KAMAN 40 kW WIND TURBINE GENERATOR - CONTROL SYSTEM DYNAMICS

Richmond Perley

Kaman Aerospace Corporation
Old Windsor Road
Bloomfield, Connecticut 06002

ABSTRACT

The Kaman 40 kW Wind Turbine Generator design incorporates an induction generator for applications where a utility line is present and a synchronous generator for standalone applications. A combination of feed forward and feedback control is used to achieve synchronous speed prior to connecting the generator to the load, and to control the power level once the generator is connected.

The dynamics of the drive train affect several aspects of the system operation. These have been analyzed to arrive at the required shaft stiffness. The rotor parameters that affect the stability of the feedback control loop vary considerably over the wind speed range encountered. Therefore, the controller gain was made a function of wind speed in order to maintain consistent operation over the whole wind speed range.

The velocity requirement for the pitch control mechanism is related to the nature of the wind gusts to be encountered, the dynamics of the system, and the acceptable power fluctuations and generator dropout rate. A model was developed that allows the probable dropout rate to be determined from a statistical model of wind gusts and the various system parameters, including the acceptable power fluctuation.

INTRODUCTION

Kaman Aerospace Corporation, under DOE sponsorship, has designed and fabricated a 40 kW, horizontal axis wind turbine generator. The work was part of the Small Wind Energy Conversion Systems (SWECS) program which is being directed by Rockwell International. The wind turbine is currently being evaluated in Rockwell's Rocky Flats, Colorado, test facility.

Three aspects of the control system dynamics are discussed in this paper. The first is the torsional characteristics of the drive train and factors affecting the selection of the drive train stiffness. Next is the effect that changes in rotor characteristics with wind speed have on the operation of the feedback control loop and the desirability of making the controller gain a function of wind speed. Finally, an analytical method for evaluating the adequacy of the control system design with respect to wind speed changes, or gusts, is discussed. The method is based on a statistical description of wind speed changes rather than on arbitrarily selected "worst gust" characteristics and, therefore, provides an objective means of assessing performance in a variety of locations.

SYSTEM DESCRIPTION

The wind turbine has a 64-foot diameter, two-blade, down wind rotor with a hub height of 75 feet. The unit has been designed to provide for direct conversion of wind power into regulated, 60 Hz, electrical power using either an induction generator for tie-in to a utility or a synchronous generator for standalone applications. The rotor operates at 69 rpm and a 1:26, two-stage, planetary gearbox provides a nominal generator speed of 1800 rpm. Cut-in wind speed is 10 mph; rated wind speed is 20 mph; and cut-out wind speed is 60 mph, at hub height.

Blade pitch is controlled to maintain the power level in the utility configuration and to maintain rotor speed, and thus frequency, in the standalone configuration. Both configurations also incorporate a feed forward control input based on wind speed.

The significant elements in the basic control loop are shown in Figure 1. The controller and the feed forward programmer are implemented in a microprocessor which also performs the startup and shutdown sequencing, as well as other monitoring and control functions. The microprocessor program includes provisions for integral control, but only proportional control is used. The output of the microprocessor is a voltage proportional to the desired blade pitch angle. A hydraulic position servo rotates the blades about the axles at the root ends. The feedback signal is proportional to rotor speed when either configuration is being brought up to the nominal operating speed and when the load is connected in the standalone (synchronous generator) configuration. The feedback signal is proportional to generator output power when the load is connected in the utility (induction generator) configuration. The distrubances to the system are changes in rotor torque due to changes in wind speed in either configuration and changes in load in the standalone configuration.

DRIVE TRAIN DYNAMICS

Several aspects of the drive train dynamics were considered in establishing the requirements for drive train stiffness: the avoidance of resonances as the rotor is brought up to operating speed; the magnitude of the rotor torque ripple that is transmitted to the load; and the impact of the drive train dynamics on the feedback control loop stability.

