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Active Power Controls from Wind Power: Bridging the Gaps

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Technical Report
NREL/TP-5D00-60574
January 2014

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List of Acronyms

AC	alternating current
ACE	area control error
AGC	automatic generation control
APC	active power control
BA	balancing area
CAISO	California ISO
CART3	3-Bladed Controls Advanced Research Turbine
DC	direct current
DDC	dynamic droop curve
DEL	damage equivalent load
DLL	dynamic-link library
EI	Eastern Interconnection
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FSC	filtered split controller
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IFRO	Interconnection Frequency Response Obligation
ISO	independent system operator
LMP	locational marginal price
MAPS	Multi-Area Production Simulation
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWTC	National Wind Technology Center
NYISO	New York ISO
PFC	primary frequency control
PI	proportional-integral
PSLF	Positive Sequence Load Flow
ROCOF	rate of change of frequency
RTO	regional transmission organization

SCADA	supervisory control and data acquisition
SDC	static droop curve
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
TEPPC	Transmission Expansion Planning Policy Committee
TSR	tip-speed ratio
UFLS	under-frequency load shedding
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WTG	wind turbine generator
WWSIS-1	Western Wind and Solar Integration Study Phase 1

Executive Summary

Wind energy has had one of the most substantial growths of any source of power generation. In many areas throughout the world, wind power is supplying up to 20% of total energy demand, and in some instances it provides more than 50% of the power in certain regions. Wind power falls under the category of variable generation, as its maximum available power varies over time (variability), and it cannot be predicted with perfect accuracy (uncertainty). Wind power, particularly variable-speed wind power, which is the majority of all wind plant capacity of the world, is also different from conventional thermal and hydropower generating technologies, as it is not synchronized to the electrical frequency of the power grid and is generally unresponsive to system frequency.

These three characteristics—variability, uncertainty, and asynchronism—can cause challenges for maintaining a reliable and secure power system. Many studies have been performed to better understand these system impacts. Utilities, balancing area (BA) authorities, regional reliability organizations, and independent system operators (ISOs) are also developing improved strategies to better integrate wind and other variable generation. Demand response, energy storage, and improved wind power forecasting techniques have often been described as potential mitigation strategies. The focus of this report is a mitigation strategy that is not often discussed and is in some ways counterintuitive: the use of wind power to support power system reliability by providing active power control (APC) at fast timescales. APC is the adjustment of a resource's active power in various response timeframes to assist in balancing the generation and load, thereby improving power system reliability.

The National Renewable Energy Laboratory (NREL), along with partners from the Electric Power Research Institute and University of Colorado and collaboration from a large international industry stakeholder group, embarked on a comprehensive study to understand the ways in which wind power technology can assist the power system by providing control of its active power output being injected onto the grid. The study includes a number of different power system simulations, control simulations, and actual field tests using turbines at NREL's National Wind Technology Center (NWTC). The study sought to understand how wind power providing APC can benefit numerous parties by reducing total production costs, increasing wind power revenue streams, improving the reliability and security of the power system, and providing superior and efficient response, while limiting any structural and loading impacts that may shorten the life of the wind turbine or its components.

The three forms of APC focused on in this study are synthetic inertial control, primary frequency control (PFC), and automatic generation control (AGC) regulation. This project and report are unique in the diversity of their study scope. The study analyzes timeframes ranging from milliseconds to minutes to the lifetime of wind turbines, spatial scope ranging from components of turbines to large wind plants to entire synchronous interconnections, and topics ranging from economics to power system engineering to control design. The study captures a more holistic view of how each of these impacts and benefits can be realized.

Wind power plants have often been deemed a non-dispatchable resource and considered similar to inflexible demand. The rest of the power system resources have traditionally been adjusted around wind power to support a reliable and efficient system. In 2008, the New York

Independent System Operator (NYISO) started using wind power plants in its dispatch procedure to help manage transmission congestion at a five-minute resolution. Now, essentially all ISOs in the United States and many areas outside the ISO regions are utilizing wind power to provide this form of dispatch capability.

These regions have found the tremendous capability that wind power can provide in controlling its output to be extremely beneficial. This capability has been often ignored because wind power (along with other renewable resources) has a free fuel source, and therefore system operators have historically attempted to use as much wind generation as possible at all times. However, in many situations, due to minimum thermal generation levels and transmission constraints, it was cheaper to utilize less than the maximum amount of available wind power to provide this dispatch flexibility to assist the power system. These two concepts—(1) that wind power can provide support to the power system by adjusting its power output, and (2) that it may be economically advantageous to do so—should certainly be explored utilizing faster and more sophisticated forms of APC.

Many of the control capabilities being researched in this project have already been generally proven technically feasible, and a few areas throughout the world have already started to request or require wind plants to provide them. However, at least in the United States, wind power is rarely recognized as having these capabilities. This may be due to differences in perspective among various stakeholders (see Figure ES-1 below).

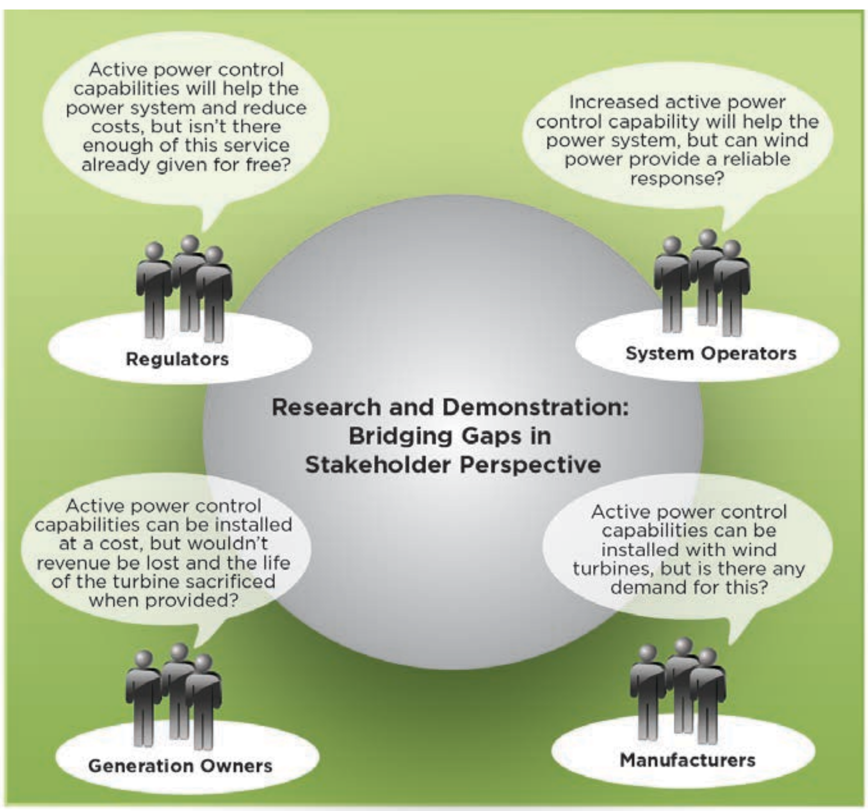

Figure ES-1. There may be different perspectives among various stakeholders on the feasibility, benefits, and economic justification for wind power to provide various forms of APC. This project bridges these gaps in perspective with research and demonstration.

For example, a manufacturer may know the capability is technically feasible but may not see a market for it because there is no demand from a developer or requirement from a utility off-taker to provide the capability. On the other hand, the system operators may desire the capability but be unsure of exactly how it performs or whether or not it will actually improve system reliability. The wind plant owners may know what features the turbines are capable of, but choose not to procure them or offer them to the off-taker if the functionality is not required or if it does not result in increased revenue. Finally, the regulators or market operators may not establish complementary policies or market designs if the markets are receiving enough capability and it is provided for free, without any outlook on how this may change in the future.

With this project's holistic research approach and extensive demonstration and dissemination plans, the team sought to close these gaps in perspective. If wind power can offer a supportive product that benefits the power system and is economic for the wind plant and consumers, this functionality should be recognized and encouraged.

The three forms of APC discussed in this study are inertial control, PFC, and AGC regulation. Brief descriptions are presented below. Figure ES-2 shows the result of aggregate APC response of system frequency following a loss-of-supply event. Figure ES-3 shows the response of balancing load and generation during normal conditions.

- **Inertial control**: Inertial control is the immediate response to a power disturbance based on a supply-demand imbalance. This response is currently given by synchronous machines that immediately inject (extract) kinetic energy of their rotating masses to (from) the grid, thereby slowing down (speeding up) their rotation and system frequency during loss-of-supply (-load) events. Aggregate inertial control will slow down the speed of frequency decline (see initial slope of frequency in Figure ES-2). Tests will analyze how wind power can bring out its own inertia through power electronics controls to provide immediate energy to reduce the rate of change of frequency.
- **PFC**: PFC is the response following inertial control that increases (decreases) the output of generators to balance generation and load during loss-of-supply (-load) events. This response is typically given by conventional generators with turbine governor controls that adjust output based on the frequency deviation and its governor droop characteristic. The aggregate PFC response will bring frequency to a new steady-state level (see Figure ES-2, 20–30 s after frequency drop). Tests will analyze how wind power can provide energy in this timeframe to assist in arresting frequency deviation, raising the frequency nadir (minimum frequency point) for a given loss of supply, and stabilizing the system frequency following a disturbance.
- **Regulation and AGC**: AGC is used during normal conditions and emergency events. Regulation, also called load frequency control and secondary control, is typically provided by resources with direction of an automatic control signal from a centralized control operator and is a response slower than PFC. The AGC response will bring frequency back to its nominal setting (which, in North America, is 60 Hz). This can be seen in Figure ES-2 at 5–10 minutes after the frequency decline. It also reduces the area control error (ACE) to ensure that frequency and interchange energy schedules between regions are kept to set points during normal conditions (see the red trace in Figure ES-3).

Tests will analyze how wind power can provide this control to stabilize frequency and reduce ACE.

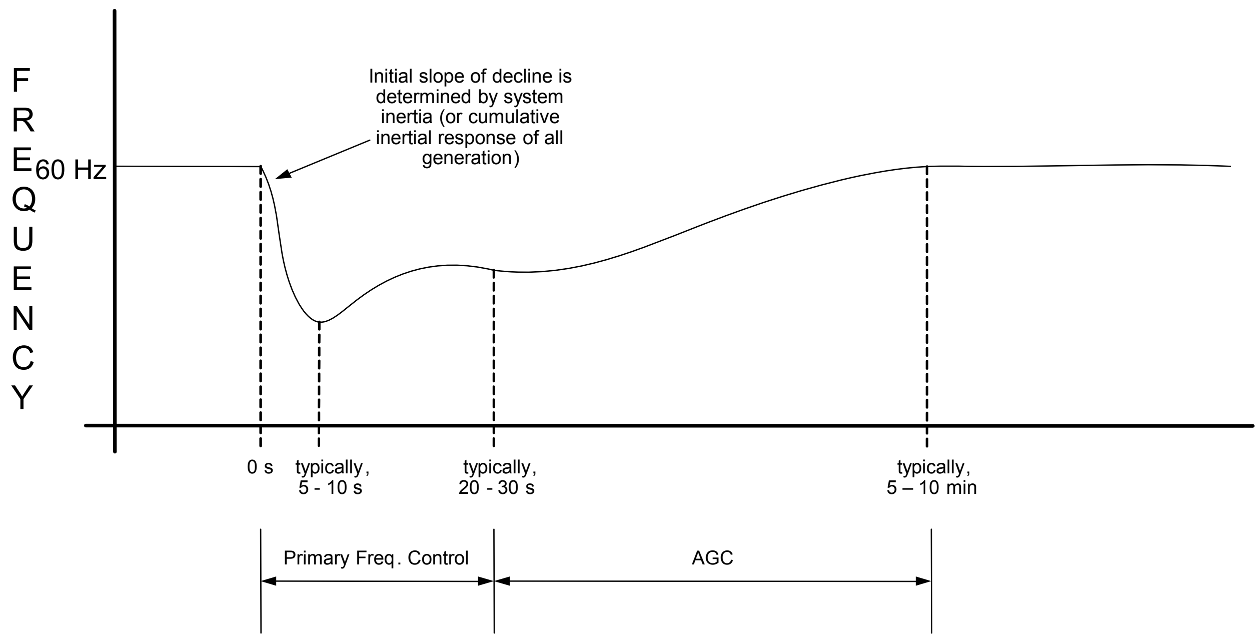

Figure ES-2. Frequency trace following a large contingency event (i.e., loss of a large generating unit). Inertial control, PFC, and AGC (secondary frequency control) each serve a different purpose, and their response timeframes are also at different points of the frequency recovery.

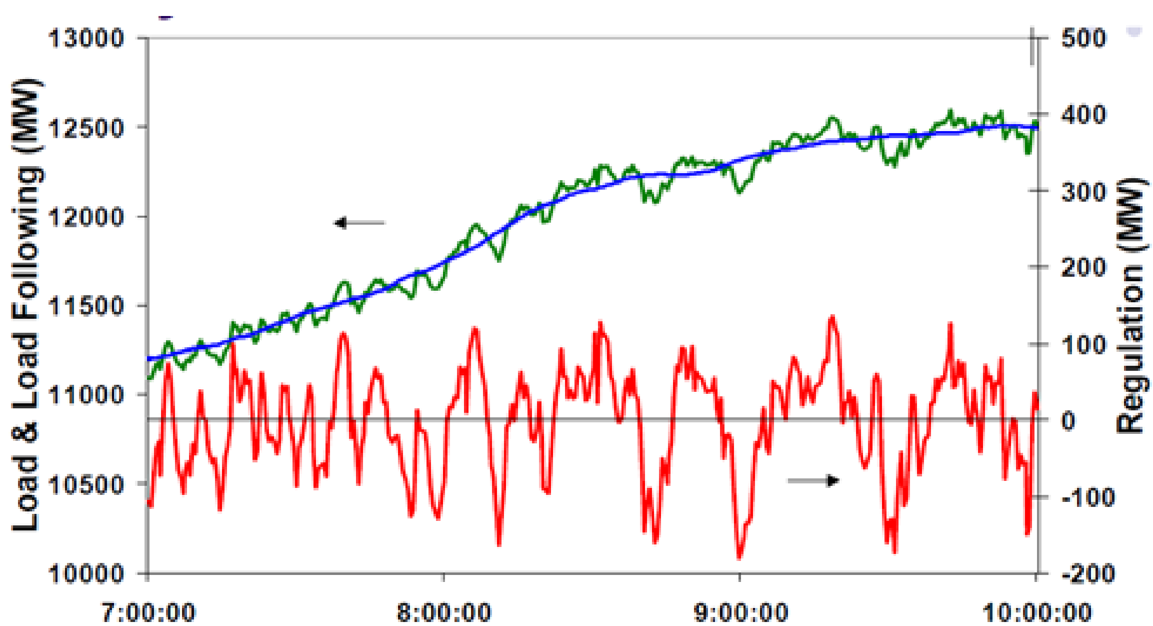

Figure ES-3. Regulation and load following during normal conditions.

For wind power to provide these three services, it is essential that three things happen.

First, the wind power response needs to improve power system reliability if it is provided, and not impair it. Wind turbines are quite different from conventional steam, combustion, and hydro turbines. The APC response provided will likely be different from the response from conventional plants, and it is essential that this response is analyzed and understood to support power system reliability. Second, it must be economic for wind power plants, as well as for electricity consumers, to provide these forms of APC, considering the additional capital costs for the controls. Also, when wind power activates these controls, it often must reduce the amount of energy it sells to the market. It would thus make little sense for wind to provide these controls if there are no incentives to provide it, or if it raises costs to electricity consumers. Third, providing the three forms of APC should not have negative impacts on the turbine loading or induce structural damage that could reduce the life of the turbine. The control design should be carefully optimized to provide a superior response, but ensure that it does so without adversely impacting the wind turbine or any of its components. Simulations and measured data in the field can show how different control strategies can impact loading.

This study sought to analyze each of these issues. While plenty of additional analysis and research can be performed to examine these topics even further, this is the first holistic approach aimed at addressing these questions together. Our analysis shows that wind power can support power system reliability by providing these controls, but the combination of these controls should be carefully considered. Our analysis also shows that forms of APC that currently have existing markets can allow wind to earn additional revenue and reduce production costs to consumers, although the magnitude of these revenues will highly depend on the trends of these markets, as typical prices are highly volatile. This study also analyzed how new ancillary service markets could be designed for the services that do not currently exist. Lastly, this study determined that any loading impacts caused from providing these controls are very small and, when considered with the benefits of reduced loading from de-rating the turbine, will actually have a positive effect on loading. Market designs, reliability criteria, the competitive field, and the evolution of the design for each of these controls will dictate future opportunities in various regions.

Economics and Steady-State Power System Impacts

The first task of this work focuses on the impacts of using wind power for APC on the steady-state operation of the power system, as well as the associated economic impacts. The goal of this task is to understand how wind providing APC affects steady-state operations, wind power revenue, and electricity production costs, as well as how markets may evolve to address new needs.

As an overview, below is the current status of each of the three APC services addressed in this report in terms of steady-state operations and U.S. market designs.

- **Inertial control status:** Inertial control on the system level is not a requirement in any region of the United States. It is inherently provided by synchronous machines (generators and motors). Hydro-Quebec is one system that has begun to require unit-specific inertia from wind generators. Inertial control is not explicitly scheduled for any resource, and there is no market or incentives to provide it in the United States.

- **PFC status:** PFC has a balancing area (BA) requirement in Europe and is in the process of becoming a requirement in North America. The North American Electric Reliability Corporation (NERC) is revising its BAL-003 requirement to incorporate frequency response requirements, which at the time of this writing are subject to FERC approval. In the Electric Reliability Council of Texas (ERCOT), rules require wind power plants to have the capability to provide PFC if they are operating at a point where they can do so (i.e., only if they were previously curtailed and have headroom to provide more energy during under-frequency events). There is currently no market or incentives to provide PFC in the United States, with the caveat that ERCOT requires any resources that are selected and paid by the spinning reserve market to be frequency responsive. It is not explicitly scheduled.
- **Regulation and AGC status:** Regulation is required on a BA level to meet the NERC CPS1 and CPS2 requirements. The requirements usually change based on load levels, day of week, season, and time of day. Restructured energy market regions have ancillary service markets that incentivize resources to provide regulation, and it is explicitly scheduled alongside the energy market in the unit commitment and economic dispatch models. As of the writing of this report, wind power currently does not provide regulation in any of the market regions of the United States.

The U.S. Eastern Interconnection has had a significant decline in its frequency response over the past 20 years. Many potential reasons have been discussed as the catalyst for this, but one of the major reasons is a lack of incentives for generators to provide PFC. In addition to the absence of incentives, there may be disincentives for market participants to provide PFC. Settlement systems may have financial penalties in place for generators that produce power at a level that is different from what they were asked to produce, without accounting for the source of the deviation. For example, a generator can be fined for producing at greater than a certain percentage from its scheduled output. Providing PFC will mean a generator's output will be dependent upon the system frequency when the frequency strays from its nominal setting.

The example equation below shows that for an area that has a 5% droop setting and a 3% tolerance band for under- or over-generating, current rules will result in any generator with a properly enabled governor that is assisting reliability to be automatically penalized with a 90 mHz frequency deviation. As rare as this may be, the fact that this risk is still present, and with a cost to the provision of PFC and without any incentive for providing it or any standard or grid code enforcing it, generators have every reason to disable their governors or operate in a way that provides little or no response.

$$\frac{1\, p.u.power}{0.05\, p.u.frequency} = \frac{0.03\, p.u.power}{X\, p.u.frequency}$$

$$X = 0.0015\, p.u.frequency = 90\, mHz\ for\ a\ 60\ Hz\ system$$

Four approaches were developed in this study to eliminate this disincentive and provide an incentive. The first two eliminate the penalty with different degrees of complexity, but they do not include a strong incentive for providing PFC. The third approach is to add a frequency response requirement to a separate ancillary service market, like the spinning reserve market.

While this would create an incentive for resources to be frequency responsive, it is difficult to combine two services that have different requirements and different costs.

The last approach is a separate PFC ancillary service market. This market would be similar to other ancillary services with some exogenous requirement, both in MW and in MW/Hz, that would result in a reliable system and avoid under-frequency load shedding following a very large, credible disturbance. This approach would effectively create the necessary incentives and link together the specific needs and costs of PFC. The major drawbacks to this approach are the complexity of the market software, increased data and compliance requirements, and the regulatory hurdles to obtain agreement from market participants and other stakeholders.

To illustrate the fourth approach, the study designed an example of a separate PFC ancillary service market. For wind power (and all other resources) to be able to provide PFC to support power system reliability and do so economically, incentives must be present. This design carefully incorporates the characteristics of inertia, PFC capacity, responsiveness of this capacity to frequency, limited insensitivity to frequency (i.e., keeping governor deadbands to a limit), faster triggering and deployment speeds, and a stable and sustainable response. The design also ensures the prices, auction bidding structure, and settlement rules are set in a manner to incentivize these characteristics. The design must also lead to an aggregate response that meets the system needs, making it both efficient and reliable. Finally, the market was designed to be applicable to systems that are part of large interconnected areas, such as those in the Eastern and Western Interconnections of the United States, as well as isolated systems, which have quite different characteristics given the interconnected nature of system frequency.

The model emulated that of a security-constrained unit commitment (SCUC)—the clearing engine that typically solves pool-based day-ahead markets. It took the characteristics of typical unit commitment models with the added constraints and inputs to incorporate the PFC market, which is coupled with the energy and other ancillary service markets through co-optimization. Droop curve settings, governor deadbands, and inherent thermal or hydrological time constants were all part of the inputs to determine the level of PFC a resource can provide. The design accounted for certain characteristics that were also supported in part by the load (e.g., the synchronous motor inertia and load damping characteristics). An iterative procedure between the SCUC and a dynamic frequency response model was developed to correctly emulate the speed of response.

Prices were designed to reflect the marginal cost theory. The PFC prices are based on the marginal cost to provide that service. As PFC is highly coupled with energy and secondary reserve services, it was co-optimized with these markets. Assuming the market operator considers capacity reserved for PFC to be a more critical need than spinning or non-spinning secondary reserve, a pricing hierarchy was followed so the PFC price was greater than or equal to the prices for those services. The pricing for inertial control was based on the marginal cost of inertia with relaxation of the integrality constraint of all units' online status. Lastly, a number of considerations were made for bidding and settlements, including market mitigation, cost allocation, bidding allowance, and compliance monitoring.

A number of case studies were examined with this market design using the IEEE Reliability Test System (3,000 MW peak). A first set of simulations was made with two base cases: the current market design without PFC, and the same design with the PFC market design incorporated (BC1: current; BC2: with PFC design). The second set of simulations added 15% wind power penetration to each simulation, where the wind power was asynchronous and without any PFC capabilities (WC1: current; WC2: with PFC design). These comparisons are shown in Table ES-1 and Table ES-2 below. The comparison with the wind power systems had a greater difference in results between cases than the simulations without wind. In the wind cases, the system without a PFC market design provided for much less PFC than when the PFC requirement market was introduced, and could potentially have led to a greater possibility of reliability issues (the requirement of total PFC on this system is 44 MW). The relative cost difference between the wind cases was also greater, meaning it cost more to retrieve the required PFC on the system with a greater percentage of asynchronous resources.

In all cases, the amount of inertia was not significantly changed, meaning that the PFC market did not impact the amount of inertia in the system, mostly because enough inertia to meet requirements was typically met inherently due to energy and secondary reserve requirements. Additional studies were performed to further analyze this market design. It was found that extreme penetrations of asynchronous resources could lead to inertia pricing benefiting the reduction of inefficient make-whole payments. It was also found that improving certain capabilities, like reducing the governor deadband, would lead to increased revenue for an individual generating unit, meaning the incentives built into this market design could lead to innovation and improvements to PFC capabilities. If designed in this manner, the market could likely lead to enough incentive for wind power plants to install these capabilities and provide PFC when the market incentivizes them to do so.

Table ES-1. Base Case Comparison

	BC1	BC2
Production Costs ($)	568,297	569,315
Avg. Units Online per Hour	20	19
Avg. Inertial Energy per Hour (MVAs)	8563	8618
Avg. $P1^{ss}$ per Hour (MW)	43.7	48.4

Table ES-2. Wind Case Comparison

	WC1	WC2
Production Costs ($)	401,287	403,616
Avg. Units Online per Hour	17	17
Avg. Inertial Energy per Hour (MVAs)	7283	7310
Avg. $P1^{ss}$ per Hour (MW)	36.75	48.1

A final part of this task analyzed the potential for wind power plants providing AGC regulation in a system that included a regulation ancillary service market. The study was performed on the California Independent System Operator (CAISO) system, simulating its energy, regulation up, regulation down, and other ancillary service markets during a two-month period. A summary of the costs for CAISO and the rest of the Western Interconnection is shown in Table ES-3 for a case without regulation provided by wind, and one where wind is allowed to provide up to 20% of the regulation up and regulation down requirements.

Table ES-3. Cost and Import Level Impact for Western Interconnection and California

Case	Western Interconnection Costs ($)	CAISO Costs	CAISO Start-Up Costs	Net Import to CAISO (GWh)
NoWindReg	$5,610M	$1,550M	$27.9M	7,359
WindReg20	$5,607M	$1,531M	$26.3M	7,626
Change	-$3.1M	-$19.5M	$1.6M	267
Change (% of Base)	-0.2%	-1.3%	-5.7%	3.6%

The cost reductions for the Western Interconnection were relatively small (0.2%), while the cost reduction for CAISO was greater (1.3%). The total revenue increase for CAISO wind power was $5.5M, or $1/MWh, a small but not insignificant number. If wear-and-tear costs or efficiency penalties were included in the thermal generation costs, both cost reductions and revenues could increase. CAISO also shows almost a 6% reduction in start-up cost when wind is providing regulation. The fast control available from wind power to provide this service could also benefit from new "pay-for-performance" market design schemes via new revenues. However, the potential impact of forecast errors on the ability to provide the full dedicated regulation response could influence how much of it system operators are willing to allow wind power to provide. All of these issues should be pursued in more detail to understand how wind can participate in the regulation market.

Dynamic Stability and Reliability Impacts

Increased variable wind generation can have a number of impacts on the dynamic stability and reliability of the power system. Lower system inertia was identified as one such impact, as it would result in faster-declining frequency during large loss-of-supply events, resulting in a greater risk of lower frequencies that can lead to voluntary load-shedding, machine damage, or even blackouts. A decrease in system inertia will necessitate an increase in the requirements for PFC reserves in order to arrest frequency at the same nadir following a sudden loss of generation. Similarly, a decrease in PFC can result in lower steady-state frequencies, also leaving the system at greater risk.

In order to properly study these dynamic impacts on power system reliability, the wind plant generator dynamic models must be understood, and so must the types of frequency events that occur on these systems. Significant penetrations of wind on the system without APC can then be studied to see how much system frequency performance is degraded. Adding APC to the wind plants can then be studied to show how much it improves the response and reliability.

Electrical generator models must be developed that appropriately model the ways that wind power plants can provide APC. This study examined the characteristics of the four types of wind plants and how each can provide various levels of synthetic inertial control or PFC. The most popular form of wind turbine generators, those of variable speed, can provide a power boost (similar to inertial control) during frequency events as long as the generator, power converter, and wind turbine structure are designed to withstand that overload. These types can also provide PFC, given a level of reserve capacity.

