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Projektleitung Energieforschung
International Energy Agency IEA

Implementing Agreement for a Programme of Research and Development on Wind Energy Conversion Systems

1981 Meeting of Experts of Annex III and IIIa
Integration of Wind Power into
National Electricity supply Systems

Organised by
Project Management for Energy Research (PLE)
of the Nuclear Research Establishment Jülich (KFA)
on behalf of the
Federal Minister of Research and Technology
and The Wind Energy Group of University Regensburg

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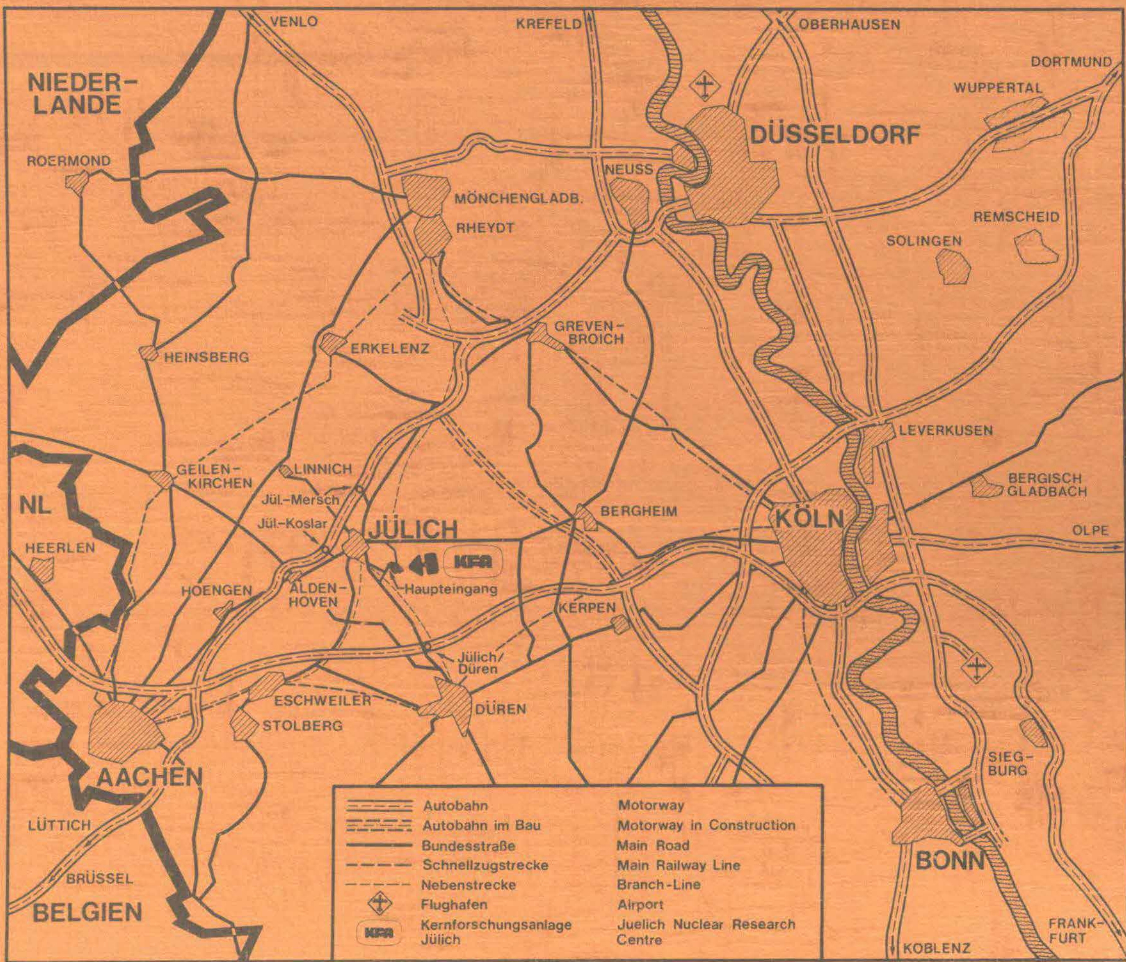

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Scientific Coordination:
W. Dub, G. Obermair (University Regensburg)
and R. Windheim (PLE KFA Jülich)

The German LS WECS GROWIAN: 3 MW from 12 m/sec up to 24 m/sec wind velocity, Kaiser-Wilhelm-Koog, mouth of the Elbe. View to SW in main wind direction. First rotation autumn 1982.

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Expert Meeting on Annex III: Integration of Wind Power into National Electricity Supply Systems.

Place:	Haus der Begegnung der University of Regensburg Hinter der Grieb 8 D-8400 Regensburg
Date:	January 29/30, 1981

January 29, 1981:

14.30
1. Opening adress
2. Adoption of the Agenda

Part I: Task III

3. Meteorological data basis
   (L.Jarass reporting)
   Discussion
4. Assessment of technical potential: problems, methods and results
   (G. Obermair reporting)
   Discussion
   BREAK
5. Economic evaluation
   (L. Hoffmann reporting)
   Discussion

19.00 Reception

January 30, 1981:

9.00 Part II: Task IIIa

1. Status report of Task IIIa for the Netherlands
   (W. Dub reporting)
   Discussion
2. Problems of integrating wind power into an electricity grid
   2a) Power fluctuation: technical and statistical aspects
       (H. Pape reporting)
       Discussion
       BREAK
   2b) Forecasting wind power output
       (W. Dub reporting)
       Discussion

11.30 LUNCH

13.30 2c) Assured load carrying capability and capacity credit
       (H. Pape reporting)
       Discussion

14.30 END

Session A: IEA-Task III

Paper A1

METEOROLOGICAL DATA BASIS

L. Jarass

ATW, FRG

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0 Introduction
1 Data Material
2 Representativeness of Data Material
3 Mean Wind Speed
4 Daily and Seasonal Time Variation of Wind Speed
5 Temporal Distribution of Wind Speed
6 Lulls
7 Correlation of Wind Speeds
8 Extreme Wind Velocities
9 Wind Directions
10 Locations Favorable for Wind Power Generation

0 INTRODUCTION

According to Annex III of the Implementing Agreement for a Program of Research and Development of Wind Energy Conversion Systems in 1978 a study was commissioned by the International Energy Agency (IEA) with the working title "Integration of Wind Power into National Electricity Supply Systems".

The final report of this study with the title "Large Scale Wind Power Utilization: An Assessment of the Technical and Economic Potential for the Federal Republic of Germany" was finished in September 1979 and transfered to the participating countries Japan, the Netherlands, Sweden, the United States of America and the Federal Republic of Germany.

A completely revised and shortened version of this final report has been published recently by Springer-Verlag, Berlin/Heidelberg/New York, titled "Wind Energy: An Assessment of the Technical and Economic Potential. A Case Study of the Federal Republic of Germany".

1 Data Material

Wind speed and direction data of many years from 16 observation points in the Federal Republic of Germany were evaluated:

- about 1.2 million wind speed data
- and an approximately equal amount of wind direction data.

For our evaluation the choice of stations was limited to typical locations in the coastal area and plains of Northern Germany, and in addition to mountain-top, slope and valley locations in the mountains of Central and South Germany, as well as town locations in the Forealp area and an exposed location in the Alps. Figure 1 shows the geographical locations of the stations used in the study.

For the purpose of better comparison, the analysis of the data was done for more or less the same periods of time; for coastal stations, the years 1969 to 1976 were analysed, for inland stations the years 1969 and 1972. The data in question are hourly mean figures for wind speed and direction, measured at heights of 10 m to 30 m above ground. Some data are taken at heights of up to 290 m.

Fig. 2 shows hourly mean wind speeds for two different months at List, a station which is representative for the North German coastal area.

FIG. 1: METEOROLOGICAL STATIONS

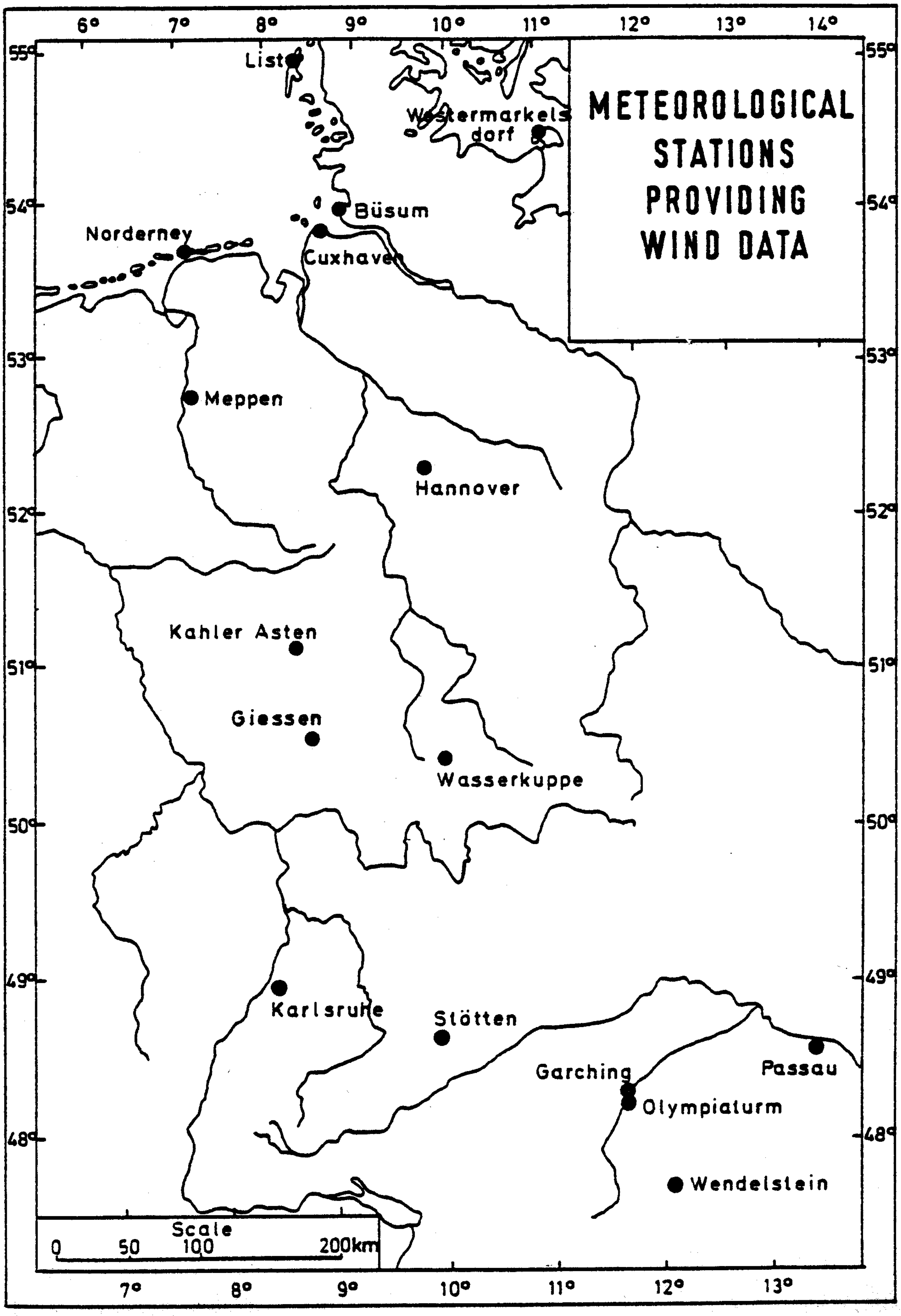


Fig. 2: Hourly Mean Wind Speeds

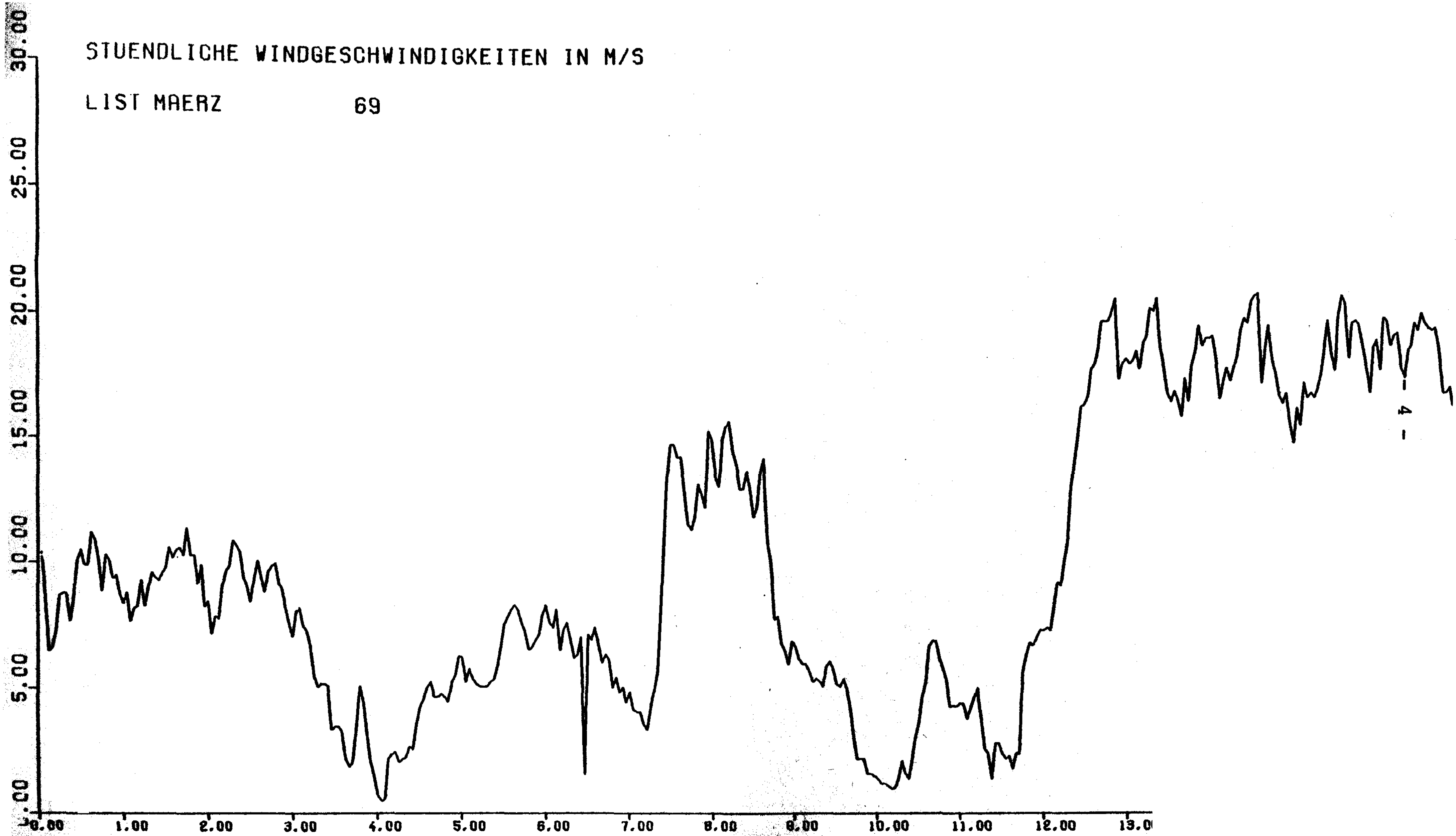


Fig. 2 : Hourly Mean Wind Speeds

2 Representativeness of Data Material

In all studies of the usability of wind power, there is a lack of wind speed data taken at greater heights (50 m to 250 m). These are the heights which are really relevant for the large-scale technical conversion of wind energy into electrical energy. Fortunately we have at least some data measured at greater heights, but only data from few selected hours or days are available. For the evaluation of the economics of wind energy this measuring period is unquestionably to short. The remaining data were measured at heights of between 10 m and 40 m and thus, because of the strong influence of surface roughness inland, present mostly only the turbulenc near the ground. It is only at coastal locations that measurements of about 40 m above sea level (List, Norderney) can be considered representative for greater heights as well.

As long as no long-term series of measurements from higher altitudes are available, extrapolation procedures must be relied on.

According to accepted meteorological opinion, the annual mean wind speed at 100 m hub height for different North German coastal locations is more or less equal in magnitude. The absolute value of this annual mean wind speed at hub height of 100 m is at the moment unknown and can only be estimated. Thus representative wind speeds, measured at heights of up to 40 m were extrapolated to the annual mean wind speed assumed for a height of 100 m.

The original wind data were in principle processed in an unaltered form and stored for analysis as ordered data; in what follows, the unaltered original wind speed, measured at 10 to 40 m height are analysed, these wind speeds are neither extrapolated to greater heights nor transformed.

3 Mean Wind Speeds

On the North German coast, the annual mean of hourly mean wind speeds is about 7 m/s to 7.5 m/s at a height of 10 m to 40 m above ground. With the extraoplation procedure of Hellmann, mean wind speeds of 8 m/s to 8.5 m/s at about 100 m - the height which is technically of relevance - are obtained. At Meppen, which is about 100 km inland, an annual mean of 7 m/s to 7.5 m/s was measured at a height of 80 m. At a height of 100 m, a mean wind speed of at least 7.5 m/s is to be reckoned with. For our calculations we took a plausible annual mean wind speed of 8 m/s at 100 m hub height as the reference, and used 6 m/s and 10 m/s as alternative standards.

The coefficient of variation is for all coastal stations about 0.5 corresponding to an annual standard deviation of about 50% of the annual mean wind speed.

4 Daily and Seasonal Time Variation of Wind Speed

The large undisturbed coastal stations List (on the island of Sylt) and Norderney whose data can be regarded as measured at heights of 40 m above sea level, provide fairly usable information about the mean daily time variation of wind speeds compare Fig. 3. Measurements at this height indicate that the mean is nearly the same at all times of the day, with a variation of ± 5% in each mean. In a few month the mean wind speeds fluctuate as much as ± 10% during a day.

The seasonal variation of wind speed and of energy demand shows high positive correlation. Fig. 4 shows that the greatest supply of wind power and the highest demand for energy both occur in late autumn and early winter.

FIG. 3: MEAN DAILY TIME VARIATION

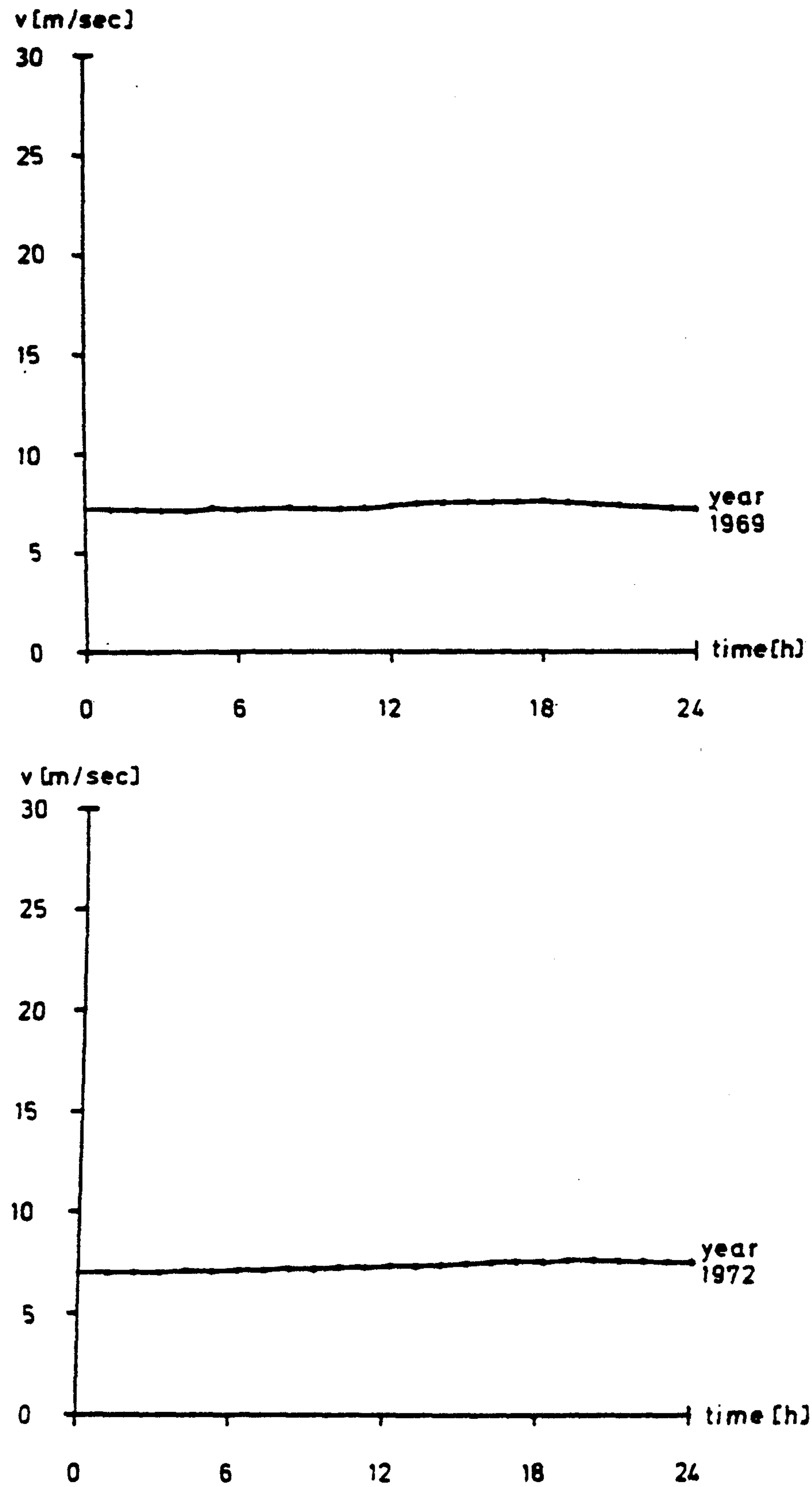
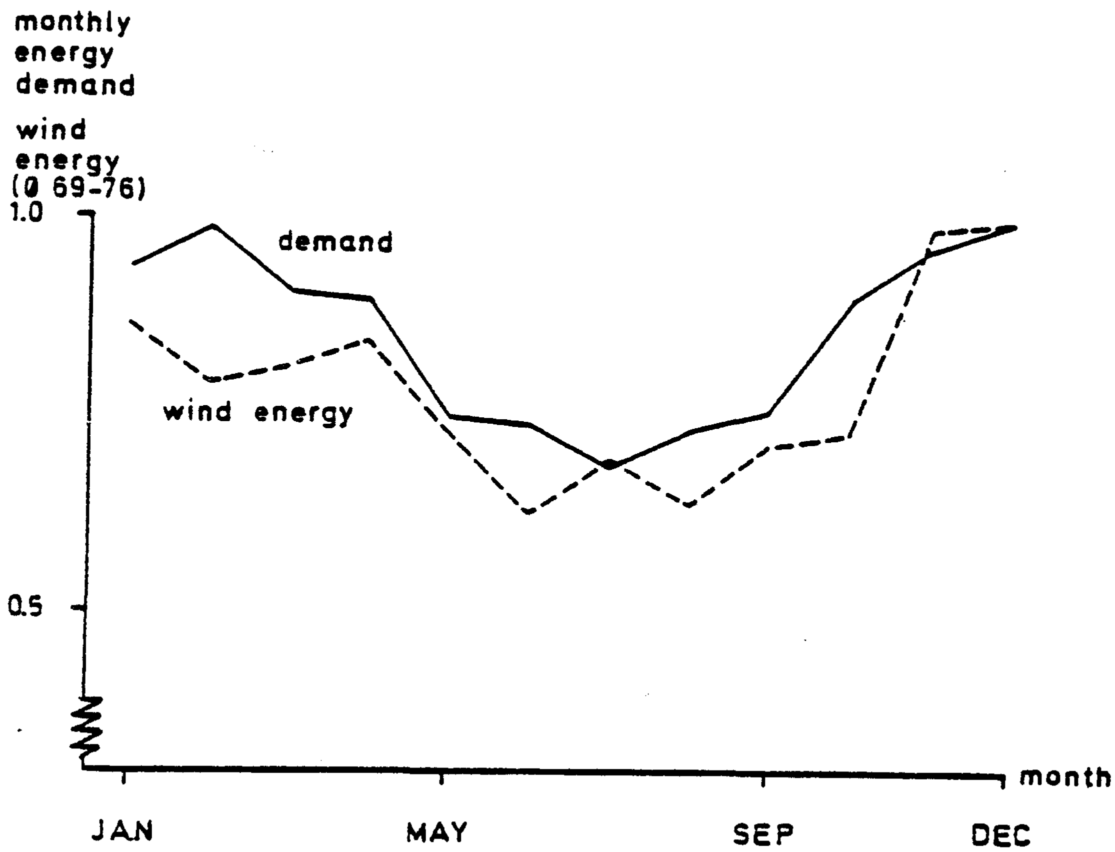