Drive Train Elements

A schematic representation of the drive train components with all elements referred to the rotor shaft speed is shown on Figure 2. The rotor is represented by the rigid-body inertia, I_R, and the slope of the torque-speed curve, C_R, at a particular operating condition. (The elastic modes of the rotor are high enough in frequency to be unimportant in these analyses.) The combined stiffness of the rotor shaft and the gearbox is included in K_S. There is an elastomeric coupling between the gearbox and the generator to accommodate shaft misalignment. Its inertia, I_C, is significant with respect to the other elements, but its stiffness, K_C, and damping, C_C, are not. The generator is represented by its mechanical losses, C_{GL}; rotor inertia, I_G; and the coupling to the load. The coupling of the induction generator, C_{GC}, is the slope of the torque-speed curve. The utility line connection is considered to be a zero impedance sink. The coupling of the synchronous generator appears as a stiffness, K_{GC}. In this case, the load impedance is finite, with a loss term, C_L, corresponding to 40 kW, as well as an inertia term, I_L, to account for large motor loads.

Resonances

The load is not connected while the rotor is being brought up to speed or during periods of rotor overspeed. (The control system limits overspeed to 125% of rated speed.) This results in a very underdamped resonance determined largely by the rotor shaft-gearbox stiffness, generator inertia, and generator mechanical losses. These resonant frequencies are plotted as a function of rotor shaft-gearbox stiffness on Figure 3. The synchronous generator configuration has lower resonant frequencies because of the higher generator inertia. The criterion for stiffness in this case is that the resonant frequency be higher than the two-per-rev frequency of the vibratory rotor torque at the 125% overspeed condition. Since rated rotor speed is 69 rpm, the resonant frequency should be greater than 2.9 Hz. This requires a stiffness greater than 120,000 ft-lb/radian.

Torque Ripple

The behavior of the two configurations in transmitting torque ripple from the rotor to the load is quite different because of the different load characteristics. The standalone configuration exhibits an underdamped resonance while the utility configuration is highly damped by the induction generator coupling characteristics and the zero impedance sink of the utility line. The torque transmissivity of each is shown on Figures 4 and 5 as a function of frequency and stiffness. The important criterion in this case is the torque transmissivity at the predominant rotor torque-ripple frequency of two-per-rev, or 2.3 Hz. This is shown on Figure 6 as a function of rotor shaft-gearbox stiffness.

For the standalone configuration, it is desirable that the torque ripple at the load be less than 10% of the actual load even when the system is lightly loaded (e.g., at 10% of rated load). Therefore, the torque ripple transmitted to the load should be less than 1% of rated torque. An analysis of the rotor indicates a two-per-rev vibratory torque at the rotor equal to about 13% of rated torque. Therefore, a torque attenuation of about 0.076 is desired. This requires a stiffness greater than 180,000 ft-lb/radian.

For the utility configuration, the torque transmissivity increases with increasing stiffness to a maximum value of 0.25. This would cause a ripple in the generator output equal to about 3% of rated load, or about 1.3 kW. Discussions with utility companies indicate that this would not be significant on a high capacity utility line. There will be a random phase relationship among two or more units connected to a common utility line, so their ripple components do not add directly. Therefore, this consideration does not put a constraint on stiffness.

Impact on Control Loop

During startup in either configuration, or when the load is connected in the standalone configuration, the feedback control loop is configured to control rotor speed. The feedback signal is rotor shaft speed measured at the node marked Ω_R on Figure 2. Because the admittance of the rotor inertia is very large in comparison to the other admittances at the frequencies of interest to the feedback control loop, the phase lag between rotor torque and rotor speed is essentially 90° and independent of reasonable values of rotor shaft-gearbox stiffness.

When the load is connected in the utility configuration, the feedback control loop is configured to control power level. The feedback signal is the power measured at the generator output. This corresponds to the node marked Ω_G on Figure 2. The phase lag between rotor torque and this point is the sum of the 90° lag noted above and the additional lag from Ω_R to Ω_G. The latter is largely determined by the stiffness, K_S, and C_{GC}, and decreases as the stiffness is increased. This additional lag is approximately 45° at a frequency corresponding to $K_S/(2\pi\ C_{GC})$. Since the frequencies of interest to the control loop stability are in the range of 1/2 to 3 Hz, a stiffness greater than 830,000 ft-lb/radian is desired.