It is important that the generators are maintained at a constant tip-speed ratio and that the pitch angle is controlled so that the rotor speed follows the target speed. Wind power plants have the flexibility to adjust droop curve settings, inertia constants, and governor deadbands depending on system needs and requirements. Wind power can also respond to new designs like non-symmetric or non-linear droop curves, if desired.

Frequency events were recorded on both the U.S. Eastern and Western Interconnections since 2011. These data were used to better understand the types of events that occurred on each interconnection and the typical frequency nadirs, settling frequencies, ratios between nadir and settling frequency, and overall distribution of frequency. Figure ES-4 shows a histogram of frequency nadir (top) and settling frequency (bottom) for the Western Interconnection for significant frequency events recorded during 2011–2013. These data were also used for the field testing discussed later so that the wind turbine tests used actual frequency to reflect realistic responses.

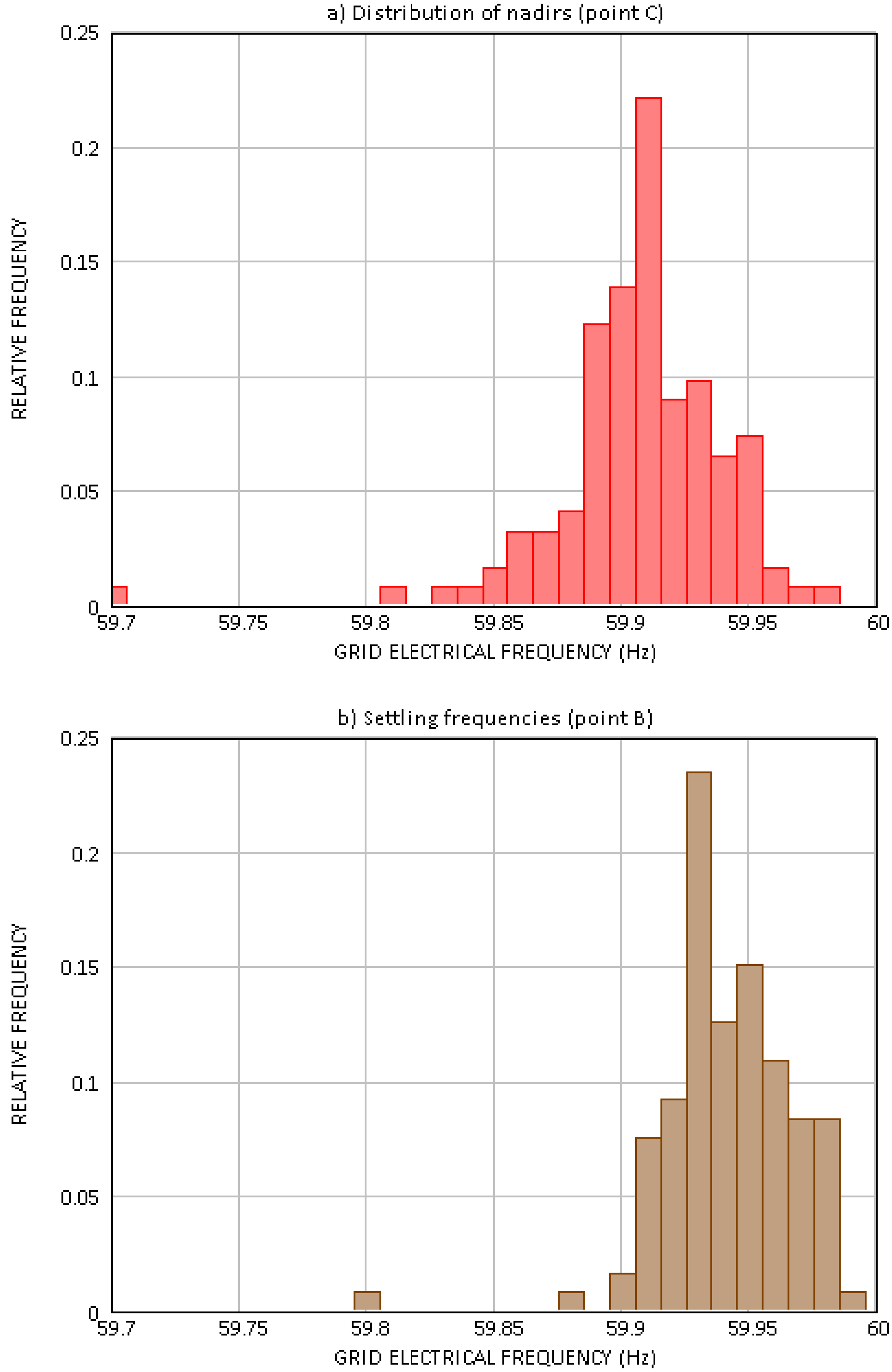

Figure ES-4. Distribution of low-frequency event data. Point C is the frequency nadir and point B is the settling frequency.

The team performed a study on the Western Interconnection with up to 50% instantaneous wind penetration. The purpose of the study was to analyze how the system would meet the new frequency response obligation requirements being proposed (i.e., the BAL-003-1 NERC standard). A very large disturbance was simulated (two large nuclear units at 2600 MW) and the frequency response was analyzed. Scenarios were performed at 15%, 20%, 30%, 40%, and 50% instantaneous wind penetrations for four cases: 1) normal wind power plant operation without APC, 2) providing inertia only, 3) providing PFC only, and 4) providing both inertia and PFC. The results are shown in the figures below for frequency nadir (Figure ES-5) and settling frequency (Figure ES-6).

The ability of wind plants to provide PFC was shown to be tremendously beneficial in this study. At very high penetrations, it was shown that when wind power plants provide synthetic inertia only, it can actually result in a lower frequency nadir than if the plants provided nothing at all (assuming all wind plants are at below-rated wind speeds). However, a combined inertia and PFC response from these plants significantly improved the frequency nadir and settling frequency at all wind penetration levels. Further study analyzed the effect of the percentage of conventional generators providing frequency response as well as the impact of reduced response from conventional generators combined with various wind APC strategies and wind penetrations on the response given by other generators on the system.

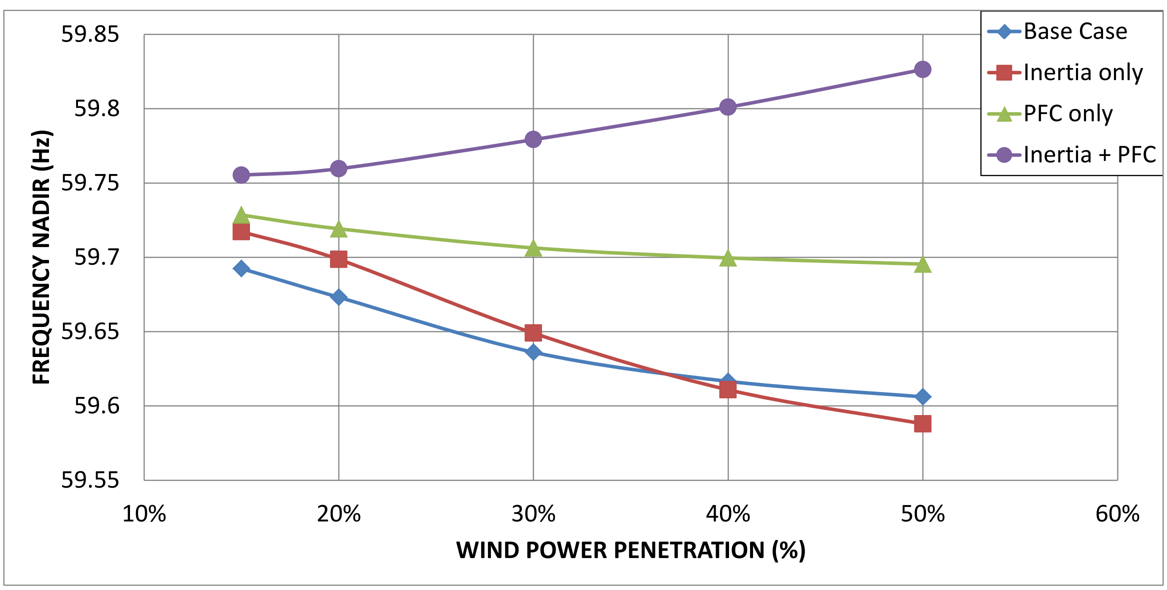

Figure ES-5. Impact of wind power controls on frequency nadir.

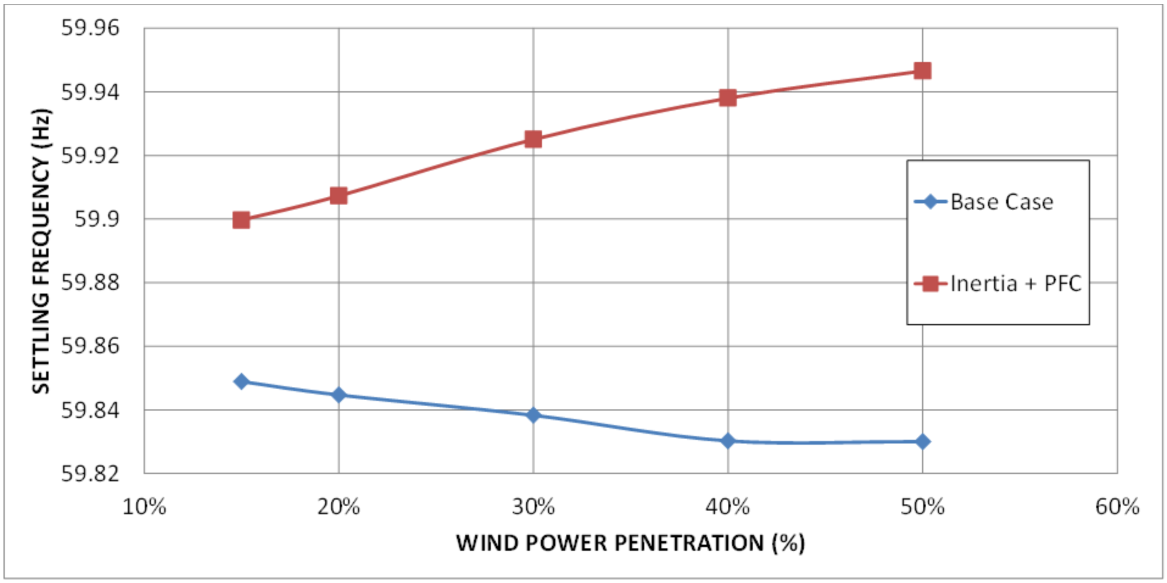

Figure ES-6. Impact of wind power controls on settling frequency.

Controller Design, Simulation, and Field Testing

The final task of this study examined APC designs and their performance using both simulations and field tests. This work focused on developing and testing new controller designs that are capable of simultaneously actively de-rating, following an AGC command, and providing PFC. Furthermore, this task evaluated the structural loading induced by the various APC designs. The controllers were designed in an environment (Simulink) that can be directly ported to the 3-Bladed Controls Advanced Research Turbine (CART3) for field testing at the NWTC.

Several control systems were designed and evaluated in this task for providing the various APC services (power reserve, AGC following, and PFC). These methodologies were combined into a single adjustable controller called the torque-speed tracking controller (TTC). The controller allowed for implementation in simulation or field testing of the various approaches to power reserve, AGC following, and PFC provision, and in various combinations. Additionally, the controller featured adjustable design parameters, which allowed tradeoff analysis between aggressive responses and structural loads.

This design was used in simulation to understand the impact of different control designs on structural loads. Damage equivalent load (DEL) is a standard metric for comparing fatigue loads in wind turbine components. Figure ES-7 shows the DEL with the use of TTC with a 10% de-rating (i.e., operation at 90% of maximum available power), with and without the provision of AGC regulation, normalized to the DELs from the traditional maximum power capture strategy. As can be seen, the participation in continuous AGC has very little impact on the overall DEL.

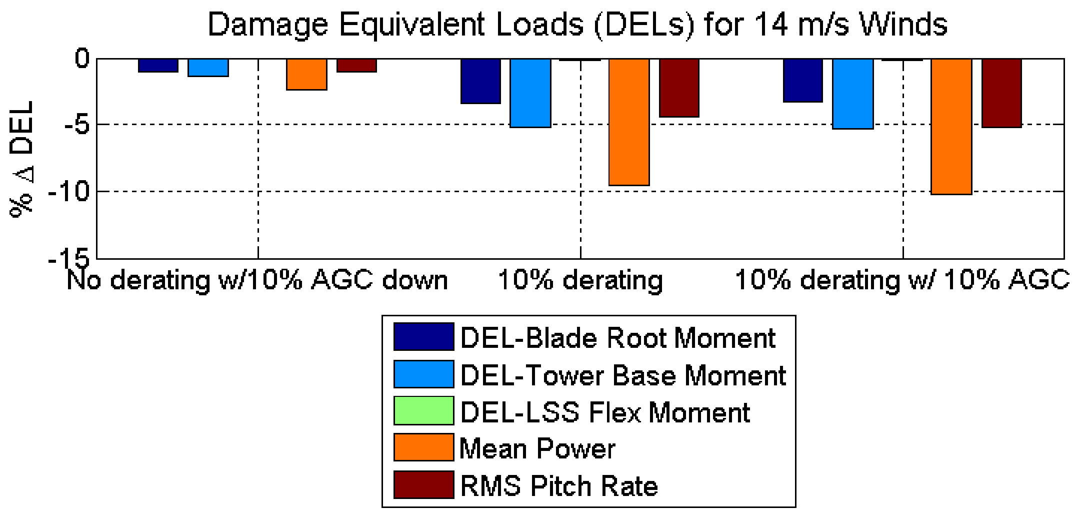

Figure ES-7. The induced DELs on turbine components comparing de-rating and AGC utilization.

The team also performed field tests at the NWTC using the 600 kW CART3 wind turbine with both AGC and PFC tests. First, field tests were performed to evaluate a wind speed estimator that was necessary for de-rating modes in understanding the amount of available power in the wind. The first chart in Figure ES-8 shows a field test where the turbine was given a de-rate command, followed by a simulated under-frequency event. The response followed both the de-rate command and the provision of PFC. The high-frequency fluctuations seen would likely be smoothed out significantly when the entire wind plant is being considered, rather than just a single turbine.

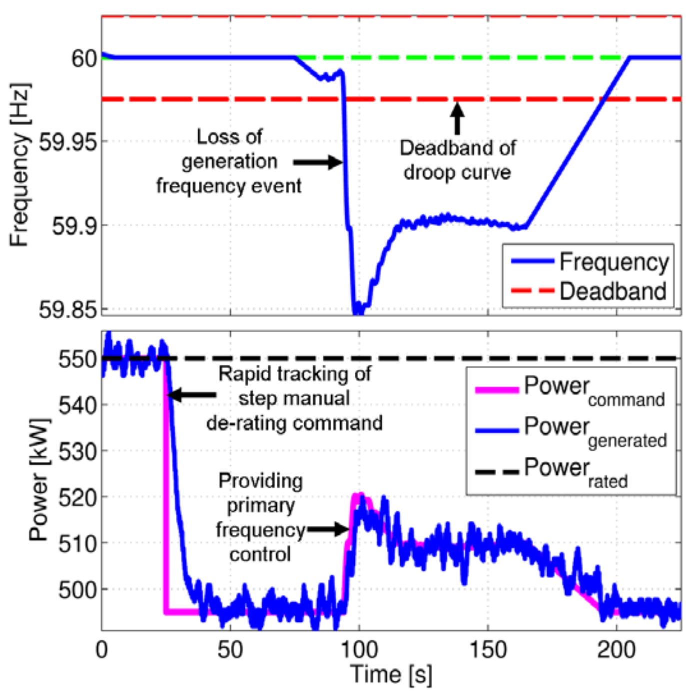

Figure ES-8. Field test data that shows the turbine tracking a step change in the de-rating command followed by PFC response to an under-frequency event.

The second chart in Figure ES-9 shows the CART3 following an AGC command, which is derived from actual ACE data from a Western Interconnection BA. In this chart, a few instances of reductions in the de-rating command occur when the available wind power drops below the rated power. The figure shows how the controller estimates the power available in the wind (P_{avail}), de-rates with respect to the estimation so that there is power overhead to follow the AGC command ($P_{cmd\ Dr}$), and then tracks this level plus the AGC command ($P_{cmd\ Dr\ +\ AGC}$). The signal P_{gen} is the actual output power, which effectively tracks the desired output power even given the varying wind conditions. Again, it is likely that the high-frequency fluctuations of this response would be reduced when considering the entire wind plant.

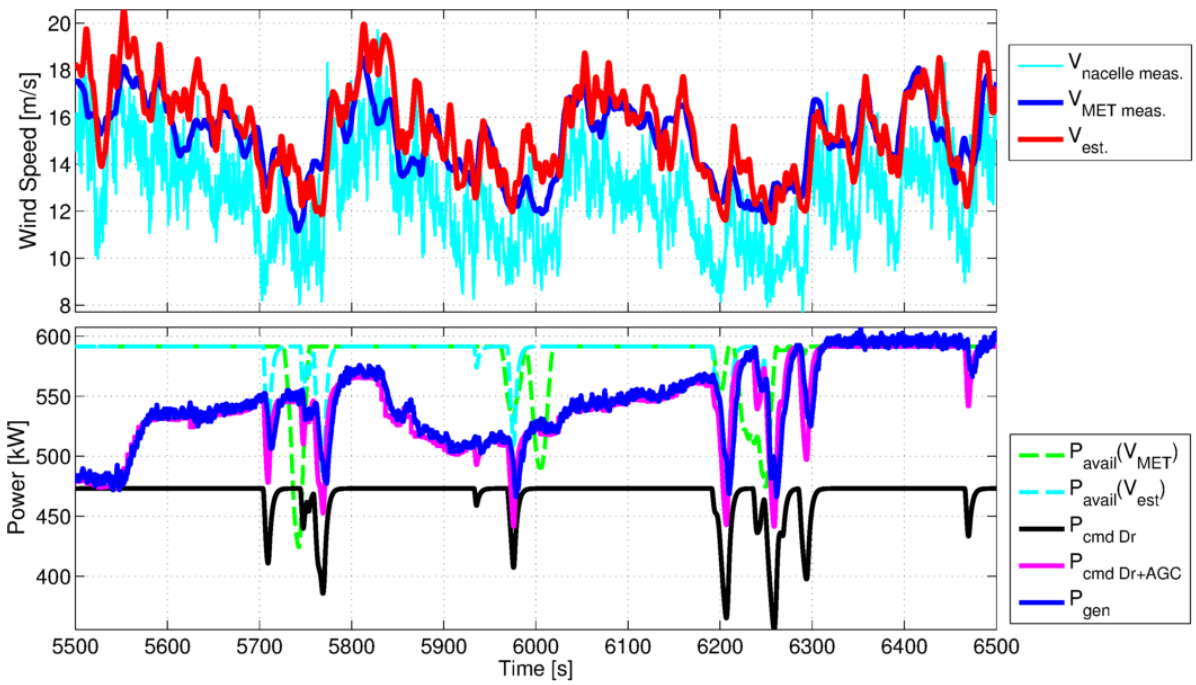

Figure ES-9. A field test of the CART3 turbine following an AGC command.

Conclusions and Next Steps

This study provides a number of insights into the practicality of wind power plants providing the finest forms of APC to support power system reliability. A number of steady-state, dynamic, and machine-level simulations as well as field tests were conducted to understand the benefits and impacts of wind plants providing this response.

These studies just start the conversation, and numerous opportunities exist for fine-tuning this research. Simulations, and especially field tests, that model the entire wind-plant-level controls are needed to produce more realistic results. Improved control designs with advanced tracking technologies like LIDAR can also improve the response performance. A better understanding of the interaction between regulation and PFC, which are responses typically simulated with different tools, should be achieved so that any reliability issues that occur between the seams of these two timeframes can be assessed. Further economic studies can also show the impact of transmission, forecast error, and new rules like the "pay-for-performance" regulation rule (based on FERC Order 755) on the revenue streams and production cost reductions of wind power plants providing these services.

The studies detailed in this report have shown tremendous promise for the potential for wind power plants to provide APC. Careful consideration of these responses will improve power system reliability. Careful design of the ancillary services markets will result in increased revenue for wind generators and reduced production costs for consumers when these services are provided. Careful design of control systems will result in responses that are in many ways superior to those of conventional thermal generation, all while resulting in very little effect on the loading and life of the wind turbine and its components. With all these benefits that may result from careful engineering analysis, there should be no reason that wind power plants cannot provide APC to help support the grid, and help wind power forever abandon its classification as a “non-dispatchable” resource.

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1 Introduction

Wind energy has had one of the most substantial growths of any source of power generation in recent years. In many areas throughout the world, wind power is supplying up to 20% of total energy demand. In the United States, balancing areas (BAs) like the Public Service of Colorado have occasions where over 50% of the hourly demand is supplied by wind power. Wind power falls under the category of variable generation, as its maximum available power varies over time, and it cannot be predicted with perfect accuracy. Wind power, particularly variable-speed wind power, is also different from conventional thermal and hydropower generating technologies, as it is not synchronized to the electrical frequency of the power grid nor is it responsive to system frequency. These three characteristics—variability, uncertainty, and asynchronism—can cause challenges for maintaining a reliable and secure power system. Many studies have been performed to better understand these impacts [1]–[3]. Utilities, balancing area (BA) authorities, regional reliability organizations, and independent system operators (ISOs) are also developing improved strategies to better integrate wind and other variable generation. One of these strategies is the use of wind power to support the active power balance of the power system by providing active power control (APC). This is the focus of this report.

The National Renewable Energy Laboratory (NREL), along with partners from the Electric Power Research Institute and University of Colorado and collaboration from a large international industry stakeholder group, embarked on a comprehensive study to understand the ways in which wind power technology can assist the power system by providing control of its active power output being injected onto the grid. The study includes power system simulations, control simulations, and actual field tests using turbines at NREL's National Wind Technology Center (NWTC). The study sought to understand how this contribution of wind power providing APC can benefit the total system economics, increase revenue streams, improve the reliability and security of the power system, and provide superior and efficient response while reducing any structural and loading impacts that may reduce the life of the wind turbine or its components. The three forms of APC that this study focuses on are synthetic inertial control, primary frequency control (PFC), and automatic generation control (AGC). This project and report are unique in the diversity of their study scope. The study analyzes timeframes ranging from milliseconds to minutes to the lifetime of wind turbines, locational scope ranging from components of turbines to large wind plants to entire synchronous interconnections, and topics ranging from economics to power system engineering to control design. With this comprehensive analysis and the team's diverse expertise, the team plans to capture a more holistic view of how each of these impacts and benefits can be realized.

Many of the control capabilities being researched in this project have already been generally proven as technically feasible [4]. However, at least in the United States, wind power is rarely providing this control in existing power systems. This may be due to differences in perspective among various stakeholders (see Figure 1-1). For example, a manufacturer may know the capabilities are technically feasible but may not see a market for it because there is no demand from a utility off-taker to provide the capability. On the other hand, the system operators may desire the capability but be unsure of exactly how it performs or whether or not it will actually improve system reliability. The wind owners may know what features the turbines are capable of, but choose not to procure them or offer them to the off-taker if the functionality is not required or if it does not result in increased revenue. Finally, the regulators or market operators may not establish complementary policies or market designs if the markets are receiving enough capability and it is provided for free, without any outlook on how this may change in the future. With this project's holistic research approach and extensive demonstration and dissemination plans, the team sought to fill these gaps in perspectives. If wind power can offer a supportive product that benefits the power system and is economic for the wind plant and consumers, there should be no reason not to allow it.

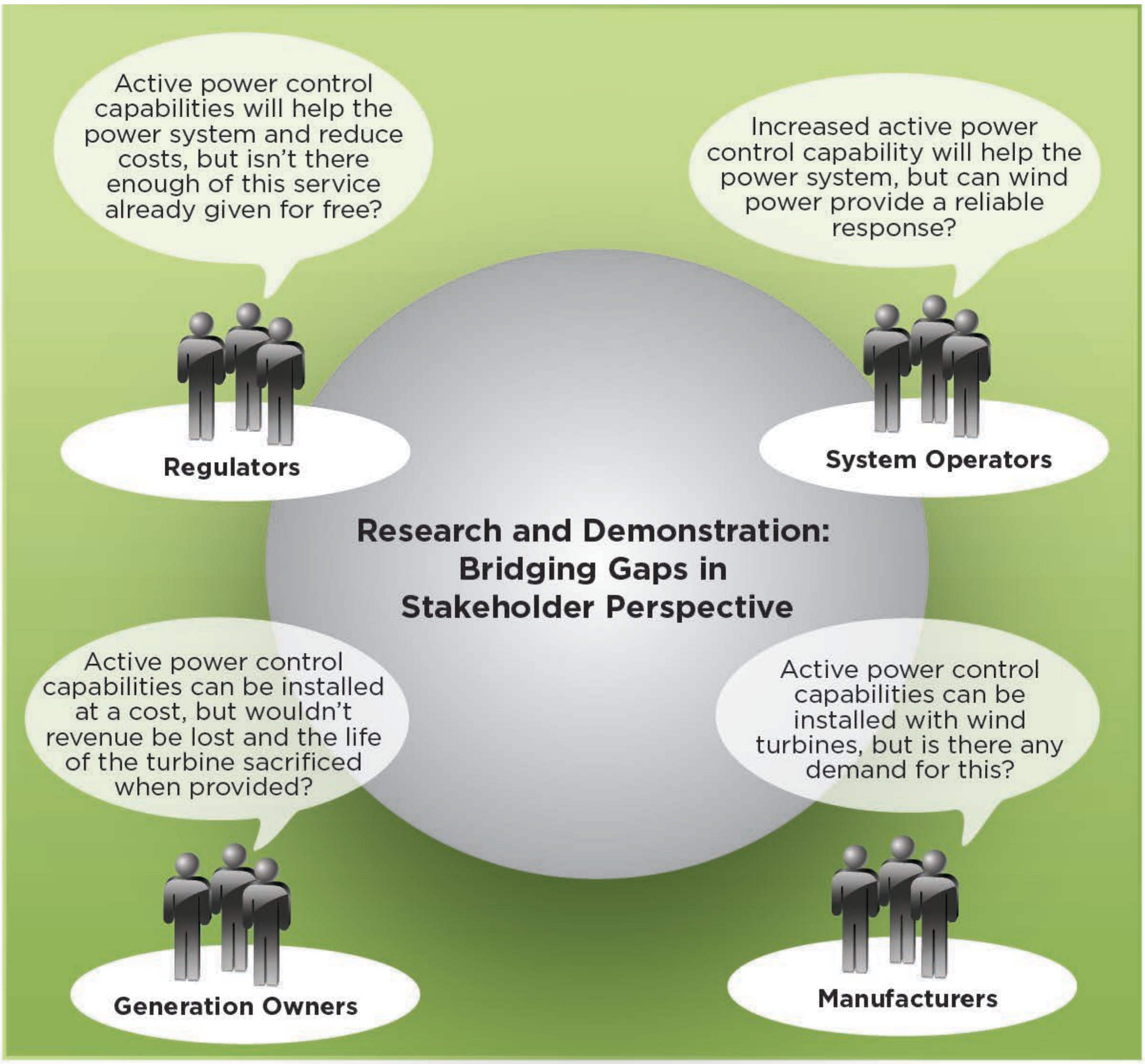

Figure 1-1. There may be different perspectives among various stakeholders on the feasibility, benefits, and economic justification for wind power to provide various forms of APC. This project bridges these gaps in perspective with research and demonstration.

