.74	99.90	99.90	99.90	0.		
65	11	20.30	23.32	25.42	42.68	47.50	73.84	81.42	90.08	95.31	98.18	100.0	464.2	211.0
		4.95	6.06	7.36	25.79	32.64	89.43	97.98	98.93	99.38	99.65	40.0		
		1.39	2.02	2.56	14.69	25.79	95.99	99.74	99.90	99.90	99.90	0.		
65	12	12.01	14.36	16.06	31.86	36.80	67.54	77.38	88.81	95.45	98.64	100.0	555.9	207.6
		2.02	2.56	3.22	14.69	19.77	82.89	95.99	98.42	98.93	99.38	40.0		
		0.47	0.62	0.82	7.36	12.51	91.14	99.18	99.65	99.65	99.65	0.		
65	13	21.05	24.26	26.50	44.92	50.02	77.28	84.69	92.64	96.96	99.01	100.0		
		5.86	7.44	8.88	28.98	37.49	91.85	98.44	99.31	99.57	99.77	40.0		
		2.06	2.76	3.57	20.30	30.76	96.53	99.76	99.91	99.91	99.91	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
66	1	17.31	20.26	22.34	40.26	45.45	74.54	82.81	91.82	96.73	99.01	100.0	472.4	205.2
		4.01	4.95	6.06	22.67	32.64	89.43	98.42	99.18	99.53	99.74	40.0		
		1.07	1.58	2.02	14.69	22.67	95.99	99.81	99.90	99.90	99.90	0.		
66	2	19.59	22.85	25.15	44.51	49.97	78.98	86.54	94.21	97.95	99.47	100.0	425.0	198.0
		4.95	6.06	8.86	29.12	36.32	93.94	99.18	99.65	99.81	99.90	40.0		
		1.58	2.56	3.22	19.77	29.12	97.98	99.93	99.98	99.98	99.98	0.		
66	3	14.78	17.19	18.88	33.62	37.98	64.33	72.98	83.88	91.38	96.13	100.0	566.3	218.2
		2.56	3.22	4.01	14.69	19.77	80.23	95.05	97.44	97.98	98.61	40.0		
		0.62	0.82	1.07	7.36	12.51	87.49	98.61	99.38	99.38	99.38	0.		
66	4	14.55	17.07	18.86	34.65	39.36	67.62	76.57	87.29	94.03	97.76	100.0	541.5	213.1
		2.56	3.22	4.01	17.11	22.67	82.89	95.99	98.42	98.61	99.18	40.0		
		0.62	0.82	1.07	8.86	14.69	91.14	99.18	99.65	99.65	99.65	0.		
66	5	15.25	17.92	19.82	36.56	41.54	70.67	79.50	89.61	95.53	98.52	100.0	513.9	209.3
		2.56	4.01	4.95	19.77	25.79	85.31	97.44	98.61	99.18	99.53	40.0		
		0.82	1.07	1.39	10.57	17.11	92.64	99.53	99.81	99.81	99.81	0.		
66	6	18.02	21.17	23.40	42.67	48.21	78.24	86.18	94.19	98.03	99.52	100.0	438.7	197.5
		4.95	6.06	7.36	25.79	36.32	92.64	98.93	99.53	99.81	99.90	40.0		
		1.39	2.02	2.56	17.11	25.79	97.44	99.90	99.97	99.97	99.97	0.		
66	7	24.00	27.73	30.32	51.26	56.86	84.21	90.51	96.34	98.86	99.74	100.0	360.2	186.3
		7.36	10.57	10.57	36.32	48.04	96.78	99.74	99.90	99.95	99.98	40.0		
		2.56	4.01	4.95	29.12	42.08	99.38	99.99	100.00	100.00	100.00	0.		
66	8	31.28	35.48	38.33	59.79	65.10	88.61	93.41	97.58	99.26	99.84	100.0	290.9	173.6
		12.51	14.69	17.11	49.17	57.92	98.93	99.93	99.98	99.99	100.00	40.0		
		4.95	6.06	8.86	42.08	55.96	99.86	100.00	100.00	100.00	100.00	0.		
66	9	30.43	34.45	37.19	57.88	63.07	86.79	91.97	96.75	98.88	99.71	100.0	311.1	180.7
		10.57	12.51	17.11	46.04	55.96	98.42	99.86	99.97	99.98	99.99	40.0		
		4.01	6.06	7.36	36.32	51.61	99.74	100.00	100.00	100.00	100.00	0.		
66	10	16.65	19.41	21.35	38.12	42.99	71.06	79.50	89.25	95.12	98.23	100.0	503.8	210.9
		3.22	4.01	6.06	19.77	29.12	87.49	97.44	98.61	99.18	99.53	40.0		
		1.07	1.39	1.58	12.51	19.77	93.94	99.53	99.81	99.81	99.81	0.		
66	11	21.86	25.27	27.65	47.14	52.49	80.13	87.19	94.35	97.91	99.42	100.0	404.9	197.1
		6.06	8.86	8.86	32.64	42.08	95.05	99.18	99.74	99.86	99.93	40.0		
		2.02	2.56	4.01	22.67	32.64	98.42	99.95	99.98	99.98	99.98	0.		
66	12	23.82	27.43	29.94	50.13	55.55	82.55	89.08	95.43	98.40	99.58	100.0	375.6	191.8
		7.36	8.86	10.57	36.32	44.04	96.78	99.53	99.86	99.90	99.97	40.0		
		2.56	3.22	4.95	25.79	42.08	98.93	99.98	100.00	100.00	100.00	0.		
66	13	20.63	23.85	26.10	44.72	49.88	77.31	84.69	92.56	96.84	98.91	100.0		
		5.72	7.25	8.79	29.12	37.56	91.49	98.39	99.24	99.48	99.69	40.0		
		1.94	2.68	3.59	20.57	30.50	96.08	99.70	99.87	99.87	99.87	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
67	1	13.70	16.17	17.93	33.73	38.51	67.52	76.74	87.70	94.44	98.04	100.0	546.7	211.4
		2.56	3.22	4.01	14.69	22.67	82.89	95.99	98.42	98.61	99.18	40.0		
		0.62	0.82	1.07	8.86	14.69	91.14	99.18	99.65	99.65	99.65	0.		
67	2	18.53	21.58	23.73	41.93	47.12	75.63	83.58	92.17	96.83	99.02	100.0	457.6	203.7
		4.01	6.06	7.36	22.67	32.64	91.14	98.42	99.38	99.65	99.81	40.0		
		1.39	1.58	2.56	14.69	25.79	96.78	99.81	99.93	99.93	99.93	0.		
67	3	14.16	16.84	18.77	36.25	41.54	72.69	81.85	91.78	96.99	99.21	100.0	503.5	203.3
		2.56	4.01	4.01	19.77	25.79	89.43	97.98	98.93	99.38	99.74	40.0		
		0.82	1.07	1.39	10.57	17.11	93.94	99.65	99.86	99.86	99.86	0.		
67	4	12.26	14.53	16.16	31.06	35.66	64.50	74.07	85.80	93.34	97.55	100.0	578.0	212.3
		1.58	2.56	3.22	12.51	19.77	80.23	95.05	97.44	98.42	98.93	40.0		
		0.35	0.62	0.82	6.06	10.57	87.49	98.93	99.38	99.38	99.38	0.		
67	5	16.09	18.84	20.78	37.70	42.67	71.37	79.97	89.79	95.55	98.49	100.0	504.0	209.4
		3.22	4.01	4.95	19.77	25.79	87.49	97.44	98.61	99.18	99.53	40.0		
		0.82	1.39	1.58	10.57	19.77	93.94	99.53	99.81	99.81	99.81	0.		
67	6	26.78	30.45	32.96	52.55	57.66	82.66	88.75	94.89	97.99	99.38	100.0	362.3	193.8
		8.86	10.57	12.51	36.32	47.97	96.78	99.53	99.86	99.90	99.95	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.98	100.00	100.00	100.00	0.		
67	7	30.91	34.92	37.64	58.11	63.22	86.65	91.81	96.63	98.81	99.68	100.0	310.6	181.1
		10.57	14.69	14.69	46.54	55.96	98.42	99.86	99.97	99.98	99.99	40.0		
		4.01	6.06	7.36	36.32	51.70	99.74	100.00	100.00	100.00	100.00	0.		
67	8	29.32	33.49	36.35	58.27	63.79	88.47	93.48	97.73	99.37	99.88	100.0	299.7	171.6
		10.57	12.51	17.11	47.82	57.92	98.93	99.93	99.98	100.00	100.00	40.0		
		4.01	6.06	7.36	42.08	55.96	99.86	100.00	100.00	100.00	100.00	0.		
67	9	27.44	31.32	33.98	54.67	60.01	85.30	91.03	96.38	98.78	99.69	100.0	336.3	183.8
		8.86	12.51	14.69	42.08	51.19	97.98	99.81	99.95	99.98	99.98	40.0		
		3.22	4.95	6.06	32.64	46.11	99.53	100.00	100.00	100.00	100.00	0.		
67	10	18.24	21.18	23.25	40.75	45.75	73.68	81.74	90.77	95.98	98.62	100.0	475.0	208.2
		4.01	6.06	6.06	22.67	32.64	89.43	97.98	98.93	99.38	99.65	40.0		
		1.39	1.58	2.02	14.69	22.67	95.05	99.74	99.90	99.90	99.90	0.		
67	11	14.01	16.73	18.69	36.57	42.01	73.85	83.02	92.69	97.50	99.40	100.0	495.1	200.5
		2.56	4.01	4.95	19.77	25.79	89.43	97.98	99.18	99.53	99.74	40.0		
		0.82	1.07	1.39	10.57	19.77	95.05	99.74	99.90	99.90	99.90	0.		
67	12	16.92	19.89	21.99	40.28	45.61	75.43	83.77	92.63	97.24	99.24	100.0	467.2	202.4
		4.01	4.95	6.06	22.67	32.64	91.14	98.42	99.38	99.65	99.81	40.0		
		1.07	1.58	2.02	14.69	22.67	95.99	99.81	99.93	99.93	99.93	0.		
67	13	19.86	22.99	25.19	43.49	48.63	76.48	84.15	92.41	96.90	99.02	100.0		
		5.28	7.10	8.30	27.27	35.90	91.11	98.20	99.17	99.47	99.69	40.0		
		1.81	2.57	3.22	19.24	29.07	95.64	99.70	99.86	99.86	99.86	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
68	1	19.77	23.00	25.26	44.31	49.66	78.24	85.82	93.66	97.64	99.34	100.0	430.3	199.1
		4.95	6.06	7.36	29.12	36.32	92.64	98.93	99.65	99.74	99.90	40.0		
		1.58	2.02	2.56	19.77	29.12	97.44	99.93	99.97	99.97	99.97	0.		
68	2	18.75	21.74	23.85	41.55	46.58	74.38	82.31	91.13	96.16	98.69	100.0	466.9	207.5
		4.01	6.06	7.36	22.67	32.64	91.14	98.42	99.18	99.38	99.74	40.0		
		1.39	1.58	2.02	14.69	22.67	95.99	99.74	99.90	99.90	99.90	0.		
68	3	16.92	19.81	21.85	39.52	44.65	73.69	82.06	91.29	96.42	98.87	100.0	481.2	205.8
		4.01	4.95	6.06	22.67	29.12	89.43	97.98	99.18	99.53	99.74	40.0		
		1.07	1.58	2.02	12.51	22.67	95.05	99.74	99.90	99.90	99.90	0.		
68	4	12.10	14.41	16.07	31.39	36.15	65.90	75.62	87.25	94.38	98.11	100.0	568.0	210.1
		2.02	2.56	3.22	14.69	19.77	80.23	95.05	97.98	98.61	99.18	40.0		
		0.35	0.62	0.82	6.06	12.51	89.43	98.93	99.53	99.53	99.53	0.		
68	5	18.64	21.70	23.85	42.06	47.24	75.69	83.61	92.17	96.83	99.01	100.0	456.6	204.3
		4.01	6.06	7.36	22.67	32.64	91.14	98.61	99.38	99.53	99.81	40.0		
		1.39	2.02	2.56	14.69	25.79	96.78	99.81	99.93	99.93	99.93	0.		
68	6	21.50	25.02	27.49	47.94	53.58	82.21	89.14	95.72	98.64	99.69	100.0	388.7	190.6
		6.06	8.86	8.86	32.64	44.04	95.99	99.53	99.86	99.93	99.97	40.0		
		2.02	3.22	4.01	22.67	36.32	98.93	99.98	99.99	99.99	99.99	0.		
68	7	23.67	27.19	29.63	49.25	54.52	81.20	87.88	94.61	97.97	99.41	100.0	387.9	195.7
		7.36	8.86	10.57	32.64	44.04	95.99	99.38	99.81	99.86	99.93	40.0		
		2.56	3.22	4.01	25.79	36.32	98.61	99.97	99.99	99.99	99.99	0.		
68	8	25.53	29.23	31.78	51.94	57.25	83.26	89.47	95.51	98.39	99.56	100.0	362.1	190.8
		8.86	10.57	12.51	36.32	48.02	96.78	99.65	99.86	99.93	99.97	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.98	100.00	100.00	100.00	0.		
68	9	26.58	30.52	33.24	54.58	60.13	86.16	91.85	96.95	99.07	99.80	100.0	332.0	180.9
		8.86	10.57	12.51	42.08	51.90	97.98	99.86	99.95	99.98	99.99	40.0		
		3.22	4.95	6.06	32.64	47.00	99.65	100.00	100.00	100.00	100.00	0.		
68	10	21.73	25.09	27.44	46.70	51.99	79.50	86.62	93.95	97.68	99.32	100.0	410.8	198.3
		6.06	7.36	8.86	29.12	42.08	93.94	99.18	99.65	99.81	99.90	40.0		
		2.02	2.56	3.22	19.77	32.64	98.42	99.95	99.98	99.98	99.98	0.		
68	11	23.12	26.73	29.24	49.62	55.13	82.67	89.29	95.65	98.55	99.65	100.0	377.5	190.5
		7.36	8.86	10.57	36.32	44.04	96.78	99.53	99.86	99.93	99.97	40.0		
		2.56	3.22	4.01	25.79	36.32	98.93	99.98	100.00	100.00	100.00	0.		
68	12	22.65	25.80	27.96	45.35	50.07	75.25	82.34	90.41	95.33	98.09	100.0	442.3	210.5
		6.06	7.36	8.86	29.12	36.32	91.14	98.42	99.18	99.53	99.65	40.0		
		1.58	2.56	3.22	17.11	29.12	96.78	99.81	99.93	99.93	99.93	0.		
68	13	20.91	24.19	26.47	45.35	50.58	78.18	85.50	93.19	97.25	99.13	100.0		
		5.80	7.34	8.67	29.17	38.41	92.77	98.71	99.46	99.65	99.81	40.0		
		1.91	2.63	3.29	20.05	31.05	97.10	99.82	99.93	99.93	99.93	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
69	1	17.63	20.67	22.82	41.39	46.75	76.33	84.46	93.00	97.38	99.27	100.0	456.3	201.4
		4.01	4.95	6.06	22.67	32.64	91.14	98.61	99.38	99.65	99.86	40.0		
		1.39	1.58	2.02	14.69	25.79	96.78	99.86	99.95	99.95	99.95	0.		
69	2	31.40	35.52	38.32	59.31	64.51	87.83	92.75	97.17	99.07	99.77	100.0	297.8	176.6
		10.57	14.69	17.11	48.32	57.92	98.61	99.93	99.98	99.99	100.00	40.0		
		4.95	6.06	7.36	42.08	55.96	99.86	100.00	100.00	100.00	100.00	0.		
69	3	27.22	31.01	33.62	53.87	59.12	84.28	90.15	95.82	98.49	99.58	100.0	346.3	188.5
		8.86	10.57	12.51	42.08	50.23	97.44	99.74	99.90	99.95	99.98	40.0		
		3.22	4.95	6.06	32.64	44.04	99.38	99.99	100.00	100.00	100.00	0.		
69	4	21.10	24.32	26.57	45.07	50.19	77.38	84.75	92.64	96.95	99.01	100.0	431.4	203.4
		4.95	7.36	8.86	29.12	36.32	92.64	98.61	99.53	99.65	99.86	40.0		
		1.58	2.56	3.22	19.77	29.12	97.44	99.90	99.97	99.97	99.97	0.		
69	5	15.32	18.18	20.22	38.45	43.89	74.98	83.75	92.94	97.54	99.39	100.0	479.0	200.9
		3.22	4.95	4.95	19.77	29.12	89.43	98.42	99.38	99.65	99.81	40.0		
		1.07	1.39	1.58	12.51	22.67	95.99	99.81	99.93	99.93	99.93	0.		
69	6	20.74	24.00	26.28	45.15	50.40	78.17	85.56	93.32	97.38	99.21	100.0	426.4	201.0
		6.06	7.36	8.86	29.12	36.32	93.94	98.93	99.53	99.74	99.86	40.0		
		1.58	2.56	3.22	19.77	29.12	97.44	99.90	99.97	99.97	99.97	0.		
69	7	29.94	33.98	36.75	57.74	63.02	87.10	92.29	96.99	99.01	99.76	100.0	310.1	179.3
		10.57	14.69	14.69	44.04	55.96	98.42	99.86	99.97	99.98	99.99	40.0		
		4.01	6.06	7.36	36.32	51.84	99.74	100.00	100.00	100.00	100.00	0.		
69	8	24.25	27.75	30.17	49.44	54.60	80.69	87.32	94.13	97.66	99.27	100.0	389.7	197.6
		7.36	8.86	10.57	32.64	44.04	95.05	99.18	99.74	99.86	99.93	40.0		
		2.56	3.22	4.01	25.79	36.32	98.61	99.97	99.99	99.99	99.99	0.		
69	9	23.35	27.11	29.73	51.10	56.85	84.81	91.11	96.75	99.06	99.81	100.0	357.7	183.5
		7.36	8.86	10.57	36.32	47.77	97.44	99.74	99.93	99.97	99.98	40.0		
		2.56	4.01	4.95	29.12	42.08	99.38	99.99	100.00	100.00	100.00	0.		
69	10	17.85	21.07	23.36	43.25	48.99	79.75	87.60	95.18	98.53	99.70	100.0	426.9	193.3
		4.95	6.06	7.36	25.79	36.32	93.94	99.18	99.74	99.86	99.93	40.0		
		1.39	2.02	2.56	17.11	29.12	97.98	99.95	99.98	99.98	99.98	0.		
69	11	16.94	20.03	22.23	41.52	47.15	78.05	86.25	94.41	98.20	99.60	100.0	445.5	196.4
		4.01	4.95	6.06	25.79	32.64	92.64	98.93	99.65	99.81	99.90	40.0		
		1.39	1.58	2.02	17.11	25.79	97.44	99.90	99.97	99.97	99.97	0.		
69	12	26.78	30.69	33.38	54.45	59.92	85.73	91.47	96.70	98.95	99.76	100.0	335.1	183.1
		8.86	12.51	14.69	42.08	52.42	97.98	99.81	99.95	99.98	99.99	40.0		
		3.22	4.95	6.06	32.64	46.36	99.53	100.00	100.00	100.00	100.00	0.		
69	13	22.71	26.19	28.62	48.39	53.78	81.26	88.12	94.92	98.19	99.51	100.0		
		6.73	8.82	10.19	33.14	42.64	94.89	99.25	99.72	99.84	99.93	40.0		
		2.41	3.41	4.20	24.96	36.52	98.30	99.94	99.98	99.98	99.98	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
70	1	20.86	24.46	26.99	48.30	54.21	83.81	90.62	96.69	99.10	99.84	100.0	377.8	184.7
		6.06	7.36	10.57	32.64	44.04	96.78	99.65	99.90	99.97	99.98	40.0		
		2.02	3.22	4.01	25.79	36.32	99.18	99.99	100.00	100.00	100.00	0.		
70	2	15.28	18.02	19.97	37.24	42.37	72.23	81.06	90.88	96.33	98.89	100.0	501.3	206.4
		3.22	4.01	4.95	19.77	25.79	89.43	97.98	98.93	99.38	99.65	40.0		
		0.82	1.39	1.58	10.57	19.77	93.94	99.65	99.86	99.86	99.86	0.		
70	3	26.12	29.81	32.35	52.25	57.47	83.00	89.16	95.24	98.22	99.48	100.0	362.0	192.3
		8.86	10.57	12.51	36.32	48.05	96.78	99.55	99.86	99.93	99.97	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.98	100.00	100.00	100.00	0.		
70	4	10.49	12.59	14.12	28.57	33.18	63.16	73.36	85.89	93.75	97.91	100.0	598.4	209.6
		1.39	2.02	2.02	10.57	17.11	80.23	93.94	97.44	98.42	98.93	40.0		
		0.26	0.35	0.47	4.95	8.86	85.31	98.61	99.38	99.38	99.38	0.		
70	5	9.00	10.96	12.40	26.57	31.25	62.76	73.66	86.85	94.73	98.51	100.0	610.5	205.5
		1.07	1.58	1.58	10.57	14.69	77.33	93.94	97.44	98.42	98.93	40.0		
		0.19	0.26	0.35	4.01	7.36	85.31	98.61	99.38	99.38	99.38	0.		
70	6	16.60	19.60	21.73	40.45	45.94	76.52	84.89	93.53	97.76	99.45	100.0	459.9	199.7
		4.01	4.95	6.06	22.67	32.64	91.14	98.61	99.53	99.65	99.86	40.0		
		1.07	1.58	2.02	14.69	22.67	96.78	99.86	99.95	99.95	99.95	0.		
70	7	23.45	27.07	29.59	49.99	55.49	82.83	89.38	95.66	98.53	99.63	100.0	374.6	190.3
		7.36	8.86	10.57	36.32	44.04	95.99	99.53	99.86	99.93	99.97	40.0		
		2.56	3.22	4.01	25.79	42.08	98.93	99.98	100.00	100.00	100.00	0.		
70	8	29.95	34.00	36.76	57.76	63.05	87.13	92.30	96.99	99.01	99.76	100.0	309.9	179.3
		10.57	12.51	17.11	46.05	57.92	98.61	99.86	99.97	99.98	99.99	40.0		
		4.01	6.06	7.36	36.32	51.90	99.74	100.00	100.00	100.00	100.00	0.		
70	9	17.51	20.63	22.85	42.15	47.75	78.22	86.28	94.35	98.14	99.57	100.0	441.4	197.0
		4.01	4.95	7.36	25.79	36.32	92.64	98.93	99.65	99.81	99.90	40.0		
		1.39	2.02	2.56	17.11	25.79	97.44	99.90	99.97	99.97	99.97	0.		
70	10	14.45	17.15	19.09	36.51	41.77	72.59	81.67	91.58	96.85	99.14	100.0	502.8	204.3
		3.22	4.01	4.95	19.77	25.79	89.43	97.98	98.93	99.38	99.65	40.0		
		0.82	1.07	1.39	10.57	17.11	93.94	99.65	99.86	99.86	99.86	0.		
70	11	23.34	26.68	29.00	47.56	52.58	78.56	85.46	92.84	96.92	98.93	100.0	411.7	202.9
		6.06	8.86	10.57	32.64	42.08	93.94	98.93	99.53	99.74	99.86	40.0		
		2.02	3.22	4.01	22.67	32.64	97.98	99.93	99.98	99.98	99.98	0.		
70	12	22.79	26.13	28.44	47.10	52.16	78.54	85.53	92.98	97.05	99.01	100.0	414.3	202.6
		6.06	8.86	10.57	29.12	42.08	93.94	98.93	99.53	99.74	99.86	40.0		
		2.02	3.22	4.01	19.77	32.64	97.98	99.93	99.98	99.98	99.98	0.		
70	13	19.15	22.26	24.44	42.87	48.10	76.61	84.45	92.79	97.20	99.18	100.0		
		5.16	6.54	8.24	26.85	35.88	91.35	95.16	99.22	99.53	99.71	40.0		
		1.70	2.47	3.06	18.45	28.27	95.48	95.68	99.86	99.86	99.86	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
71	1	15.74	18.73	20.87	40.01	45.71	77.54	86.08	94.52	98.33	99.66	100.0	456.1	195.8
		4.01	4.95	6.06	22.67	32.64	92.64	98.93	99.53	99.81	99.90	40.0		
		1.07	1.58	2.02	14.69	22.67	96.78	99.90	99.97	99.97	99.97	0.		
71	2	16.07	18.85	20.83	38.05	43.11	72.27	80.89	90.56	96.06	98.74	100.0	497.0	207.9
		3.22	4.01	4.95	19.77	29.12	87.49	97.44	98.93	99.38	99.65	40.0		
		1.07	1.39	1.58	12.51	19.77	93.94	99.65	99.86	99.86	99.86	0.		
71	3	15.57	18.56	20.71	39.95	45.68	77.73	86.27	94.66	98.40	99.68	100.0	455.3	195.2
		4.01	4.95	6.06	22.67	32.64	92.64	98.93	99.65	99.81	99.90	40.0		
		1.07	1.58	2.02	14.69	22.67	97.44	99.90	99.97	99.97	99.97	0.		
71	4	12.84	15.26	17.00	32.86	37.74	67.71	77.24	88.41	95.05	98.40	100.0	549.9	209.2
		2.02	2.56	3.22	14.69	22.67	82.89	96.78	98.42	98.61	99.18	40.0		
		0.47	0.82	1.07	7.36	12.51	91.14	99.18	99.65	99.65	99.65	0.		
71	5	16.36	19.42	21.61	40.97	46.68	78.17	86.49	94.68	98.37	99.66	100.0	447.6	195.5
		4.01	4.95	6.06	22.67	32.64	92.64	98.93	99.65	99.81	99.90	40.0		
		1.39	1.58	2.02	14.69	25.79	97.44	99.90	99.97	99.97	99.97	0.		
71	6	34.72	38.97	41.83	62.66	67.67	89.33	93.71	97.57	99.20	99.80	100.0	271.7	171.1
		12.51	17.11	19.77	53.76	63.68	99.18	99.97	99.99	100.00	100.00	40.0		
		6.06	7.36	10.57	44.04	57.92	99.93	100.00	100.00	100.00	100.00	0.		
71	7	27.94	31.77	34.40	54.65	59.87	84.65	90.39	95.91	98.52	99.58	100.0	340.1	187.9
		8.86	12.51	14.69	42.08	51.78	97.44	99.74	99.90	99.95	99.98	40.0		
		3.22	4.95	6.06	32.64	44.04	99.38	99.99	100.00	100.00	100.00	0.		
71	8	35.39	39.77	42.72	64.07	69.15	90.55	94.65	98.09	99.44	99.88	100.0	257.6	164.5
		14.69	17.11	19.77	55.96	67.36	99.53	99.98	100.00	100.00	100.00	40.0		
		6.06	8.86	10.57	48.66	63.68	99.97	100.00	100.00	100.00	100.00	0.		
71	9	30.35	34.42	37.20	58.21	63.47	87.35	92.45	97.06	99.04	99.77	100.0	306.3	177.9
		10.57	14.69	14.69	46.33	55.96	98.61	99.90	99.98	99.99	100.00	40.0		
		4.01	6.06	7.36	36.32	52.71	99.81	100.00	100.00	100.00	100.00	0.		
71	10	24.59	28.01	30.37	49.04	54.01	79.45	86.09	93.17	97.05	98.97	100.0	399.0	202.0
		7.36	8.86	10.57	32.64	44.04	95.05	99.18	99.65	99.81	99.90	40.0		
		2.56	3.22	4.01	22.67	36.32	98.42	99.95	99.98	99.98	99.98	0.		
71	11	21.40	24.59	26.81	44.99	49.99	76.68	84.00	92.00	96.51	98.78	100.0	435.9	205.7
		6.06	7.36	8.86	29.12	36.32	92.64	98.61	99.38	99.65	99.81	40.0		
		1.58	2.56	3.22	19.77	29.12	97.44	99.86	99.95	99.95	99.95	0.		
71	12	21.33	24.90	27.41	48.29	54.06	83.09	89.94	96.25	98.90	99.78	100.0	381.9	187.6
		6.06	7.36	8.86	32.64	44.04	96.78	99.65	99.90	99.93	99.98	40.0		
		2.02	3.22	4.01	25.79	36.32	98.93	99.98	100.00	100.00	100.00	0.		
71	13	22.69	26.10	28.48	47.81	53.10	80.38	87.35	94.41	97.91	99.39	100.0		
		6.95	8.87	10.30	32.92	42.74	93.96	99.00	99.58	99.73	99.85	40.0		
		2.55	3.60	4.54	24.49	35.29	97.55	99.86	99.94	99.94	99.94	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
72	1	12.81	15.24	16.99	32.96	37.88	68.06	77.61	88.74	95.28	98.52	100.0	547.3	208.8
		2.02	3.22	4.01	14.69	19.77	85.31	95.99	98.42	98.93	99.38	40.0		
		0.47	0.82	1.07	7.36	14.69	91.14	99.18	99.65	99.65	99.65	0.		
72	2	24.22	27.78	30.25	49.94	55.20	81.61	88.17	94.74	98.01	99.42	100.0	381.9	194.9
		7.36	8.86	10.57	32.64	44.04	95.99	99.38	99.81	99.86	99.95	40.0		
		2.56	3.22	4.01	25.79	36.32	98.61	99.98	99.99	99.99	99.99	0.		
72	3	23.24	26.73	29.15	48.69	53.97	80.82	87.60	94.46	97.90	99.39	100.0	392.9	196.6
		6.06	8.86	10.57	32.64	44.04	95.05	99.38	99.74	99.86	99.93	40.0		
		2.56	3.22	4.01	22.67	36.32	98.61	99.97	99.99	99.99	99.99	0.		
72	4	22.47	25.95	28.37	48.15	53.54	81.05	87.94	94.79	98.12	99.49	100.0	394.4	195.6
		6.06	8.86	10.57	32.64	44.04	95.05	99.38	99.74	99.86	99.93	40.0		
		2.02	3.22	4.01	22.67	36.32	98.61	99.97	99.99	99.99	99.99	0.		
72	5	32.69	36.71	39.43	59.52	64.46	86.88	91.83	96.50	98.70	99.62	100.0	301.9	182.2
		12.51	14.69	17.11	47.08	55.96	98.42	99.86	99.97	99.98	99.99	40.0		
		4.95	7.36	8.86	42.08	53.61	99.74	100.00	100.00	100.00	100.00	0.		
72	6	30.48	34.57	37.36	58.45	63.72	87.55	92.61	97.15	99.08	99.78	100.0	303.9	178.3
		10.57	14.69	14.69	47.07	55.96	98.61	99.90	99.98	99.99	100.00	40.0		
		4.01	6.06	7.36	42.08	53.25	99.81	100.00	100.00	100.00	100.00	0.		
72	7	42.80	47.38	50.39	70.95	75.51	93.22	96.28	98.72	99.62	99.92	100.0	206.1	151.6
		17.11	22.67	25.79	63.68	77.33	99.86	100.00	100.00	100.00	100.00	40.0		
		8.86	12.51	14.69	63.68	77.33	100.00	100.00	100.00	100.00	100.00	0.		
72	8	40.79	45.27	48.25	68.85	73.52	92.21	95.61	98.41	99.51	99.88	100.0	222.9	157.4
		17.11	22.67	25.79	63.68	74.21	99.74	99.99	100.00	100.00	100.00	40.0		
		7.36	10.57	14.69	55.96	74.21	99.99	100.00	100.00	100.00	100.00	0.		
72	9	25.46	29.17	31.73	51.98	57.32	83.42	89.62	95.62	98.45	99.58	100.0	361.0	190.7
		8.86	10.57	12.51	36.32	47.78	96.78	99.65	99.86	99.93	99.97	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.99	100.00	100.00	100.00	0.		
72	10	21.92	25.42	27.87	48.00	53.53	81.64	88.57	95.30	98.42	99.61	100.0	391.7	193.3
		6.06	8.86	10.57	32.64	44.04	95.99	99.38	99.81	99.90	99.95	40.0		
		2.02	3.22	4.01	22.67	36.32	98.61	99.97	99.99	99.99	99.99	0.		
72	11	31.55	35.88	38.83	60.95	66.39	89.87	94.40	98.12	99.49	99.90	100.0	277.9	168.1
		12.51	14.69	17.11	50.75	63.68	99.18	99.97	99.99	100.00	100.00	40.0		
		4.95	7.36	8.86	44.04	57.92	99.93	100.00	100.00	100.00	100.00	0.		
72	12	32.83	36.74	39.38	58.87	63.68	85.79	90.85	95.83	98.32	99.45	100.0	311.4	186.7
		12.51	14.69	17.11	44.04	55.96	98.42	99.81	99.95	99.97	99.98	40.0		
		4.95	6.06	8.86	36.32	51.50	99.65	100.00	100.00	100.00	100.00	0.		
72	13	28.44	32.24	34.83	54.78	59.89	84.35	90.09	95.70	98.41	99.55	100.0		
		9.90	12.78	14.70	41.49	52.23	96.53	99.39	99.77	99.86	99.92	40.0		
		3.99	5.64	7.11	34.53	47.49	98.66	99.92	99.97	99.97	99.97	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
73	1	30.23	34.33	37.12	58.27	63.58	87.55	92.63	97.17	99.09	99.78	100.0	304.8	177.9
		10.57	14.69	17.11	47.78	55.96	98.61	99.90	99.98	99.99	100.00	40.0		
		4.01	6.06	7.36	42.08	53.04	99.81	100.00	100.00	100.00	100.00	0.		
73	2	26.25	30.20	32.94	54.51	60.13	86.41	92.09	97.11	99.14	99.82	100.0	330.9	179.8
		8.86	10.57	14.69	42.08	51.95	98.42	99.86	99.95	99.98	99.99	40.0		
		3.22	4.95	6.06	32.64	47.21	99.65	100.00	100.00	100.00	100.00	0.		
73	3	29.54	33.79	36.70	58.99	64.58	89.19	94.03	98.01	99.47	99.90	100.0	292.0	170.3
		10.57	14.69	17.11	47.52	57.92	98.93	99.95	99.99	100.00	100.00	40.0		
		4.01	6.06	7.36	42.08	55.96	99.90	100.00	100.00	100.00	100.00	0.		
73	4	18.02	21.20	23.45	42.91	48.50	78.71	86.62	94.49	98.18	99.58	100.0	434.7	196.3
		4.95	6.06	7.36	25.79	36.32	93.94	98.93	99.65	99.81	99.90	40.0		
		1.39	2.02	2.56	17.11	29.12	97.98	99.93	99.98	99.98	99.98	0.		
73	5	22.64	26.18	28.64	48.78	54.25	81.92	88.69	95.30	98.39	99.59	100.0	386.2	192.8
		6.06	8.86	10.57	32.64	44.04	95.99	99.53	99.81	99.90	99.97	40.0		
		2.02	3.22	4.01	25.79	36.32	98.61	99.98	99.99	99.99	99.99	0.		
73	6	27.24	31.21	33.95	55.32	60.83	86.49	92.06	97.03	99.09	99.80	100.0	326.3	180.4
		8.86	12.51	14.69	44.04	53.17	98.42	99.86	99.97	99.98	99.99	40.0		
		3.22	4.95	6.06	32.64	48.26	99.65	100.00	100.00	100.00	100.00	0.		
73	7	32.70	36.89	39.73	60.74	65.89	88.56	93.25	97.40	99.15	99.79	100.0	286.1	174.5
		12.51	14.69	17.11	50.64	57.92	98.93	99.93	99.98	99.99	100.00	40.0		
		4.95	7.36	8.86	44.04	55.96	99.90	100.00	100.00	100.00	100.00	0.		
73	8	44.20	48.77	51.78	72.05	76.50	93.56	96.47	98.78	99.64	99.92	100.0	198.3	148.2
		19.77	25.79	29.12	67.36	77.33	99.90	100.00	100.00	100.00	100.00	40.0		
		8.86	12.51	17.11	63.68	80.23	100.00	100.00	100.00	100.00	100.00	0.		
73	9	31.39	35.66	38.57	60.40	65.80	89.32	93.98	97.90	99.40	99.88	100.0	283.8	170.8
		12.51	14.69	17.11	51.02	57.92	99.18	99.95	99.99	100.00	100.00	40.0		
		4.95	7.36	8.86	44.04	57.92	99.90	100.00	100.00	100.00	100.00	0.		
73	10	25.25	28.96	31.53	51.89	57.27	83.56	89.77	95.75	98.52	99.61	100.0	360.7	190.0
		7.36	10.57	12.51	36.32	48.04	96.78	99.65	99.86	99.93	99.98	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.99	100.00	100.00	100.00	0.		
73	11	21.69	25.35	27.93	49.37	55.26	84.39	91.00	96.85	99.15	99.85	100.0	368.9	184.2
		6.06	8.86	10.57	36.32	44.04	97.44	99.74	99.93	99.97	99.98	40.0		
		2.02	3.22	4.01	25.79	42.08	99.18	99.99	100.00	100.00	100.00	0.		
73	12	25.65	29.54	32.23	53.59	59.19	85.73	91.59	96.85	99.04	99.79	100.0	339.6	182.1
		8.86	10.57	12.51	42.08	51.62	97.98	99.81	99.95	99.98	99.99	40.0		
		3.22	4.01	6.06	32.64	44.04	99.53	100.00	100.00	100.00	100.00	0.		
73	13	27.90	31.84	34.55	55.57	60.98	86.28	91.85	96.89	99.02	99.78	100.0		
		9.74	12.71	15.04	43.63	53.02	97.88	99.76	99.92	99.96	99.98	40.0		
		3.76	5.48	6.94	35.97	49.35	99.44	99.99	99.99	99.99	99.99	0.		