Stiffness Selection

Each of the considerations above establishes a minimum constraint on rotor shaft-gearbox stiffness. The largest of these, 830,000 ft-lb/radian for the utility configuration control loop at rated load, was taken as the design requirement. Deflection measurements were made after the system was assembled. These measurements included the rotor shaft, gearbox, and coupling, and showed a stiffness of about 460,000 ft-lb/radian for low torque levels and 2,500,000 ft-lb/radian near rated torque. This level of stiffness is satisfactory because the constraint imposed by

consideration of the utility configuration control loop requires a stiffness greater than 460,000 ft-lb/radian, which is important only at torque levels near rated torque.

CONTROL LOOP GAIN

A review of Figures 1 and 2 shows that the magnitude of the control loop gain is determined by the following:

No Load:

$$\text{Gain} = (A_C)\left(\frac{\partial T_R}{\partial \theta}\right)\left(\frac{1}{C_R + C_{GL}}\right)$$

Utility With Load:

$$\text{Gain} = (A_C)\left(\frac{\partial T_R}{\partial \theta}\right)\left(\frac{1}{C_R + C_{GL} + C_{GC}}\right)(A_G)$$

Standalone With Load:

$$\text{Gain} = (A_C)\left(\frac{\partial T_R}{\partial \theta}\right)\left(\frac{1}{C_R + C_{GL} + C_L}\right)$$

where:

A_C = Controller gain factor

$\frac{\partial T_R}{\partial \theta}$ = change in rotor torque per unit change in pitch angle

C_R = slope of the rotor torque-speed curve, C_{GL}, C_{GC}, C_L, as defined on Figure 2

A_G = a constant that relates generator power to generator slip speed

Two of these factors, $\frac{\partial T_R}{\partial \theta}$ and C_R, are derived from the rotor characteristics and vary considerably over the range of expected operating conditions. The slope of the torque-speed curve, C_R, increases from 170 ft-lb-sec/radian at 10 mph to 6254 ft-lb-sec/radian at 60 mph. The torque derivative with pitch, $\frac{\partial T_R}{\partial \theta}$, is zero when the maximum available power is being delivered (i.e., regulation is not possible). However, if power is restricted to the lesser of 40 kW or 80% of the maximum available, the torque derivative increases from 90 ft-lb/deg. to 1980 ft-lb/deg. as the wind increases from 10 to 60 mph. The three gain functions, normalized to their values at 20 mph are shown on Figure 7. The functions with load are based on the lesser of 40 kW or 80% of the maximum power available.

The loop gain in the no load case changes by a factor of almost 5. However, this case is primarily concerned with startup which takes place when the wind speed increases above 10 mph or decreases below 60 mph. The loop gains at these two points only differ by a factor of 1.5. More importantly, the control loop stability analysis indicated that a fixed controller gain could be selected that would provide adequate speed regulation at 10 and 60 mph and satisfactory overshoot characteristics at 20 - 25 mph. Test data has verified this projection up to 30 mph. Test data for startups above 30 mph have not yet been collected.

When the standalone configuration is operated with full load, the changes in the torque derivative are almost fully compensated by changes in the total damping and the loop gain is essentially constant. As the load is decreased, the curve approaches the no load curve. In this case also, the control loop stability shows sufficient gain margin to achieve adequate speed regulation and satisfactory overshoot characteristics under all of the wind speed and load conditions.

The utility configuration differs in two respects. First, the damping term is dominated by C_{GC}, the very steep slope of the induction generator torque-speed curve. Therefore, the change in loop gain is almost equal to the change in the torque derivative, a factor of 20 for 10 to 60 mph. Second, because of the added phase lag of the drive shaft dynamics, the gain margin available is much less than that available in the other modes. The result is that the controller gain that provides adequate power regulation at 20 - 25 mph causes instability at 60 mph. Therefore, the controller gain in this mode is made a function of the mean wind speed such that the total loop gain remains essentially constant.

RESPONSE TO WIND SPEED CHANGES

The ability of a variable-pitch wind turbine to maintain a given power level in the presence of wind speed changes is limited by the capabilities of the pitch change mechanism. Therefore, knowledge of the wind variability that must be accomodated is needed to establish the required capabilities of the pitch change mechanism.