A number of studies have been completed by industry and academia to understand the potential power system impacts of high wind power penetration [1]–[3]. The studies show three major impacts of significant wind power penetration. First, wind power forecast errors are relatively more significant than load forecast errors, which causes issues for scheduling resources to meet the demand. Second, the increased wind power variability causes a need for faster correction of the generation and load balance. Finally, the studies find that wind power is neither synchronous nor dispatchable in its current form and that it provides little to no flexibility for supporting power system reliability. These issues can cause adverse effects to power system reliability and can increase costs when other resources may be more inefficiently operated in order to mitigate these impacts. The previous studies quantify the reliability impacts, integration cost increases, and mitigation strategies that can improve the impacts caused by wind power. However, the studies rarely evaluate how wind power itself can provide some of the flexibility needed to support power system reliability.

The ways in which a wind plant can provide APC to support reliability can vary based on the system needs. The various forms of APC generally fit under the category of operating reserve: capacity that can be adjusted above or below the current operating point that can be used during certain situations to ensure the reliability and security of the power grid [5]. One instance that requires APC from generating units on the system is during a contingency disturbance event, such as a large conventional generating unit being forced out of service and therefore causing the system to be deficient on generating power to meet the load demand. The electrical frequency of an interconnection must be kept very near to its nominal level. In North America, this level is 60 Hz.

Figure 1-2 shows the frequency following a large disturbance. At the very instant of the loss of a large supply of power (i.e., a large generator), other synchronous generators will extract kinetic energy from their rotating masses to slow down the rate of change of the frequency decline and maintain stability [6]. This *inertial control* slows down the rate of frequency deviation. Soon after the disturbance, turbine governors will sense the frequency change and provide additional power in order to replace the lost power and arrest the frequency decline. During this dynamic event the frequency will at some point hit its nadir (the minimum frequency), and as the generation once again meets demand it will soon stabilize at a new equilibrium point of some off-nominal frequency (i.e., below 60 Hz). This response is called *primary frequency control* (PFC) and is used to stabilize the frequency at a steady-state value. The state and issues involved with PFC are discussed in a comprehensive report by the IEEE Task Force on Generation Governing [7]. Finally, response is needed to return the frequency back to its nominal setting (e.g., 60 Hz) and reduce the area control error (ACE). This usually occurs fully within 5–15 minutes. This is *secondary frequency control* and is often provided using automatic generation control (AGC). A similar series of responses is required during loss-of-load events, (i.e., loss of a large block of load or loss of a pumped storage plant during pumping operation). In this case the electrical frequency increases and the response is needed to bring it back down to its nominal setting. These three responses each have different characteristics, policies, requirements, and market rules for incentivizing their provision. Therefore, the way in which a wind plant can provide each response will differ substantially.

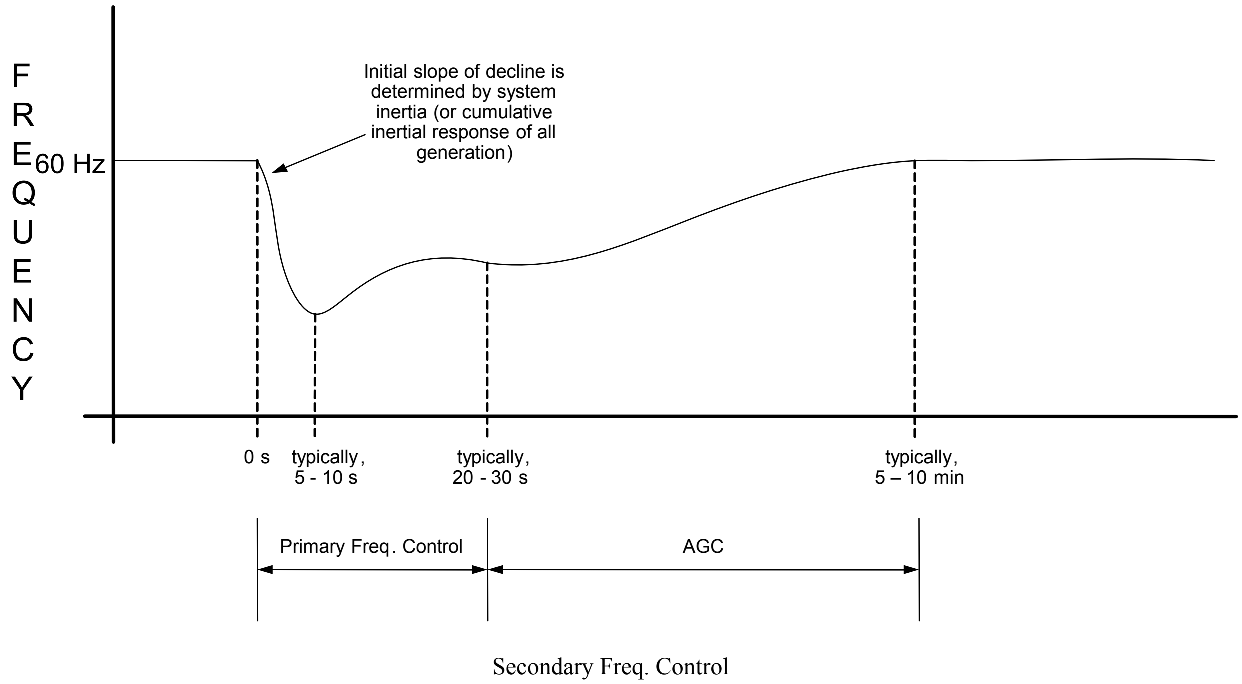

Figure 1-2. Frequency trace following a large contingency event (i.e., loss of a large generating unit). Inertial control, PFC, and secondary frequency control each serve a different purpose, and their response timeframes are also at different points of the frequency recovery.

The control of active power on the grid is also important to system operators during normal conditions (i.e., when a disturbance has not occurred but normal variations in load and generation are still occurring) [8]. The system must maintain the frequency and limit any unscheduled power flow violations during all times. This normal response can happen during different timescales, as seen in Figure 1-3. *Regulation* is often provided by generating units that have AGC, and that are following signals given directly by the system operator control center to regulate the area control error (ACE). *Load following* is slower and may or may not be automatically scheduled. Regulation corrects the current balancing error, while load following follows the anticipated demand. Similar to those services provided during disturbance events, these services have some differences in the type of control needed, as well as the economics and incentives, and therefore different methods of control might be necessary for each service.

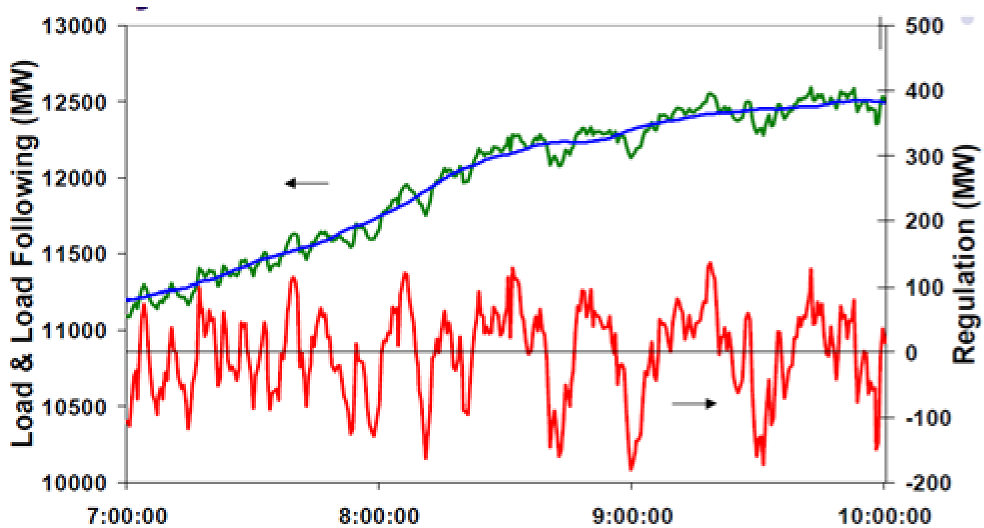

Figure 1-3. Regulation and load following during normal conditions.

Table 1-1 shows the different forms of control, how they are used, and other common terms used interchangeably by the industry. The need for each of these services is determined by the area or by a large reliability regulator (like NERC or other regional reliability organizations) [9]–[10]. The categories in bold are those the team has found most critical to study due to system needs and economics for wind power to provide. This study focuses on these three forms of control: inertial control, primary frequency control, and regulation/AGC. A more detailed description is then given for the three services, which serves as the prime definition for each of these terms throughout the rest of this report.

Table 1-1. The Different Active Power Controls, Their Uses, and Common Terms

Control	Use	Other common terms
Inertial control	***Used to slow down the initial rate of change in frequency***	***Inertia, synthetic inertial control (e.g., from non-synchronous response)***
PFC	***Used to bring frequency to a steady-state level***	***Governor response, droop control, primary control reserve, frequency responsive reserve***
Secondary frequency control	Used to bring frequency back to its nominal level or to bring ACE down to zero	Contingency reserve, spinning reserve, secondary control reserve
Regulation	***Used to control balancing error within dispatch scheduling using AGC during normal, non-event conditions***	***Regulating reserve, load frequency control, AGC reserve, regulation up, and regulation down***
Load following	Used to follow the anticipated net load between dispatch intervals during normal, non-event conditions	Following reserve, dispatch reserve, tertiary reserve

- **Inertial control**: Inertial control is the immediate response to a power disturbance based on a supply-demand imbalance. This response is currently given by synchronous machines that immediately inject (extract) kinetic energy of their rotating masses to (from) the grid, thereby slowing down (speeding up) their rotation and system frequency during loss-of-supply (-load) events. Aggregate inertial control will slow down the speed of frequency decline. Tests will analyze how wind power can bring out its own inertia through power electronics controls to provide immediate energy to reduce the rate of change of frequency.
- **PFC**: Primary frequency control (PFC) is the response following inertial control that increases (decreases) the output of generators to balance generation and load during loss-of-supply (-load) events. This response is typically given by conventional generators with turbine governor controls that adjust output based on the frequency deviation and its governor droop characteristic. The aggregate PFC response will bring frequency to a new steady-state level. Tests will analyze how wind power can provide energy in this timeframe to assist in arresting frequency deviation, raising the frequency nadir for a given loss of supply, and stabilizing the system frequency following a disturbance.
- **Regulation and AGC**: AGC is used during normal conditions and emergency events. Regulation, also called load frequency control and secondary control, is typically provided by resources with direction of an automatic control signal from a centralized control operator and is a response slower than PFC. The AGC response will bring frequency back to its nominal setting (which, in North America, is 60 Hz). It also reduces the ACE to ensure that frequency and interchange energy schedules between regions are kept to set points during normal conditions. Tests will analyze how wind power can provide this control to maintain nominal frequency and reduce ACE.

For wind power to provide these three services, it is essential that three things happen. First, the wind power must assist in power system reliability. Wind turbines are quite different from steam, combustion, and hydro turbines. It is asynchronous from the electrical system, coupled through power electronics. It also has a fuel source—the wind—that cannot be relied on consistently. These characteristics, along with the many other characteristics that make wind power plants different from conventional plants, mean that the APC response provided will likely be different than the response from conventional plants. The wind power response should improve power system reliability if it is provided. Studies combined with field tests should be able to show how this provision can improve power system reliability.

Second, it must be economic for wind power plants, as well as electricity consumers, to provide these forms of APC. If providing the service made wind power significantly more expensive without a means to recover that cost, it would limit its further adoption. Evolving market designs and needs can dictate whether or not this is possible. Most of the restructured power markets in the United States have ancillary services markets that pay resources for providing services ancillary to the provision of energy in order to support power system reliability. It is possible that these markets provide a larger share of total revenue in the future. It is important that the three services are carefully considered when applicable and that wind power plants are treated equally to other suppliers of these services. It is also important that the usage of wind power plants providing APC does not increase the costs to consumers. Studies can demonstrate evolving market designs and can also demonstrate the economic efficiency of wind providing APC for its own revenue streams and for reducing the total costs to consumers.

Lastly, when providing the three forms of APC, there should not be negative impacts on the turbine loading or structural damage that could reduce the life of the turbine. The careful control design should be optimized by providing a superior response, but ensure that it does so without adversely impacting the wind turbine or any of its components. Simulations and measured data in the field can show how different control strategies can impact loading.

Different modeling and analysis techniques are needed for the different objectives of this study. Three tasks are laid out below:

- Economics and steady-state power system impacts
- Dynamic stability and reliability impacts
- Controller design, simulation, testing, and loads analysis.

Each task answers questions related to specific objectives. Although the tasks themselves may use different types of analyses, it is important that results of one task are used as input to another, so that the holistic perspective is maintained. For example, the steady-state task team needs to know what type of dynamic response wind power can provide in order to know if it has met the steady-state objective, and the dynamic response task team needs to know the actual parameters of the wind turbine response provided by the controls simulations and field tests in order to properly model the response of wind with the rest of the system. The overall goal is to provide manufacturers, system and market operators, regulators, and wind plant owners/operators with the full set of information regarding all the different impacts and benefits that occur with wind power plants providing APC to the power system.

The report is organized as follows. Section 2 discusses the economic and steady-state power system impacts for wind providing APC. Section 3 discusses dynamic stability and reliability impacts on systems where wind is integrated, both with and without APC. Section 4 discusses the control designs and tests that can show improved response and reduced loading impacts. Section 5 concludes the report.

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2 Economics and Steady-State Power System Impacts

The first task of this work focuses on the impacts of using wind power for active power control (APC) on the steady-state operation of the power system. This includes both the steady-state operational impacts as well as the economic impacts. Here, steady-state generally refers to timeframes where the system is at equilibrium and time ranges greater than minutes. The goal of this task is to understand how wind providing APC affects steady-state operations, how markets may be evolved accordingly to address new needs, how the revenue streams of wind power are affected, and how electricity consumer costs are affected.

In the United States, restructured electricity markets have been organized throughout the country. These markets generally follow a standard market design [1]. This standard market design includes two-settlement systems with co-optimized energy and ancillary services markets, locational marginal pricing for energy, and financial transmission rights markets in place for hedging [2]. Energy markets are designed so that the marginal provider of energy will set the energy price for each location. Physical power flows (although typically approximated with the DC power flow approach) affect how the pricing is calculated. These prices are called the locational marginal price (LMP). Energy is sold to the generator at the generator's LMP and is bought by the loads at the load LMP.[1]

Ancillary service markets are a unique characteristic of the overall evolving wholesale electricity market design. The ancillary services as defined by the Federal Energy Regulatory Commission (FERC) Order 888 [3] are listed below, with their applicability to ancillary service markets taken from [4]:

- **Scheduling, system control, and dispatch**: This is the service that the Independent System Operator (ISO) or Regional Transmission Organization (RTO) provides. It is *not applicable* to our discussion on ancillary services market design.
- **Reactive supply and voltage control from generation service**: Reactive power supply and voltage control is generally supplied as a *cost-based service*.
- **Regulation and frequency response service**: Today, *regulation* is typically supplied and priced by *dynamic markets* in ISO/RTO regions. It is used to assist in controlling frequency. However, frequency response, or *PFC*, as defined by the droop response of governors autonomously responding to frequency, is generally *not included in any dynamic markets, nor is it given cost-based rates*.
- **Energy imbalance service**: Energy imbalance is usually the service of the real-time markets balancing out the imbalance from the forward markets and is therefore *priced by the real-time energy markets*.
- **Operating reserve – synchronized reserve service**: This service is typically supplied and priced by *dynamic markets* in ISO/RTO regions.

[1] Although typically, the load will pay an aggregated, zonal, load-weighted LMP, whereas the generator is paid the specific nodal LMP.

- **Operating reserve – supplemental reserve service**: This service is typically supplied and priced by *dynamic markets* in ISO/RTO regions.

Of these services, competitive markets and explicit scheduling exist for operating reserve – synchronized, operating reserve – supplemental, and regulation services (but not frequency response). Energy imbalance service is accommodated by the real-time energy markets, although new market designs are also trying to incentivize resources to provide longer-term flexibility [5]–[6]. This new product being designed is similar to the load-following service described in Table 2-1.

Wind power has historically been considered as a non-dispatchable resource, without any capabilities to provide any of the aforementioned ancillary services. However, only a few years ago, a few market areas started to allow wind to participate in the real-time energy markets as a way to balance generation and manage transmission congestion by efficient market-based curtailment through the economic dispatch [7]. This transition from a non-dispatchable resource to one that can assist at times for relieving transmission constraints provides a logical evolution for wind to start providing faster forms of APC.

For an overview, we now discuss the current status of each of the three APC services discussed throughout this report in terms of steady-state operations and market designs in the United States.

- **Inertial Control:** Inertial control on the system level is not a requirement in any region of the United States. It is inherently provided by synchronous machines (generators and motors). Hydro-Quebec is one system that has begun to require a unit-specific inertia requirement from wind generators [8]–[9]. Inertial control is not explicitly scheduled, and there is currently no market or incentives to provide it in the United States.
- **PFC:** PFC has a balancing area (BA) requirement in Europe and is in the process of becoming a requirement in North America. The North American Electric Reliability Corporation (NERC) is revising its BAL-003 requirement to incorporate frequency response requirements, which at the time of this writing are subject to FERC approval [10]. In the Electric Reliability Council of Texas (ERCOT), rules require wind power plants to have the capability to provide primary frequency control (PFC) if they are operating at a point where they can do so (i.e., only if they were previously curtailed and have headroom to provide more energy during under-frequency events) [11]. There is currently no market or incentives to provide PFC in the United States, with the caveat that ERCOT requires resources that are selected in the spinning reserve market to be frequency responsive. It is not explicitly scheduled.
- **Regulation and AGC:** Regulation is required on a BA level to meet the NERC CPS1 and CPS2 requirements [12]. The requirements usually change based on load levels, day of week, season, and time of day. Restructured energy markets have ancillary service markets that incentivize resources to provide regulation, and it is explicitly scheduled alongside the energy market in the unit commitment and economic dispatch models. As of the writing of this report, wind power currently does not provide regulation in any of the market regions in the United States.

Due to the current status of these services, the team sought out initiatives to (1) understand the issues with not having incentives for inertial control and PFC, (2) design how the incentives and scheduling could be structured for inertial control and PFC, and (3) understand the operational and economic impacts if wind were allowed to provide regulation and AGC in an area with an existing regulation ancillary service market. This is how the section is structured, and results are based on [13], [14]–[15], and [16], for Sections 2.1, 2.2, and 2.3, respectively.

2.1 Approaches toward Incentivizing Primary Frequency Control

In the United States, there is no requirement that BAs, or synchronous interconnections, have adequate frequency response.[2] There are currently no incentives for individual resources to provide PFC, either. This lack of requirement and incentives likely has many causes, but is mostly due to frequency response having been an inherent feature available in conventional generating technologies and the fact that most interconnections have generally had more response than was needed. Both of these reasons may not hold true in future systems, based on current trends.

Recent studies have shown that the frequency response in the United States, and especially in the Eastern Interconnection (EI), has been declining [17]. Reasons for this include high governor deadbands, generators operating in modes that do not offer frequency-responsive reserve (e.g., sliding pressure mode), governors that are not enabled, a reduced percentage of direct drive motor load, and many others [18]–[19]. Although at low levels today, significant penetrations of electronically coupled renewable resources like wind and photovoltaic solar power can further reduce interconnection frequency response if they are installed without additional enhancements that can provide frequency response [20]. However, the decline in frequency response may also be due to the electricity market design in some areas that may not incentivize PFC, or in some cases offer disincentives.

The need for incentivizing PFC was one of the principal recommendations of an IEEE Task Force report on generation governing concerns [21]. Additional concepts on the incentives were given in [22]. Little attention has been given to PFC incentives since this initial report, and no U.S. region currently has a market for this service. As regions begin to understand the need for reliable frequency response and create the standards to guide this need, it will become more important to ensure incentives are in place to assist the individual resources. In our analysis, we focus on ISO and RTO regions, which already have restructured energy and ancillary services markets. However, in non-restructured areas (i.e., regulated utility areas), it is equally important for the BA operator to offer incentives for this response.

It is important to distinguish between PFC and secondary frequency control, as there is often confusion as to how each is performed and how each should be incentivized. Secondary frequency control is used to correct the ACE by bringing it back to zero. Positive ACE means the BA is over-generating, and negative ACE means it is under-generating. Most BAs that are part of large interconnected systems in North America, and elsewhere, will perform tie-line bias control [23]. With tie-line bias control, the ACE signal is determined based on Equation (2-1).

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[2] Since the writing of [13], there has been a draft standard for obtaining a minimum amount of frequency response for balancing areas in the U.S. interconnections. This is BAL-003-1, which is discussed further in Section 3.

$$ACE = NI_A - NI_S - 10B(F_A - F_S) \qquad (2\text{-}1)$$

Where NI_A is the actual net interchange with neighboring BAs in MW, NI_S is the scheduled net interchange in MW, B is the frequency bias MW/0.1Hz (10 coefficient makes units of MW/Hz), F_A is the actual frequency in Hz, and F_S is the scheduled frequency in Hz. The net interchange is the sum of all interchanges of a BA out of (+) and into (-) the area. If the actual net interchange is greater than the scheduled net interchange, the BA is over-generating. The second part of the equation [$- 10B(F_A - F_S)$] is introduced to ensure that systems are providing PFC, and that the AGC does not counter its PFC obligation. The frequency bias, B, is a constant, with the units of MW/0.1 Hz, which represents the amount of frequency response that the BA has, or should have. The value as it is shown in Equation (2-1) is negative, showing that generation should increase when frequency is low and decrease when frequency is high. We now give some numerical examples.

Scenario 1

NI_S = 500 MW $\qquad$ NI_A = 600 MW

F_S = 60 Hz $\qquad$ F_A = 60 Hz

B = -200 MW/ 0.1 Hz

ACE = 100 MW

In Scenario 1, the BA is transmitting 100 MW more power than it has scheduled. Therefore, the BA is over-generating by 100 MW, as seen in its 100 MW ACE. The AGC would send signals to the resources on regulation to reduce output and thereby reduce the 100 MW ACE back to zero. Somewhere else on the interconnection, a BA or a collection of BAs has an ACE of -100 MW. If all these areas strive to correct this ACE, there is no negative impact on frequency.

Scenario 2

NI_S = 500 MW $\qquad$ NI_A = 600 MW

F_S = 60 Hz $\qquad$ F_A = 59.95 Hz

B = -200 MW/ 0.1 Hz

ACE = 0 MW

In Scenario 2, the BA is again transmitting 100 MW more power out of its BA than it has scheduled. However, this time the actual frequency is below the scheduled frequency. According to the BA's frequency bias, B, it is providing the correct amount of PFC to assist the interconnection. By incorporating the 10 coefficient, we have: (-2000 MW/Hz)*(-0.05 Hz) = 100 MW of PFC that is needed. Therefore, the 100 MW of over-generation from the BA is necessary, and so the AGC should not attempt to correct the imbalance between actual and scheduled interchange, hence the 0 MW of ACE. Elsewhere on the interconnection, there is imbalance that is causing the frequency deviation. Once that BA corrects the imbalance, the frequency returns to its nominal setting, and the above BA can release its PFC.

Scenario 3

NI_S = 500 MW NI_A = 500 MW

F_S = 60 Hz F_A = 59.95 Hz

B = -200 MW/ 0.1 Hz

ACE = -100 MW

In the final example, this BA is balancing out its schedule and not producing any unscheduled flows out of its system. However, since the frequency is below its nominal setting, it should be providing PFC. Because it is not, it now has a negative ACE, showing it is providing less generation than it should be. The AGC would then send signals to its regulating resources to provide more power and bring ACE back up to zero. The PFC obligation is thereby supplied by secondary regulation. Since PFC is provided at much faster response times (seconds vs. minutes), using secondary control to meet the needs of PFC is not the desired approach to this issue. If this occurred consistently and more BAs did not provide PFC, it is possible that the frequency decline would become even greater and run the risk of load shedding, machine damage, or potential blackouts.

The above examples are simply intended to show that PFC and regulation are two distinct, separate, but related services. Markets that exist for regulation would not then necessarily incentivize the desired need for PFC. This distinction is very important as we discuss the current market designs and new approaches that may assist in providing incentives for PFC.

2.1.1 Design of Markets

An electricity market can be difficult to design well, as it must carefully consider the alignment of the market incentives with the needs of the power system. Unintended consequences can occur, reducing the effectiveness of the market or causing undesired impacts in separate, related markets. The objective of a market is to elicit an incentive for providers to supply the desired product in an economically efficient manner. The market will create competition, which will initiate market participants to minimize their costs of providing the particular service. This means that a well-designed market will induce the least-cost solution, subject to the various physical constraints and objectives of the market.

When a new market is introduced, there will typically be short-run and long-run adjustments. Initially, market suppliers may have limited ability to respond because operational changes or equipment needs or modifications may be required. After the suppliers make these changes, the market is likely to function smoothly in the absence of market power.

Rules can be used in cases where markets are too difficult to design, or if the market would be fundamentally flawed as a result of market power or other concerns. For example, the ancillary service of voltage support is typically a cost-based service [24]. Voltage support does not have a market with dynamic pricing or competitive suppliers. Voltage support is serviced with injecting and absorbing reactive power, and reactive power does not travel far on the transmission system. Since reactive power does not travel far, there are few suppliers of voltage support when it is needed in a particular location, limiting the competition for that service. This type of limitation is the main reason behind creating rules and standards for supplying voltage and reactive power support rather than introducing a dynamic market. Complexity, natural monopolies, cost of administrating the market, and low diversity in costs from competitors (i.e., if all suppliers would inherently cost the same to supply the service, and innovations to reduce costs are not possible) are all reasons why rules may be more practical than introducing markets for certain services.

2.1.2 Disincentives in the Current Market Design

Sometimes, in the absence of markets for particular services, there may be flaws when that service is coupled with other incentives. We will highlight an example of how current energy market designs may be giving disincentives to potential suppliers of PFC. In most ISO regions, energy is settled at prices and schedules that are produced from a security-constrained economic dispatch (SCED, or security-constrained unit commitment, SCUC) model. The energy markets are based on two settlement systems, so that a forward market will create initial schedules, and a real-time market will accommodate the differences in demand from what was expected in the forward market. The day-ahead market is the common forward market where day-ahead schedules and day-ahead LMPs are produced. In the real-time market, differences from the day-ahead market are settled at the real-time LMP, which can be quite different than the day-ahead LMP at the same location, based on the new characteristics of the demand, as well as generation and transmission availability. Therefore, the full settlement of a generator is based on Equation (2-2) where DA is day-ahead, RT is real-time, Pg is the generation schedule, i is the index for the generator, and h is the index for the hour.

$$Payment_{i,h} = Pg_{i,h}^{DA} * LMP_{i,h}^{DA} + (Pg_{i,h}^{RT} - Pg_{i,h}^{DA}) * LMP_{i,h}^{RT} \tag{2-2}$$

The only time that payment may differ from this situation is when generators do not produce the same amount of energy as they are scheduled in the real-time market. Even though it is a real-time market, the schedules are produced for some time in the future (usually 5–10 minutes ahead). Therefore, it cannot predict the energy that the generators will produce, nor can it predict the exact demand. Because generators have particular control over the output that they produce, most ISOs provide disincentives for the generators to produce energy differently from directed. In some cases, this may be a change of LMP to reflect the actual conditions (i.e., the prices are given ex post, where prices are based on actual outcomes, rather than ex ante, where prices are based on expected outcomes [25]). In other cases, financial penalties may be assessed to those market participants who stray from the schedule they were given. Both methods should work in incentivizing generators to follow their schedule as closely as possible.