FIG. 4: MONTHLY WIND ENERGY PRODUCTION AND ENERGY DEMAND



5 TEMPORAL DISTRIBUTION OF WIND SPEEDS

At the two relatively undisturbed stations List on Sylt and Norderney which are representative for the North Sea coast about 26% of the wind speeds are below 5 m/s. This is about the cut-in wind speed v_{min} of large wind power plants, measured at 40 m height. Single wind power plants would thus be at a stand still about 26% of the time.

About 54% of the wind speeds lie between the cut-in speed of 5 m/s and 10 m/s. About 20% are above. This means that at a rated speed v_{nom} of 10 m/s, measured at 40 m height a single wind power plant can be operated about 54% of the time with partial load and 20% of the time at rated load.

6 Lulls

Long-lasting lulls occur mostly in summer - at this time the demand for electricity is low in any case. For the large-scale technical utilization of wind power, it is expedient to define a lull as a continuous period of time having wind speeds which are lower than the cut-in speed v_{min} of about 5 m/s. The average duration of single lulls ($v \leq 5$ m/s) is between 7 and 10 hours for coastal areas. During the 8-year observation period, the longest lull on the coast at List lasted for 130 hours and in Norderney for 83 hours - both in the year 1970.

If one defined a lull as a wind speed of less than or equal to 8 m/s the average duration of lulls on the coast is about 17 to 33 hours, and inland about 16 to 500 hours. The longest lulls in this sense ($v \leq 8$ m/s) during the 8-year observation period were 275 hours in List in the year 1975, and 470 hours in Norderney in the year 1969.

With increasing annual mean wind speed both the average duration of lulls and their frequency decrease.

7 Correlation of Wind Speeds

With increasing distance between stations, the correlation of wind speeds falls slowly; on the coast, at a distance of 100 km to 200 km the correlation coefficient (Brave-Pearson) still is relatively high at 0.7. Long lulls are caused by global weather conditions and thus cannot be fully compensated for even by a compound system of wind power plants over a large area on the North Sea coast.

Autocorrelation of Wind Speeds

The wind speeds of a particular meteorological station are highly correlated within a few hours, in the range of days and weeks they are correlated very little. It can clearly be seen from Figure 2 (diagrams for the temporal variation of hourly wind speeds over a month) that the wind speeds do not manifest a regular structure, and that, in addition, the autocorrelation in the range of more than 3 hours decreases rapidly. In the range of less than 3 hours the wind speeds are very highly correlated. Figure 5 shows, for example that the wind speeds almost always alter only minimally from one hour to the next. This applies at least to the hourly mean wind speeds.

Of particular interest is the autocorrelation of wind power production. Figure 6 shows the relation between wind power production during the hour t-1 and the hour t. The technology of GROWIAN is used here as a basis for wind power production. It can be seen that, in contrast to the wind speeds, the wind power production alters considerably from hour to hour. This is due to the fact that, in the range of about 6 m/s to 11 m/s, in which range a large proportion of the hourly mean values lie, the power produced by GROWIAN rises from 0 MW to the rated production of 3 MW.

8 Extreme Wind Velocities

As long as there exist neither sufficient measurements with high temporal resolution nor simultaneous measurements of wind speed and direction at various greater heights, static and dynamic considerations about stability

FIG. 5: CHANGE OF HOURLY MEAN WIND SPEED,
TIME DIFFERENCE 1 HOUR

VON: 1970 IN LIST

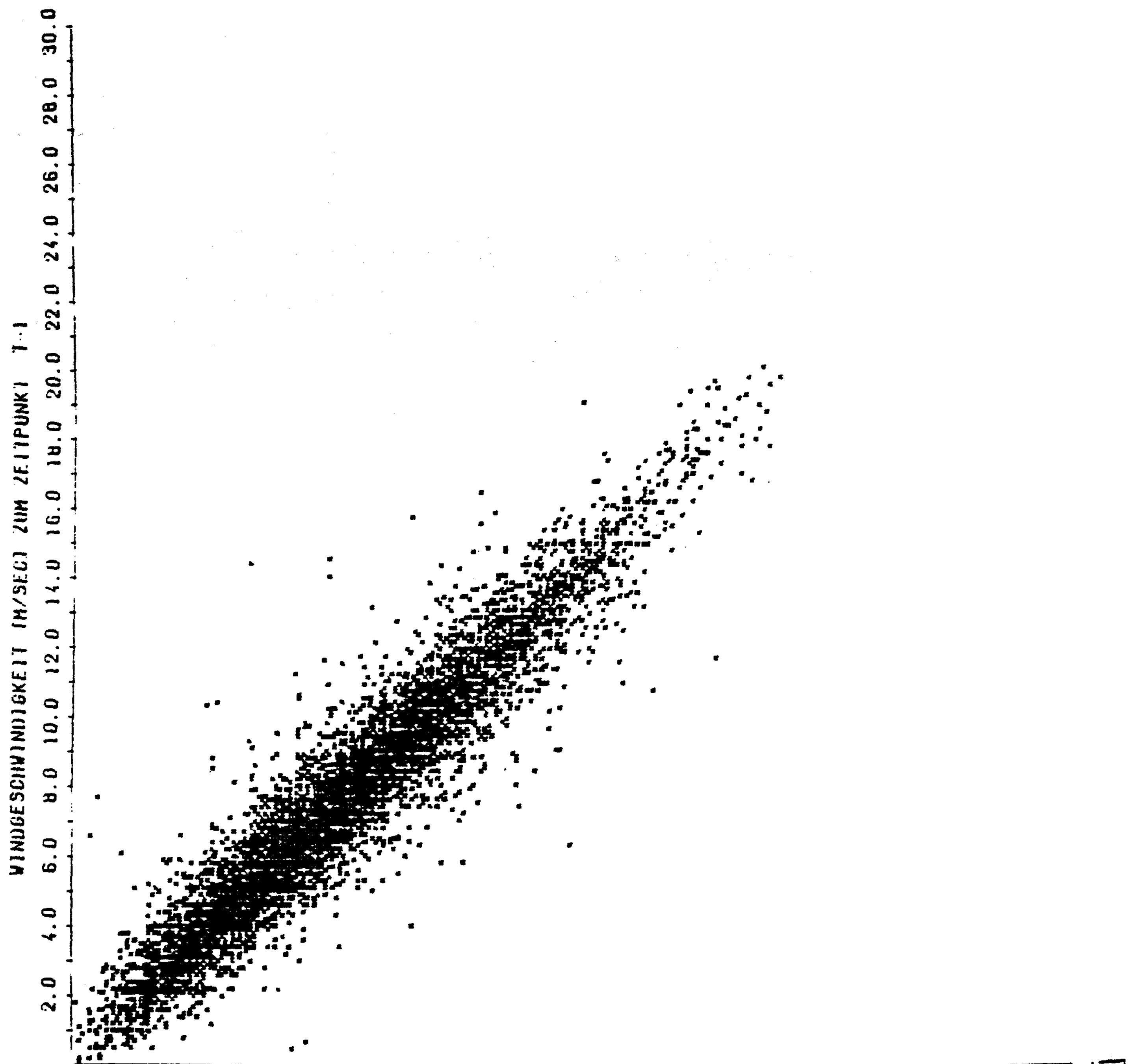
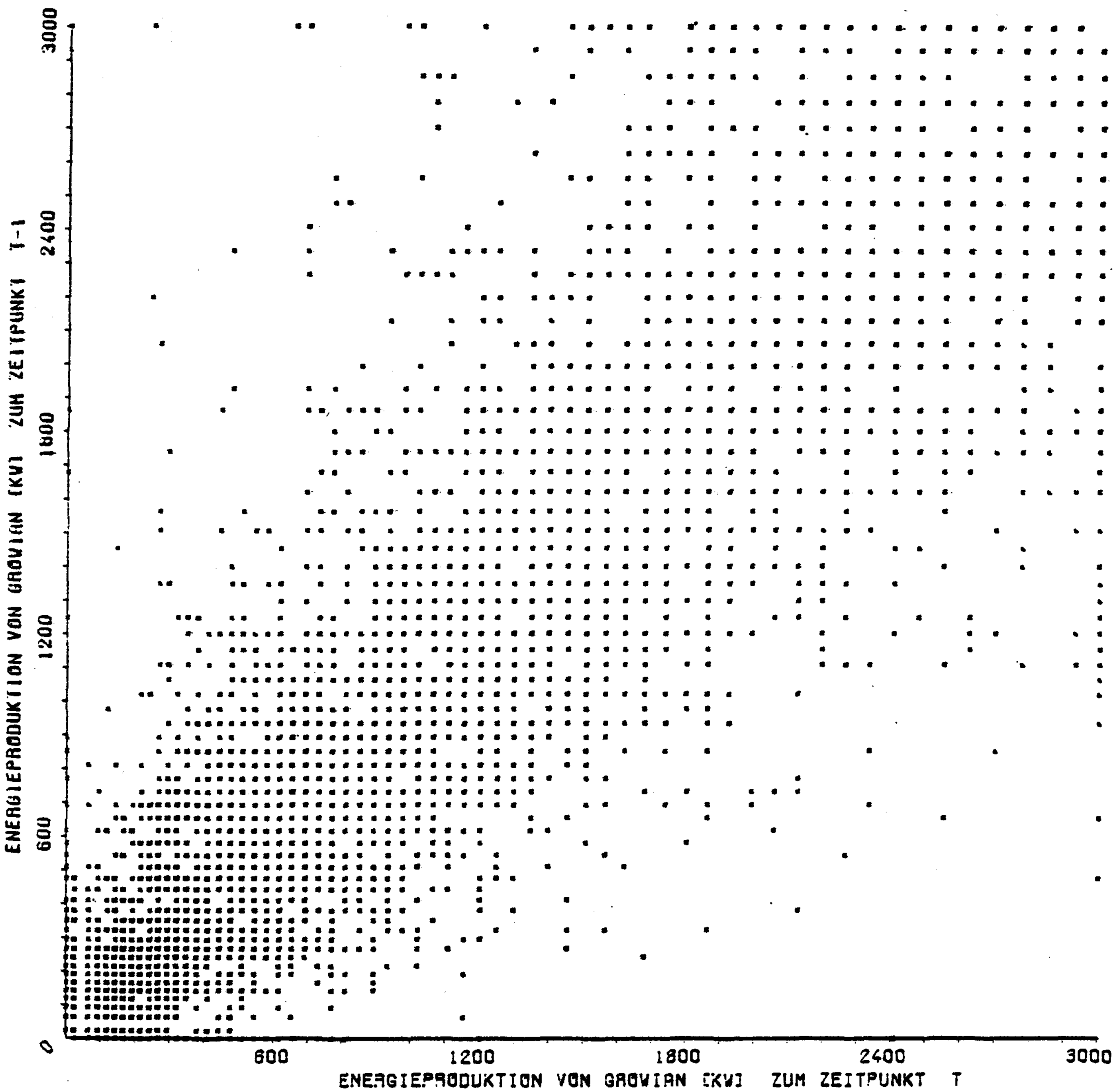


FIG. 6: CHANGES OF HOURLY MEAN ENERGY PRODUCTION, TIME DIFFERENCE 1 HOUR

VON: 1970 IN LIST
NORMIERT AUF 8.0 [M/SEC] - GROWIAN-TECHNOLOGIE
(RADIUS: 50.2 M , INSTALLIERTE LEISTUNG: 3 MW)



for the operating safety of wind power plants must be made according to hourly and ten-minute extreme wind speeds at a height of 10 m to 70 m.

On the North German coast, the maximum of hourly mean wind speeds amounts to 30 m/s. The maximum of ten-minute mean wind speeds amounts to 50 m/s. In addition to this, a change in the mean wind speed of two successive hours of up to 20 m/s in the maximum case must be expected. These figures are based on an 8-year observation period, hundred year winds can certainly rise above.

9 Wind Directions

Prevailing wind directions do exist, but are not so dominant as to significantly influence the minimum separating distance between wind power plants required to prevent a wake effect, see Figure 7. In addition, the prevailing wind directions change to a fair extent from year to year. Neither does a weighting of wind direction with energy production (as in Figure 8) lead to a strongly dominant prevailing wind direction.

10 Locations Favorable for Wind Power Generation

Our examinations show that locations on the North Sea coast and in the adjacent inland areas can quite reasonably be considered favorable for the production of wind energy. This is because they have relatively high and fairly regular wind speeds. These regions have a natural supply of kinetic energy (wind power) of about 3000 kWh to 3500 kWh annually per m^2 covered, measured at a height of up to

Fig. 7: Polar Diagram of Direction Distribution (Norderney 72)

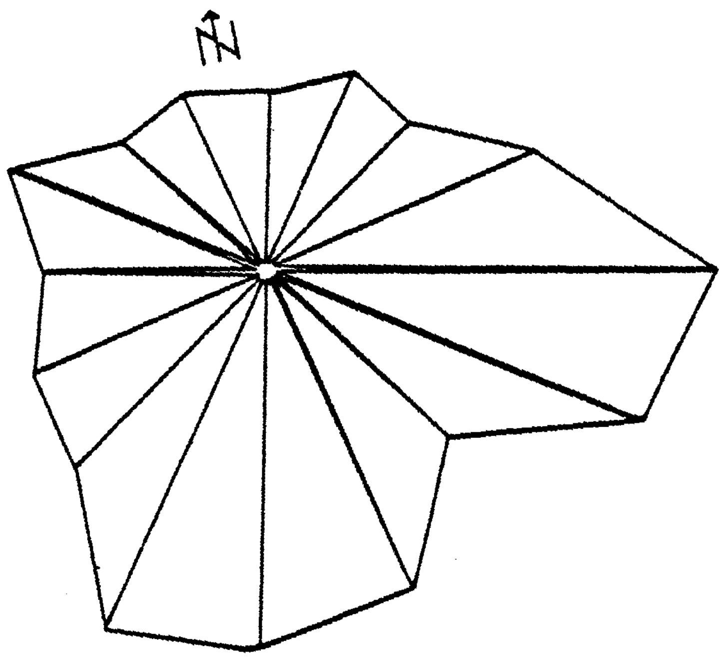
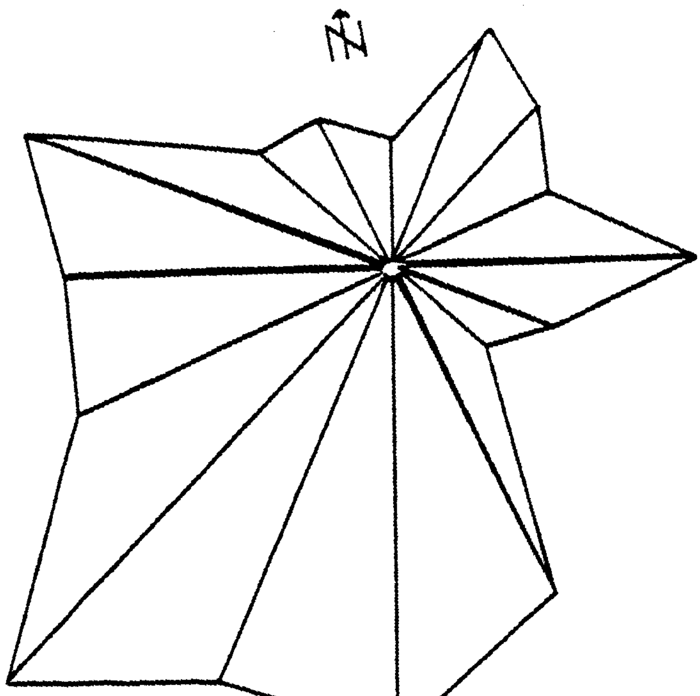


Fig. 8: Polar Diagram of Fig. 7, Weighted with the Energy Production Function of GROWIAN



40 m. In addition, exposed hill and mountain-top locations inland with a natural supply of kinetic energy of up to 2000 kWh/m^2 annually, measured at a height of 10 m to 20 m, also count as possible locations for wind power plants. Measurements at such locations are, however - due to the high surface roughness - to be regarded as only limitedly reliable. At the moment, no reliable statements about other inland locations can be made due to the lack of sufficient wind speed measurements at greater heights.

Paper A2

ASSESSMENT OF TECHNICAL POTENTIAL: PROBLEMS, METHODS AND RESULTS

G. Obermair
University of Regensburg, FRG

The technical and economic problems posed by the integration of wind energy into the supply system are summarized in viewgraph 1:
The Natural Potential, given by the stochastic wind field $\vec{v}(r,t)$ over the total area is going through what may be called a technical filter to be reduced to the Technical Potential. The technical filter involves stability and control requirements ("integrability"), the efficiency of wind converters ("production function") and the exclusion of technically unaccessable areas ("usable area").

The Technical Potential in turn is reduced to an Economic Potential by the economic filter which involves competitiveness from the individual investor's point of view, measured against other energy sources, comparative social costs and socio-economic preferences and the actual cost and existing use of land for wind energy parks.