To meet this need, the description of wind variability must relate the magnitude of wind speed changes to the time interval over which they are observed and the frequency with which they can be expected at the planned location of the wind turbine. The magnitude and time interval, with respect to the dynamic characteristics of the wind turbine, determine the impact on the wind turbine. The frequency determines whether or not they need to be accommodated. For example, wind speed changes that cause disruptions in the delivered power less frequently than once per month or once per year need not be accommodated. However, the system must accommodate wind speed changes that could cause damage more frequently than once per lifetime of the machine.

Cliff and Fichtl (Reference 1) have developed a description of wind speed changes based on turbulence theory. It allows the calculation of the root-mean-square (RMS) value of the change in wind speed over a time interval as a function of the mean wind speed, nature of the terrain (surface roughness), height above the surface, and the scale of the affected device. The RMS value and the characteristics of a Normal distribution determine the probability of exceeding a particular magnitude of speed change in any one time interval. The probability and the duration of the observation time interval determine the

number of times the change is exceeded per hour of the mean wind speed. This can be combined with a mean wind speed distribution to determine the number of times the change is exceeded per year.

Figure 8 illustrates one form of the Cliff and Fichtl description using a particular mean wind speed distribution and a 64-foot diameter rotor 75 feet above terrain with a surface roughness of 0.05 meters (high grass). It describes the wind speed changes that occur during the 1.4 hours per year that the mean wind speed is between 50 and 60 miles per hour. It shows, for example, that if observations are made at one-second intervals, twenty changes greater than 12.5 mph will be seen, but changes greater than 18 mph will only be seen once in five years during 50 - 60 mph winds. On the other hand, if the observation interval is increased to 2.5 seconds, changes greater than 18 mph will be seen almost 20 times per year. This provides a satisfactory description of wind speed changes for determining the required capabilities of the pitch change mechanism. The method of using it is described below.

Figure 9 shows what happens to the rotor speed of a wind turbine with feed forward control when the wind speed changes at a rate faster than the pitch mechanism can follow. After a short delay, the pitch changes at its maximum rate. Since that is less than the rate required to compensate for the wind speed change, a torque unbalance develops and the rotor accelerates. Eventually, the proper pitch angle is reached and the rotor returns to the proper speed. The important parameter is the maximum change in rotor speed, $\Delta\Omega$, since this determines the maximum change in the delivered power. (The control system is configured to disconnect the load if some critical value is exceeded.)

Therefore, the dynamics of the wind turbine are analyzed to determine the wind speed changes (magnitude and time interval) that cause a rotor speed change equal to the critical value, Ω_c. This is shown on Figure 10 for two values of mean wind speed and a certain system configuration. The result is dependent on mean wind speed because the pitch change required by the rotor to compensate for a given wind speed change decreases with increasing mean wind speed. For wind speed changes above the curve, the rotor speed change is greater than the critical value. For the stand-alone synchronous generator application, a critical speed change of 10% was used, i.e., a 10% change in frequency and voltage. For the induction generator connected to a utility line, a critical speed change equal to the slip at rated power was used.

The 55 mph system characteristic is superimposed on the wind change characteristics for mean winds between 50 and 60 mph on Figure 11. This shows that the highest incidence of exceeding the critical speed change occurs for the wind speed changes that are observed over intervals of about one second. This occurs a little more than 0.2 times per year during the 1.4 hours per year that the wind is between 50 and 60 mph. If the pitch rate were only 3°/sec, instead of 6°/sec, it would occur much more frequently. The process illustrated on Figure 11 is repeated for each of the wind speed intervals necessary to cover the operating range of the wind turbine. The exceedance rates for each interval are then summed to determine the total number of times per year the critical speed change is exceeded. The result is shown in the top data set of Figure 12. The system parameters under the control of the designer are then adjusted until an acceptable exceedance rate is achieved.

The second and third data sets on Figure 12 illustrate the influence of the system characteristics in determining the critical wind speed characteristics. Although both systems have about the same exceedance rate, the synchronous generator configuration, with its longer time constant (ratio of inertia to damping), reacts with the larger wind speed changes seen with longer observation time intervals. While the induction generator configuration has 97% of its exceedances when the mean wind is between 50 and 60 mph, the comparable figure for the synchronous generator configuration is 81%. The fourth data set on Figure 12 gives the results when the maximum pitch rate is adjusted so that the critical speed is exceeded about 12 times per year for the induction generator configuration with a lag of 0.15 sec.

