CONTROLLING WIND ENERGY

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Wind power installed capacity is experiencing rapid growth, with 41.7 gigawatts (GW) of generating capacity installed globally in 2011, increasing the worldwide capacity by 21%[1]. Wind energy provided only 2.9% of the global electricity supply in 2011, but countries such as Denmark, Portugal, Spain, Ireland, and Germany have high wind energy penetration, producing, respectively, 29%, 19%, 19%, 18%, and 11% of their annual electrical energy from wind turbines[1]. The goal of wind power plants is to maximize profit by maximizing energy production while protecting the turbines from damaging structural loads. The turbulent, stochastic nature of the wind causes fluctuations in the power generation of the wind turbines, which must be accommodated by the utility grid operators, as the reliability of the utility grid is dependent on real-time balancing of electrical generation and load. Until recently, there have been no requirements or market incentives for wind turbines to control their power generation in response to the imbalances of active power in the grid, leaving this task up to conventional generators. Higher wind energy penetration levels have increased the interest for wind turbines to provide these ancillary services, or services that support utility grid reliability, through active power control (APC).

This article provides an overview of utility grid operation by introducing the fundamental behavior of the electrical system, explaining the importance of maintaining grid reliability through balancing generation and load, and describing the methods of providing ancillary services using conventional utilities. This article also introduces the basic structural components of wind turbines, explains the traditional control systems for capturing maximum power, and highlights control methods developed in industry and academia to provide active power ancillary services with wind energy.

UTILITY GRID OPERATION AND ANCILLARY SERVICES

The utility grid is a network of electrical transmission and distribution lines used to connect power generation plants to the load. The majority of electrical power is generated from coal, natural gas, nuclear, and hydroelectric power generation facilities, cumulatively referred to here as conventional utilities. Conventional power plants use synchronous generators that are directly coupled with the utility grid. A synchronous generator produces an alternating current (AC) power waveform with a frequency that is proportional to the rotational speed of the generator drive shaft. Conventional power plants are designed to generate AC power with a frequency equal to that of the grid (e.g., 60 Hz in North America and 50 Hz in Europe), but will fluctuate in speed as the grid frequency fluctuates. These speed fluctuations occur because the rotational speed of a conventional generator is coupled to the grid frequency through its magnetic field, which transforms electrical imbalances between generation and load into mechanical torque on the generator drive shaft and changes the rotational speed of the generator. These electrical imbalances are felt by all conventional utilities directly connected to the grid, so the grid frequency changes as a result of the coordinated speed change of the generators. The grid frequency will increase if power generation exceeds the load, and the grid frequency will decrease if the load exceeds generation.

It is crucial to keep the grid frequency within a close tolerance of the desired frequency to ensure the reliability of the grid. Sudden imbalances between generation and load may cause large fluctuations in grid frequency, referred to as a grid frequency event. An over-frequency event may be induced by a transmission fault that disconnects a branch of the load, and an under-frequency event may occur if a generating utility trips off-line, or suddenly disconnects. When the electrical power imbalances are too large, generators may disconnect from the grid as their speed deviates out of the designed operating range. Under-frequency events are generally more common and more problematic, as each generator that disconnects exacerbates the imbalance between load and generation, which can result in uncontrolled rolling blackouts. To avoid such blackouts, grid operators practice under-frequency load shedding (UFLS) if the grid frequency drops below a specified threshold, lowering the electrical demand by disconnecting particular load regions allowing the generators to recover from the event[2]. Even a momentary loss of power is undesirable and can have a significant impact on some customers, which is why grid operators strive to take

FOR UTILITY GRID RELIABILITY

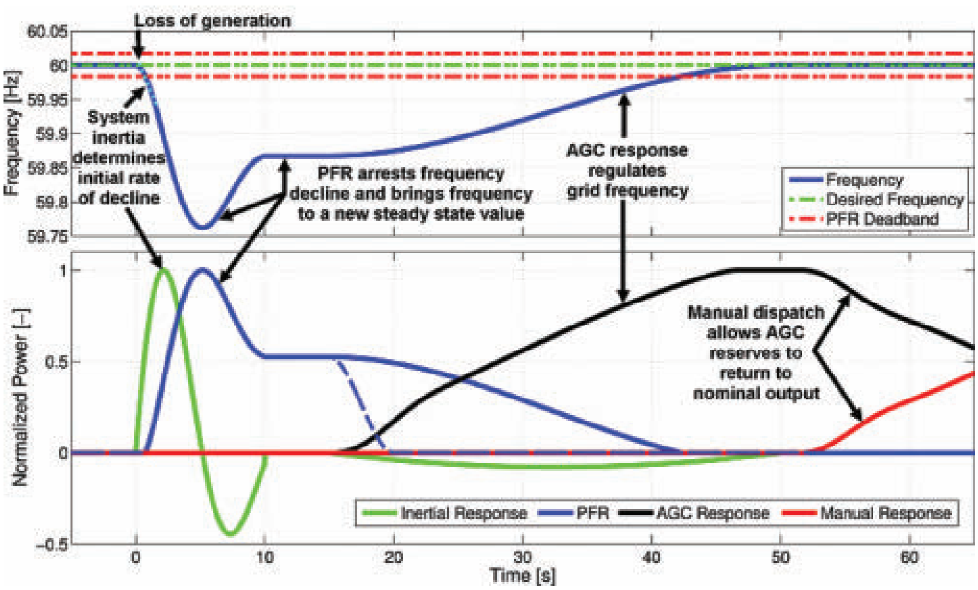

FIGURE 1 An example of grid frequency during a loss of generation frequency event and the possible response from the various frequency control regimes are shown in the upper and lower subplots respectively. Each of the power responses in the lower plot is normalized to the maximum power of the response, as these responses will vary significantly depending on the properties of the utility grid. The timing and ramp rate of economic dispatch of the manual power response is also highly variable. The solid blue line represents the ideal PFR calculated from frequency error, though many utilities can only provide this response for a limited time as depicted by the dashed blue line.

the necessary steps to ensure reliable service.