		0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00			
74	1	28.83	32.76	35.44	56.00	61.25	85.73	91.23	96.39	98.74	99.67	100.0	326.9	184.9
		10.57	12.51	14.69	44.04	53.74	97.98	99.81	99.95	99.98	99.98	40.0		
		4.01	4.95	7.36	32.64	48.16	99.65	100.00	100.00	100.00	100.00	0.		
74	2	28.66	32.63	35.35	56.27	61.60	86.31	91.74	96.73	98.91	99.73	100.0	322.3	181.9
		8.86	12.51	14.69	44.04	55.96	98.42	99.86	99.95	99.98	99.99	40.0		
		4.01	4.95	7.36	36.32	49.14	99.65	100.00	100.00	100.00	100.00	0.		
74	3	18.05	21.17	23.37	42.33	47.77	77.47	85.46	93.68	97.75	99.42	100.0	444.9	199.7
		4.01	6.06	7.36	25.79	32.64	92.64	98.61	99.53	99.74	99.86	40.0		
		1.39	2.02	2.56	17.11	25.79	97.44	99.90	99.97	99.97	99.97	0.		
74	4	19.15	22.36	24.62	43.79	49.22	78.33	86.03	93.91	97.81	99.42	100.0	432.4	199.1
		4.95	6.06	7.36	25.79	36.32	92.64	98.93	99.65	99.74	99.90	40.0		
		1.58	2.02	2.56	17.11	29.12	97.44	99.90	99.97	99.97	99.97	0.		
74	5	21.71	25.14	27.54	47.29	52.71	80.65	87.70	94.72	98.12	99.50	100.0	401.1	195.7
		6.06	8.86	8.86	32.64	42.08	95.05	99.38	99.74	99.86	99.93	40.0		
		2.02	3.22	4.01	22.67	32.64	98.42	99.97	99.98	99.98	99.98	0.		
74	6	26.92	30.81	33.48	54.39	59.81	85.44	91.20	96.52	98.86	99.72	100.0	337.0	184.5
		8.86	10.57	14.69	42.08	52.11	97.98	99.81	99.93	99.98	99.98	40.0		
		3.22	4.95	6.06	32.64	44.04	99.53	100.00	100.00	100.00	100.00	0.		
74	7	26.42	30.20	32.80	53.21	58.53	84.20	90.18	95.90	98.56	99.62	100.0	350.2	188.9
		8.86	10.57	12.51	42.08	50.36	97.44	99.65	99.90	99.95	99.98	40.0		
		3.22	4.95	6.06	29.12	44.04	99.38	99.99	100.00	100.00	100.00	0.		
74	8	24.50	28.28	30.90	51.98	57.59	84.71	90.88	96.53	98.93	99.77	100.0	353.7	185.3
		7.36	10.57	12.51	36.32	49.11	97.44	99.74	99.93	99.97	99.98	40.0		
		2.56	4.01	4.95	29.12	44.04	99.38	99.99	100.00	100.00	100.00	0.		
74	9	27.72	31.71	34.45	55.74	61.21	86.56	92.06	96.99	99.06	99.79	100.0	323.6	180.4
		8.86	12.51	14.69	44.04	55.96	98.42	99.86	99.97	99.98	99.99	40.0		
		4.01	4.95	6.06	36.32	48.84	99.65	100.00	100.00	100.00	100.00	0.		
74	10	26.08	29.80	32.37	52.52	57.80	83.50	89.61	95.55	98.38	99.55	100.0	357.7	190.7
		8.86	10.57	12.51	36.32	48.67	96.78	99.65	99.90	99.93	99.97	40.0		
		3.22	4.01	4.95	29.12	42.08	99.18	99.99	100.00	100.00	100.00	0.		
74	11	17.33	20.42	22.62	41.73	47.28	77.73	85.87	94.10	98.03	99.53	100.0	446.3	198.1
		4.01	6.06	7.36	22.67	32.64	92.64	98.93	99.53	99.74	99.86	40.0		
		1.39	1.58	2.56	17.11	25.79	97.44	99.90	99.97	99.97	99.97	0.		
74	12	26.23	30.27	33.07	55.22	60.99	87.54	93.03	97.66	99.38	99.89	100.0	320.9	175.9
		8.86	10.57	14.69	44.04	55.96	98.42	99.90	99.98	99.99	100.00	40.0		
		3.22	4.95	6.06	36.32	49.43	99.74	100.00	100.00	100.00	100.00	0.		
74	13	24.30	27.96	30.50	50.87	56.31	83.18	89.58	95.72	98.55	99.63	100.0		
		7.51	9.79	11.83	36.65	47.13	96.32	99.51	99.83	99.90	99.95	40.0		
		2.82	3.88	5.05	27.97	40.25	98.91	99.97	99.99	99.99	99.99	0.		

