Grid Operation and Coordination with Wind - 2

1.0 Introduction

In this set of notes, we will study the need for regulation. We have stated in previous notes that regulation occurs in the time frame of about 1 minute. Figure 1 [1] illustrates the time frame relative to the initial transient period (studied in previous notes) and the later load following and scheduling time periods. This very good picture provides a view on:

- Relation between inertial response (kinetic energy), primary reserves, and secondary reserves, and
- Effect of load frequency sensitivity

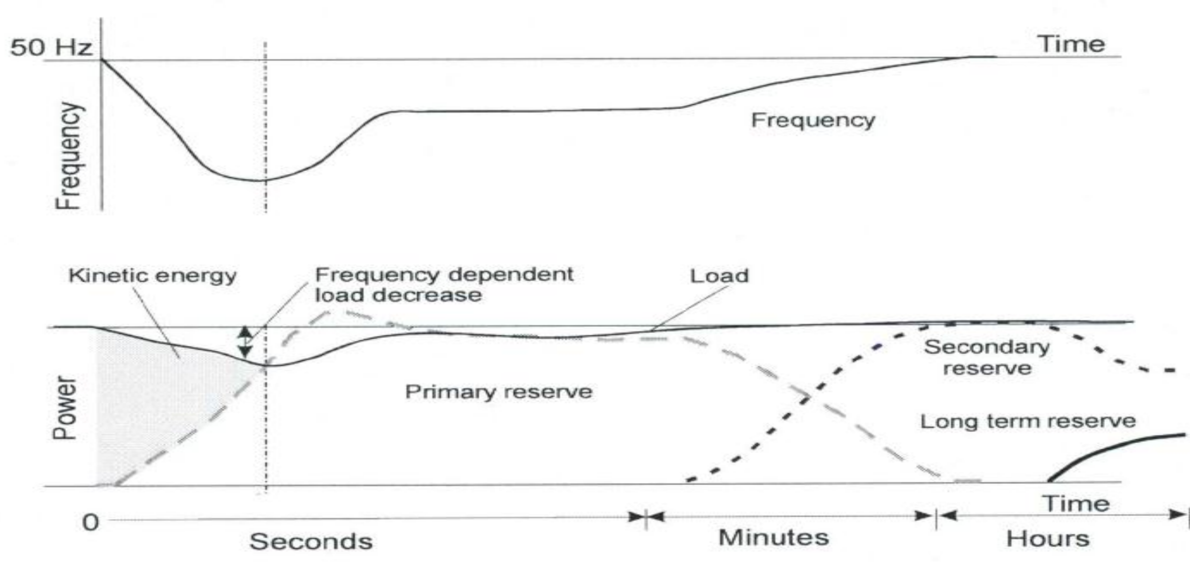


Fig. 1 [1]

Given our interest in these notes is on regulation, we will focus on primary frequency control. Figure 1 uses the term “primary reserves” to capture the power operations requirement that there must be generation interconnected at any given moment having spinning reserve (difference between capacity and existing generation level) sufficient to compensate for credible events which cause load-generation imbalance.

The North American Electric Reliability Corporation (NERC) states in [2],

> “As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.”

We will see most existing wind turbines today do not have control capability necessary to provide regulation. But perhaps even more significant is the variability associated with wind, i.e., wind not only does not help regulate, it contributes to a need for more regulation.

2.0 Variability of wind power

There are two important ways to understand the variability in wind power: temporally and spatially.

2.1 Temporal variability

Clearly wind speed varies with time, so that the wind speed for turbine k at time t_1, $v_k(t_1)$, will generally differ from the wind speed for turbine k at time t_2, $v_k(t_2)$, where $t_2>t_1$. For fixed speed machines, because the mechanical power into a turbine depends on the wind speed, and because electric power out of the wind generator depends on the mechanical power in to the turbine, variations in wind speed from t_1 to t_2 cause variations in electric power out of the wind generator.

Double-fed induction generators (DFIGs) also produce power that varies with wind speed, although the torque-speed controller provides that this variability is less volatile than fixed-speed machines.

For a single turbine, this variability depends on three features: (1) time interval; (2) location; (3) terrain.

2.1.1 Time interval

Variability in wind plant output tends to increase with time interval, that is, 12 hour variation tends to be larger than 4 hour, which tends to be larger than 1 hour, etc. Table 1 [3] illustrates this tendency for a number of regions around the world by showing maximum increase and decrease for 10-15 minute intervals, 1 hour intervals, 4 hour intervals, and 12 hour intervals.

Table 1 [3]

			10–15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Number of sites	max decrease	max increase	max decrease	max increase	max decrease	max increase	max decrease	max increase
Denmark	300x300 km^2	>100			-23%	+20%	-62%	+53%	-74%	+79%
-West Denmark	200x200 km^2	>100			-26%	+20%	-70%	+57%	-74%	+84%
-East Denmark	200x200 km^2	>100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km^2				-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km^2	>100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km^2	30			-15%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km^2	56			-17%	+19%	-40%	+40%		
US Midwest	200x200 km^2	3	-34%	+30%	-39%	+35%	-58%	+60%	-78%	+81%
US Texas	490x490 km^2	3	-39%	+39%	-38%	+36%	-59%	+55%	-74%	+76%
US Midwest+OK	1200x1200km^2	4	-26%	+27%	-31%	+28%	-48%	+52%	-73%	+75%

Figure 2a [3] illustrates this tendency for the Midwestern US via distributions for 1-hour, 4-hour, and 12-hour intervals.

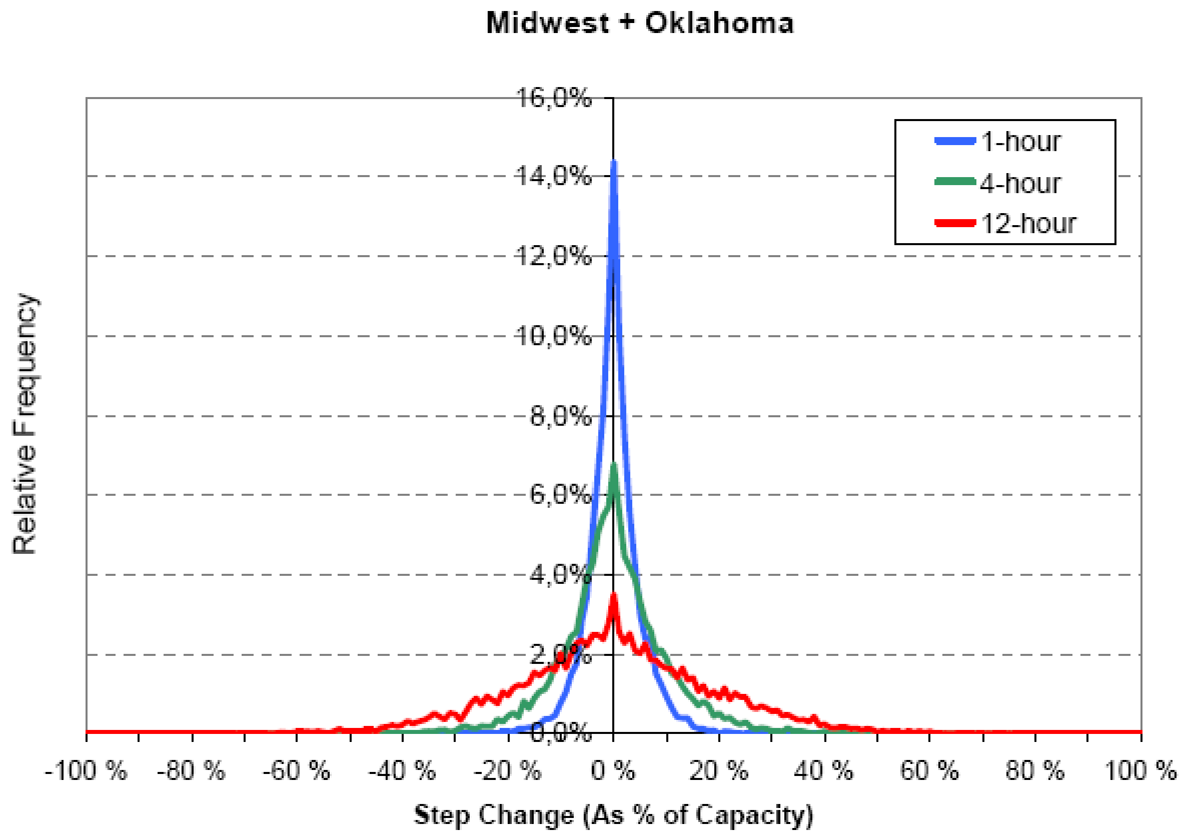


Fig. 2a [3]

A plot similar to Fig. 2a is shown in Fig. 2b, except this data is from Germany [3].

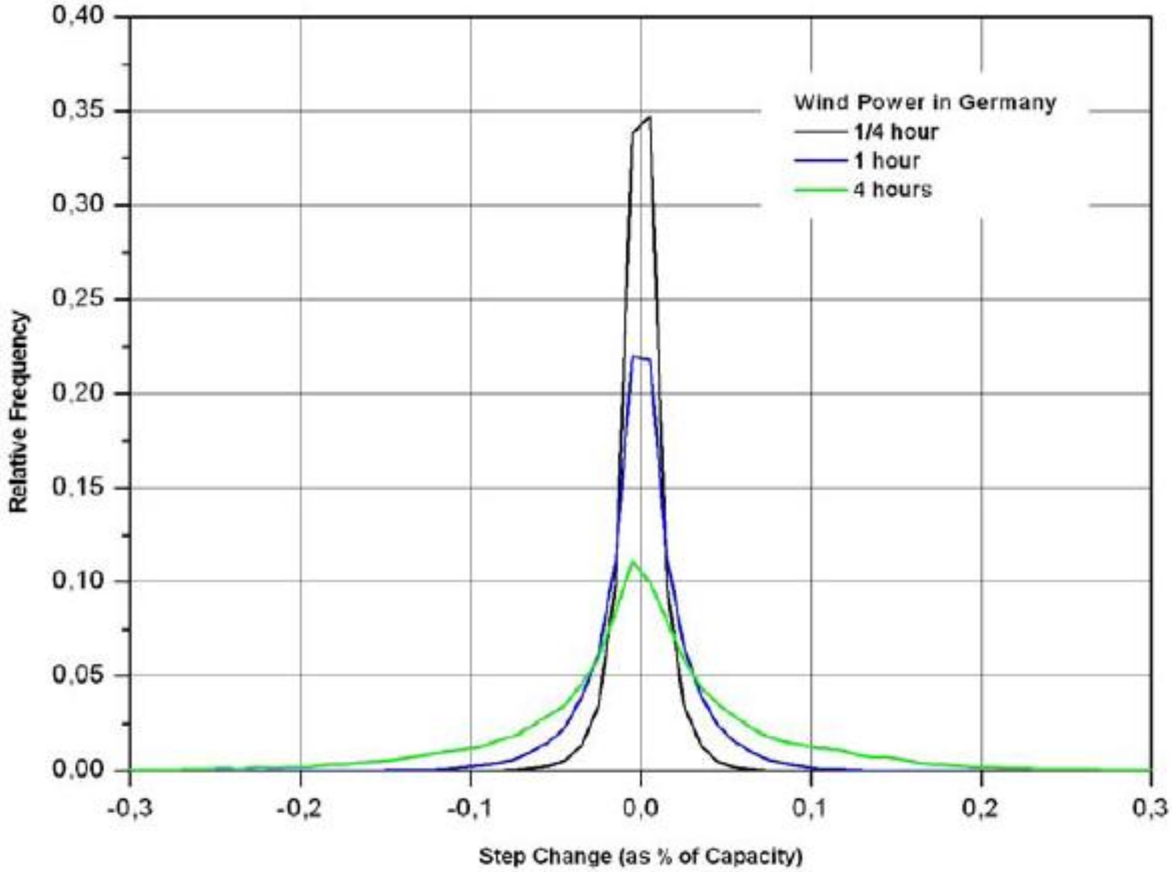


Fig. 2b [3]

Perhaps the most severe kind of variation occurs during extreme weather events where turbines can be shut down to avoid rotor overspeed in high wind conditions. A wind farm can go from near-full output to near-zero output when a severe storm passes through the area. Examples of such occurrences are described below [3]:

o Denmark: 2000 MW (83% of capacity) decrease in 6 hours or 12 MW (0.5% of capacity) in a minute on 8th January, 2005.

o North Germany: over 4000 MW (58% of capacity) decrease within 10 hours, extreme negative ramp rate of 16 MW/min (0.2% of capacity) on 24th December, 2004

o Ireland: 63 MW in 15 mins (approx 12% of capacity at the time), 144 MW in 1 hour (approx 29% of capacity) and 338 MW in 12 hours (approx 68% of capacity)

o Portugal: 700 MW (60% of capacity) decrease in 8 hours on 1st June, 2006

o Spain: Large ramp rates recorded for about 11 GW of wind power: 800 MW (7%) increase in 45 minutes (ramp rate of 1067 MW/h, 9% of capacity), and 1000 MW (9%) decrease in 1 hour and 45 minutes (ramp rate -570 MW/h, 5% of capacity). Generated wind power between 25 MW and 8375 MW have occurred (0.2%-72% of capacity).

o Texas, US: loss of 1550 MW of wind capacity at the rate of approximately 600 MW/hr over a 2½ hour period on February 24, 2007.