Grid operators generally do not control the electrical load on the grid, so they must maintain a balanced system by coordinating the generation in real-time. Power generation is typically procured and scheduled to match the load forecast through power markets that operate from one day to five minutes ahead of time. Operational reserves must be procured by the grid operators to participate in regulating the balance of generation and load, either from automatic or manual power commands[3]. Capable generators can also provide a stabilizing response to sudden disturbances on the grid[2] and are described in more detail later in this article.

The need to maintain sufficient operational reserves becomes an important integration cost with wind power. The grid operators in areas with low wind energy penetrations can view the variable wind power generation as an unmodeled disturbance, forcing their operating reserves to handle the power fluctuations. Increased wind energy penetrations have pushed the grid operators to utilize wind power forecasts to schedule generation in coordination with the wind, rather than procuring larger amounts of operating reserves to respond to the fluctuations in wind generation. Utilizing wind forecasts and five minute generation schedule updates have significantly decreased this integration cost of wind energy[1].

CONVENTIONAL GENERATOR ANCILLARY SERVICES

Conventional utilities can provide various active power ancillary services to control grid frequency over different time scales. These services can be divided into three categories which are inertial response, primary frequency response, and frequency regulation, which are all depicted in **Fig. 1.** This article provides a general overview of these ancillary services through simplified explanations, for a more thorough explanation, see reference 3.

The first frequency control regime is provided by the physical spinning inertia of all the synchronous conventional utilities, as their spinning inertia resists changes in speed, providing an inherent and instantaneous inertial response to changes in grid frequency. The inertial response of the grid is not a controlled response; it is a physical characteristic of the total rotational inertia attached to the generators that determines the initial rate of frequency change immediately after a generation or load disturbance.

The second frequency control regime consists of capable generating units providing controlled power responses to changes in grid frequency. This actuation is called a primary frequency response (PFR), which is designed to arrest large frequency fluctuations during the first 10 to 15 seconds after a frequency event, reducing the maximum grid frequency deviation from nominal and bringing the grid to a new steady state frequency after the event transient.

A PFR can be produced by synchronous generators with governors that control the turbine working fluid input valves as the generator speed varies. When enabled, a governor can provide a PFR by temporarily increasing/decreasing the fluid pressure through the turbine, resulting in a respective increase/decrease in the generator power output, so long as the generator is producing power and its nameplate capacity, or rated power, is not exceeded. After a grid frequency event a typical PFR from a steam turbine provides a power change of 5% of rated power in the first 5 seconds, whereas gas turbines typically change 5-8%[4]. After this initial 5-second rapid change in power output, steam plants typically ramp at 1-3% of rated power per minute, but gas plants can typically ramp significantly faster at 5-8% of rated power per minute[4]. The behavior of a governor is often characterized by a droop curve, which relates grid frequency to perturbations in power output. The primary components of a droop curve are the deadband, in which grid frequency fluctuations do not induce actuation, and the slope, or droop, which specifies the change in output power when the frequency fluctuates outside of the deadband. A droop slope is usually expressed as a percentage, indicating the percent change from nominal frequency that corresponds with a 100% change in rated power output of the utility. A common droop slope is 5%.

The third and final frequency control regime consists of regulating grid frequency by following the automatic and manual power commands generated by the grid operator. The automatic power commands are generated to correct the generation imbalance within each grid operator balancing area by sending a power control signal to each participating generator, a process known as automatic generation control (AGC). The manual power commands are produced by the grid operator to allow the automatic regulating reserves to return to their nominal state, to respond to anticipated changes in the forecasted load, or to change the power of particular generating units when it is economically or logistically preferable[3].

