Chapter 3

Wind power variability and the grid

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Prerequisite Competencies:
1. Differential and integral calculus.
2. Understanding of power and energy as described in physics.

Module Objectives: This module will enable students to:
1. kjh;
2. kjh.

3.0 Introduction

The power grid has been operated since the early part of the 20th century on the basis that at each and every second, the power demanded and the power supplied must be *almost* balanced. The word "almost" is used in the previous sentence because very small imbalances happen all the time as users modify their demand by turning on and off lights, ovens, air conditioners, motors, commercial operations, and entire manufacturing processes. At the millisecond following each change, there is an imbalance, and the generation supplying the system has to compensate. There are also cumulative, steady-state imbalances that occur over the course of several seconds, and also over the course of minutes to hours, and it is necessary for generators to compensate for these changes as well. We refer to these changes as *variability*. Conventional generators are under special control to perform this multi-time frame compensation of variability. It is important to realize that variability has always been present in power grids because of the variation of the load. However, the integration of wind power increases this variability and as a result, it increases the need to compensate for it in order to maintain power balance. In this chapter, we present the basic problem, we discuss wind power production, we summarize the control systems used to handle variability, and we identify potential solutions.

3.1 Wind power variability and power balance

The basic problem is that wind is a variable resource when it is controlled to maximize its power production. This issue is often considered via the *net load*. The net load is defined for a particular time as the MW demand at that time less the MW supply from the variable generation (VG). If there is no solar PV in the system, then the VG power output is the wind power output. Therefore, we have that

NETLOAD.MW=(LOAD.MW+LOSSES.MW)-WIND.MW

What we will see in these notes is that wind power increases the variability of the net load. We will also see that the grid requires that the MW generation supplied by the conventional generation to always equal net load, i.e.,

GEN.MW=NETLOAD.MW

A well-known attribute associated with conventional generation is that “expensive” generation (based on marginal costs) is usually able to modify its MW power output quickly. We refer to the action of “modify its MW power output” as *ramping*. For example, a combustion turbine (CT), which is essentially a jet engine, is able to ramp quite quickly, but its marginal costs depend on the cost of natural gas which is normally rather high. On the other hand, coal units ramp quite slowly, but their marginal costs depend on the cost of coal which is rather low.

Nuclear units are run at fixed levels so that they are never allowed to ramp. This is partly because they are very inexpensive units. In addition, changing MW power output results in changing plant operating conditions which increases likelihood of forced outage. Nuclear plants try hard to avoid forced outages because it can result in significant effort, and possible increased plant down-time, in responding to inquiries of the Nuclear Regulatory Commission.

Increased variability requires more ramping capability. The traditional way to obtain more ramping capability is to invest in more combustion turbines. This costs money.

Therefore increased wind penetration therefore leads to the following problem. As wind penetration increases, it increases the variability of the net load. The increased variability of the net load requires increased expenditures. These increased expenditures can be viewed as additional costs associated with wind power.

It is worth pointing out this juncture that variability is not the same as uncertainty. Whereas MW variability results in a changing resource, the way that resource can change might be known, in which case it is certain, or unknown, in which case it is uncertain. Likewise, an uncertain resource may not be known (since it is in the future), but once its time is here, it will be fixed, and therefore not variable.

We have seen in Chapter 2 that wind is also an uncertain resource. That is we do not know with certainty what its MW output will be in the future. This uncertainty is addressed by improving forecasting.

It is important to recognize the difference between variability and uncertainty and the corresponding different approached to solving them (CTs for variability and better forecasting for uncertainty).

3.2 Characterizing wind power production

In this section, we derive the fundamental equation for power output from a wind turbine. We begin from Figure 1, which illustrates the wind speed variation as the wind passes through the turbine blades.

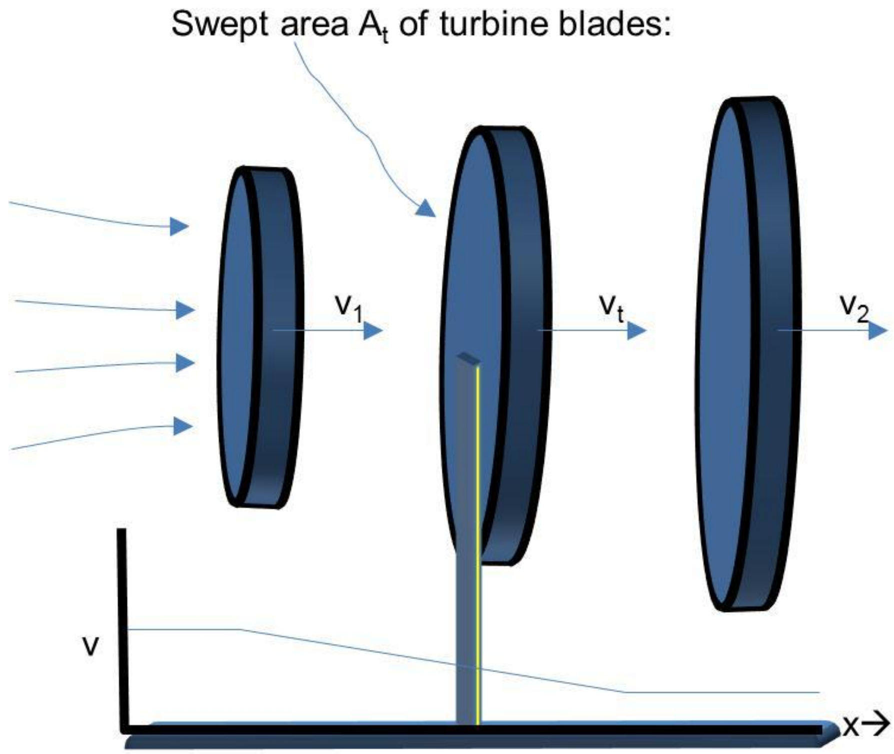

Figure 1: Illustration of wind speed variation before, at, and following the turbine

In considering Figure 1, we define the *mass flow rate* as the mass of substance which passes through a given surface per unit time. The conservation of mass requires that the mass flow rate must be the same in all three segments of the wind path, because if that were not true, it would imply that mass was either being created or destroyed, in violation of the conservation of mass. Therefore, denoting mass flow rates in the three positions identified in Figure 1 as Q_1, Q_t, and Q_2, with units of kg/sec, we obtain that

$$Q_1 = Q_t = Q_2 \tag{1}$$

This flow rate can be expressed as the mass of air is proportional to its density per unit volume, ρ in kg/m^3, times the area over which it flows, A, times its velocity, v. Denote the three areas and velocities of Figure 1 as A_1, v_1; A_t, v_t; and A_2, v_2, respectively. Then (1) becomes

$$\rho A_1 v_1 = \rho A_t v_t = \rho A_2 v_2 \tag{2}$$

Because the wind speed must slow down as it passes through the turbine blades, we must have

$$v_1 > v_t > v_2 \tag{3}$$

For both (2) and (3) to hold, we must also have

$$A_1 < A_t < A_2 \tag{4}$$

showing that the three disks of Figure 1 must have larger cross sectional from left to right. This is said to justify the arrangement of Figure 1.