2.1.2 Location and terrain

There are two major attributes to wind power variability: location (latitude of the site on the globe) and terrain. Reference [4] says the following:

> "In medium continental latitudes, the wind fluctuates greatly as the low-pressure regions move through. In these regions, the mean wind speed is higher in winter than in the summer months. The proximity of water and of land areas also has a considerable influence. For example, higher wind speeds can occur in summer in mountain passes or in river valleys close to the coast because the cool sea air flows into the warmer land regions due to thermal effects. A particularly spectacular example are the regions of the passes in the coastal mountains in California through to the lower lying desert-like hot land areas in California and Arizona."

2.2 Spatial variability

Reference [3] provides 24 hour plots of normalized power output from (a) a single turbine in the region; (b) a group of turbines in the same wind plant within the region; and (c) all turbines in the region (in this case, the "region" was the country of Germany). Figure 3 illustrates, where one observes that the variability of the single turbine, as a percentage of capacity, is significantly greater than the variability of the wind plant, which is in turn significantly greater than the variability of the region.

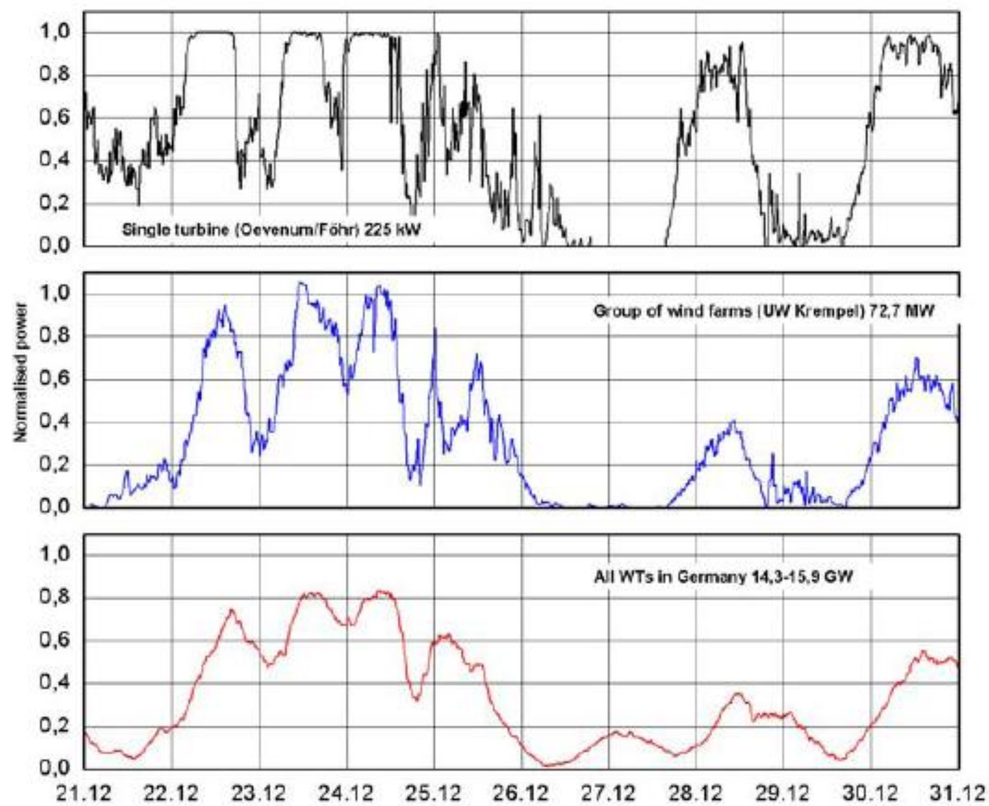


Fig. 3 [3]

We refer to this effect as "geographical smoothing" where the variability of a larger region, as a percentage of the capacity, is typically less than that of smaller portion of the same region. Table 2 [3] provides another view of this effect.

Table 2 [3]

		14 turbines		61 turbines		138 turbines		250+ turbines	
		(kW)	(%)	(kW)	(%)	(kW)	(%)	(kW)	(%)
1-second	Average	41	0,4	172	0,2	148	0,1	189	0,1
1-second	Std	56	0,5	203	0,3	203	0,2	257	0,1
1-minute	Average	130	1,2	612	0,8	494	0,5	730	0,3
1-minute	Std	225	2,1	1 038	1,3	849	0,8	1 486	0,6
10-minute	Average	329	3,1	1 658	2,1	2 243	2,2	3 713	1,5
10-minute	Std	548	5,2	2 750	3,5	3 810	3,7	6 418	2,7
1-hour	Average	736	7,0	3 732	4,7	6 582	6,4	12 755	5,3
1-hour	Std	1 124	10,7	5 932	7,5	10 032	9,7	19 213	7,9

This tendency may also be observed via Fig. 4 below [1]. This is a *duration curve*, which provides the number of hours on the horizontal axis for which the wind power production exceeds the percent capacity on the vertical axis. Observations regarding this curve follow:

- The single turbine reaches or exceeds 100% of its capacity for perhaps 100 hours per year, the area called “Denmark West” has a maximum power production of only about 90% throughout the year, and the overall Nordic system has maximum power production of only about 80%.
- At the other extreme, the single turbine output exceeds 0 for about 7200 hours per year, leaving 8760-

7200=1560 hours it is at 0. The area wind output rarely goes to 0, and the system wind output never does.

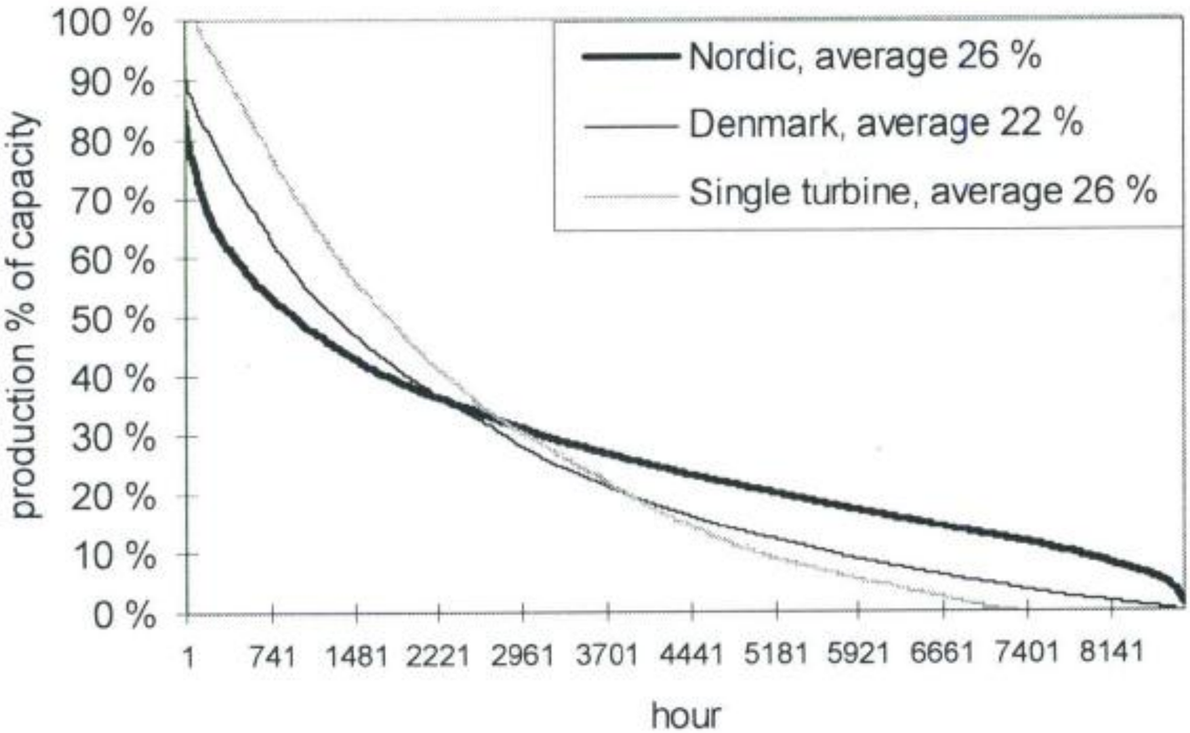


Fig. 4

Another interesting way to look at wind production variability combines both temporal and spatial effects. To understand this approach, we define the correlation coefficient for two time series x and y as

$$r_{xy} = \frac{\sum_{i=1}^{N} (x_i - \mu_x)(y_i - \mu_y)}{N\sqrt{\sum_{i=1}^{N} (x_i - \mu_x)^2}\sqrt{\sum_{i=1}^{N} (y_i - \mu_y)^2}} = \frac{\sum_{i=1}^{N} (x_i - \mu_x)(y_i - \mu_y)}{N\sigma_x\sigma_y} \qquad (1)$$

where N is the number of points in the time series, and μ_x, μ_y and σ_x, σ_y are the means and standard deviations, respectively, of the two time series. The correlation coefficient indicates how well two time series, x and y in this case, follow each other. It will be near 1.0 if the two time series follow each other very well, it will be 0 if they do not follow each other at all, and it will be near -1 if increases in one occur with decreases in another.

Consider taking minute-by-minute measurements for wind turbine power production at a large number of locations within a 600 km radius. There will be many different distances between each location. We assume that we have such measurements over an extended period of time, say 3 years.

We then compute sequential (consecutive) averages of time intervals T for each location. Then compute a T-interval average at t=0, t=T, t=2T, t=3T,…. For example, we may choose T=5 minutes, so we obtain, at each location x1, x2, x3,… a time series of sequential 5 minute averages. We can then compute the correlation coefficient between time series at each pair of locations.

The computed correlation coefficient can then be plotted against the distance between each pair of locations.

This can be done for various values of T, e.g., T=5 min intervals, T=30 min intervals, T=1 hr intervals, and so on.

Fig. 5 [5] illustrates the resulting plot where it is clear that for 5 minute intervals, there is almost no correlation for locations separated by more than about 20 km. This is because wind gusts tend to occur for only a relatively small region. This suggests that that even small regions will experience geographical smoothing at 5 min intervals.

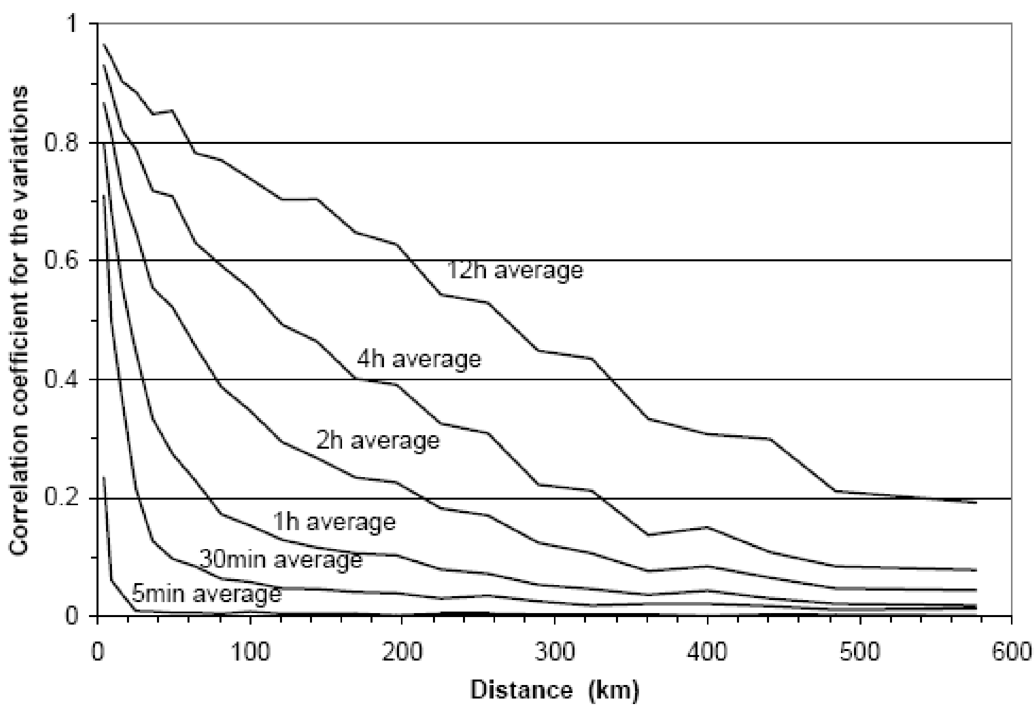


Fig. 5

At the other extreme, for 12 hour intervals, Fig. 5 indicates that wind power production is correlated even for very large regions, since these averages are closely linked to overall weather patterns that can be similar for very large regions.

Figure 6 [6] shows another way to view smoothing, where clearly the variability of the 1 farm, given as a percentage of its capacity, is significantly greater than that of the entire region of Western Denmark.