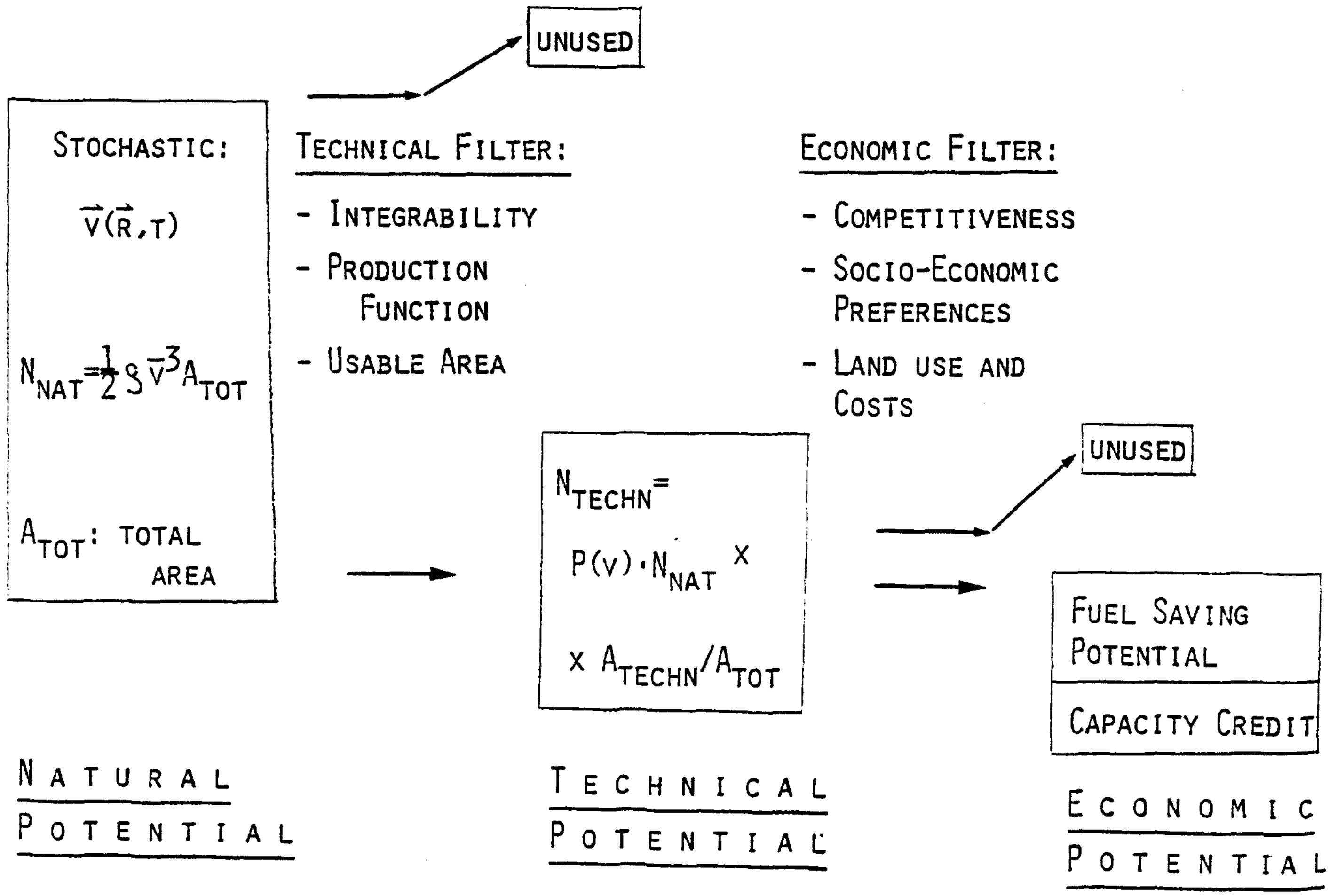
The technical filter is described in more detail in viewgraphs 2, 3 and 4.

Integrability:

The stability requirements on the electric energy that is actually fed into the grid are very high with respect to frequency and voltage,but also the power fluctuations of

ASSESSMENT OF WIND ENERGY POTENTIAL .

PROBLEMS :



VIEWGRAPH 1

the stochastic source wind have to be smoothed out to such an extent that the remaining fast variations can be completely absorbed by the primary regulation capacity of the grid and the slow components by the stand-by reserve of the existing power station mix.

Different time regimes of the wind fluctuations may be regulated by different control measures as shown in viewgraph 2.

Our computer model SWING (Simulation of Wind Energy Integration into the National Grid) was aimed primilarily at simulating the possible response of the integrated system to slow variations of wind power (1 hour ... years), a restriction imposed largely by the data base which consists mostly of hourly means of wind speeds and hence of predicted wind energy productions for each hour. One result of the simulation is an estimate of the additional stand-by operation of conventional plants due to wind fluctuations which for the German coast region amounts roughly to a 10% increase at a wind energy penetration of 10%.

<u>Production function:</u>

Viewgraph 3 shows the (more or less standard) assumptions for the power coefficient and the (stationary!) production function $P(\vec{v})$ of a large WEC which are the basis for predictions of the total hourly wind energy production of a given wind park and of its temporal fluctuations. Due again to the lack of high time resolution wind data (~ 1 second) these assumptions may be considered at best reasonable in the sense of least arbitrariness; however, as pointed out in viewgraph 4, the use of a stationary production function $P(\vec{v})$ presupposes optimum values, i.e. an infinitely fast reaction of all

METHODS 1:

THE TECHNICAL FILTER : 1.

1. INTEGRABILITY (INTO REGIONAL OR NATIONAL GRID)

GOALS:
- FREQUENCY AND VOLTAGE : ABSOLUTELY STABLE.
- POWER OUTPUT : ~ STABLE OVER ~ 1 HOUR

MEANS:

FLUCTUATIONS IN $\vec{v}$

TIME REGIME:	MEANS AND CONTROLS
0 ... MINUTES	FLYWHEEL EFFECT AERODYNAMIC EFFICIENCY VARIABLE N: ELECTRONIC CONTROL *)
MINUTES ... HOUR	VARIABLE PITCH ANGLE LOCAL COMPOUNDS
HOUR ... DAY	REGIONAL COMPOUNDS (NATIONAL COMPOUNDS)
DAY ... YEARS	RESERVE CAPACITY OF THE ENTIRE GRID

*) PREFERENTIALLY WITH DOUBLY FED ASYNCHRONOUS GENERATORS.

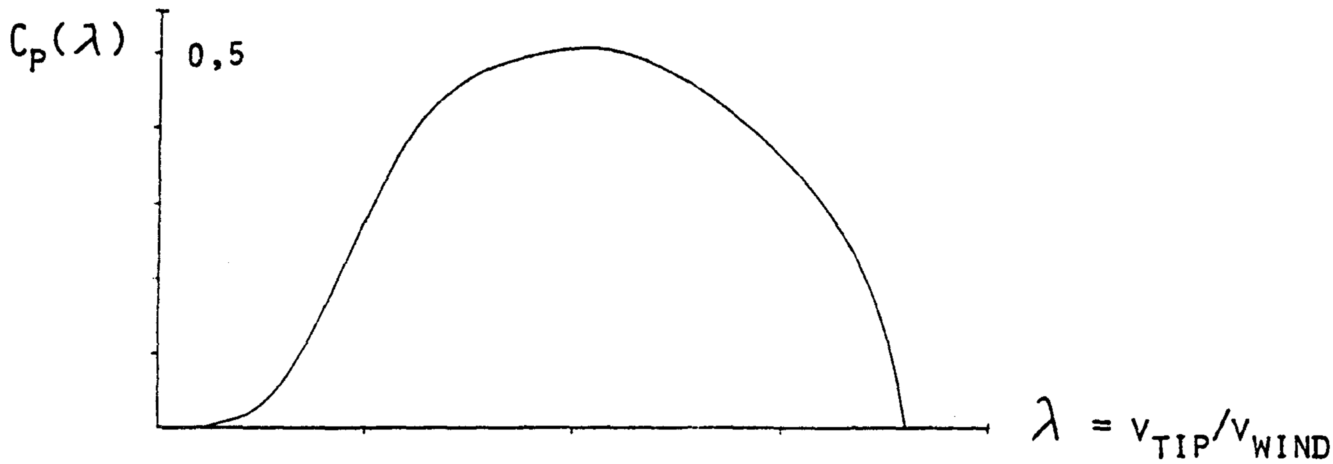
VIEWGRAPH 2

METHODS 2:

THE TECHNICAL FILTER : 2

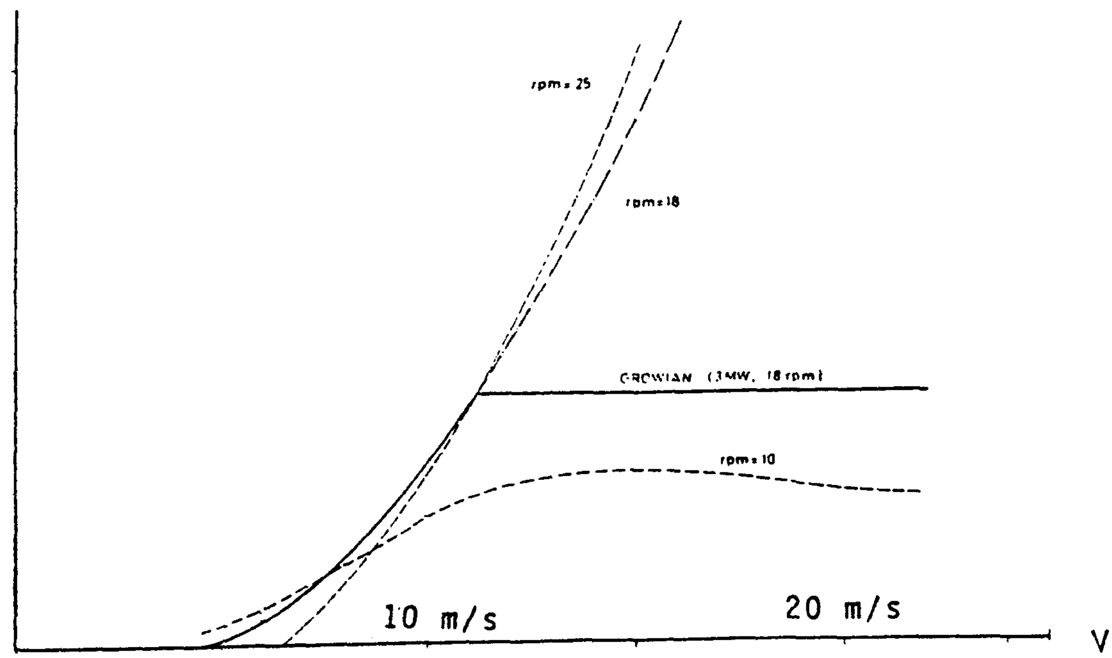
2. PRODUCTION FUNCTION

FOR STATIONARY FLOW ($\vec{V}$ HOMOGENOUS, VERY SLOWLY VARYING IN TIME)



FROM THEORY AND WIND TUNNEL MEASUREMENTS

P(v) : STATIONARY PRODUCTION FUNCTION



FROM THEORY AND WIND TUNNEL MEASUREMENTS!

PROBLEM :

$P(\bar{v})$ ASSUMES AT ALL TIMES OPTIMUM VALUES OF

BLADE ANGLE α

CONING ANGLE ψ

ROTOR SPEED $\hat{n}$

GENERATOR EXCITATION $N_{EXC.}$, $f_{EXC.}$, $\vartheta_{EXC.}$

DYNAMIC RESPONSE $P(\vec{v}(t))$ MUST INCLUDE TRANSIENT EFFECTS OF THE FLOW-PATTERN AND AT LEAST THE SIX VARIABLES α, ψ, $\hat{n}$, N_{EXC}, f_{EXC}, ϑ_{EXC}.

passive and active controls of the rotor and the generator at all times. Our knowledge of true dynamic production function $P(\vec{v}(t))$ is at present severely restricted by insufficient data for typical fast wind fluctuations on one hand, by our ignorance with respect to the corresponding typical transient behaviour of the aerodynamic flow pattern and the mechanical and electric components of a WEC on the other.

Continuous high time resolution wind measurements in relevant heights which are now undertaken by several groups in different countries and also by our group, will contribute to the prediction of the required typical dynamic production function $\bar{P}(\vec{v}(t))$.

Assuming for the time being the $P(\vec{v})$-data of viewgraph 4 for the machine described in the table of viewgraph 5 (GROWIAN) we have obtained from an analysis of the wind data of many years from the North-German coast region the following central result: 80 m above ground on flat, smooth terrain the mean annual power output is $\bar{N}/A = 160\ W/m^2$ per square meter of rotor area which - for the considered WEC GROWIAN - amounts to 40% of the installed generator capacity.

The remaining viewgraphs 6 and 7 give a summary of the methods used in the valuation of a wind energy production: the value of this production may be determined as the sum of the values of saved fuel ("fuel savings") and of saved investment in conventional power plants ("capacity credit").

The calculation of fuel savings is straightforward once the annual wind energy production and the increased standby fuel consumption have been determined; the result is that the relative fuel savings are proportional and nearly equal to the wind energy penetration.

RESULTS 1 : POWER PRODUCTION

USING - P ($\bar{v}$)

- REAL $\bar{v}^{1H}_{80M}$ FROM NORTH SEA COAST
- GROWIAN DATA :

installed power generating capacity	:	3 MW
rotor diameter	:	100 m
rotor area	:	7,854 m^2
rated rotor speed	:	18 rpm
specific power capacity of the generator	:	382 W/m^2
specific mechanical power per unit area	:	424 W/m^2
cut-in wind velocity v_{min}	:	4.5 m/sec
rated wind velocity v_{nom}	:	11.2 m/sec
cut-out wind velocity v_{max}	:	24 m/sec
adaptability of rated rotational speed	:	± 10%
number of rotor blades	:	2
generator	:	asynchron.
generator rated rpm	:	1,500 rpm
gear ratio	:	1/83
speed of turbine direction adjustment	:	0.33 degrees/sec
mast height	:	100 m

WE FIND $\boxed{\bar{N} / A = 160\ W / m^2}$: MEAN ANNUAL POWER OUTPUT

(40% OF N_{NOM}/A)

VIEWGRAPH 5

METHODS 2:

A) FUEL SAVINGS

B) CAPACITY CREDIT

A) FUEL SAVINGS

RULE : WHENEVER THERE IS WIND ENERGY, IT IS USED !

$$\boxed{\text{FUEL SAVINGS/YR} = \text{ANNUAL WIND ENERGY PRODUCTION} - \text{FUEL SPENT FOR ADDITIONAL STAND-BY AND CONTROL}}$$

RESULTS:

$$\text{RELATIVE FUEL SAVINGS} = \frac{\text{FUEL SAVED BY WIND}}{\text{TOTAL FUEL SPENT}} \sim$$

$$\sim \text{PENETRATION } P = \frac{N_{\text{NOMINAL WIND}}}{N_{\text{NOM CONVENTIONAL}} + N_{\text{NOM WIND}}}$$

VIEWGRAPH 6

METHODS 2:

B) CAPACITY CREDIT

RULE : IF X IS THE AVAILABLE CAPACITY OF ANY COMPOUND OF POWER PLANTS AND F(X) ITS PROBABILITY DENSITY, THEN THE ASSURED LOAD CARRYING CAPABILITY IS GIVEN BY

$$\int_0^G F(x)\,dx = \alpha$$

WHERE $1 - \alpha$ IS THE DESIRED SUPPLY SECURITY (USUALLY 97%)

CENTRAL ASSUMPTION

THE RELATIVELY LOW AVAILABILITY OF WIND POWER Y CAN ALSO BE EXPRESSED BY A DISTRIBUTION G(Y) WHICH SHOWS AT MOST A SMALL SEASONAL VARIATION.

→ THE CAPACITY CREDIT OF WIND POWER PLANTS CAN BE DETERMINED FROM THE CONVOLUTION OF F(X) AND G(Y) .

The conventional capacity that can be displaced by a given penetration of wind power stations may be evaluated with the probabilistic method generally accepted by the utilities and known as loss-of-load-probability method. In practice difficult statistical questions will certainly arise when this concept is applied to a strongly fluctuating source which shows both systematic (e.g. annual) and stochastic variations. Later contributions to the meeting will come back to this point.

Paper A3

ECONOMIC EVALUATION

L. Hoffmann
University of Regensburg, FRG

The economic significance of wind energy has to be assessed - like any other energy source - under three aspects:

- Its potential contribution to the country's energy supply;
- its competitiveness vis-a-vis other energy sources and
- its social desirability, measured by its contribution to the realization of general socio-economic goals.

I. The Supply Potential of Wind Energy

According to estimates officially adopted by the German Government, the technically feasible contribution of wind energy to the country's electricity generation is about 220 Terawatt hours (TWh) annually which is roughly 70% of the Federal Republic's gross electricity generation in 1975 or 30% of the projected generation in the year 2000. It is assumed that the utilization of wind energy for other purposes than electricity generation is negligible in a highly industrialized country like Germany.

A full utilization of the technically feasible potential would require approximately 30 000 wind mills of the GROWIAN type. The question of how such a large number of mills could be implemented in a densely populated country liek Germany is still open. It also is questionable whether such high rates of penetration can ever become operational from a technical point of view. For the time being it therefore is appropriate to assume that only a small percentage of the potential would be utilized in the foreseeable future, if wind energy should become competitive. However, even if the utilization amounts to only 10% of the technical potential or about 20 TWh, this already would be equivalent to the present electricity generation of nuclear power plants or to the electricity coming from hydro sources around 1985/90. Hence, as one among several other sources, wind energy could make a significant contribution to the Federal Republic's energy supply, and would thereby reduce the country's dependence on external factors.

II. The Competiveness of Wind Energy

1. The Evaluation Method

Under present conditions, wind energy competes in the Federal Republic of Germany mainly with electricity generation from coal, oil and nuclear power plants. However, if one thinks in terms of future expansions of the elctricity supply system, the competition is mostly with coal and nuclear power plants. Wind energy therefore can be said to be competitive if, with the same security of supply, its costs per kilowatt (kW) or per kilowatt hour (kWh) are not higher than those of newly built coal or nuclear power plants. These costs may be called the break-even-costs of wind energy. Considering the time required for planning and construction of a small park of wind mills, it is safe to assume, that hardly any electricity generation from this source can be expected before 1985. It therefore appeare reasonable to make the cost comparison on a 1985 price basis.

In calculating the break-even-costs of wind energy, it has to be taken into account that, different to its conventional competitors, wind energy cannot be produced continuously. To achieve the same security of supply, wind energy systems therefore have either to be supplemented by sufficient storage devices or the other power plants have to maintain a corresponding excess capacity.

Which solution is preferable cannot be answered in general, but depends on wind conditions as well as the size and spatial extension of the wind energy system.

The break-even-costs have therefore been calculated in the present project for a clearly defined and realistic situation, which is that of Northern Germany (the four states of Schleswig-Holstein, Hamburg, Bremen, Niedersachsen), Accounting for about 15% of the Federal Republic's electricity consumption. It was found that in order to balance out the unsteady supply of wind energy, storage devices are grossly uneconomic in this area, because spatially extended calms of long duration (100 hour range) would require extremely large storage facilities with only short annual utilization. This result probably can be generalized for most large scale integration systems.

The integration of wind energy into a conventional electricity system without additional storage facility has to be evaluated according to the general principles of project evaluation. Following these principles, a project is adopted or rejected depending on whether the entire system's marginal revenue resulting from the project exceeds its marginal costs or not.[1] Hence, we could compare costs and revenue of the system without wind energy with cost and revenue of the system with wind energy.

The differences between the two are the marginal costs and revenues. If we keep output constant, because wind energy is considered as an alternative to additional conventional power sources, the calculation boils down to a cost comparison[2]. We would ask, how much is saved in terms of fuel and conventional capacity due to the employment of wind energy and how much has to be spent on the construction and operation of the wind mills. If the savings just break even with the additional expenses, total marginal costs are zero and we are just on the switching point from rejecting to adopting the project. Savings to exactly this amount are therefore called break-even-costs.

For the present project it was decided to calculate only break-even-costs on wind power plants, because there is still substantial uncertainty around the investment and operating costs of large scale wind mills, as long as there has not been sufficient construction and operating experience.

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[1] In a simplified way this can be demonstrated as follows:
Maximize net revenue (NR):

$$NR = R(\text{Revenue}) - C(\text{Costs}) = \max!$$

First order condition:

$$R' \text{ (marginal revenue)} = C' \text{(marginal costs)}$$

[2] If the conventional system is denoted by index 1, wind power by index 2 and output by x, we have in this case:

$$NR = R(\bar{x}) - [C_1(x_1) + C_2(\bar{x}-x_1)] = \max!$$

$$\bar{x} = x_1+x_2$$

First order condition:
C_1' (marginal costs of conv. syst.) = C_2' (marginal costs of wind power)

These principles of project evaluation are standard in the economic literature since several decades. However, sometimes renewable energy sources apparently are evaluated by a comparison of the unit costs (for construction, operation and distribution) of the new plants, in our case wind power plants, plus the additional unit costs of the conventional system due to lower capacity utilization with the fuel savings in the conventional system. This calculation appears intuitively plausible on a first look, but leads to non-sensical results, as may be illustrated by the following example:

Case 1: System without wind power.
Assumption:
Production: 100
Fixed costs: 150
Variable costs: 50

This results into:
Unit costs: 2
Of which
Fixed unit costs 1,5,
Variable unit costs 0,5.

Case 2: System with wind power.
Assumption:
Production: 100
Of which
Conventional system: 50
Wind power plants: 50
Fixed costs of conventional system as before: 150
Variable costs (due to 50% reduction of conventional production) 25
Costs of wind power system: x

This results into:
Unit costs of conventional system: 3,5
Of which
Fixed unit costs: 3,0
Variable unit costs: 0,5.

According to the above calculation rule, one would compare unit costs of the wind power system (x/50) plus additional fixed unit costs of the conventional system (1,5) with the fuel saving per unit (variable unit costs) of 0,5. Wind power is then economically viable if:

$$x/50 + 1{,}5 < 0{,}5$$

By rearrangement one obtains:

$$x < -50$$

The conclusion is that under the assumed cost structure wind power can never be economic, even if its costs (x) were negative. This obviously is non-sensical.

2. Results

The calculations are based on the German wind turbine prototype GROWIAN, which at a tower height of 100 m has a diameter of 100 m and an installed capacity of 3 MW resulting in a specific installed capacity of 380 W/m^2.

On the basis of 1977 fuel costs, the study assumed for 1985 average fuel cost savings of 0.06 DM_{85} per kWh_e produced by wind turbine and 2000 DM_{85} per kW saved conventional capacity (capacity credit). The calculations were based on standard capitalized value methods resulting in the assessment of the break-even-costs for investment and operation.

For the specific case of Northern Germany the capacity displacement capability or capacity credit ranges from 40% of the wind energy system's rated capacity for 100 GROWIANs to 10% for 3000 GROWIANs.

Calculated per installed kW, the value of the capacity credit amounts to 1500 DM_{85}/kW for the first 100 GROWIANs (300 MW) declining to 750 DM_{85}/kW for the first 3000 GROWIANs (9000 MW). The declining relative importance of the capacity credit is due to the fact that with growing wind energy penetration of the electricity supply system, the availability of wind energy becomes the limiting factor for system reliability.