We now turn to deriving the wind power production equation. Note that the horizontal axis of Figure 1 is denoted *x*. Therefore, we may express the wind velocity, m/sec, as

$$v = \frac{\Delta x}{\Delta t} \tag{5}$$

The air mass flowing, kg, in any Δx, is given by

$$\Delta m = \rho A \Delta x \tag{6}$$

And the mass flow rate at the swept area is

$$Q_t = \frac{\Delta m}{\Delta t} = \frac{\rho A_t \Delta x}{\Delta t} = \rho A_t v_t \tag{7}$$

3.2.1 Power production expression

We now derive the power extracted from the wind by the turbine, as a function of the three velocities v_1, v_t and v_2. We will do this, first, based on kinetic energy change, and second, based on force on the turbine blades. Then we will equate the two expressions.

By kinetic energy change: We express the change in kinetic energy as the wind slows from v_1 to v_2 according to:

$$\Delta KE = \frac{1}{2} m\left(v_1^2 - v_2^2\right) \tag{8}$$

The power extracted from the wind is then the change in kinetic energy per unit time, according to

$$P = \frac{\Delta KE}{\Delta t} = \frac{1}{2}\frac{m}{\Delta t}\left(v_1^2 - v_2^2\right) = \frac{1}{2} Q_t \left(v_1^2 - v_2^2\right) \tag{9}$$

Substitute (7) into (9) to obtain:

$$P = (1/2)\rho A_t v_t (v_1^2 - v_2^2) \tag{10}$$

By force on turbine blades:
The force on the turbine blades is given as the product of mass and acceleration, which we express as

$$F = ma = m\frac{\Delta v}{\Delta t} = \frac{m}{\Delta t}\Delta v = Q_t\left(v_1 - v_2\right) \tag{11}$$

Since energy is the product of force and displacement, power is the time rate of energy change, and velocity is the time rate of displacement change, the power extracted from the wind is the product of the force on the turbine blades and the velocity at the turbine blades, given by

$$P = F v_t = Q_t v_t \left(v_1 - v_2\right) \tag{12}$$

Substitute (7) into (12) to obtain

$$P = \rho A_t v_t^2 (v_1 - v_2) \tag{13}$$

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We have now derived the power extracted from the wind in two different ways, resulting in (10) and (13). So we can now equate these two expressions, resulting in

$$(1/2)v_t(v_1^2 - v_2^2) = v_t^2(v_1 - v_2) \tag{14}$$

Expand the left-hand-side difference of squares to obtain:

$$(1/2)v_t(v_1 - v_2)(v_1 + v_2) = v_t^2(v_1 - v_2) \tag{15}$$

Now cancel the *(v_1-v_2)* terms and the v_t terms on both sides to obtain:

$$(1/2)(v_2 + v_1) = v_t \tag{16}$$

Now substitute (16) into (13):

$$P = \rho A_t((1/2)(v_1 + v_2))^2(v_1 - v_2) = \frac{\rho A_t}{4}(v_1^2 - v_2^2)(v_1 + v_2) \tag{17}$$

Factor out a v_1^3 term to obtain

$$P = \frac{\rho A_t v_1^3}{4}\left(1 - \left(\frac{v_2}{v_1}\right)^2\right)\left(1 + \frac{v_2}{v_1}\right) \tag{18}$$

The last expression is important, because we observe the presence of the v_1^3 term in the power expression.

3.2.2 Wind stream speed ratio

We observe that the term v_2/v_2 occurs twice in the expression of (18). In fact, for a given turbine, and a given control condition (i.e., pitch and blade velocity), this ratio, which is the ratio of the wind downstream wind speed v_2 to the upstream wind speed v_1, is constant, even when the upstream wind speed changes. Therefore we can replace it with a parameter which we will call the *wind stream speed ratio*, denoted as a. That is,

$$a = \frac{v_2}{v_1} \tag{19}$$

Substitution of (19) into (18) results in

$$P = \frac{\rho A_t v_1^3}{4}(1 - a^2)(1 + a) \tag{20}$$

Since the wind stream speed ratio a can be controlled, and since, as a wind farm owner, we would like to maximize our revenues from selling energy, it is of interest to identify the value of a, which results in the maximum power production P. This can be found using standard calculus, by differentiating P with respect to a, in (20), resulting in

$$\frac{\partial P}{\partial a} = \frac{\rho A_t v_1^3}{4}\left[-2a(a+1) + (1 - a^2)\right] = 0 \tag{21}$$

Setting the expression inside the brackets to 0, and expanding, we obtain

$$-2a^2 - 2a + 1 - a^2 = -3a^2 - 2a + 1 = 0 \tag{22}$$

Factoring, and solving for a, we get:

$$(-3a + 1)(a + 1) = 0 \Rightarrow a = 1/3, a = -1 \tag{23}$$

This means we have extreme points at the two values of a, 1/3 and -1. The extreme point corresponding to a = -1 is not of interest, because it corresponds to the condition where v_2=-v_1, that is, when the downstream wind speed is exactly equal but opposite in direction to the upstream wind speed. If this condition could be realized, (20) shows that it would result in a power production value of *P=0*, definitely not a maximum.

The extreme point corresponding to *a=1/3* corresponds to the condition where v_2 is a third of v_1. Substituting *a=1/3* into (20), we obtain

$$P=\frac{\rho A_t v_1^3}{4}(1-\frac{1}{9})(\frac{4}{3})=\frac{\rho A_t v_1^3}{4}\frac{8}{9}\frac{4}{3}=\frac{8\rho A_t v_1^3}{27} \tag{24}$$

Observe the units of (24) are (kg/m^3)(m^2)(m^3)/(sec^3) which is a joule/sec or a watt.

3.2.3 Performance coefficient and Betz limit

Equation (20) gave us the power produced by the turbine, and (24) gives us the maximum power produced by the turbine. Another quantity of interest is the power produced by the turbine as a percentage of the power in the upstream wind, i.e., the percent power extracted from the air stream. To get this, we need to express the power in the upstream wind.