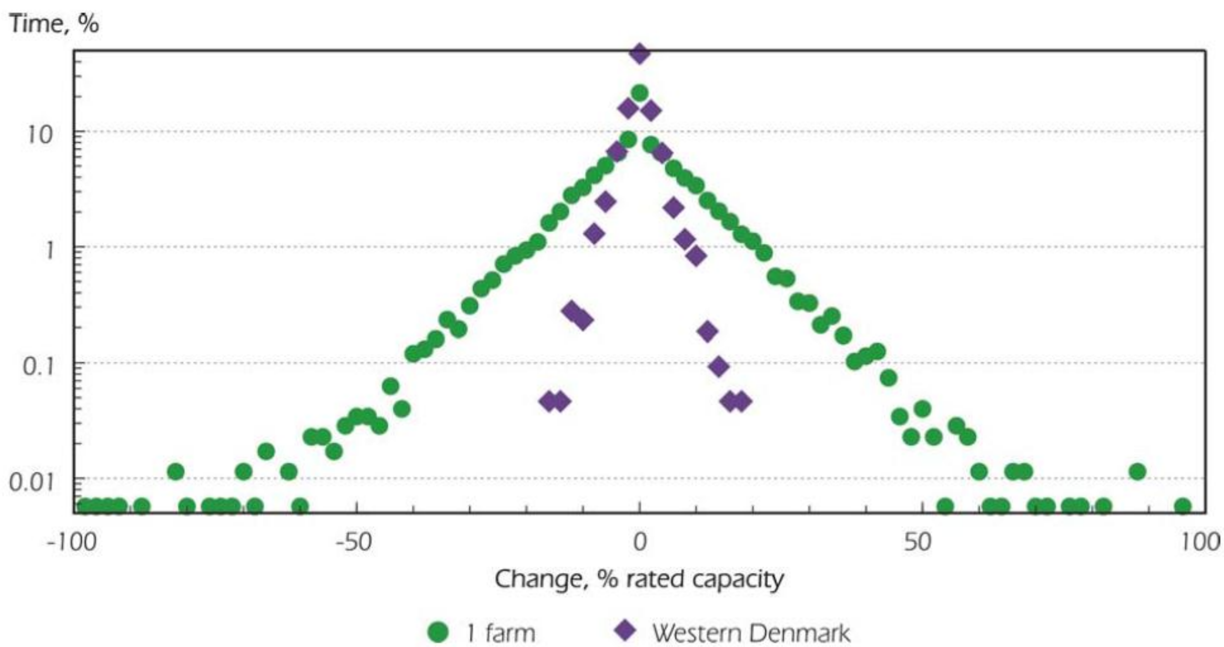


Fig. 6 [6]

Figure 7 [3] is similar to Fig. 6 except it is for Germany.

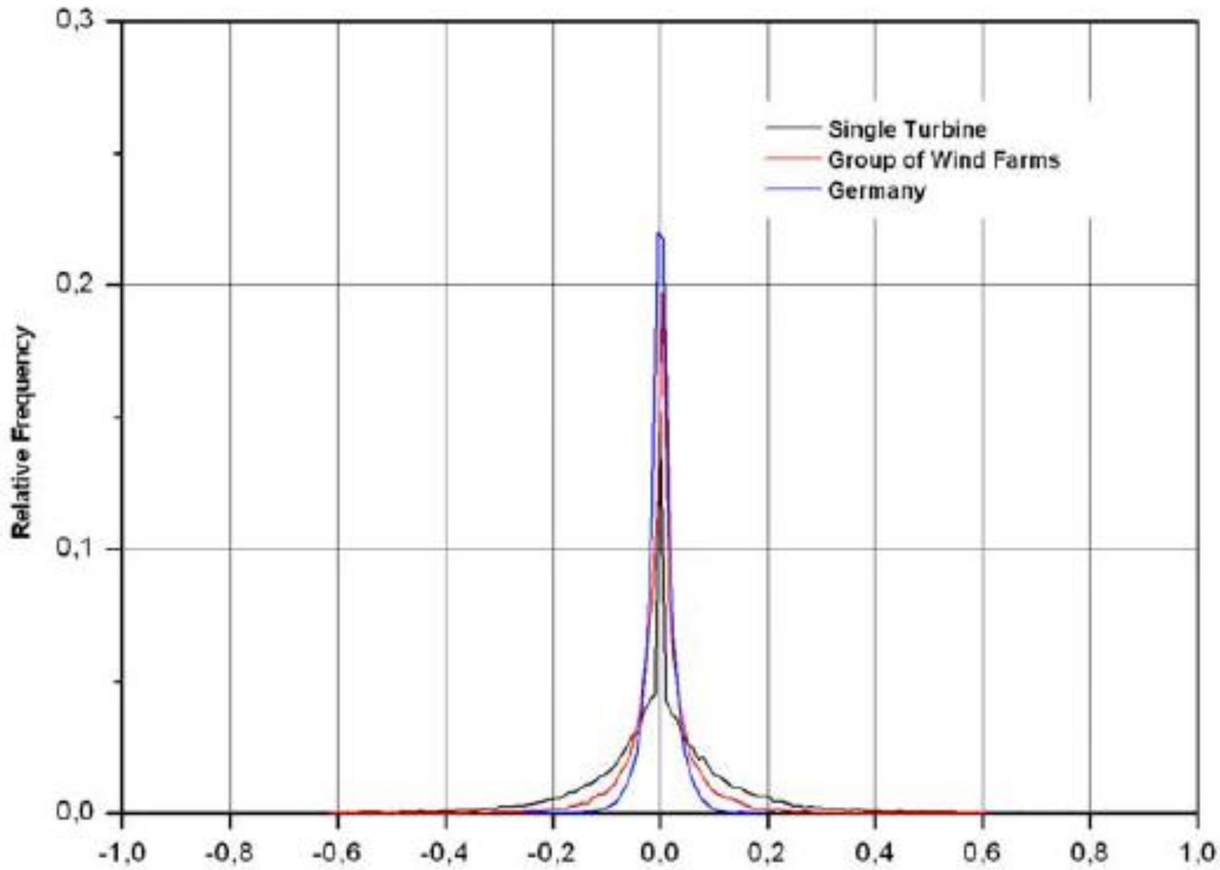


Fig. 7 [3]

If data used to develop Figs. 6 and 7 is captured for a large number of wind farms and regions, the standard deviation may be computed for each farm or region. This standard deviation may then be plotted against the approximate diameter of the farm's or region's geographical area. Figure 8 [3] shows such a plot, where the variations were taken hourly.

It is clear that hourly variation (normalized by capacity), as measured by standard deviation, decreases with the wind farm's or region's diameter.

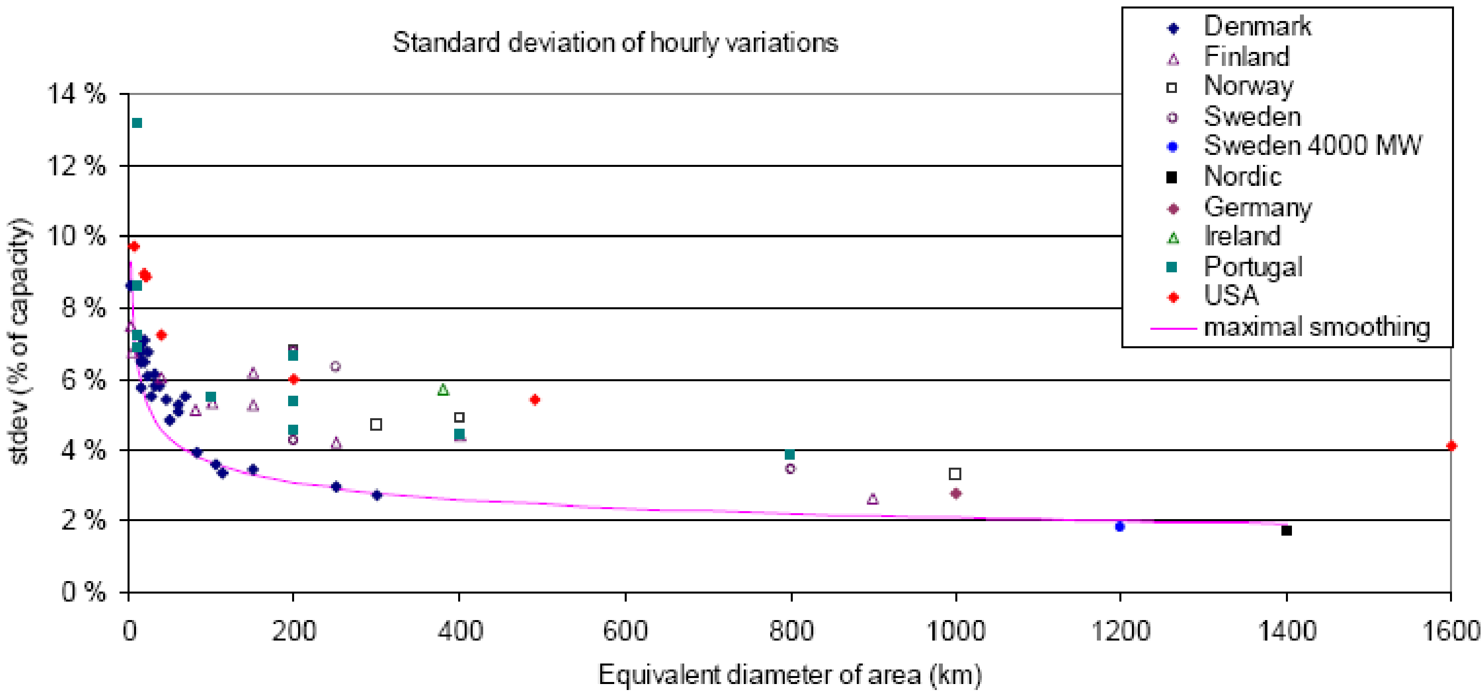


Fig. 8 [3]

Reference [5] makes the following comment about geographical smoothing:

> "How large is the smoothing effect? It becomes more noticeable if there is a large number of turbines spread over a larger area. The smoothing effect of a specified area has an upper limit. There will be a saturation in the amount of variation; that

is, where an increase in the number of turbines will not decrease the (relative) variations in the total wind power production of the area. Beyond that point, the smoothing effect can be increased only if the area covered becomes larger. And there is a limit to that effect, too. The examples we use are from comparatively uniform areas. If wind power production is spread over areas with different weather patterns (coasts, mountains and desert), the smoothing effect will probably be stronger."

3.0 Variability of net demand

The load varies from minute to minute and from hour to hour. A control area's portfolio of conventional generation is designed to meet that load variability. This is done by ensuring there are enough generators that are on governor control, and that there are enough generators having ramp rates sufficient to meet the largest likely load ramp. Typical ramp rates for different kinds of units are listed below (given as a percentage of capacity):

- ➔ Diesel engines 40 %/min
- ➔ Industrial GT 20 %/min
- ➔ GT Combined Cycle 5 -10 %/min
- ➔ Steam turbine plants 1- 5 %/min
- ➔ Nuclear plants 1- 5 %/min

For example, one utility states that in their generation portfolio [7],

> "Coal units typically have ramp rates that are in the range of 1% to 1.5% of their nameplate rating per minute between minimum load and maximum load set points. Coal unit minimum load set-points range from 20% to 50% of nameplate, depending on the design of the air quality control system being used. For example, a 500 MW coal plant may have a minimum load of 100 MW and would be able to ramp up at the rate of 5 MW per minute. In addition, it can take a day or more to bring a coal plant up to full load from a cold start condition. Natural gas-fired combustion turbines, on the other hand, can normally be at full load from a cold start in 10 to 30 minutes (which results in an effective ramp rate of 3.3% to 10% of their nameplate rating per minute)."

Without wind generation, one selects a generation portfolio to satisfy load variability. Figs. 9-11 show 1 hr, 10 min, 1 min load variability for a particular control area.

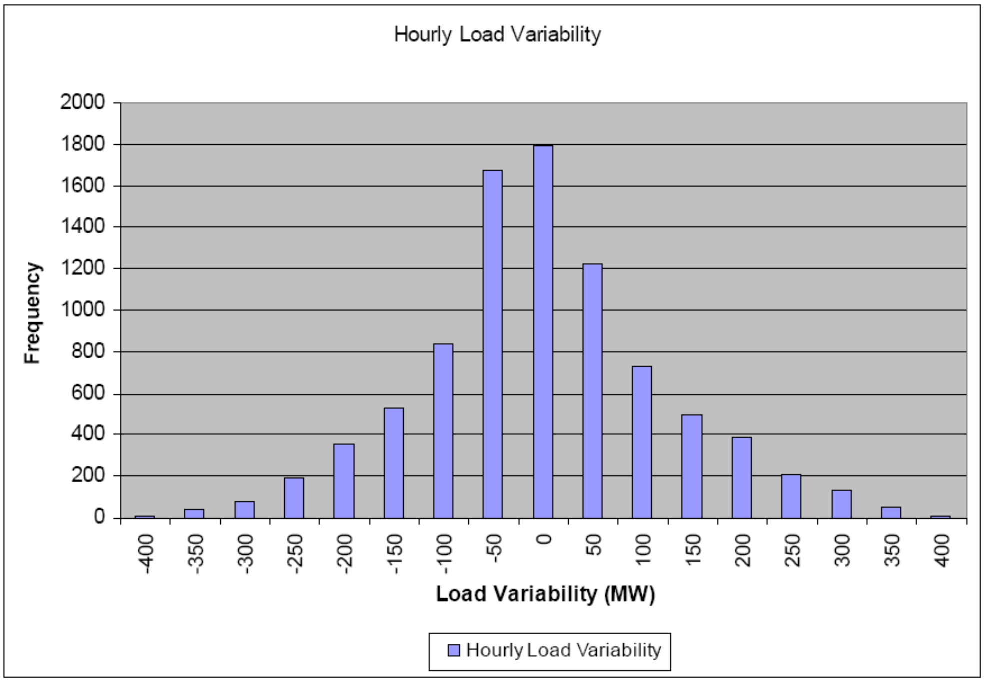

Hourly Load Variability
Frequency
2000
1800
1600
1400
1200
1000
800
600
400
200
0
-400
-350
-300
-250
-200
-150
-100
-50
0
50
100
150
200
250
300
350
400
Load Variability (MW)
Hourly Load Variability