III. MONTHLY ARRAY OUTPUT DISTRIBUTIONS FOR 40 PERCENT ARRAY DIVERSITY

	0.00	29.35	50.58	252.06	318.38	827.73	1067.97	1125.00	1125.00	1125.00	
1	5.37	6.80	8.33	27.67	36.31	91.86	98.47	99.38	99.57	99.77	40.0
2	5.91	7.78	9.66	30.08	39.55	93.21	98.79	99.44	99.63	99.81	40.0
3	5.88	7.67	9.08	29.68	38.23	92.76	98.64	99.39	99.60	99.76	40.0
4	3.54	4.73	5.72	20.87	29.13	87.34	97.16	98.79	99.16	99.49	40.0
5	4.53	6.12	7.04	24.47	32.54	89.81	98.03	99.12	99.47	99.69	40.0
6	7.68	10.00	11.63	36.26	46.43	95.97	99.43	99.79	99.88	99.95	40.0
7	9.79	12.87	14.37	43.64	53.53	97.67	99.75	99.92	99.96	99.98	40.0
8	12.35	15.50	18.43	49.13	60.12	98.44	99.83	99.95	99.97	99.99	40.0
9	8.78	11.07	13.18	40.63	50.69	97.42	99.72	99.91	99.95	99.98	40.0
10	5.51	7.13	8.55	27.77	37.99	92.83	98.76	99.40	99.67	99.82	40.0
11	5.96	7.86	9.23	31.18	39.59	93.92	98.98	99.57	99.76	99.87	40.0
12	7.06	8.83	10.71	33.68	43.48	94.55	99.03	99.61	99.76	99.86	40.0

IV. ARRAY MEAN POWER AVERAGE OVER 10 YEARS

437.2 418.3 424.5 496.2 463.1 372.1 327.8 293.2 342.2 430.5 412.8 394.4

V. ARRAY -MW HOURS- AVERAGE OVER 10 YEARS

43909.0 37948.3 42639.8 48232.7 46517.8 36168.1 32928.3 29452.4 33264.7 43239.7 40123.4 39613.8

APPENDIX D
A DIRECT METHOD FOR SELECTING
WIND-TURBINE GENERATOR
PARAMETERS FOR MAXIMUM OUTPUT

A DIRECT METHOD FOR SELECTING WIND-TURBINE GENERATOR *

Parameters for Maximum Energy Output

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Abstract

To achieve maximum energy transfer from the wind it is necessary to match the parameters of a wind-turbine generator to the characteristics of the wind regime in which it is to operate. The best match will lead to the minimum-energy-cost design. This paper presents a direct method for determining the most important parameters, and discusses their application in the determination of a minimum-energy-cost design. It also contains a brief discussion of the question of fixed-speed rotor operation vs variable speed rotor operation.

Notation

- A rotor swept area (disc area), ft^2 .
- C annual cost, dollars, of the wind-turbine generator (WTG) system.
- C_p WTG output / ft^2 divided by wind power / ft^2 .
- D rotor diameter, ft.
- E_s specific WTG annual output in kW-hr / ft^2 rotor area A.
- H hours that each wind velocity V occurs per year
- P power, watts
- P_R rated WTG output, watts
- P_S rotor specific power rating in rated watts / ft^2 swept area ($P_S = P_R / A$)
- ρ air density, slugs / ft^3 .
- V free wind velocity, normal to rotor disc.
- V_E wind velocity at which maximum energy occurs.
- V_O wind velocity at which WTG maximum over-all efficiency is obtained (velocity of C_p max)
- V_R wind velocity at which P_R is reached
- $\bar{V}$ mean annual wind velocity

Introduction

In designing a WTG system of a given power rating it is possible to choose a wide range of rotor diameters. A large-diameter rotor will drive the system to its rated output at a low wind velocity, but will waste a portion of the high-wind-velocity energy components. A small rotor will require a high wind velocity to attain rated output, but will be largely ineffective at low wind velocities. The best system will have its rotor diameter and other components chosen to produce electrical energy at minimum cost in the wind regime at its site. Such a system can be designed with the aid of two parameters, the rotor loading P_S , and the annual energy output E_s , which are normalized per square foot of rotor swept area A.

In a wind regime characterized by the number of hours H that each wind velocity occurs per year, and for a given P_S , there is only one V_O and only one V_R that will maximize E_s . Use of the correct V_O and V_R is desirable because the resulting match between the system and the wind will maximize annual energy transfer, and will therefore require the minimum rotor diameter for a given annual energy output. Use of the minimum-diameter rotor will lead to the most economical design on an energy basis.

This paper presents a straightforward procedure for determining E_s , V_O , and V_R in terms of P_S .

* The method requires input wind velocity data at an assumed WTG hub height. The method could be extended to include hub height variations.

Matching the WTG to the Wind

It is assumed that a table is available giving the number of hours H for each velocity V per year. This information can be scaled from a velocity-frequency curve⁽¹⁾, with data taken at 1-mph intervals, or it can be obtained indirectly from a velocity-duration curve.

(1) Calculate $\frac{1}{2}\rho V^3$ and $\frac{1}{2}\rho V^3 H$ for each V . The quantity $\frac{1}{2}\rho V^3$ is the total wind power in watts/ft², and $\frac{1}{2}\rho V^3 H$ is the 1-year-total wind energy in watt-hours/ft².

(2) From aerodynamic considerations and test data, construct a plot of system C_p vs $\frac{V}{V_0}$. Although the shape of this curve will be determined principally by the rotor characteristics, the efficiency of the transmission, generator, etc. can be included. From the normalized C_p curve derive a series of curves showing C_p vs V , chosen so that C_p will peak at convenient values of V_0 such as 14, 17, 20, 23, and 26 mph.

(3) Multiply $\frac{1}{2}\rho V^3 H$ (for each V , at 1-mph intervals) by the corresponding C_p from one of the series of C_p curves to obtain $\frac{1}{2}\rho V^3 H C_p$. The total for all velocities used, $E_s = \sum \frac{1}{2}\rho V^3 H C_p$, is the annual output of a 1-ft² WTG for a particular V_0 , assuming no transmission or generator power limitation.

These steps were performed using a $\bar{V}=15$ mph wind regime (V ranged from 5-40mph in 1-mph steps) and C_p data from Juul's paper⁽²⁾ on the Gedser WTG, with an assumed maximum C_p of 0.35. Here the total, $E_s = 73.4 \text{ kW-hr/ft}^2/\text{yr}$ is plotted as point A, Fig. 1. This is one point on the curve marked $\infty \text{ W/ft}^2$, which shows E_s vs V_0 when feathering is not required to protect the generator. Other points on this curve were obtained by repeating the process with $V_0 = 14, 17, 23$, and 26 mph.

(4) To insert finite system power-limit parameters, assume various specific WTG power ratings, P_s such as 10, 15, 25, 36, and 50 rated watts per ft² of swept area A . Calculate $\frac{1}{2}\rho V^3 C_p$ for each V . When V becomes high enough for a particular $\frac{1}{2}\rho V^3 C_p$ to exceed the chosen P_s , it will be necessary to decrease the original scaled value of C_p so that each successive value of V will make $\frac{1}{2}\rho V^3 C_p = P_s$. This is actually what the WTG does when it feathers. Multiply $\frac{1}{2}\rho V^3 H$ by the corresponding decreased values of C_p to obtain $\frac{1}{2}\rho V^3 H C_p$. $E_s = \sum \frac{1}{2}\rho V^3 H C_p$ is the specific annual energy output for a chosen power limit. Here, if $P_s = 25 \text{ W/ft}^2$, and $V_0 = 20$ mph again, $E_s = 69.38 \text{ kW-hr/ft}^2/\text{yr}$, which is plotted as point B, Fig. 1. By repeating this process for various V_0 's and P_s 's, the family of curves in Fig. 1, can be completed.

A dashed line drawn through the peaks of the curves gives the maximum E_s that can be obtained as a function of V_0 and P_s for the selected wind regime and C_p characteristic over the selected P_s range. At any point along this line the WTG has been matched to the wind for maximum annual energy transfer. Maximum economy of energy production must also lie along this line because such operating will require minimum disc area A for a given energy output.

Fig. 2 contains plots of E_s max and V_0 (scaled from Fig. 1) and V_R , all vs P_s . The values of V_R corresponding to each maximum in Fig. 1 are obtained by noting where feathering occurs in the tabulated data as described above, and interpolating, if necessary.