A properly functioning governor will respond autonomously to frequency deviations, without the intervention of a control room operator. This is what they are designed to do, and this response is vital for power system reliability. In conversations with ISO employees, and in various manuals, tariffs, and user guides of the U.S. ISOs, the authors have found that few, if any, ISOs incorporate frequency as input into the market settlements system. A frequency deviation will cause a generator with a turbine governor to adjust its output to assist the interconnection in arresting the frequency decline (or frequency increase in the case of a loss of load), and its energy output will deviate from its real-time energy schedule. This can result in the generator receiving a financially penalty for deviating from its energy schedule.

As an example, if the ISO has a 3% tolerance band around its financial penalties, this means that if a generator deviates from its schedule by more than 3% of its operating capacity above or below its energy schedule, it will receive a financial penalty for not following schedule. Assuming, that a generator with a properly functioning governor has a 5% droop curve, we have the following:

$$\frac{1\, p.u.power}{0.05\, p.u.frequency} = \frac{0.03\, p.u.power}{X\, p.u.frequency}$$

$$X = 0.0015\, p.u.frequency = 90\, mHz\, for\, a\, 60Hz\, system \tag{2-3}$$

This means that any time the frequency deviates more than 90 mHz (i.e., if frequency dips below 59.91 Hz or above 60.09 Hz), any generator with a functioning governor and a 5% droop curve will automatically be penalized under this rule if frequency is not incorporated within the market settlements system. This is a significant disincentive. If the generator has no other incentive to provide PFC, which occurs when there is no ancillary service market for the service, it will have no motivation to enable its governor or operate in modes to provide the response. Because PFC is a crucial service to the power system, this can have drastic effects if this becomes a trend, which some researchers believe is the case [21].

Some important points are worth mentioning here. First, a 90 mHz deviation, especially in the EI, is extremely rare. A very large loss of supply or loss of two or more large generating units would have to occur for a frequency deviation of this magnitude to occur in large interconnections. Second, frequency usually begins to return to its nominal level a few minutes after the disturbance event. Penalties may be based on an hourly average production, meaning that a deviation based on the frequency response would likely have little impact on deviations from the hourly schedule. The point is, regardless of these caveats that may lessen the impact of these disincentives from providing PFC, there is still a disincentive, and with a cost to its provision and without any incentive for providing the response or any standard or grid code enforcing it, generators have every reason to disable their governors or operate in a way that provides little or no response. When the governors are disabled, the frequency response would then have to come from the secondary (AGC) response, a much slower response, which may cause degradation in the overall system frequency response, and put the system at higher risk for under-frequency load-shedding and other issues.

2.1.3 Market Design Proposals

Next, we discuss four proposals for new or modified market designs to provide alternative levels of incentives at varying levels of market design effort. There are two often conflicting goals in market design. Including more complexities to characterize the responses of the market participants and system will better reflect what is needed as the desired response. This should also limit market participant gaming. However, the more complex the market design, the more difficult and expensive it will be to implement and obtain regulatory approval. In this regard, the benefits may be diminished in smaller markets. With these issues in mind, we have proposed four market design proposals for consideration. If any of the ISOs were to choose any of these proposals, or a combination of them, they would likely work out specific details through the regular ISO stakeholder process to determine which design best fits their particular region.

Proposal 1: Elimination of Penalties during Frequency Events

The simplest proposal would eliminate penalties during frequency events, as discussed in the previous section. A rule could be implemented so that over-generation penalties do not apply when frequency is below some threshold, and under-generation penalties do not apply when frequency is above some threshold during any instant within the settlements interval. This would assure market participants who enable the governor and provide sufficient PFC cannot be harmed financially when they do so.

The benefit of this change is that it is relatively simple to implement. No new markets or changes to scheduling software are required, and there are no changes to the resulting prices or schedules. However, it would mean that frequency would have to be recorded in the settlements system, and that some basic logic would have to be added to the settlements system. The logic would simply check every penalty assessed to see if there were any frequency excursions that would have triggered governors to cause the penalty, and void the penalty if so. A simple threshold could be based on a typical governor deadband. If the frequency deviation is within the governor deadband, the governors do not react, and therefore there is no reason to void the penalty. If the frequency deviation is outside the deadband, then the governors react and there is a reason to ensure that no resources with functioning governors are penalized during these times. While this proposal may eliminate disincentives, there is still no incentive for resources to enable governors and provide PFC.

Proposal 2: Specific Accountability of Frequency Response to Avoid Penalties

The second option applies additional parameters to the settlements system, so that only those resources that offer PFC avoid penalties. In this proposal, in addition to the frequency being used in the settlements system, governor droop and governor deadband are added. The settlements system now includes the logic to determine what the resource's output should be during frequency excursions and during normal conditions. Instead of avoiding penalties during frequency excursions, the settlements system knows what the frequency-responsive units should have provided based on the frequency and its response characteristics. Resources without a governor or operating in a mode that does not provide frequency response should not avoid these penalties.

The benefit of this change is that it ensures proper frequency response and still retains the original goals of penalties and settlements for those resources that are not following schedules, whereas Proposal 1 may eliminate the penalties for resources regardless of whether they are actually helping the system during the frequency excursions. This can better incentivize resources to provide the desired frequency response. However, there is added complexity in that additional parameters and logic must be added to the settlements software. The complexity of the software logic will depend on the time resolution of the retained frequency measurements. Also, if this proposal is implemented without any rule that certain resources are required to enable governors, there is still no incentive for those resources to enable governors and provide the frequency response.

Proposal 3: Incorporate Frequency-Responsive Requirement within Spinning Reserve Requirement

The third proposal can likely be implemented in conjunction with either Proposal 1 or Proposal 2. This proposal would require that any resource providing spinning reserve and participating in the existing spinning reserve market enable its governors and provide frequency-responsive reserve with enforcement. There is a connection between spinning reserve and frequency-responsive reserve because both are responsive to disturbances on the system. The spinning reserve would then be required to respond both to system operator commands and autonomously to frequency deviations. This offers an additional incentive for resources to provide PFC in contrast with Proposal 1 or Proposal 2 by themselves. The resources would have to enable the governors to earn revenue in the modified spinning reserve market.

This is also a relatively easy market design change to implement. However, it is not clear that this change by itself will obtain the correct amount of PFC. Resources differ in the amount of PFC they are capable of providing. Scheduling sufficient spinning reserve might not result in sufficient frequency response being available. Further, the amount of available PFC could change as the mix of resources providing the spinning reserve changes. Imposing specific frequency-response capability requirements on spinning reserve resources would likely limit the spinning reserve supply and increase the price [22]. Energy prices could also be impacted because spinning reserve resources also supply energy and are influenced by reserve constraints. Locational constraints for spinning reserve and frequency response often differ, further complicating a simple joint supply requirement. Spinning reserves in many areas have locational requirements to avoid overloading the transmission system during contingency events. Frequency-responsive reserves may have completely different location-based requirements, or none at all, which would add a further complexity if the two were paired together in one market. Besides these issues, the proposal would be relatively easy to implement, making an incentive available for resources to provide frequency-responsive reserve.

Proposal 4: Separate Primary Frequency Control Ancillary Service Market

The fourth proposal is the implementation of a new PFC ancillary service market within the ISO. This proposal is also recommended by [22]. The market would incorporate the reliability requirement of a minimum amount of frequency-responsive reserve, similar to spinning reserve. This requirement, in both MW and MW/0.1 Hz, would ensure enough headroom and enough sensitivity to avoid under-frequency load-shedding following some large, credible interconnection-wide event. The resources would offer their droop curves, response range, time delays, and governor deadbands, and the market would select the least-cost optimization that meets the specified reliability requirements. As PFC is tightly coupled with energy and other reserves, it would be beneficial to co-optimize this service with energy, as is done with the other ancillary services. The possible design of this ancillary service market is discussed in Section 2.2 as well as in more detail in [14]–[15].

This proposal includes the incentives in Proposal 3 to provide frequency-responsive reserve. However, it avoids the issues of pairing two services at the same price when they are in fact different services, as well as the other issues involved (e.g., measurement of compliance and locational requirements). The major issue is the complexity of implementing this new market, with regard to both software and regulatory complexity. The market software would have to be enhanced to incorporate these new parameters and requirements. It would also have to go through large regulatory hurdles to introduce a new market to consumers, which would require the approval of stakeholders and federal regulators. Many opponents would argue that more markets and more complexity is not always the answer. How the new market affects the costs borne by the consumer would also need to be studied further.

Comparison

Table 2-1 gives an overview of the four market design proposals discussed in the previous sections. Each has different ways of eliminating disincentives, providing incentives, and increasing market design complexity. Each of these proposals has different advantages and can also be paired with another to achieve the best efficiency. The benefits will likely be system specific. The implementation costs and regulatory hurdles of Proposal 4 can make it less attractive and perhaps not appropriate in certain markets. However, this option will establish clear incentives for resources to enable governors and provide PFC, while eliminating any disincentives that penalize resources in the energy market for providing this response. Importantly, if there is no cost for providing the service and lots of competition to provide it during certain instances, then it should result in a price of zero. This often occurs with the other ancillary services like spinning reserve, especially at night when the supply-side competition is high and costs are low. If this market were created, it would be important to monitor the activities and outcomes through normal market monitoring procedures to ensure proper competition exists and resources are not gaming the market through loopholes or other means.

Table 2-1. Comparison of Market Design Proposals

Market Design Proposal	Eliminate Disincentives?	Provide Incentives?	Complexity L: Low M: Medium H: High	Limitations
Proposal 1: *Elimination of penalties during frequency events*	Yes, penalties would no longer be assessed during frequency disturbances	No, but could be paired with Proposal 3 or 4	L: Very minor changes to settlements rules	Penalties will be avoided regardless of whether the resource is providing frequency response
Proposal 2: *Specific accountability of frequency response to avoid penalties*	Yes, for resources that can properly provide frequency responsive reserve	No, but could be paired with Proposal 3 or 4	L-M: Somewhat complicated logic, but only to the settlements system	No requirement to enable governors
Proposal 3: *Incorporate frequency-responsive reserve requirement within spinning reserve requirement*	No, but could be paired with Proposal 1 or 2	Yes, resources that provide frequency response can bid in spinning reserve market	M: Settlements system, monitoring requirements, and regulatory complexities would result	Price signals may not be clear due to joining of two services in one market
Proposal 4: *separate frequency-responsive reserve ancillary service market*	No, but could be paired with Proposal 1 or 2	Yes, correct implementation would give clear incentives for resources to provide frequency-responsive reserves	H: Many different software programs would be impacted significantly; Large regulatory process	Complexity of market will be expensive and will take time for market participants to learn

For Proposals 3 and 4, some type of system-wide standard must direct how the scheduling and pricing are made to incentivize resources in the correct manner. While a system standard is absolutely required for a market to exist, unit-specific standards can exist as an alternative to a market. For example, if every generating unit on the system was required to have its governor enabled with specific characteristics, the need for a PFC market might be avoided. The original movement toward deregulating the wholesale electricity sector initiated from the fact that new supply-side technologies could offer energy at various ranges of costs, and deregulation helps to reduce costs borne by consumers by promoting competition. It is also designed to promote innovation for supply-side technologies to improve their technology to reduce costs and increase revenue. This trend can be seen in the technologies that provide PFC. Many technologies have different ways of providing this control. For example, nuclear generators rarely have governors, as they are generally operated with load limiting. Combined-cycle gas turbine technology has a very different frequency response than conventional steam turbine technologies. Wind generators, which historically have not provided any PFC, can be equipped with power electronics that can control the blade pitching to provide PFC. However, adding this control will likely come at a cost. By introducing PFC incentives, it would be up to the wind plant market participant to decide whether or not to include this control, based on how much revenue it believes it can earn. Photovoltaic solar or electronically interfaced storage would face the same question. Furthermore, proper incentives that value superior response could promote innovation for new technologies to improve the response. This new trend of different market participants being able to supply different forms of PFC at different costs may reveal that a PFC market is a more efficient alternative to unit-specific requirements.

2.2 Market Design for Primary Frequency Control

As the previous subsection described the issues with and potential alternatives to an incentive structure for the supply of PFC, this section is a follow-up to the fourth proposal, how a separate PFC ancillary service market could actually be designed and implemented given the design of energy and ancillary service markets in current U.S. market areas. For wind power to be able to provide this service and economically do so, a proper design must first be created. This design would be desired if wind power or any other technology requires an incentive to reduce energy output and have the appropriate control technology to provide PFC. The design must carefully incorporate the valuable characteristics of sufficient PFC, which include inertia, power capacity, responsiveness to frequency, limited insensitivity to frequency, faster triggering and deployment speeds, and a stable and sustainable response. The design must ensure prices, auction bidding structure, and settlements are set to incentivize these desired characteristics. The design must link to the reliability requirements needed for a reliable response, and given the variety of market systems in the United States and elsewhere, must be applicable towards pool-based market regions, which are part of large synchronous interconnections as well as isolated systems. For full details on this work, please see [14]–[15].

2.2.1 Reliability Requirements

The literature has proposed previous designs for scheduling PFC, e.g., those seen in [26]–[29]. These works portrayed the important pieces of PFC scheduling, along with some aspects of market design. However, these works focused only on market regions that were the sole operators of an interconnection (i.e., island systems), and did not fully incentivize all the characteristics necessary for sufficient PFC response. This work expands on these previous works to capture the design more generally.

Figure 2-1 shows the frequency during the first 30–40 s following a disturbance. Different metrics are presented that can illustrate the performance of PFC from the interconnection perspective.

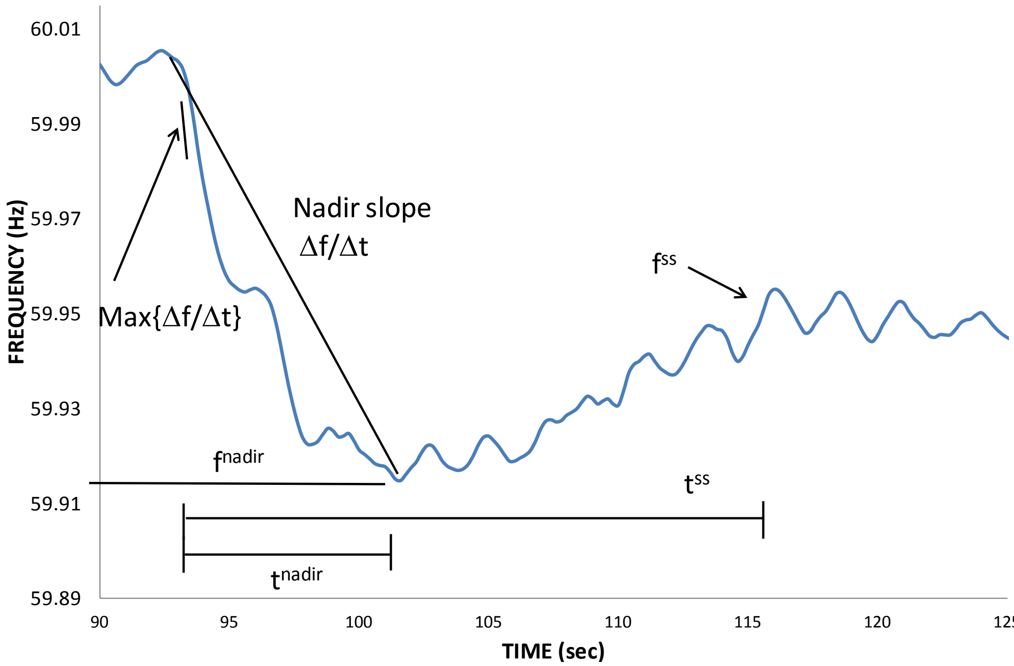

Figure 2-1. Western Interconnection frequency during the first instances following a disturbance, and some metrics that can show the performance of PFC.

The *Max {Δf/Δt}* and nadir slope are both shown. The greater these slopes are, the sooner the frequency could reach under-frequency load shedding (UFLS) set points. Additionally, some systems may operate with rate of change of frequency (ROCOF) relays, where fast changes of frequency can trigger generation protection schemes or load shedding. Therefore, it is important that the maximum slope be kept below some level. The *Max {Δf/Δt}* will depend almost entirely on the amount of synchronous inertia on the system, including both generators and loads, but the nadir slope will also depend on the triggering speed of PFC.

The frequency nadir (f^{nadir}) is also an important metric. In both the Continental European [30] and proposed North American [31] PFC standards, the requirement is based on reaching a frequency that avoids UFLS when some pre-designated largest credible disturbance occurs. However, this frequency is in both cases the steady-state frequency (f^{ss}). The f^{nadir} can typically reach a level below f^{ss}. Therefore, if the ultimate result is to avoid UFLS during the disturbance, f^{nadir} may be a more critical metric, as it will be the closest frequency to triggering UFLS. The requirement may also be dependent on the size of the loss of supply, i.e., the metric is expressed in MW/Hz. The triggering speed, droop setting, governor deadband levels, and synchronous inertia of the system will all contribute to the nadir metrics. Each characteristic must be incentivized to provide an appropriate f^{nadir} that avoids UFLS.

Figure 2-1 also shows the steady-state frequency f^{ss}. A related metric, which is expressed in MW/Hz (or MW/0.1Hz), is the typical requirement seen in the European and proposed North American policies. The metric shows the deviation of f^{ss} from nominal frequency with respect to the size of the disturbance. Another important metric is the time it takes for the system to reach its steady-state frequency (t^{ss}). This metric is part of the European requirement, where full deployment of PFC is required between 15 s and 30 s. These metrics would depend on the governor droop setting, deadband, headroom (amount of capacity above generation level), and

PFC deployment speed of resources providing PFC and load damping. Each characteristic must be incentivized to achieve the desired steady-state frequency objectives.

Although not depicted in Figure 2-1, the secondary response is also important in the consideration of PFC. Both the European and North American systems have a requirement for frequency (or ACE) to return to nominal (ACE to zero) within some time period (t^{rec}). Likewise, during the recovery, the response should remain stable, avoiding oscillations in frequency, as well as sustainable, such that the PFC response is sustained consistently without withdrawal until replacement from secondary reserves.

2.2.2 Scheduling and Incentive Characteristics

Each of the previously mentioned metrics can be used to show the performance of PFC from an interconnection-wide perspective. In most market regions, like in the North American EI and WI and in the Continental European Interconnection, market regions are a subset of the entire synchronous interconnection. Each region is operating a market that decides its own suppliers without having much of the information to understand the commitment and dispatch of the entire interconnection or set frequency-based criteria. Instead, offline studies are needed to set requirements for each region to ensure reliability of the entire interconnection. We therefore describe seven characteristics that can be incentivized for individual units that will lead to acceptable performance on the entire interconnection. The full formulation can be seen in [14]. Many of the equations are left out here for the purpose of brevity, but the characteristics are described below.

The first characteristic is to ensure resources are providing enough synchronous inertia so that the Max $\{\Delta f/\Delta t\}$ does not exceed a limit that can cause triggering of ROCOF relays or lead to instability or triggering of UFLS. This requires having enough online units with enough synchronous inertia, and therefore can change what units need to be online if the requirements are not met. The study did not evaluate the benefits or ability of wind plants to provide synthetic inertial control, but if the response is achieving the objective of reducing the ROCOF and possibly triggering UFLS, there should be no limitation to that provision. However, if because it is synthetic, the response does not achieve the goal or does not contribute to achieving this goal as well as synchronous inertia, the applicability of wind providing synthetic inertial control should be reevaluated in the context of this market design.

The second characteristic is to ensure enough PFC capacity is available. As this constraint is a capacity-based requirement only, it does not incorporate the speed of the response, which is covered later. It simply makes sure enough PFC capacity is available during a loss of supply.

The third characteristic is to ensure PFC is sensitive enough to frequency to avoid triggering of UFLS and to limit the deviation of f^{ss} from nominal, as well as limit insensitivity to frequency. This will influence the droop characteristics, with units providing more power per change in frequency, thereby reducing the level to which frequency deviates. It also limits the insensitivity to frequency, by influencing units to be responsive to small changes and reducing their governor deadbands.

The fourth characteristic is to ensure that PFC is triggered fast enough to avoid UFLS and that it is fully deployed within a time limit to ensure stability and limit risk. In this case, the market design is evaluating the PFC response at the time shortly before the expected nadir is to occur (t^{nadir}), and at the time it should reach its steady-state level (t^{ss}). A simplified process diagram is shown in Figure 2-2, and it is described in full detail in [14]. The market design iterates between the security-constrained unit commitment model and a dynamic frequency model. The dynamic model will show individual resource response based on the loss of supply, the other individuals and their characteristics, and a single block that represents the rest of the interconnection. If the total response at the two critical times does not meet their requirement, coefficients are calculated representing the response (i.e., $\alpha^{nadir} = P@t^{nadir}/P1$ and $\alpha^{ss} = P@t^{ss}/P1$, where P1 is the amount of capacity based on the droop setting and headroom). These coefficients are then brought back into the SCUC market model to ensure the commitment and dispatch provides enough response at these times. In these instances, the MW being produced will be accounted for with the associated needs, and therefore will incentivize resources to respond more quickly.

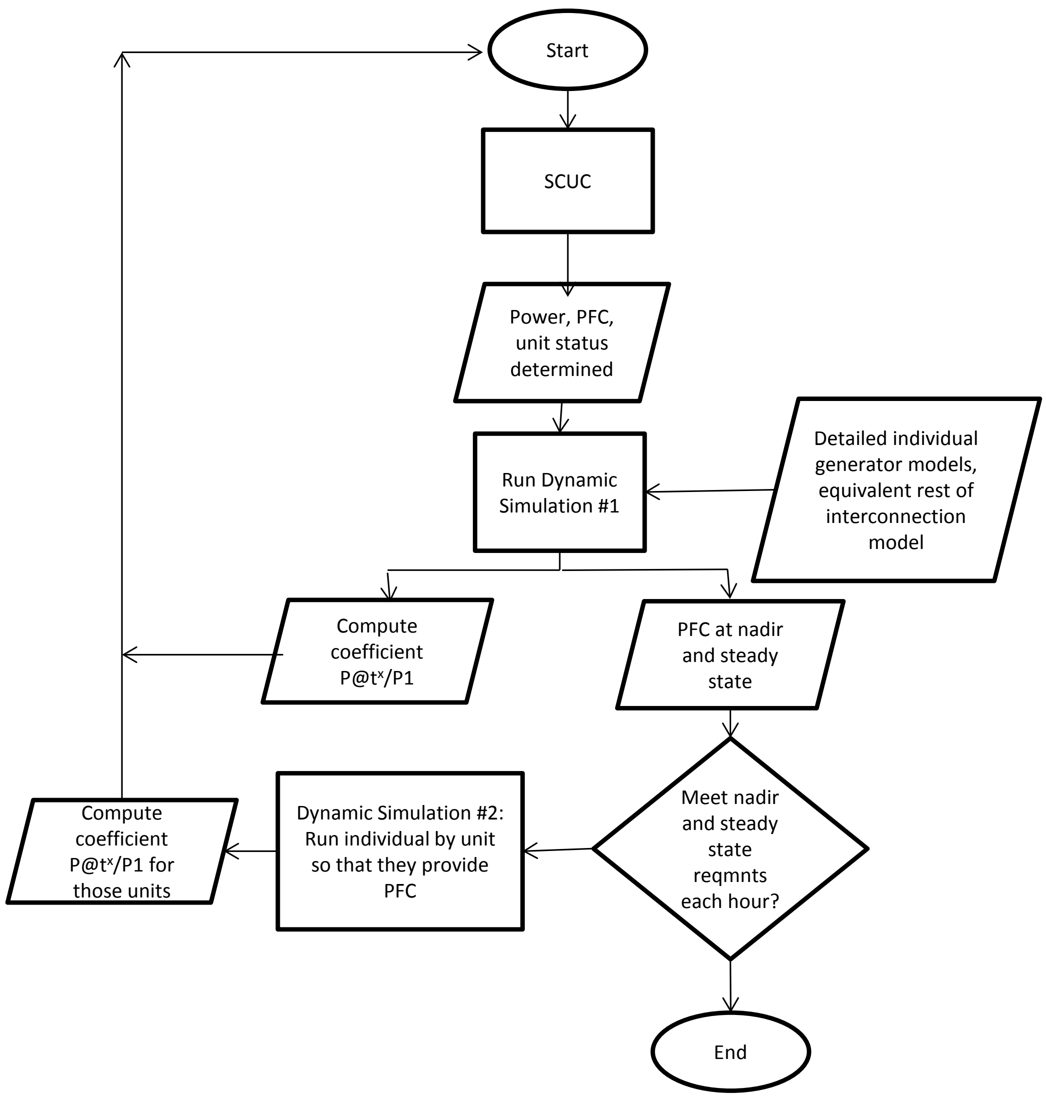

Figure 2-2. Process for ensuring that PFC is triggered fast enough to avoid UFLS, and that it is fully deployed within a time limit to ensure stability and limit risk.

The fifth characteristic is to ensure that PFC response is stable and does not cause instability or oscillatory frequency behavior. This is done by only allowing proportional droop curves. The consequences are stated in [32] and illustrated in Figure 2-3. The variability of the generation and load imbalance caused an oscillation in frequency when governors stepped in and out of their deadbands, which should be avoided.

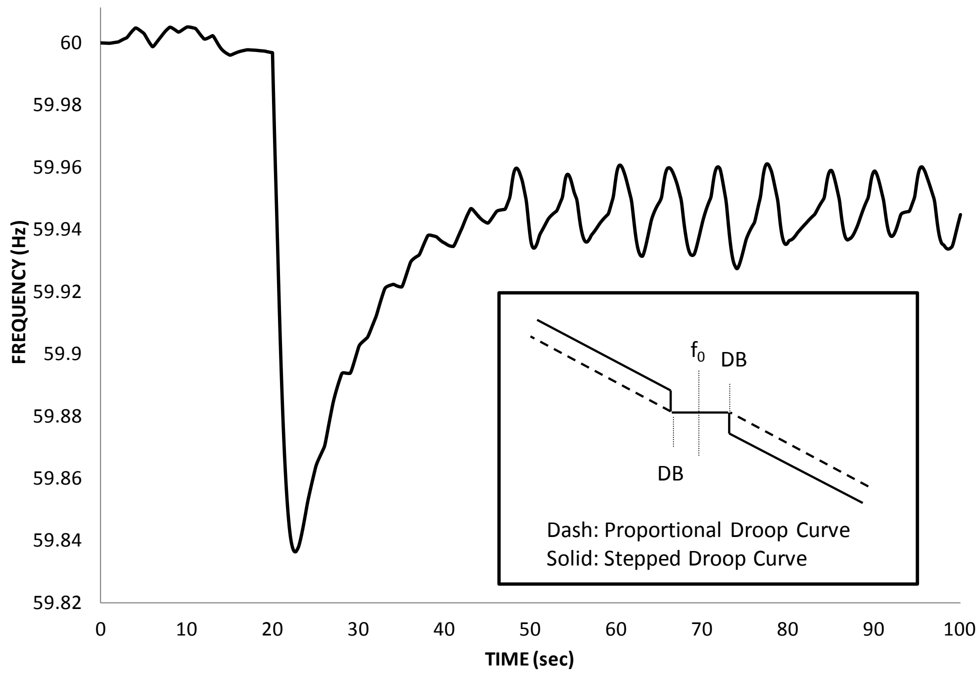

Figure 2-3. Simulated frequency response following disturbance with units having a stepped droop curve governor response and illustration of proportional vs. stepped droop curves.