Fig. 9

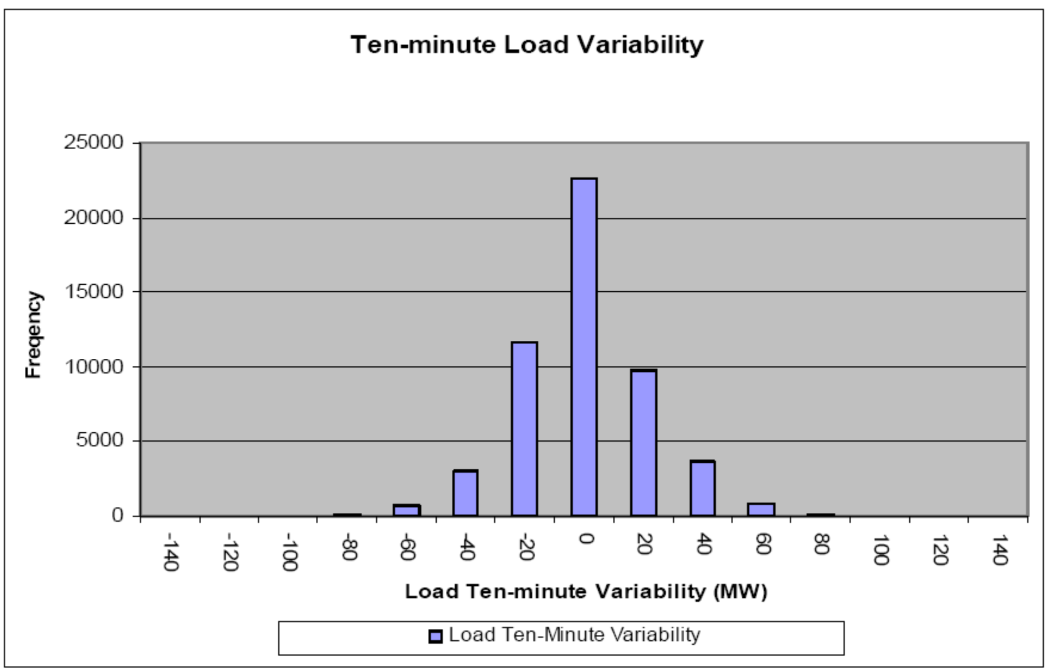

Ten-minute Load Variability
Freqency
25000
20000
15000
10000
5000
0
-140
-120
-100
-80
-60
-40
-20
0
20
40
60
80
100
120
140
Load Ten-minute Variability (MW)
Load Ten-Minute Variability

Fig. 10

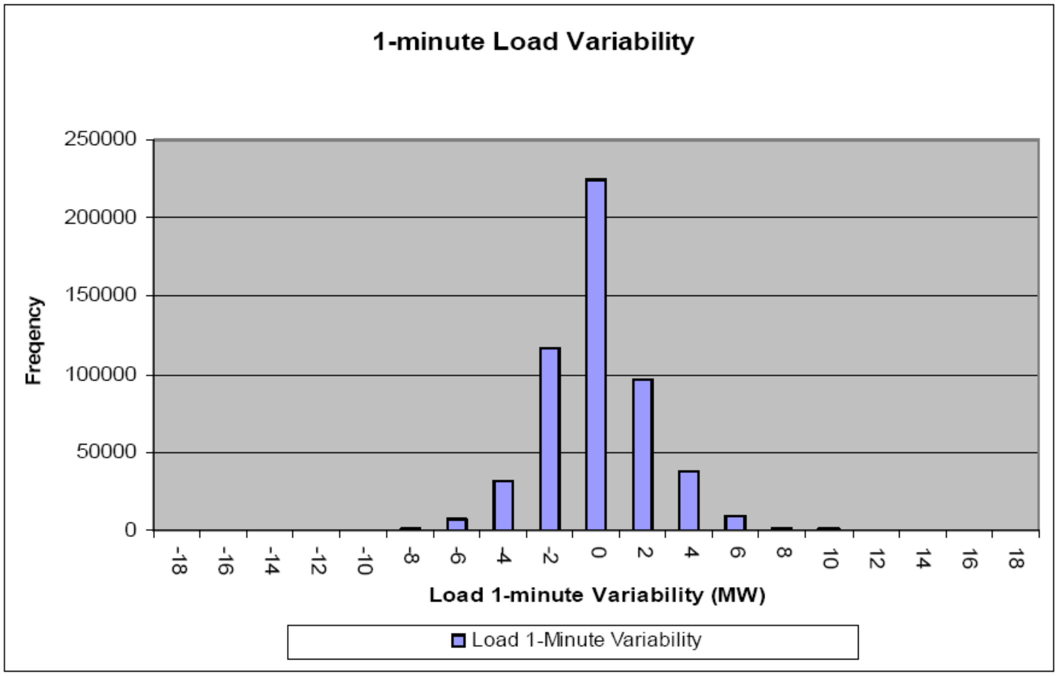


Fig. 11

These plots show that the particular control area responsible for balancing this load must have capability to ramp 400 MW in one hour (6.7 MW/min), 80 MW in 10 minutes (8 MW/min), and 10 MW in one minute (10 MW/min) in order to meet all MW variations seen in the system. This shows that different time frames need to be considered when assessing ramping needs (longer time frames heavily influence ramping capacity whereas shorter time frames influence ramping rates for a portion of the ramping capacity). One would make a serious error for this system if all 400 MW of ramping capacity had only 6.7 MW/min ramp rate!

The question arises: what happens to these requirements if wind is added to the generation portfolio? Figures 12-14 show variability of a certain amount of wind generation in this control area.

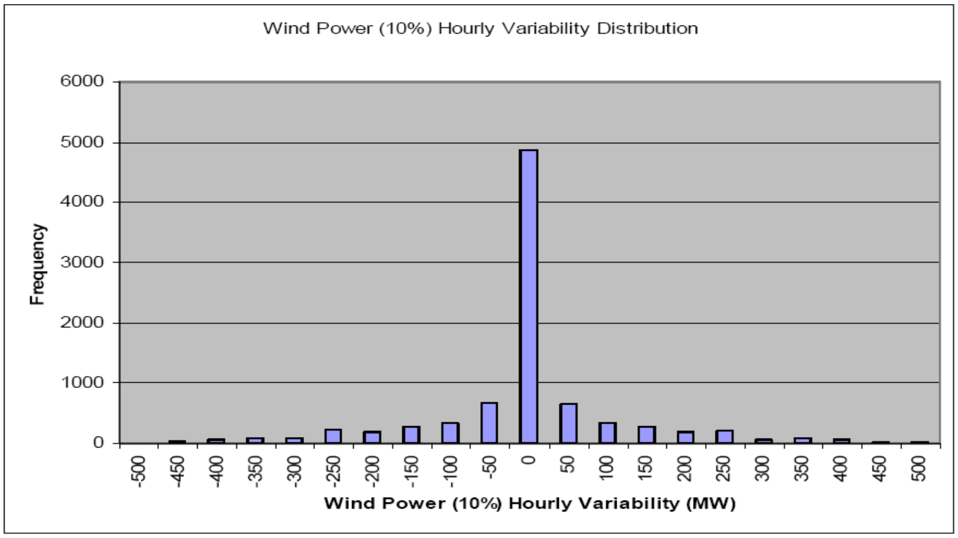


Fig. 12

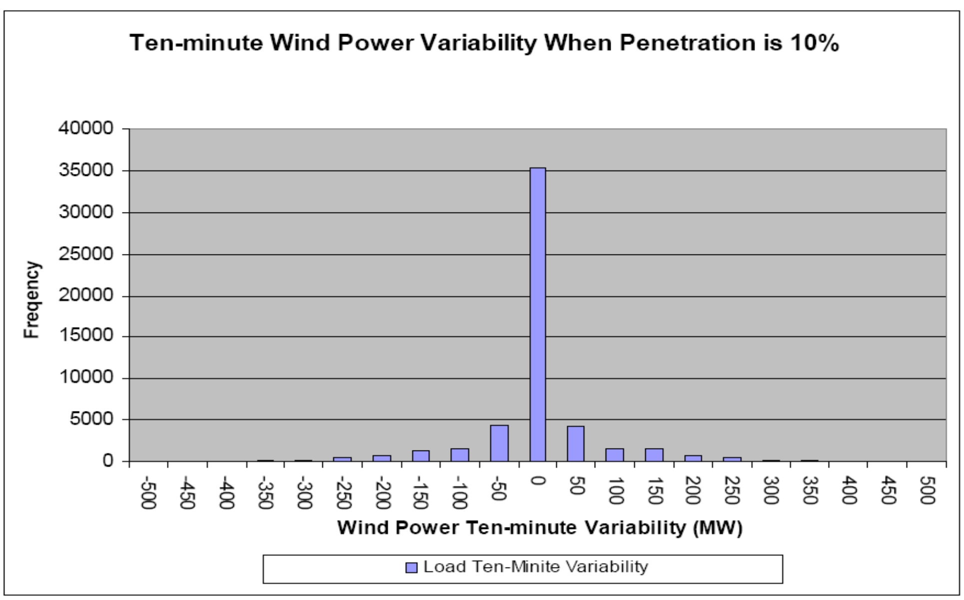


Fig. 13

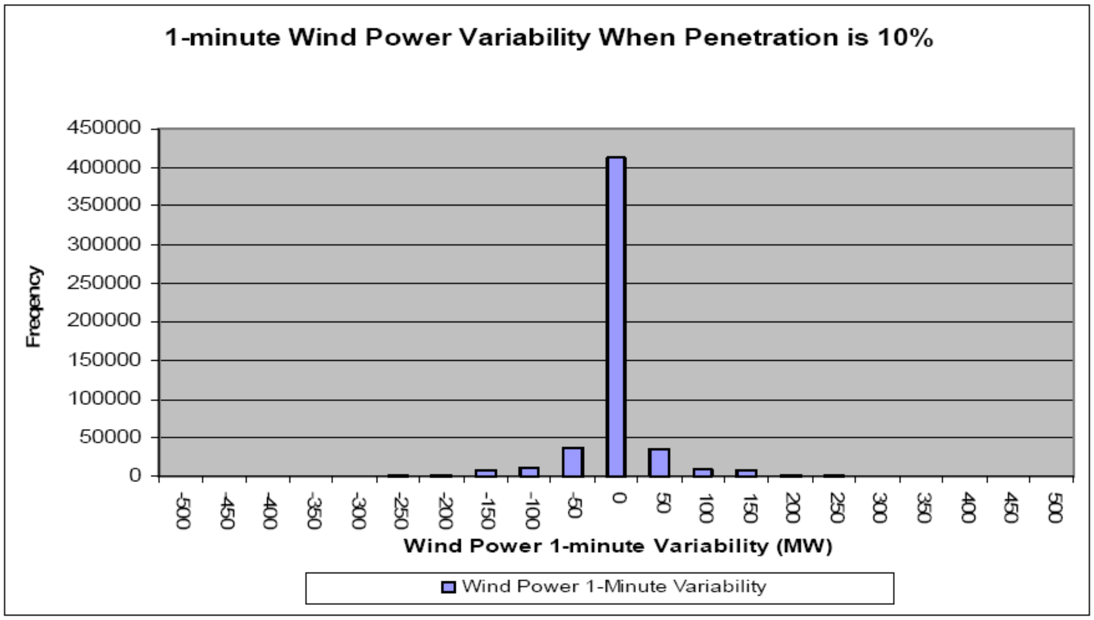


Fig. 14

To gain some insight, note that what we are asking is the following question:

Given two random variables x (load) and y (wind power) for which we know the distributions $f_x(x)$ and $f_Y(y)$, respectively, how do we obtain the distribution of the net-load random variable z=x-y, $f_z(z)$?

Answer: If these random variables are *independent*, then for the means, $\mu_z=\mu_x-\mu_y$, and for the variances, $\sigma_z^2=\sigma_x^2+\sigma_y^2$.

The impact on the means is of little interest since the variability means, for both load and wind, will be ~0.

On the other hand, the impact on the variance is of great interest, since it implies the distribution of the difference will always be wider than either individual distribution. Therefore we expect that when wind generation is added to a system, the maximum MW variation seen in the control area will increase.

We can manually create the distribution for net-load as follows. For each time interval, subtract the wind power from the load to yield the net-load. Then compute variability from each interval to the next. Application of this approach results in the distributions of net-load for 1 hour, 10 minute, and 1 minute intervals, as shown in Figs. 15, 16, and 17.

For ease of comparison, Figs. 15, 16, and 17 also show the distribution of only load.

Table 3 summarizes for each interval the standard deviation, σ, and the maximum variation, corresponding to load only and net-load.