It should be noted that there is no "worst gust" that would produce the same results, even if the "worst gust" is a function of mean wind speed.

These results are based on a particular wind speed distribution. The distribution was chosen to represent the 95th percentile of the 138 geographical locations tabulated by Frost and Long (Reference 2). That is, the rate of exceeding the critical speed will be greater than that calculated at 5% of the locations and less than that calculated at 95% of the locations. The distribution is described at the 10 meter reference height by Weibull coefficients of 9.8 mph and 1.4.

REFERENCES

1. Cliff, W. C., and Fichtl, G. H., "Wind Velocity Change (Gust Rise) Criteria for Wind Turbine Design," DOE Report PNL-2526, July 1978.

2. Frost, W., and Long, B. H., "Engineering Handbook on the Atmospheric Environmental Guidelines for use in Wind Turbine Generator Development," NASA Report (Contract NAS8-32118), November 1977.

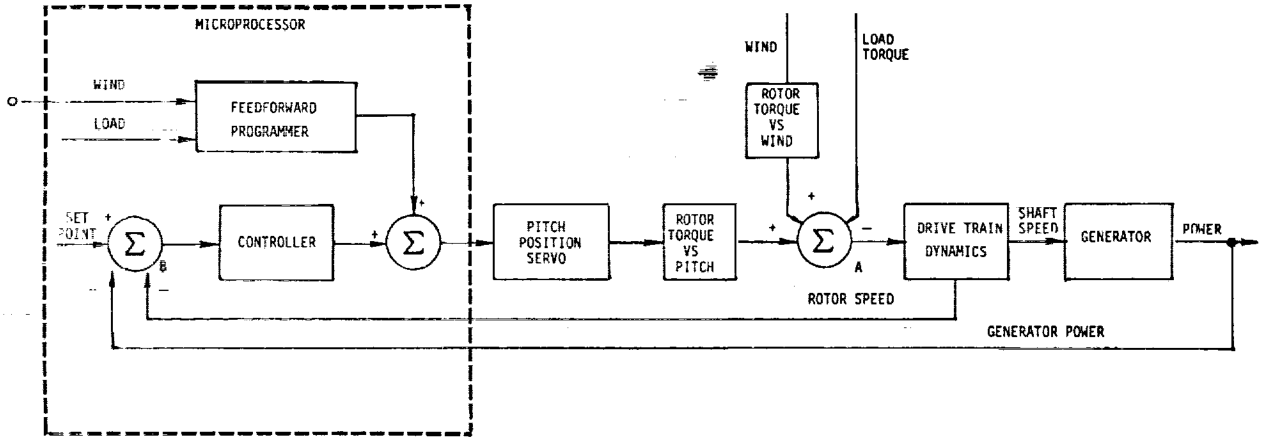
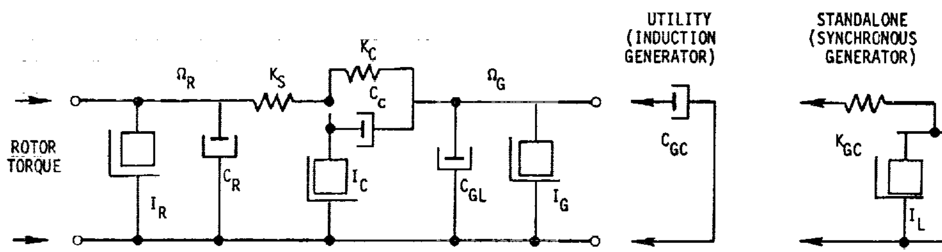


Figure 1 - Basic control loop.



ROTOR:	I_R	6425	ft.lb.sec^2/rad.
	C_R	286	ft.lb.sec/rad.
COUPLING:	K_C	3.5×10^6	ft.lb./rad.
	C_C	15	ft.lb.sec/rad.
	I_C	92	ft.lb.sec^2/rad.