Due to the limited importance of the capacity credit, the fuel savings that could be achieved by installing a wind energy system account for the larger share of the system's break-even-costs. Based on the assumed average fuel cost savings of 0.06 DM_{85}, the fuel credit amounts to about 4100 DM_{85} per installed kW up to a penetration rate of 15% (4000 GROWIAN).

The break-even-costs lie between 5600 DM_{85}/kW and 4850 DM_{85}/kW depending on the penetration rate, where two thirds can be spent for the investment and about one third has to be saved for operation and maintenance, assuming yearly O + M costs of 3% of the initial investment cost.

Today's cost of investment is about 5000 DM_{81}/kW, using the quoted costs of the first quasi-commercial turbines based on prototypes like the US MOD2 or the German GROWIAN. This means that at the assumed mean wind speed of 8 m/s, 1981 investment costs are about 50% above the 1985 break-even-costs for investment. However, the first GROWIANs probably could be erected at the most favourable sites. With wind speeds at such locations of up to 10 m/s, the break-even-costs are about 50% higher. Apparently, at such sites, GROWIANs already today are in the range of the economic viability.

It also has to be considered that the nominal fuel price increases of 8% annually assumed in our study up to 1985 are far too low. During 79/80 the price for heavy fuel oil and gas more than doubled, the price for coal increased by more than 50%. Today's FRG fossil fuel cost are 0.14 DM_{81}/kWh_e (480 DM_{81}/t) for heavy fuel oil, 0.10 DM_{81}/kWh_e (260 DM_{81}/t) for German black coal and 0.06 DM_{81}/kWh_e (150 DM_{81}/t) for imported black coal.

If the average fuel cost savings in 1985 are 0.14 DM_{85}/kWh_e instead of the assumed 0.06 DM_{85}/kWh_e, the break-even-costs of wind turbines increase by about 50%, according to our sensitivity analysis, bringing the break-even-cost of investment to about 5000 DM_{85}/kW, which is in the range of today's cost of investment.

III. Social Desirability

The social evaluation also proceeds at first according to the principle of keeping production and distribution costs per kWh for a given supply area to a minimum. The problem is, however, from the social point of view, much more complex than in the case of a private producer.

Firstly, the notion of costs must be more broadly defined. If the generation of electricity gives rise to costs which do not appear in the cost budgets of the electricity boards, then these are obviously still costs for the entire economy, which must ultimately be met by the society as a whole. For example, damage to health through air pollution caused by fossil-fired power plants raises the expenditure for the public health service and thus the contribution to health insurance. In the case of a social evaluation, costs of this sort have to be seen as costs of the electricity production. In order that these social costs be taken into account in the capital expenditure and sales planning of the electricity boards, they must be converted into private costs of the concerned enterprises by corresponding taxation.

The situation is somewhat different in the case of social costs which are to be expected due to the foreseeable scarcity of a primary energy source, a scarcity which is currently not anticipated by the market. In the case of crude oil, for example, a scarcity is to be expected in the eighties, and the necessary adaption process will give rise to costs to the whole economy, which are not yet reflected in the current oil prices and thus do not influence the investment decisions of the electricity boards. In this case too, it would be advisable, by means of corresponding taxes, to take the looming tendency to scarcity already into account in the present cost calculations of the enterprises, so that investment decisions are reached which appropriately reflect the market situation prevailing when the new investment come into production.

In the case of minimizing social costs, attention must also be paid that competitive production processes are evaluated under the same starting conditions. When, for example, the construction of coal power plants fired with German hard coal is subsidized because it raises the use of inland primary energy and thereby supply security, wind power plants have to be credited by a corresponding amount if compared with the former.

Another example is to be found in the governmental guarantees granted for the building of coal and nuclear power plants. The subsidy element of such guarantees is the premium which in the case of a private insurer would have to be paid for a comparable risk insurance. In a cost comparison, this premium too would have to be charged to the power plant concerned or to be credited to the wind power plant. The same would have to be done with the risk coverage for nuclear power plants, which is only partly borne by the power station.

A social evaluation can finally also deviate from the market prices because of superordinate targets of economic and social policy. Thus for example, a certain independence of the national energy supply is a recognized target of economic policy. It is thus entirely imaginable that the production by plants which are independent of imports such as wind power plants, will be valued higher than a production which is highly dependent on imports, such as for example nuclear power. The independence of energy supply is in this case seen simply as an additional benefit. In the private calculation this benefit will become visible when the state places a subsidy on those plants which particularly contribute to independence. With respect to the relative use of the various production possibilities, exactly the same thing can be achieved when the other production plants are correspondingly taxed.

Session B: IEA-Task IIIa

Paper B1

ASSESSMENT OF THE POTENTIAL OF LWECS IN THE NETHERLANDS

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1. Meteorological data

Data of the 5 stations

CABAUW, CADZAND, KORNWERDERZAND, TERSCHELLING, VLISSINGEN

were placed at our disposal by the Koninklijk Nederlands Meteorologisch Instituut (KNMI).

Tab.1.1 gives a description of the stations and the meteorological data.

The data which have been evaluated, were as follows:
- hourly mean wind speeds and hourly mean wind directions of Cadzand (1972-1975), Kornwerderzand (1969-1975) Terschelling (1969-1975) and Vlissingen (1969-1975),
- half hourly mean wind speeds and half hourly mean wind directions of Cabauw (1973).

Formula

$$\hat{v}^{h}_{ijk} = \left(\frac{\ln h - \ln z_o}{\ln h_a - \ln z_o}\right) \cdot \bar{v}_{ijk} \tag{1.1}$$

was used to extrapolate the wind speed $\bar{v}_{ijk}$ being measured in the height h_a of the anemometer. z_o stands for the terrain roughness length. $\hat{v}^{h}_{ijk}$ is the extrapolated value, i.e., the hourly (or half hourly) mean wind speed prevailing in height h on i.th hour of day j in month k.

station	Cabauw	Cadzand	Kornwerderzand	Terschelling	Vlissingen
data	half hourly mean wind speed; half hourly mean wind direction	hourly mean wind speed; hourly mean wind direction	hourly mean wind speed; hourly mean wind direction	hourly mean wind speed; hourly mean wind direction	hourly mean wind speed; hourly mean wind direction
data source	KNMI	KNMI	KNMI	KNMI	KNMI
data length	[1973]	[1972, 1975]	[1969, 1975]	[1969, 1975]	[1969, 1971],[1972, 1975]
geographical co-ords	$51^{o}97'$N, $04^{o}92'$E	$53^{o}23'$N, $03^{o}23'$E	$53^{o}04'$N, $05^{o}20'$E	$53^{o}22'$N, $05^{o}13'$E	$51^{o}27'$N, $03^{o}36'$E
description of the station and the surroundings	Inland station in the Lopiker Waard (linear distance to the coastal line about 45 km); open, flat terrain in the surroundings; meadows and pastures. Obstacle-free measurements with booms at the free placed tower. Station in the bottom of the tower. The height of the tower is 215 m. Measurements according to WMO in the height of 10 m are taken at a self-supporting mast, 70 m apart the main tower. Out of the flight corridor Schiphol and Schiebruek; next village 5 km in NNO.	Coastal forefield, next to the mouth of the stream Schelde, about 250 m to the mainland. In SSE of the station are sand dunes; next houses 2,5 km in SE. Data are transmitted by radio and telephone cable to the station of Vlissingen.	At the northern end of Afsluit-dike, which is seperating Ijssel-Sea and Wardenzee. Main land in 2.5 km distance. Mast at the south point of the Lorentz-look. In 200 m distance in WNN are houses and in 50 m distance in the south is a bunker.	West-frisian island, self-supporting mast on a flat, sandy beach. Obstacle-free from E to W. From W to NW in 400 m distance undulated dunes. In NW in 2 km the village of West-Terschelling. Data are transmitted in the Lighthouse of West-Terschelling via cable.	Situated at the habour of Vlissingen, in the beginning of the mouth of the Schelde. Till January 1972 the mast was at a harbour dam 300 m SW of the station-building. Since January 1972 the data are measured at the flat-roof of the station building. The height of the building is 14 m a.g.l. Build-up area in the near surrounding is slight to dense. Quite near in NW the town of Vlissingen.
altitude of ground above sea level (a.s.l.)	0.6 m	0 m	2 m	1 m	4 m
altitude of anemometer above ground level (a.g.l.)	10 m, 80 m, 200 m	13 m	10 m	10 m	till 12.1971: 10 m since 01.1972: 24 m
representativ for	inland plains used for pastures and meadows, scarcely populated rural areas, Polder	western coast line next to Belgium	coastal area in the northern Ijssel-Sea and the Wardenzee with spreaded islands	West-Frisian Islands, flat beaches	mouth-area of a stream; regular obstacle coverage

Tab.1.1: Description of stations and meteorological data (the Netherlands)

The formula is based on the law of the logarithmic wind profile.

The half hourly mean wind speeds which had been measured in Cabauw (1973) in 80 m height a.g.l. were taken in order to compare the extrapolation formula (1.1) with the extrapolation formula, see [7],

$$(1.2) \qquad \hat{v}^{h}_{ijk} = \left(\frac{h}{h_a}\right)^{\alpha} \bar{v}_{ijk}$$

where $\alpha = \dfrac{1}{(1/2\ln(h \cdot h_a) - \ln z_o)}$

and the extrapolation formula

$$(1.3) \qquad \hat{v}^{h}_{ijk} = \left(\frac{h}{h_a}\right)^{\alpha} \bar{v}_{ijk}$$

where α is taken to be a constant (α=0.22), depending on the "typical" terrain roughness length; see [4].

The z_o-values of (1.1) and (1.2) were made dependent on the wind direction. Taking h_a = 10 m and h = 80 m the comparison was made with regard to the following error-criteria: The mean square error s_1

$$s_1 := \sum_{k=1}^{12} \sum_{j=1}^{\text{ult.}} \sum_{i=1}^{48} \left(\hat{v}^{80}_{ijk} - \bar{v}^{80}_{ijk}\right)^2$$

and the mean absolute deviation s_2

$$s_2 := \sum_{k=1}^{12} \sum_{j=1}^{\text{ult.}} \sum_{i=1}^{48} \left|\hat{v}^{80}_{ijk} - \bar{v}^{80}_{ijk}\right|$$

where $\bar{v}^{80}_{ijk}$: half hourly mean wind speed measured in the height of 80 m a.g.l. (i=1,...,48; j=1,..., ultimo; k=1,...,12).

Tab.1.2 shows the result:

extrapolation formula	MSE s_1	MAD s_2
(1.1)	$5,327 \cdot 10^4$	$2,347 \cdot 10^4$
(1.2)	$5,367 \cdot 10^4$	$2,349 \cdot 10^4$
(1.3)	$5,647 \cdot 10^4$	$2,493 \cdot 10^4$

Tab.1.2: Comparison of extrapolation formulas

Tab.1.3 gives the values extrapolated up to a height of 100 m. Values put in brackets have been calculated with missing data of at least 10%.

The calculations show that the lowest wind speeds occur in the months of May to September. The maximum of these monthly mean wind speeds in mainly found in November. Ranking the months by the height of the mean wind speeds, a two-class order depending on seasonality is given by

November - April; May - October.

A more detailed order, is given by

November
January, December
March, April, October
February, May, September
June, July
August

Apart from places like Vlissingen, where the wind speeds are lower because of the vicinity of the city, the annual

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	year
Cadzand	72	7,9	6,8	8,3	11,1	9,1	6,3	7,0	7,6	7,2	7,8	9,9	9,7	8,2
	73	-	9,5	7,2	9,9	7,9	7,3	8,0	7,5	8,2	7,7	10,4	(9,4)	8,5
	74	9,7	10,4	7,5	9,3	8,3	8,6	9,9	7,9	10,2	9,7	10,3	14,1	9,7
	75	12,0	7,8	8,6	7,9	9,0	8,3	8,1	6,4	8,3	7,1	8,0	7,3	8,2
Kornwerderzand	69	8,3	8,9	9,5	9,5	8,1	8,0	6,9	7,9	7,1	7,0	11,9	7,4	8,4
	70	7,5	8,3	9,4	9,7	8,1	7,5	9,5	7,1	9,3	10,1	10,9	7,7	8,8
	71	8,5	8,9	8,8	8,2	7,8	9,2	7,8	9,4	7,2	9,5	10,4	9,4	8,8
	72	9,6	7,6	8,8	11,5	10,2	8,7	7,9	9,0	7,2	7,0	11,2	10,0	9,0
	73	6,9	10,2	7,5	10,2	8,5	7,8	8,2	7,4	7,6	6,8	11,6	9,6	8,5
	74	10,1	8,7	7,5	7,9	7,8	8,1	10,2	7,0	10,5	7,7	10,4	13,2	9,1
	75	12,1	6,1	7,7	8,0	9,1	7,5	8,1	6,5	9,2	(12,1)	-	-	(8,3)
Terschelling	69	9,4	11,0	10,6	9,6	8,3	7,9	7,2	8,4	7,9	8,2	13,7	8,8	9,2
	70	-	8,0	10,5	10,2	8,7	8,2	9,6	7,6	10,0	11,7	12,1	9,0	(9,8)
	71	8,8	9,3	9,2	8,3	7,9	8,5	7,4	9,4	7,3	10,2	11,6	10,8	9,1
	72	11,0	9,2	8,8	10,7	9,4	7,6	7,0	8,5	6,9	7,1	11,0	9,8	8,9
	73	6,9	10,4	7,7	10,3	8,9	7,3	7,9	(7,6)	(8,5)	8,5	13,9	11,5	9,2
	74	11,0	(9,5)	8,9	8,7	8,3	7,9	10,4	7,1	10,1	10,3	12,0	14,6	9,9
	75	13,0	7,4	9,1	8,5	9,8	8,0	7,6	7,2	10,9	9,9	10,7	11,3	9,5
Vlissingen	69	7,7	7,5	7,8	8,4	6,7	7,3	5,7	7,0	6,4	5,8	10,5	7,2	7,3
	70	6,1	8,9	8,2	8,3	5,8	6,1	8,0	6,2	7,3	9,3	10,3	7,2	7,6
	71	7,8	6,9	7,4	7,0	5,5	7,7	5,4	7,5	5,6	7,4	7,5	6,9	6,9
	72	6,0	6,3	7,3	9,6	7,9	6,4	6,3	6,5	5,6	6,3	9,1	7,9	7,1
	73	5,8	7,9	5,6	7,7	6,3	5,2	6,0	5,6	6,3	6,2	8,6	8,4	6,6
	74	9,1	8,6	6,4	7,1	6,3	6,7	8,2	6,0	8,1	6,4	9,7	12,3	7,9
	75	10,7	6,2	7,1	6,9	7,5	6,8	7,4	5,8	7,8	6,6	7,3	6,4	7,2
Cabauw	73	5,2	7,6	5,3	7,6	6,1	5,3	5,7	5,0	5,3	5,2	7,7	7,9	6,1

Tab. 1.3: monthly mean wind speed and annual mean wind speed in 100 m height

mean wind speeds in the coastal region of the Netherlands will be within the range of [7.6 m/s; 9.3 m/s] in 50 m height and within the range of [8.2 m/s; 9.9 m/s] in 100 m height. Considerably lower values in the order of 5.5 m/s in 50 m height and in the order of 6 m/s in 100 m height have to be expected for inland stations like Cabauw.

2. Wind turbine design and technical basics

The electrical power output of the generator of a wind turbine with variable blade angle is given by

$$(2.1) \qquad P = \begin{cases} 0 & v < v_I \\ \eta \, c_p \, 0.5 \, \rho \, v^3 \, F & v_I < v < v_R \\ P_R & v_R < v < v_O \\ 0 & v > v_O. \end{cases}$$

Let P_m be the mechanical power, i.e. the power at the rotor shaft. The efficiency of converting kinetic energy into mechanical energy is then by definition given by

$$c_p := \frac{P_m}{0.5 \, \rho \, v^3 \, F}.$$

Given the profile of the blades, c_p is mainly determined by the blade angle and the tip speed ratio λ, i.e. the speed of the blade tip divided by the wind speed. As for the dependence on the blade angle see [5] or [6]. We assume that the blade angle is always the one maximizing the c_p-value. Thus, c_p only depends on the tip speed ratio

$$\lambda = \frac{2 \pi r f}{60 v}$$

with
r rotor radius [m]
f rotor speed [$\min^{-1}$].

The $c_p(\lambda)$-functions we used are shown in Fig.2.1. The curve 'ECN' is recommended in [6], as part of the main characteristics of the standard wind turbine, which should be used in the research-phase of the Dutch National Wind Research Program. Fig.2.1 reflects the efficiency if the turbine is operated at constant rpm and variable pitch angle, whereby the pitch angle is adjusted such that below rated wind speed $c_p(\lambda)$ is maximum.

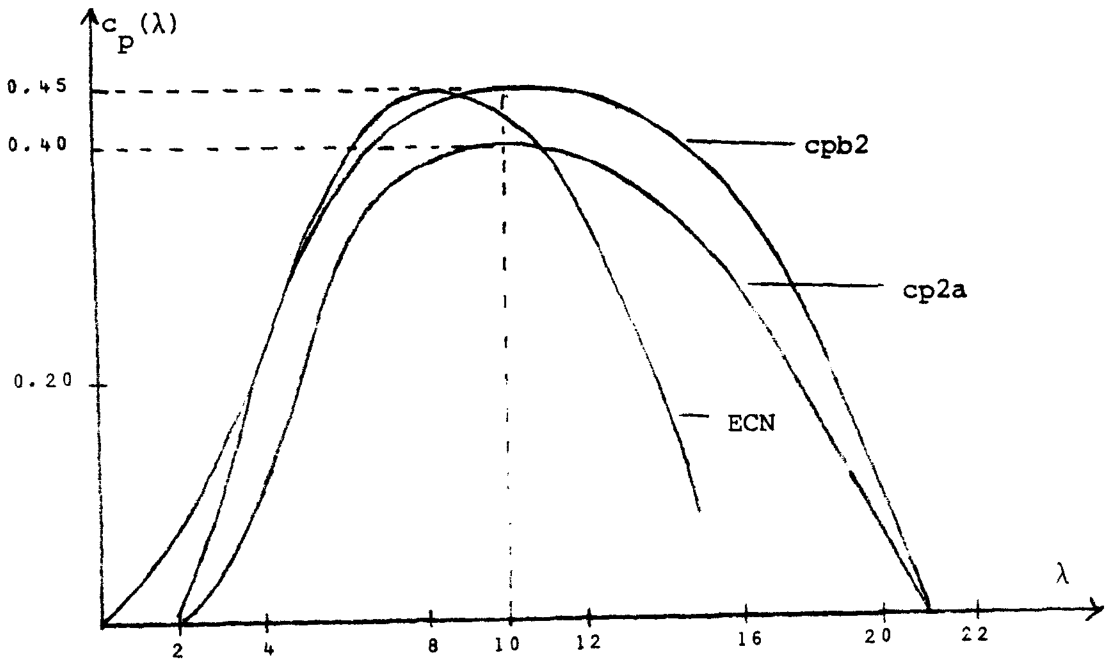

Fig.2.1: efficiency of converting kinetic energy into mechanical energy as a function of the tip speed ratio

The efficiency of converting mechanical power into electrical power is given by

$$\eta := \frac{P}{P_m} = \frac{P}{c_p \; 0.5 \; \rho \; v^3 \; F}.$$

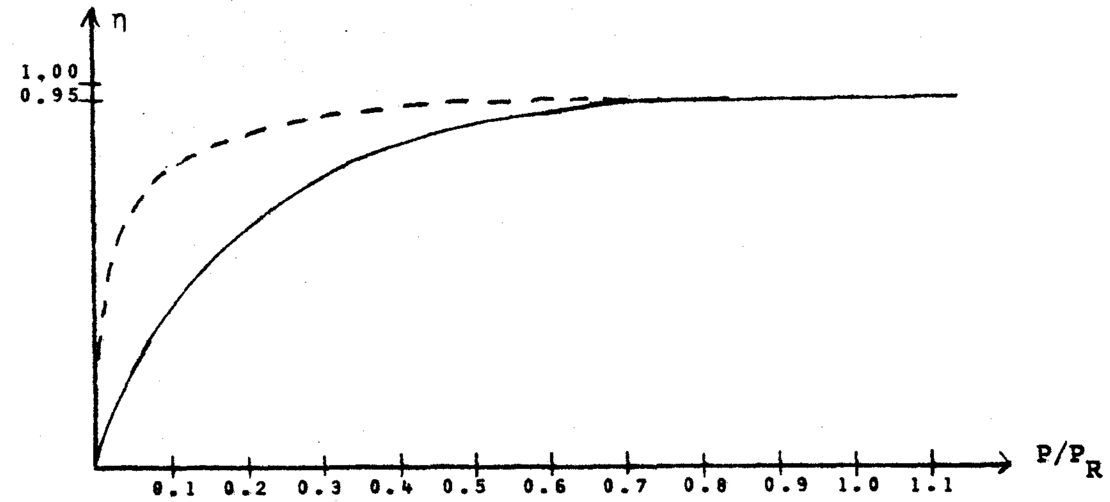

Fig.2.2: efficiency of converting mechanical energy into electrical energy versus ratio electrical power/rated electrical power

Proceeding on Fig.2.3 the following linear relationship approximately holds between the mechanical power P_m, the rated electrical power P_R and the electrical power P, which can be taken at the binder of the generator:

$$(2.2) \qquad P = \begin{cases} 0 & P_m/P_R < 0.10 \\ -\frac{10}{95} P_R + \frac{100}{95} P_m & 0.10 < P_m/P_R < 1.05 \\ P_R & P_m/P_R > 1.05 \end{cases}$$

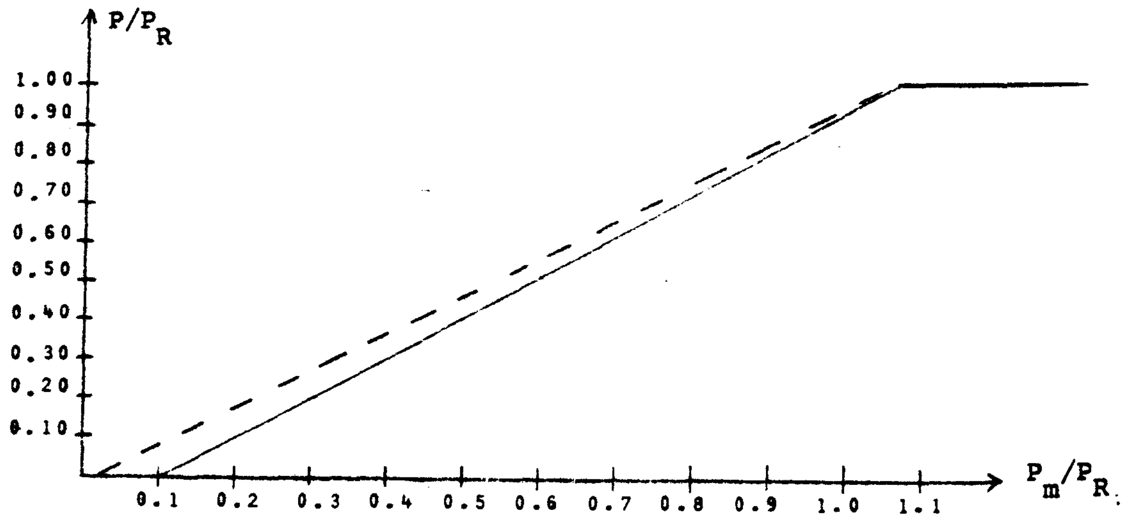

Fig.2.3: electrical power P as a function of the mechanical power P_m

The dashed lines in Fig.2.2 and Fig.2.3 are given for comparison. They are a rough sketch of the functions considered by ECN in the paper [6], specifying the characteristics of a standard wind turbine for the Netherlands.