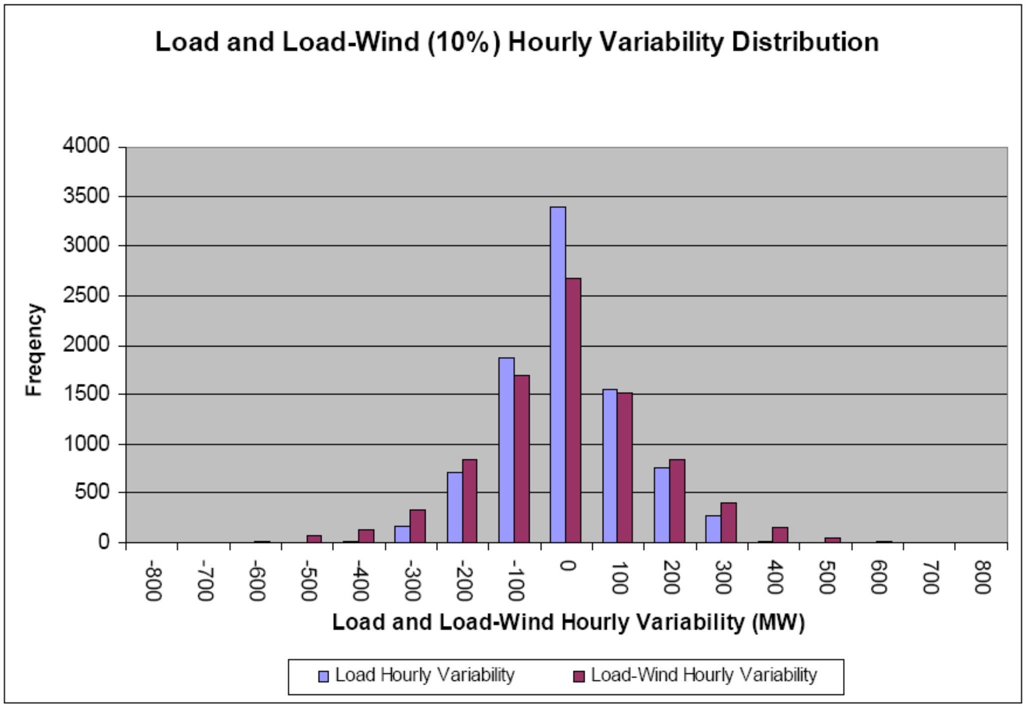

Load and Load-Wind (10%) Hourly Variability Distribution
Freqency
4000
3500
3000
2500
2000
1500
1000
500
0
-800
-700
-600
-500
-400
-300
-200
-100
0
100
200
300
400
500
600
700
800
Load and Load-Wind Hourly Variability (MW)
Load Hourly Variability
Load-Wind Hourly Variability

Fig. 15

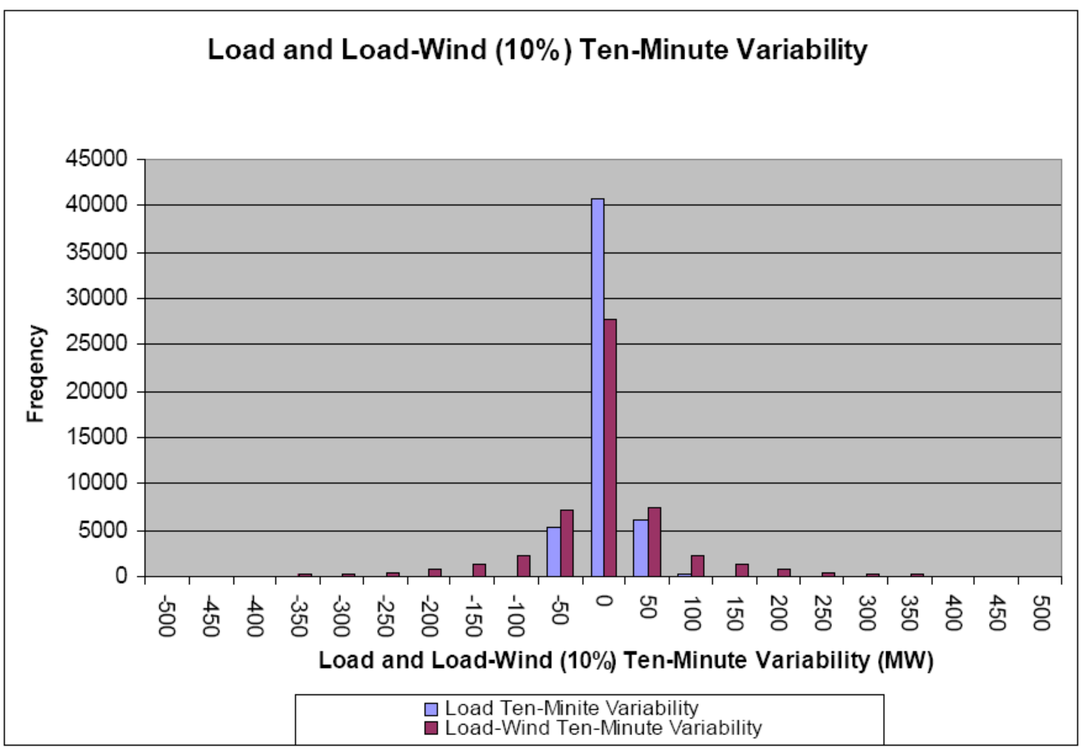

Load and Load-Wind (10%) Ten-Minute Variability
Freqency
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
-500
-450
-400
-350
-300
-250
-200
-150
-100
-50
0
50
100
150
200
250
300
350
400
450
500
Load and Load-Wind (10%) Ten-Minute Variability (MW)
Load Ten-Minite Variability
Load-Wind Ten-Minute Variability

Fig. 16

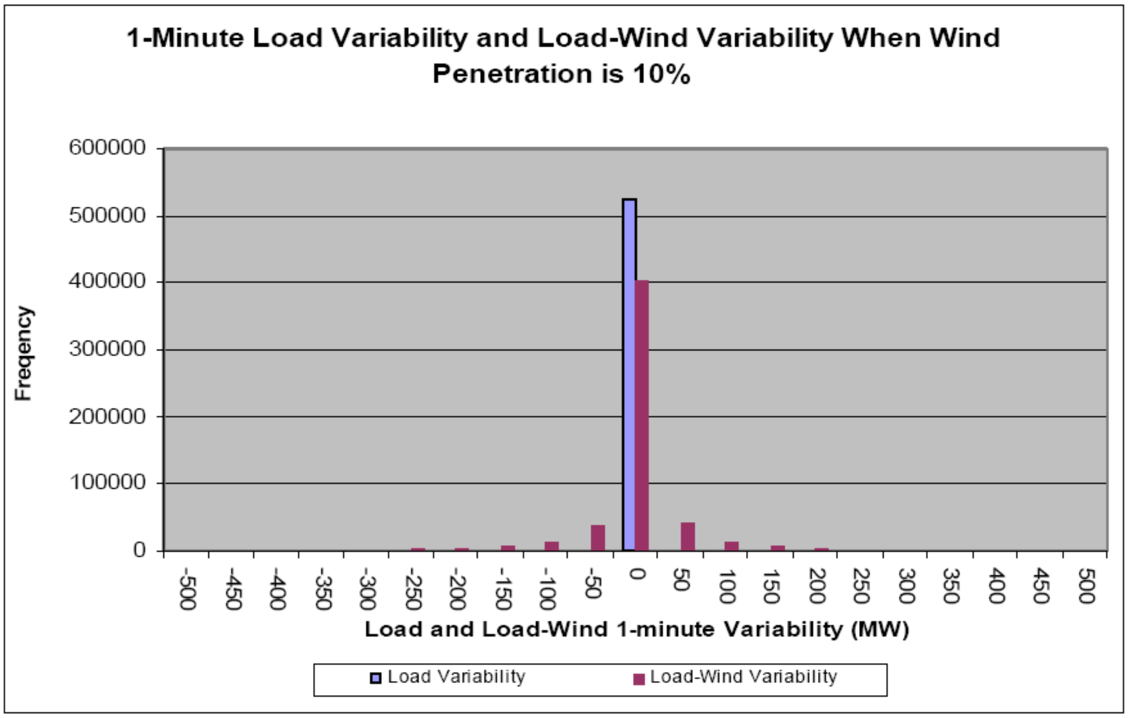


Fig. 17

Table 3

	1 hour		10 min		1 min	
	σ	max	σ	max	σ	max
Load	123	400	22	80	2.7	10
Net load	170	600	80	350	61	250

It is emphasized that the data of Table 3 is not necessarily representative of the effects of a 10% wind penetration level as the wind distributions were manufactured from a single wind source and therefore do not reflect geographical smoothing. Such smoothing would tend to diminish the variance of the wind distribution and thus the increase in variance on the net-load distribution.

For example, reference [8, pg. 162] indicates that:

> "Should wind power penetration reach 5-10 per cent, the wind variations become comparable with random, short-term demand variations. Concern may arise not only from the magnitude of the variability, but also the rate of change, and hence the dynamic requirements placed upon the conventional generation. There will thus be a requirement for extra regulating/secondary reserve – typically somewhere between 2 and 10 per cent of the installed wind power capacity for a 10 per cent wind penetration."

Two additional comments need to be made in regards to the additional MW variability caused by wind:

- It is possible that the magnitude of effects characterized in Table 3 may be caused by wind, but only for large penetration levels occurring in a very small geographical region or for significantly higher penetration levels.

- It is important to understand when, during the day, the high-MW variability instances occur. To understand this issue, one needs to realize that most control area operators will provide more reserve during times of high load variability, for example, during morning rise and evening fall. Therefore, if the high net-load variability instances occur during times of high load variability, then the amount of additional reserves necessary to handle it will be relatively small. On the other hand, if the high net-load variability instances occur during times of low load variability, then the amount of additional reserves will be relatively large. For example, wind could create a need for 25% reserves on top of what is otherwise a 15% afternoon requirement, or it could create a need for 25%

reserves on top of what is otherwise a 20% morning requirement. The first case would require an additional 10% during the afternoon, whereas the second case would require an additional 5% during the morning. The latter situation would be less costly.

4.0 Limiting wind ramp rates

There are two basic ways to address the effect of wind on increased MW variability, as follows:

1. Increase non-wind MW ramping capability during periods of expected high variability using one or more of the below:
    a. Conventional generation
    b. Storage (e.g., pumped storage, CAES, batteries…)
    c. Load control
2. Increase control of the wind generation
    a. Provide regulation and/or load following capability
    b. Limit wind generation ramp rates

We will discuss #1 later; in the next two sections, we discuss 2-a. Here, we will discuss 2-b.

Reference [8, pg. 168-169] addresses 2-b as follows:

“When the turbines are operational, the positive ramp rate can be controlled easily by adjusting the rotor pitch angle. This operation can be implemented independently for each turbine or coordinated across the entire wind farm. In contrast, the output of stall-controlled (passive) wind turbines cannot be readily controlled. …The German maximum ramping rate specification is 10 percent of turbine rating per minute, while in Ireland two settings are specified – ramp rate per minute and ramp rate over 10 minutes. The one-minute ramp rate is set currently at 8 per cent of registered capacity per minute (not less than 1 MW/minute and not higher than 12 MW/minute) while the 10 minute ramp rate is 4 per cent of registered capacity per minute (not less than 1 MW/minute and not higher than 6 MW/minute). In Great Britain, the ramping requirements are defined by the size of the wind farm – no limit for wind farms up to 300 MW capacity, 50 MW/minute between 300 and 1000 MW capacity, and 40 MW/minute beyond 1000 MW in size. With sufficient notice the ramp rate should be adjustable by the TSO, with increasing wind penetration.

In Ireland, for example, both settings (per minute and per 10 minutes) should be independently variable over the range 1-30 MW/minute. In Energinet (Denmark), the ramp rate should be adjustable within the range of 10-100 per cent turbine rating per minute."

5.0 Primary frequency control: conventional generation

A conventional synchronous generator, for both steam-turbines and hydro turbines, can control the mechanical power seen by the generator in response to either a change in set-point, ΔP_C, or in response to change in frequency, $\Delta\omega$. The dynamics of this feedback control system are developed in [9], which utilize the block diagram of Fig. 18a (Fig. 20 in [9]):

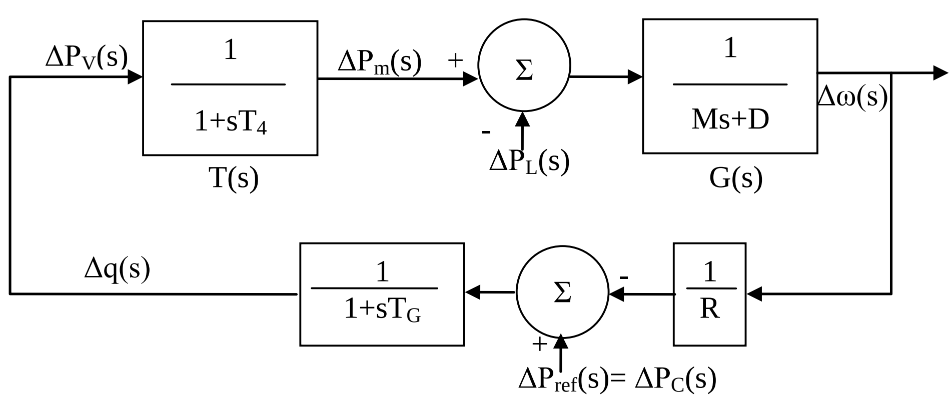


Fig. 18a

from which we may show (2a) below:

$$\Delta\hat{P}_M = \frac{\Delta\hat{P}_C}{(1+T_T s)(1+T_G s)} - \frac{1}{(1+T_T s)(1+T_G s)}\frac{\Delta\hat{\omega}}{R} \quad \text{(2a)}$$

where T_T=T_4 is the time constant of the turbine, and T_G is the time constant of the speed-governor, and the circumflex above the three variables indicates these are given in the Laplace domain.