As an example of the use of Fig. 2, consider the design of a 1-MW WTG that is to operate in the $\bar{V}=15$ mph wind. As a starting point, assume $P_s = 10 \text{ W/ft}^2$. Therefore $A = 100,000 \text{ ft}^2$, and the rotor diameter $D = 357 \text{ ft}$. $E_s \text{ max} = 47.3 \text{ kW-hr/ft}^2/\text{yr}$, so the annual energy output $AE_s \text{ max} = 4730 \text{ MW-hr}$. This is equivalent to 4730 kW-hr/kW/yr . For this rotor, $V_0 = 15$ mph, and $V_R = 18.4$ mph. Thus, in this case, the maximum-efficiency point happens to occur at the mean wind velocity, $\bar{V} = 15$ mph, and rated power is attained at 18.4 mph. Both are below the energy peak V_E at 22 mph, which is associated with the $\bar{V} = 15$ mph wind regime.

As a second example, increase P_s to 50 watts/ft², while $P_R = 1 \text{ MW}$ again. Then $A = 20,000 \text{ ft}^2$, and $D = 160 \text{ ft}$. $E_s \text{ max} = .75 \text{ kW-hr/ft}^2/\text{yr}$, which is much higher than in the previous example. Unfortunately $AE_s \text{ max} = 1500 \text{ MW-hr/yr}$, a much lower value because of the small rotor area. A 55% decrease in rotor diameter has produced a 68% decrease in energy output. The cost of the second, smaller rotor, and the lower-torque, smaller-ratio transmission would be less in the second example, as might be that of the tower, which would experience less thrust. Other costs, including those of the generator, controls, etc. would be approximately the same. It is possible, therefore, that the use of the larger rotor would be more economical.

In the second example $V_0 = 21.7$ mph, and $V_R = 36$ mph. It is apparent that the smaller rotor would make use of the high-energy winds which occur infrequently, as opposed to the large one, which depends upon the low energy, high-frequency winds. The maximum-efficiency point of the smaller rotor happens to nearly coincide with the wind-energy peak.

It is possible that the most economical WTG design will have V_0 slightly higher than $\bar{V}$, and will have V_R approximately equal to V_E .

Determining the Minimum-Cost Design

This brief section is included to show how the normalized parameters considered here can be used in determining a minimum-cost WTG design. Given a WTG power rating P_R , assume a series of appropriate rotor areas A , calculate each corresponding P_s , and obtain each $E_s \text{ max}$ from Fig. 2. Determine the total annual system cost C for each value of A . The annual cost will include both the annual operating expenses and the cost per year of capital items amortized over the anticipated operating life of the equipment. The energy cost per dollar, $E/\$ = AE_s \text{ max}/C$. Plot a curve of $E/\$$ vs A , find the value of corresponding to the minimum, recalculate P_s , and read V_0 and V_R from Fig. 2.

Other Modes of Operation

To this point the constant-speed rotor WTG has been used as a base for calculation. It is of interest to consider variable-speed operation in which the rotor RPM is made proportional to the wind velocity, which has the possibility of maintaining a constant C_p at all wind velocities up to the feathering point in order to produce more output. Keeping C_p constant is not completely practical for various reasons, both aerodynamic and power-conversion wise, but it will be assumed here for purposes of illustration. Table 1 shows the MW-hr/yr output of 357-ft and 160-ft rotors, which are the diameters used in examples 1 and 2 respectively, under various conditions of operation.

Line 1 applies to the mythical 100% efficient WTC that can extract and deliver all of the wind kinetic energy. It requires no additional comment.

In line 2 operation is assumed at a constant $C_p=0.35$ up to the maximum wind $V=37$ mph, at which point the system would be shut down. This is a special case of variable-speed operation in which there is no transmission and generator power limit. Such a system is sometimes proposed because it will extract the maximum possible energy from the wind. The 357-ft rotor would require a 25.8 MW transmission and generator, while the 160-ft rotor would require 5.16 MW. Both of these requirements are totally unrealistic because of the high cost of the transmission and generator in relation to the rest of the system.

Realism is approached (but not reached) in line 3, which calls for a constant $C_p=0.35$ up to the same feathering points discussed in examples 1 and 2. The WTG's are now both rated at 1 MW, which may lead to a reasonable cost balance between rotor, transmission and generator, and tower, etc. This is idealized variable-speed operation, as discussed above.

Line 4 repeats, for comparison, the outputs of the original examples, with conventional constant-speed rotors giving typically-poor efficiencies at low wind velocities.

Comparison of lines 3 and 4 shows that, for the 357-ft rotor, idealized variable-speed operation, line 3, will produce an annual energy output of 4970 MW-hr/yr, a 5.1% increase over the constant-speed (line 4) value of 4730 MW-hr/yr. The complexity and probable high cost of the variable-speed system, which would require either a variable-speed transmission, a variable-speed generator, or both, would not seem justified by such a small increase in output.

The increase is 19.5% when the 160-ft rotor is operated at variable speed as opposed to constant speed. The percent increase is greater here because the increased C_p 's cover a much wider span of wind velocities below the feathering point. It is probable that this mode of operation is still not justified, because it would almost certainly be less expensive to increase the rotor diameter by 10%, which would have the same affect on annual output, than to go to a variable-speed system.

Conclusion

A method has been given for matulirly a WTG to the wind. Calculations have been completed for one particular wind regime, with data sufficient for the immediate determination of important WTG parameters.

A series of charts similar to Fig. 2 but for $\bar{V}=8, 10, 12, 15, 18$ and 22 mph would be of great help in the design of small and medium-size WTG's at sites where detailed meteorological studies have not been made in advance.

Table 1		357 ft dia MW-hr/yr	160 ft dia MW-hr/yr
1.	100% efficient WTG (all wind KE converted to electrical energy)	26,100	5220
2.	$C_p=0.35$ at all V through 37 mph	9134 (25.8 MW rating)	1827 (5.16MW rating)
3.	Variable-speed rotor $C_p=0.35$ up to feathering point	4970 (1-MW rating)	1792 (1-MW rating)
4.	Constant-speed rotor $C_{p\max}=0.35$ Gedser-type C_p variation	4730 (1-MW rating)	1500 (1-MW rating)

References

1. Golding, E. W. *The Generation of Electricity by Wind Power*, Spon, London, 1955 pp. 25 - 27.
2. Juul, J., *Design of Wind Power Plants in Denmark*, United Nations Conference on New Sources of Energy, *Proceedings*, vol. 7, *Wind Power*, pp. 229-239.

Fig. 1 Specific energy output in $\text{kw-hr/ft}^2/\text{yr.}$ vs V_0 , the wind velocity at which system efficiency (over-all C_p) is maximum.

Fig. 2 Maximum specific energy output $E_s \text{ max}$, rated velocity V_R , and max - C_p velocity V_0 vs rotor loading P_S .

APPENDIX E

PRODUCTION COST MODEL DESCRIPTION*

GENERAL BACKGROUND AND THEORY

The program is based upon an economic scheduling technique which calculates the statistically expected production costs for the thermal units, taking into account the forced outages of these units. This technique makes use of a thermal unit model characterized by:

1. A minimum load level for fuel input rate
2. Two loading sections each with its own heat rate which applies between the power ratings of the section
3. A forced outage rate plus other parameters used to describe maintenance practices, fuel costs and so on (Partial unit outages may be considered for all units.)

For a given monthly maintenance interval, the loads to be served by the thermal units are arranged by the program's logic into a load duration form in ascending order of magnitude and with each load level described by its magnitude, duration, and the duration in that interval of the particular load or greater. Units are committed to serve the load in a priority order which may be either input or developed by the logic of the program on an economic basis. Units are committed and run at minimum load to ensure that the load, plus the specified spinning reserve margin, will be met under conditions of no forced outages.

Thermal units may have a maximum of three loading segments. The first segment is from zero to minimum load and the unit may be loaded only at the minimum power point. For units which are not block loaded, the second

*Information Courtesy of Power Technologies, Inc.

segment is from minimum load to a mid-power point and the unit may be loaded at a maximum of 20 discrete loading levels between minimum and maximum. The same is true for loadings between the mid-point and maximum power points. Economic dispatch is based upon the incremental costs of the various unit loading segments. That is, once a unit is committed to the line, it is not loaded beyond minimum load until the system's incremental cost level rises to the unit's value. This dispatch calculation is facilitated by the development of a loading table automatically within the program. The loading segments of the various thermal units are ordered such that units are committed in sequence to meet the spinning reserve and then loaded in the incremental cost sequence. Units that are not "block loaded" are allowed to be scheduled at various power levels which are, at steps, determined by the difference between the section's maximum and minimum powers and the value used to round the capacity and load data. Block-loaded units are loaded only at the power level specified. With this technique, a loading segment of a unit is fully used before the next segment is called upon.

The consideration of forced outages means that a unit will be called upon to supply not only the load it would normally supply if only the economic dispatch were considered, but also it will be called upon to supply the load normally supplied by more economic units during the times when they are forced out of service. Suppose, for instance, we have dispatched some 'n' units (i. e. , loading segments) and are analyzing the loading of the (n+1)st segment for a week of 168 hours. We require a capacity-availability table for the first 'n' units as follows:

<u>Capacity Availability</u>	<u>Exact Probability of Given Capacity</u>	<u>Probability of Given Capacity or Less</u>
MW		
900	p(900)	1.000
890	p(890)	

Capacity Availability	Exact Probability of Given Capacity	Probability of Given Capacity or Less
880	$p(880)$	.
.	.	.
.	.	.
.	.	.
800	$p(800)$	$P_c(800)$
790	$p(790)$	$P_c(790)$
.	.	.
.	.	.
.	.	.
10	$p(10)$	.
0	$p(0)$	.

Let us also assume that the (n+1)st unit has the following characteristics:

Capacity	=	100 MW
Forced Outage Rate	=	0.10 per unit
Minimum Load	=	20 MW
Minimum Load Cost	=	80 \$/Hr
Incremental Cost	=	3.0 \$/MWH

and portions of the interval load data are as follows:

<u>Load</u>	<u>Duration</u>	<u>Duration of Given Load or Greater</u>
MW	Hours	Hours
.	.	.
.	.	.
.	.	.
1100	8	30
1060	10	40

E-4

<u>Load</u>	<u>Duration</u>	<u>Duration of Given Load or Greater</u>
MW	Hours	Hours
1020	10	50
1000	12	62
980	8	70
940	10	80
920	16	96
900	20	116
860	10	126
820	8	134
800	10	144
780	6	150
⋮	⋮	⋮

The loading of the unit with no forced outages considered in the first 'n' units can be calculated from the following table:

<u>System Load</u>	<u>Load Duration</u>	<u>Generation Level</u>	<u>"Expected Duration"</u>
MW	Hours	MW	Hours
920	16	20	14.4
940	10	40	9
980	8	80	7.2
1000 or more	62	100	55.8

The data in the last column are for the generation loading levels and take into account the 90 percent availability of the unit being dispatched, but not the less than 100 percent availability of 900 MW from the first 'n' units. The actual expected durations of generation power levels shown on the table above need to be multiplied by the probability of having 900 MW available in the first 'n' units.

Next, consider the capacity state with 890 MW available in the first 'n' units. This event has a probability of $p(890)$. The expected durations of loading on the (n+1)st unit with a capacity state of 890 MW are as follows:

<u>System Load</u>	<u>Load Duration</u>	<u>Generation</u>	<u>Generation Duration</u>
MW	Hours	MW	Hours
900	20	100	$p(890) \times 18$
920	16	30	$p(890) \times 14.4$
940	10	50	$p(890) \times 9$
980	8	90	$p(890) \times 7.2$
1000 or more	62	100	$p(890) \times 55.8$

The process can be continued with different capacity states for the first 'n' units until a capacity state of 800 MW is reached. In this case, the only possible load level on the new unit is 100 MW with a system load of 800 MW or more and the expected duration is:

$$0.9 \times 38 \times P_c(800)$$

where $P_c(800)$ is the probability of a capacity of 800 MW or less on the 'n' unit system.

The calculations are straightforward but tedious. When a segment has been dispatched for a scheduling interval, it is added to the system capacity-availability table. Before the second segment of a unit can be dispatched, its segment must be removed from the capacity-availability table to avoid counting the unit outages twice.

The computational procedure requires a number of engineering approximations to permit the rapid computation. A maximum of two incremental loading sections may be used to dispatch each thermal unit. Another is the treatment of the duration of unit loadings at their minimum power points

where loadings between 0 percent and 50 percent of minimum power are ignored and those greater than 50 percent of minimum power are taken at the full minimum power point. In several test cases for various systems and with zero forced outages, the logic of this program has been tested against more complex models using several incremental loading segments for each unit and more complex computational techniques for economic scheduling. In all cases, the economic results were within a quarter of one percent of each other, indicating the appropriateness of the engineering approximations made.

This program has several added features which will permit it to model:

- Units which are simultaneously fired with two fuels in their last loading section
- Units which have partial outage rates applicable to their last loading section
- "Participation units" which are defined as units for which a fixed MW amount has been designated as a sale; this amount is to be supplied whenever the unit is available
- Hydroelectric plants which have a three-point probability distribution of the amount of energy expected to be available

Unit sales or sales of system energy represented by pseudo-hydro plants may be costed by supplying demand and energy cost rate data.

The program can compute the loading profiles (i. e. , MW demand versus total duration) for emergency energy required over the system's tie lines. Tie lines may be specified to the program simply by giving the number of ties, the rating of each and a cost rate for emergency energy supplied over the ties.

PROGRAM OUTLINE

The section outlines the program input data requirements and the structure of the program and discusses its general features and output options. The program is intended for both fuel budgeting and long-range planning studies.

Block Diagram and Input

Figure E-1 shows a block diagram of this program. The general input requirements include the following types of data.

1. Load Model

- a. Monthly peak as a fraction of the seasonal peak.
- b. Twenty-five load levels and their corresponding durations for each month. The load levels are in per unit of the monthly peak and the total duration of the load should add up to the specified hours in the study month.
- c. Three seasonal peaks are used in any given year:
 - The previous year's winter peak is used for January, February, March and April
 - The summer peak is used for May, June, July, August, September and October
 - The current year's winter peak is used for November and December

2. Hydro: Sales, Purchases

A maximum of five hydro plants and/or system wide energy sales, and/or energy purchases may be specified. For each month, energy, maximum demand and minimum demand are given: for

E-8

Figure E-1. Block Diagram of Probabilistic Production Cost Program

sales these data are input as negative values. Revenues from sales may be calculated by inputting demand and energy cost rates.

3. Thermal Unit Data

Each unit is the own "type" and has its own fuel cost, fuel type, fuel energy content, and inflation factors and so on. Provision has been made to handle nuclear, coal, oil and gas fuels. Units which have two incremental loading sections may use two fuel types (i. e. , oil plus coal) in the last section. Units are assigned to plants by input. Unit sales data and partial outage rates may also be specified.

Maintenance cost data are both fixed (thousands of \$/year) and variable (\$/MWH). They may be inflated independently of the fuel inflation. The variable O&M costs are added to the incremental fuel costs and used for commitment and dispatch purposes.

Thermal characteristics consist of maximum, mid-point and minimum power load levels, a minimum load fuel input and incremental heat rates which apply between power points. Units may be block loaded by using the same value for the minimum and maximum power points, leaving the mid-power point zero. Units which have only one incremental loading section should also leave the mid-power point zero.

Maintenance may be pre-scheduled or scheduled using input maintenance cycles.

4. Priority Order

The commitment order may be specified by input or developed by the program logic. The minimum downtime data for each unit is used in the program only for developing a commitment order.

5. Original System

The units in the original system must be listed as part of the general input data.

6. Other General Data

- a. A rounding value in MW is used to round off both the MW loads and the unit capacity data. This is necessary to keep the number of possible capacity outage states in the capacity-availability tables finite and to speed up the running time. A value of 10 MW should be satisfactory for medium to moderately large system studies.

Values of two MW or five MW may be suitable, however, for smaller systems. The capacity-availability tables are dimensioned for 500 entries, each step representing the rounding value in MW. Thus, a rounding value of 10 MW would enable a table of 5000 MW to be completely represented. If capacity data are entered in the annual input, all the MW values should be rounded using the value input in the general data input.

- b. Unit loading profiles, tables of the hours of duration of various generation loading levels, may be output on an annual or monthly basis for a maximum of ten units. We would expect that the major interest in these would probably be in the loading profiles for the emergency ties.
- c. Emergency ties may be incorporated by inputting the number of ties, their maximum rating and the cost of the energy supplied.

- d. Present-worth calculation data are also part of the general input. These include the present worth rate and the reference year for the calculation. Present values are calculated as of the first of the reference year, assuming that production charges are paid at the end of the year.

Annual input may include changes to the general input data. Annual peak loads should be supplied as well as unit additions and retirements. These unit changes should be supplied on a chronological basis and are made in the program on the first of the month specified. Prescheduled maintenance data must also be provided as annual data. Spinning reserve margins are specified in MW by months. They may be read in as annual data and will be left as is until new values are read in subsequent years as part of the annual data input.