The sixth characteristic is to ensure a sustainable PFC, so that after reaching f^{ss} there is a constant recovery with no withdrawal of PFC until secondary reserve is deployed to recover frequency. In the proposed market design, we require a minimum time that the PFC must be available following its deployment without withdrawal.

The seventh characteristic is to ensure enough secondary reserve is available to return the frequency to its nominal schedule within some time to ensure the system is quickly returned to normal. Because primary and secondary frequency control reserves are so closely linked in the full recovery of the system frequency following a disturbance, it is important that both be considered in the market design.

Each of these characteristics is built into a modified SCUC model. The SCUC model will schedule and commit sufficient resources at the lowest cost while ensuring that these characteristics are incorporated and all other appropriate reliability requirements are met. The SCUC will determine the schedules for energy and ancillary services, including PFC. It will also determine the prices of these services, which is discussed next.

2.2.3 Pricing

Energy and ancillary services markets in pool-based electricity markets have generally followed the marginal pricing concept, where schedules are based on simultaneously minimizing total energy and ancillary services bid-in production costs, and the bid cost of the marginal resource providing the service sets the price for all resources providing that service. The prices are equal to the partial derivative of the Lagrangian function with respect to the demand for that service, also referred to as the dual value or shadow price. We adopt the same concept for the prices that are used for PFC services. We also adopt the concept of pricing hierarchy, so that the more valuable response will always be rewarded greater than those of lesser value [33]. The Lagrangian function now contains the constraints and Lagrangian multipliers of each of the new PFC requirements. Due to the new constraints and based on the marginal pricing theory and pricing hierarchy, Equation (2-4) shows the LMP and Equations (2-5) through (2-9) show the ancillary service clearing prices (ASCP) for each of the reserve categories, where $\mathcal{L}$ is the Lagrangian, L_n is the load at bus n, μ is the shadow price of transmission congestion, $SF_{n,l}$ is the shift factor of bus n on line l, LF is the loss factor, α_L is the coefficient for how much PFC at critical times is provided with respect to the total amount of PFC available, Δf^{max} is the maximum frequency deviation the system will allow, f_0 is the nominal frequency, and $P10$, $P1ss$, $P1nadir$, $P2spin$, and $P2nonspin$ are the PFC quantities for capacity only, at t^{ss}, and at t^{nadir}, and secondary reserve for spinning and nonspinning reserve, respectively. The variables β_1-β_5 are the dual values for each of those services in that order.

$$LMP_n = \frac{\partial \mathcal{L}}{\partial L_n} = \lambda + \sum_{l=1}^{NL} \mu_l * SF_{n,l} - \lambda * LF_i - \beta_1 * \alpha_{L,t}^{nadir} * \frac{\Delta f^{max}}{f_0} - \beta_2 * \alpha_{L,t}^{ss} * \frac{\Delta f^{max}}{f_0} - \beta_3 * \frac{\Delta f^{max}}{f_0} - \beta_4 * \frac{\Delta f^{max}}{f_0} - \beta_5 * \frac{\Delta f^{max}}{f_0} \tag{2-4}$$

$$ASCP_{P1nadir} = \frac{\partial \mathcal{L}}{\partial P1_A^{nadirReq}} = \beta_1 \tag{2-5}$$

$$ASCP_{P1SS} = \frac{\partial \mathcal{L}}{\partial P1_A^{ssReq}} = \beta_2 \tag{2-6}$$

$$ASCP_{P10} = \frac{\partial \mathcal{L}}{\partial P1_A^{0Req}} = \beta_3 + \beta_4 + \beta_5 \tag{2-7}$$

$$ASCP_{P2spin} = \frac{\partial \mathcal{L}}{\partial P2_A^{spinReq}} = \beta_4 + \beta_5 \tag{2-8}$$

$$ASCP_{P2nonspin} = \frac{\partial \mathcal{L}}{\partial P2_A^{nspinReq}} = \beta_5 \tag{2-9}$$

The LMP typically includes components for energy, transmission congestion, and electrical losses. In this design there is an additional component. Because load affects how much PFC is required, or reduces the level of how much PFC from generation is required, the payment is discounted as shown. Generally, due to the small ratio of Δf^{max} to f_0, this component would not typically have a significant impact on energy prices, but could during times of scarcity. For the ASCP, we again reiterate the importance of pricing hierarchy for services that share capacity. As the PFC capacity can contribute to secondary reserve, but secondary reserve cannot contribute to

PFC capacity, the price for PFC capacity must be greater than or equal to the prices of the lower-valued services. Since $P1^{nadir}$ and $P1^{ss}$ are PFC at critical instances that are dynamic and cannot contribute to secondary reserve as $P10$ can, these prices do not follow the hierarchy. The pricing hierarchy only applies to positive reserve services. If considering downward reserve services (i.e., PFC and secondary reserve for over-frequency or high ACE), these services could have their own, separate hierarchy. Each of the PFC prices is paid to providers of those services. Due to the design of constraints for the three PFC services at different critical times, and the fact that they are all binding based on their capacity, only one of β_1, β_2, or β_3 can be nonzero at a time. This prevents double counting and incentivizes speed when speed is needed, or capacity when capacity is needed.

Pricing of synchronous inertia is not as straightforward. If the price of inertia were based on the marginal cost of providing inertia and set as the marginal cost of providing synchronous inertia (representing a change in cost with an infinitesimally small change in inertia demand), this price would always be zero. The only way to increase the amount of synchronous inertia (with the exception of synthetic inertia from wind plants and other non-synchronous machines) on the system is to turn additional units online, which is a discrete change and not continuous. This would eliminate an incentive to provide inertia when the system needs it. For example, a generator that is turned on solely due to an inertia constraint, where the energy price and other reserve constraints are not enough to make up for its total costs, the resource has no incentive to turn on, and must be paid uplift. Similar to some designs being used for pricing of energy when gas turbines are turned on (see [34]–[35]), we propose that an additional SCUC is run following the final SCUC, with identical constraints, but that the integer variables, like the unit status variable, are continuous between zero and one. This allows for a non-zero price for synchronous inertia whenever there is a need that cannot be satisfied with the other constraints on the system.

Some final considerations are discussed for completing the market design, although many of the final rules will vary based on the specific market and its existing rules, and the development of those rules within the stakeholder process. We provide a list of these considerations, which we believe are an important part of the complete design of a PFC ancillary service market.

- The payments for PFC services are allocated to the loads based on their load share, or should follow the allocation of other reserve used for loss-of-supply events.
- Market mitigation of PFC in day-ahead markets should be relaxed, as there are no locational constraints.
- No external bid-in costs should be placed for synchronous inertia, $P1^{ss}$, or $P1^{nadir}$.
- Individuals participating in the PFC ancillary service market are waived of under- and over-generation penalties during events where frequency deviates by more than the individual's deadband (for reasons for this, see Section 2.1).
- PFC and synchronous inertia payments for day-ahead and real time are all included in the total payment. If the total profit including these payments is negative, the resource receives a make-whole payment to force the profit to zero.
- PFC suppliers should be monitored to ensure they are offering what they have sold to the PFC market. Phasor measurement unit technology could make advanced monitoring

feasible, but it is likely that current monitoring technology would meet the needs. Without appropriate excuse, poor or no performance from market participants should be penalized, and after persistent violations, be prevented from participating in this market.

2.2.4 Case Studies

We now describe a few case studies that were run using the scheduling model and market design discussed in Sections 2.2.2 and 2.2.3 on the IEEE Reliability Test System [36]. The system contains 24 buses, 38 branches, and 32 generators. The generating units include nine coal steam turbines, 11 oil steam turbines, four oil combustion turbines, six hydro turbines, and two nuclear plants. The inertia constant of these resources is given from [37], all droop characteristics are set at 5%, and governor deadbands are set at 36 mHz. Simulations are run for a 24-hour period on the peak load day, with the load profile shown in Figure 2-4. For the full set of results, please see [15].

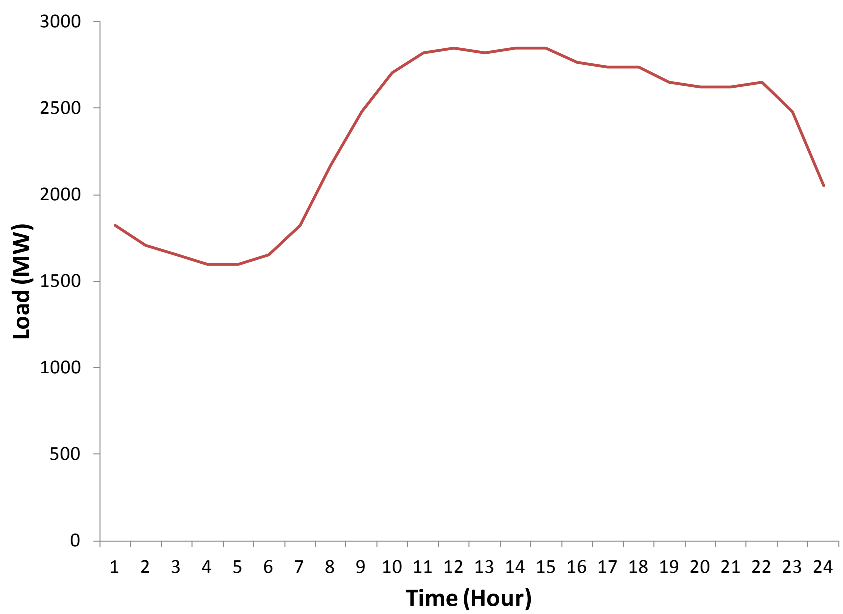

Figure 2-4. Load profile from peak load day.

The test system is assumed to be a market region that is part of a large synchronous interconnection, e.g., the U.S. Western Interconnection (WI). Table 2-2 shows the values that are assumed for the rest of the interconnection, while Table 2-3 shows the associated reliability requirements used in the study.

Table 2-2. Parameters for Rest of Interconnection

Δf^{max} (Hz)	*Inertia Constant - H (s)*	*Loss of Supply Studied - P_{Loss} (MW)*	*Total Generation - P (MW)*	*Total Capacity - P^{max} (MW)*	*Equivalent Droop Curve - R (%)*
0.2	6.5	2800	175,000	185,000	22

Table 2-3. Reliability Requirements for PFC

$P1_A^{0Req}$ (MW)	$P1_A^{NadirReq}$ (MW)	Δf^{max} (Hz)	I_A^{Req} (MVAs)	$P2^{Req}$ (MW)	DB^{max} (Hz)	t^{ss} (s)	t^{nadir} (s)	t^{rec} (min)
44	33	0.2	5500	120	0.1	30	4	10

Table 2-3 shows in order the PFC requirement at t^{ss}, the PFC requirement at t^{nadir}, the maximum allowed frequency deviation, the synchronous inertia requirement, secondary reserve requirement, maximum allowed governor deadband, time resources should be providing all $P1^{ss}$, time that resources should be providing $P1^{nadir}$, and time that resources should be providing secondary response.

2.2.4.1 Base Case Study

For the base case study, two comparisons were simulated: the system with a secondary reserve requirement without any PFC requirements (BC1), and the system with all PFC and secondary reserve requirements (BC2). An overall comparison can be seen in Table 2-4, and the prices can be seen in Figure 2-5.

Table 2-4. Base Case Comparison

	BC1	BC2
Production Costs ($)	568,297	569,315
Avg. Units Online per Hour	20	19
Avg. Inertial Energy per Hour (MVAs)	8563	8618
Avg. $P1^{ss}$ per Hour (MW)	43.7	48.4

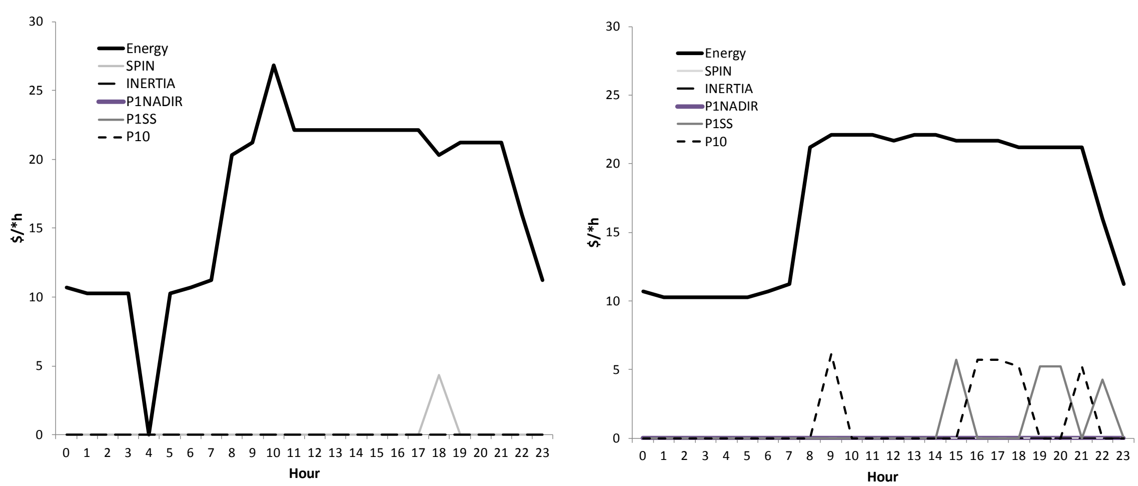

Figure 2-5. Prices for BC1 (left) and BC2 (right). Prices are in ($/MVAs-h) for inertia and ($/MWh) for all other services.

The general results of Table 2-4 show that there is not a significant difference in costs or schedules. In BC1, the amount of PFC was calculated by the droop setting of all online units with headroom, assuming all units had enabled governors. In this scenario, 11 hours would not have met the PFC capacity requirement, although only by a very small amount. As both BC1 and BC2 are meeting the same demand, Figure 2-5 shows the importance of co-optimization and how the ancillary service markets can impact the energy price. The energy price (LMP) is averaged over all locations, although the simulations did not result in significant locational differences. While BC2 has more hours in which ancillary service providers are being paid, the average energy price was less volatile and about the same ($0.10 higher on average, mostly due to the $0 LMP in BC1 at hour 4). With PFC constraints, BC2 also committed slightly less units but more frequency-responsive units. For BC2, the spin price is never binding due to the PFC requirements being active. For hours 15, 19, 20, and 22, the PFC requirement was actually binding due to $P1^{ss}$, which demanded a faster response than the PFC capacity available. Therefore, only the amount that contributed for up to t^{ss} would be paid for those hours. The synchronous inertia price was zero for all hours, as the requirements of energy, spin, and PFC inherently committed enough synchronous inertia.

2.2.4.2 Study with Nonsynchronous Wind Power without PFC Capabilities

Next, a scenario was run in which 15% wind energy was added to the IEEE Reliability Test System. Although it is generally agreed upon that the addition of variable renewable resources like wind will have little impact on PFC requirements, if these technologies are not equipped with additional capabilities, and if they displace resources that are, further degradation of PFC can be realized. The wind power in this study does not provide PFC or synchronous inertia. Figure 2-6 shows the wind and load profiles for this case study. Table 2-5 shows the results.

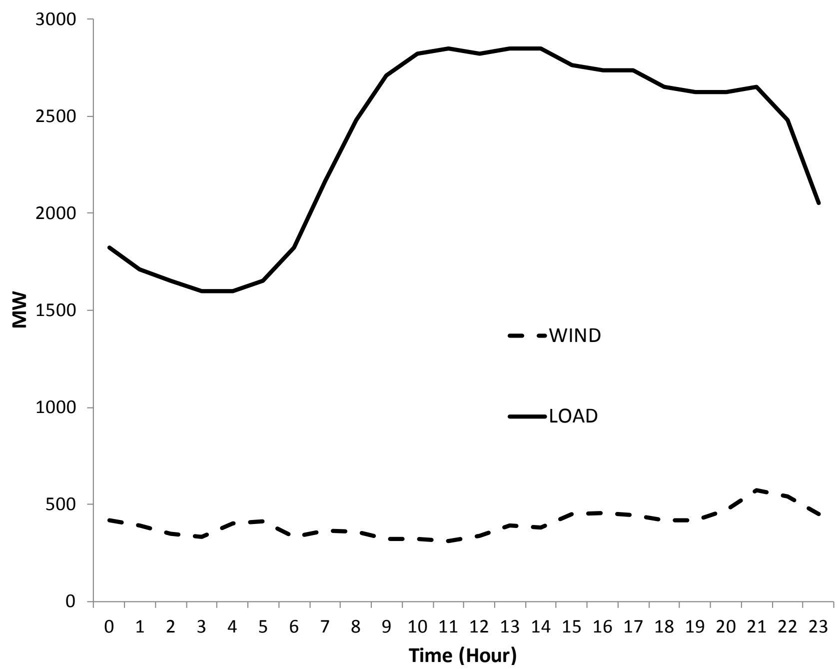

Figure 2-6. Load and wind for simulation.

Table 2-5. Wind Case Comparison

	WC1	WC2
Production Costs ($)	401,287	403,616
Avg. Units Online per Hour	17	17
Avg. Inertial Energy per Hour (MVAs)	7283	7310
Avg. $P1^{ss}$ per Hour (MW)	36.75	48.1

In this case study, the differences between the cases become more significant. The relative cost difference is about three times as much as in the base case (still slightly below 1% of the total), meaning WC2 requires slightly more changes to ensure enough PFC. The most significant difference is the average amount of PFC available by the steady-state time. As the wind power is displacing the commitment of conventional technologies and does not provide the capability itself, the amount inherently available while meeting energy and secondary reserve requirements is much less than that for a system with only conventional resources. Overall, the amount of inertia was not significantly impacted, meaning that the 15% wind case had little impact on the amount of synchronous inertia committed compared to the required amount. The price of synchronous inertia was still zero. Also, with PFC constraints enforced to ensure that enough response was available (WC2), the average LMPs in this study were less than with just the energy and secondary reserve constraints (WC1). Table 2-6 shows the difference in revenues received from the units in both scenarios. Although additional revenues are received in the PFC ancillary service market, it does not necessarily mean higher overall costs to consumers.[3]

Table 2-6. Revenue from Each Service for WC1 and WC2

	Total Energy Payments ($)	**Total PFC Payments ($)**	**Total Spin Payments ($)**	**Total Payments ($)**
WC1	$736,618	0	$24	$736,642
WC2	$722,229	$2,359	0	$724,588

2.2.4.3 Synchronous Inertia Pricing

In all the previous studies, synchronous inertia never resulted in a nonzero price. The inertia requirement that we have used in the previous case studies, when combined with the inertia of the synchronous load, is always inherently met due to the energy, spin, and PFC requirements. Therefore, in order to exemplify the pricing methodology of incentivizing enough inertia on the system, we study a 50% wind penetration system, with all PFC constraints set to zero except for the synchronous inertia requirement, I_A^{Req}, of 5500 MVAs. Inertia may be a very important need, particularly in island systems [38]. In systems where there is a need to have minimum inertia online, without payments, it is possible that certain resources do not recover their costs in the

[3] This study did assume that all resources on the system bid in their true marginal costs, which may not be the case in reality.

energy market alone when they are brought online to simply meet the synchronous inertia requirement. These resources would be paid make-whole payments to ensure they do not receive negative profits. Make-whole payments are important to ensure resources are willing to respond appropriately to the system operator's directions when needed for reliability. However, in most cases, when possible, incentives built into the pricing are more desirable due to their transparency. Figure 2-7 shows the prices for both energy and synchronous inertia for this 50% wind penetration case.

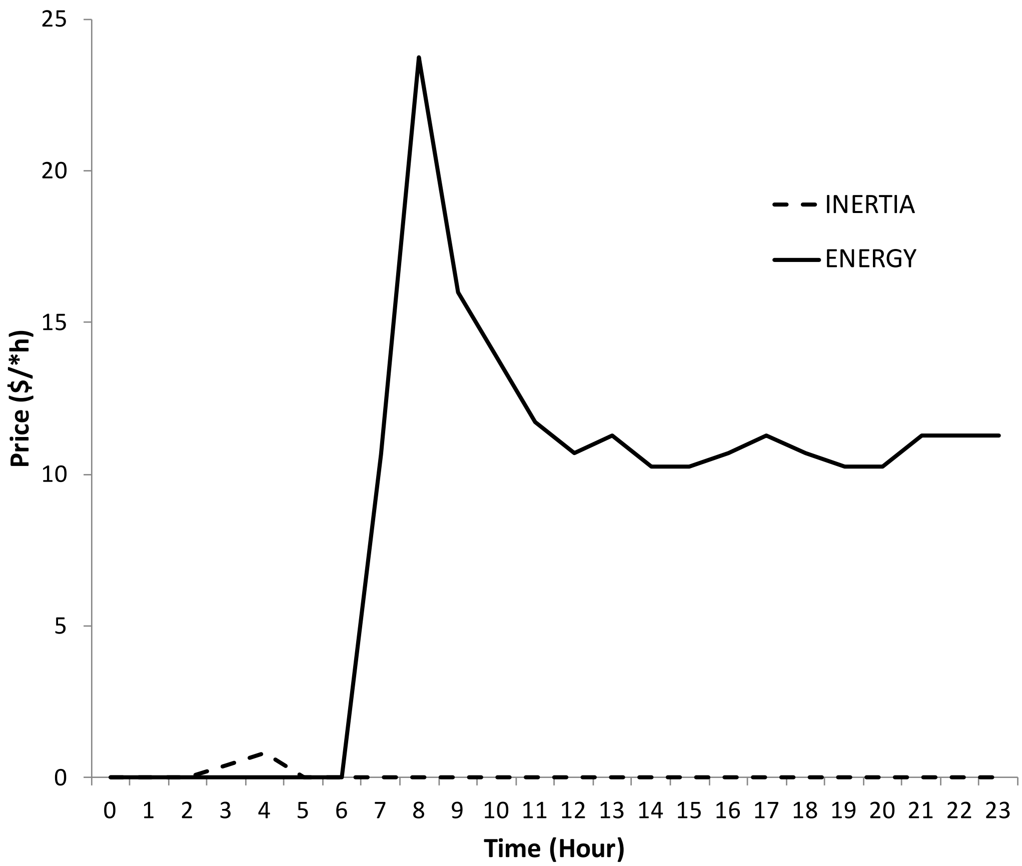

Figure 2-7. Prices for energy and synchronous inertia for 50% wind penetration system with all other PFC constraints eliminated. Prices are in ($/MVAs-h) for inertia and ($/MWh) for energy.

The price of inertia is only binding for two hours. As discussed in Section 2.2.3, the price of inertia is calculated from a separate SCUC run, where the integrality constraints are relaxed. The price is in $/MVAs-h, so even though it is small, the multiplier will result in non-trivial payments to units with large capacities and inertia constants. In this case, due to the minimum up times, minimum capacities, and fairly high start-up and no-load costs, many units were not made whole by revenue in the energy market alone (uplift is expected to some degree due to nonconvexities). When incorporating the inertia pricing, the uplift was reduced by 13% (from $11,340 to $10,016). For example, one generator received $1200 from its inertia settlement, reducing its make-whole payment. This pricing offers more incentives for resources to stay online when they are needed for reliability, when the energy market does not offer that incentive.

2.2.4.4 Innovation Improvements

A last set of analyses was aimed at understanding if there are incentives for improving one's response capabilities to improve system reliability when needed. This case study used one unit and made incremental improvements to its PFC capabilities to see the difference in revenues earned. Table 2-7 shows the payments, costs, and revenues of the unit in the base case, and by reducing its droop curve from 5% to 4%, reducing its governor deadband from 36 mHz to 10 mHz, and increasing its inertia constant from 3 s to 4 s (this is not a practical adjustment that can be made, but it still provides valuable insight).

Table 2-7. Revenue Based on Incremental Improvements to PFC Capabilities

	Total Energy Payment ($)	Total PFC Payment ($)	Total Cost ($)	Total Rev. = Payment – Cost ($)	Change in Rev. vs. Base Case $ / %
Base Case	87,277	333	71,256	16,355	-
Reducing *R* to 4%	96,337	496	71,108	25,725	9,370 / 57%
Reducing *DB* to 10 mHz	93,789	587	71,089	23,287	6,932 / 42%
Increasing Inertia Constant to 4 s	87,277	333	71,256	16,355	-

The first two modifications increase the profit significantly, whereas the third, having more inertia, has no effect. These results suggest that the market design incentivizes better response from resources providing PFC capability when that response is needed. When increased demand for a certain capability is not desired by the market, the resource does not have incentive to improve that capability.

2.2.4.5 Summary

Overall, the results of these case studies reveal some important insights on the potential for a PFC market design. The studies showed that in today's systems with mostly conventional resources that inherently have many of these capabilities, the need is not significant, but in future systems with more resources that do not inherently provide the services, it could be more important. The results also do not attempt to simulate the behavior seen in many of today's systems, especially in the U.S. EI, which has a trending frequency response decline likely due to resources not operating in modes that provide PFC. The simulations also showed that the design should incentivize some innovation and improvements to PFC capabilities that would improve power system reliability. However, it is important to note that the more detailed effects should be studied on systems that pursue a similar type of design to ensure that no unintended consequences results from the market. For example, a 1% droop setting would likely provide over-control and would not be desired from the system perspective. These further rules would need to be attached to the market design proposed in this study.

This market design, which is applicable to market regions that are part of large synchronous interconnections as well as isolated systems, should assist in halting trends like the current frequency response decline, as well as prepare the systems for a new paradigm of large penetrations of variable renewable and asynchronous technologies like wind power. It is incredibly possible for wind power plants to start providing PFC, as discussed throughout this report, but a market design like the one discussed here would be necessary. Wind power can actually adjust many of the control capabilities discussed, as it is able to increase response when the system needs it, rather than needing to commit additional units, which provides a tremendous benefit in reducing costs while maintaining sufficient response to ensure a reliable and secure power system. Wind power plants could also assess, based on current market prices and the outlook of those prices in the future, whether to spend extra capital to purchase the equipment and control software needed to provide PFC capabilities. With this market design in place, it may be that so much of the conventional fleet begins to provide the response, providing more response than is required and bringing down PFC prices. This may show that there is no need for wind power to install the capability at that time. In any case, the transparency in the prices from a market like this should help inform these new technologies what types of response and characteristics they should provide.