The power in the upstream wind can be obtained using, once again, the notion of the change in kinetic energy per unit time, as we did in (8). However, here we will set $v_2=0$, which gives us the change in the kinetic energy of the wind if the downstream wind speed is 0, i.e., it gives us the total kinetic energy of the upstream wind. This is done as follows:

$$P_{in}=\frac{\Delta KE}{\Delta t}=\frac{1}{2}\frac{m}{\Delta t}\left(v_1^2-0\right)=\frac{1}{2}Q_1 v_1^2=\frac{1}{2}\rho A_t v_1 v_1^2=\frac{1}{2}\rho A_t v_1^3 \tag{25}$$

Now recall from (20), the expression of the power produced by the turbine, repeated here for convenience:

$$P=\frac{\rho A_t v_1^3}{4}(1-a^2)(1+a) \tag{20}$$

The ratio of the power produced by the turbine to the power of the upstream wind is defined as the performance coefficient and denoted by C_p, given by:

$$C_p=\frac{P}{P_{in}}=\frac{\frac{\rho A_t v_1^3}{4}(1-a^2)(1+a)}{\frac{1}{2}\rho A_t v_1^3}=\frac{1}{2}(1-a^2)(1+a) \tag{26}$$

From (26), we observe that the maximum value of C_p occurs when its numerator is maximum, i.e., when the power produced by the turbine is maximum. We already found, in the previous section, this to occur when *a=1/3*. Substitution of this value into (26) results in

$$C_p=\frac{P}{P_{in}}=\frac{1}{2}(\frac{8}{9})(\frac{4}{3})=\frac{16}{27}=0.5926 \tag{27}$$

This is very interesting in that it indicates an upper limit to the percentage of power we may transfer from a given wind stream to a turbine blade, and that is 59.26%. This limit is referred to as the Betz limit.

3.2.4 Control of performance coefficient , power production

There are two basic methods used to control the performance coefficient so that it is maintained at its maximum value under all conditions: pitch and rotor speed via generator speed-torque control.

The first method is via pitch control where the blades are rotated about an axis extending through the center of the blades from the hub. We denote pitch by θ; it is illustrated in Figure 2. The angle θ=0 corresponds to the minimum pitch position where C_P is maximized. Increasing the pitch reduces C_P.

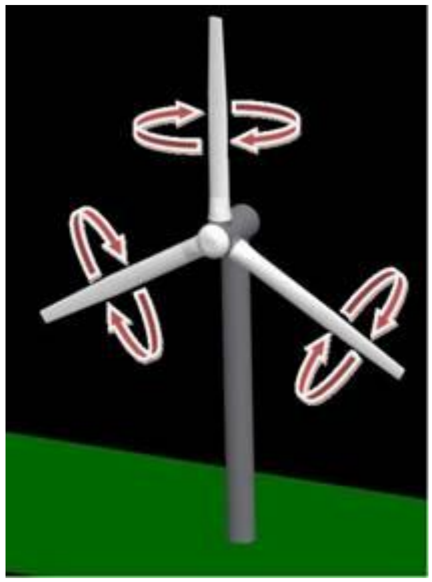

Figure 2: Illustration of pitch

The second method is rotor speed through generator-converter torque-speed control as characterized by the tip-speed ratio, denoted by λ. The tip speed ratio is given by:

$$\lambda = \frac{u}{v_1} = \frac{\omega R}{v_1} \tag{28}$$

where

- u is the tangential velocity of the blade tip
- ω is the rotational velocity of the blade
- R is the rotor radius
- v_1 is the upstream wind speed.

Figure 3 illustrates the dependence of C_P on tip speed ratio and pitch angle for the GE SLE wind turbine. It is clear from this figure that we should express C_P as a function of tip speed ratio and pitch angle, i.e,.

$$C_p = C_p(\lambda, \theta) \tag{29}$$

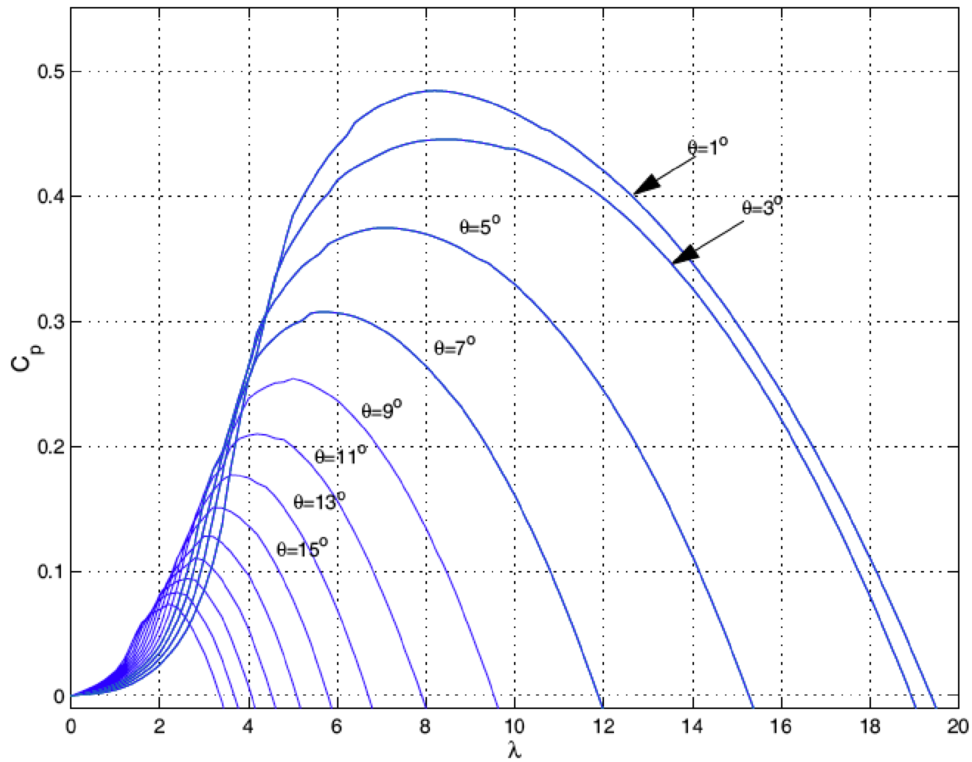

Figure 3: Variation of C_p with tip speed ratio and pitch angle

Using (26), we can write the power production as a function of the power of the upstream wind, according to

$$P = C_p P_{in} \tag{30}$$

And substituting (29) into (30) results in

$$P = C_p(\lambda, \theta) P_{in} \tag{31}$$

Finally, using (25), we obtain

$$P = C_p(\lambda, \theta)\left[\frac{1}{2}\rho A_t v_1^3\right] \tag{32}$$

or

$$P = \frac{1}{2} C_p(\lambda, \theta) \rho A_t v_1^3 \tag{33}$$

We observe clearly from (33) that wind power production is a function of three types of influences:

1. Design factors:
    - Swept area A_t
2. Environmental factors:
    - Air density, ρ (~2.225kg/m^3 at sea level)
    - Wind speed v^3
3. Control factors affecting C_p:
    - Tip speed ratio through the rotor speed ω
    - Pitch angle θ

3.2.5 Power curve

We now assume that we can precisely control pitch and/or tip speed ratio so that, for a given wind speed, we always operate exactly at the maximum power production point. This is the control strategy of most turbines operating in the US today. This results in operation along the locus of points observed in Figure 4.