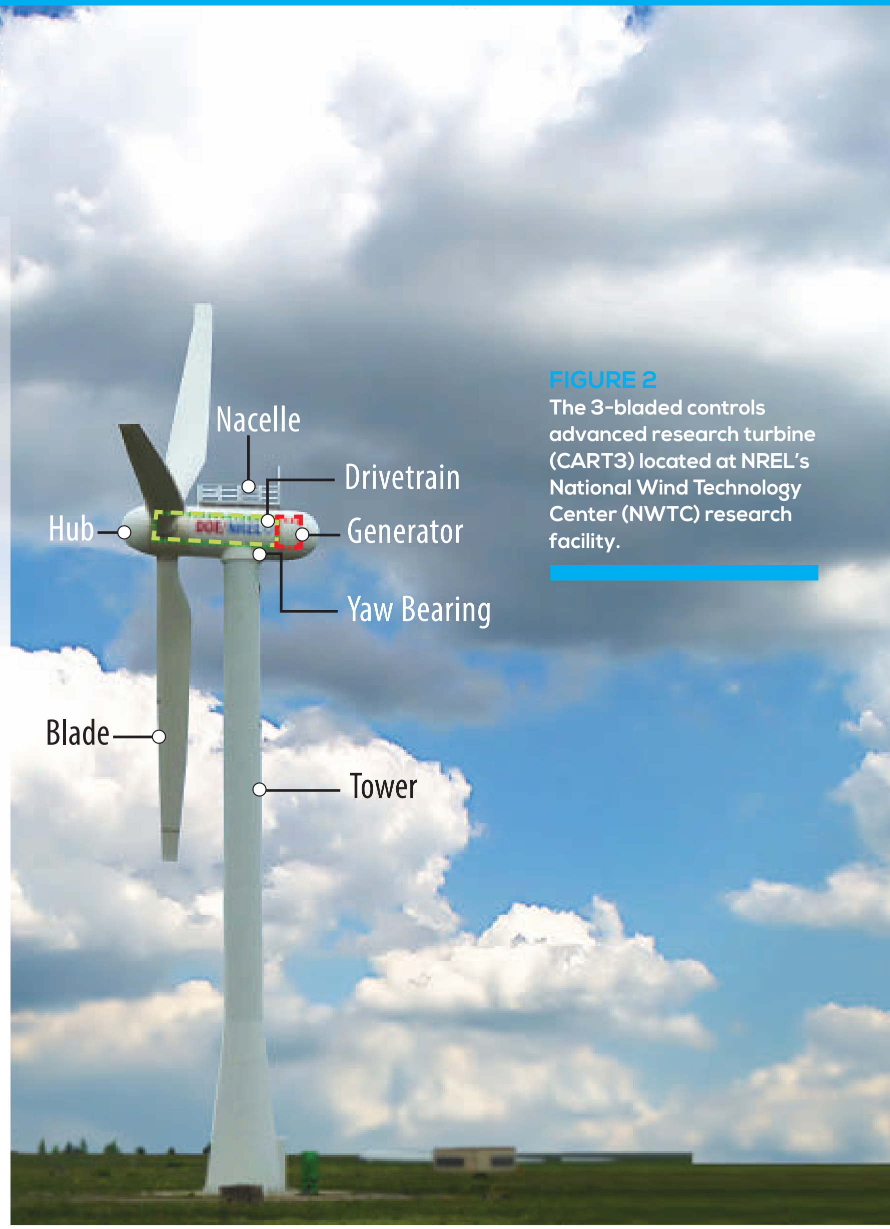

FIGURE 2
The 3-bladed controls advanced research turbine (CART3) located at NREL's National Wind Technology Center (NWTC) research facility.

WIND ENERGY BASICS

As the wind industry matures, wind energy is becoming cost competitive with conventional generation sources. The wind industry is affected by many interrelated political, technical, environmental, and infrastructural aspects. For example, as the U.S. wind market grows, the regions with favorable political and environmental conditions, such as states with renewable portfolio standards and adequate wind and transmission resources, have developed many of the best wind resource sites in close proximity to electrical transmission lines. Installing new transmission infrastructure is generally cost prohibitive for individual wind farm projects, so the location of new wind farms is often constrained to areas with existing electrical infrastructure, which has led to the decline in the overall quality of the wind resource in projects developed over the past decade[1]. To lower the cost of energy produced at these sites, wind turbine manufacturers and wind farm developers have been improving manufacturing and installing larger turbines to capture power at these lower resource sites more efficiently. In 2011, there were increases in the average nameplate generating capacity (to 1.97 MW), rotor hub height (to 81 meters), and rotor diameter (to 89 meters)[1].

WIND TURBINE OVERVIEW

Utility scale horizontal-axis wind turbines are large flexible structures that are composed of many different components. Wind turbines use large blades to generate rotational lift from the kinetic energy of the wind stream. Most large-scale wind turbines can independently pitch their blades to control aerodynamic power capture. The blades are mounted on a hub that transfers the power to a drivetrain which is connected to an electrical generator. The drivetrain of a wind turbine often uses a multi-stage gearbox to increase the rotational speed of the generator shaft, although direct-drive generators have been developed that do not require a gearbox. A protective housing called the nacelle contains the drivetrain and generator. A yaw bearing is used to connect the nacelle to the top of the turbine support tower and a yaw motor is used to track the predominant direction of the wind (see **Fig. 2**).

The power of a uniform wind stream with constant velocity passing perpendicularly through the swept area of the rotor plane is $P_w = \frac{1}{2}\rho A V^3$, where P_w is the power (W) available in the wind, ρ is the air density (kg/m^3), A is the swept area (m^2) of the rotor disk perpendicular to the wind direction, and V is the wind speed (m/s). The wind turbine rotor can only capture a fraction of the power available in the wind, and this fraction, or the aerodynamic efficiency of the rotor, is referred to as the *power coefficient* C_P. The theoretical upper limit for C_P is the Betz Limit of 16/27. The power coefficient is often characterized as a function of the collective blade pitch β, measured in degrees, and the tip-speed ratio (TSR) λ. The TSR is a dimensionless metric defined as the ratio of the tangential speed of the blade tips divided by the effective wind speed perpendicular to the rotor plane, or $\lambda = \frac{\Omega_r R}{V}$, where R is the rotor radius (m) and Ω_r is the rotational speed (rad/s) of the rotor. Varying either the blade pitch or the TSR (through changes in the rotor speed) will result in a change of the power coefficient. A characterization of C_P is shown as a contour plot in **Fig. 3**.