UTILITY:	C_{GL}	26.4	ft.lb.sec/rad
	I_G	189	ft.lb.sec^2/rad.
	C_{GC}	44,000	ft.lb.sec^2/rad.
STANDALONE:	C_{GL}	26.4	ft.lb.sec/rad.
	I_G	280	ft.lb.sec^2/rad.
	K_{GC}	$.8\times10^6$	ft.lb./rad.
	C_L	1364	ft.lb./rad.
	I_L	189	ft.lb.sec^2/rad.

Figure 2 - Drive train elements.

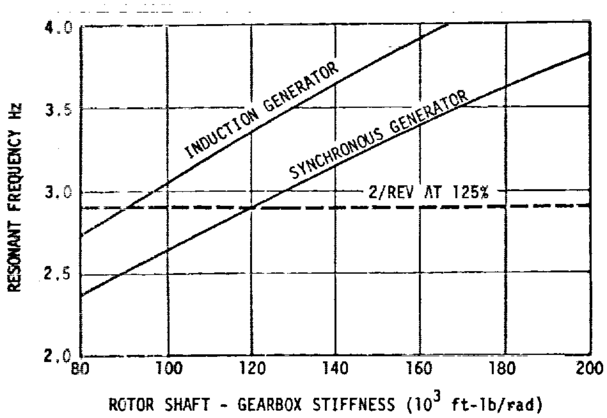


Figure 3 - No load resonant frequency.

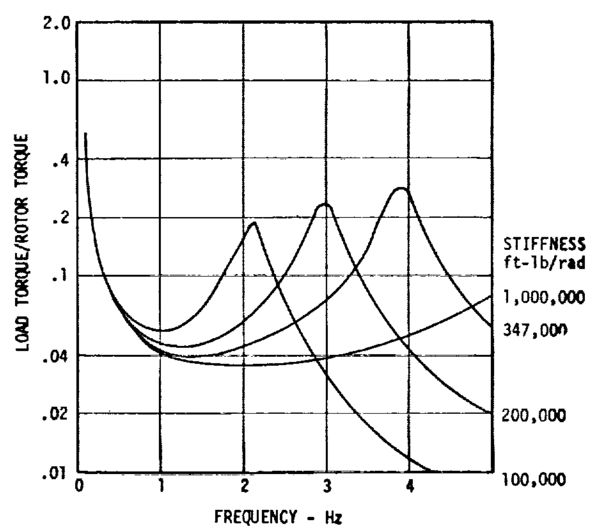


Figure 4 - Standalone configuration.

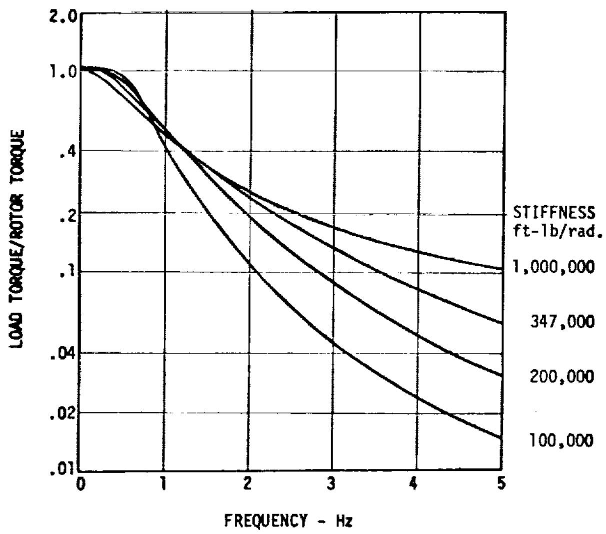


Figure 5 - Utility configuration.

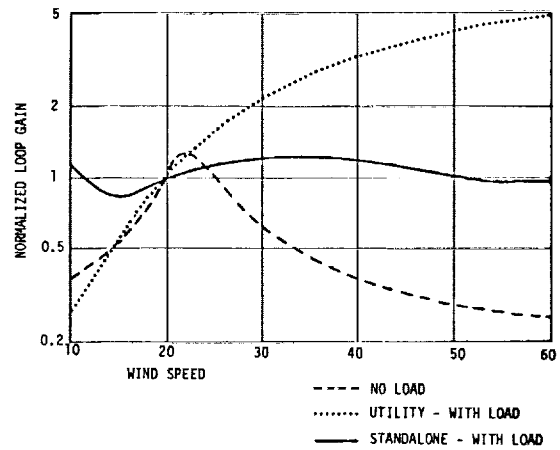


Figure 7 - Loop gain functions.