Load Model

The load model is set up for the year prior to the start of the monthly calculations and modified for hydroelectric plant operations, energy sales, and purchases in the monthly calculation loop. The program has the number of hours in each month stored internally. The program has the number of hours in each month stored internally. The program will compensate for leap years. The load data are set up in MW for the year and monthly peaks accumulated for use in the maintenance outage scheduling. These interval peaks are reduced for hydro generation and energy purchases, and increased for energy sales for maintenance outage allocations. Initially, three seasonal peaks must be input. From the first year on, the program automatically cycles the seasonal peaks.

Maintenance Scheduling

Maintenance scheduling is done using monthly intervals and may be performed on the basis of:

- a. Prescheduled input maintenance by unit.
- b. Prescribing maintenance cycles for the units which specify the number of consecutive months the unit is to be on-maintenance each year.

Maintenance outages are allocated automatically on the basis of leveling on-peak reserves over the year. This is accomplished in the program by leveling the sum of the peak load, plus capacity on maintenance each interval. For this calculation, units added to the system during the year are considered to be on-maintenance outage prior to their installation date, and units retired during the year are considered on-maintenance after their retirement date.

Unit Commitment and Dispatch Ordering

The priority for unit commitment is established initially for all units ever expected to be in the system if done automatically by the program's logic. It may also be read in as a data list, in which case it could be altered annually.

In the annual calculation loop, all of the units input are ordered such that:

- The units are committed in proper priority sequence.
- The loading segments of the units are listed in economic order for dispatching.

The economic ordering is on the basis of incremental costs, recognizing that units must be

1. Committed before they can be dispatched incrementally
2. Committed in order

The program's logic can handle block loaded units (i. e. , maximum and minimum power levels are equal) and automatically adjusts the minimum load fuel input to compensate for any changes in minimum power levels due to rounding of capacities. The minimum and mid-power points may also be adjusted automatically to permit the use of loading levels which are spaced by integer multiples of the MW rounding value.

If a unit commitment priority order is not input, the program will calculate the priority order in the following way:

- Units are grouped by minimum downtimes.
- Groups of units are committed in order of their downtime rule, with the longest downtimes committed first. A 168-hour, or longer, downtime rule designates a "must-run" unit. Must-run units are all committed prior to the incremental loading of any unit.
- Within a given group of units with the same downtime, units are ordered in accordance with their full-load average production cost, with the most economic units committed first.

If this automatic ordering is to be used regularly, it is possible that it may be found desirable to shift the priority ordering from the routine where it is done once per study, to a different subroutine where it would be done annually. This may appear desirable if different fuel inflation rates are used which disturb the economic ordering of the units. Leaving the priority ordering in the initial input routine will be faster.

Monthly Load Modification

Each month the loads are modified to reflect the effect of the hydro plants, contracts for energy sales, and contracts for energy purchases. Specifying minimum and maximum MW demands permits the representation of both run-of-river and peak-shaving generation. The allocation procedure in the program is a non-iterative peak-shaving technique. The input data includes a three-point probability distribution to represent the variation in hydro-energy availability. The monthly energy input is the average, or mean value. An error message is printed if too much energy consumption for the given capability is specified for any month.

Energy sales are handled as a "negative peak shave" and allocations over time are based on the assumption that the purchasing company has a load distribution with a shape identical to the selling systems.

The representation of energy purchases and sales includes the option to have the program compute the cost of the purchases and the revenues from the sales. This may be done by inputting cost rates for demand and energy charges. The purchase costs will be shown on the output as part of the system total cost. The revenues will be summarized along with the sale of energy from particular units.

Modified Commitment and Spinning Reserve

During the study year, each month could conceivably have a different pattern of units available. Both the actual unit commitment and dispatch for any one month may be different from any of the others. The program logic must, therefore, proceed through the year by considering each monthly interval separately. In each month, a list is prepared of units which can run. This list is ordered properly for unit commitment and economic dispatch and is actually a list of the loading segments of the available units.

Spinning reserve requirements may be specified in MW by months. The term "spinning reserve" must be taken in the conventional sense as it applies under the condition of no forced outages. The unit commitment and dispatching order are rearranged for each month so that units are committed and loaded so as to have at least the specified spinning reserve margin for all the interval load levels under the condition of no forced outages.

Economic Dispatch

To calculate the dispatch and expected production costs, the modified loads for each month are arranged in a separate load duration curve in ascending order. In the computation of the production costs for a given unit, the assumption is made that it can be loaded at minimum load and in equally spaced levels between minimum and mid-power levels, and between mid-power and maximum power levels. These loading levels are limited to a maximum of 20 for each incrementally loaded segment. They are separated by MW values which are an integral multiple of the MW rounding value. Each year, each unit's power points are tested and minor adjustments made in the minimum and mid-power points to accommodate this requirement. Mid-points are adjusted without altering the fuel cost rates. When minimum load points are adjusted, the no-load fuel cost rate is adjusted.

The dispatch procedure is referred to as the "unit dispatch" method. The basic calculation in the dispatch routine is the computation of the expected durations of the various generation levels for each unit which is not a block-loaded generator. To accomplish this, the scheduling routine must compute a capacity-availability table for all segments of previously committed and dispatched segments of the thermal units.

When a unit is first committed, it will be put in this table with a rating equal to its minimum load level. If the unit is a block-loaded plant, this minimum load level is also the maximum level so that this kind of unit is dispatched in

a single computation. Units which are to be loaded on an incremental basis will have a second, and perhaps a third loading segment between minimum and maximum load levels. When the calculation has reached the stage where the next segment of the unit is to be scheduled, the portion of the unit in the table must be removed from the capacity-availability table to avoid such logical inconsistencies as attempting to schedule the unit in its second loading segment during intervals when it is on forced outage. The schedule of expected loading durations for the next segment is then calculated by convolving the interval's load distribution and the capacity-availability distribution for the previously loaded units to obtain a probability distribution for the various generation power levels. The computation was illustrated in the previous section and is performed in terms of expected durations (i. e., hours) rather than normalized probability figures. The same procedure is followed with the third section of the unit. After each segment's loading is computed, it is added to the capacity-availability table. Units with partial outages as well as full capability outage rates are added to the table using a special routine.

This calculation of the expected loading patterns will yield the statistically expected costs and the operation of each unit, taking into account both the full and partial forced outages of the thermal units. With this unit's dispatch technique, the complete distribution of duration-versus-power level is calculated for each unit. This distribution may be saved and output on a monthly or annual basis as a unit-loading profile.

Unit Sales

The sale of energy from a specific unit may be modeled by inputting a value for sold power. The sale is calculated on the assumption that it will always be made whenever the unit is available. Therefore, in dispatching the unit to meet the system's own load, the maximum capability of the unit will be

reduced by the amount of the sale. This is equivalent to assuming that the capability represented by the sale will never be used to cover the system-load-spinning-reserve requirement.

The production costs to cover the unit sale energy are calculated after the first incrementally loaded segment is dispatched in the program. The output summary will include these costs. If a unit with a sale has a monthly or annual loading profile printed out, the outputted profile does not include the sale. The revenues for the sale are computed and outputted separately from the costs.

Emergency Energy Supply

When forced outages are considered in the calculation of the energy supplied by the system's thermal units, theoretically there will always be a portion of the load which cannot be supplied for some fraction of the time. This expected energy loss for a month or year is one measure of the generation system's reliability. The program can calculate a cost for the required emergency supply each month and the distribution of the duration of various demand levels if emergency tie data are specified.

As a special input data block, emergency ties may be specified by giving:

- The number of tie lines
- The rating of each (only one value is input)
- The energy cost in \$/MWH

The program will dispatch these identical ties in sequence after all of the thermal units are scheduled. They will not be included in the system's total capacity and their calculated generation and costs will be output after the

summary for the units actually in the system. They do add to the count of the total number of units in the system, however.

Emergency energy supplies on tie lines may also be simulated by pseudo-thermal units. When this is done, these units will be committed and dispatched in order, and their capability included in the system data.

Output

Besides outputting the optional unit loading profiles, the program produces summaries of the input, annual summaries and optional monthly summaries of unit generation, cost, revenues, and the monthly loads, hydro, sales and purchases and resultant load patterns. These unit performance summaries are unit-by-unit and plant-by-plant summaries of operating data, fuel consumption and cost, operations and maintenance costs and total production costs. Revenues for energy sales from the system and specific units are also output. Units should normally be assigned to a plant by input. For the annual output, the accumulated expenses and present worths of both the current year's and the accumulated annual production expenses are given.

The output also contains a summary of the energy content of the load, the energy in the hydro plants and contracts, the energy from unit sales, and the energy supplied by the designated emergency supplies. The apparent required thermal generation is shown in the energy summary as the load energy plus the unit sales energy minus the hydro energy minus the emergency energy supplied. Under the system summary data, the calculated thermal energy supplied is shown as the sum of the calculated generation of each of the units. There will generally be a difference between these two total thermal generation figures due to numerical round-off and truncation errors in the calculation. These differences should be much less than a fraction of one percent of the interval's total energy requirement.

The output is apt to contain error messages. In most cases, it will be found that these are the result of inconsistent and/or erroneous input data. When they occur, it is advisable to check the input data.

APPENDIX F
PRODUCTION COST MODEL GENERAL INPUT SUMMARY

This appendix provides a computer listing of the PCM general input summary. Because of the program's general planning usage, this specific listing is for a study concerning the conversion of some of the Hibbard oil-fired units to coal. The wind system inputs were thus zero for this study.

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

MONTHLY PEAKS IN PER UNIT OF SEASONAL PEAKS

JANUARY	FEBUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
732.0	752.000	713.090	696.000	727.000	748.000	739.000	816.000	826.000	826.000	891.000	920.000

LOADS IN PER UNIT OF MONTHLY PEAK

JANUARY		FEBUARY		MARCH		APRIL		MAY		JUNE	
LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS
0.61	3.	0.64	1.	0.66	1.	0.67	2.	0.62	2.	0.67	1.
0.62	8.	0.65	5.	0.66	4.	0.63	4.	0.63	2.	0.67	7.
0.63	6.	0.67	25.	0.68	3.	0.69	12.	0.64	14.	0.69	10.
0.65	22.	0.68	18.	0.69	13.	0.71	18.	0.66	12.	0.70	14.
0.67	28.	0.70	19.	0.71	29.	0.72	25.	0.68	26.	0.72	28.
0.68	38.	0.71	27.	0.72	39.	0.73	29.	0.69	32.	0.73	33.
0.70	26.	0.73	34.	0.74	33.	0.75	52.	0.71	52.	0.75	42.
0.72	36.	0.74	26.	0.75	23.	0.76	33.	0.73	38.	0.76	44.
0.74	59.	0.76	54.	0.77	35.	0.78	29.	0.74	40.	0.78	28.
0.75	45.	0.77	30.	0.78	49.	0.79	40.	0.76	49.	0.79	38.
0.77	36.	0.79	33.	0.80	32.	0.81	31.	0.78	40.	0.80	34.
0.79	37.	0.81	41.	0.81	31.	0.82	41.	0.79	26.	0.82	38.
0.80	41.	0.82	29.	0.83	27.	0.83	28.	0.81	44.	0.83	23.
0.82	33.	0.84	41.	0.84	24.	0.85	39.	0.82	31.	0.85	41.
0.84	41.	0.85	41.	0.86	34.	0.86	34.	0.84	48.	0.86	26.
0.86	45.	0.87	48.	0.87	27.	0.88	55.	0.86	47.	0.88	19.
0.87	58.	0.88	54.	0.89	45.	0.89	46.	0.87	46.	0.89	41.
0.89	46.	0.90	57.	0.90	55.	0.91	60.	0.89	43.	0.91	54.
0.91	54.	0.91	52.	0.92	62.	0.92	48.	0.91	57.	0.92	42.
0.92	36.	0.93	41.	0.93	35.	0.93	33.	0.92	32.	0.93	57.
0.94	23.	0.95	28.	0.95	47.	0.95	36.	0.94	16.	0.95	57.
0.96	19.	0.96	23.	0.96	14.	0.96	26.	0.96	7.	0.96	33.
0.97	6.	0.98	14.	0.98	13.	0.98	16.	0.97	5.	0.98	20.
0.99	3.	0.99	2.	0.99	8.	0.99	6.	0.99	10.	0.99	13.
1.00	1.	1.00	1.	1.00	1.	1.00	1.	1.00	1.	1.00	1.

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

LOADS IN PER UNIT OF MONTHLY PEAK

JULY		AUGUST		SEPTEMBER		OCTOBER		NOVEMBER		DECEMBER	
LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS	LOAD	DUR HRS
0.61	1.	0.64	1.	0.62	1.	0.65	2.	0.63	1.	0.63	2.
0.62	4.	0.65	4.	0.63	1.	0.65	2.	0.64	3.	0.63	3.
0.64	8.	0.66	17.	0.65	6.	0.67	8.	0.66	29.	0.95	1.
0.65	8.	0.69	19.	0.67	5.	0.69	17.	0.67	43.	0.67	18.
0.67	18.	0.69	29.	0.68	18.	0.70	17.	0.69	39.	0.68	28.
0.69	27.	0.71	25.	0.70	26.	0.72	21.	0.70	53.	0.70	36.
0.70	27.	0.72	34.	0.71	26.	0.73	31.	0.72	42.	0.72	51.
0.72	54.	0.74	58.	0.73	39.	0.75	44.	0.74	32.	0.73	45.
0.74	50.	0.76	43.	0.75	56.	0.76	47.	0.75	28.	0.75	52.
0.75	45.	0.77	47.	0.76	60.	0.78	33.	0.77	29.	0.76	35.
0.77	41.	0.79	57.	0.78	40.	0.79	32.	0.78	36.	0.78	29.
0.79	28.	0.80	44.	0.80	37.	0.81	42.	0.80	52.	0.80	44.
0.80	39.	0.82	28.	0.81	25.	0.82	19.	0.82	43.	0.81	33.
0.82	31.	0.83	26.	0.83	24.	0.84	35.	0.83	53.	0.83	44.
0.84	40.	0.85	41.	0.84	27.	0.85	29.	0.85	63.	0.85	45.
0.86	43.	0.87	50.	0.86	37.	0.87	32.	0.86	40.	0.86	52.
0.83	36.	0.88	64.	0.88	27.	0.88	40.	0.88	46.	0.88	60.
0.89	63.	0.90	56.	0.89	77.	0.90	54.	0.90	42.	0.89	50.
0.91	48.	0.91	33.	0.91	81.	0.91	46.	0.91	30.	0.91	44.
0.92	34.	0.93	30.	0.93	63.	0.93	47.	0.93	14.	0.93	17.
0.94	33.	0.94	19.	0.94	36.	0.95	54.	0.94	16.	0.94	10.
0.96	24.	0.96	9.	0.96	17.	0.96	42.	0.96	5.	0.96	10.
0.97	17.	0.98	6.	0.97	10.	0.98	21.	0.98	3.	0.97	8.
0.99	0.	0.99	3.	0.99	4.	0.99	4.	0.99	1.	0.99	2.
1.00	1.	1.00	1.	1.00	1.	1.00	1.	1.00	1.	1.00	1.

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

HYDRO. INTERCHANGE SALES AND PURCHASES

NUMBER	IDENTITY	MONTH	MINIMUM MW DEMAND	MAXIMUM MW DEMAND	MONTHLY MWH ENERGY SALES ARE NEGATIVE
1	STLUIS	1	31.	44.	29000.
		2	27.	48.	27500.
		3	37.	47.	30000.
		4	68.	83.	56400.
		5	76.	79.	55200.
		6	63.	81.	55900.
		7	35.	42.	25600.
		8	19.	55.	30200.
		9	14.	57.	31100.
		10	17.	67.	32900.
		11	28.	59.	34700.
		12	23.	53.	29600.
2	MISIPI	1	6.	6.	4300.
		2	8.	8.	5300.
		3	9.	9.	5900.
		4	23.	23.	16700.
		5	23.	23.	15900.
		6	23.	23.	16400.
		7	19.	19.	13600.
		8	14.	14.	10200.
		9	15.	15.	10500.
		10	15.	15.	10200.
		11	16.	16.	11200.
		12	8.	8.	5200.
3	ECON	1	0.	124.	23000.
		2	0.	124.	23000.
		3	0.	132.	23000.
		4	0.	183.	34000.
		5	0.	223.	41000.
		6	0.	231.	43000.
		7	0.	250.	45000.
		8	0.	253.	47000.
		9	0.	226.	42000.
		10	0.	167.	30000.
		11	0.	151.	28000.
		12	0.	139.	25000.