Function (2.2), shown in Fig.2.3, corresponds to practical experiences as demonstrated by the test results of the Danish NIBE-A wind turbine; see [8].

The technical parameters of the two wind turbines examined in this study are listed in Tab.2.1.

	WECS I	WECS II
rated power P_R	3 MW	0.8 MW
cut-in wind speed v_I	6.5 m/s	6 m/s
cut-out wind speed v_O	24 m/s	24 m/s
rated wind speed v_R	12.7 m/s	12.6 m/s
rotor radius r	50.2 m	25 m
rotor speed f	18.5 min^{-1} ± 15%	35 min^{-1}
hub height h	100 m	50 m
$c_p(\lambda)$-function	cp2a of Fig.2.1	cpb2 of Fig.2.1
η	see (2.2)	see (2.2)

Tab.2.1: characteristics of the wind turbines

The technical parameters of WECS I are taken from GROWIAN I as stated in [3]. The technical parameters of WECS II do not stem from any existing wind turbine. However, the parameters of the NIBE wind turbines are quite similar to WECS II; see [8]. The rotor speed of 35 min^{-1} is the one that maximizes the annual wind energy production.

3. Wind energy production

Tab.3.1 shows the energy production of WECS I as calculated with the characteristics of Chapter 2.

As can be seen from Tab.3.1 the monthly energy production varies more than the annual energy production. This is true for both different months of a year and identical months in different years. Disregarding December 1974 and January 1975, where the wind speeds were exceptionally high, the highest energy production of each month is about 2-3 times the lowest energy production of each month. The same is valid when looking at the highest monthly energy production for each year.

Because of this high variation a statement of the monthly mean energy production does not have any informational substance. Only a rank order makes sense. Of course, as the monthly energy production is determined by the monthly mean wind speed, the same ranking results as with regard to the monthly mean wind speed. Thus, starting with the month with the highest energy production, the ranking goes as follows:

November
January, December
March, Arpil, October
February, May, September
June, July
August

How far single locations differ from the compound system of the locations with regard to the wind energy output is demonstrated in Fig.2.1 by the power duration curves. Curves CA, KO, TE, indicate the number of hours

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	year
Cadzand	72	0.7	0.4	0.8	1.4	0.9	0.4	0.5	0.7	0.6	0.7	1.1	0.8	9.1
	73	0.4	1.0	0.6	1.0	0.7	0.6	0.7	0.6	0.8	0.7	1.2	0.9	9.2
	74	1.1	1.0	0.7	1.0	0.8	0.9	1.2	0.7	1.2	1.1	1.1	1.8	12.6
	75	1.6	0.6	0.8	0.7	1.0	0.8	0.8	0.3	0.8	0.6	0.7	0.6	9.3
Kornwerderzand	69	0.8	0.9	1.1	1.0	0.7	0.7	0.5	0.7	0.5	0.5	1.4	0.6	9.4
	70	0.6	0.7	1.0	1.0	0.8	0.6	1.0	0.5	1.0	1.1	1.2	0.7	10.3
	71	0.8	0.8	1.0	0.9	0.7	1.1	0.7	1.1	0.5	1.0	1.0	1.1	10.8
	72	1.1	0.7	0.8	1.4	1.1	0.8	0.8	0.9	0.6	0.6	1.3	1.1	11.2
	73	0.5	1.1	0.7	1.1	0.8	0.7	0.8	0.6	0.7	0.5	1.4	1.0	9.8
	74	1.2	0.8	0.7	0.7	0.7	0.7	1.3	0.5	1.1	0.7	1.2	1.7	11.3
	75	1.6	0.3	0.7	0.7	1.1	0.7	0.8	0.4	0.8	1.0	1.2	1.3	10.5
Terschelling	69	1.1	1.1	1.3	1.1	0.8	0.7	0.5	0.9	0.7	0.8	1.6	0.9	11.5
	70	0.8	0.9	1.3	1.2	0.8	0.7	1.1	0.7	1.1	1.3	1.3	1.0	12.3
	71	0.9	0.9	1.1	0.9	0.8	0.9	0.6	1.2	0.6	1.2	1.3	1.3	11.7
	72	1.4	0.8	0.8	1.3	1.0	0.7	0.6	0.9	0.5	0.6	1.2	1.1	10.9
	73	0.5	1.2	0.7	1.1	1.0	0.6	0.8	0.5	0.7	0.8	1.5	1.3	10.6
	74	1.3	0.9	1.0	0.9	0.9	0.7	1.3	0.6	1.0	1.0	1.4	1.9	12.8
	75	1.7	0.6	1.0	0.8	1.2	0.8	0.7	0.6	1.2	1.1	1.3	1.4	12.4
Vlissingen	69	0.6	0.7	0.6	0.8	0.5	0.6	0.3	0.6	0.4	0.3	1.2	0.6	7.3
	70	0.3	0.9	0.9	0.8	0.3	0.4	0.7	0.4	0.7	1.1	1.2	0.6	8.1
	71	0.7	0.5	0.7	0.5	0.2	0.7	0.3	0.6	0.3	0.6	0.6	0.6	6.3
	72	0.5	0.4	0.7	1.1	0.7	0.4	0.3	0.5	0.3	0.4	1.0	0.7	6.9
	73	0.3	0.7	0.3	0.7	0.4	0.2	0.4	0.3	0.5	0.4	0.9	0.8	5.9
	74	0.9	0.7	0.5	0.5	0.4	0.5	0.8	0.4	0.9	0.5	1.0	1.6	8.8
	75	1.3	0.3	0.5	0.5	0.6	0.4	0.6	0.3	0.7	0.4	0.6	0.3	6.7
Cabauw	73	0.2	0.7	0.2	0.6	0.4	0.2	0.3	0.2	0.3	0.3	0.7	0.7	4.8

Tab. 3.1: monthly and annual energy production in GWh of WECS I (≙ GROWIAN I)

of energy output equal to at least the ordinate value a 3-MW wind turbine located at Cadzand, Kornwerderzand, Terschelling produced in 1975. As for curve C of the compound system, the energy output is the average output of 3-MW wind turbines located in equal numbers at Cadzand, Kornwerderzand and Terschelling.

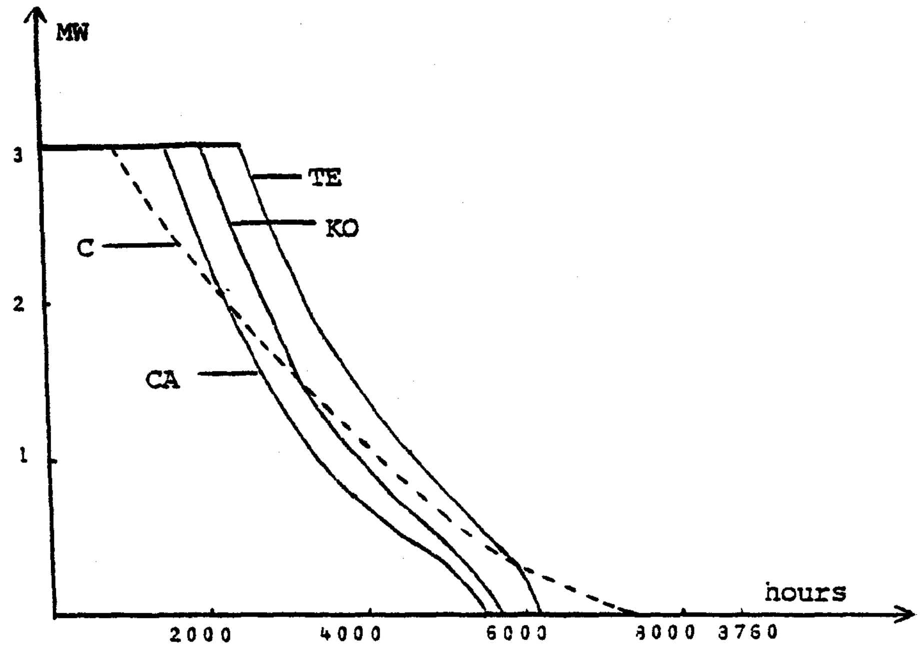

Fig.3.1: power duration curves of 3-MW wind turbine. Year of reference: 1975, Cadzand (CA), Kornwerderzand (KO), Terschelling (TE), compound system (C).

Fig.3.1 demonstrates that the standstill time of the compound system is lower than that of any single wind turbine. On the other side, the compound system production of rated output is also lower. This is due to the fact that the compound system only produces the rated output if every wind turbines produces its rated output.

At sites with wind regimes similar to those of Cadzand, Kornwerderzand or Terschelling a 3-MW wind turbine has to be expected to be 25% to 40% of the year at a standstill due to too low or too high wind speeds. At wind regimes similar to those of Vlissingen the standstill time increases to 40% to 50% of the year and at wind regimes like those of Cabauw to about 50% to 65% of the year.

The estimated monthly and annual energy production are classified below finally:

	range of annual energy output (GWh/a)	
	0.8-MW wind turbine	3-MW wind turbine
obstacle-free coastal region (CA, KO, TE)	[2.2; 3.2]	[9; 13]
built-up coastal region (VL)	[1.3; 2.1]	[5.5; 9]
obstacle-free inland region (CB)	[0.9; 1.5]	[4.5; 7]

4. Wind energy production and electricity consumption

Tab.4.1 gives the daily percentages the total load, i.e. the total electricity consumption, that a compound system of 3-MW wind turbines would have met in 1975. The compound system is composed as follows:

300 3-MW wind turbines exposed to the wind regimes of Cadzand (1975),

300 3-MW wind turbines exposed to the wind regimes of Kornwerderzand (1975),

300 3-MW wind turbines exposed to the wind regimes of Terschelling (1975).

The year 1975 was chosen because the (half hourly) load data which had been placed at our disposal by the KEMA (N.V. tot Keuring van Elektrotechnische Materialen, Arnhem) stemmed from that year. Not that 1975 cannot be judged as a "typical" year.

The installed wind power capacity of 2700 MW amounts to 20% of the installed power plant capacity of about 13 500 MW in 1975 [2,S.14]. The total electricity production of 1975 amounted to 46 600 GWh. As can be checked by means of Tab.3.1 the 900 wind turbines would have produced 9600 GWh in 1975, i.e. 20.8% of the total electricity production.

According to Tab.4.1 the daily load share varies between 68.5% (22.06.1975) and 0% (27.07., 29.07. and 28.08.1975). Furthermore, there are considerable differences from day to day. Thus, the statement that the mean value of the daily load share amounts to 21.6% would have been without any informational substance for the daily scheduling of power plants in 1975.

Lack of regularity in the daily load share of succeeding days is also demonstrated by Fig.4.1. Fig.4.1 shows the load as well as the wind energy output of March 1975.

A cautious generalisation of the results shown in Tab. 4.1 permits the conclusion that the daily load shares tend to be higher in those months (October - April) having a comparatively high electricity demand. A similar result has been shown to hold for West Germany.

Therefore, let us assume that about 900 3-MW wind turbines have been installed, each year producing an energy

DAY	JAN	FEB	MAR	APR	MAI	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	25.556	20.423	5.355	21.240	44.980	22.937	25.487	6.430	33.113	38.186	4.114	18.888
2	6.933	2.540	14.861	33.670	25.176	34.202	12.650	1.971	8.320	25.510	11.758	31.435
3	22.462	16.728	18.675	7.014	42.772	27.485	10.932	6.644	8.481	45.794	24.462	35.221
4	37.853	26.991	2.044	19.681	61.143	26.450	40.505	15.233	8.710	47.873	3.419	30.653
5	60.931	16.921	2.321	12.773	62.149	3.728	41.466	15.889	2.597	53.958	26.076	12.256
6	47.404	13.485	10.862	3.645	52.567	2.844	25.505	6.203	9.540	37.472	25.197	34.661
7	37.147	5.969	18.724	35.059	40.179	8.948	12.146	3.881	11.296	37.297	34.798	28.277
8	30.159	13.009	9.208	47.011	6.321	18.884	10.162	8.724	8.659	28.916	41.177	29.158
9	29.440	2.429	0.780	30.444	2.009	18.204	7.718	14.215	42.742	19.665	58.617	20.405
10	32.142	4.341	0.308	14.540	10.710	19.092	0.981	6.607	31.253	11.897	15.333	4.293
11	46.828	1.434	14.746	11.616	41.362	20.188	2.291	7.873	31.261	34.443	1.817	1.104
12	58.661	7.359	31.328	33.453	17.084	5.563	29.998	9.791	41.782	50.946	26.780	8.208
13	37.222	16.775	23.873	10.299	22.747	0.519	36.268	2.367	39.511	25.190	1.721	37.696
14	45.599	16.951	4.715	29.765	9.114	4.952	27.153	9.755	14.438	23.026	3.900	13.134
15	40.117	11.615	19.949	34.361	2.133	3.281	59.189	25.555	31.602	27.081	27.912	6.765
16	21.256	21.249	41.252	11.333	24.100	6.754	54.138	57.622	14.090	3.948	21.300	8.040
17	38.897	41.957	28.572	9.913	19.275	5.790	2.423	42.494	17.850	9.418	14.515	17.536
18	22.565	4.749	37.078	10.963	12.780	7.178	5.316	21.906	25.580	24.366	40.360	7.977
19	18.497	7.274	44.658	27.005	6.574	0.939	9.979	11.709	1.346	17.740	37.256	5.920
20	46.993	3.194	36.851	3.795	9.232	1.682	20.804	43.601	20.498	30.702	34.855	1.402
21	42.437	12.103	16.088	0.890	36.080	43.064	8.158	4.144	14.462	3.759	37.624	31.670
22	40.005	11.507	16.368	1.322	41.774	68.509	53.526	8.198	13.308	1.162	24.526	13.723
23	44.627	4.124	1.027	18.395	36.821	19.559	58.885	7.551	37.159	14.352	42.891	32.513
24	40.160	4.649	30.530	11.447	5.484	37.160	55.346	6.774	22.354	7.808	28.602	45.820
25	41.230	36.003	34.332	21.829	33.136	17.194	34.423	13.374	46.018	0.181	25.064	47.138
26	45.718	10.716	25.365	16.048	36.880	9.450	3.698	0.807	47.259	1.171	20.765	37.788
27	42.071	1.052	7.963	8.402	43.505	30.749	0.0	3.647	43.443	8.381	25.690	39.877
28	31.332	0.727	17.210	1.870	15.844	44.453	0.156	4.043	28.740	6.232	30.266	45.676
29	31.875	-----	26.308	15.205	27.758	50.452	0.0	0.0	16.975	0.410	29.642	30.449
30	24.772	-----	5.280	19.875	31.181	42.555	1.001	0.547	21.365	6.835	4.039	38.896
31	25.648	-----	13.675	-----	48.125	-----	12.854	4.106	-----	7.218	-----	44.867

Tab.4.1: daily load share of 900 3-MW wind turbines in 1975

output such that with regard to 1975 the annual load share amounts to 20%. The annual load share is defined as the mean daily load share. Due to the increase in electricity consumption this share will decrease in the course of time. Taking into account that the average annual growth rate of electricity consumption amounted to 4% in the period 1975 - 1980 [2,S.35] and then calculating with annual growth rates of 2%, 3% and 4%, the values shown in Tab.4.2 result. Of course, some care must be taken with regard to the growth rates. Presently there is no growth in the Netherlands; from 1979 to 1980 even a small decrease has been observed. However, the utilities still state figures as mentioned above. More detailed results are shown in Tab.4.3. These results and the figures given in Tab.4.1 might be used to give a first approximation how tha power plant operating strategy is affected.

	annual growth rate of electricity consumption from 1980 onwards (4% up to and including 1980)		
	2%	3%	4%
1975	20.0%	20.0%	20.0%
1976	18.5%	18.5%	18.5%
1980	16.4%	16.4%	16.4%
1985	14.9%	14.2%	13.5%
1990	13.5%	12.2%	11.1%
1995	12.2%	10.6%	9.1%
2000	11.1%	9.1%	7.5%

Tab.4.2: development of annual load share of 900 3-MW wind turbines related to the load share of 1975.

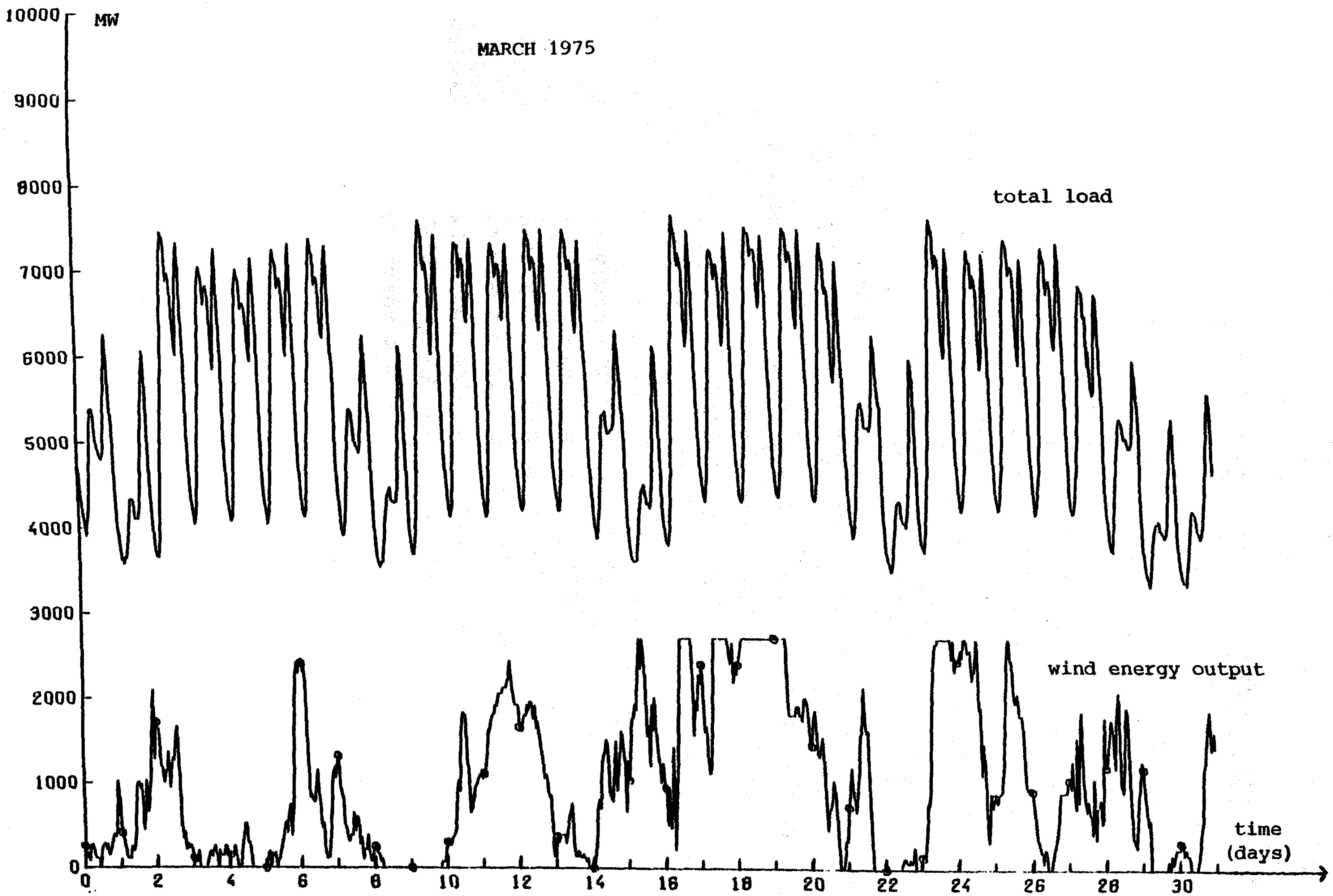

Fig. 4.1: total load and power output of 900 3-MW wind turbines in March 1975. Location of wind turbines (number of wind turbines): Cadzand (300), Kornwerderzand (300), Terschelling (300).

daily load share	year 1975	1980	1985	1990	2000
≥ 1%	0.96	0.94	0.94	0.93	0.93
≥ 5%	0.82	0.80	0.78	0.75	0.70
≥ 10%	0.68	0.63	0.60	0.58	0.52
≥ 15%	0.57	0.51	0.84	0.44	0.36
≥ 20%	0.48	0.42	0.36	0.32	0.22
≥ 30%	0.34	0.21	0.15	0.09	0.01
≥ 40%	0.16	0.04	0.03	0.01	0.00
≥ 50%	0.04	0.01	0.00	0.00	0.00

Tab.4.3: relative frequencies of the daily load share of 900 3-MW wind turbines if the relative frequencies related to 1975 remain constant. Annual growth rates of load: 4% from 1975 - 1980; 2% from 1980 onwards.