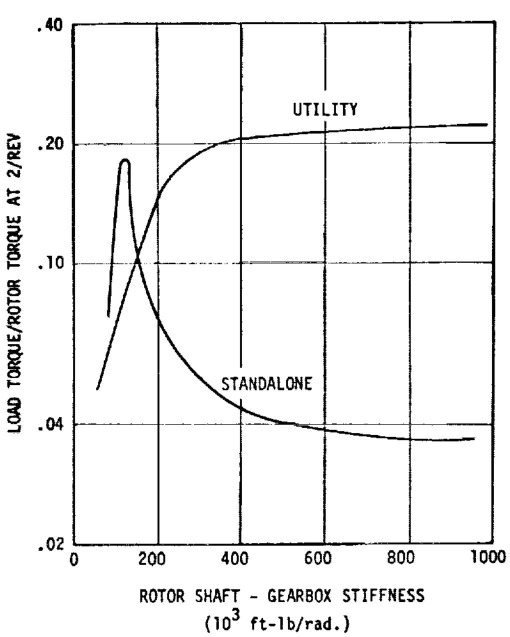


Figure 6 - Torque transmissivity.

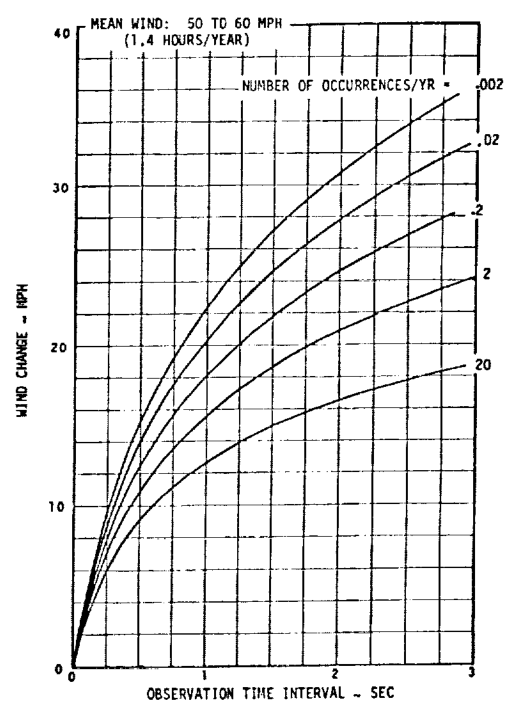


Figure 8 - Wind change characteristics.

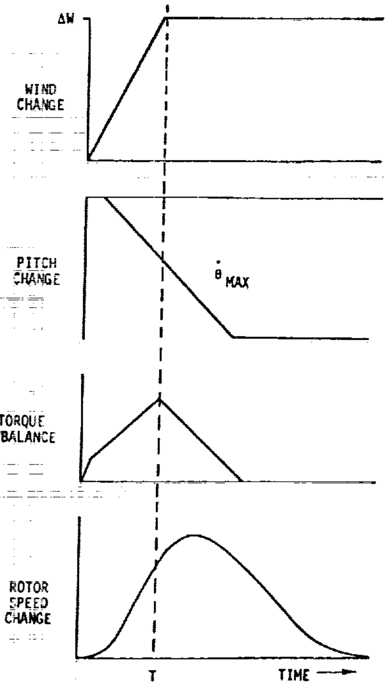


Figure 9 - Response to wind change.