We can also derive from Fig. 18a:

$$\boldsymbol{\Delta\hat{\omega} = \frac{\Delta\hat{P}_C}{(1+T_T s)(1+T_G s)(Ms+D)+1}} \quad \text{(2b)}$$

Substitution of (2b) into (2a) results in

$$\boldsymbol{\Delta\hat{P}_M = \frac{\Delta\hat{P}_C}{(1+T_T s)(1+T_G s)} - \frac{1}{(1+T_T s)(1+T_G s)R[1+(1+sT_T)(1+sT_G)(Ms+D)]}} \quad \text{(2c)}$$

Consider a step-change in power of ΔP_C which in the LaPlace domain is:

$$\Delta\hat{P}_C = \frac{\Delta P_C}{s} \quad \text{(3)}$$

Substitution of (3) into (2c) results in:

$$\Delta \hat{\boldsymbol{P}}_{\boldsymbol{M}} = \frac{\Delta \boldsymbol{P}_{\boldsymbol{C}}}{\boldsymbol{s}(1+\boldsymbol{T}_{\boldsymbol{T}}\boldsymbol{s})(1+\boldsymbol{T}_{\boldsymbol{G}}\boldsymbol{s})}\left[1-\frac{1}{\boldsymbol{R}[1+(1+\boldsymbol{T}_{\boldsymbol{T}}\boldsymbol{s})(1+\boldsymbol{T}_{\boldsymbol{G}}\boldsymbol{s})(\boldsymbol{M}\boldsymbol{s}+\boldsymbol{D})]}\right] \quad (4)$$

We examine eq. (4) by considering $\Delta P_M(t)$ for very large values of t, i.e., for the steady-state using the final value theorem, which is:

$$\lim_{t \to \infty} f(t) = \lim_{s \to 0} s\hat{f}(s) \quad (5)$$

Applying eq. (5) to eq. (4), we get:

$$\begin{aligned}
\Delta \boldsymbol{P}_{\boldsymbol{M}} &= \lim_{\boldsymbol{t} \to \infty} \Delta \boldsymbol{P}_{\boldsymbol{M}}(\boldsymbol{t}) = \lim_{\boldsymbol{s} \to 0} \boldsymbol{s}\Delta \hat{\boldsymbol{P}}_{\boldsymbol{M}} \\
&= \lim_{s \to 0}\left\{\frac{\boldsymbol{s}\Delta \boldsymbol{P}_{\boldsymbol{C}}}{\boldsymbol{s}(1+\boldsymbol{T}_{\boldsymbol{T}}\boldsymbol{s})(1+\boldsymbol{T}_{\boldsymbol{G}}\boldsymbol{s})}\left[1-\frac{1}{\boldsymbol{R}[1+(1+\boldsymbol{T}_{\boldsymbol{T}}\boldsymbol{s})(1+\boldsymbol{T}_{\boldsymbol{G}}\boldsymbol{s})(\boldsymbol{M}\boldsymbol{s}+\boldsymbol{D})]}\right]\right\} \quad (6) \\
&= \Delta \boldsymbol{P}_{\boldsymbol{C}} - \frac{\Delta \boldsymbol{\omega}}{\boldsymbol{R}}
\end{aligned}$$

Therefore,

$$\Delta P_M = \Delta P_C - \frac{\Delta \omega}{R} \quad (7)$$

In eq. (7), ΔP_M, ΔP_C, and $\Delta\omega$ are

- Time-domain variables (not LaPlace variables)
- Steady-state values of the time-domain variables (the values after you wait a long time)

Although we have not developed relations for ω, P_M, and P_C (but rather $\Delta\omega$, ΔP_M, and ΔP_C), we assume that the local behavior as characterized by eq. (6) can be extrapolated to a larger domain, so that a plot of P_M vs. ω for a certain setting of $P_C=P_{C1}$ is as in Fig. 19.

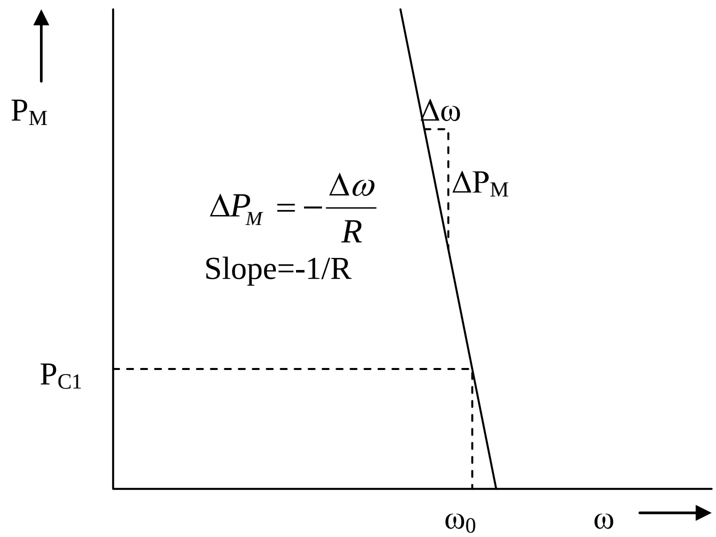


Fig. 19

It is assumed in Fig. 19 that the adjustment to the generator set point, designated by $P_C=P_{C1}$, is done by the AGC control system which results in $\omega=\omega_0$. The plot, therefore, provides an indication of what happens to the mechanical power P_M, and the frequency ω, following a disturbance from this pre-disturbance condition for which $P_M=P_{C1}$ and $\omega = \omega_0$.

It is clear from Fig. 19 that the "local" behavior is characterized by $\Delta P_M = -\frac{\Delta\omega}{R}$.

If we were to change the generation set point to $P_C=P_{C2}$, under the assumption that the secondary control that actuates such a change maintains ω_0, then the entire characteristic moves to the right, as shown in Fig. 20.

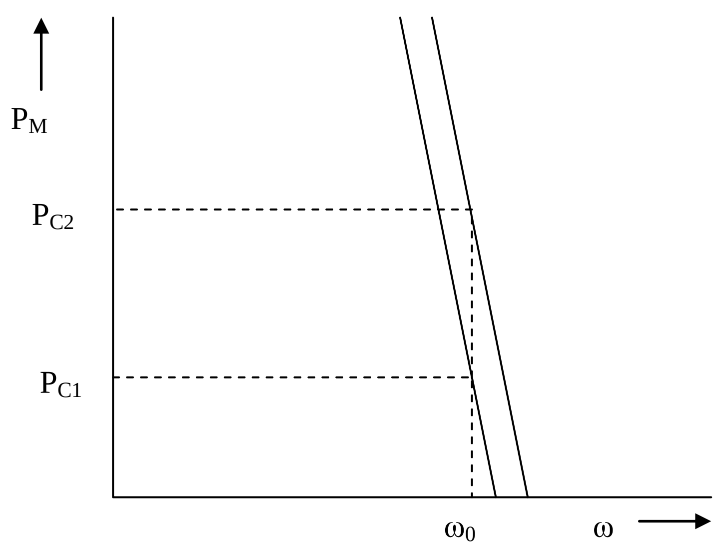


Fig. 20

We may invert Fig. 20, so that the power axis is on the vertical and the frequency axis is on the horizontal, as shown in Fig. 21.

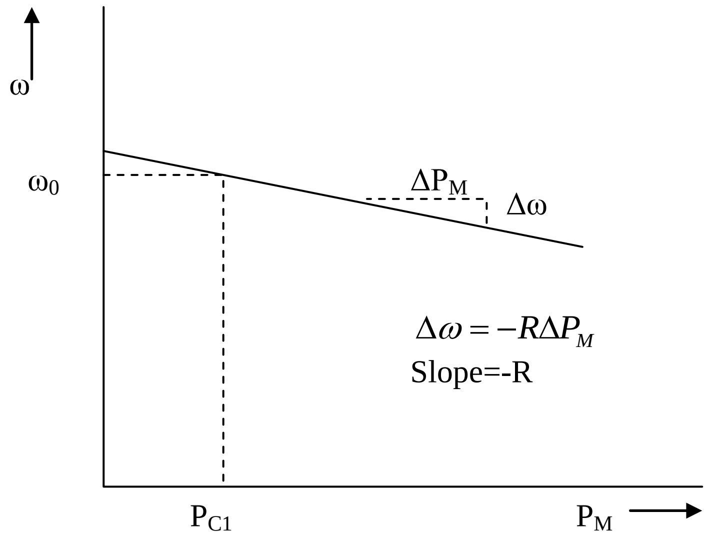


Fig. 21

Fig. 22 illustrates what happens when we change the generation set point from $P_C=P_{C1}$ to $P_C=P_{C2}$,

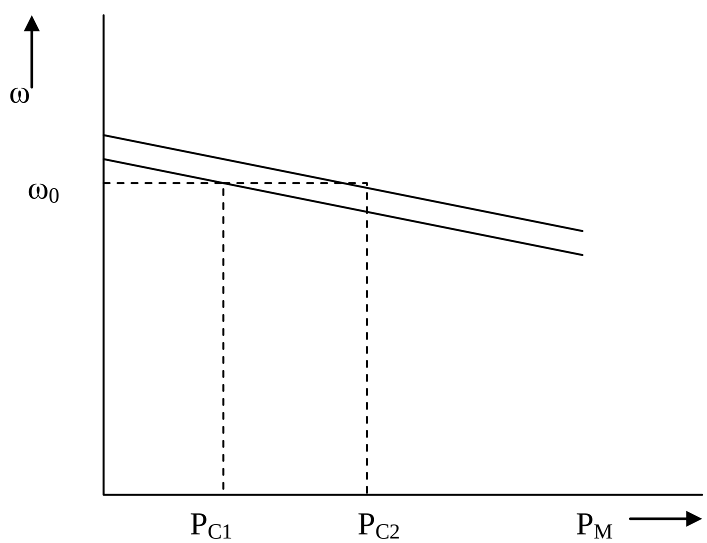


Fig. 22

It is conventional to illustrate the relationship of frequency ω and mechanical power P_M as in Figs. 23 and 24, rather than Figs. 10 and 20. Do not think however that Figs. 21 and 22 show P_M as the "cause" and ω as the "effect." As repeated now in different ways, they are both "effects" of the primary control system response to a frequency deviation caused by a load-generation imbalance.

From such a picture as Figs. 21 and 22, we obtain the terminology "droop," in that the primary control system acts in such a way so that the resulting frequency "droops" with increasing mechanical power.

The R constant, previously called the regulation constant, is also referred to as the droop setting. When power is specified in units of MW and frequency in units of rad/sec, then R has units of rad/sec/MW.

When both power and frequency are specified in pu, then R is dimensionless and relates fractional changes in ω to fractional changes in P_M. In North America, most governors are set with R_{pu}=0.05, i.e., if a disturbance occurs which causes a 5% increase in steady-state frequency (from 60 to 57 Hz), the corresponding change in unit output will be 1 pu (100%).

Now let's consider a general multimachine system having K generators. From eq. (6), for a load change of ΔP MW, the i^{th} generator will respond according to:

$$R_{pui} = -\frac{\Delta f / 60}{\Delta P_{Mi} / S_{Ri}} \Rightarrow \Delta P_{Mi} = \frac{-S_{Ri}}{R_{pui}} \frac{\Delta f}{60} \qquad (8)$$

The total change in generation will equal ΔP, so:

$$\Delta P = -\left[\frac{S_{R1}}{R_{1pu}} + \ldots + \frac{S_{RK}}{R_{Kpu}} \right] \frac{\Delta f}{60} \qquad (9)$$

Solving for Δf results in

$$\frac{\Delta f}{60} = \frac{-\Delta P}{\left[\frac{S_{R1}}{R_{1pu}} + \ldots + \frac{S_{RK}}{R_{Kpu}} \right]} \qquad (10)$$

Substitute eq. (9) back into eq. (7) to get:

$$\Delta P_{Mi} = \frac{-S_{Ri}}{R_{pui}} \frac{\Delta f}{60} = \frac{S_{Ri}}{R_{pui}} \frac{\Delta P}{\left[\frac{S_{R1}}{R_{1pu}} + \ldots + \frac{S_{RK}}{R_{Kpu}}\right]} \qquad (10)$$

If all units have the same per-unit droop constant, i.e., $R_{pui}=R_{1pu}=\ldots=R_{Kpu}$, then eq. (10) becomes:

$$\Delta P_{Mi} = \frac{-S_{Ri}}{R_{pui}} \frac{\Delta f}{60} = \frac{S_{Ri}\Delta P}{\left[S_{R1} + \ldots + S_{RK}\right]} \qquad (11)$$

which generalizes our earlier conclusion for the two-machine system that units “pick up” in proportion to their MVA ratings. This conclusion should drive the way an engineer performs contingency analysis of generator outages, i.e., one should redistribute the lost generation to the remaining generators in proportion to their MVA rating, as given by eq. (11).

This is a nice feature of how power systems with conventional generation operate to share in performing the primary control function, each generator picks up their “share” according to their size. Larger generators pick up more than smaller generators. But all contribute.

6.0 Primary frequency control: wind generation

Most wind turbines operating in the world today do not employ primary frequency control. However, this is because there have been no requirements to do so, not because it is not possible to do so.

6.1 Frequency control requirements for wind

A brief review of the websites from TSOs (in Europe), reliability councils (i.e., NERC and regional organizations) and ISOs (in North America) suggest that there are no requirements regarding use of primary frequency control in wind turbines. Representative examples include [10] which indicates neither Turkey, Norway, or Germany require wind turbines to participate in providing primary reserves, and [11] which indicates neither British Columbia Transmission Company (BCTC), Manitoba Hydro, Hydro Quebec, or Alberta Electric System Operator (AESO) requires frequency regulation capability.

There do appear to be some requirements for having *capability* to provide frequency control. For example, the 2007 Nordic Grid Code [12], which specifies grid requirements for transmission system operators in Denmark, Finland, Iceland, Norway and Sweden, states, pg. 173, “Automatic control of the wind turbine active production as a function of the system frequency must be *possible*.” Likewise, reference [11] indicates that with respect to frequency regulation capability,

- BCTC will specify “on a site by site basis,”
- Hydro Quebec requires that wind turbines be “designed so that they can be equipped with a frequency control system (WTG >10 MW)”
- Manitoba Hydro “reserves the right for future wind generators”

Clearly, neither the Europeans nor the Canadians are *requiring* frequency control.

The problem has been recognized by a very recent publication of the North American Electric Reliability Corporation [13] (April 2009), where it says (pg. 63), “Interconnection procedures and standards should be enhanced to address voltage and frequency ride-through, reactive and real power control, frequency and inertial response and must be applied in a consistent manner to all generation technologies."