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

HYDRO. INTERCHANGE SALES AND PURCHASES

NUMBER	IDENTITY	MONTH	MINIMUM MW DEMAND	MAXIMUM MW DEMAND	MONTHLY MWH ENERGY SALES ARE NEGATIVE
4	MH	1	0.	0.	0.
		2	0.	0.	0.
		3	0.	0.	0.
		4	0.	0.	0.
		5	0.	0.	0.
		6	0.	0.	0.
		7	0.	0.	0.
		8	0.	0.	0.
		9	0.	0.	0.
		10	0.	0.	0.
		11	0.	0.	0.
		12	0.	0.	0.
5	WIND	1	0.	0.	0.
		2	0.	0.	0.
		3	0.	0.	0.
		4	0.	0.	0.
		5	0.	0.	0.
		6	0.	0.	0.
		7	0.	0.	0.
		8	0.	0.	0.
		9	0.	0.	0.
		10	0.	0.	0.
		11	0.	0.	0.
		12	0.	0.	0.

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

HYDRO. INTERCHANGE SALES AND PURCHASES

NUMBER	IDENTITY	MONTH	ENERGY IN P.U. OF AVERAGE			CUMULATIVE PROBABILITY OF ENERGY OR LESS		
			MINIMUM	AVERAGE	MAXIMUM	MINIMUM	AVERAGE	MAXIMUM
1	STLUIS	1	0.82	1.11	0.00	0.37	1.00	0.00
		2	0.73	1.02	1.28	0.25	0.54	1.00
		3	0.86	1.05	0.00	0.33	1.00	0.00
		4	0.91	1.05	0.00	0.33	1.00	0.00
		5	1.00	1.00	0.00	1.00	0.00	0.00
		6	0.84	0.96	1.07	0.21	0.42	1.00
		7	0.89	0.97	1.04	0.21	0.33	1.00
		8	0.48	1.03	1.35	0.33	0.50	1.00
		9	0.35	0.97	1.35	0.29	0.42	1.00
		10	0.39	1.12	1.45	0.33	0.62	1.00
		11	0.61	1.00	1.23	0.29	0.54	1.00
		12	0.57	1.05	1.28	0.29	0.58	1.00
2	MISIPI	1	0.00	0.00	1.00	0.00	0.00	1.00
		2	0.00	0.00	1.00	0.00	0.00	1.00
		3	0.00	0.00	1.00	0.00	0.00	1.00
		4	0.00	0.00	1.00	0.00	0.00	1.00
		5	0.00	0.00	1.00	0.00	0.00	1.00
		6	0.00	0.00	1.00	0.00	0.00	1.00
		7	0.00	0.00	1.00	0.00	0.00	1.00
		8	0.00	0.00	1.00	0.00	0.00	1.00
		9	0.00	0.00	1.00	0.00	0.00	1.00
		10	0.00	0.00	1.00	0.00	0.00	1.00
		11	0.00	0.00	1.00	0.00	0.00	1.00
		12	0.00	0.00	1.00	0.00	1.00	0.00
3	ECON	1	0.00	0.00	1.00	0.00	0.00	1.00
		2	0.00	0.00	1.00	0.00	0.00	1.00
		3	0.00	0.00	1.00	0.00	0.00	1.00
		4	0.00	0.00	1.00	0.00	0.00	1.00
		5	0.00	0.00	1.00	0.00	0.00	1.00
		6	0.00	0.00	1.00	0.00	0.00	1.00
		7	0.00	0.00	1.00	0.00	0.00	1.00
		8	0.00	0.00	1.00	0.00	0.00	1.00
		9	0.00	0.00	1.00	0.00	0.00	1.00
		10	0.00	0.00	1.00	0.00	0.00	1.00
		11	0.00	0.00	1.00	0.00	0.00	1.00
		12	0.00	0.00	1.00	0.00	0.00	1.00
4	MH	1	0.00	0.00	0.00	0.00	0.00	0.00
		2	0.00	0.00	0.00	0.00	0.00	0.00
		3	0.00	0.00	0.00	0.00	0.00	0.00
		4	0.00	0.00	0.00	0.00	0.00	0.00
		5	0.00	0.00	0.00	0.00	0.00	0.00
		6	0.00	0.00	0.00	0.00	0.00	0.00
		7	0.00	0.00	0.00	0.00	0.00	0.00
		8	0.00	0.00	0.00	0.00	0.00	0.00
		9	0.00	0.00	0.00	0.00	0.00	0.00
		10	0.00	0.00	0.00	0.00	0.00	0.00
		11	0.00	0.00	0.00	0.00	0.00	0.00
		12	0.00	0.00	0.00	0.00	0.00	0.00

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

HYDRO. INTERCHANGE SALES AND PURCHASES

NUMBER	IDENTITY	MONTH	ENERGY IN P.U. OF AVERAGE			CUMULATIVE PROBABILITY OF ENERGY OR LESS		
			MINIMUM	AVERAGE	MAXIMUM	MINIMUM	AVERAGE	MAXIMUM
5	WIND	1	0.00	0.00	0.00	0.00	0.00	0.00
		2	0.00	0.00	0.00	0.00	0.00	0.00
		3	0.00	0.00	0.00	0.00	0.00	0.00
		4	0.00	0.00	0.00	0.00	0.00	0.00
		5	0.00	0.00	0.00	0.00	0.00	0.00
		6	0.00	0.00	0.00	0.00	0.00	0.00
		7	0.00	0.00	0.00	0.00	0.00	0.00
		8	0.00	0.00	0.00	0.00	0.00	0.00
		9	0.00	0.00	0.00	0.00	0.00	0.00
		10	0.00	0.00	0.00	0.00	0.00	0.00
		11	0.00	0.00	0.00	0.00	0.00	0.00
		12	0.00	0.00	0.00	0.00	0.00	0.00

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

TYPE	IDENT.	PLANT NO.	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	MAINT. CYC. NO.	CODES STG. POS.	MIN. HRS DOWNTIME	FUEL COST \$/MBTU	1+INFLATION FACTOR FUEL	O M COSTS FIXED VAR	0 M COSTS
										KB/YR	\$/MWH
1	AUR1	1	1	17.000	1	1	168	0.6000	1.0800	1.0600	0. 2.9500
2	BOS1	2	1	17.000	1	2	168	0.4500	1.0800	1.0600	0. 1.8500
3	BOS2	2	1	17.000	1	2	12	0.4500	1.0800	1.0600	0. 1.8500
4	BOS3	2	1	17.000	1	4	168	0.4500	1.0800	1.0600	0. 1.8500
5	HIBB1	3	3	6.340	1	3	12	1.8700	1.0800	1.0600	0. 5.4900
6	HIBB2	3	3	6.340	1	3	12	1.8700	1.0800	1.0600	0. 5.4900
7	HIBB3	3	3	6.340	1	3	12	1.8700	1.0800	1.0600	0. 5.4900
8	HIBB4	3	3	6.340	1	3	168	1.8700	1.0800	1.0600	0. 5.4900
9	WIN2	4	3	6.340	1	3	12	1.8700	1.0800	1.0600	0. 5.4900
10	WIN3	4	3	6.340	1	3	12	1.8700	1.0800	1.0600	0. 5.4900
11	AUR2	1	1	17.000	1	1	12	0.6000	1.0800	1.0600	0. 2.9500
12	NSP1	5	6	0.000	-1	0	12	14.0000	1.0000	1.0000	1500. 0.0000
13	NSP2	5	6	0.000	-1	0	12	9.0000	1.0000	1.0000	3000. 0.0000
14	NSP3	5	6	0.000	-1	0	12	14.3000	1.0000	1.0000	500. 0.0000
15	NSP4	5	6	0.000	-1	0	12	15.7000	1.0000	1.0000	4000. 0.0000
16	NSP5	5	6	0.000	-1	0	12	15.7000	1.0000	1.0000	4000. 0.0000
17	NSP6	5	6	0.000	-1	0	12	16.6000	1.0000	1.0000	2000. 0.0000
18	DPLSDP	6	6	0.000	-1	0	12	13.0000	1.0000	1.0000	50. 0.0000
19	DPLSDP	6	6	0.000	-1	0	12	13.0000	1.0000	1.0000	50. 0.0000
20	OTP1	8	6	0.000	-1	0	12	7.0000	1.0000	1.0000	240. 0.0000

*FUEL TYPES STD UNIT

1 COAL TONS
2 NUCLEAR MWD
3 OIL BBL

*FUEL TYPES STD UNIT

4 GAS MCF
5 SPECIAL NONE
6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

TYPE	IDENT.	PLANT NO.	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	MAINT. CODES		MIN. HRS DOWNTIME	FUEL COST \$/MBTU	1+INFLATION FACTOR		O M COSTS	
					CYC. NO.	STG. POS.			FUEL	O M	FIXED KS/YR	VAR \$/MWH
21	OTP2	9	6	0.000	-1	0	12	7.3000	1.0000	1.0000	400.	0.0000
22	OTP3	8	6	0.000	-1	0	12	7.3000	1.0000	1.0000	1000.	0.0000
23	MPC1	9	6	0.000	-1	0	12	6.0000	1.0000	1.0000	840.	0.0000
24	MPC2	9	6	0.000	-1	0	12	4.0000	1.0000	1.0000	1540.	0.0000
25	MPC3	9	6	0.000	-1	0	12	8.0000	1.0000	1.0000	1600.	0.0000
26	MPC4	9	6	0.000	-1	0	12	3.0000	1.0000	1.0000	1200.	0.0000
27	MDU1	10	6	0.000	-1	0	12	7.3000	1.0000	1.0000	600.	0.0000
28	MDU2	10	6	0.000	-1	0	12	7.3000	1.0000	1.0000	480.	0.0000
29	NWPS	11	6	0.000	-1	0	12	7.3000	1.0000	1.0000	60.	0.0000
30	OPPD1	12	6	0.000	-1	0	12	12.0000	1.0000	1.0000	480.	0.0000
31	OPPD2	12	6	0.000	-1	0	12	14.0000	1.0000	1.0000	4200.	0.0000
32	ISP1	13	6	0.000	-1	0	12	14.0000	1.0000	1.0000	5400.	0.0000
33	ISP2	13	6	0.000	-1	0	12	14.0000	1.0000	1.0000	3000.	0.0000
34	MH	14	6	0.000	-1	0	12	6.0000	1.0000	1.0000	2000.	0.0000
35	DEF1	15	6	0.000	-1	0	12	15.0000	1.0000	1.0000	3200.	0.0000
36	DEF2	15	6	0.000	-1	0	12	17.0000	1.0000	1.0000	1200.	0.0000
37	DEF3	15	6	0.000	-1	0	12	18.0000	1.0000	1.0000	2000.	0.0000
38	DEF4	15	6	0.000	-1	0	12	18.0000	1.0000	1.0000	5600.	0.0000
39	DEF5	15	6	0.000	-1	0	12	19.0000	1.0000	1.0000	4000.	0.0000
40	DEF6	15	6	0.000	-1	0	12	19.0000	1.0000	1.0000	8000.	0.0000

*FUEL TYPES STD UNIT

1 COAL TONS
2 NUCLEAR MWD
3 OIL BBL

*FUEL TYPES STD UNIT

4 GAS MCF
5 SPECIAL NONE
6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

TYPE	IDENT.	PLANT NO.	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	MAINT. CODES		MIN. HRS DOWNTIME	FUEL COST \$/MBTU	1+INFLATION FACTOR		O M COSTS	
					CYC. NO.	STG. POS.			FUEL	O M	FIXED K\$/YR	VAR \$/MWH
41	DEF7	15	6	0.000	-1	0	12	19.0000	1.0000	1.0000	6000.	0.0000
42	BOS3A	2	1	17.000	1	4	168	0.4500	1.0800	1.0600	0.	1.8500
43	BOS4	2	1	17.000	1	3	168	0.4500	1.0800	1.0600	0.	1.8500
44	BRK1	16	1	17.000	1	4	168	0.6000	1.0800	1.0600	0.	1.2500
45	BUTTE	17	6	0.000	-1	0	12	5.0900	1.0800	1.0000	27000.	0.0000
46	BUTTE1	17	6	0.000	-1	0	12	5.0900	1.0800	1.0000	19058.	0.0000
47	HIBB2C	3	1	17.000	1	3	12	0.6000	1.0800	1.0600	0.	5.4900
48	HIBB3C	3	1	17.000	1	3	12	0.6000	1.0800	1.0600	0.	5.4900
49	HIBB4C	3	1	17.000	1	3	168	0.6000	1.0800	1.0600	0.	5.4900
50	EMERCY	0	0	0.000	-1	0	0	15.0000	1.0000	1.0000	0.	0.0000
51	EMERCY	0	0	0.000	-1	0	0	15.0000	1.0000	1.0000	0.	0.0000
52	EMERCY	0	0	0.000	-1	0	0	15.0000	1.0000	1.0000	0.	0.0000
53	EMERCY	0	0	0.000	-1	0	0	15.0000	1.0000	1.0000	0.	0.0000

*FUEL TYPES STD UNIT

1 COAL TONS
 2 NUCLEAR MWD
 3 OIL BBL

*FUEL TYPES STD UNIT

4 GAS MCF
 5 SPECIAL NONE
 6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

TYPE	IDENT.	MINIMUM FUEL INPUT MBTU/HR	MIN LOAD MW	MID LOAD MW	MAX LOAD MW	INCREMENTAL HEAT RATE BTU/KWH		FORCED FULL	OUTAGE RATE PARTIAL
						SECTION 1	SECTION 2		
1	AUR1	174.00	10	45	55	10740.	13500.	0.0500	0.1000
2	BOS1	145.00	10	50	70	9625.	11850.	0.0500	0.1000
3	BOS2	145.00	10	50	70	9625.	11850.	0.0500	0.1000
4	BOS3	750.00	50	250	350	8500.	9600.	0.0700	0.4600
5	HIBB1	118.00	5	10	25	12000.	13470.	0.1000	0.4500
6	HIBB2	114.00	5	10	25	11200.	13330.	0.1000	0.4500
7	HIBB3	104.00	5	10	30	11100.	12700.	0.1000	0.4500
8	HIBB4	103.00	5	10	35	11500.	12400.	0.1000	0.4500
9	WIN2	77.40	5	0	10	14600.	0.	0.5000	0.0000
10	WIN3	69.40	5	0	15	14600.	0.	0.5000	0.0000
11	AUR2	174.00	10	45	55	10740.	13500.	0.0500	0.1000
12	NSP1	0.00	0	0	75	1000.	0.	0.1300	0.0000
13	NSP2	0.00	0	0	50	1000.	0.	0.1100	0.0000
14	NSP3	0.00	0	0	25	1000.	0.	0.1300	0.0000
15	NSP4	0.00	0	0	100	1000.	0.	0.1300	0.0000
16	NSP5	0.00	0	0	200	1000.	0.	0.1300	0.0000
17	NSP6	0.00	0	0	100	1000.	0.	0.1300	0.0000
18	DPLSDP	0.00	0	0	5	1000.	0.	0.1100	0.0000
19	DPLSDP	0.00	0	0	5	1000.	0.	0.1100	0.0000
20	GTP1	0.00	0	0	10	1000.	0.	0.1100	0.0000

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

TYPE	IDENT.	MINIMUM FUEL INPUT MBTU/HR	MIN LOAD MW	MID LOAD MW	MAX LOAD MW	INCREMENTAL HEAT RATE BTU/KWH		FORCED FULL	OUTAGE RATE PARTIAL
						SECTION 1	SECTION 2		
21	OTP2	0.00	0	0	10	1000.	0.	0.1300	0.0000
22	OTP3	0.00	0	0	25	1000.	0.	0.1300	0.0000
23	MPC1	0.00	0	0	20	1000.	0.	0.1100	0.0000
24	MPC2	0.00	0	0	80	1000.	0.	0.1100	0.0000
25	MPC3	0.00	0	0	40	1000.	0.	0.1300	0.0000
26	MPC4	0.00	0	0	30	1000.	0.	0.1300	0.0000
27	MDU1	0.00	0	0	25	1000.	0.	0.1100	0.0000
28	MDU2	0.00	0	0	5	1000.	0.	0.1100	0.0000
29	NWFS	0.00	0	0	25	1000.	0.	0.1100	0.0000
30	OPPD1	0.00	0	0	70	1000.	0.	0.1600	0.0000
31	OPPD2	0.00	0	0	90	1000.	0.	0.1600	0.0000
32	ISP1	0.00	0	0	85	1000.	0.	0.1400	0.0000
33	ISP2	0.00	0	0	100	1000.	0.	0.1400	0.0000
34	NH	0.00	0	0	100	1000.	0.	0.5000	0.0000
35	DEF1	0.00	0	0	80	1000.	0.	0.1400	0.0000
36	DEF2	0.00	0	0	30	1000.	0.	0.1400	0.0000
37	DEF3	0.00	0	0	50	1000.	0.	0.1400	0.0000
38	DEF4	0.00	0	0	140	1000.	0.	0.1400	0.0000
39	DEF5	0.00	0	0	100	1000.	0.	0.1400	0.0000
40	DEF6	0.00	0	0	200	1000.	0.	0.1400	0.0000