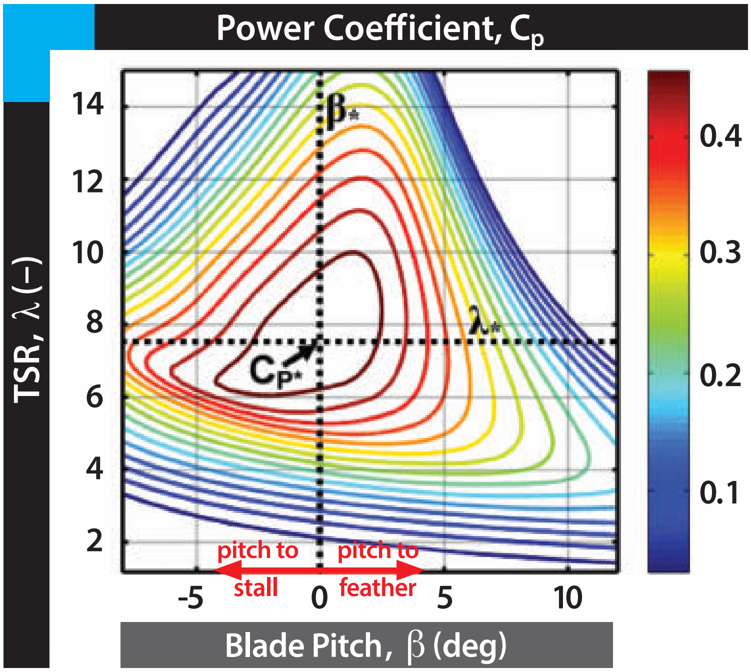

FIGURE 3 A characterization of the power coefficient C_P of an example 5MW turbine model. The black dotted lines represent the tip-speed ratio λ_* and the collective blade pitch β_* at which C_P is a maximum, or C_{P*}. This plot refers to positive pitch angles as pitching to feather and negative pitch angles as pitching to stall.

Unlike synchronous conventional utilities that are directly connected to the utility grid, most modern wind turbines are variable-speed machines, and the generator speed is not directly coupled to the grid frequency. The decoupling of the wind turbine speed and the grid frequency is performed with power electronics. The primary reason for variable-speed operation of wind turbines is to reduce the structural loads on the turbine components. The power electronics reduce turbine loads by adding compliance between the wind turbine and the utility grid, which can be thought of as a direct electrical coupling with the spinning inertia of all the other generators connected to the grid. For example, if there was a rapid increase in wind (i.e., a rapid increase in aerodynamic power captured by the blades), a variable-speed wind turbine with power electronics can absorb some of the power increase as kinetic energy as the turbine increases speed, whereas a wind turbine directly coupled with the grid would likely experience increased blade and drivetrain deflection because of the stiff coupling of the generator with the utility grid, therefore inducing increased structural loads. Another motivation for variable-speed operation of wind turbines is the ability to increase power capture over a range of wind speeds, as described in the following section. The control system on variable-speed turbines can use the power electronics to control the electrical load on the generator, which induces a mechanical torque load applied to the drivetrain via the generator.

TRADITIONAL WIND TURBINE CONTROL SYSTEMS

Traditionally wind turbine operation is divided into multiple regions of operation (see **Fig. 4**.) The turbine is considered to be in Region 1 when the winds are too low to generate power. When the wind turbine is generating power below its rated power, the goal of the control system is to maximize energy production and the turbine is considered to be in below-rated, or Region 2 operation. When the turbine is generating rated power, it is considered to be in above-rated, or Region 3 operation. The goals of the control system in Region 3 are to regulate the speed and power of the turbine and reduce the damaging structural loads experienced by the turbine components; these goals are achieved primarily through controlling the pitch angles of the blades. In order to protect the turbine against damage, the turbine will shut down when experiencing very high-speed winds, referred to as Region 4. The transition between Regions 1 and 2 is often referred to as Region 1.5 and the transition between Regions 2 and 3 is often referred to as Region 2.5.

Wind turbine control systems use a feedback measurement of the generator shaft speed to control both the pitch angle of the blades and the load torque applied to the generator end of the high-speed shaft. In Region 2 the goal is to maximize energy capture by operating the turbine at its maximum power coefficient C_{p*} as shown in **Fig. 3**. The control system tries to maintain C_{p*} by keeping the blades pitched at β_* and tracking the tip speed ratio λ_*. The control system tracks λ_* by controlling the speed of the turbine via the generator load torque τ_g

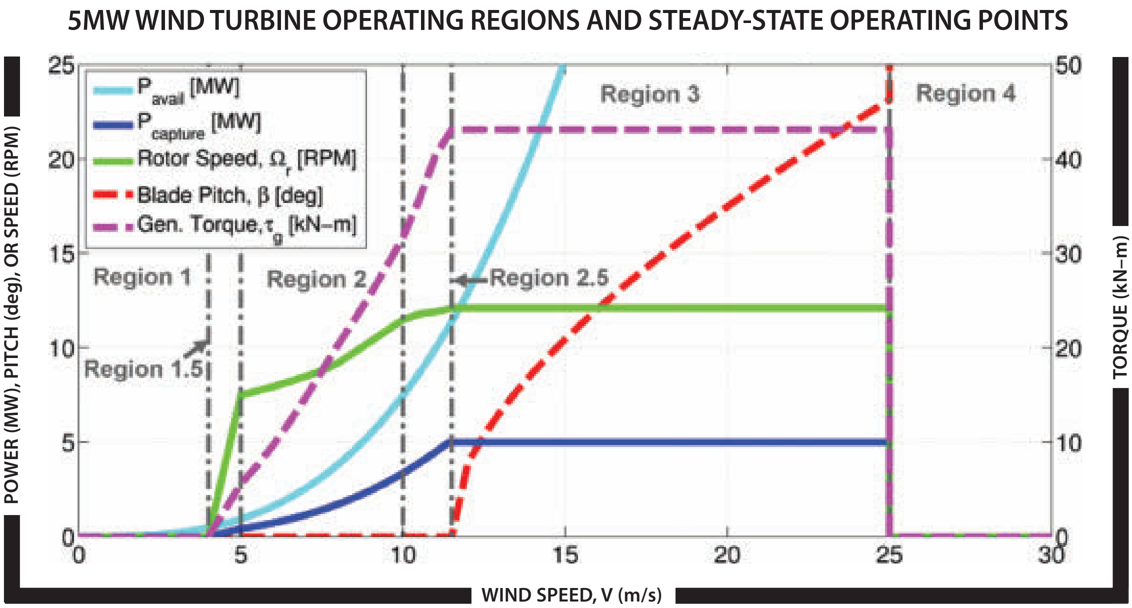

FIGURE 4 The operating regions and steady-state operating points of an example 5MW turbine model.