Tab.4.3 gives the "probabilities" that the daily load share will exceed a given percentage. For example, the "probability" is only 3% (1%, 0%) that daily energy output of 900 3-MW wind turbines will hold a share of 40% of the daily load in 1985 (1990, 2000). Knowing about the mean value trap, it is necessary to point out that a daily value of 40% can mean that during night a share of 50%-60% is possible.

Thus, due to the fact that, more than half of the daily electricity is produced by base load power plants, a probability of only 3% in 1985 for a share of 40% does not say, that base load is not affected by wind. It might happen that base load power plants have to be regulated due to wind power, even when LWECS are installed in that low penetration discussed here. As there is already now the tendency to renounce regulation at bigger base load units, like nuclear plants, a conflict might appear. Regarding a situation where no energy storage system to average the load fraction over a day is included, the figures in Tab. 4.3 and Tab.4.1 do not exclude that base-load units are affected by wind power, which is totally fed into the grid.

5. Number of wind turbines

Even the largest wind turbines are still very small by contemporary utility standards. The largest planned wind turbines have a rated power of about 5 MW whereby new coal fired or nuclear units planned by the utilities have power ratings of about 1000 MW.

Thus, in order to contribute substantially to the Netherlands' energy balance, thousands of wind turbines have to be erected. The question arises where to locate all the wind turbines needed in a densely populated country like the Netherlands. Social, environmental and economic impacts will surely arise and effect the number of wind turbines being build.

Which number is noteworthy and might be erected from a spatial point of view? Based on the figures discussed in the Netherlands Research Program on Wind Energy, see [1], [9], [10], wind energy was projected to contribute about 1,5-2 percent to the Netherlands' total energy consumption in 1980, i.e., 15-20 percent to the total electricity production in 1980. The total electricity production estimated by the KEMA will be 57 TWh in 1980. Therefore the production of wind energy in 1980 should be within the interval [8.55 TWh, 11.4 TWh]. According to Chapter 3 the annual energy output of the 3.0-MW wind turbine is expected to be in the interval [9 GWh; 13 GWh] in obstacle-free coastal regions. The corresponding interval for the 0.8-MW wind turbine is expected to be [2.2 GWh/a; 3.2 GWh/a]. In built-up coastal regions the output of the 3.0-MW turbine is supposed to be within the interval [5.5 GWh/a; 9 GWh/a] or for the 0.8-MW wind turbine within the interval [1.3 GWh/a; 2.1 GWh/a]. In obstacle-free inland regions the wind energy output can be expected to be within the interval [4.5 GWh/a; 7 GWh/a] for the 3.0-MW wind turbine. The corresponding interval for the 0.8-MW wind turbine is expected to be [0.9 GWh/a; 1.5 GWh/a].

Considering the mean values of these expected energy outputs we give below the numbers of wind turbines required to produce about 10 TWh/a, i.e. the mean value of the interval [8.55 TWh/a; 11.4 TWh/a]. The annual wind energy production within these bounds corresponds to the projected contribution of wind energy to the total electricity production in 1980 as outlined in the Dutch wind energy program.

The following numbers of wind turbines are required:

annual energy output of 9.97 TWh by / site	3-MW wind turbine	0.8-MW wind turbine
coastal regions with low terrain roughness; obstacle-free	906	3692
coastal regions close to built-up areas	1377	5864
inland station; obstacle-free region	1734	8306

According to a study [11], looking at the physical planning aspects, there should be place enough to locate 900 3-MW wind turbines or 3600 0.8-MW wind turbines in Dutch coastal regions, which are characterized by good regimes.

6. Literature

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Paper B2

POWER FLUCTUATIONS: TECHNICAL AND STATISTICAL ASPECTS

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1 Technical Aspects

This paper deals with wind power fluctuations which occur in the range of time of some minutes.

Considering a period of some minutes the power output of wind turbines shows an increasing or decreasing tendency which is superimposed by additional fluctuations; see Fig. 1.

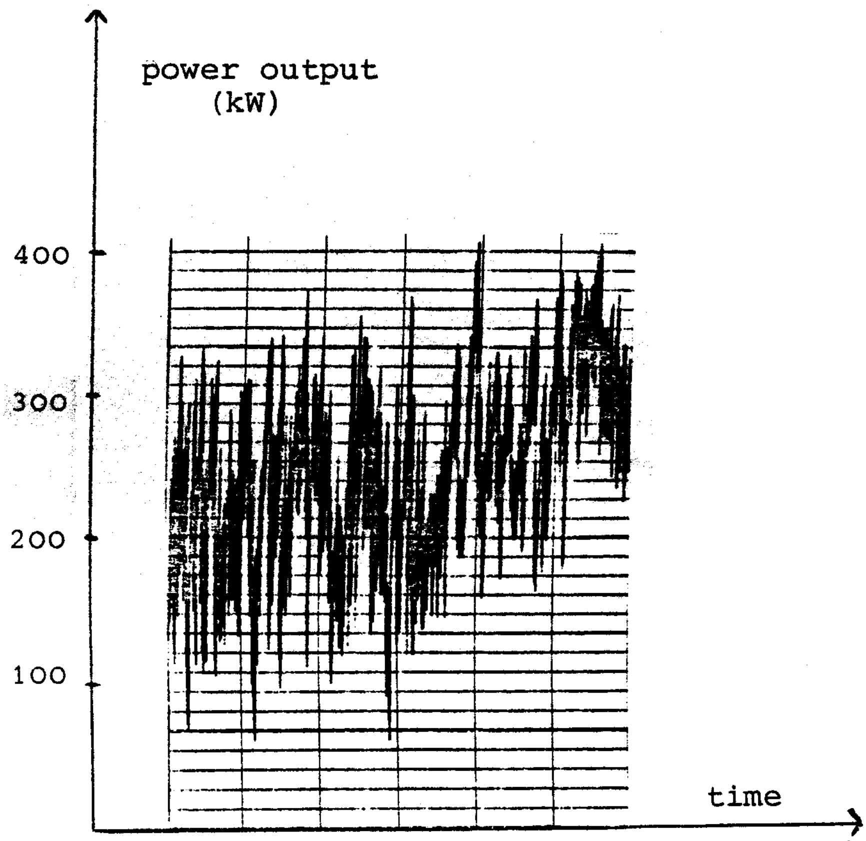

Fig. 1: power output of the Danish Nibe-A wind turbine (rated power 630 kW, hub height 45 m, rotor speed 34 min^{-1}) within ca. 12 minutes.

The Nibe-A wind turbine is operated with a constant rotor speed of 34 min^{-1}. Due to late investigations there would have been a much more regular power output than the one shown in Fig.1 if the wind turbine had been operated with a variable rotor speed. This can be achieved by use of a double fed asynchronous generator. This generator is a promising concept for large wind turbines with variable pitch angle. The double fed asynchronous generator permits a limited speed range and thereby giving the blade control sufficient time to respond to changing wind conditions. For technical details see [1], [3] and [4]. Fig.2 shows the considerable reduction of power fluctuations by use of a double fed asynchronous generator.

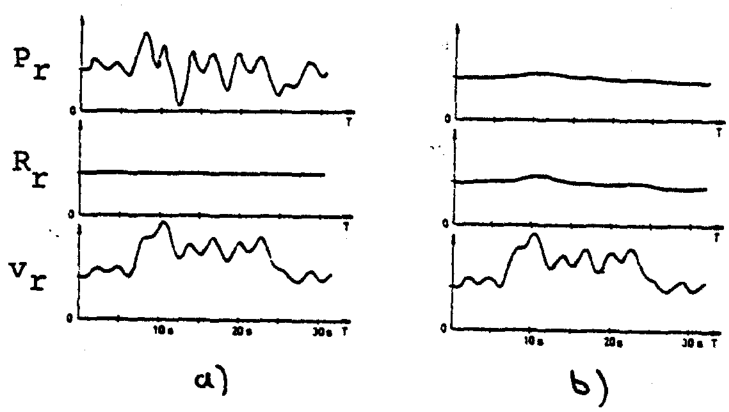

Fig.2: power output of a large wind turbine [1]

a) synchronous generator or asynchronous generator (squirrel cage rotor)

b) double fed asynchronous generator

P_r: rated power

R_r: rated rotor speed

v_r: rated wind speed

Though the absolute height of power output fluctuations can be considerably reduced by use of a double fed asynchronous generator, there will remain fluctuations which shall have to be regulated by the grid.

The secondary regulation will have to regulate the continous increase or decrease in wind power output lasting for some minutes and the primary regulation will have to regulate the superimposing fluctuations. The mode of operation of both regulation concepts is shown in Fig.3.

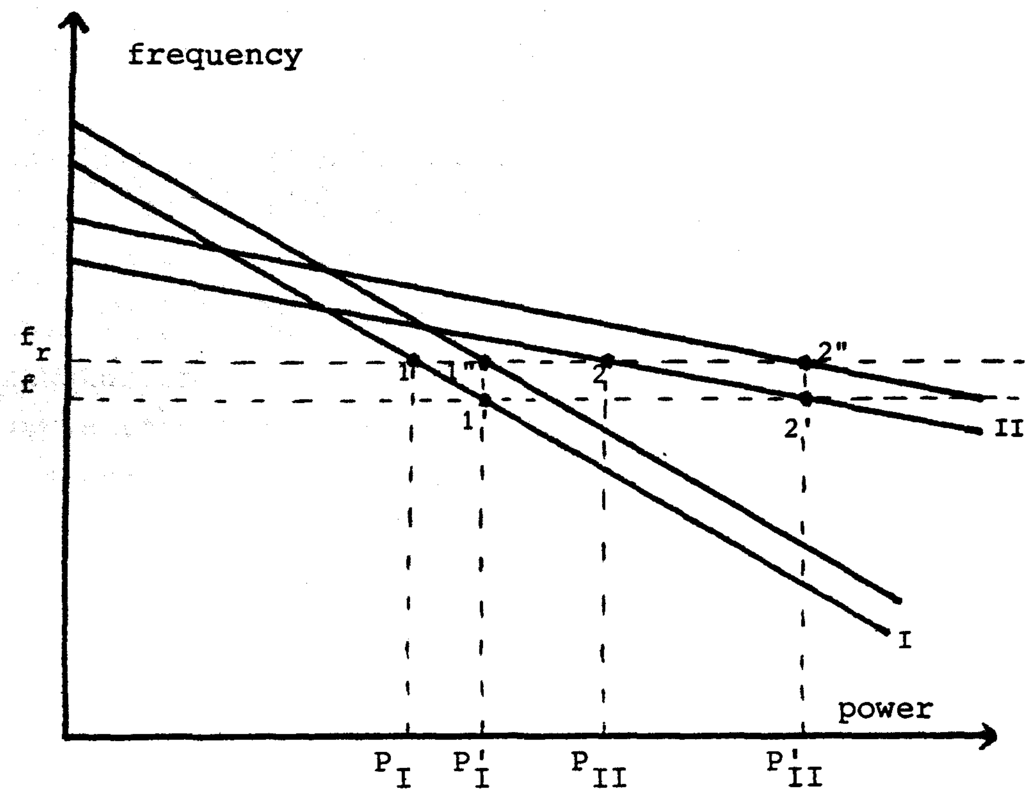

Fig.3: frequency characteristics of two power plants connected to the same grid [6].

At the frequency f_r power plant I is operated at power P_I; power plant II is operated at power P_{II}. If the load increases, the frequency will decrease. According to their frequency characteristics power plant I will be operated at power P_I' and power plant II will be operated at power P_{II}' if the frequency decreases to f. The return to the rated frequency f_r is achieved by a parallel shifting of both frequency characteristics.

It should be noted, however, that the frequency characteristics of Fig.3 are not representative for all power plants. The regulation of power plants is expensive; in particular the regulation of large thermal power plants. Thus, there is the tendency not to integrate large thermal power plants into the regulation as far as possible [7].

For example, base load power plants usually only participate in the frequency-power-regulation in the case of emergency, given for example by a breakdown of a power plant . Fig.4 shows the frequency characteristic of a base load power plant.

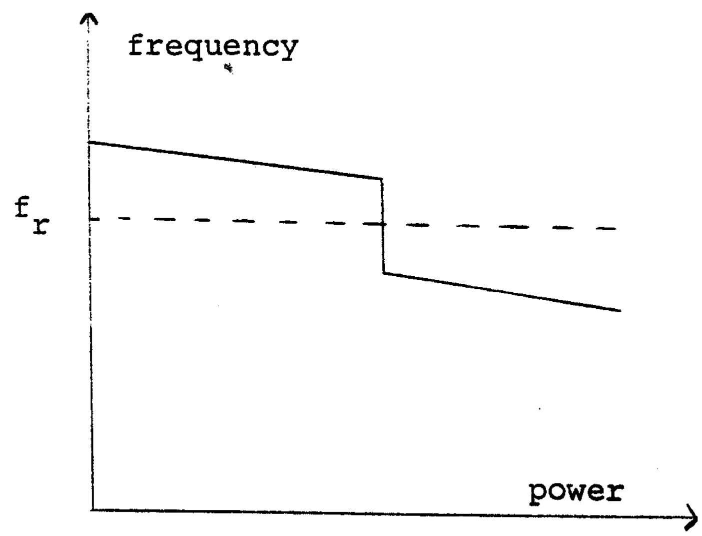

Fig.4: frequency characteristics of a base load power plant [6].

If a single wind turbine or a small number of turbines is connected to the grid the regulating capacity of the grid will presumably be sufficient to compensate for all power fluctuations of wind turbines. This is demonstrated by the few existing wind turbines. However, increasing the number of wind turbines there will come the stage where additional regulating capacity will be required. In particular an amplification of the secondary regulation will presumably be absolutely necessary if a large number of wind turbines is installed. Compared with the power plant mix of today, more plants like gas turbines will be required which enable a fast and automatic response to a continous increase or decrease of wind power output lasting for some minutes.

In order to estimate the number of wind turbines which may not require any additional primary or secondary regulation capacity the following consideration may be useful.

The primary and secondary regulation compensate for load fluctuations of at least 1% of the short-term mean load. Deviations from the rated grid frequency of 50 Hz are limited to ±30 mHz [7]. To all appearances neither the full band width of the primary regulation nor the full band width of the secondary regulation is used in doing so. Furthermore, a cluster of wind turbines may smooth out the fluctuations of each single wind turbine to some extent and there may also be a smoothing effect between the fluctuating electricity demand and the fluctuations in wind power output. Thus, the assumption that power fluctuations of wind turbines to the amount of 1% of the load will be regulated without having to install additional regulating capacity, does not seem to be unrealistic.

In order to dertermine the absolute number of wind turbines this statement is valid for, the grid must be known wind power is fed into, the load of the grid must be known and the absolute height of wind power fluctuations must be known. With respect to the grid it should be noted that according to the utility standards of today each partial grid is obliged to compensate as far as possible for the power fluctuations which are caused in it's grid. The exchange of power between grids shall only be used in the case of emergency, given for example by a breakdown of a thermal power plant.

2 STATISTICAL ASPECTS

It has been argued in the literature (see for example [2], [5]) that an increasing number of wind turbines tends to generate a much more regular power output than each single wind turbine. This is proofed as follows:

Be

$P_T(j)$ random variable "mean power output of wind turbine j in period T" $(j=1,\ldots,n)$

$P_T(n) := \sum_{j=1}^{n} P_T(j)$ random variable "mean power output of n wind turbines in period T"

Assuming that

$$\mu_T(j) = \mu_T \; \forall_j \quad \text{(expected values)}$$

(2.1)

$$\sigma_T^2(j) = \sigma_T^2 \; \forall_j \quad \text{(variances)}$$

and that the random variables $P_T(j)$ are stochastically independent it follows that

$$(2.2) \qquad \lim_{n\to\infty} \frac{\sigma_T(n)}{\mu_T(n)} = \lim_{n\to\infty} \frac{1}{\sqrt{n}} \frac{\sigma_T}{\mu_T} = 0.$$

Thus, measured by the coefficient of variation $\sigma_T(n)/\mu_T(n)$ an increasing number of wind turbines would reduce the power fluctuations of each single wind turbine.

However, if the length of period T does not exceed a few minutes, the assumption

$$(2.3) \qquad \begin{matrix} \mu_T(j_1) \neq \mu_T(j_2) \\ \sigma_T^2(j_1) \neq \sigma_T^2(j_2) \end{matrix} \qquad (j_1, j_2 = 1, \ldots, n; j_1 \neq j_2)$$

seems to be more realistic than (2.1). Subject to (2.3), the asymptotic result

$$(2.4) \qquad \lim_{n\to\infty} \frac{\sigma_T(n)}{\mu_T(n)} = \lim_{n\to\infty} \frac{\sqrt{\Sigma\sigma_T^2(j)}}{\Sigma\mu_T(j)} = 0$$

does not hold in general, unless for example

$$(2.5) \qquad \sigma_T(j) \leqslant \mu_T(j) \ \forall_j .$$

Condition (2.5) is not very restrictive. Thus, (2.4) can be assumed to hold. However, (2.4) has hardly any practical value. First of all (2.4) is an asymptotic result. Thus, the speed of convergence must be known in order that (2.4) has any empiric relevance. However, even if this were the case, (2.4) would be of no use regarding the central problem of regulating wind power fluctuations. The <u>actual</u> wind power output has to be regulated whereas (2.4) refers to the <u>mean</u> wind power output. In addition, as parameters and not random variables are considered in (2.4), the probability that the power output of wind turbines will be within a given interval in period T, cannot be calculated from (2.4).

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FORECASTING WIND POWER OUTPUT

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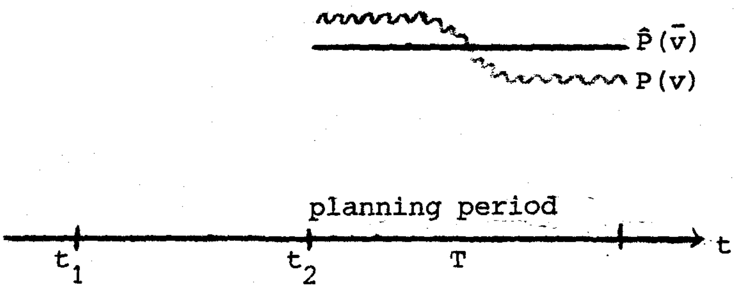
The conventional power plant mix of an utility is currently operated by a strategy to meet the load, i.e. the demand, at any time. A prediction of the load can be given almost accurate due to dominant cycles in the behavior of the consumers and exact temperature forecasts. The power plants of the utilities' mix, are characterized by the rated power, the fuels fired, the start up/shut down times, range of regulations, costs, etc.. Mainly by these features, they are classified in peak, intermediate and base load power plants.

A peak load plant generally has low capital costs but high running costs and short start up times (e.g. minutes). Intermediate load plants may consist of former base load plants which are smaller and more expensive to run than present base load. They are regulated more quickly and can be started faster than present base load. Base load plants which meet the bottom part of the demand have high capital costs but low running costs. The utilities try to operate the b.l. plants continously, i.e. operation times of about 24 hours and more. The base load scheduling times are superimposed by the scheduling times for intermediate and peak load plants. This planning strategy is affected once again by weekly plannings of maintenance, the hourly and daily dispatching and the selling (buying) of excess (deficit) power. This operating strategy is going to supply the power to meet the demand with a probability of 97% in the FRG, whereby of course reserve capacity has to be kept to achieve this goal.

To incorporate the stochastic source wind in the operating strategy it is necessary to forecast the wind energy output. The better the forecast will be, the more the costs of operating the power plant mix and the grid will be affected. Basically, the operating reserve and the grid regulation as well as the primary regulation are affected. Reliable forecasts of wind power should make it possible to adapt profitable running strategies by the utilities.

This paper is not dealing with short-term forecasts in the range of seconds to minutes. These forecasts might be used to give hints abouts the fluctuations of the wind speed. Due to local circumstances, turbulence, gustiness, precipitation, etc., these short-term power fluctuation affect the economics and technical characteristics of the wind turbines.