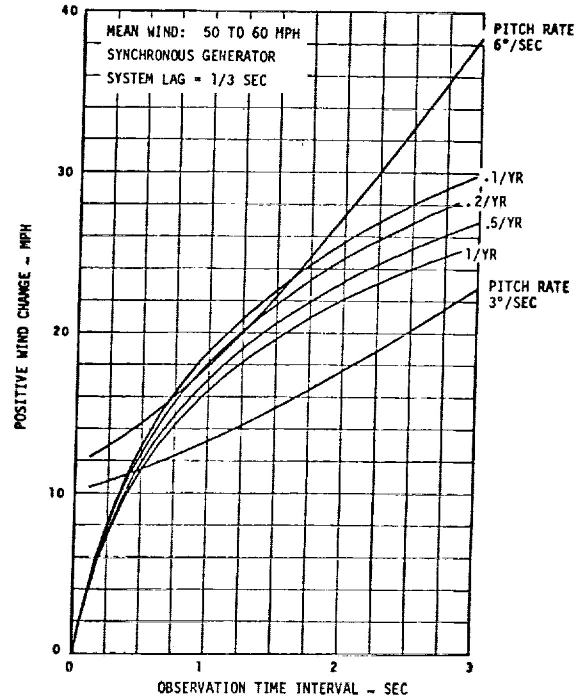


Figure 11 - Critical wind change.

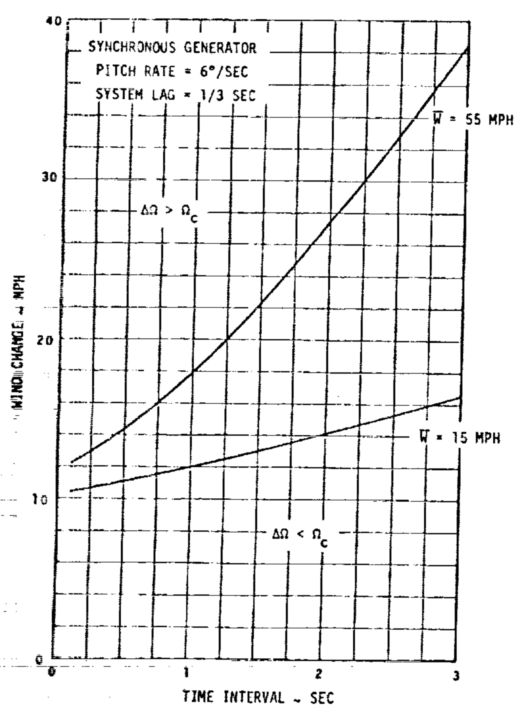


Figure 10 - System characteristics.

CENTER OF WIND SPEED INTERVAL (MPH)	SYSTEM TIME CONSTANT (SEC)	WIND CHANGE TIME INTERVAL (SEC)	WIND CHANGE MAGNITUDE (MPH)		NUMBER OF OCCURRENCES PER YEAR
SYNCHRONOUS GENERATOR:	Rate 6°/sec, Lag .33 sec				
15	5.06	---	---		0
25	4.65	2.3	16.3		.000
35	2.53	1.6	18.6		.000
45	1.55	1.2	18.5		.018
55	1.07	1.0	18.3		.256
				TOTAL	.274
SYNCHRONOUS GENERATOR:	Rate 4.2°/sec, Lag .15 sec				
15	5.06	4.3	16.3		.000
25	4.65	2.7	15.1		.000
35	2.53	1.9	18.3		.000
45	1.55	1.6	18.8		.174
55	1.07	1.3	18.9		.766
				TOTAL	.941
INDUCTION GENERATOR:	Rate 6°/sec, Lag .15 sec				
15	.35	---	---		0
25	.33	2.1	18.3		.000
35	.31	1.2	17.4		.000
45	.29	.9	15.5		.027
55	.27	.7	14.0		.971
				TOTAL	.998
INDUCTION GENERATOR:	Rate 4.2°/sec, Lag .15 sec				
15	.35	---	---		0
25	.33	2.5	16.8		.000
35	.31	1.5	16.0		.002
45	.29	1.1	14.1		1.600
55	.27	.8	12.8		9.191
				TOTAL	10.793

Figure 12 - Rate of exceeding critical speed change.

QUESTIONS AND ANSWERS

R. Perley

From: R.A. Edkin

Q: Why does an induction machine with only 1% slip exhibit a high damping characteristic?

A: *The damping term is inversely proportional to the slip at rated torque. The damping term is the ratio of a torque to the speed change necessary to produce that torque.*