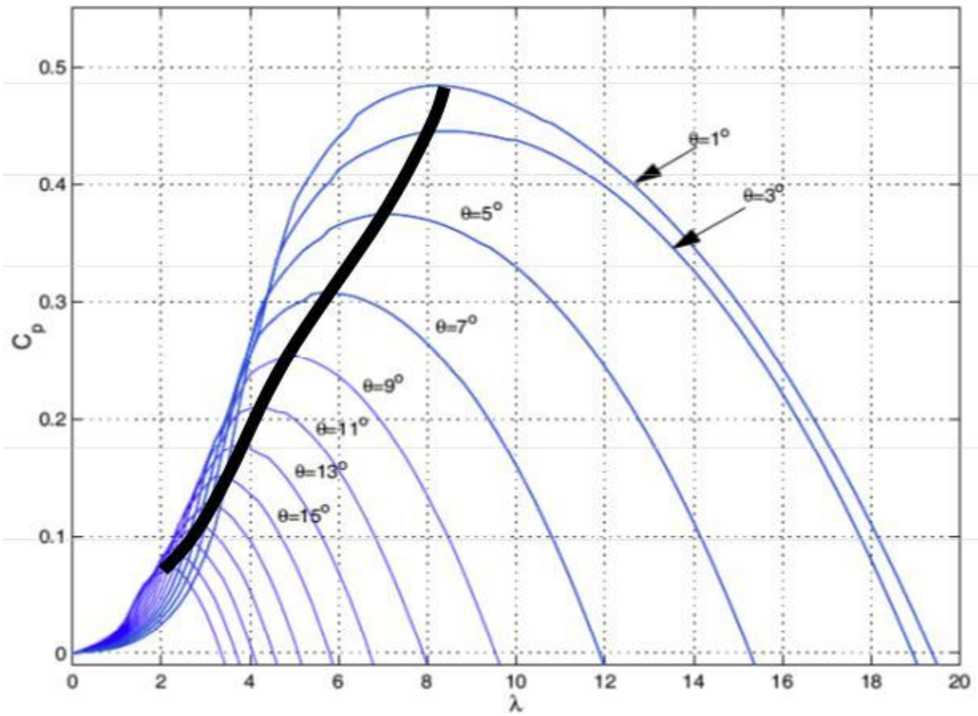

Figure 4: Operation under control to maximize power production

Any other control strategy besides that identified in Figure 4 will "spill" wind!

There are four ranges of speed for a wind turbine:

- Low-speed operation: This is the region from λ=0 to λ=2. Within this range, the wind does not provide enough torque to rotate the turbine. This range is bounded by the cut-in speed.
- Normal speed operation: This is the range shown by the solid black line in Figure 4. Generator-convertor control is used to obtain optimal tip-speed ratio in this range.
- High-speed operation: This is a region above the value of λ that produces maximum power production but remains below a safe speed. At this speed, the power output is limited to the turbine rating using pitch control.
- Very high-speed operation: Above a certain speed, operation of the turbine is no longer safe. This range is bounded by the cut-out speed. This

Figure 5 illustrates a power curve for a typical wind turbine, showing the various ranges of operation as described above.

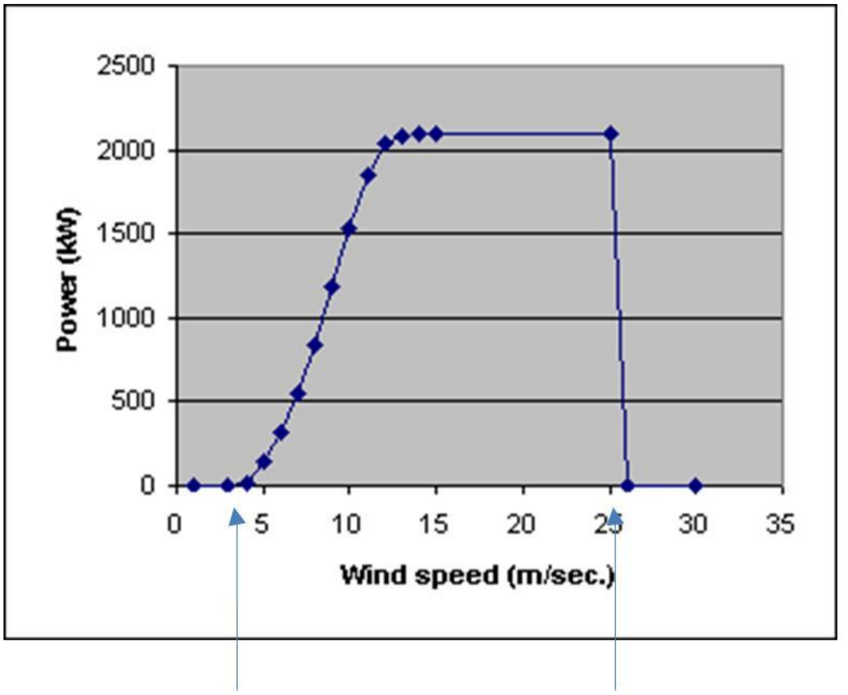

Figure 5: Power curve for a typical wind turbine

3.3 Power system control

For conventional generation, MW output is controlled at four levels, which we describe here. All control levels are motivated by the need to provide continuous power balance, with levels 1-2 also providing frequency control and levels 3-4 also providing economic optimization.

Before describing these control levels, it is important to understand that there are four different time frames which require control. One is the transient time period, illustrated by the red line in Figure 6 [1]. This is for a rather large imbalance situation where transient control is most effective. The time frame associated with the transient time period is generally 1-20 seconds. Figure 7 [2] illustrates time frames 2 and 3 which correspond to regulation and load following, respectively. Regulation occurs within the time frame of about 4 seconds to about 3 minutes. Load following occurs within the time frame of every 5 minutes. Time frame 4, not illustrated with a picture, occurs in a 24 hour time frame.