2.3 Economics and Revenue Impacts from Wind Power Providing Regulation

The final section focused on economics and steady-state analysis focused on regulation, an existing ancillary service market, and how wind power providing this service impacts the costs of the system, revenues of the wind plants, and steady-state operation of the power system. As discussed earlier, we are not aware of wind power currently providing regulation in any of the United States market regions. Some previous work looked at the impact of wind providing regulation, but ignored any impacts that wind would have on the system itself while doing so, including scheduling and pricing [39]. Additional research has looked from the market perspective on how wind plants providing regulating reserve benefit the system by reducing the need for short-term reserve for wind variations and by having additional fast reserve from wind plants [40]. In this study, a production cost simulation model, Plexos, is used to advance this research and ensure that results are realistic with how the system would actually be operated if wind power were allowed to provide regulation. Full details on the study can be found in [16].

The study looked at the California ISO (CAISO), but modeled all of the WI for a two-month period. The CAISO is the only region in these simulations that allowed for wind to provide regulation, and limited the requirement to less than 20% that could be supplied by wind. In this study, regulation up and regulation down are separate services that can be supplied by different resources that have room to move up or down, respectively, from their energy schedule. Table 2-8 shows differences in production costs for both the WI and CAISO, as well as start-up costs and net import into CAISO.

Table 2-8. Cost and Imports Impacts for WI and California

Case	WI Costs ($)	CAISO Costs	CAISO Start-Up Costs	Net Import to CAISO (GWh)
NoWindReg	$5,610M	$1,550M	$27.9M	7,359
WindReg20	$5,607M	$1,531M	$26.3M	7,626
Change	-$3.1M	-$19.5M	$1.6M	267
Change (% of Base)	-0.2%	-1.3%	-5.7%	3.6%

These results show that total production costs are not significantly impacted. This is expected; regulation costs make up a very small piece of total operational costs, especially considering that the modeling here does not consider additional costs to provide regulation by conventional generators (e.g., wear and tear or efficiency losses). However, there is nonetheless a total system-wide production cost savings of $3M when wind is allowed to provide regulating reserve. In California alone, production costs are reduced by $19M. Putting this in the context of the amount of MWh generation from wind (which totals approximately 5.5 TWh), the total savings are approximately $0.55/MWh of wind generated when looking at the total WI system, or $3.50/MWh when looking only at savings in California (the California savings would have to be put in context of increased cost of imports). Table 2-9 shows additional results related to regulation costs and prices.

Table 2-9. Impact of Wind Providing Regulating Reserve on Regulating Reserve Costs and Prices

Case	Reg Up Cost ($)	Reg Down Cost ($)	Avg Reg Up Price ($/MW-hr)	Avg Reg Down Price ($/MW-hr)	# Hours >$100/ MW-hr
NoWindReg	390,730	318,428	30.1	8.5	27
Wind Reg20	27,255	5,809	28.5	6.7	17
Change	(363,475)	(312,618)	(1.6)	(1.8)	(10)
Change (%)	-93%	-98%	-5%	-22%	-37%

As shown in Table 2-9, there is a dramatic reduction in regulation costs when wind provides regulation. This is due to a few hours in the two-month period when regulating reserve would need to be provided by a very expensive resource, including expensive start-up costs; allowing wind to provide this reserve for those few hours can significantly reduce costs for both regulation up and down.

To better understand what is occurring, we illustrate how wind power provides regulation. Figure 2-8 shows the provision for a short time period as well as the average for the entire period. Table 2-10 shows the results of how much wind contributed to regulation needs. As expected, the average provision of regulation down is significantly higher than regulation up. It can also be seen that the average amount of regulating reserve provided from wind does not seem to be impacted by average wind generation; this may be due to the fact that, in the study here, wind provides an average of 10% of energy, and therefore periods when wind is being curtailed are very rare. Instead, the provision of regulation from wind will mainly be driven by the overall system cost implications.

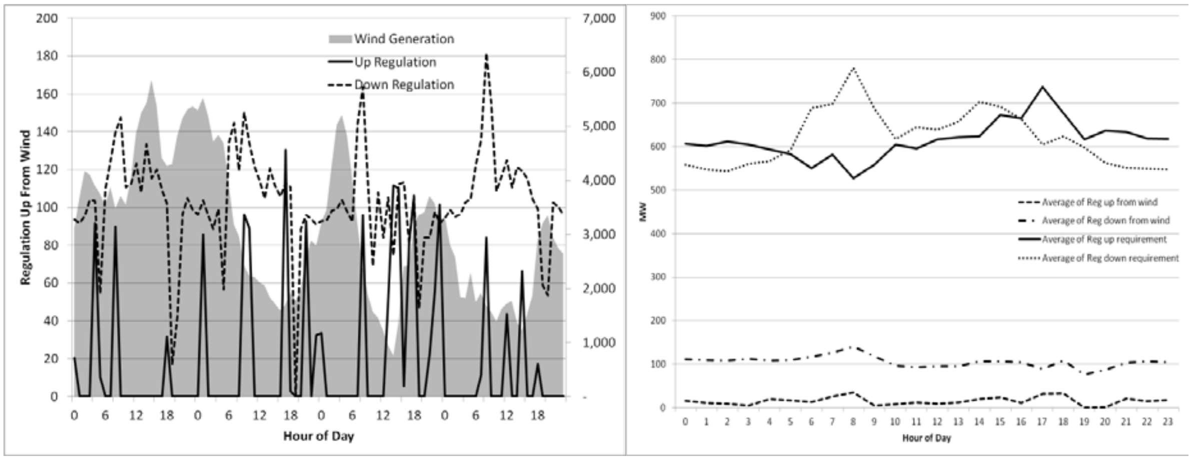

Figure 2-8. Provision of regulation for four days in April (left), and averaged by hour for entire two-month study (right).

Table 2-10. Summary of Wind Providing Regulation

	Reg Up	**Reg Down**
Average Provision (MW-h)	16	105
Number of Hours (% of hours)	388 (26%)	1450 (99%)
Correlation with Regulation Price	0.37	0.17
Average Requirement (MW)	615	620
Average % of Requirement from Wind	1%	6%
% of Total Wind Generation	0.40%	2.80%

Applying a limit on the amount of regulation from wind seems reasonable due to its inherent uncertainty in output; however, it is shown that much of the benefit of wind providing regulation is still realized even if this limit is relatively strict. It is also clear that allowing this feature in wind plants will impact energy and regulation prices; due to the complex relationship between energy and ancillary services prices, this may increase or reduce prices at different times of day and year, while still reducing total system costs.

Allowing wind to participate in providing this ancillary service would produce societal cost benefits (albeit very small in the context of total costs according to these results), reduce wear and tear of other generation, and potentially increase wind generator revenues. This study showed that the revenue from wind increased from $333.5M to $339M in total, equaling a $1/MWh increase. With the inclusion of wear-and-tear and efficiency penalties, it is possible that this could be further increased. In addition, the new market designs for regulation to meet FERC's Order 755, *frequency regulation compensation* [41], could demonstrate an increased value and increased revenue to wind power, as well. Because the control is very fast, it is possible that wind can provide a faster control signal with more mileage and high accuracy and earn a premium in this market. However, the impact that wind power forecast errors may have on the predicted regulation capacity available would also be a factor that could reduce this accuracy. Both of these characteristics should be studied further to understand the impacts that wind has on the operation, revenue, and total costs when providing this service.

2.4 Summary and Conclusions

This research has shown that benefits are possible for wind power plants providing APC when market designs incentivize that control. While market designs do not currently exist for PFC and inertial control, their careful design may be essential when current trends lead to a decline in the response. This response should spur the growth of resources that are willing to provide it, which could include wind power plants in the future. Regulation, which has an existing market, was shown to have benefits if wind power plants were allowed to provide it. These benefits include reductions in production costs, which can be passed on to consumers, as well as additional revenues for the wind power plants. These revenues could increase with further reliance on ancillary service markets revenues compared to energy markets, inclusion of increased wear-and-tear costs on thermal plants for providing this response, and new incentives that value faster response. Other pricing mechanisms may be developed in future systems for these services, which developers would have to continue to monitor, for example [42]–[43].

It is important that wind power plants, when providing APC, do not adversely impact the costs borne by consumers, and, when applicable, only positively impact their own revenue streams. We have shown, albeit preliminarily, that wind can have positive effects on its revenue and production cost reduction with regard to AGC and regulation. We have also shown, again preliminarily, that this can happen for PFC if appropriate incentives and market designs are implemented and the need for additional service from wind power plants is apparent in the market pricing, and that costs and positive revenues can occur with PFC as well. For a synthetic inertia response, it is likely that economics will not incentivize wind power plants to provide the service, at least not for large synchronous interconnections, and not for a long time in the future. Islanded systems or systems with extremely high penetrations of non-synchronous machines may show that there are economic incentives for this response when appropriate market designs are implemented. It may be that grid codes promote the use of inertia rather than markets, which, due to the limited market benefits shown in this work, may be appropriate. However, if there is an appropriate amount of any of these services, and the cost of installing the capability for wind plants is high, unit-specific grid codes may be a very inefficient manner of getting the response. Finally, the extra flexibility of parameter tuning of PFC and synthetic inertia from wind plants (i.e., tunable inertial control and non-symmetric and tunable droop settings, as shown in Section 3) can provide a further benefit to both reliability and market efficiency. This flexibility is not typically as readily available from conventional thermal and hydro power plants, and should be studied further. While these results are all promising for the continued research of wind power plants providing all three APC services, further details should be studied on the impacts of wind providing each of these services for more specific systems, including more specific characteristics of the power system, and more specific designs of the existing markets.

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3 Dynamic Stability and Reliability Impacts

Increased variable wind generation can have many impacts on the dynamic stability and reliability of the power system. Lower system inertia was identified as one such impact, as it would result in faster declining frequency during large loss-of-supply events, resulting in greater risk of lower frequencies that can lead to voluntary load-shedding, machine damage, or even blackouts. A decrease in system inertia will necessitate an increase in the requirements for PFC reserves in order to arrest frequency at the same nadir following a sudden loss of generation. Similarly, a reduction in PFC reserve can result in lower steady-state frequencies, also leaving the system at greater risk. The U.S. industry has begun to document frequency response implications for various regions. A 2010 study commissioned by the Federal Energy Regulatory Commission (FERC) examined the impacts of higher amounts of wind penetration on the frequency response of the three interconnections in continental North America [1]. The study was not able to model the Eastern Interconnection (EI) to adequately replicate actual system response, but it was able to show that the Western Interconnection (WI) and Texas Interconnection can operate reliably with the studied wind penetrations, which were modest values of 2012 predictions. The main conclusions were that the rapid delivery of PFC from existing resources was of much greater importance than the amount of wind on the system for improving the level of the frequency nadir. A recent study for the California ISO (CAISO) [2] examined cases with high levels of wind and solar generation and found that a reduction in system inertia due to higher levels of renewable generation will not have significant impacts on frequency response when compared to the reduction of PFC. Further studies were performed in the EI and WI in [3]–[4]. Both of these studies also examined the impacts on the same interconnections of various penetrations of wind power providing both synthetic inertial control and PFC. In [2], the fast transient frequency support using controlled inertial control from wind power was shown to help increase the under-frequency load shedding (UFLS) margin and reduce the risk of load shedding. It was shown that the benefit of these responses can be several times greater per MW than was observed for PFC in the conventional generation fleet.

An excellent state-of-the-art review of inertia control provided by wind power was conducted in [5]. It was shown that many ISOs/RTOs in different countries have begun recognizing the value of inertial control provided by wind power, and its importance for system reliability. In particular, REE (Spain), Hydro Quebec (Canada), ERCOT (Texas), Ireland, Denmark, and others are in different stages of implementing wind inertia requirements in their system operations [6]–[7]. Commercial providers are also offering inertial control capabilities and showing the benefits they can bring [8]–[9]. Further research investigates advanced active power control (APC) schemes for wind turbines and the impact of these resources on system frequency [10]–[13].

The second task of this report focuses on describing the dynamic impacts of PFC and inertia controls on system frequency response and how it may affect dynamic stability and system reliability. Different wind turbine technologies are in use, and each type requires a different control technique for implementing APC. The impact of each of these technologies on frequency response is different. We describe the modeling of different wind plant types, the controls to modify each type to provide PFC and synthetic inertial control, and the predicted effects on the system-wide frequency response of including these controls. We then briefly outline a frequency event monitoring program that is used to validate real frequency events occurring on the U.S. EI and WI. Lastly, detailed dynamic simulations in the time domain have been conducted to demonstrate the efficacy of the control approaches on the WI and the performance of frequency response on the system. Further details on these results can be found in [14]–[15] for Section 3.1 and [3] and [16] for Section 3.3.

3.1 Wind Plant Electrical Models

The difference among turbine types is mostly based on the electrical generation part of the turbines. This includes the generator, power converter, and control algorithms used. The control strategies used to control the prime mover (rotor) are generally similar. These strategies commonly use mechanical brakes and blade pitch control to avoid run-away conditions and to keep the mechanical stresses on the mechanical components of the wind turbine generator (WTG) in the operating range within the design tolerance. The pitch angle of the blades is usually controlled in the high wind speed region to keep the aerodynamic power within the generator's rating, thus allowing the output power and/or rotor speed to be kept within its limits.

Figure 3-1 illustrates the four types of WTGs. Type 1 through Type 3 are based on induction generators. These turbines require a gearbox to match between the generator speed (high-speed shaft) to the turbine speed (low-speed shaft). However, Type 4 WTGs may or may not employ a gearbox depending on the type of generator.

The specific topologies shown in Figure 3-1 are:

- Type 1: Induction generator – fixed speed
- Type 2: Wound rotor induction generator with adjustable external rotor resistance – variable slip
- Type 3: Doubly Fed Induction Generator (DFIG) – variable speed
- Type 4: Full converter system with permanent magnet synchronous generator (PMSG) – variable speed, direct drive.

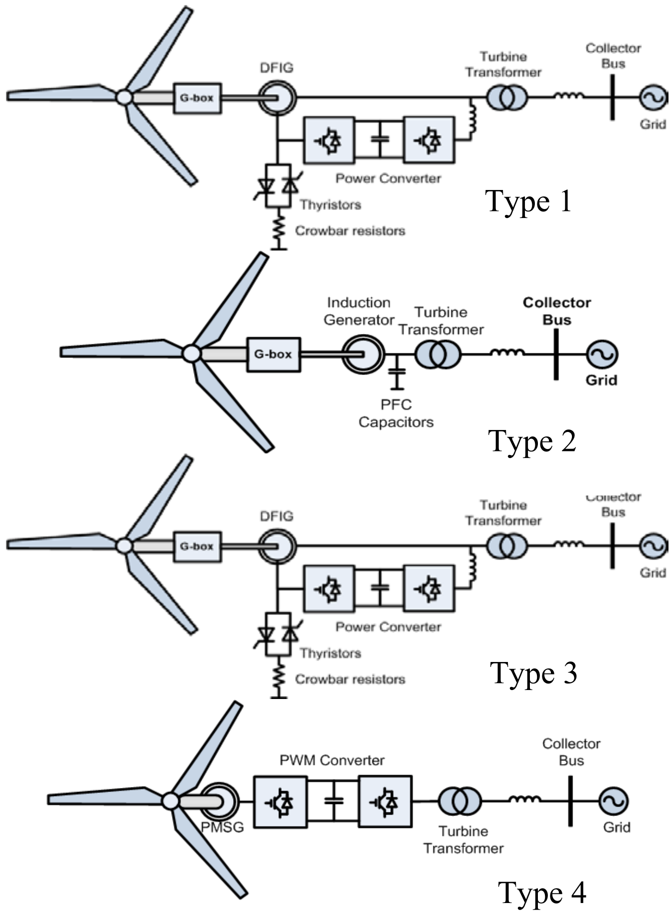


Figure 3-1. Different types of WTGs.

The collective inertial control of wind power plants will depend on the electrical characteristics of the individual wind turbines. Fixed-speed wind turbines have different inertial control compared to synchronous generators. However, they do not intrinsically decrease the power system inertia due to their electromechanical characteristics. On the other hand, variable-speed wind turbines have their rotating mass decoupled from the grid and do not inherently exhibit an inertial control unless controlled for that specific purpose.

3.1.1 Inertial Control Characteristics of Wind Turbine Generators

The amount of additional power from kinetic energy that wind turbines can release onto the grid depends on the turbine's initial wind rotor speed. The change in rotor kinetic energy due to RPM decline (transition from speed ω_0 to speed ω_1) can be calculated as the following:

$$\Delta E = \frac{1}{2}J({\omega_0}^2 - {\omega_1}^2) = \frac{1}{2}J(2\omega_0\Delta\omega + \Delta\omega^2) \quad \text{[Joule]} \qquad (3\text{-}1)$$

Where J is wind rotor inertia $[kg \cdot m^2]$, and $\Delta\omega$ is change in rotor speed.

Then, the power released can be estimated as

$$\Delta P = \frac{\Delta E}{\Delta t} \quad \text{[watt]} \tag{3-2}$$

As it follows from the above equations, the magnitude of ΔP depends on initial speed ω_0, drop in speed $\Delta\omega$, and duration of the drop Δt. The dependence of ΔP on RPM drop calculated for Δt = 15 s for a typical 1.5 MW variable-speed wind turbine is shown in Figure 3-2.

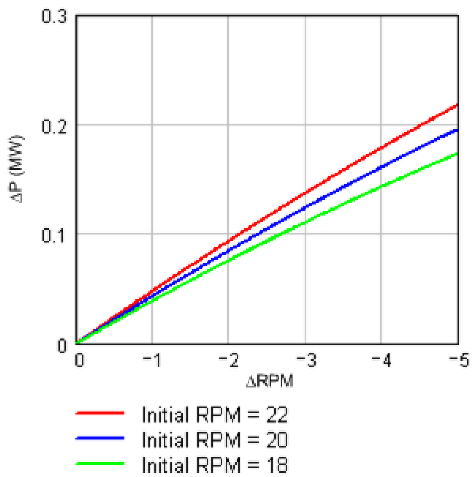


Figure 3-2. Example dependence of ΔP on RPM decline.

As can be observed in Figure 3-2, the 1.5 MW wind turbine is capable of releasing up to 200 kW from the inertia in 15 s when the wind rotors slow down by 5 RPM from initial speed. With appropriate controls, this turbine inertia can be "connected" directly to the grid. This short-term capability of injecting additional power onto the grid makes it possible for wind power plants to participate in providing inertial control until the PFC of the power system is activated.

It is important to note that the inertial control of the conventional generators is dependent on their physical mass, as well as the physics of the synchronous machine, and cannot be changed. In the case of wind turbines, the inertial control can be tuned to improve power system performance during certain time periods, such as providing significant response during the very first instant of the frequency decline.

The main limiting factors for inertial control are the extra heat due to additional power generation, and the additional stress on turbine mechanical components. The duration of inertial control is not long enough to generate thermal losses high enough to become a risk factor in the generator winding. The power electronic converters of WTGs allow for short periods of up to 110% of MVA ratings.. The impacts on the mechanical components need detailed study for each particular wind turbine to ensure very low impact on component life (this is discussed later in Section 4).

3.1.2 Type 1 and Type 2 WTG Model Design

The Type 1 and Type 2 WTGs are directly connected to the grid. These types of wind turbines are capable of contributing to the release of kinetic energy stored in the turbine's rotating parts (i.e., blades, gearbox, generator, etc.). Consider the graph shown in Figure 3-3. The wind turbine is rated at 1.5 MW, the wind speed is at its rated level (10.8 m/s), and the wind turbine is operating at its rated operating point (point A) which is the crossing point between the aerodynamic power (P_{aero}) and the generator output (P_{gen}).

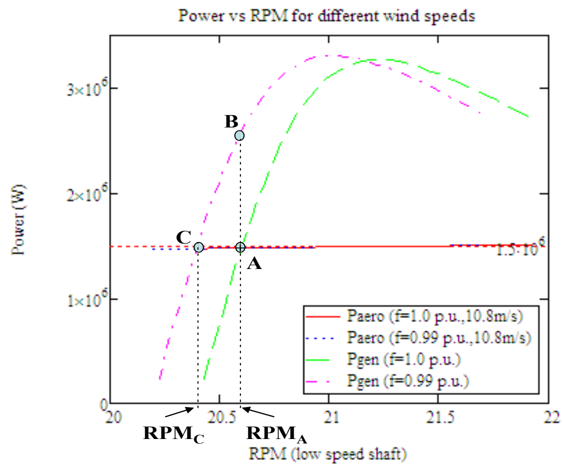


Figure 3-3. Illustration of kinetic energy transfer during a frequency decline for Type 1 and 2 WTGs.

For Type 1 WTGs, when there is a sudden drop in the frequency by 1%, the rotor speed does not change instantaneously due to the inertia of the turbines. However, the generator power-speed characteristic moves to the left, thus the operating point moves from point A to point B instantaneously. As a result, there is a difference between the aerodynamic power and the generated power ($P_{aero} < P_{gen}$). The rotational speed decreases until there is a new balance operating condition at point C ($P_{aero} = P_{gen}$). The time it takes to move from B to C depends on the size of the inertia of the generator and the blades, and the difference between P_{gen} and P_{aero}. In the process of traveling from point B to point C, the kinetic energy within the turbine is transferred to the grid to help arrest the frequency decline. The size of the kinetic energy transfer can be approximated from the inertia and the rotor speeds (H, RPM_A, and RPM_C). There is a very negligible difference in the aerodynamic power caused by the frequency drop.

For Type 2 WTGs, when there is a sudden drop in the frequency by 1%, the generator power-speed characteristic moves to the left; however, the output generation, P_{gen}, is kept at its rated value, because the external rotor resistance will control the output power at rated values, thus the operating point will move from point A to point C instead of to point B. If the operating frequency returns to normal, the operating point will move back to point A.

A simplified power system is presented in Figure 3-4. The system consists of synchronous generators, a wind power plant, and a load. A generator is switched off, thus, creating a sudden drop in frequency. The simplified governor-based conventional generator models shown in Figure 3-4 were based on speed-governing systems represented in [17] and were developed using Matlab Simulink. The wind rotor power curves are modeled using the Cp curves and scaled H constants given in [18]. A single wind turbine representation was used for the wind power plant model.

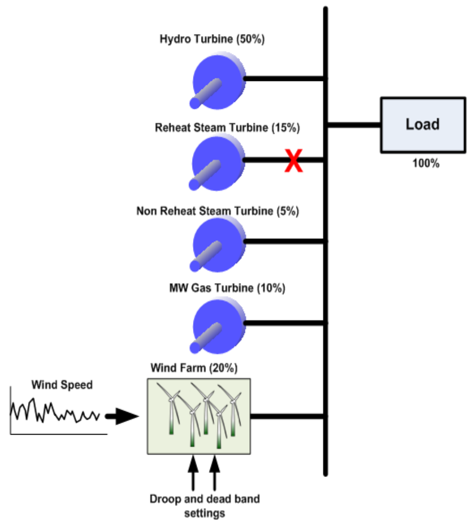


Figure 3-4. Simplified governor-based power system model.

In this illustration, a large 2 MW Type 1 wind turbine is used. A steam turbine is tripped offline, amounting to 15% of the load. If the inertia available in the grid is large, the drop in frequency is not significant relative to the loss. For example, as shown in Figure 3-5, the nadir drops down to 59.82 Hz. As the frequency drops, the output power of the WTG increases from 1.94 MW up to 1.98 MW. The inertial response energy released is delivered at a peak power value of 40 kW with a duration of about 1 second. The system is critically damped, and the frequency is eventually returned to stable operation. An interesting observation is the trajectory of the operating point as the power versus speed is drawn as shown in Figure 3-5. It travels from point A to point B and will eventually return to point A when the AGC returns the frequency to its nominal level.

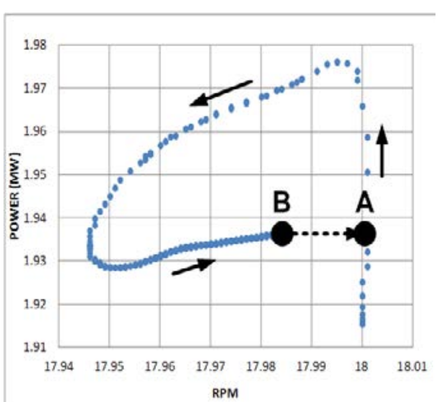


Figure 3-5. Trajectory of operating point during a frequency decline for Type 1 WTG for a system with large inertia.

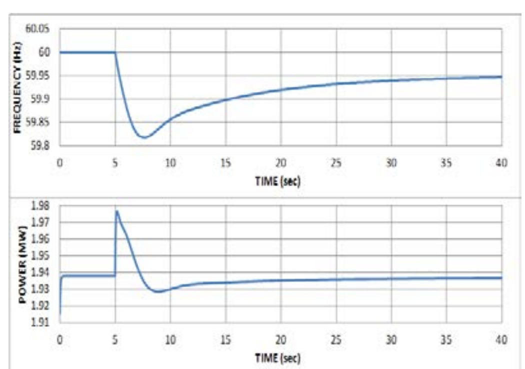


Figure 3-6. Frequency response of Type 1 WTG connected to a power system with large inertia.

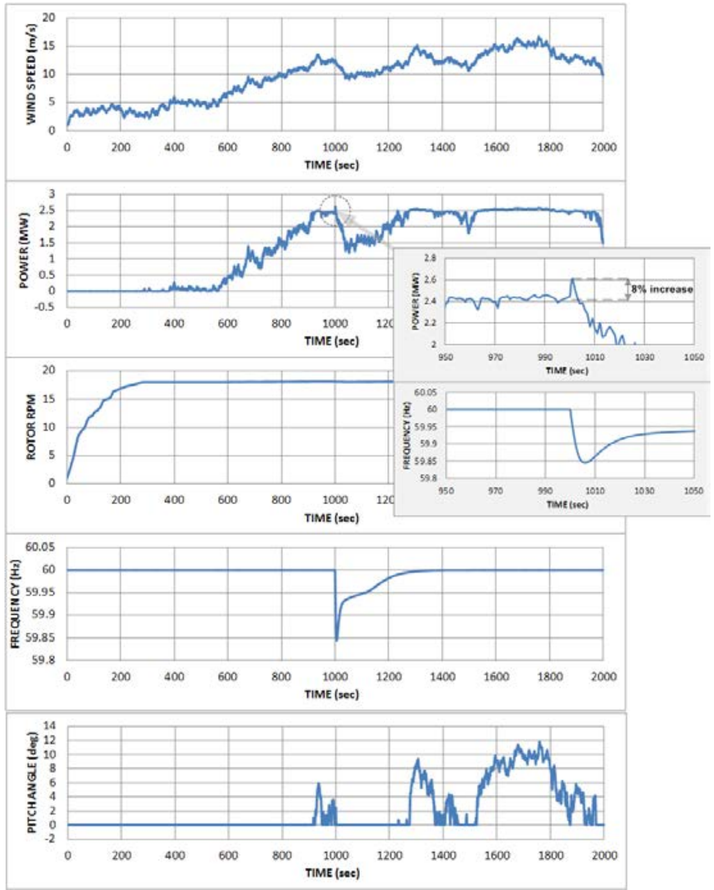


Figure 3-7. Inertial response of Type 1 WTG during normal operation.