through a well-known feedback control law:

$$\tau_g = K_* \Omega_g^{\,2}, \quad K_* = \tfrac{1}{2}\rho A R^3 \frac{C_P(\beta_*, \lambda_*)}{\lambda_*^3 N_{gear}^{\;3}} \qquad (1)$$

where N_{gear} is the gearbox ratio of the generator speed to rotor speed. In Region 3, many wind turbines use a proportional-integral (PI) control system to vary the collective pitch of the turbine blades to regulate the turbine to the rated speed. The PI control system may be gain-scheduled according to the current blade pitch angle to account for different aerodynamic sensitivity at different blade pitch positions. Turbines with active pitch control systems are either designed to pitch to feather or pitch to stall, as shown in **Fig. 3**. Pitching to feather is more common in large-scale turbines because it is quieter and induces lower structural loads, though pitching to stall can be a faster way to reduce the aerodynamic power capture. Some wind turbines have strain gauges embedded inside each blade to provide a feedback measurement used to individually pitch the blades and mitigate the once-per-revolution fatigue loads induced by wind variations over the rotor plane, most notably the vertical shear typical from higher wind speeds at increased heights.

DAMAGE EQUIVALENT LOADS (DELS)

Variations in stress on the turbine components cause fatigue, which over time may lead to failures. Time-series data of the loads on various turbine components can be obtained from both sensor measurements and simulations. The damage equivalent load (DEL) computed from such a time series is the amplitude of a sinusoidal load, at a given constant frequency, that would cause the same fatigue damage as that time series itself[5]. The DEL is useful because it provides a single number for each time series, allowing comparisons of the amount of damage caused.

The calculation of a DEL assumes $N = CS^{-m}$, where N is the number of cycles to failure at load amplitude S, and C and m are material properties[5]. This DEL calculation approximates the S-N curve, or Wöhler curve, as a straight line when plotted on a log-log scale, with slope determined by m (see **Fig. 5**). A value of m = 3 to 3.5 is typically used for welded steel (tower), m = 6.8 for ductile iron (hub), and m = 10 for glass-reinforced plastic (blades).

To calculate a DEL one must first extract the local maximum and minimum values and then create a vector of reversal amplitudes (B) via the rainflow counting method[5]. The DEL is then calculated as:

$$DEL = \left(\frac{\sum_i B_i^m}{T} \right)^{\frac{1}{m}} \qquad (2)$$

where T is the total time. As m increases, the DEL depends more heavily on the largest amplitude reversals. The DEL calculation is only an estimate of fatigue damage and neglects several factors such as mean-load levels. The DEL is most useful for comparison of relative fatigue damage on the same turbine component under different conditions.

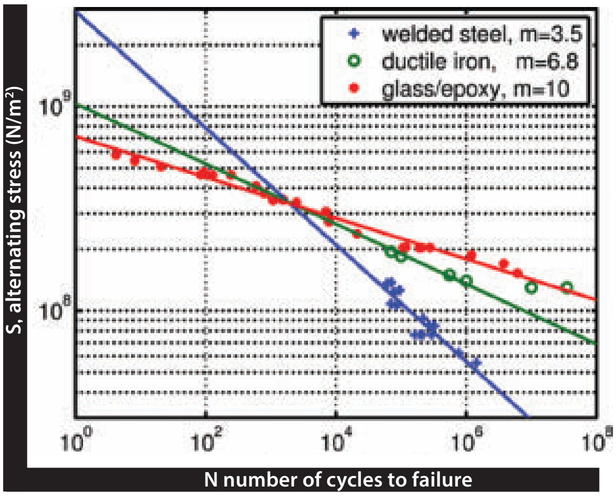

FIGURE 5 Example S-N data for welded steel (R = 0.1)[6], ductile iron (R = 0)[6], and glass/epoxy (R = -1)[7], along with lines of $N = CS^{-m}$. The rightmost two points of ductile iron were excluded from its curve fit because those stresses are below the fatigue limit for the material, below which the S-N curve is flat. The data are taken with three different values of stress ratio (R) (ratio of minimum to maximum stress), and therefore are not intended for direct comparison with each other.

WIND ENERGY ACTIVE POWER CONTROL FOR ANCILLARY SERVICES

Historically, wind power has not provided APC ancillary services, because there have been no requirements from grid operators or market incentives to do so. Most large-scale modern wind turbines are de-coupled from the utility grid via their power electronics, so they do not inherently provide an inertial response to fluctuations in grid frequency. However, increasing wind energy penetration on some grids has brought about new requirements for wind turbines to provide active power control services[1]. These new requirements and the necessity to maintain grid reliability have led industry and academia to actively research methods to provide APC ancillary services with wind turbines. Research on wind APC has focused on control systems that can meet or exceed new requirements, balancing the speed of tracking power commands, increased actuator usage, and induced structural loads without exceeding the safe operating limits of the turbine.

Providing a full range of active power ancillary services from a wind turbine or wind farm requires a measurement of the grid frequency for providing frequency responses and communication between the grid operator and the wind farm for frequency regulation and active de-rating services. A wind farm control system can be used to determine individual turbine power commands, which can be tracked by the individual turbine control system (see **Fig. 6**).