Main issue of this paper is the discussion of time periods which allow a reoptimization of the base, intermediate and peak load plants incorporated. Scheduling in t_1 the mix employed from a time t_2 onward, it is favourable to 'know', based on a forecast, that there will be an increase in wind energy output, i.e. input to the grid by $\Delta \hat{P}(\bar{v}) > 0$, from a time t_2 onwards. One might then be able to switch off a peak load unit or substitute an intermediate unit by another one, which is less expensive to run. On the other side, if a decrease in power output, i.e. $\Delta \hat{P}(\bar{v}) < 0$, is forecasted for the planning period T, the dispatcher might start up an additional unit.



with $\hat{P}(\bar{v})$: forecasted wind energy output

$P(v)$: actual output

T : planning period

In which way the dispatcher will proceed is basically depending on T. What forecast periods T are the most interesting for the operating strategy of an utility? Of course, this question cannot be answered in general, due to different penetration levels, structures of the grid and pooling possibilities. However, some margins can be given [1]. The most important scheduling periods for operation are:
(2h-6h), (6h-12h), (12h-24h) and (24h-48h).

For these time spans forecasts are required. Not only a single projection is asked by the dispatcher but a forecast of the trace on the basis of time series, which consist of highly resolved measurements. So far, half hourly forecasts are wanted to be available for the range of (2h-6h), [1].

However, what is meteorology currently capable to offer? Given the production function of a wind turbine

$$P = \begin{cases} 1/2\ \eta\ c_p\ \rho\ A\ v^3 & v_I \leq v < v_R \\ P_R & v_R \leq v < v_o \\ 0 & \text{else} \end{cases}$$

with η : efficiency of converting mechanical energy into electric energy

c_p: efficiency of converting kinetic energy into mechanical energy

ρ : air density

A : swept rotor area

P_R: rated electrical power of the wind turbine

v_I: cut-in wind speed

v_R: rated wind speed

v_o: cut-out wind speed

the forecast of P requires the forecast of the wind speed v. Of course, due to the technical characteristics of the turbine and its cubic relationship to power output, the wind speed is a highly sensitive parameter. However, the more accurate it can be predicted the less surprises will occur.

For planning purposes not the momentaneous value v is important, but a mean value $\bar{v}_T$ for a planning period T.

However, already v is a composed phenomena. Wind is generated by the uneven heating and cooling of the earth's surface and the rotation of the earth. In the 500 meters atmospheric or planetary boundary layer, the wind is affected by a number of local conditions such as topography, roughness of the earth's cover and air temperature gradients. At the surface, wind velocity is zero. At an altitude above purely surface effects, the wind velocity increases with height. The vertical variation is called wind shear and is a function of surface features, conditions up wind and vertical variations of temperature. Excessive shear and turbulence forces can be destructive to the operation of LWECS on the grid. Usually, turbulence is defined as rapid changes of the wind speed and direction about a mean at each elevation point.

Therefore, let us assume that the momentaneous wind speed v_t prevailing at time t is composed of a mean wind speed $\bar{v}_t$ and a turbulence u_t. Let j be the index for the site, then the random variable 'horizontal wind speed $V_t(j)$' is defined as

$$(1) \qquad V_t(j) := \bar{V}_T(A) + U_t(j) \quad t \in T,\ j = \{j \in A / j = 1, \dots, n\}$$

In order to forecast the wind speed $V_t(j)$ for a period T, one should first try to examine if there exist any regularity. Besides, causal explanations due to meso-scale or large-scale synoptic variations and which are for example expressed in equations like the one by Navier-Stokes, one can try to find some hidden variations by means of the spectral analytic approach. For this approach, the assumption of weak-stationarity has to be fulfilled. When decomposing the wind into an energy spectrum, it is clear, that energy is distributed over the whole range of frequences λ. Van de Hoven [4] examined for example the wind speed (hourly mean values) in 100 m by spectral analysis. Fig.1 gives the spectrum.

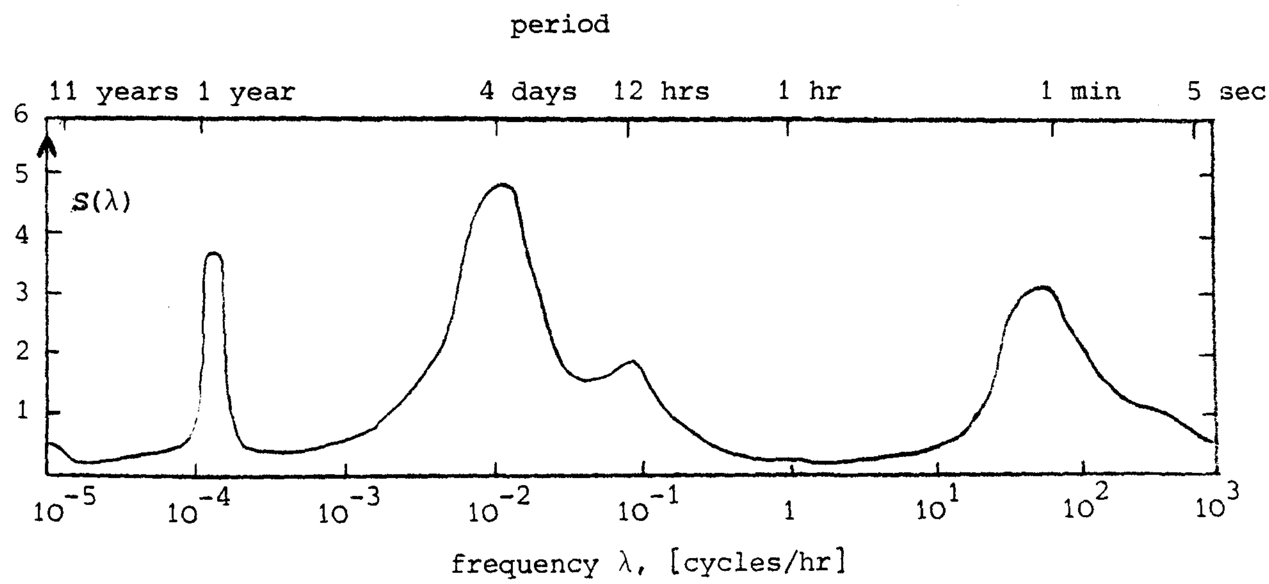


Fig.1: Schematic spectrum of wind speed near the ground. S(λ) is the power spectral density.

E.L. Peterson [2] investigated spectras at different heights from 7 m to 123 m agl.. The hourly measurements of ten-minute averages were taken at Risø 1958-1967. The spectrum based on realisations, measured at a height of 56 m is given in Fig.2.

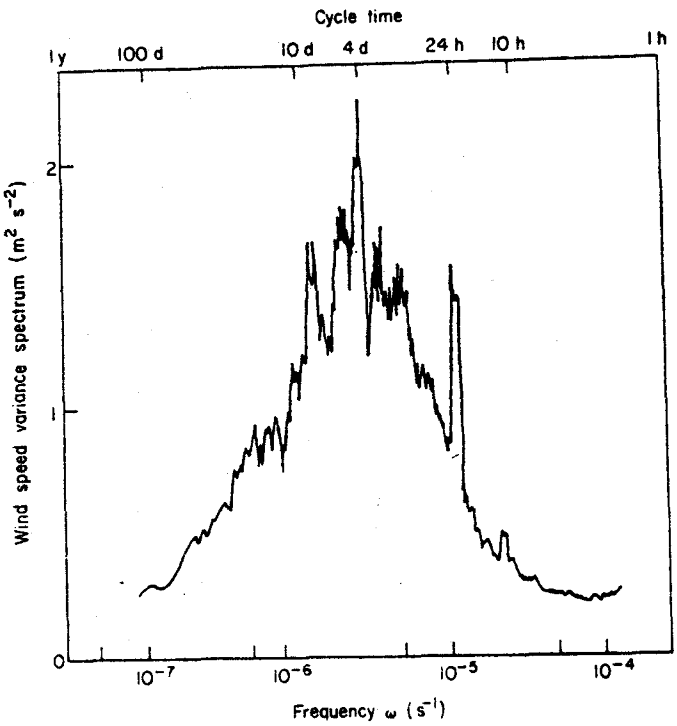


Fig.2: Spectrum of horizontal wind speed.

The two analysis affirm that cycles, characterized by the relative height of the amplitude of the spectrum, are found in the range of seconds to minutes due to energy input from shear and convective turbulence generation as well as gustiness, in the range of 1-3 hours due to meso-scale meteorological variations and in the range of 4 days and of 10 days due to large-scale baroclinic and barotropic instability. In addition the spectrum of Van Hoven shows some peaks at the frequency range of 1 year and 11 years. The peak in the frequency range of 4 days in Fig.1 hides a substantial amount of fine structure as can be seen in Fig.2.

A striking feature of the spectrum, shown in Fig.1, is the broad gap between $\omega \approx 0.5\ h^{-1}$ and $\omega \approx 20\ h^{-1}$, i.e. the interval [3 min., 2 hours]. Subsequent measurements have confirmed that the existance of such a gap is an almost universal feature of the wind speed spectrum. Its significance is to provide a clear distinction between the region of large-scale motion ($\omega < 0.5\ h^{-1} \equiv P > 2\ h$) and the region of small-scale motion ($\omega > 5\ h^{-1} \equiv P < 12$ minutes); [3]. Thus, in order to facilitate the forecasting, it should be emphasized to investigate the cyclic behavoir in the low frequency range. The wind speed variance spectrum shown in Fig.2 covers a frequency interval between the yearly period and the spectral gap. In addition to the 1 day periodicity, the amplitude of which declines with increasing height, the figures exhibits a group of spectral peaks with periods in the range of 3-10 days.

It is possible to give some causal explanation for the longer periods by means of a convolution of exogenous variables, e.g. pressure, temperature, humidity, friction and stability indicies. However, as the forecast has to be site- and height-dependent, it will put forward some difficulties to determine the initial values of the functional dependency between wind speed and its predictors. Site dependent roughness length, average friction velocity and accurence of different stability classes have to be taken into account.

As conservative generalization it surely holds, that the current synoptic network is insufficient, when forecasts are needed for time scales up to 6 hours. The forecast methods based on regression equations or delphi methods, i.e. subjective forecasts by meteorologists, are designed to predict for a time horizon of 12-48 h [1]. Maybe some progress will be gained when time series approaches mixed with à priori information are tested and verified.

Let us now assume, that there exists an unbiased and convergent estimation of $\bar{v}_T$. To forecast the mean wind power $P_T(n)$, a forecast for a realization $p_T(n)$ of $P_T(n)$ can be given. Be $\bar{V}_T$ the random mean wind speed and let $\hat{f}$ be the estimated density of $\bar{V}_T$.

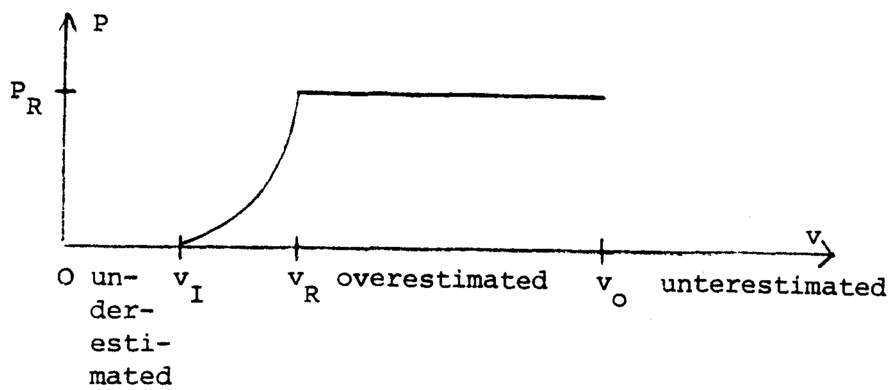
Simplifying the production function by taking the efficiencies c_p and η as constant, the average power is a function of $\bar{V}_T$. It follows with $c := c_p \cdot 1/2 \cdot \rho \cdot A$

$$\hat{p}_T(n) := n[c\int_{v_I}^{v_R} \bar{v}_T^3\, \hat{f}(\bar{v}_T)\, d\bar{v}_T + P_R \int_{v_R}^{v_o} \hat{f}(\bar{v}_T)\, d\bar{v}_T]$$

However, it may be argued, that it is impossible to get an estimation of the density $\hat{f}$. Therefore, assuming an estimation $\hat{\bar{v}}_T$ exists, an estimation of $\hat{p}_T(n)$ is given by

$$\hat{p}_T(n) = \begin{cases} 0 & 0 < \hat{\bar{v}}_T < v_I \\ n\ c \cdot \hat{\bar{v}}_T^3 & v_I < \hat{\bar{v}}_T < v_R \\ n\ P_R & v_R < \hat{\bar{v}}_T < v_o \\ 0 & v_o < \hat{\bar{v}}_T \end{cases}$$

Looking at a graph of P, one recognizes being confronted with a decision problem.



With regard to the a.m. estimation $\hat{p}_T(n)$ there will be an under- or overestimation of the output, depending on the definition range of v. With respect to the fact that the wind speed is a cubed expression in the production function, the wind speeds higher than the mean value compared to speeds lower than the mean value result in relativ higher power outputs. Therefore, using the mean value of the wind speeds the sketched deviations will result.

To reduce the decision problem, i.e. how to weigh the under- and overestimations, it is useful to have a look at a power duration curve. It turns out that for most of the time the wind speed is in the interval $[v_I\ v_R]$. Therefore, it is interesting to gain an estimation for that interval.

Let c_p and η be constant, then the mean power for T for n turbines is

$$P_T(n) = \frac{1}{T} \int_{T_a}^{T_b} \Big(\sum_{j=1}^{n} c\ V_t^3(j)\Big)dt$$

Substituting $V_t(j)$ by (1), $P_T(n)$ can be written as

$$P_T(n) = nc\ \bar{V}_T^3 + 3c\ \bar{V}_T^2\ \frac{1}{T}\int(\Sigma\ U_t(j))dt + 3c\ \bar{V}_T\ \frac{1}{T}\int(\Sigma\ U_t^2(j)dt + c\ \frac{1}{T}\int(\Sigma\ U_t^3(j))dt.$$

We define the mean wind speed in T as

$$\bar{v}_T := \frac{1}{T}\int(\frac{1}{n}\Sigma\, v_t(j))dt.$$

Let $\hat{\bar{v}}_T$ be the estimator of $\bar{v}_T$. If $\hat{\bar{v}}_T \simeq \bar{v}_T$ the error-term expression in (1) becomes zero

$$\int (\Sigma\ u_t(j))dt = 0.$$

Under this weak condition, the estimator of $P_T(n)$ is given as

$$\hat{p}_T(n) = nc\ \hat{\bar{v}}_T^3 + 3c\ \hat{\bar{v}}_T\ \frac{1}{T} \int (\Sigma\ u_t^2(j))dt + c \cdot \frac{1}{T} \int (\Sigma\ u_t^3(j))dt.$$

The second term on the right side of the equation is always greater or equal zero. To decide on the last term, an assumption about the distribution of $U_t(j)$ has to be made. For a family of distributions, which seems to be for wind speeds quite plausible, the term will become positive. However, even if the third term is supposed to be negative, the sum of the second and third term can still be positiv. Therefore, there usually will be a positive term added to the first term $nc\hat{\bar{v}}_T^3$.

The conclusion is, that having a good estimator of the mean wind speed $\bar{v}_T$ for a planning period T, the mean wind power output will be underestimated, as long as the wind speed is the range of cut-in and rated.

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ASSURED LOAD CARRYING CAPABILITY AND CAPACITY CREDIT

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Both the term "assured load carrying capability" and the term "capacity credit" refer to the installation of power plants. In order to understand how the utilities proceed in planning how much capacity shall be installed we have to start with the term "available capacity".

1 Available Capacity of Thermal Power Plants

Definition 1

Consider thermal power plants planned for employment in period T. The available capacity of these power plants at the time $t \in T$ is given by the sum of the rated capacities minus scheduled outages (planned maintenance) and forced outages at $t \in T$.

Comments

The available capacity is a random variable as only the probability of forced outages will be known.

Transmission or distribution outages are not considered when determining the available capacity. Furthermore, it is assumed that primary energy, i.e. gas, oil, coal and uranium can be obtained in the desired quantities. There may be limitations in the future. However, due to the possibility of storage of these primary energies, the quantities as well as the availability can presumably be forecasted exactly. It should be mentioned here, that the primary energy wind differs in this respect considerably from the primary energies gas, oil, coal and uranium.

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[1] This article is a revised version of the paper given at the Expert Meeting. The author would like to thank the participants, whose helpful comments enabled this revised and more complete version.

In order to determine the probability distribution of the random variable "available capacity" the following assumptions are made:

Assumption 1

A forced outage is equivalent to a breakdown of the power plant.

Comment

Only technical defects causing a breakdown of the power plant are considered whereas technical defects causing a short-term reduction of power output are neglected. Such defects are assumed to be compensated by the regulation of other plants. Thus, such defects represent a short-term planning problem however, not a long-term planning problem.

Assumption 2

Given a certain power plant the probability of a forced outage is assumed to be independent of the actual time $t \in T$.

Comments

Although the probability of a forced outage may be greater in times of high load than in times of low load, assumption 2 seems to be a reasonable approximation to reality.

Assumption 2 does not state that each thermal power plant has the same probability of a forced outage. Power plant types differ in the probability which depends in large on the age of the power plant. According to [6] the following probabilities are reasonable:

age of thermal power plant	probability of a forced outage
less than a year	0.20
one to ten years	0.10
more than ten years	0.12

We now introduce the following symbols ($j=1,\dots,n$):

$X_{t,j}$ random variable "available capacity of the thermal power plant j at time $t\in T$"

P_j rated capacity of the thermal power power plant j

q_j probability that the thermal power plant j will breakdown at time $t\in T$ ($0 < q_j < 1$)

If the thermal power plant j is maintained due to the maintenance plan at time $t\in T$ we choose $q_j=1$.

The random variables $X_{t,j}$ can be considered to be stochastically independent. Thus, the random variable

$$X_t = \sum_{j=1}^{n} X_{t,j}$$

i.e. the random variable "available capacity of the thermal power plant mix at time $t\in T$", has the probability function

$$h(x_j) = \begin{cases} \prod_{j=1}^{n} q_j & x_t=0 \\ \sum\limits_{\substack{j \text{ with} \\ P_j=P_l}} \left((1-q_j) \prod_{k\neq j} q_k\right) & x_t=P_l \quad (l=1,\dots,n) \\ \vdots & \\ \prod_{j=1}^{n}(1-q_j) & x_t= \sum_{j=1}^{n} P_j \\ 0 & \text{otherwise} \end{cases}$$

The random variable X_t has the expected value

$$EX_t = \sum_{j=1}^{n} (1-q_j)P_j$$

and the variance

$$\mathrm{var}X_t = \sum_{j=1}^{n} q_j(1-q_j)P_j^2.$$

For the sake of simplicity the probability function $h(x_t)$ is mostly approximated by a normal density with parameters EX_t and $varX_t$ (see [2,p.139], [3,p.10], [5]).

In the strict sense the approximation should only be made unless the hypothesis that the approximation is valid cannot be refused due to a statistical test. According to numerical investigations [3] the normal distribution can be taken provided that $n > 150$; $q_j > 0.10$ $(j=1,...,n)$ and $\Sigma P_j > 20\ 000$ (MW).

2 Available Capacity of Wind Turbines

Just as thermal power plants wind turbines will have outages due to planned maintenance work as well as due to unpredictabel technical defects. In addition, there will be outages due to the wind speed being below the cut-in speed or above the cut-out speed, i.e. there will be outages caused by the non-availability of the primary energy wind Up to now outages of thermal power plants caused by the non-availability of the primary energy (gas, oil, coal, uranium) are very unlikely to happen and can be neglected.

For obvious reasons wind turbines should be maintained during summer (May - September). In summer the wind speed and thus the wind energy production tends to be lower than in spring, autum and winter. Moreover, the electricity consumption is in summer lower than in the rest of the year. However, installing a large number of wind turbines it will presumably not be possible to maintain all wind turbines during summer.

Just as at thermal power plants be probability of an unpredictabel technical defect will mainly depend on the age of the wind turbine. Experience will show whether the values stated on the preceeding page also hold for wind turbines. Up to now a technical outage rate of 5% is usually calculated which; see [1,p.24].

It is more important from a methodical point of view that the probability of a technical defect can be assumed to be time independent. This assumption is also made when considering thermal power plants.

Neither independent of the time nor of the location is the wind energy production, however. Considering for example the Dutch coastal region there seem to be significant differences in the monthly wind energy production of at least the following classes of months:

November
January, December
March, April, October
February, May, September
June, July
August

However, not only the monthyl wind energy production must be known in the sense that the distribution of a corresponding random variable is known, but in principle the wind energy production of each instant must be known in the same sense. This is due to the demand that the utilities have to guarantee a safe electricity supply at each instant. Regarding the employment of existing power plants the safe supply is mainly guaranteed by the spinning reserve and the stand-by capacity. Regarding the determination of the total capacity to be installed, that capacity includes the spinning reserve and the stand-by capacity. Thus, calculating with a wrong distribution of the random variable "available capacity of wind turbines at the time t" it may happen that there will be either a lack of reserve capacity at the time t in the future or that there will be too much reserve capacity. In the first case a safe electricity supply of the current standard cannot be guaranteed any longer and the second case is not economic, i.e. gives rise to superfluous costs.

Unfortunately, up to now there does not exist any investigation answering the following question for a given site: For which periods are there significant differences in the distribution of the random variable "available capacity of wind turbines" and how do the distributions look like? Of course, the question will be hard to answer. Especially from a pure operational point of view there will have to be posed an upper limit to the length of the period. It will presumably not be possible to determine each daily or even hourly distribution, i.e. 365 resp. 8760 distributions. The best way to proceed may consist in testing several hypothesis of the kind that the hourly (daily, weekly) distribution does not differ from the monthly or seasonal distribution.

It should be noted that only personal aspects argue against considering the available capacity a parameter instead of a random variable.