An example of simulated time series when a Type 1 wind turbine operates under variable wind speed conditions is shown in Figure 3-7. The turbine pitch control is operated to limit the turbine output electrical power at 2.5 MW. The simulation is conducted for 2000 s. The frequency decline starts at t = 1000 s when the turbine was operating at rated power. In this particular example, the inertial contribution represents around an 8% increase on power output during the initial stages of frequency decline. This number will vary depending on initial rate of change of frequency (ROCOF) as shown in Figure 3-7.

In the next simulation, the inertia of the power system is reduced by half. When the same load is used, and the same loss of generation occurs, the system frequency drops deeper than in the previous case (with large inertia). As shown in Figure 3-8, the nadir is shown to reach 59.7 Hz. As the frequency drops, the output power of the WTG increases from 1.94 MW up to 2.15 MW. The inertial response energy released is delivered at a peak power value of 750 kW with a duration of about 0.5 s. It is also shown that the post transient is more oscillatory, although the settling time is shorter. An observation of the trajectory of the wind plant's operating point is shown in Figure 3-9. The oscillation settles down and eventually moves from point A to point B, then returns to point A.

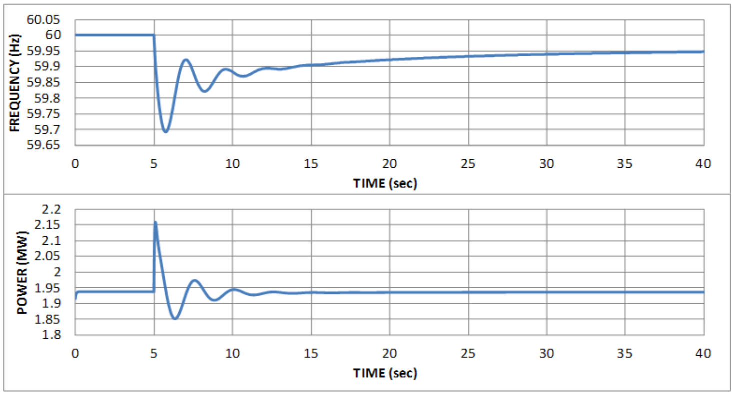


Figure 3-8. Frequency response for Type 1 WTG connected to a power system with low inertia.

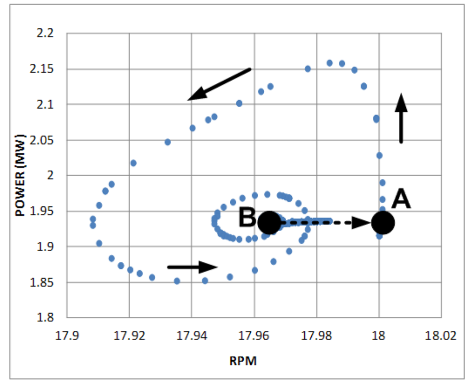


Figure 3-9. Trajectory of operating point during a frequency decline for Type 1 WTG for a system with low inertia.

According to [19], commercial fixed-speed wind turbines rated above 1 MW have of inertia constant (H) values of 3–5 s. Some fixed-speed WTGs have dual-speed operation that is achieved with two-winding induction generators. The value of H in this case must be calculated based on the MVA ratings of each winding.

With the pitch controller, it is possible to operate wind turbines at different pitch angles (or scheduled pitch angles). This allows the WTG to set aside the reserve power to be called when needed. Figure 3-10 shows an example of a WTG operating at a reduced output power. The operation follows the path **ABCDE**. The shaded area represents the reserve power available that can be retrieved. The obvious disadvantage of this algorithm is that during productive winds, the output power has to be reduced losing out on potential revenue.

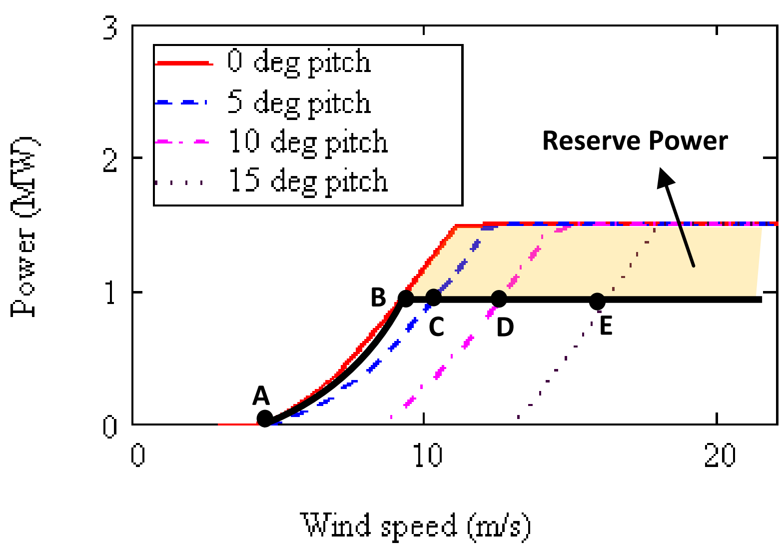


Figure 3-10. Scheduled reserve power with pitch controller.

3.1.2.1 Type 1 Wind Turbine Generator—Power Speed Characteristic

Type 1 WTGs use squirrel-cage induction generators and operate in a very narrow slip range (about 1% rated slip). The active power versus the rotational speed is shown in Figure 3-11. Both the power and the rotor speed are given in per-unit quantities. The output current versus the rotational speed is given in Figure 3-11. Note that the induction generator is always absorbing reactive power from the line; thus, reactive compensation is usually implemented by switched capacitor banks, and the size of the capacitance is controlled so that the wind turbine generates power at unity power factor.

As shown in Figure 3-11, the normal operating point at rated wind speed is at point A, where the output power is at 1.0 per unit. The aerodynamic power driving the generator fluctuates with wind speed; thus, the pitch is continuously controlled to limit the aerodynamic power developed by the blades, which also limits the aerodynamic torque driving the induction generator. Instantaneously, individual WTGs may generate more or less at 1.0 per unit with small variation (indicated by the two-sided arrow); however, the average power will always be limited to 1.0 per unit. At the point of interconnection, the average output from hundreds of wind turbines will smooth out to an almost flat output when the wind speed is at or higher than rated value.

To allow power to be held in reserve, the wind turbine is operated with an output power set-point lower than what is actually available, e.g., at high wind speeds, the pitch can be controlled to generate 80% of rated power, although it is capable of generating 100% of rated power. The operating point moves from A to B, as shown in Figure 3-11.

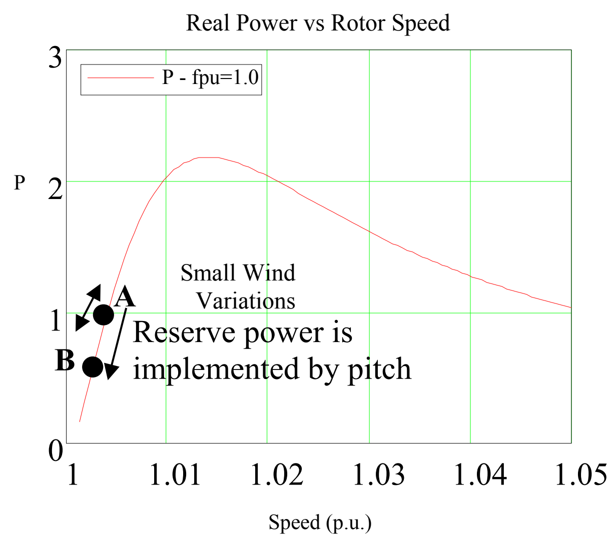


Figure 3-11. Output power versus rotor speed (Type 1 WTG).

3.1.2.2 Type 2 Wind Turbine Generator—Power Speed Characteristic

The Type 2 WTG uses a wound-rotor induction generator instead of the squirrel-cage generator used in the Type 1 WTG. The wound rotor is connected to an adjustable external rotor resistance.

Below rated wind speed, the external rotor resistance is shorted; thus, the behavior of a Type 2 WTG is the same as a Type 1 WTG when the wind speed is below its rated value. Above rated wind speed, the external rotor resistance is controlled to allow the effective rotor resistance to be varied to maintain the output power constant even as the wind speed varies; thus, although the wind speed changes, the external rotor resistance can be adjusted so that the output power stays constant. This is indicated by A and A' in Figure 3-12. The adjustable rotor resistance is implemented by using simple power electronics and resistors. Note that although the rotor resistance can be varied, in practice the pitch controller is still used to control the speed to minimize the external rotor resistance because deployment rotor resistance generates heat that must be dissipated. To minimize the heat generated, the pitch control is used. To allow power to be held in reserve, the wind turbine is operated with an output power set-point lower than available power, as in the Type 1 WTG. The operating point moves from A to B, as illustrated in Figure 3-12.

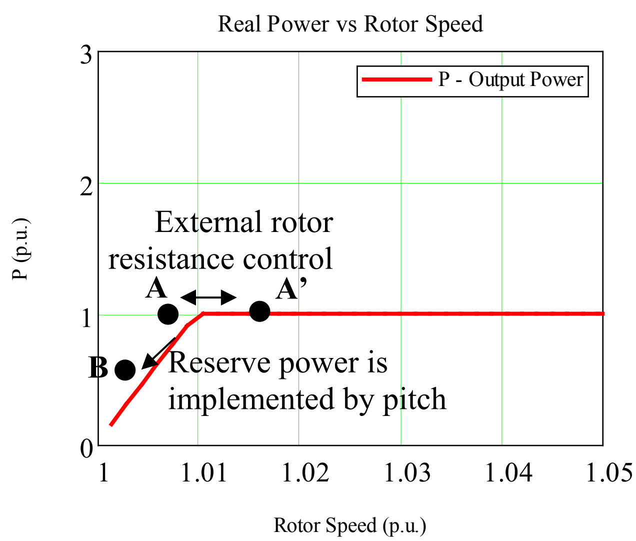


Figure 3-12. Output power versus rotor speed (Type 2 WTG).

3.1.2.3 Types of Reserve Power

Figure 3-13 shows a block diagram of the proposed controller for providing reserve power. There are several groups of control blocks performing different functions. Block 1 computes the input to the pitch controller to limit the rotational speed at rated value when the wind speed is high to avoid a runaway condition.

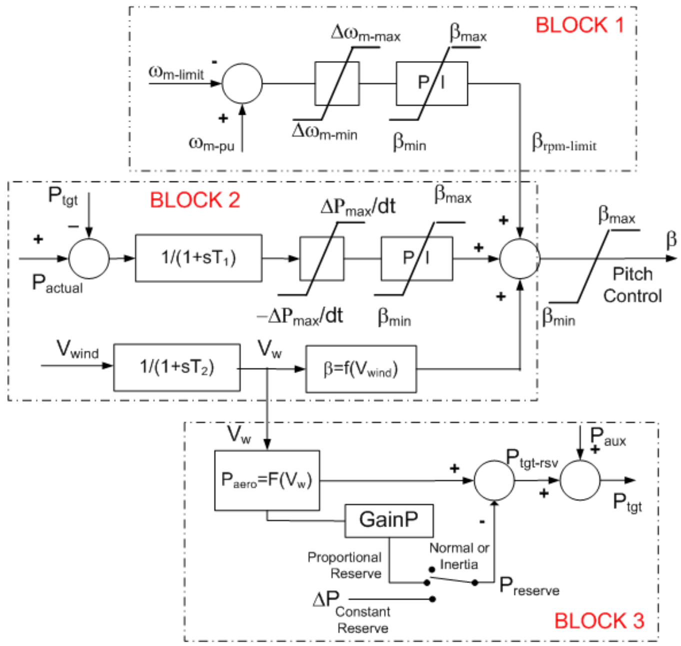


Figure 3-13. Pitch controller used to set reserve power for Type 1 and Type 2 wind turbines.

Block 2 computes the input to the pitch controller to limit the average output power of the wind turbine based on the target power P_{tgt}. The target power P_{tgt} varies with wind speed and the level of reserve power defined. In Block 2 there are two paths used: one path uses wind speed as an input to provide a feed-forward value by pre-computing the steady-state values of the pitch angle under normal situations (without reserve power) with the help of a lookup table to map higher wind speeds versus blade pitch angle; the other path takes the commanded target power P_{tgt} as an input to control the desired output power, which may include controlling the reserve power below rated wind speed and limiting the rated power above rated wind speed. The P-I controller helps to fine-tune the power controller to follow the target power.

In Block 3, the target power is computed to guide the pitch controller in adjusting the output power from the WTG. The input to Block 3 is the filtered wind speed that is translated to aerodynamic power using the power curve of the turbine (similar to the one shown by the solid-line curve in Figure 3-14) via a lookup table. The output of the lookup table is the actual output of the turbine without accommodation for reserve power. Block 3 also has a provision for users to select the method for holding reserve. These methods are explained in the next subsection. If governor droop control is implemented, the additional inputs from the droop control can be accounted for in the proposed controller via the auxiliary output power P_{aux}.

To set aside some reserve power, a constant value of reserve power (constant reserve - ΔP) or a constant proportion of the available aerodynamic power (proportional reserve—refer to the switch available in Block 3) may be selected. Figure 3-14 (a) shows wind turbine power curves if the reserve power to be held is a constant value (20% and 40% of *rated* power); Figure 3-14 (b) shows the power curves if the reserve power to be held is a constant percentage (20% and 40% of *target* power—i.e., maximum C_P operation).

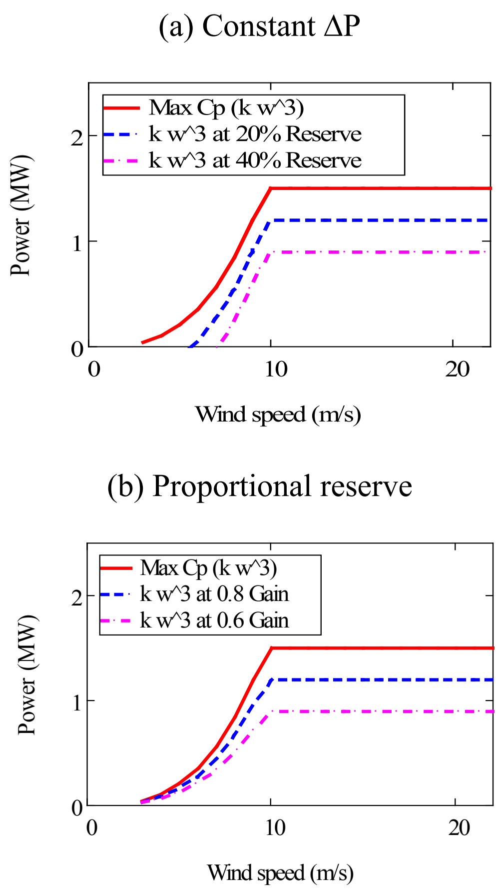


Figure 3-14. The reserve power held using two different methods.

3.1.2.4 Dynamic Simulations for Type 1 and Type 2 WTG

The performance of the proposed controller was investigated through dynamic simulations. The induction generator is represented by a typical fifth-order dynamic representation. Dynamic models were developed in PSCAD/EMTDC and tested using 150 s of wind speed data. In each case, the rated power of the wind turbine is 3 MW.

Figure 3-15 shows the traces of output power and pitch angle for a Type 1 wind turbine. It also shows the traces for constant reserve operation. Comparison between normal operation and the operation with reserve is presented. In Figure 3-15, a constant reserve power is commanded (20% of rated power—i.e., 0.6 MW). The output power shows both the available wind power (blue line) and the output power with reserve power held (green line). The pitch angle is shown to vary at a slower rate than the wind speed variation. The pitch controller is slower than the power electronics controller when used to limit the output power; thus, only the average power is limited to the rated output power. As shown in Figure 3-15, there are times when the peak of the output power briefly exceeds the rated power of the wind turbine (3 MW).

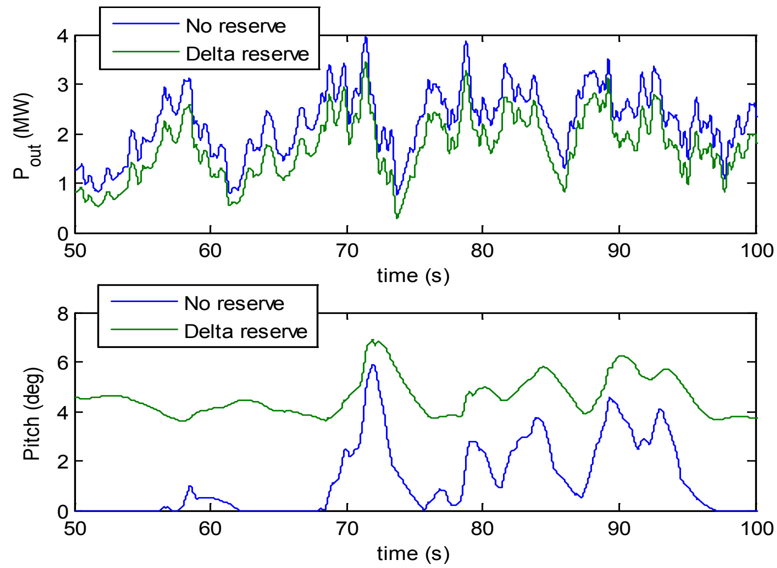


Figure 3-15. Output power and pitch angle for constant reserve power ($\Delta P_{reserve}$) implementation on a Type 1 wind turbine.

As described previously, an external rotor resistance control can be used in Type 2 wind turbines. In this implementation, the rotor resistance is used to limit the generator output current to a constant value, according to the percentage of the reserve power to be held. For example, if the reserve power to be held is 20% of *rated* power, the output current will be limited to 80% of rated current by controlling the external rotor resistance. Note that the rotor resistance control is much faster than the pitch controller; thus, the current regulation can be accomplished very effectively.

The effect of fast control of external resistance control can be shown by comparing the output power fluctuations between Type 1 wind turbines and Type 2 wind turbines, as shown in Figure 3-16. In Type 2 wind turbines, the power output is practically clamped at the maximum output power of the wind turbine, which is equal to the rated power (3 MW), whereas in Type 1 wind turbines, the output power sometimes exceeds the rated value of 3 MW.

The Type 2 WTG was simulated and the output was plotted against wind speed. Figure 3-17 and Figure 3-18 show the output power comparison between the base case and the operation with reserved power. As expected, the actual output power was scattered. However, when we used the polynomial fitting of a 7th order, the output power characteristic was similar to the one predicted in Figure 3-14. The scattered points can be attributed to the changes of the kinetic energy stored in the rotating mass (blades, generator, gearbox, etc.) because the rotational speed of the wind turbine changes with time.

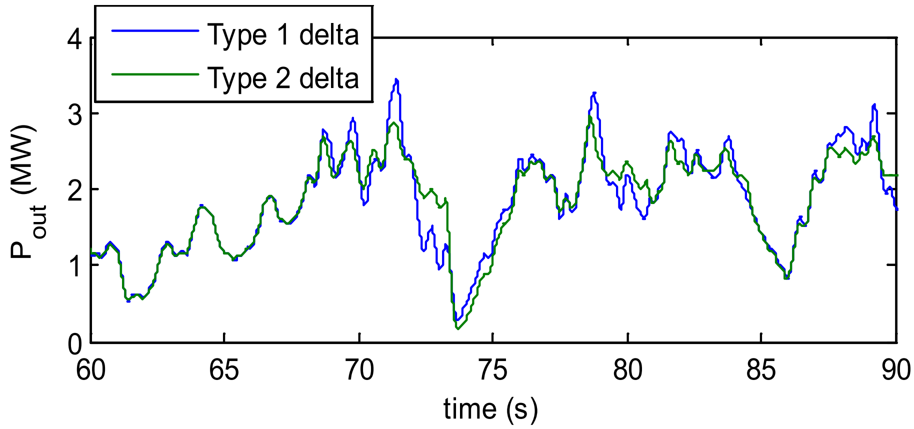


Figure 3-16. Output power comparison between the output power of a Type 1 wind turbine and that of a Type 2 wind turbine with $\Delta P_{reserve}$ = 20% of the rated power in time domain.

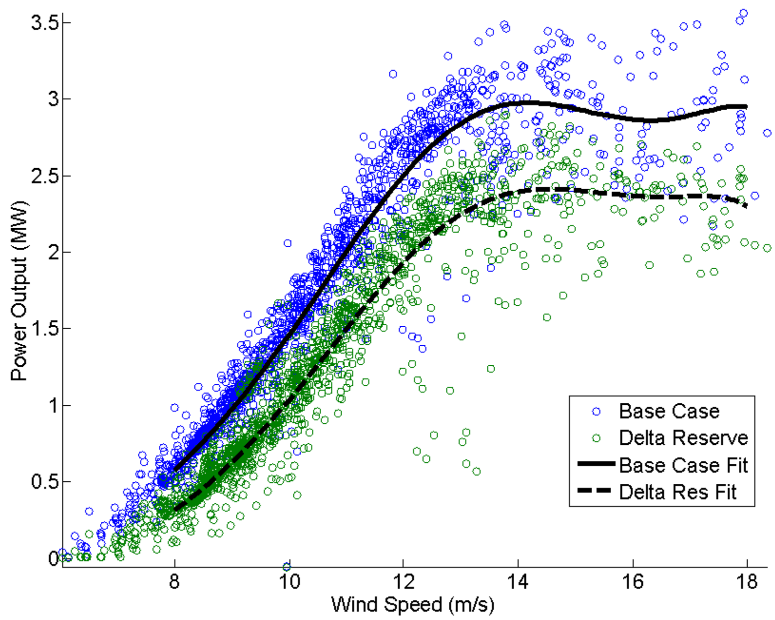


Figure 3-17. Output power comparison between the base case and delta reserve power of a Type 2 wind turbine based on the dynamic simulation with $\Delta P_{reserve}$ = 20% of the rated power.

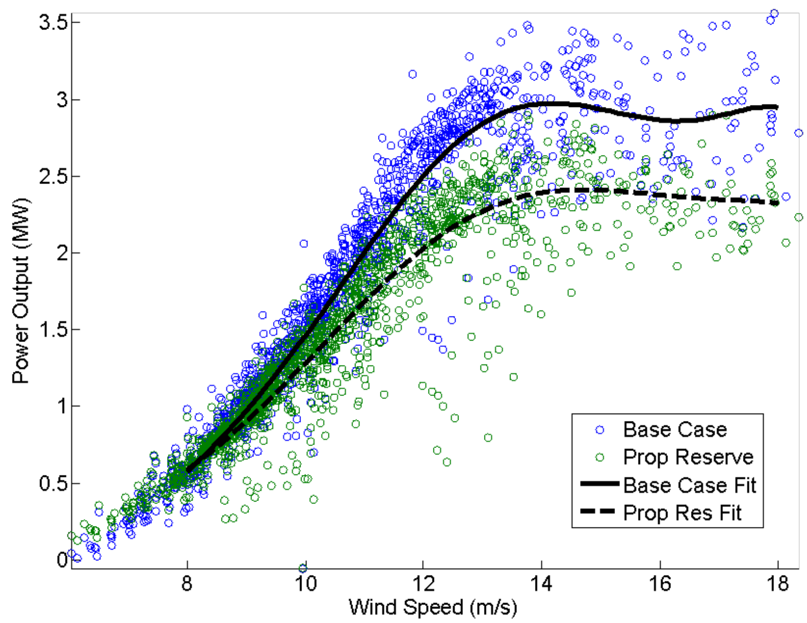


Figure 3-18. Output power comparison between the base case and proportional reserve power of a Type 2 wind turbine based on the dynamic simulation with $\Delta P_{reserve}$ = 20% of the rated power.

3.1.3 Type 3 and Type 4 WTG Model Design

The Type 3 and Type 4 WTGs are variable-speed WTGs and are the more common WTG type in the United States. The use of a power converter enables these types of WTGs to generate real and reactive power instantaneously at any commanded values. The variable-speed WTG can provide a power boost during a frequency decline provided that the generator, power converter and wind turbine structure are designed to withstand the necessary overload. Consider Figure 3-19. The wind turbine is rated at 1.5 MW, and as the wind speed varies, the generator output will be adjusted to operate the wind turbine at its optimum operating points from point A to point C. The related rotor speeds match the optimum operation for different wind speeds. Below rated power and/or rated rotor speed, the pitch angle is set to optimum pitch angle (e.g., 0 degrees). At high wind speeds, the pitch angle of the blade is controlled to limit the rotor speed.

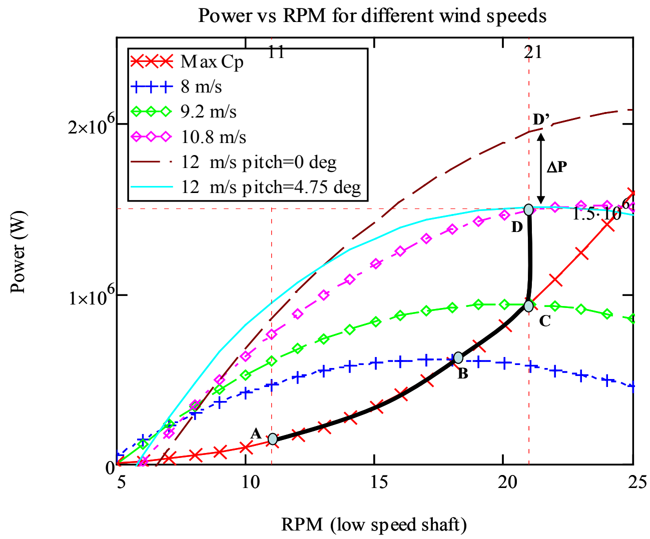


Figure 3-19. Illustration of kinetic energy transfer during a frequency decline for Type 3 and 4 WTGs.

When the wind speed reaches 9.2 m/s, the rated rotor speed (21 RPM) is reached. From then on (point C to D), the generator output is adjusted at a constant RPM. As the wind speed increases, the pitch angle of the blades must be controlled at 21 RPM. At 10.8 m/s, the rated power is reached. As the wind speed increases to 12 m/s, the pitch angle must be controlled so that the output power balance is reached ($P_{aero} = P_{gen}$). At 12 m/s, the pitch angle must be set to 4.75 degrees; otherwise, if the pitch is kept at 0 degrees, the available P_{aero} = 1.92 MW while P_{gen} is limited to its rated value at 1.5 MW, and the WTG will have a runaway condition. When the grid frequency drops, the WTG can provide additional power to help arrest the frequency decline. The maximum power boost that can be provided depends on the available P_{aero} (for 12 m/s wind P_{aero} = 1.92 MW). Of course, the power converter, the electric generator, and the mechanical components of the turbine must be designed to withstand this overloading condition.

An example simulated time series of a 1.5 MW Type 3 wind turbine providing inertial control when operating below the rated power level is shown in Figure 3-20. The frequency starts declining at t = 1000 s when the wind turbine control enables the inertial response for about 15 s in accordance with the algorithm presented in [20]. The output electrical power quickly increases, causing the rotor speed to decelerate. As can be seen in Figure 3-20, the rotor speed starts accelerating immediately after disabling the inertial response, bringing the turbine back to its normal operation in about 35 s after the fault. The pitch control of the turbine remains inactive for the whole duration, as its purpose is to protect the turbine from over-speeding. In this particular case the rotor RPM is below maximum, so no pitch action is necessary.