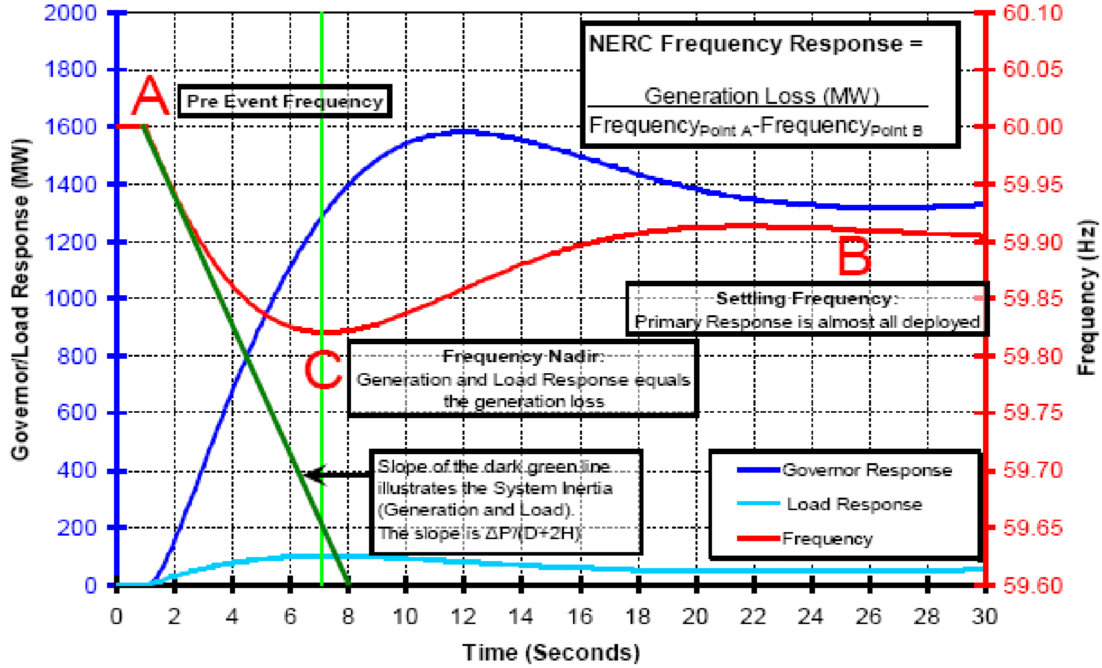

Figure 1 – Frequency Response Basics[2]

Figure 6: Transient frequency control

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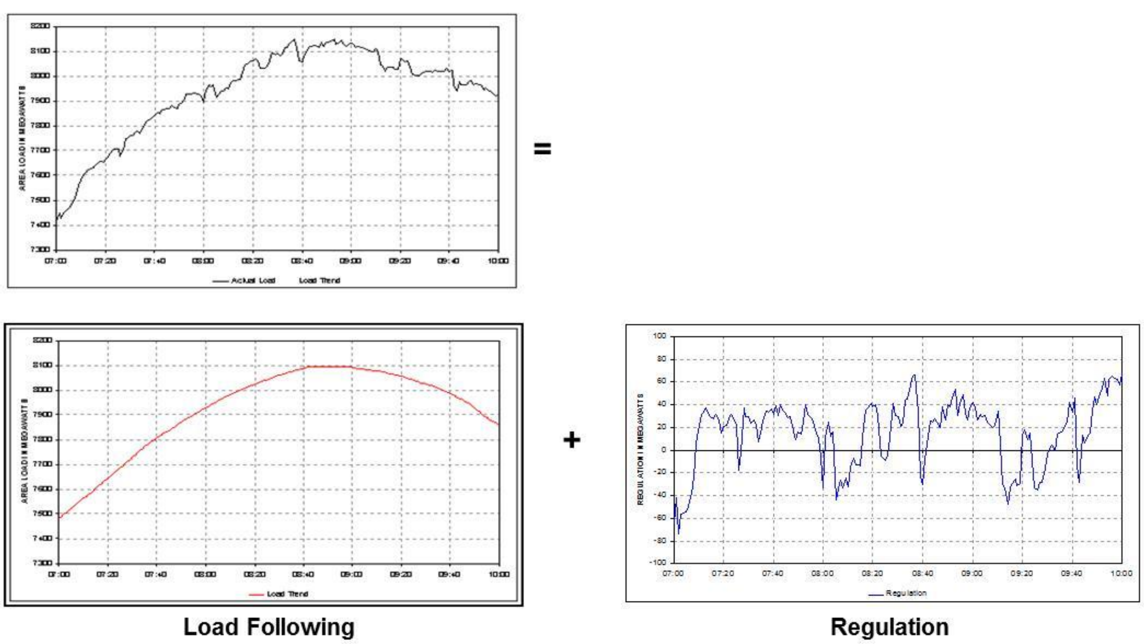

Figure 7: Illustration of regulation and load following time frames

3.3.1 Level 1, primary control

The first level is the only level that is not centralized; it is local to each generator and regulates MW output in response to transient deviations in shaft speed from its reference (synchronous) speed. It is sometimes called governor control or primary control. Its purpose is to arrest frequency deviations in the event of significant imbalances that occur.

During the time period following a change in demand, a generator's need to compensate a power imbalance shows up in its operation as a decrease in the machines' rotational velocity (a de-acceleration) if the demand was increased, or as an increase in the generators' rotational velocity (an acceleration) if the demand is decreased.

By "generator," here, we mean the type of generator used in conventional power plants such as thermal (coal, gas, nuclear), and hydro, i.e., the synchronous machine. Such generators operate in such a way that their speed of rotation is proportional to the frequency of the sinusoidal voltage (and currents) seen in the grid. When their speeds change to compensate for a demand change, this causes the frequency to change. Thus, the frequency, which we desire to be exactly 60 Hz (in North America), deviates up or down.

The primary control loop is local to each synchronous machine and senses shaft speed deviation to control the steam flow into the turbine and thus raise or lower the mechanical power provided to the generator. For example,

- when the generators is too slow, which means the demand is higher than the supply, the supply (in MW) is increased by increasing steam valve openings;
- when the generators are too fast, which means the demand is lower than the supply, the supply (in MW) is reduced by decreasing steam valve openings.