Some areas have already initiated action. For example, a recent (Feb 2009) ERCOT white paper [14] suggested the following language for standardization:

> "Wind generators need to assist in frequency control for ERCOT. One problem that has occurred has been a rapid increase in system frequency as wind generation has increased. Implementation of the nodal software addresses the main, root cause of this problem. However, as wind generation becomes a bigger percentage of the on line generation, wind generation will have to contribute to automatic frequency control. Wind generator control systems can provide an automatic response to frequency that is similar to governor response on steam turbine generators. The following draft protocol/operating guide concept is proposed for all new wind generators: All WGRs with signed interconnect agreements dated after March 1, 2009 shall have an automatic response to frequency deviations. …"

6.2 Frequency control wind by blade pitching

Figure 23 illustrates the capability of all modern (equipped with blade-pitch control) wind turbines to control blade pitch, indicating it is equivalent to steam-flow control in a conventional steam turbine.

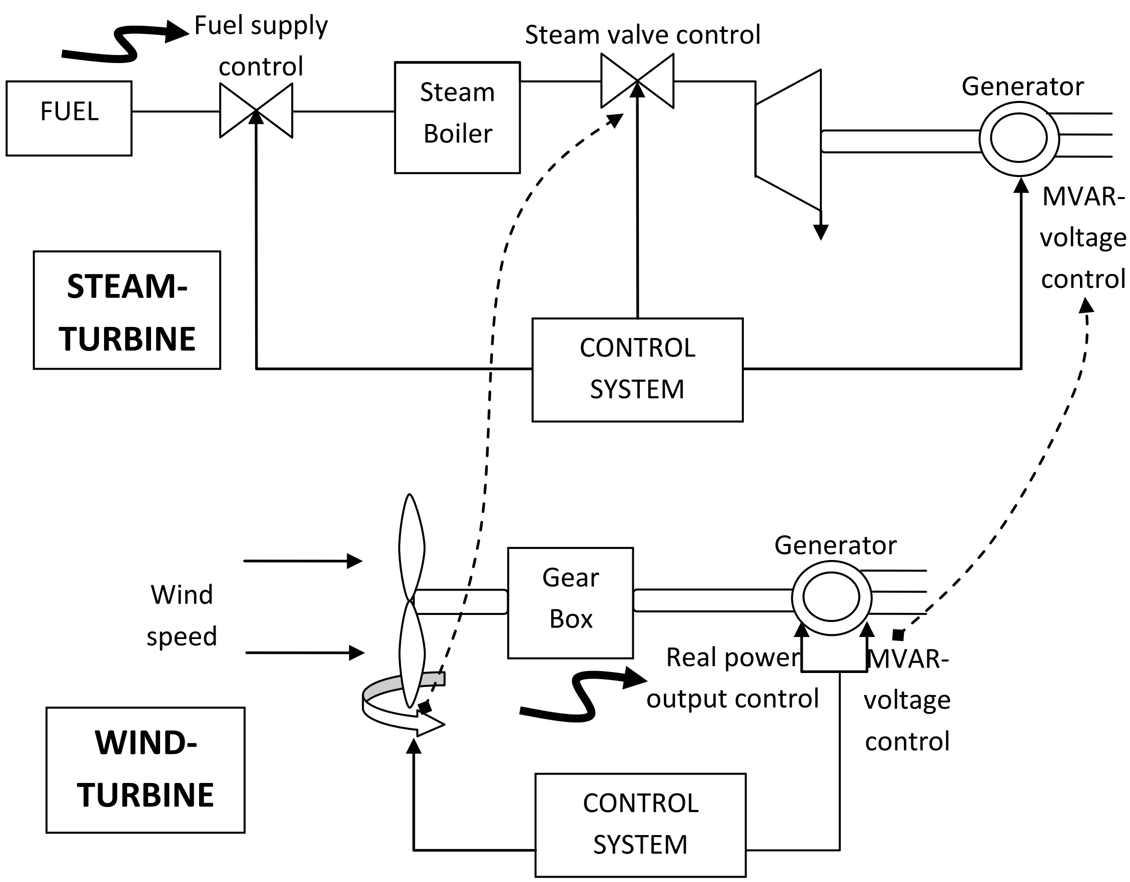


Fig. 23

It follows, then, that just as primary frequency control is accomplished through steam-valve control in steam turbines, primary frequency control can be accomplished through blade pitch control in wind turbines.

It should be recognized that blade pitch control has two main purposes for which it was developed:

- To maximize energy extraction from the wind.
- To protect the turbine under high wind conditions.

Figure 24 shows the performance coefficient curves for the GE SLE 1.5 MW wind turbine. In this plot, $C_p=P_m/P_{wind}$, λ is the tip speed ratio, and θ is equivalent to the blade pitch angle [15].

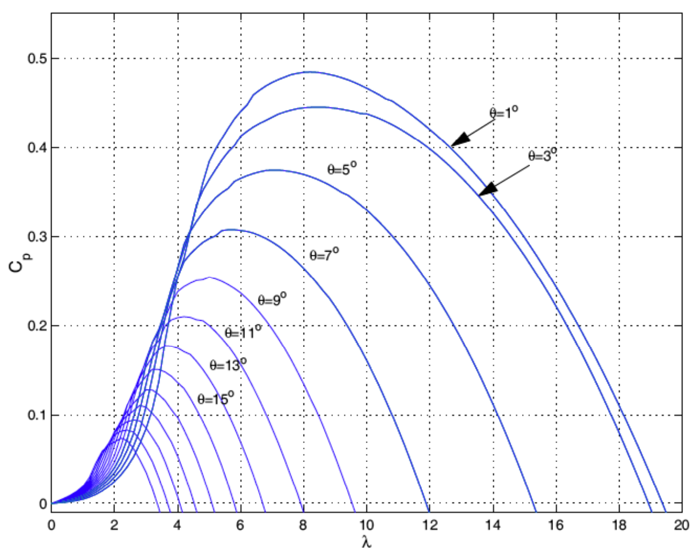


Fig. 24

Equation (12) relates mechanical power extracted from the wind to the performance coefficient.

$$P_{Mech} = \frac{1}{2} \cdot \rho_{air} \cdot A \cdot v_{wind}^3 \cdot C_p(\lambda, \theta) \tag{12}$$

where ρ_{air} is air density, A is cross-sectional area swept by the blades, v_{wind} is the wind velocity, and

$$\lambda = \frac{\omega_r R}{v_{wind}} \tag{13}$$

Therefore, for a given wind speed, we maximize power output by controlling either ω_r (rotor speed) and thus tip speed λ, or pitch angle θ, or both ω_r and θ. In fixed-speed machines, it is not possible to control ω_r, therefore our only option is to control θ. For DFIGs, both are used.

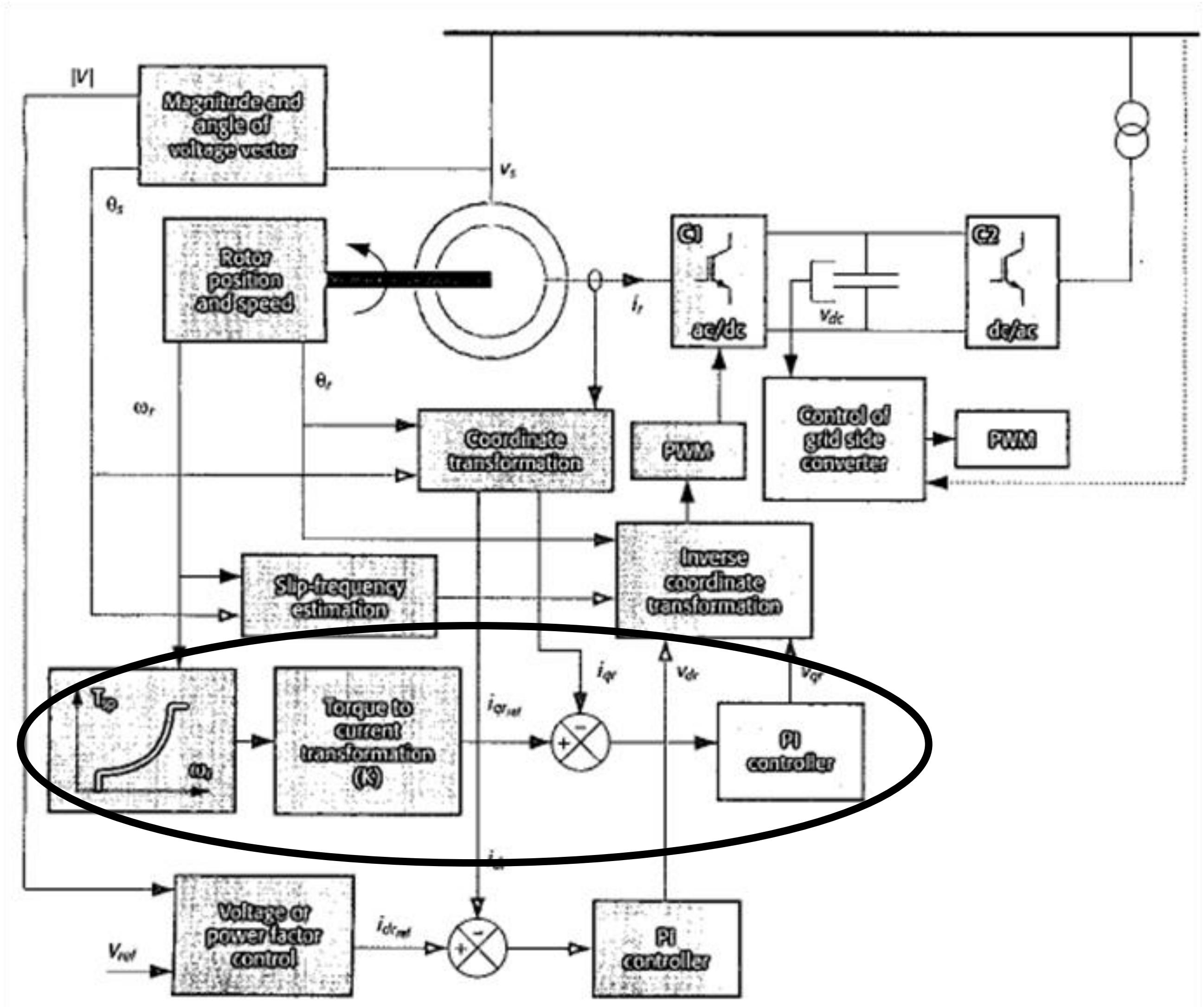
The other purpose for control of θ is to protect the machine; when wind speeds exceed a known “safe” level (typically 20-25 m/sec, or 45-56 mph), the pitch controller will feather the blades to reduce the torque on them to a level where they can be parked.

A wind turbine's pitch controller uses advanced computer-based schemes to ensure the rotor blades pitch exactly the amount required. This control scheme will normally pitch the blades a few degrees every time the wind changes to keep the rotor blades at the optimum angle and maximize output for all wind speeds. The same control mechanism could be used to provide primary frequency control such that:

- A fall in frequency (demand exceeds generation) causes a decrease in pitch angle and hence an increase in electrical output;
- An increase in frequency (generation exceeds demand) causes an increase in pitch angle and a decrease in electrical output.

6.3 Frequency control wind by rotor speed control

It is possible to utilize rotor current control through the rotor-side converter to emulate an inertial response. The corresponding block diagrams are shown in Figs. 25 and 26.



|V|
Magnitude and angle of voltage vector
v_s
θ_s
Rotor position and speed
C1
ac/dc
i_r
v_{dc}
C2
dc/ac
θ_r
ω_r
Coordinate transformation
PWM
Control of grid side converter
PWM
Inverse coordinate transformation
Slip-frequency estimation
i_{qr}
v_{dr}
v_{qr}
T_{sp}
ω_r
Torque to current transformation (K)
$i_{qr_{ref}}$
PI controller
i_{dr}
Voltage or power factor control
V_{ref}
$i_{dr_{ref}}$
PI controller

Fig. 25

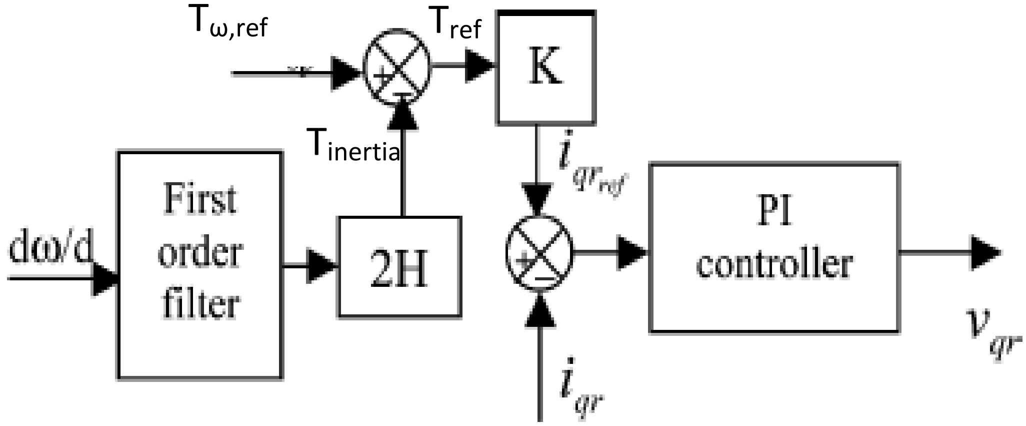


Fig. 26

Whereas the signal of Fig. 26 is proportional to rate of change of frequency, we may also introduce a signal proportional to frequency deviation from nominal, as indicated in Fig. 27.