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY
THERMAL CHARACTERISTICS

TYPE	IDENT.	MINIMUM FUEL INPUT MBTU/HR	MIN LOAD MW	MID LOAD MW	MAX LOAD MW	INCREMENTAL HEAT RATE BTU/KWH		FORCED OUTAGE RATE	
						SECTION 1	SECTION 2	FULL	PARTIAL
41	DEF7	0.00	0	0	200	1000.	0.	0.1400	0.0000
42	BOS3A	750.00	50	250	350	8500.	9600.	0.0700	0.4600
43	BOS4	1400.00	100	350	500	9000.	10000.	0.0700	0.2600
44	BRK1	1400.00	100	600	800	9600.	10000.	0.0700	0.3200
45	BUTTE	0.00	0	0	410	1000.	0.	0.1300	0.0000
46	BUTIE1	0.00	0	0	290	1000.	0.	0.1300	0.0000
47	HIBB2C	114.00	5	10	25	11200.	13330.	0.0500	0.1000
48	HIBB3C	104.00	5	10	30	11100.	12700.	0.0500	0.1000
49	HIBB4C	103.00	5	10	35	11500.	12400.	0.0500	0.1000
50	EMERCY	0.00	0	0	160	1000.	0.	0.0000	0.0000
51	EMERCY	0.00	0	0	160	1000.	0.	0.0000	0.0000
52	EMERCY	0.00	0	0	160	1000.	0.	0.0000	0.0000
53	EMERCY	0.00	0	0	160	1000.	0.	0.0000	0.0000

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

PARTICIPATION UNIT SALES					FUEL DATA FOR SECOND LOADING SECTION			
TYPE	IDENT.	MW SALE	REVENUE DEMAND \$/MW/MO	RATES ENERGY \$/MWE	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	FUEL COST \$/MBTU	1+INFLATION FACTOR
1	AUR1	0	0.	0.00	1	16.800	0.6050	1.0000
2	BOS1	0	0.	0.00	0	0.000	0.0000	1.0000
3	BOS2	0	0.	0.00	0	0.000	0.0000	1.0000
4	BOS3	50	1667.	6.50	0	0.000	0.0000	1.0000
5	HIBB1	0	0.	0.00	0	0.000	0.0000	1.0000
6	HIBB2	0	0.	0.00	0	0.000	0.0000	1.0000
7	HIBB3	0	0.	0.00	0	0.000	0.0000	1.0000
8	HIBB4	0	0.	0.00	0	0.000	0.0000	1.0000
9	WIN2	0	0.	0.00	0	0.000	0.0000	1.0000
10	WIN3	0	0.	0.00	0	0.000	0.0000	1.0000
11	AUR2	0	0.	0.00	1	16.800	0.6050	1.0000
12	NSP1	0	0.	0.00	0	0.000	0.0000	1.0000
13	NSP2	0	0.	0.00	0	0.000	0.0000	1.0000
14	NSP3	0	0.	0.00	0	0.000	0.0000	1.0000
15	NSP4	0	0.	0.00	0	0.000	0.0000	1.0000
16	NSP5	0	0.	0.00	0	0.000	0.0000	1.0000
17	NSP6	0	0.	0.00	0	0.000	0.0000	1.0000
18	DPLSDP	0	0.	0.00	0	0.000	0.0000	1.0000
19	DPLSDP	0	0.	0.00	0	0.000	0.0000	1.0000
20	OTP1	0	0.	0.00	0	0.000	0.0000	1.0000

*FUEL TYPES STD UNIT

1 COAL TONS
2 NUCLEAR MWD
3 OIL EBL

*FUEL TYPES STD UNIT

4 GAS MCF
5 SPECIAL NONE
6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY
THERMAL CHARACTERISTICS

PARTICIPATION UNIT SALES					FUEL DATA FOR SECOND LOADING SECTION			
TYPE	IDENT.	MW SALE	REVENUE DEMAND \$/MW/MO	RATES ENERGY \$/MWH	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	FUEL COST \$/MBTU	1+INFLATION FACTOR
21	OTP2	0	0.	0.00	0	0.000	0.0000	1.0000
22	OTP3	0	0.	0.00	0	0.000	0.0000	1.0000
23	MPC1	0	0.	0.00	0	0.000	0.0000	1.0000
24	MPC2	0	0.	0.00	0	0.000	0.0000	1.0000
25	MPC3	0	0.	0.00	0	0.000	0.0000	1.0000
26	MPC4	0	0.	0.00	0	0.000	0.0000	1.0000
27	MDU1	0	0.	0.00	0	0.000	0.0000	1.0000
28	MDU2	0	0.	0.00	0	0.000	0.0000	1.0000
29	NWPS	0	0.	0.00	0	0.000	0.0000	1.0000
30	OPPD1	0	0.	0.00	0	0.000	0.0000	1.0000
31	OPPD2	0	0.	0.00	0	0.000	0.0000	1.0000
32	ISP1	0	0.	0.00	0	0.000	0.0000	1.0000
33	ISP2	0	0.	0.00	0	0.000	0.0000	1.0000
34	MH	0	0.	0.00	0	0.000	0.0000	1.0000
35	DEF1	0	0.	0.00	0	0.000	0.0000	1.0000
36	DEF2	0	0.	0.00	0	0.000	0.0000	1.0000
37	DEF3	0	0.	0.00	0	0.000	0.0000	1.0000
38	DEF4	0	0.	0.00	0	0.000	0.0000	1.0000
39	DEF5	0	0.	0.00	0	0.000	0.0000	1.0000
40	DEF6	0	0.	0.00	0	0.000	0.0000	1.0000

*FUEL TYPES STD UNIT

1 COAL TONS
2 NUCLEAR MWD
3 OIL BBL

*FUEL TYPES STD UNIT

4 GAS MCF
5 SPECIAL NONE
6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

THERMAL CHARACTERISTICS

PARTICIPATION UNIT SALES					FUEL DATA FOR SECOND LOADING SECTION			
TYPE	IDENT.	MW SALE	REVENUE DEMAND \$/HW/MO	RATES ENERGY \$/MWH	FUEL TYPE *	ENERGY CONTENT OF FUEL MBTU/STD UNIT*	FUEL COST \$/MBTU	1+INFLATION FACTOR
41	DEF7	0	0.	0.00	0	0.000	0.0000	1.0000
42	BOS3A	0	0.	0.00	0	0.000	0.0000	1.0000
43	BOS4	0	0.	0.00	0	0.000	0.0000	1.0000
44	BRK1	300	8000.	14.42	0	0.000	0.0000	1.0000
45	BUTTE	0	0.	0.00	0	0.000	0.0000	1.0000
46	BUTTE1	0	0.	0.00	0	0.000	0.0000	1.0000
47	HIEB2C	0	0.	0.00	0	0.000	0.0000	1.0000
48	HIEB3C	0	0.	0.00	0	0.000	0.0000	1.0000
49	HIEB4C	0	0.	0.00	0	0.000	0.0000	1.0000
50	EMERCY	0	0.	0.00	0	0.000	0.0000	1.0000
51	EMERCY	0	0.	0.00	0	0.000	0.0000	1.0000
52	EMERCY	0	0.	0.00	0	0.000	0.0000	1.0000
53	EMERCY	0	0.	0.00	0	0.000	0.0000	1.0000

*FUEL TYPES STD UNIT

1 COAL TONS
 2 NUCLEAR MWD
 3 OIL BBL

*FUEL TYPES STD UNIT

4 GAS MCF
 5 SPECIAL NONE
 6 PURCHASES NONE

MINNESOTA POWER AND LIGHT PRODUCTION COST
 10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
 JULY 28, 1976

GENERAL INPUT SUMMARY

MAINTENANCE CYCLES					
CYCLE NO.	1	2	3	4	5
YEAR					
1	1	0	0	0	0
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	0	0	0	0	0
6	-1	0	0	0	0
7	-1	-1	-1	-1	-1

COMMITMENT PRIORITY CALCULATED AS SHOWN ON NEXT PAGE

MINNESOTA POWER AND LIGHT PRODUCTION COST
10 YEAR RUN HIBBARD FUEL CONVERSION STUDY (CONVERSION IN MAY 1978)
JULY 28, 1976

GENERAL INPUT SUMMARY

PRIORITY NUMBER	TYPE NO.	IDENTITY	COMMITMENT PRIORITY		CAP. MW	MINIMUM HRS DOWNTIME
			AVG. COST AT RATING-S/MWH			
1	4	BOS3	6.234		350	168
2	42	BOS3A	6.234		350	168
3	43	BOS4	6.485		500	168
4	2	BOS1	6.781		70	168
5	44	BRK1	8.000		800	168
6	1	AUR1	10.434		55	168
7	49	HIBB4C	13.556		35	168
8	8	HIBB4	30.628		35	168
9	24	MPC2	4.000		80	12
10	45	BUTTE	5.090		410	12
11	46	BUTTE1	5.090		290	12
12	23	MPC1	6.000		20	12
13	34	MH	6.000		100	12
14	3	BOS2	6.781		70	12
15	20	OTP1	7.000		10	12
16	21	OTP2	7.300		10	12
17	22	OTP3	7.300		25	12
18	27	MDU1	7.300		25	12
19	28	MDU2	7.300		5	12
20	29	NWPS	7.300		25	12
21	25	MPC3	8.000		40	12
22	26	MPC4	8.000		30	12
23	13	NSP2	9.000		50	12
24	11	AUR2	10.434		55	12
25	30	OPPD1	12.000		70	12
26	18	DPLSDP	13.000		5	12
27	19	DPLSDP	13.000		5	12
28	48	HIBB3C	13.760		30	12
29	31	OPPD2	14.000		90	12
30	32	ISP1	14.000		85	12
31	33	ISP2	14.000		100	12
32	12	NSP1	14.000		75	12
33	47	HIBB2C	14.369		25	12
34	14	NSP3	14.800		25	12
35	35	DEF4	15.000		30	12
36	16	NSP5	15.700		200	12
37	15	NSP4	15.700		100	12
38	17	NSP6	16.600		100	12
39	36	DEF2	17.000		30	12
40	37	DEF3	18.000		50	12
41	38	DEF4	18.000		140	12
42	39	DEF5	19.000		100	12
43	40	DEF6	19.000		200	12
44	41	DEF7	19.000		200	12
45	7	HIBB3	31.265		30	12
46	10	WIN3	32.343		15	12
47	6	HIBB2	33.162		25	12
48	9	WIN2	33.615		10	12
49	5	HIBB1	33.918		25	12
50	50	EMERGENCY	15.000		100	0

APPENDIX G
FINANCIAL PLANNING MODEL *

The Financial Planning Model allows the management group of a utility to generate financial budgets rapidly. The program can handle budget forecasts, on a company basis, of up to 10 years.

The program is actually seven subprograms (FMDL02, FMDL12, FMDL22, FMDL32, FMDL42, FMDL52 and FMDL62) chained together. Figure G-1 shows how these seven programs relate to one another. This appendix will describe each program in more detail, including any assumptions inherent in the program's structure.

FMDL02

The first program called by the Corporate Financial Planning Model is FMDL02. This program has three major functions:

- To store zeros in Common
- To read general input
- To check general data and to save it on a temporary file for later use

After having read the general data, as described in the input data section of the manual, the program performs several checks and several calculations with the data. Data checks are made as follows:

*Information Courtesy of Power Technologies, Inc.

Figure G-1. Flow Diagram of Financial Planning Model Programs

- Construction work in progress, i. e. , plant work in progress excluding items depreciable for book but not tax plus items depreciable for book but not tax, must agree with the balance sheet work in progress.
- Plant in service, pre-1969 plus post-1968, must agree with the gross plant in service as shown on the balance sheet.
- The sum of the individual bond face values must equal the bonds outstanding on the balance sheet.
- Total assets on the balance sheet must equal total liabilities.

If any of the above items do not check, the program prints out a message indicating the number of errors found and stops. The program will not proceed unless all checks are satisfied.

The following calculations are performed by the program:

The program totals post-1968 plant added to the system by plant class.
The plant classifications are as follows:

- Class 1 - production plant
- Class 2 - pollution abatement facilities
- Class 3 - other depreciable plant
- Class 4 - Nondepreciable plant
- Class 5 - items depreciable for book but not tax

The program calculates the straight-line tax depreciation rate for pollution abatement facilities and pre-1969 plant.

If an annual amortization of accelerated amortized depreciation has been input, the program will take 1/12th of this annual value and allocate it to each month. This is the monthly amortization.

The program calculates the revenues to be collected for the first month of the forecast as December's industrial electric revenues and other operating revenues from the initial balance sheet year, plus 50 percent of the other electric revenues and steam revenues from December of the initial balance sheet year.

A monthly divided credit is calculated as 1/12th of the annual input value.

The program converts the annual bond interest rate into a monthly interest accrual for each issue and sums the monthly interest accruals for all issues into a total.

The program calculates the month of next bond interest payment. It is assumed that bond interest is paid semi-annually and the months of interest payment are based on the month of the year that the bond issue will become due.

Dividends on outstanding preferred stocks are assumed to be 1/4th of the annual dividend value and allocated to January, April, July and October.

The program calculates totals on the balance sheet as follows:

Total plant	Capitalization
Net plant	Current liabilities
Current assets	Total liabilities
Total assets	

It is this calculation of total assets and total liabilities that the program uses to check total assets versus total liabilities.

Having checked the data and found no errors, the program will then save all of the general input data on a random access file. This random access file, called "FILETP," has been set up with a record length of 30 words. The program, at the end of the run, will use this for printing out the general input data.

FMDL12

Having read the general data and checked it, the model is then ready to proceed into the yearly loop. Here FMDL12 is called. This program is called once each year. Its purpose is to initialize Common for the year and to read the input values. The annual input has been described in the previous section. It should be noted that no checks are made on the annual input data.

FMDL22

Having read the annual data, the financial planning model then moves into program FMDL22. This program does the following:

- Plant accounting, including the calculation of interest during construction, book depreciation and tax depreciation
- Accounting for operating expenses
- Accounting for operating revenues
- Accounting for any "fixed" cash items

Subroutine "PLANT," the first subroutine called by FMDL22, takes the annual capital expenditures and expenses to be capitalized and, per the input, allocates them to each month. Based on the capital expenditures and the transfers of work-in-progress to in-service plant, the program calculates the monthly interest during construction credit. This is calculated using the average plant work in progress and the monthly interest during construction rate, $1/12$ th of annual value. This interest during construction, along with the expenses depreciable for book but not tax, are kept as a separate category. The amount of expenses depreciable for book but not tax to transfer to finished plant is based on the amount of the transfer and the total work in progress before the transfer.

Each month the program tests to see if there are any large, single blocks of retirements of plant to be made. One retirement of this type is allowed each year. Any retirements of plant are assumed to be from other depreciable plant and assumed to be pre-1969 plant. Normal retirements are calculated based on the transfer of other depreciable and nondepreciable plant to in-service plant during the year. The retirements are taken to be a percent, given as input, of the other depreciable plant transferred to in-service plant and a percent, also input, of the nondepreciable plant transferred to in-service plant. One-twelfth of the annual normal retirements is allocated to each month.

The program then calculates the annual book depreciation. This is based on the average plant in service for each classification and the book depreciation rate for each plant classification. One-twelfth of the annual book depreciation expense is taken each month.

Tax depreciation is also based on average plant and is calculated as follows:

- 1) Pre-1969 plant tax depreciation is straight-line method at the inputted guideline life.

- 2) Tax depreciation on pollution abatement facilities is straight-line, based on the inputted tax depreciable life: tax savings, based on a 31-year life, are normalized.
- 3) Tax depreciation for post-1968 production plant and other depreciable plant is calculated using the sum-of-the-year's-digits method and the inputted tax depreciable life: tax savings may be normalized or flowed through to income.
- 4) ADR tax depreciation for post-1970 production plant and other depreciable plant is calculated using sum-of-year's-digits method (@ 20 percent reduction of life) and the inputted tax depreciable life.

	<u>Tax Depreciation Life (years)</u>	<u>20%</u>	<u>SxD</u>
Production Plant	28	22.4	262.08
Nonproduction Plant	31	24.8	319.92

The program keeps track of the difference in tax depreciation due to liberalized depreciation. The normal tax depreciation is taken to be the straight-line method at the inputted tax depreciable life. The monthly depreciation, for tax purposes, is taken to be 1/12th of the annual value. In the calculation of tax savings, it is assumed that if the tax savings were not available, 100 percent of the tax difference would be paid in the current year.

The program next performs the accounting for the various operating expenses. It is assumed that the annual vehicle depreciation is allocated to each month as 1/12th of the annual value. Likewise, for the property tax accrual and the miscellaneous income deductions. The previous year's property tax is paid in the current year. One-sixth of last year's property tax is paid in February and June, one-third of last year's property tax is paid in May and October.

Most of the operating expenses, that is, fuel expenses, purchased and interchange power expenses, other operation expenses less vehicle depreciation, maintenance expenses, other taxes and miscellaneous income deductions are assumed to be a current deduction from cash. Total operation and maintenance expenses for tax purposes are fuel, purchased and interchange power, other operation and maintenance expenses.

The program then calculates the various revenues. Dividends from Superior are assumed to be received in March, June, September, and December, one-fourth of the annual value each of these months. The inputted other income is allocated to each month as 1/12th of the annual value. At this point in the model, it should be noted that other income does not include interest on temporary investments. This will be calculated later in the program. The cash collection for revenues from electric industry and other operating are lagged one month, while revenues from other electric and steam are lagged one-half month.