This relationship between MW supply and demand and frequency is analogous to the relationship between the water inflow and outflow, and the water level, in

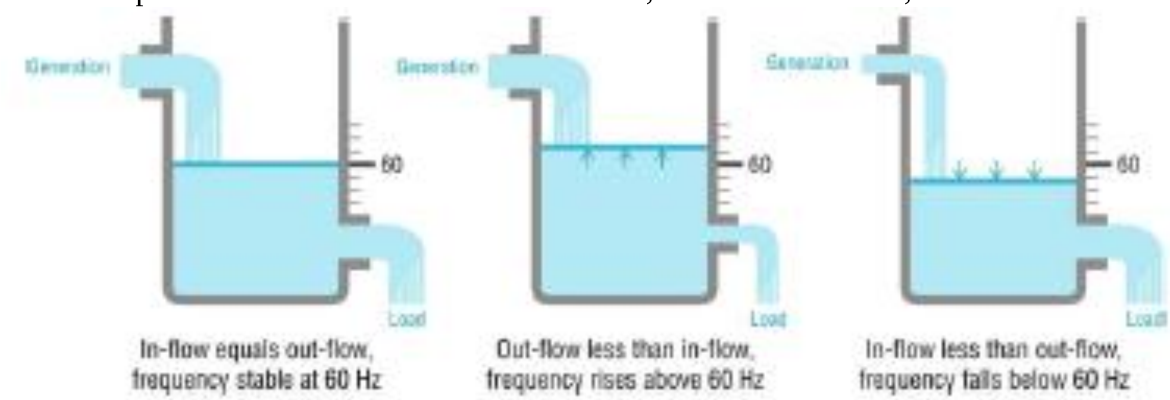

Figure 8: Analogy for supply-demand-frequency relationship

It is important to realize, however, that primary (speed-governing) controllers have deadbands. Deadbands are intervals of actuation signal within which the controller takes no action. A typical governor deadband is ±0.05 Hz. Therefore, for power imbalances which create frequency deviations less than ±0.05 Hz, primary controllers do not respond. This means that primary frequency control have little impact in regulating steady-state frequency deviations.

3.3.2 Level 2, secondary control

The second level, called secondary control, or automatic generation control (AGC), provides *regulation* and is centralized for a designated region of the network called the balancing area (BA); it regulates power production of all units in the BA, typically pulsing units every 4 seconds, in response to steady-state deviations in frequency and tie line power flow to neighboring BAs.

Control levels 1 and 2 are illustrated in Figure 9.

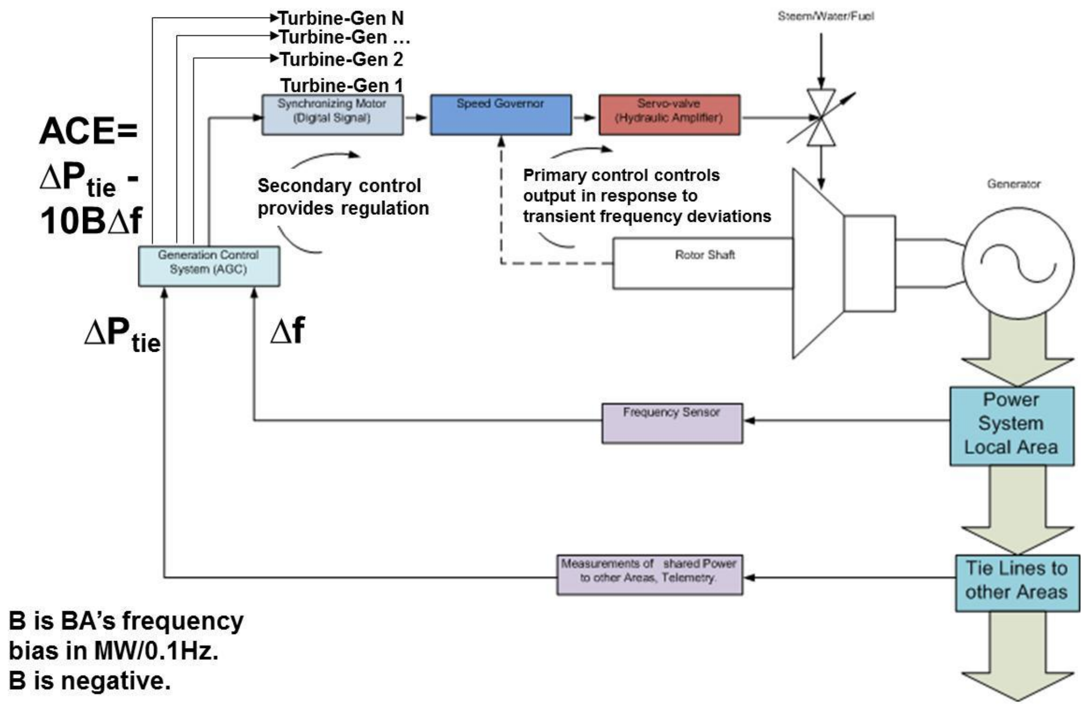

Figure 9: Control levels 1 and 2

In Figure 9, observe that the primary control loop is local to the generation, controlling steam flow to the turbine and thus controlling mechanical input power, in response to the shaft speed of the turbine-generator. On the other hand, the secondary control loop utilizes a signal called area control error (ACE) which is comprised of two components, tie line deviation, ΔP_{tie}, and frequency deviation, Δf, according to

$$ACE = \Delta P_{tie} - B\Delta f = \Delta P_{tie} + |B|\Delta f \quad (1)$$

where the constant B is the balancing area frequency bias in MW/0.1Hz and is a negative value. The tie line deviation, ΔP_{tie}, is the difference between sum total of actual exports on the tie lines, and sum total of desired (or scheduled) exports on the tie lines, according to

$$\Delta P_{tie} = P_{tie,act} - P_{tie,sch} \quad (34)$$

The frequency deviation, Δf, is the difference between the actual frequency and the desired or scheduled frequency, of which the latter is always 60 Hz in North America, i.e.,

$$\Delta f = f_{act} - 60 \quad (35)$$

ACE is the signal used to communicate to the generators whether to increase or decrease their generation levels: if ACE is negative, generation levels are increased, if positive, they are decreased. From (1), we observe:

- If ΔP_{tie}=0 and Δf =0, then ACE=0, and generation does not change;
- If ΔP_{tie}>0 which means the actual export exceeds the scheduled export, then this component would make ACE more positive therefore tending to reduce generation;
- If Δf>0 which means the actual frequency exceeds the scheduled frequency of 60 Hz, then this component would make ACE more positive therefore tending to reduce generation.

Similar observations can be made for the case of ΔP_{tie}<0 and Δf<0.

During the course of a day's normal load changes, Levels 1 and 2 control systems operate so that changes in frequency are very small. The maximum acceptable steady-state frequency deviation is 0.018Hz in the Eastern Interconnection, 0.0228Hz in the Western Interconnection, and 0.020Hz for ERCOT [3]. Frequency excursions observed outside of this range are an indication of a fairly serious imbalance problem, such as when a generator experiences an instantaneous trip.