INDIVIDUAL TURBINE APC

Actively controlling the power generation of a wind turbine is fundamentally constrained by the available wind resource, limiting the control authority of the wind turbines to de-rating below the traditional maximum energy capture control strategy. There are many different methods of generating de-rating power commands, for example:

1. Maximum power threshold—implementing an upper bound on the power produced.

2. Absolute delta—maintaining a constant power reserve from the power available in the wind.

3. Percentage delta—capturing a fraction of the power available in the wind.

Note that in order to implement de-rating method 2 or 3, an estimate of the power available in the wind is required, which can be calculated from either measurements or estimates of the effective wind over the rotor plane. Once de-rated, the turbine can track both positive and negative perturbation power commands from the grid operator and has the ability to provide a PFR during under-frequency events. A wind turbine can be de-rated by:

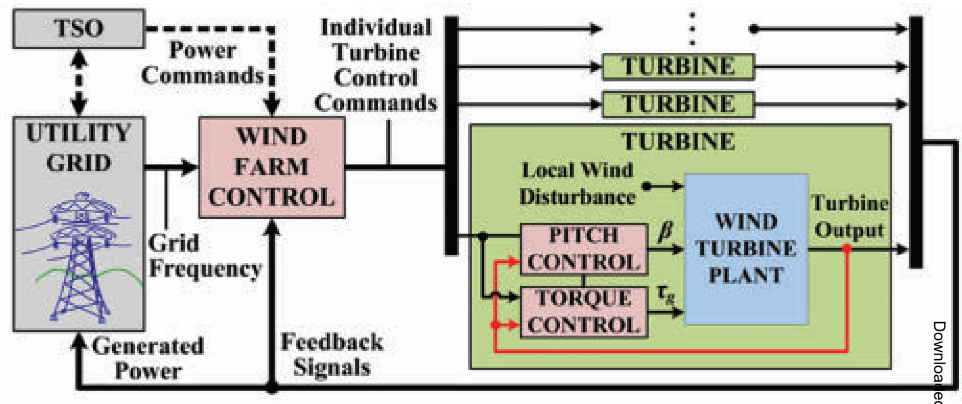

FIGURE 6 The interconnection between the utility grid, grid operator, wind farm control system, and the individual turbine control system. The wind farm controller measures the grid frequency so that it can provide a primary frequency response (PFR) and receives power commands from the grid operator, for example de-rating commands, power generation schedules, or balancing commands.

1. Rotor speed control, i.e., using the generator torque to control the turbine TSR.

2. Pitching the blades to shed extra aerodynamic power, or using a combination of the two methods.

One common de-rating method in the literature is to utilize rotor speed control to spin the turbine faster than the optimal tip speed ratio, yielding $\lambda > \lambda_*$ which results in a lower power coefficient of the turbine rotor, or $C_P < C_{P*}$, as seen in **Fig. 3**. A specified fraction of the available power in the wind can be captured by changing the traditional Region 2 feedback control gain K_* in Eq. 1 to a higher value. The steady-state power available from the wind, captured using a traditional controller, and captured using rotor speed control de-rating can be seen in **Fig. 7**.

Using rotor speed control to de-rate a turbine will spin the turbine faster than normal, storing additional kinetic energy in the turbine rotor that can be extracted when the power commands increase. The amount of kinetic energy stored in a rotating wind turbine is discussed in "Energy Stored in a Wind Turbine". This method of increasing the rotor speed can only be used during below-rated wind speeds, as the turbine should not operate higher than the rated speed for which it was designed. Once the turbine reaches rated speed, the blade pitch controller can be used to shed the additional aerodynamic power and regulate the turbine at the rated speed.

A wind turbine can provide a PFR by measuring the grid frequency and using a droop curve to generate PFR power commands. Like a conventional generator, a wind turbine can only provide a full PFR to an under-frequency event if de-rating is used, though a wind turbine must be de-rated below the available wind power rather than simply de-rating from the maximum power output. If a wind turbine attempted to provide a PFR to an under-frequency event while capturing the maximum power available from the wind, the generator torque could be increased to extract some of the kinetic energy stored in the rotor. The increased torque would likely slow the turbine, decreasing the TSR below λ_*, which would require a recovery period of reduced power output as the generator torque is decreased so the turbine may return to λ_*. Providing such a brief power increase followed by a net power decrease may be undesirable when attempting to stabilize grid frequency with a PFR.

Industry research in wind energy APC is mostly proprietary, but general trends in industry research can be seen in the patent literature and other industry publications. For example, information can be found in the public domain regarding the range of APC capabilities now available with General Electric wind turbines, such as active de-rating, inertial response emulation, and primary frequency response via a droop curve[8]. Other wind turbine manufacturers have only published patents on their APC capabilities, such as Siemens, Mitsubishi, and Vestas.

Academic research into wind turbine active power control has covered a variety of topics. Many studies have focused on the control of the generator torque through the power electronics[9]. Several recent studies have analyzed the tradeoff between aggressive primary frequency response and turbine structural loads during a frequency event, performing both grid-level and high-fidelity individual turbine simulations. One of these studies presents a control system that is capable of all three of the aforementioned wind turbine de-rating modes and providing a PFR[10]. This control system is currently being field tested on the CART3 research turbine, seen in **Fig. 2**, which is located at the NREL National Wind Technology Center. **Figure 8** depicts a time-series plot of data collected from the field.