The program then calculates the "fixed-cash" items. These items are changes to the balance sheet which are not calculated anywhere else as follows:

Fuel stock	Other current liabilities
Materials and supplies	Other liabilities
Other current assets	Other operating reserves
Other assets	Contributions in aid of construction

One-twelfth of the annual input value is allocated as the change to the balance sheet for each month. These are assumed to be current cash items. In this routine, if it has been indicated that an investment in the subsidiary is to take place, the accounting for this investment is done here. The investment in the subsidiary is assumed to be a change to the Other Assets account. Lastly, the "FIXCSH" program sets up for the retirement of bonds which become due in the current year.

FMDL32

Having performed all of the "fixed" items, that is, fixed expenditures, operating expenses, operating revenues, and other "fixed" cash items, the model next moves into FMDL32.

At the beginning of each month, the net bonds issuable is calculated as follows:

Net bonds issuable = 60% of bondable property
 - bonds issued since start of forecast period
 + bonds refunded since start of forecast period

Bondable property (annual basis) = bondable property end of previous year
 + capital expenditures
 - 0.02* (transfers to in-service plant)
 - 0.021* (cumulative bonds outstanding in
 year n-6)
 - \$750 thousands
 + retirements 24 months ago
 - retirements 12 months ago
 - 0.02* (net additions since 1945)

*

Based on the then current outstanding short-term debt, long-term debt and temporary cash investments, the program calculates the various interest accruals. The program then calculates income taxes and net income. If it is the month of common stock dividend payment (March, June, September or December), the program calculates the dividend as follows:

- Dividends never decrease
- Dividends increase in steps of one cent
- Minimum payout ratio is to be observed

Finally, a cash estimate is made. The cash estimate at this point is primarily, plus and minus, the fixed cash items, income taxes paid, interest paid or received, dividends paid and short term debt, long term debt, preferred stock and common stock issued for the month.

The State income taxes for the payment month and two previous months are paid in March, June, September and December. The Federal income tax is paid as follows:

- 80% of the tax for January, February and March is paid in April
- 80% of the taxes for payment months and previous two months are paid in June, September and December
- The balance of the Federal tax is paid in equal amounts in March and June of the following year

The program then determines if additional long-term financing is required. It is possible to run this program under three modes. First, all deficient cash is made up by short-term debt. Second, long-term financial plans may be input, in which case the short-term debt limit is ignored and any deficient cash is made up in short-term loans. Third, the program will calculate the necessary long-term financing such that the cash limits and short-term debt limit are observed.

At the beginning of each month, the end-of-the-month capitalization is forecasted. If the minimum equity ratio will not be achieved, the program will immediately issue common stock such that the minimum equity ratio will be exceeded. The program re-calculates the cash position. If the cash position is less than the calculated minimum desired cash, the program checks the short-term debt limit. If the short-term debt limit is not exceeded,

the program will issue short term debt such that the average cash position will be met. (The average cash position is an average of the minimum and maximum desired cash limits.) If the short-term debt limit will be exceeded, the program will next determine if it can issue long-term debt. Before the issuance of long-term financing, the program will retire all outstanding short-term debt.

To issue long-term debt, the following constraints must be observed. Proposed new issue, deficient cash plus short term retired, must be (1) less than or equal to net bonds issuable and (2) equal to or greater than minimum long term debt issue size. Long-term debt issued by the program will be 30-year bonds. Inputted long-term debt issues will be of the duration indicated by input.

If long-term debt cannot be issued, the program next tests to see if it can issue preferred stock. Here the program tests to see that the needed cash, if put into preferred stock, will not exceed the preferred stock ratio and that the needed cash is at least as large as the preferred stock issue size.

It is possible that the program may determine that the short-term debt limit will be exceeded and some type of long-term financial instrument should be issued and, at the same time, the program cannot issue long term debt or preferred stock. If this situation is found, the program issues the short-term debt and prints a message to indicate that a long-term issue could not be issued and the approximate number of months before the long-term debt can be issued.

If the program finds that the end of month cash will exceed the maximum cash, the program has been instructed to (1) retire all outstanding short-term loans and (2), if possible, invest in temporary investments. If financial plans have been input, the program will immediately issue common stock,

long-term debt or preferred stock, as instructed, and ignore the short-term debt limit. The program will test to see if there is excess cash and invest in temporary investments.

Having determined the new long-term financing, the program next moves to calculate the final cash flow. At the beginning of the cash flow routine, the program immediately checks to see if the cash estimate is at least greater than the minimum cash desired. If the cash estimate is below the cash minimum, additional short-term debt is issued and a new interest accrual is calculated. The program then calculates the income tax accrual, the income taxes which should be paid during the month and the net income. The cash flow is re-calculated as the cash flow after income taxes. Again a check is made to see if the end-of-the-month cash exceeds the cash minimum. If it does not, the program returns back to the beginning of the routine where additional short term debt is issued. New interest accrual, income taxes and income are calculated.

When it has been determined that the end-of-month cash position is satisfactory, the program up-dates the next month that income taxes are to be paid (State taxes - March, June, September and December; Federal taxes - April, June, September and December) and common dividends paid (March, June, September and December). For any new long-term issues, the program sets up data as follows:

- For debt - the interest accrual and interest payment schedule
- For preferred stock - the dividend payment schedule
- For common stock - the number of shares of common stock issued

The number of shares of common stock issued is based on the previous year's earnings per share and the inputted price-to-earnings ratio.

Having determined the cash flow for the month, the program then up-dates the balance sheet. If the end of the year has not been reached, the month number is up-dated and the program proceeds back to the beginning of the FMDL32 program. It should be noted that in the calculation of the income taxes, income and cash flow, the program logic follows, insofar as possible, the annual report output format.

OUTPUT

FMDL42

At the end of each year, the model calls in the FMDL42 program. The FMDL42 program prints the annual income statement, statement of income taxes, cash report and balance sheet.

FMDL52

The model then passes into program FMDL52. This program calculates and prints on an annual basis, various statistical data. This program saves all of the annual data on the random access file for print-out later. The program then tests to see if the forecast period has been completed. If it is not, that is, there are more years to calculate, the model then calls the FMDL12 program, which is the annual input program. If the program determines that it is finished, the program prints out selected pieces of the general data as follows:

- Short-term debt limit
- Cash basis

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- Long-term issue rounding values and minimum issue sizes
- Initial dividends per share, payout ratio and price-to-earnings ratio for common stock
- Capitalization ratios
- Initial annual income statement, statement of income taxes, cash report and balance sheet

FMDL62

As the last step, the model calls the FMDL62 program. It is here that various items of annual input are printed as follows:

- Federal income tax rate, surtax rate and state tax rate
- Interest rates for interest during construction, long-term debt and short-term debt
- Preferred stock dividend rate
- Annual revenues for industrial electric, other electric, steam, other operating
- Annual operation and maintenance expenses for fuel, purchased and interchange power, other operation, maintenance expense, other taxes and property taxes
- Expenditures for non-production plant and production plant
- Expenses to be capitalized; general and property taxes

Lastly, the program prints out any inputted long-term financing issues

APPENDIX H
MINNESOTA POWER & LIGHT SUMMARY REPORT

MINNESOTA POWER & LIGHT COMPANY

30 WEST SUPERIOR STREET, DULUTH, MINNESOTA 55802

PHONE (AREA 218) 722-2641

A. J. SANDBULTE
VICE PRESIDENT - FINANCE

August 31, 1976

Mr. O. H. Lindquist
Honeywell Systems & Research Center
2600 Ridgway Parkway
Minneapolis, Minnesota 55413

Dear Mr. Lindquist:

Minnesota Power & Light Company has been cooperating with Honeywell over the past several years in the evaluation of Wind Energy Conversion Systems (WECS). Honeywell is the prime contractor with ERDA as to a theoretical study to determine the relative economics of WECS for electric utilities.

The MP&L system has a very high load factor, meaning that substantial quantities of energy are required even during those hours when a more typical utility might experience a substantial load reduction (such as during the nighttime and on weekends). It was felt that MP&L's system might be able to utilize WECS to maximum economic advantage, more so than most other electric utilities.

The MP&L computerized financial and production cost models were used to simulate WECS on the MP&L electric system. Year by year analyses were run on the models for a 10-year period to determine dynamic economic factors which would be important in judging the economic viability of WECS.

Based upon the results obtained from these analyses, MP&L has concluded that with present technology and the wind characteristics in the MP&L service area, WECS is not economically feasible. MP&L's criteria was that fuel savings resulting from the use of WECS must be sufficient to pay the additional capital charges associated with WECS. Since WECS is not a firm source of power, but rather is available only when wind conditions are favorable, WECS cannot be relied upon as a firm source of generating capacity. In our view, without the coupling of WECS with an energy storage system, wind energy must be justified solely on the basis of fossil fuel energy savings.

Our analyses indicate that the point at which wind energy savings would be significant is too far in the future and too speculative at this point to justify the capital expenditure required for the installation of WECS. The capital cost of WECS produces annual carrying charges which are very substantial, not

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unlike carrying charges on fossil fueled generating units, and these annual carrying charges are not offset by fuel savings in the reasonably foreseeable future.

If the capital costs of WECS could be reduced by 25%-30% and the technological risks can be minimized, such that the year in which energy cost savings equal or exceed the fixed cost of WECS occurs at an early point in the anticipated life of the wind facilities, then WECS could become a viable energy alternative. Under such economic conditions, MP&L would seriously consider the installation of WECS. Ways in which the capital cost of WECS might be reduced would include technological breakthroughs or government subsidy (either direct or through tax policy).

A number of areas which must be considered in detail before WECS could be considered include:

(a) Maintenance considerations. No actual maintenance costs are available so conventional operation maintenance costs were assumed.

(b) The logistics involved in erecting a large number of units in a short period of time must be considered.

(c) More detail in analyzing the integration of WECS into a utility's system is necessary

(d) The environmental acceptance of large numbers of wind turbine generators including regulatory approval, licensing, zoning, possible microwave interference and other unforeseen circumstances must be evaluated.

I should point out that the WECS studies prepared by MP&L were specifically tailored to our Company and must not be considered as necessarily applicable to all utilities. Different wind characteristics, financial evaluation, fuel costs and operating philosophy could vary the conclusions by other utilities.

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Mr. O. H. Lindquist
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We appreciated the fine working relationship which has existed between Honeywell and MP&L over the past months. Please advise if we can be of any further assistance.

Very truly yours,

A. J. Sandbulte

ck

APPENDIX I
PROBLEMS ASSOCIATED WITH ESTIMATING THE
PRODUCTION COST SAVINGS OF WIND ENERGY

OVERVIEW

The value of energy produced by wind requires the probabilistic handling of energy assignment to load needs. An acceptable description of an unpredictable, natural phenomenon must be related to a utility's load requirements, power generation capability, and production costs. The MP&L Production Cost Model (PCM) described in Section V estimates production costs by assigning generation capability on an economic dispatch basis. It treats uncertainties statistically on a monthly basis. The most probabilistic element of the PCM planning prediction involves the hydroelectric energy. Section V describes how this study used the hydroelectric format in evaluating wind production cost savings. This discussion reviews the general appropriateness and implications of the technique used.

The basic problem is one of predicting how much will be saved in the production of energy to meet the load when WECS is introduced into a system. Figure I-1 represents the issues. After a WECS is installed in a system, production cost savings will be the real-time summation of the cost of displaced energy.

If wind energy is available when high loads require the use of expensive emergency purchases and/or expensive oil generation, a large cost savings will occur. In operation, the timing and generation costs will be directly assessed. The problem is to predict the probable result of years of operation.

$$\$ = [V][P]$$

$$\begin{aligned} \$ &= \begin{bmatrix} v_1 P_1 + v_1 P_2 + v_1 P_3 + v_1 P_4 \\ v_2 P_1 + v_2 P_2 + \dots \\ \vdots \\ v_4 P_1 + \dots \end{bmatrix} \\ &= \$\text{ESTIMATED} \end{aligned}$$

I-2

Figure I-1. Basic Problem of WECS PCM - Statistical Prediction of Operation (Stochastically Independent Variable)

The simplest prediction would make the assumption that the two parameters of interest are stochastically independent, i. e. they are uncorrelated events without casual relationships. This permits the load to be represented as a density function of the values of energy for the time period. The wind is likewise represented as a distribution function histogram. The value of wind energy would then be computed by assuming that each level of wind energy applies equally to every level of load value as indicated in the figure. Time dependence of the two variables is ignored. This type of calculation is assumed in the MP&L PCM for the case of run-of-river energy. No control of run-of-river hydro energy is possible and it applies equally to all hours of operation. This case was investigated with respect to WECS and is reported later in this section.

In the case of wind energy and load, time-dependent relationships can be anticipated. WECS energy could be assumed to be characteristically noon peaking or evening-morning peaking dependent upon location and season as shown in WECS Cases 1 and 2 of Figure I-2. If the utility load is represented by Load Case 1, an afternoon peaking load, the WECS Case 1 production cost savings will be much larger than for WECS Case 2, even when the WECS Total Energies were equal. In terms of Figure I-1, the statistical distribution functions could be identical in these two cases and the calculation shown would not reflect the large difference in Cost Savings.

If the load were constant, (Figure I-2, Load Case 2) a special situation exists. The time dependence of the two WEC's cases would not matter since the WECS power generated would have the same total value, regardless of time. The basic computation concept of Figure I-1 would be appropriate. This is the case generally with MP&L. MP&L has the highest load factor in the USA and typically shows very little peaking.

Figure I-2. Time Dependence of WECS to Load

Another special case would exist if a second energy source could be added which when combined with WECS provides a constant energy availability. This second source would be the MP&L hydroelectric power which serves as a short-term storage for WECS. Since MP&L already uses its hydro-power for whatever daily load leveling which occurs, this assumption can be applied to the MP&L PCM for planning purposes. The WECS was sized to support this assumption, i. e. WECS energy can be applied to the high valued loads.

ESTIMATION OF PREDICTION VARIANCE IN PRODUCTION COST SAVINGS

Section V describes how WECS energy was introduced into the production cost model for planning purposes. An investigation of the effect of making a more conservative estimate of the value of WECS in the PCM has been conducted. This analysis was requested at the April 26, 1977 review held at MP&L in Duluth, MN.

Production cost runs were made to investigate using wind energy as run-of-river hydro instead of controllable hydro as in the main study. The wind energy for each month was taken from the work previously reported. It was not possible to directly compare to the original study since a year had passed and the PCMs were dependent upon the specific cost data being used in the on-going planning activities of MP&L. The relative change in WECS cost savings with system size would be comparable. The new PCM runs reflected replacing the general mix of generation capacity, whereas the previous study reflected first displacing most expensive generation by priority assignment. In the original case, as reported in the main study, increasing WECS system size, reflected in less value for WECS. This resulted in having the 76.5 Megawatt system being much

more economical than the 151.8MW system. The larger system would often be replacing lower cost generation. When a run-of-river assignment was used, the systems were less effected by increasing system size. Table I-1 summarizes the results. The key issue is the relative amount of high cost generation replacement which occurred in the initial case. From the two cases run, it appears that the priority assignment results in a 10 percent higher return than the run-of-river assignment in production cost estimates.

Table I-1. Comparison of Priority and Run-of-River Assignment of WECS in PCM

System Size Megawatts	Savings (Present Worth) Mils/KWH WECS	Savings Decrease with Size
<u>Priority Assignment of WECS</u>		
76.5	14.0	---
151.6	11.9	-15%
300.0	9.8	-30%
<u>Run-Of-River Assignment</u>		
75.0	15.6	---
150.0	14.8	- 5%
300.0	13.5	-13%

In the main study, using priority assignment, the WEC's system had a production cost savings of 11.9 mills/KWH. By comparison to run-of-river assignments, the estimate could at worst case be high by 10 percent, about 1.2 mills/KWH. This reduction would result in a predicted

savings near the 1976 average MP&L cost of generation without WECS, 9 mills/KWH.

This result indicates that assigning WECS energy on a run-of-river basis is almost equivalent to assignment on the average cost of power generation whereas its assignment on the basis of hydro-priority results in a 10 percent increase in estimated energy cost savings.

In overview, the value of wind energy must also include its sales price. The average sales price of MP&L in 1976 was 2.4¢ /KWH. The total return would be the sum of the sales return and the production cost savings, i. e. 2.4¢ /KWH + 1.2¢ /KWH or 3.6¢ /KWH. Since the general cost of WECS generation was estimated at 2.8¢ /KWH (Table 5-5), a positive net return is possible. A decrease of 1.2 mills/KWH would not change the positive position.

As the study has indicated, the capital cost and financial assumptions are a much larger consideration than the PCM assumptions used in the MP&L study. It must be noted however, that the high load factor and constant need for purchased power by MP&L create a special situation. Improved methods of handling the time relationships between load and wind are mandatory for applications where load peaking is a dominant factor.