For example, the mean value of the past could be taken to represent the "available capacity of wind turbines". A corresponding procedure is often chosen for hydro power plants; see [7,p.13].

Another proposal is made in [1 ,p.42]. The "available capacity of wind turbines at the time t" could be estimated by the minimum wind energy production which occured at that time during the last 30 years. However, this procedure is extremely pessimistic and seems to be an unjustified assessment of wind energy.

3 Assured Load Carrying Capability of Power Plants

<u>Definition 2</u>
The assured load carrying capability is that available capacity that will result with a probability of at least $(1-\alpha)$.

α is usually taken from the interval (0.03, 0). See [6, p.36].

Definition 2 shall guarantee a safe energy supply. Such a passage is found in the corresponding definition of German utilities [8 ,p.21]. However, it will help to understand the term capacity credit if we seperate the demand for a safe energy supply from the assured load carrying capability.

In the terminology of statistic the assured load carrying capability is the α quantil of the random variable "available capacity".

However, if the "available capacity" is not considered a random variable but a parameter the assured load carrying capability is identical with the parameter.

4 Capacity Credit of Wind Turbines

The capacity credit of wind turbines refers to the question, whether it is possible to dispense with conventional capacity if wind turbines are installed. However, a uniform operational definition of the capacity credit does not exist.

We assume that there is a number of wind turbines in a future period T. T shall represent a certain year. We begin by giving a definition of the capacity credit related to a fixed time $t \in T$. The definition is afterwards extended to the period T.

Both definition are based on the supply concept of the utilities which runs as follows.

Condition 1

Capacity is installed to that extent that the assured load carrying capability is not less than the expected peak load at each time $t \in T$.

Note that the assured load carrying capability is defined to be that available capacity which will result with a given probability of at least $(1-\alpha)$ with α being usually element of the interval $(0; 0.03)$.

That condition 1 corresponds in principle to the supply concept of the utilities follows for example from [8 ,p. 21].

4.1 THE CAPACITY CREDIT AT THE TIME $t \in T$.

For each period T there will always be a stock of conventional power plants. This stock is formed by all the existing power plants which will not be dismantled before the end of period T. In addition, all those power plants belong to the stock whose installation has already been decided and will be finished before the beginning of period T. The stock shall be composed of power plants with rated powers $P_1,\ldots,P_n$. The random variable X_t gives the available capacity of the stock at time $t \in T$.

Furthermore, additional conventional power plants are required for the definition of the capacity credit:

a) conventional power plants with rated powers $P'_{n+1},\ldots,P'_{n+r}$ $(r\in\{0,1,\ldots\})$ and an available capacity X'_t at time $t\in T$;
b) conventional power plants with rated powers $P''_{n+1},\ldots,P''_{n+s}$ $(s\in\{0,1,\ldots\})$ and an available capacity X''_t at time $t\in T$;

Finally let l_t be the non-random variable "expected peak load at time $t\in T$" and remember that $(1-\alpha)$ is the given supply security.

The following definitions of the capacity credit are subject to the condition $W(X_t < l_t) < \alpha$ or, equivalent, $g_{X_t}(\alpha) > l_t$ for all $t\in T$; i.e. the stock of conventional capacity being conceivable for the period T in the planning instant meets the supply concept of the utilities (Condition 1). This condition will probably hold unless the period T is too far ahead in the future. Let T as usual cover a year then for any T up to about the year 1990 the conceivable stock of conventional capacity will presumably meet the requirements of the utilities.

Thus, up to about 1990 wind turbines will not have a capacity credit in that sense that conventional power plants will not be built if wind turbines are being built. As will be explained in the sequel the capacity credit should then better be named additional supply security credit. Of course, in the lapse of time this additional supply security credit will turn into a real capacity credit. It should be noted , that this procedure corresponds to common utility standards as is indicated by the amount of excess capacity existing.

Definition 3

The capacity credit of wind turbines at time $t\in T$ is given by the conventional capacity

$$P'_{n+1}+\ldots+P'_{n+r}$$

subject to

$$W(X_t+X'_t < l_t) = W(X_t+Y_t < l_t)$$

Comment

As has been mentioned we assume that $W(X_t < l_t) < \alpha$ or, equivalent, $g_{X_t}(\alpha) > l_t$ for all $t \in T$. Thus, the stock of conventional capacity has an assured load carrying capability of at least the expected peak load and consequently fulfills the supply concept of the utilities (Condition 1). As any additional capacity - conventional as well as wind turbine capacity - can be assumed to always increase the assured load carrying capability of the stock, it holds that

$$g_{X_t+X'_t}(\alpha) = g_{X_t+Y_t}(\alpha) > g_{X_t}(\alpha) > l_t.$$

Thus, definition 3 guarantees that the supply concept of the utilities is fulfilled.

Adding wind turbines to the stock of conventional capacity the assured load carrying capability of the resulting system is higher than that one of the stock or, the probability that the expected peak load cannot be met decreases. The same effect could be achieved by adding additional conventional capacity to the stock. The capacity credit of wind turbines is given by exactly that amount of conventional capacity that would yield that effect.

Definition 4

The capacity credit of wind turbines at time $t \in T$ is given by the conventional capacity

$$P''_{n+1}+\ldots+P''_{n+s}$$

subject to

$$W(X_t < l_t) = W(X_t - X''_t + Y_t < l_t).$$

Comment

Remember that $W(X_t < l_t) < \alpha$ resp. $g_{X_t}(\alpha) > l_t$ is assumed to hold, i.e. the stock of conventional capacity has an assured load carrying of at least the expected peak load and thus fulfills the supply concept of the utilities. Adding wind turbines to the stock the assured load carrying capability of the resulting system increases. Thus, one could dispense with some power plants of the stock when adding wind turbines and still obtain an assured load carrying capability fulfilling the supply concept. The capacity credit of wind turbines is given by exactly that amount of conventional capacity that could be dispensed with.

Unfortunately, both definitions are not applicable from a numerical point of view as the capacity credit is only implicitly included by the functions X'_t resp. X''_t. To avoid this problem it seems to be necessary to consider hypothetical firm capacities c'_t resp. c''_t. It is to be hoped that the resulting error committed by this procedure is negligible. We then get the following definitions.

Definition 5 (Equivalent Firm Capacity Concept)

The capacity credit of wind turbines at time $t \in T$ is given by the firm capacity c'_t resulting from

$$W(X_t + c'_t < l_t) = W(X_t + Y_t < l_t).$$

<u>Definition 6</u> (Effective Load Carrying Capability Concept)
The capacity credit of wind turbines at time $t \in T$ is given by the firm capacity c_t'' resulting from

$$W(X_t < l_t) = W(X_t + Y_t < l_t + c_t'').$$

Let us now consider two different times $t_1, t_2 (t_1 \neq t_2)$. If there is a period of two months between t_1 and t_2 the conventional power plants being maintained at t_1 will differ from those being maintained at t_2. Thus, the distribution of the random variable X_{t_1} will differ from the distribution of the random variable X_{t_2}. Furthermore, the wind speeds prevailing at t_1 can be expected to be significantly different from those prevailing at t_2. Consequently, the random variable Y_{t_1} will have another distribution than the random variable Y_{t_2}. Finally, the expected peak loads will differ, i.e. $l_{t_1} \neq l_{t_2}$. As a result of these changes the capacity credit at t_1 will not equal the capacity credit at t_2.

It must be assumed that different values for t will in general result in different capacity credits unless the t_i are not too close together. The question arises which capacity credit is the real capacity credit?

4.2 The Capacity Credit of a Period

Of course, the a.m. question can only be answered by the utilities, i.e. we have to know which evaluation criterium is used by the utilities. However, up to now the utilities have not been confronted with highly stochastic energy sources as is the wind energy. Thus, it is not surprising that there does not exist any uniform criterium.

We shall now consider two definitions of the capacity credit of period T which may be accepted by the utilities. Both definitions will be given in conjunction with the EFC-concept. Corresponding definitions in conjunction with the ELCC-concept are straightforward and will be omitted.

Definition 7 (Mean value concept)
The capacity credit of wind turbines in the period T is given by the firm capacity

$$c = \frac{1}{T} \int_t c'_t \, dt.$$

with c'_t resulting from

$$W(X_t + c'_t < l_t) = W(X_t + Y_t < l_t) \quad \text{for all } t \in T.$$

Definition 8
The capacity credit of wind turbines in the period T is given by the capacity credit at the time t* of the peak load in period T, i.e. the capacity credit is given by the firm capacity d resulting from

$$W(X_{t*} + d < l_{t*}) = W(X_{t*} + Y_{t*} < l_{t*}).$$

Before we are going to comment on these definitions it should again be emphasized that both definitions only are proposals. There does not exist a uniform definition of the capacity credit up to now.

According to Definition 7 the capacity credit in period T is equal to the mean capacity credit of that period. As the mean value criterium is a customary criterium of evaluation and as Definition 7 fulfills the supply concept of the utilities, Definition 7 would presumably not be rejected by the utilities. However, this capacity credit will be difficult to calculate. Considering two times

t_1, t_2 being not too close together the distributions of the random variables X_{t_1}, X_{t_2} will presumably be different and the same will hold with regard to the distributions of the random variables Y_{t_1}, Y_{t_2}. Thus, in order to calculate a capacity credit according to Definition 7 it will be necessary to determine for a given site at which times of a given period (year) the a.m. distributions will be significantly different and also to determine the explicit form of the different distributions. This topic has hardly been paid any attention up to now.

Definition 8 is justified by the fact that the coincidence of power availability and peak demand is essential in power system studies [4].

Let us finally sum up as follows. It has been shown that the term capacity credit is an extremely complex term. Up to now there are a lot of questions left open as is also indicated by the number of different definitions.

The capacity credit must be based on the supply concept of the utilities which is roughly characterized by installing capacity to that amount that the assured load carrying capability of all power plants is at least equal to the expected peak load. As both the expected peak load and the assured carrying capability vary within a given time of reference - usually one year - it is obvious that the capacity credit should take into account this time dependence. Unfortunately, however, up to now there does not exist sufficient detailed knowledge regarding the time dependence of wind energy production. It is known that there is a seasonal pattern of wind energy production but the question is still left open whether the distribution of the random variable "available capacity of wind turbines in the season ..." also holds for smaller periods (weeks, days) than the whole season.

Of course, the problem of the time dependence omits from a formal point of view if the capacity credit is related to a fixed time by definition. However, when using such a definition one should be aware that for the definition to make sense one implicitly has to assume that there will not be a mismatch between the available capacity and the expected load at other instants then the fixed time.

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*Paper B5**

MÖGLICHKEITEN ZUR VERMEIDUNG VON STARKEN SCHWANKUNGEN DER ELEKTRISCHEN ABGABELEISTUNG VON WINDENERGIEANLAGEN

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Bei der Umwandlung der kinetischen Energie des Windes in elektrische Energie durch Windenergiekonverter ist die Primärenergie durch die Geschwindigkeit der Luftströmung vorgegeben. Sie ist daher im Gegensatz zu thermischen Kraftwerken nicht regelbar und unterliegt sowohl lang- und mittelfristigen Schwankungen als auch kurzfristigen Variationen im Sekundenbereich (Böen). In Abhängigkeit der Betriebsart und dem Regelungsverfahren des Windenergiekonverters sind somit entsprechend starke Leistungs- bzw. Drehzahländerungen möglich.

Windenergieanlagen, die im Verbund mit dem öffentlichen Versorgungsnetz arbeiten, müssen zur Vermeidung von Überlastungen die Aufnahme der Leistung aus dem Wind über eine schnelle Verstellung des Blatteinstellwinkels regeln. Hierbei können allerdings kurzzeitige Schwankungen der Aufnahmeleistung von der Regelung nicht ganz vermieden werden, so daß bei Anlagen mit Synchrongeneratoren die Leistungsfluktuationen in voller Höhe und bei Anlagen mit Asynchrongeneratoren (durch die auftretende geringe Drehzahlvariation, Schlupf) etwas abgeschwächt vom Netz aufgenommen werden müssen.

Eine Möglichkeit, trotz schwankendem Primärangebot, eine Vergleichmäßigung der abgegebenen Leistung zu erreichen, ist die Zwischenspeicherung von kinetischer Energie durch Ausnutzung der rotierenden Massen als Schwungrad, indem Drehzahlvariationen in einem bestimmten Bereich zugelassen werden [1]. Durch die Einspeisung von Gleich- oder Wechselstrom in den Läuferkreis von Asynchronmaschinen mit Schleifringläufern oder durch die Beeinflussung der Schlupfleistung ist ein drehzahlvariabler Betrieb am Netz möglich.

* This paper was not presented at the meeting and is issued in addition

In der Windenergieanlage GROWIAN soll ein solcher doppeltgespeister Asynchrongenerator eingesetzt werden. Hier ist der Ständer der Maschine über einen Transformator mit dem Netz verbunden. In den Läufer wird aber von einem Direktumrichter ein niederfrequenter Strom eingespeist, dessen Frequenz der Differenz aus Läuferdrehzahl und Netzfrequenz entspricht. Durch Veränderung der Phasenlage des Läuferstroms ist auch die Regelung der Blindleistung möglich. Mit der Größe des Drehzahlvariationsbereiches nimmt auch die Größe des Umrichters zu, so daß für die Windenergieanlage GROWIAN dieser Bereich auf ±10% statisch und ±15% dynamisch eingegrenzt worden ist. (Details dieser Regelung sind [2] zu entnehmen.)

Bild 1 zeigt zusammenfassend die elektrischen Prinzipschaltbilder von Windenergieanlagen mit verschiedenen Arten von Drehstromgeneratoren.

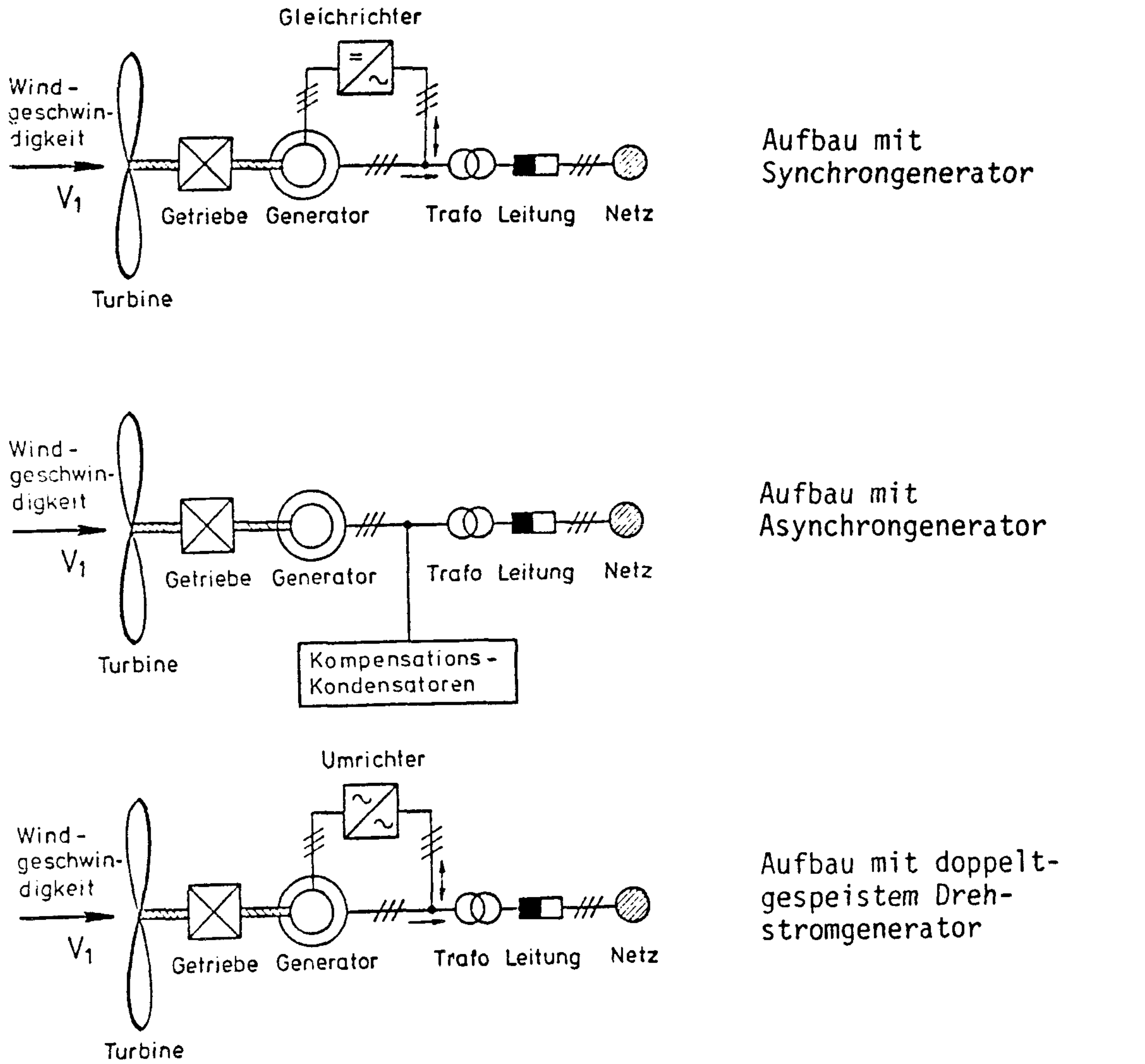

Bild 1: Aufbau von Windenergieanlagen mit unterschiedlichen Wechselstromgeneratoren am Netz

Ein einfacheres Verfahren zur begrenzten Drehzahlvariation im Netzbetrieb ist die Änderung der Drehmoment-Drehzahlkennlinie der Asynchronmaschine durch die Beeinflussung der Rotorschlupfleistung. Da der Einsatz von Läuferwiderständen zu große Verluste verursachen würde, wird über einen ungesteuerten Gleichrichter [3] und einen netzgeführten Wechselrichter Schlupfleistung in das Drehstromnetz zurückgespeist. Über eine schnelle, verhältnismäßig einfache Regelung des Zwischenstromkreises läßt sich das Drehmoment und damit Wirkleistung und Drehzahl beeinflussen. Die Anlage benötigt allerdings induktive Blindleistung aus dem Netz. Der Aufbau entspricht im wesentlichen der Anlage mit doppeltgespeister Asynchronmaschine. Der Stromrichter und die Regelung haben aber gegenüber der doppeltgespeisten Maschine eine wesentlich vereinfachte Struktur.
Bild 2 zeigt im Vergleich die Ergebnisse von digitalen Simulationen des Betriebsverhaltens von Windenergieanlagen im MW-Bereich für die beschriebenen Generatortypen bei gleichem Windgeschwindigkeitsprofil.

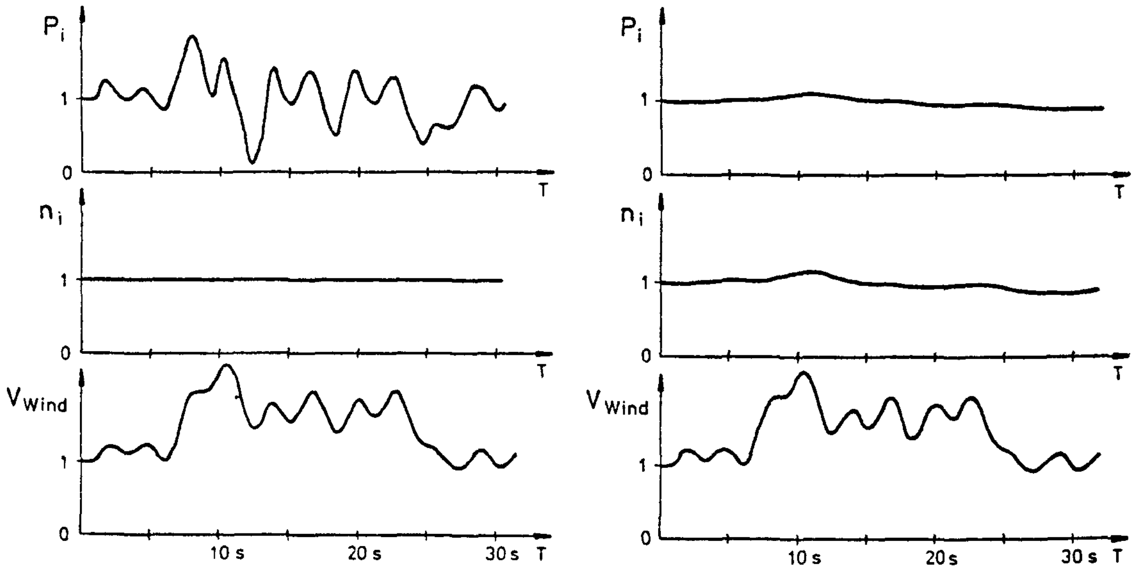

Bild 2: Verhalten einer Windenergieanlage (MW-Leistungsbereich) im Netzbetrieb (in normierter Darstellung)

a) Synchron- bzw. Asynchron-Generatoren (KS-Läufer)

b) Asynchrongeneratoren mit Schleifringläufern

n_i = Drehzahlistwert , P_i = Leistungsistwert

Die Ergebnisse für Anlagen mit Synchron- und Asynchrongeneratoren (siehe Bild 2a) sind in ihrer stark schwankenden Leistungsabgabe sehr ähnlich und deshalb nicht gesondert aufgeführt. Das Betriebsverhalten der doppeltgespeisten Asynchronmaschine und der Anlage mit Schlupfleistungsrückgewinnung (siehe Bild 2b) sind im Hinblick auf den Wirkleistungsverlauf nahezu identisch und ebenfalls nicht getrennt wiedergegeben. Hier ist der beschriebene Vergleichmäßigungseffekt der abgegebenen Leistung durch die Drehzahlvariation sehr deutlich zu erkennen.

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