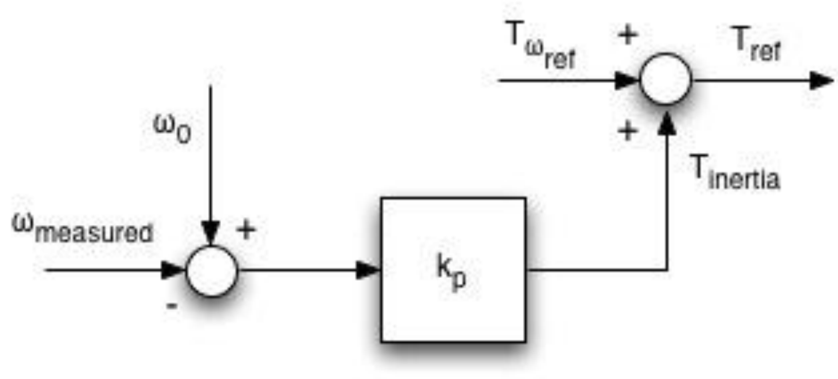


Fig. 27

Reference [8, p. 183] indicates that whereas this approach, speed control, “may be well suited for continuous, *fine*, frequency regulation, blade pitch control (see section 6.2) can provide fast acting, *coarse* control both for frequency regulation as well as emergency spinning reserve.” Also, it should be recognized that speed control “borrows” inertial energy from the blades and therefore cannot be sustained for too long. And in the words of [16], “Not only will real power obtained by borrowing rotor energy have to be withdrawn; it will be necessary to reduce electrical power output to reaccelerate the rotors.”

The two forms of control have been studied together in reference [17], where the analysis was done on a design characterized by Fig. 28.

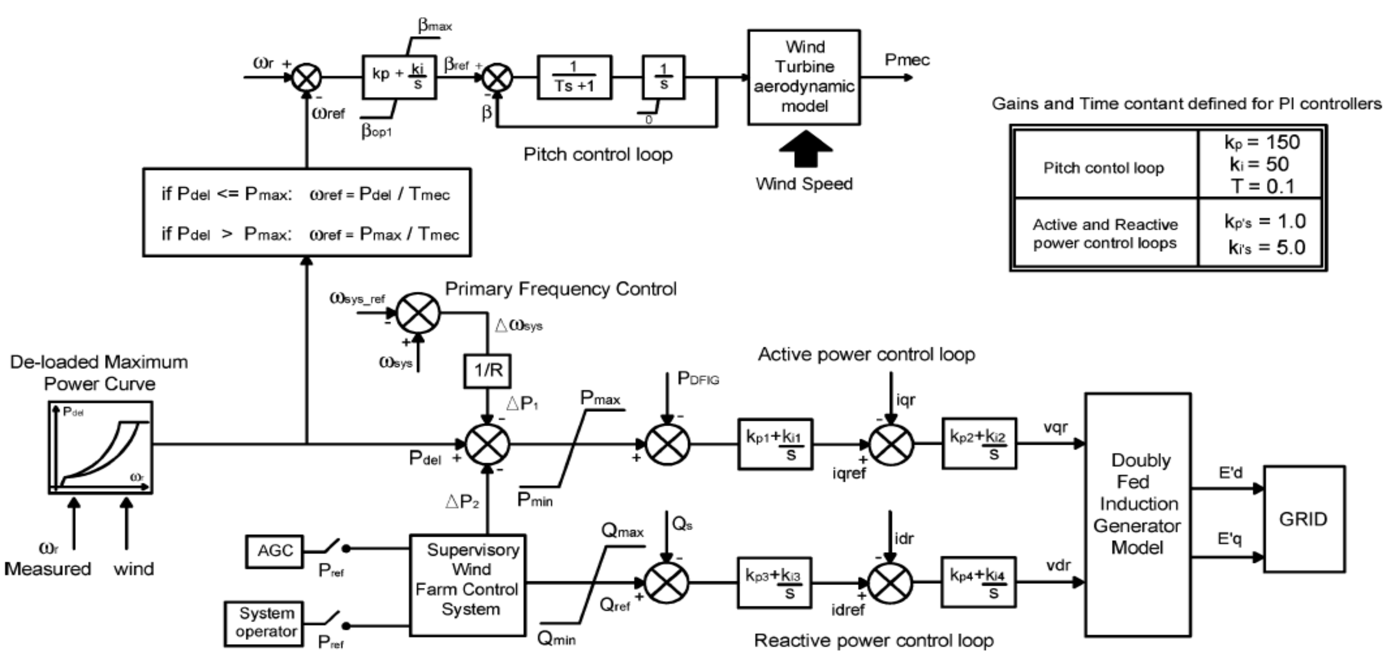


Fig. 28

In addition, it is of interest that there is a 160 MW off-shore wind farm off the coast of Denmark called Horns Rev where these control capabilities have been implemented & tested. Slides on this facility are at [18].

Three additional comments should be made at this point.

First, primary frequency control for over-frequency conditions, which requires generation reduction (reg-down), can be effectively handled by pitching the blades and thus reducing the power output of the machine. Although this action "spills" wind, it is effective in providing the necessary frequency control.

Second, primary frequency control for under-frequency conditions, which requires generation increase (reg-up), requires some "headroom" so that the wind turbine can increase its power output. This means that it must be operating below its maximum power production capability on a continuous basis. This also implies a "spilling" of wind.

Reg-up primary frequency control for wind turbines has been referred to as "delta control" since its ability to respond to under-frequency requires a "delta" between the actual production level and the available production capability.

<u>Third</u>, another important function that is achievable by pitch control is ramp rate limitation.

The two forms of control, ramp-rate limitation, and delta, are illustrated in Fig. 29 for the Horns Rev facility [18].

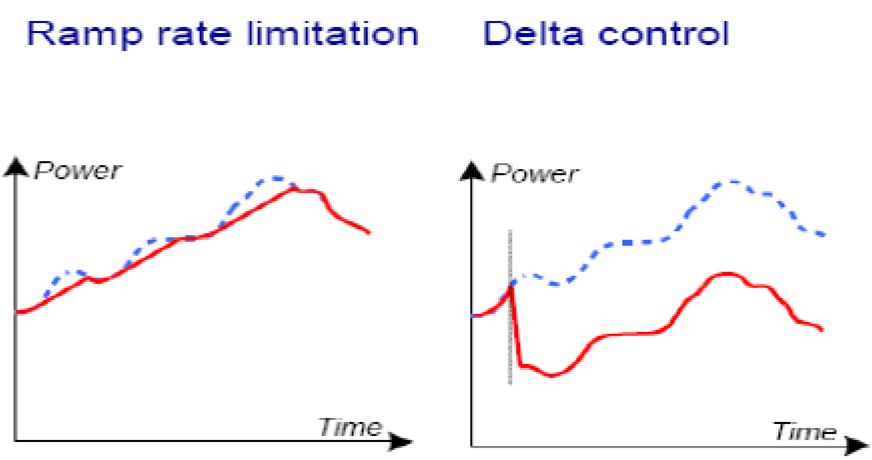


Fig. 29

It is controversial whether wind turbines should "spill" wind in order to provide frequency control, in contrast to using all wind and relying on conventional generation to provide the frequency control. The answer to this question is certainly related to what wind penetration levels the industry/society will ultimately implement.

Reference [19] reported some testing, described in the caption in the below figure. Note the reg-down ramp rate of 2.4 MW/sec, for a 60 MW farm, 4% per sec! This fast ramp rate suggests wind energy can very effectively compete with other forms of generation in the regulation market, should wind owners see it as economic to do so.

"Figure 9 illustrates the power response of a 60-MW wind plant with GE turbines to a 2% increase in system frequency. During this test, the site was initially producing slightly less than 23 MW. The system overfrequency condition was created using test software that injected a 2% controlled ramp offset into the measured frequency signal. The resulting simulated frequency increased at a 0.25 Hz/s rate from 60 Hz to 61.2 Hz. While the frequency is increasing, the farm power drops at a rate of 2.4 MW/s. After 4.8 s the frequency reaches 61.2 Hz and the power of the farm is reduced by approximately 50%. The overfrequency condition is removed with a controlled ramp back to 60 Hz at the same 0.25 Hz/s rate. The plant power then increases back to an unconstrained power level. This level is slightly higher than the unconstrained level prior to the test due to an increase in the wind speed. These rates of frequency change are representative of relatively severe system disruptions. The plant response is adjustable with control settings. The ramp rate power limiter becomes disabled whenever the system is responding to frequency-related grid conditions and automatically becomes active again once the system frequency is within the droop deadband."

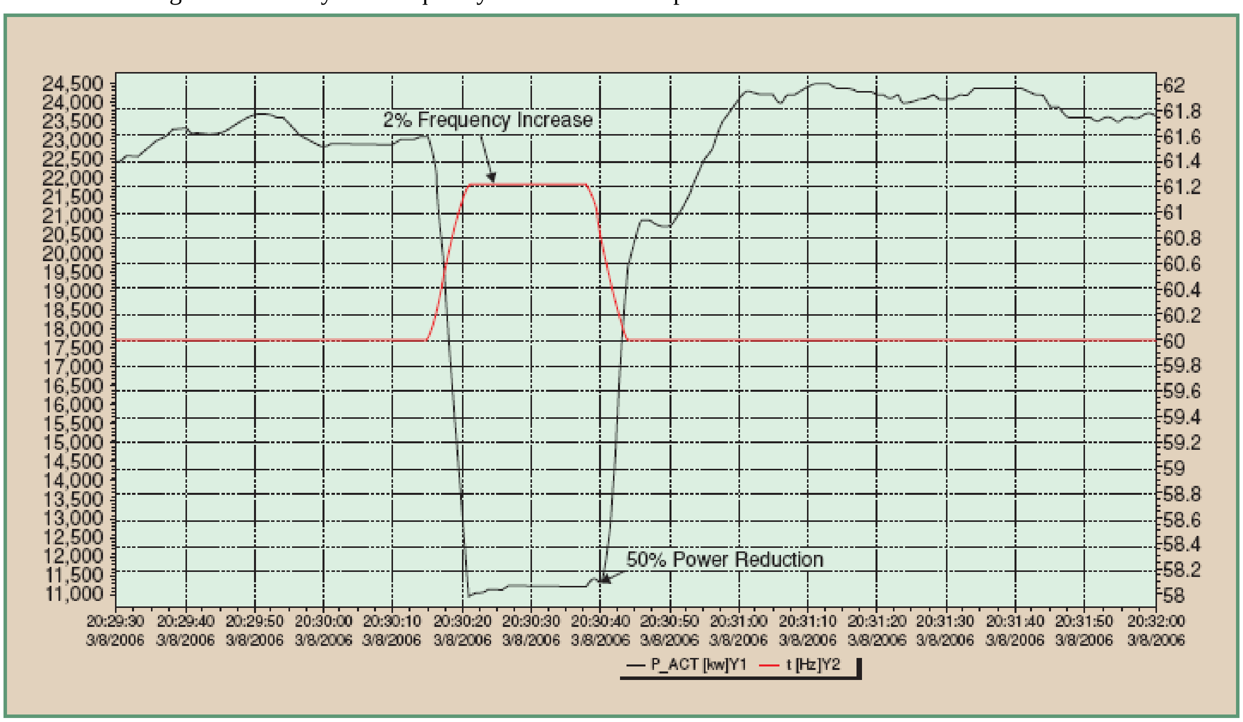


figure 9. Power response of plant to overfrequency condition.

However, reference [16] provides some cautions, as follows (pg. 65).

> There are at least two possibilities by which a wind plant would be able to offer the ability to increase output in response to a dip in frequency:
>
> - by operating below its maximum output for the present (momentary) wind condition and using pitch control to increase its power output
>
> - by maneuvering its electronic converters to increase electrical power output and borrowing the required mechanical input from the kinetic energy stored in its rotors
>
> Both of these approaches might allow a wind plant to offer quick response to a frequency dip and this would be favorable to the grid. However both approaches will inevitably be subject to in-plant constraints such as limits on coupling torques and turbine aerodynamic limits, for example. Further, pitch control can only increase turbine power if the wind is favorable at the moment and response provided by borrowing energy from the rotors cannot be sustained beyond a few seconds. Not only will real power obtained by borrowing rotor energy have to be withdrawn; it will be necessary to reduce electrical power output to reaccelerate the rotors.
>
> Thus, Frequency Response capability offered by a wind plant will not be the same as the primary control capability of conventional plants. While primary response capability offered by a conventional plant can be counted on with good assurance once the appropriate control modes are selected by its operator, the response capability of a wind plant will always be conditional on the statistics of the wind.

And on pg. 70,

The required attention to system control should involve the following:

a. BAs should be continually aware of the primary response capability in effect, both as a total for the area and by individual turbine.

b. BAs should be continually aware of the secondary response capability in effect, both as a total for the area and by individual turbine.

c. Plant load control systems should be required to operate with proper frequency bias when running in local preselected load control mode.

d. The allocation of secondary control responsibility between prescheduling of plant outputs and LFC should give precedence to reliability principles over market concepts; excessive use of prescheduling should be avoided.

e. The control mode status of all plants with respect to primary control, local load control, and LFC should be reported continually and currently to BA control centers.

f. The terminology used to describe plant control modes and status should be standardized nationally.

g. Plant operating and engineering staffs should be knowledgeable about the ways their control actions affect the security and reliability of the grid.

h. BA operating staff should be continually sensitive to the response that the plants will be able to deliver and should have clear authority, based on the overriding principles of reliability, to require plants to operate at outputs and in control modes that may differ from the indications of markets. Presecheduling and dispatch of generation resources should aim to minimize the ordering of output changes and changes of control mode on short notice.

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