Wind turbines have the flexibility of being variable-speed machines, allowing for rapid extraction of power from the rotor's kinetic energy through the electronically controlled generator torque. In addition, the blade pitch rates can allow for more rapid ramping of power than conventional steam plants, especially for regulation purposes. Despite these advantages, providing rapid power changes with a wind turbine is much more challenging than conventional generation. Wind turbines have long flexible blades, often use a gearbox, and sit atop a flexible tower. Controlling the generator load torque to quickly extract the kinetic energy from the turbine raises the concern of inducing damaging loads on the wind turbine gearbox, blades (primarily through bending moments aligned with the rotor plane), and tower (primarily the side-side bending moment of the tower). Rapid power changes induced by pitching the blades result in fast variations to the thrust on the rotor plane, possibly damaging the blades and tower (primarily through moments induced perpendicular to the rotor plane and the fore-aft bending moment of the tower), and increased potential to wear out the pitch actuators.

Providing a primary frequency response with de-rated wind turbines has been shown to be capable of responding faster than conventional generators, reducing the maximum frequency deviation when compared to a coal plant directly replacing the wind generation[10]. Providing a primary frequency response using a common droop curve slope, the same as the grid connected conventional generators, improves the grid frequency transient while only slightly increas-

STEADY-STATE POWER CAPTURE WITH $\beta = \beta_*$

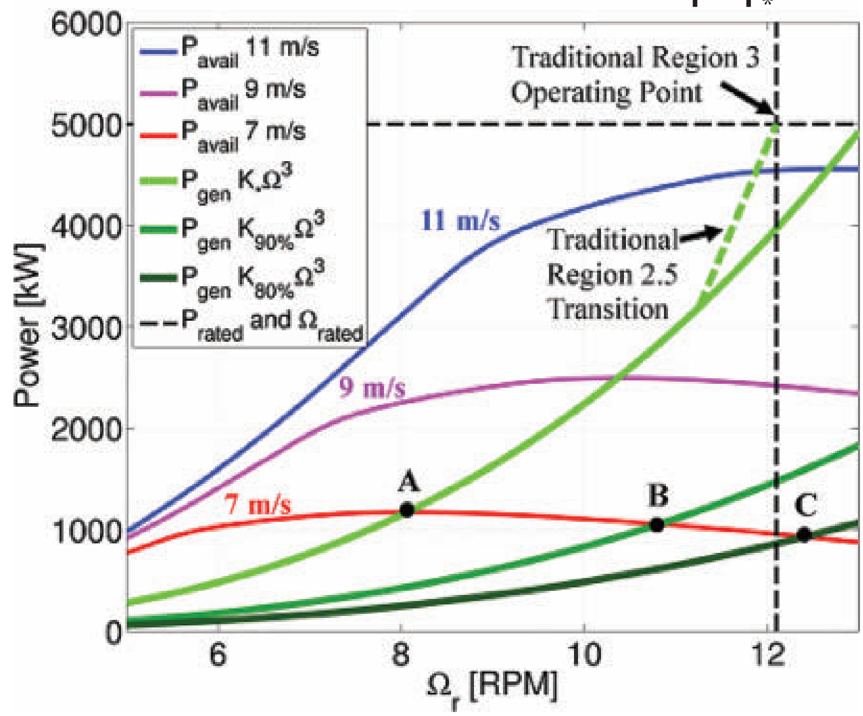

FIGURE 7 Steady-state power capture curves for varying wind speeds at β_* for an example 5MW wind turbine model. Also shown is the steady-state power generation using a traditional control system using the Region 2 torque control $\tau_g = K^*\Omega g^2$ and an example Region 2.5 transition that could be used to reach rated speed and rated power simultaneously. The de-rated control trajectories that capture 90% and 80% of the power available from the wind are shown, with point 'A' lying on the traditional maximum power capture trajectory and points 'B' and 'C' lying on the 90% and 80% power capture trajectories for a wind speed of 7 m/s, respectively.

Energy Stored in a Wind Turbine

The kinetic energy (KE) [joules] stored in a body with rotational inertia J [kg-m^2] rotating with speed Ω [rad/s] is

$$KE = \frac{1}{2}J\Omega^2$$

The rated speed, total rotational inertia, and energy stored in a 550kW, 1.5 MW, and 5MW turbine rotor spinning at rated speed is presented in the table below. The energy storage is presented in kWh and also the number of hours you could power a 60 watt light bulb with the energy stored in the rotor.

rated power [MW]	rated speed [rad/s]	inertia [kg-m^2]	energy stored [kW-h]	60 W light [hrs]
0.55*	3.9	611,061	1.29	21.5
1.5	2.14	2,962,443	1.88	31.4
5	1.27	38,759,228	8.68	144.7

*CART3 research turbine, as seen in Fig. 2.

ing a subset of the DELs induced on the turbine components. When the wind turbine control system used a more aggressive (steeper) droop curve with a 2.5% slope, the loss-of-generation frequency transient was improved further but significantly increased the induced DELs [10]. The tradeoff between the frequency response and the DELs does require further investigation, since the DELs are used to calculate fatigue damage and grid frequency events may only happen several times a week.

De-rating the turbines can reduce the DELs because of the reduced power capture, but attempting to maintain an absolute or delta reserve with high bandwidth can lead to increased actuation and higher DELs due to rapid fluctuations in the wind speed measurement or estimates. The DELs induced by participating in AGC will also depend on the bandwidth of AGC command tracking.