3.3.3 Levels 3 and 4

We have already discussed levels 3 and 4 in Chapter 2, although we did refer to them as control levels. We briefly summarize them here.

The third level typically operates every 5 minutes to set each generator's basepoint power production level to optimize the BA's economic objective via an algorithm called the security-constrained economic dispatch (SCED). The SCED forms the basis of the real-time electricity markets. The third level performs load following.

The fourth level operates daily to provide next-day 24 hour power plant schedules in terms of their hourly interconnection status (up or down) and approximate dispatch via another optimization algorithm called the security-constrained unit commitment (SCUC), combined with SCED. The SCUC/SCED combination forms the basis of the day-ahead electricity markets.

In the nine electricity market systems of North America, electric energy is bought and sold where input data for levels three and four optimization algorithms SCED and SCUC are provided by participants making offers to sell and bids to buy energy, resulting in solutions that provide participant allocations in terms of locational marginal prices (LMPs) and quantities. Within the same optimization framework, a set of ancillary services are also bought and sold, including regulation, spinning reserve, and non-spinning reserve. Regulation and spinning reserve markets provide resources used by control levels two and three to provide regulation and load following.

A summary of control levels 1-4 power system control is given in
Table 1.

Table 1: Summary of control levels 1-4

Control level	Name	Time frame	Control objectives	Function
1	Primary control, governor	1-20 secs	Power balance and transient **frequency**	Transient control
2	Secondary control, AGC	4 secs to 3 mins	Power balance and steady-state **frequency**	Regulation
3	Real-time market	Every 5 mins	Power balance and **economic-** dispatch	Load following and reserve provision
4	Day-ahead market	Every day, 24 hrs at a time	Power balance and **economic-**unit commitment	Unit commitment and reserve provision

3.4 Wind energy increase of variability

3.4.1 Moving average to get regulation component

The problem at hand requires separate of the regulation component from the load following component. To do this, define L_k, LF_k, and LR_k as the load, load following component, and regulation component respectively, at time kΔt.
We assume that the load, L_k, is given for k=1,…,N.

The load-following component is given by a moving average of length 2T time intervals, i.e.,

$$LF_k = \frac{1}{2T+1}\sum_{i=k-T}^{k+T} L_i = \frac{L_{k-T} + L_{k-T+1} + \ldots + L_k + \ldots + L_{k+T-1} + L_{k+T}}{2T+1} \quad (36)$$

For example, in [4], the authors obtained load data taken at Δt=2 minute intervals, and then choose to compute LF_k based on a 28 minute rolling average, and so T was chosen as 7, resulting in

$$LF_k = \frac{L_{k-7} + L_{k-6} + \ldots + L_k + \ldots + L_{k+6} + L_{k+7}}{15} \quad (37)$$

When k=20 (the 20th time point), then

$$LF_{20} = \frac{L_{13} + L_{14} + \ldots + L_{20} + \ldots + L_{26} + L_{27}}{15} \quad (38)$$

and given that each time point corresponded to a Δt=2 minute interval, in terms of minutes, we would have

$$LF_t = LF_{40} = \frac{L_{26} + L_{28} + \ldots + L_{40} + \ldots + L_{52} + L_{54}}{15} \tag{39}$$

Figure 10 [5] illustrates a result of this computation, where it is clear that the moving average tends to smooth the function.

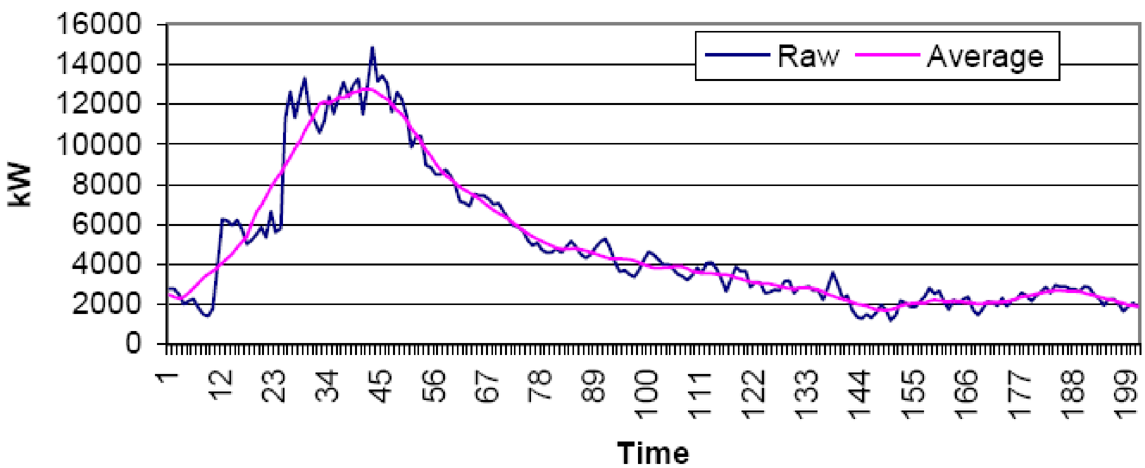

Figure 10: Illustration of moving average computation [5]

Once the load following component is obtained, then the regulation component can be computed from

$$LR_k = L_k - LF_k \tag{40}$$

Because the regulation component varies about the mean, its distribution tends to be normal, as confirmed by Figure 11 [5] which was obtained from application of (40) to the data of Figure 10.

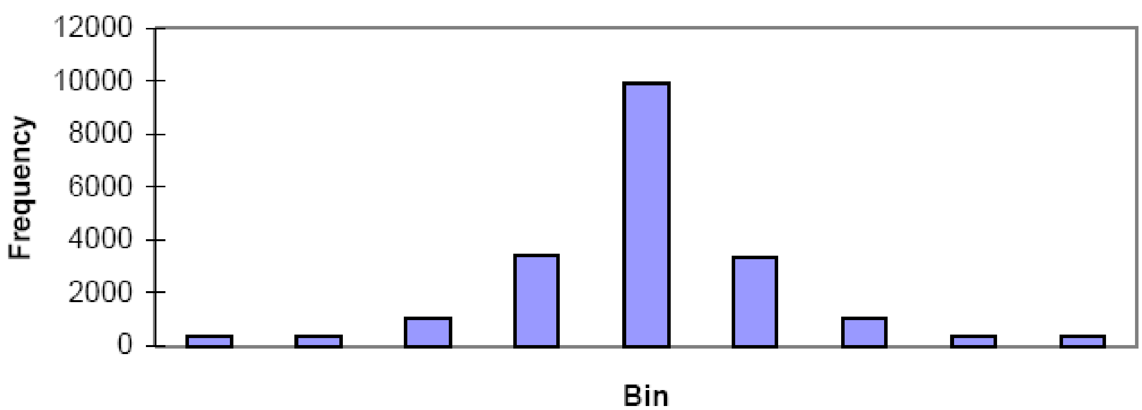

Figure 11: Illustration of normally distributed load variation

3.4.2 Variance as a measure of regulation burden

Consider X to represent a random variable. Where the expected value, or first moment, of a random variable provides the "centroid" or "balance point", there is another widely used value that is also derived from the definition of moments.

The second moment, or variance, of a random variable is indicative of the "spread" or "dispersion" of a random variable. In other words, the variance tells how concentrated about the expected value the distribution is. A lower (closer to zero) variance means the distribution is concentrated tightly around the expected value. A higher (further form zero) variance means the distribution is concentrated loosely around the expected value.

Variance is denoted by the symbol σ_x^2. Variance, the average of the square of the deviation of X from its own mean, is given by

$$\sigma_x^2 = \sum_{i=1}^{n} p_i (x_i - \mu_x)^2 \tag{41}$$

where p_i, from the probability mass function of X, is the probability of occurrence of x_i. If each x_i is equally probable,

$$\sigma_x^2 = \frac{1}{n} \sum_{i=1}^{n} (x_i - \mu_x)^2 \tag{42}$$

The positive square root, σ_x, of the variance is called the standard deviation of a random variable and is a useful measure. If a distribution is approximately normal, then approximately 68% of the values are within 1 standard deviation of the mean, approximately 95% of the values are within two standard deviations, and approximately 99.7% of the values are within 3 standard deviations, as illustrated in Figure 12.

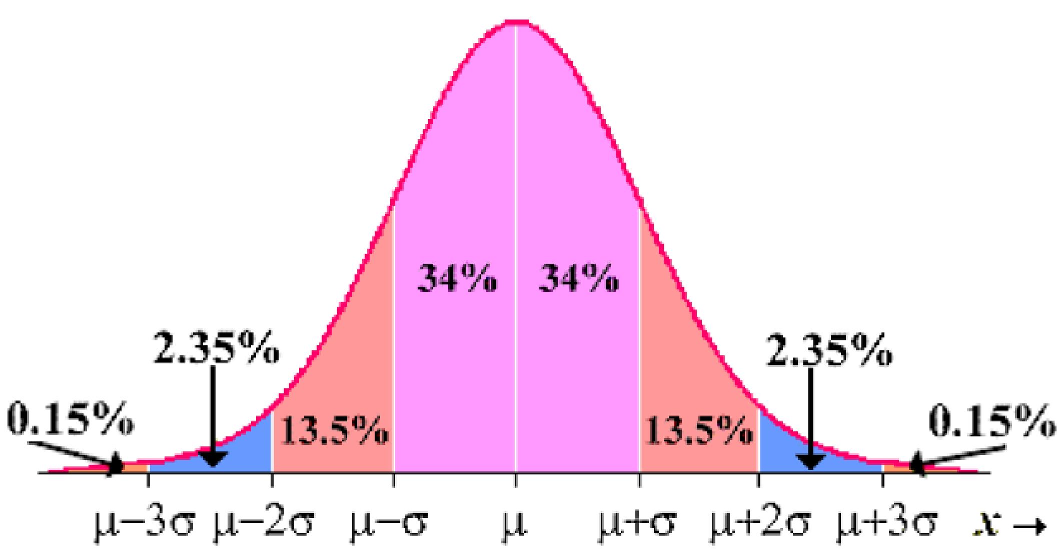

Figure 12: Normally distributed random variable and standard deviation

In designing engineering systems, it is often reasonable to assume that if the design accounts for all situations within 3σ of the mean, then the design is acceptably robust, since in such a case, the design will account for 99.7% of all possible situations.

We use 3σ to quantify regulation needs of a particular load or resource. That is, we assume that the generation reserve available to provide regulation for a particular variable resource or load is 3σ, where σ^2 is the variance of the variable resource or load.

We refer to 3σ as the *regulation burden* of the resource or load.

If two random variables are independent, then the variance of their sum (or their difference) is

$$\sigma_z^2 = \sigma_x^2 + \sigma_y^2 \tag{43}$$

This is significant because, as we recall from Section 3.1, the net is the difference between the load and the wind generation, i.e., (neglecting losses):

NETLOAD.MW=LOAD.MW-WIND.MW

Considering load and wind power as random variables, we see that (43) enables us to obtain the variance of the net load (Z) by adding the variance of the load (X) to the variance of the wind power (Y). Recalling, again from Section 3.1, that the power system requires:

GEN.MW=NETLOAD.MW

we see that the increased variability of the net load must be matched by the generation. This means that the generation must be capable of handling this variability. It is always the case that increasing wind penetration levels will eventually require solutions to handle the increased variability.

3.5 Solutions to increased variability

Power from a wind or solar generator can be controlled, albeit to a lesser extent than conventional generation. This control is currently used to maximize energy production. Generation owners prefer not to control output for any other purpose unless revenues for the provided service exceed those obtained when maximizing energy production.

Conventional generation must compensate for VG, which has two important implications for conventional generators, both of which are played out in the second level of control (AGC). First, increased levels of conventional generation are required to participate in meeting the variability. If the variability is large enough, base-load power plants (plants held at almost constant power), e.g., combined cycle natural gas, coal, and nuclear plants, may need to participate. The so-called “cycling” of these plants increase maintenance, forced outage rates, and emissions and it decreases lifetimes, which result in additional costs imposed on plant owners. Second, the portfolio of generation which will meet this variability must have increased response capabilities, e.g., portfolio average response capability of 5%/min may need to increase to 7%/min, where the percentage is of a machine’s rated power production capability. Table xx shows typical ramp rates and relative costs of various generation technologies.

Table 2: Typical ramp rates & costs associated with various generation technologies

	%/min	$/mbtu	$/kw	LCOE,$/mwhr
Coal	1-5	2.27	2450	64
Nuclear	1-5	0.70	3820	73
NGCC	5-10	5.05	984	80
CT	20	5.05	685	95
Diesel	40	13.81		

There are various ways to meet the additional variability imposed by VG, including deploying combustion turbines, demand control, and/or storage technologies, or increasing the size of the BA. A final approach is to enable VG control away from its maximum energy extraction point. Ramp-down capability is available if the VG is on-line and generating, but ramp-up capability is only available if the VG is generating below its maximum energy extraction point. Today, much attention is focused on identifying the most cost-effective array of investments to address increased variability imposed by VG.

Problems

References

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