CART3 APC FIELD TEST RESULTS: FREQUENCY INPUT AND POWER

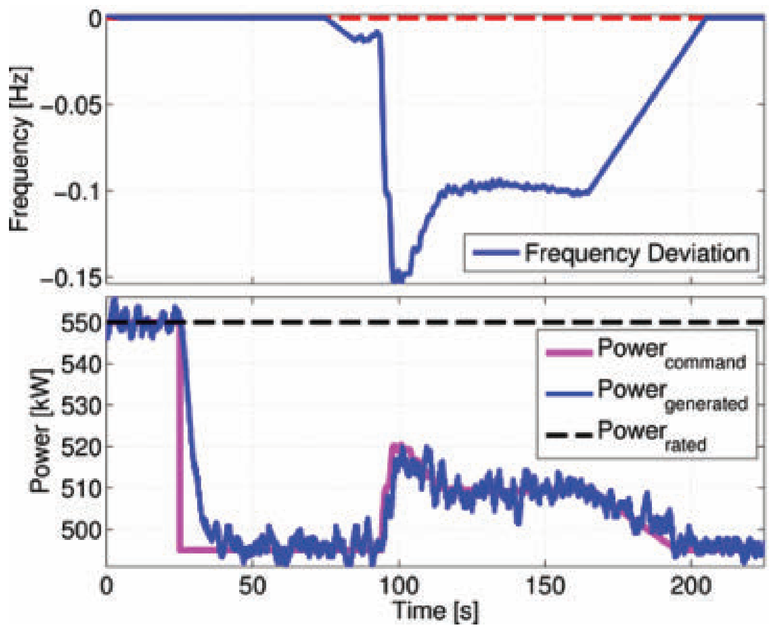

FIGURE 8 The frequency data input and power that is commanded and generated during a field test with the 550 kW NREL CART3 wind turbine. The frequency data was recorded on the ERCOT interconnection in Texas (data courtesy of Vahan Geovorgian, NREL). The upper plot shows the grid frequency, which is passed through a 5% droop curve with a deadband to generate a power command. The high-frequency fluctuations in the generated power would be smoothed when aggregating the power output of an entire wind farm. For more information on the control system used during this field test see reference 10.

WIND FARM APC

Wind turbine APC control systems can influence the structural loads and power generation capability of downstream turbines as the wake of the upstream turbine is dependent on the control actions taken. Such phenomena need to be taken into account when realistically assessing the performance of a plant-wide APC strategy. Coordinated frequency control across an entire wind farm has a number of potential advantages over control systems that only consider a single turbine. Coordinated strategies can allow individual turbines to de-rate differently depending on local wind conditions, for example by accounting for the aerodynamic wakes induced by upwind turbines through consideration of the wind velocity, wind direction, and the wind farm layout.

High fidelity simulations of numerous wind turbines in a single wind farm are generally highly resource intensive, and many currently available simulation codes are not appropriate for evaluating plant-wide effects. NREL's FAST code is a numerical modeling code based on blade-element momentum theory that allows for high fidelity simulations of aero-elastic wind turbine models operating with turbulent wind inflow [11]. The FAST code is a useful tool for the design and analysis of wind turbine control systems, but until recently simulations were limited to a single turbine, as downstream wake effects and turbulence evolution, both important in wind farm simulations, were not considered. An advanced simulation tool called Simulator for Offshore Wind Farm Applications (SOWFA) is under development at NREL to simulate multiple wind turbines with the FAST code. SOWFA uses a computational fluid dynamics solver that can compute evolving turbulence conditions and wake propagation, allowing for multiple FAST models to be coupled together [12]. Such a simulation tool can be used to evaluate the turbine interactions that arise as a consequence of performing coordinated APC across an entire wind farm.

Lack of high fidelity wind farm simulation software has not stopped plant-wide active power control systems from being investigated and implemented. Horns Rev and Nysted, both Danish offshore wind farms, are outfitted with plant-wide APC systems [13]. A plant-wide supervisory controller at these wind farms can issue power commands to individual turbines based on current power system load and measurements regarding the power available at each individual turbine across the wind farm. The individual turbines are also equipped with their own active power controllers, allowing for plant-wide de-rating, in either absolute or percentage delta operation. Such control systems represent the state-of-the-art of the industry pertaining to wind farm APC.

CONCLUSIONS

Higher wind energy penetrations are being reached with decreasing cost of integration because of technology improvements and their adoption. Grid operators can now accommodate fluctuating wind power thanks to improved forecasting, the implementation of more frequent updates in power generation markets, and the ability to rapidly curtail wind when necessary. Several European grid operators in countries like Spain, Denmark, and Ireland as well as the ERCOT system in Texas now require new wind farms to have certain APC capabilities to enable wind farms to provide reliable service to the utility grid.

As the penetration of wind energy continues to grow, the participation of wind turbines and wind farms in grid frequency stability is becoming more important. Wind turbine manufacturers and academic researchers have developed control systems with the capabilities to meet recent requirements set by grid operators, but research to determine the full capabilities of wind turbine APC is ongoing. Areas of interest for future research include continued development of wind turbine APC controllers that can provide rapid power response while reducing the structural loading on turbine components and optimizing the provision of active power ancillary services from wind farms. Research must consider the balance of aggressive power control against increased actuator usage and structural loads, as well as the potential coupling of APC and conventional turbine control loops while allowing the supervisory control system to maintain safe operation. Such research will help determine the full benefit of widespread adoption of advanced APC services provided by wind turbines.

The future of wind energy development and deployment depends on many factors, such as policy decisions, economic markets, and technology improvements. Improvements through research and development in areas such as forecasting, turbine manufacturing processes, blade aerodynamics, power electronics, and active power control systems will continue to be a key driver for wind energy technology. The U.S. Department of Energy (DOE) claimed there are "no insurmountable barriers" to reaching the goal of 20% wind production by the year 2030[1]. Reaching such goals for high wind energy penetrations will provide interesting and exciting research opportunities to determine new market mechanisms, operational methods, and technology capabilities to increase the adoption of this variable resource for a more reliable, efficient, and sustainable future. ■

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