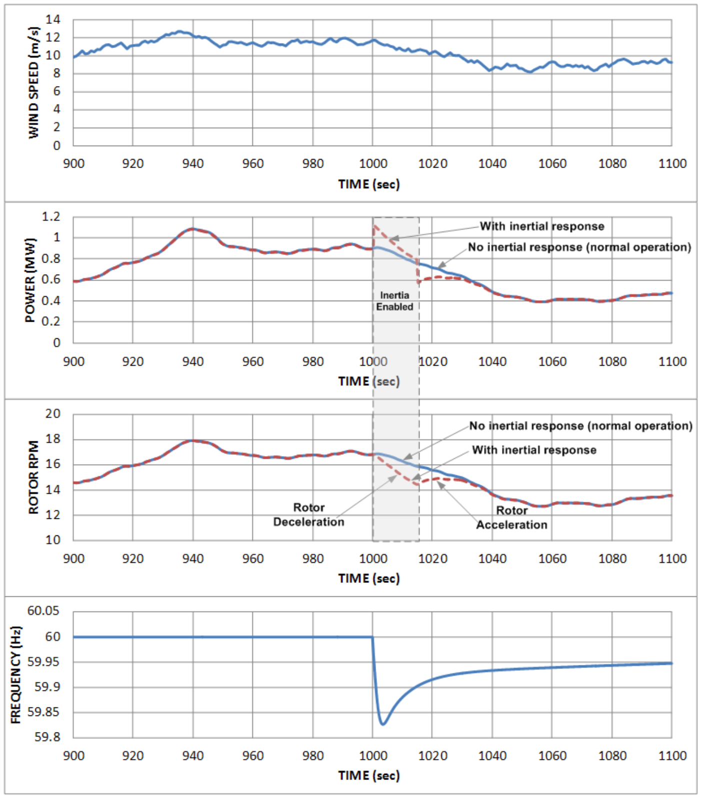


Figure 3-20. Simulated example of Type 3 inertial response (lower power).

Another observation from Figure 3-20 is that the inertial response of this variable-speed WTG is somewhat "energy neutral." In other words, the initial period of over-production triggered by inertial response is followed by a period of under-production due to the turbine operating below its optimum power point. Nevertheless, the overall benefit of such inertial response is still significant because it assists the power system in arresting the initial ROCOF, and allows time for slower system PFC response.

Another simulation example is shown in Figure 3-21, where the frequency decline occurs during the time when the turbine is operating at rated power. In this case, the inertial control is enabled at t = 1600 s followed by similar dynamics as in the previous case. However, the return to normal operation at the pre-disturbance level is faster than in the previous case due to more favorable conditions (the wind speed is above the rated value, so there is power available from wind to provide incremental electric power). The pitch control would have been active in normal operation, as shown in Figure 3-20. However, during the time when inertial control is enabled, the pitch control disables itself due to turbine deceleration to lower rotational speeds.

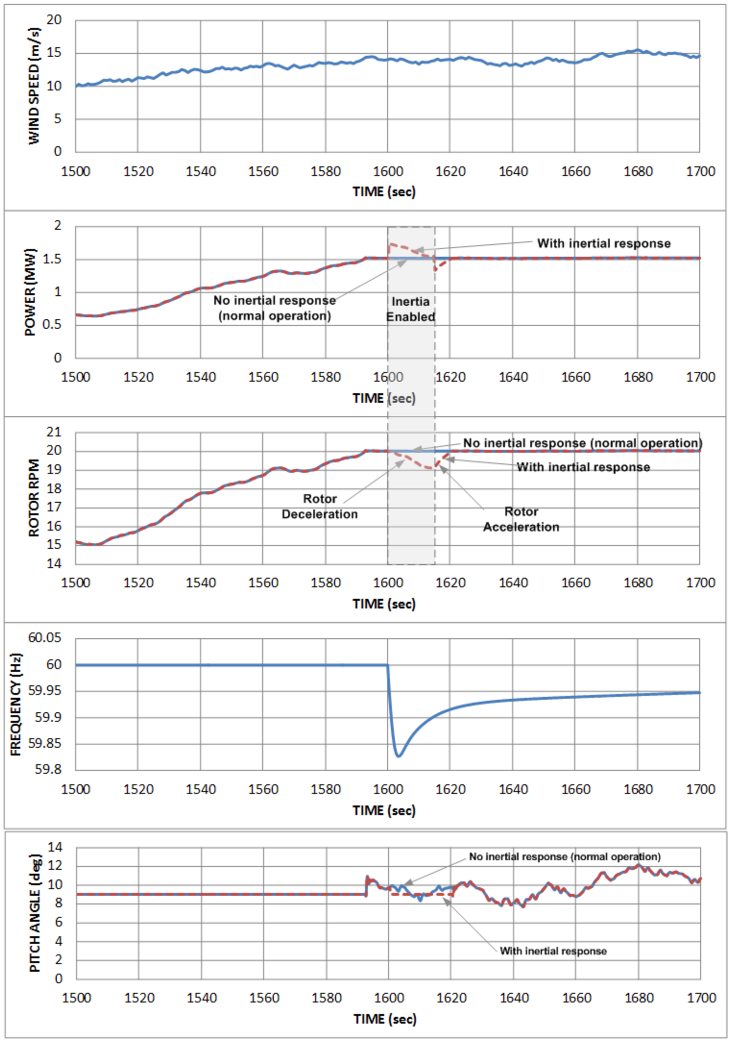


Figure 3-21. Simulated example of Type 3 inertial control (rated power).

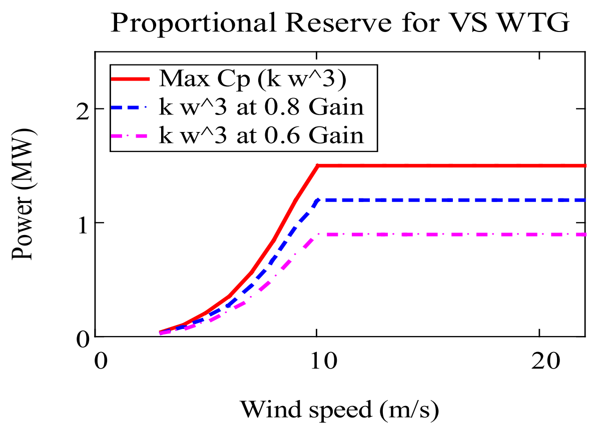
Unlike conventional synchronous generators, the controlled inertial control from variable-speed WTGs is dependent on the initial pre-disturbance conditions. The changing wind conditions and initial RPMs will have significant impact on controlled inertial response.

The majority of grid-connected WTGs in power systems throughout the world are variable speed, so enabling controls to provide an emulated inertial response in case of frequency disturbances can become an essential service to the grid by helping improve system frequency response. Ultimately, grid codes may be modified to include forms of inertial response from wind turbines depending on given utility needs.

3.1.3.1 Reserve Power – Type 3 and Type 4 WTG

When setting aside some reserve power, the portion of aerodynamic power that will be reserved should be included as a constant proportion of the rated power (constant reserve – ΔP) or a constant proportion of the available aerodynamic power (proportional reserve). This spinning reserve capability can be used to implement "governor control" to help the grid by decreasing or increasing the reserve power held from or delivered to the grid. In Figure 3-22 (a), the amount of reserve power is a constant output power as a percentage of the rated power, and in Figure 3-22 (b), the amount of reserve power is a fraction of the target power (C_{pmax} operation).

a) Constant ΔP



b) Proportional reserve

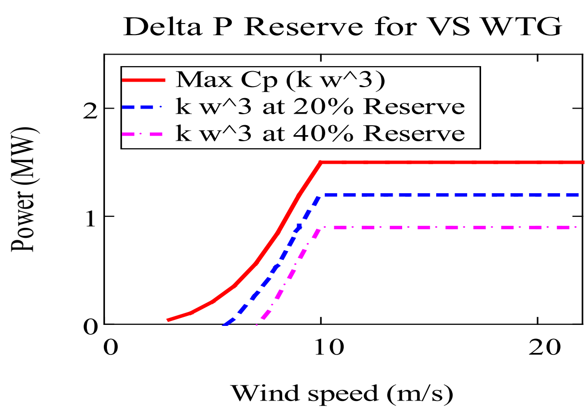


Figure 3-22. The reserve power for a variable-speed WTG using two different methods.

Figure 3-23 illustrates how the control strategy works. The WTG is operated at variable speed. The electrical output power is commanded to follow the thick red line in normal operation without the reserve requirement. With the reserve requirement enabled, the dashed green line (indicating the proportional reserve) is the path followed. This is done via converter control. The thin red line represents the aerodynamic power of the WTG at 8 m/s without pitch action, and the operating point of the WTG is at point A for optimal operation. To fulfill the reserve requirement, the pitch is controlled to ensure that the aerodynamic operation of the WTG will be maintained at optimal tip-speed ratio (TSR), and the aerodynamic power moves from the thin red line to the dashed green line after the pitch angle is adjusted. The new operating point is point B. Moving the operating point from point A to point B requires both the aerodynamic adjustment via pitch angle control and power converter control. The purpose of keeping the TSR at the optimal value is to optimize the response of the turbine when the pitch is returned to normal (pitch angle $\beta = 0°$); thus, the turbine will return to operating at optimum C_p right away. The operating point moves back from point B to point A when the reserve power of a wind plant is recalled (i.e., reserve requirement is disabled), and it will return the performance coefficient to C_{pmax} operation.

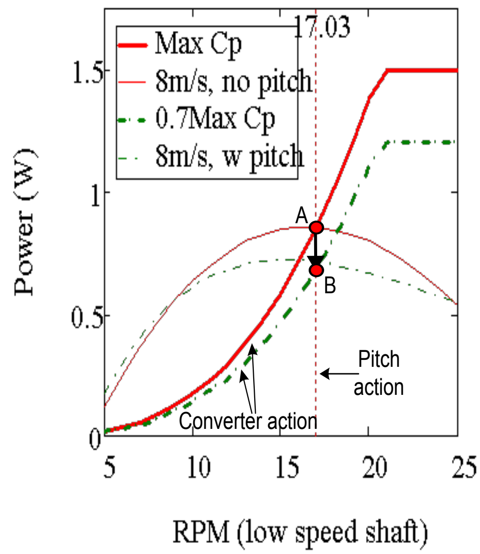


Figure 3-23. Operating points for the proposed control.

3.1.3.2 Control Block Diagram

The control block diagram for the proposed controller is presented in Figure 3-24. There are several groups of control blocks performing different functions:

- Block 1 ensures that the operation of the WTG is maintained at a constant TSR. The input to this block is the wind speed. The average (filtered) value of the wind speed is used to compute the corresponding rotor speed to keep the TSR constant at the optimal target value (TSR_{tgt}). The reason for keeping the TSR at TSR_{tgt} is to ensure that the WTG will respond instantaneously and return to its original operating point quickly when the pitch angle is returned to normal.
- Block 2 controls the pitch angle so that the rotor speed follows the target rotor speed ($\omega_{m\text{-}tgt}$) and the TSR is kept at TSR_{tgt}. Another function of this block is to ensure that the rotor speed will never exceed the rated (upper limit) rotor speed ($\omega_m < \omega_{m\text{-}limit}$). Thus, this will prevent the runaway problem when the turbine becomes disconnected from the grid. The output of this block will be limited ($0° < \beta < 30°$).
- In Block 3, the target power is computed to guide the pitch controller in adjusting the output of the WTG. The input to Block 3 is the rotational speed that will be translated to

the calculated power (P_{calc}) deliverable at maximum C_p operation. From this calculated power, the reserve power must be subtracted to obtain the electrical power, including the reserve power – P_{tgt_rsv}. Another input is P_{aux}, to include the governor droop control capability if it is implemented (discussed in the next section). Finally, the output of the block is the target power. Note that the target power at lower-than-rated rotor speed must be checked to ensure the operating torque of the generator will not exceed the designed maximum torque (corresponding to output power at maximum rated torque P_{ratedT}). This precaution will allow the mechanical torque limit to be observed to preserve the gearbox, the shaft, and other mechanical components of the WTG. Finally, the target power P_{tgt} will be used to command the power converter so that the total output of the generator will be equal to P_{tgt}.

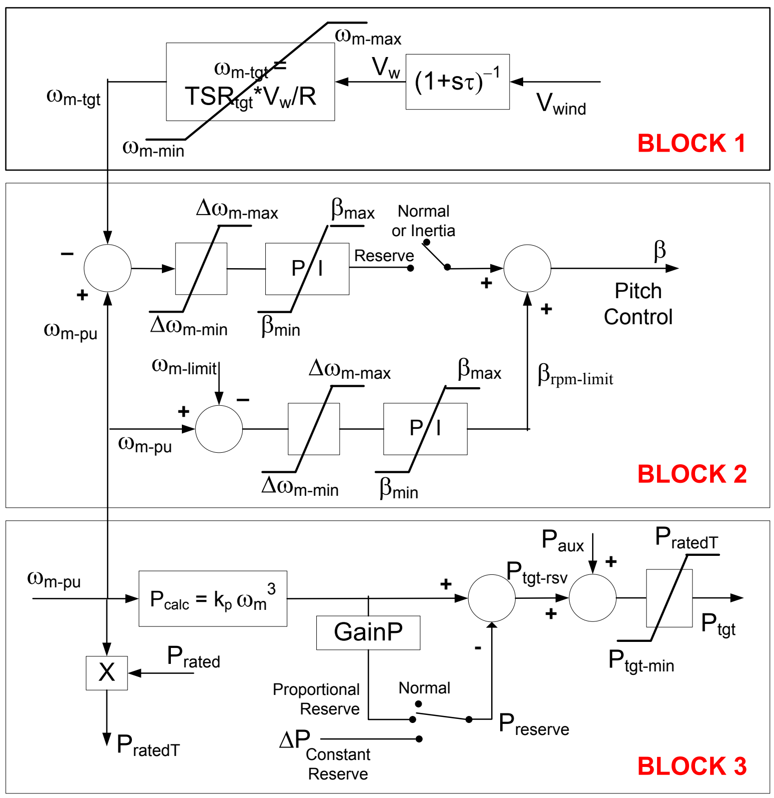


Figure 3-24. Pitch controller and real power controller used to set reserve power for Type 3 and Type 4 WTGs.

Models of Type 3 and Type 4 turbines, including the controller described above, were developed in MATLAB/Simulink. Details of the models are presented in [15]. Figure 3-25 shows a test wind-speed time series, and the corresponding power output, for the cases with and without reserve requirement enabled. As shown in Figure 3-25, the requested reserve is 20% of the rated power output (constant ΔP). Figure 3-26 illustrates the result of proportional reserve power implementation. The requested reserve is 10% of the available aerodynamic power (proportional reserve). For both operations, the plots show that the reserve controller functions act as desired.

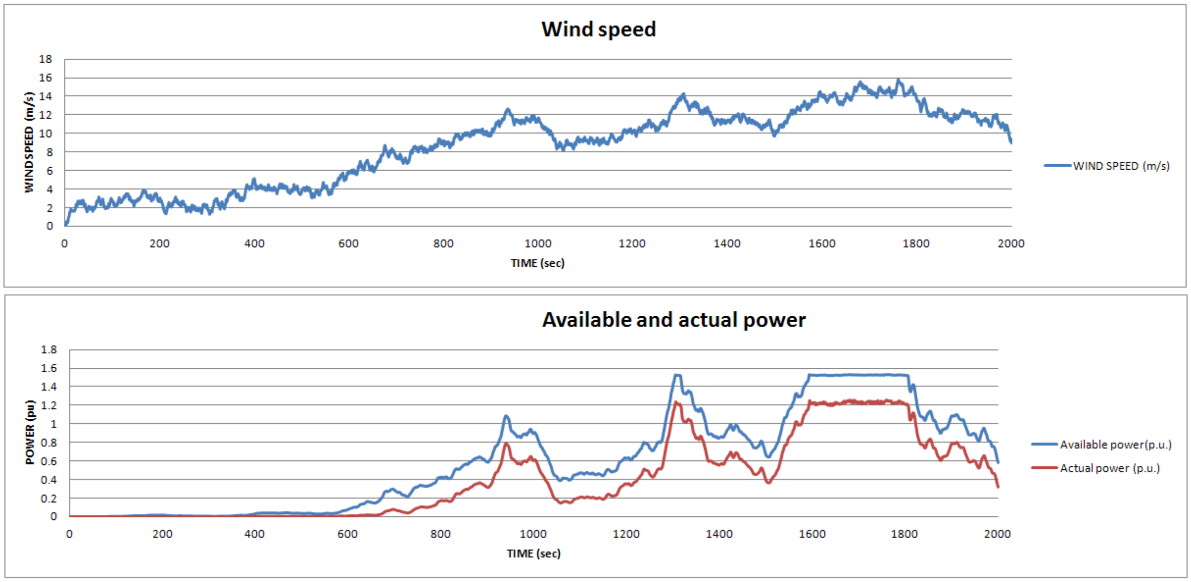


Figure 3-25. Constant reserve power implementation ($\Delta P_{reserve}$ = 20%).

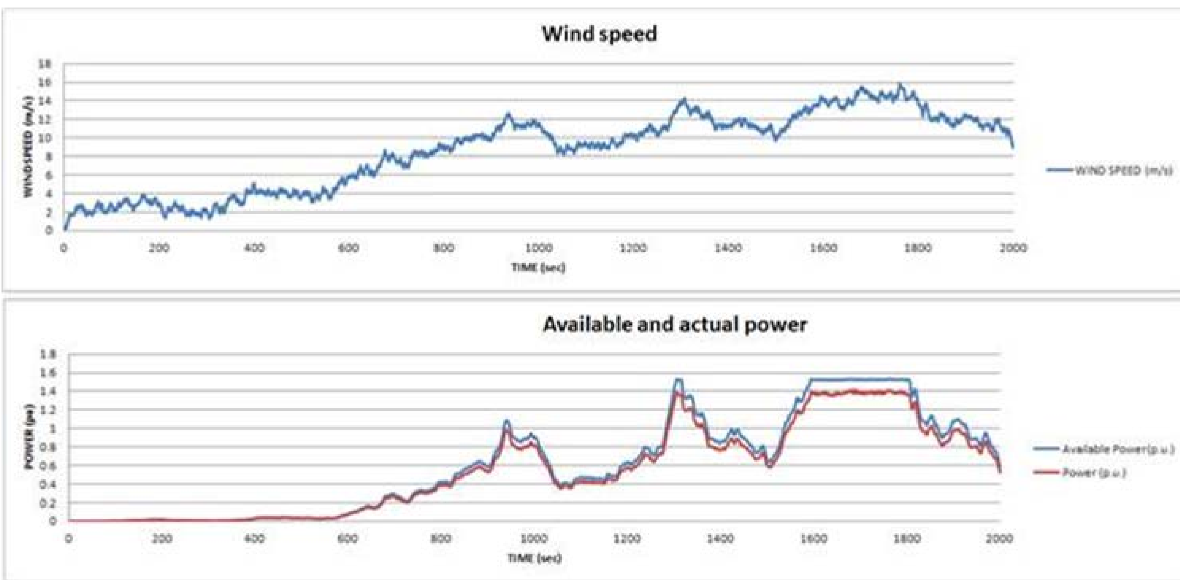


Figure 3-26. Proportional reserve power implementation (reserve = 10%).

3.1.3.3 Primary Frequency Control Capability

With spinning reserve implemented in a wind plant, non-symmetric droop characteristics similar to that shown in Figure 3-27 can be implemented. As in the case of inertial control, the PFC parameters (deadbands, droops, reserve margin) can be tuned to different values for optimum system performance.

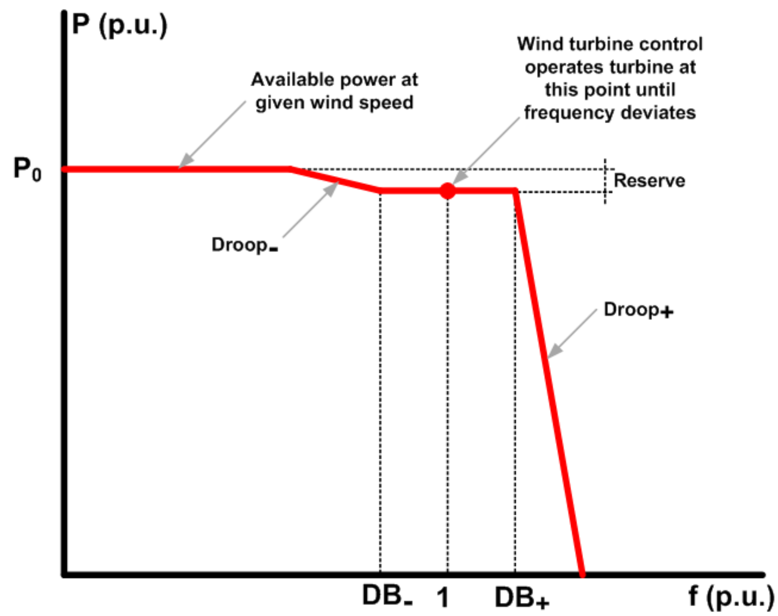


Figure 3-27. PFC implemented with a frequency droop on a wind power plant.

The PFC will take the frequency of the grid as the input and the commanded additional power P_o as the output. Note that the wind plant can respond to system over-frequency by shedding the output power (droop+), and it can respond to system under-frequency by deploying the reserve power (droop -). The P_{aux} shown in Block 3 in Figure 3-24 can be used with $P_{aux} = P_o$ (output of the governor control) to accomplish the governor control. This is discussed further in Section 3.3.

3.2 NREL Frequency Events Monitoring

This section describes statistics on the electrical frequency of an interconnection. This information is important for a multitude of reasons. The large collection of disturbance events can help with dynamics modeling by alignment of frequency behavior for the interconnection simulations for validation purposes. Secondly, the occurrence of frequency events and the magnitude of these events will help the controls team understand how the wind plants may provide this response in the future and how this may affect the loading impacts of the turbines. Lastly, the traces themselves were used as inputs to the field tests to test a variety of different realistic frequency-based events. This frequency data is important for a general understanding of the frequency response performance of an interconnection, and can be used for increased understanding of the ways wind can support frequency with the use of APC.

NREL has developed a custom monitoring system and software for continuous unattended grid frequency monitoring and frequency event capturing. The NI Labview-based software was developed specifically for accurate grid frequency calculations from measured AC voltage waveforms (captured at 5 kHz sampling frequency) and can run on any PC. The hardware consists of an NI cDAQ-9171 chassis with a 9225 voltage measurement module (24-bit, 300 VRMS) and connects to the PC via USB 2.0 cable (Figure 3-28). NREL has two such systems. The first one was installed at the National Wind Technology Center (NWTC) in June 2011 and has since been continuously monitoring the WI frequency. The second system has been installed at NREL's offices in Washington, DC, for monitoring the grid frequency in the EI.

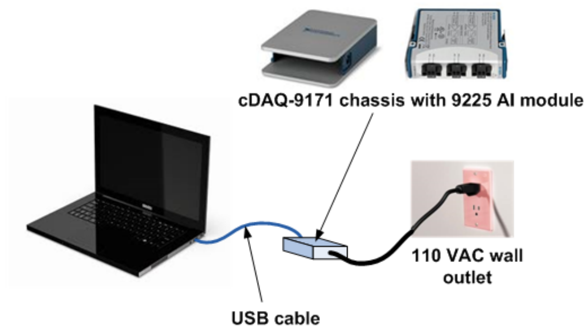


Figure 3-28. NREL grid frequency monitoring system.

The user interface of the Labview-based software is shown in Figure 3-29. It allows live, continuous 24/7 monitoring and recording of grid frequency. It also allows control of software triggers for event capturing. The trigger system is based on user-selected absolute values for min and max measured frequencies, relative change in frequency, rate of change of frequency, and time window for online analysis. This allows users to select which frequency events are important enough to be recorded.

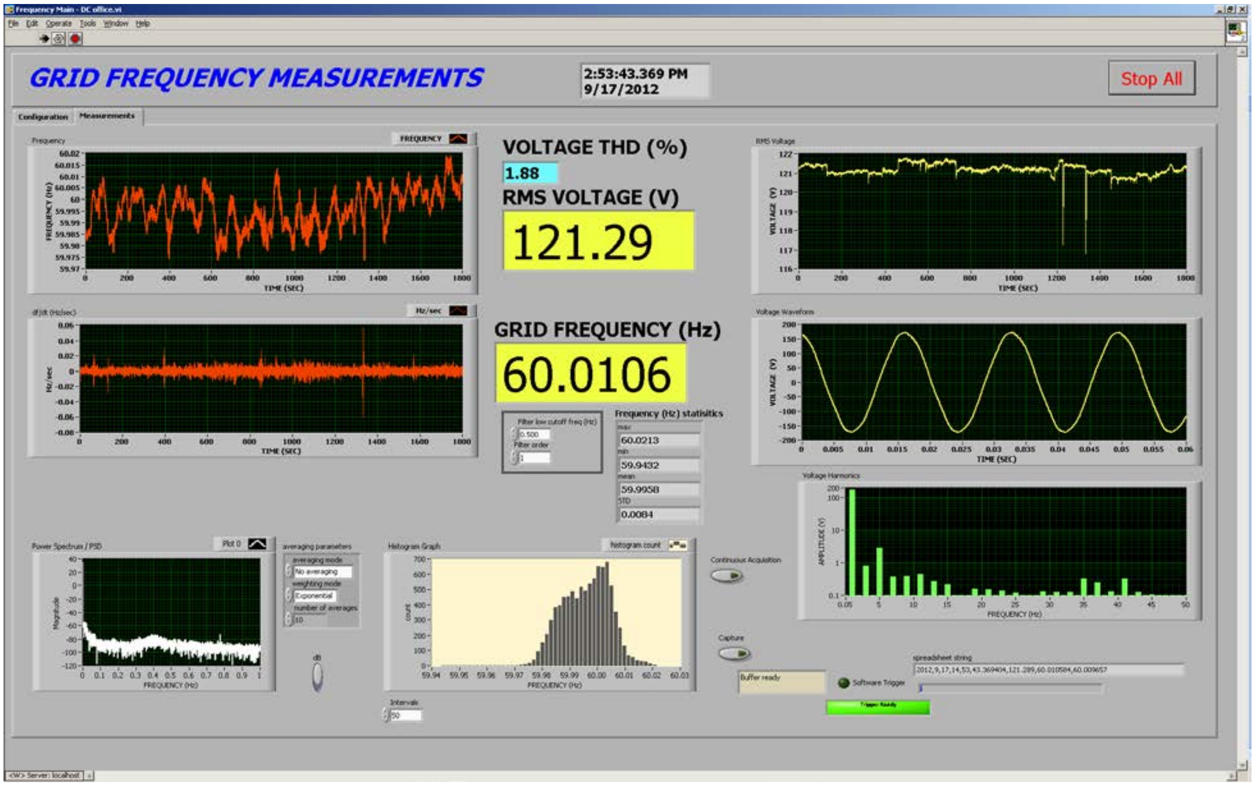


Figure 3-29. Software user interface.

A large number of WI frequency events captured by the NREL system are shown in Figure 3-30. A summary of the same data is shown in Appendix D. The lowest WI frequency nadir observed so far has been around 59.82 Hz, and the largest recorded drop in frequency from the pre-fault level was 197.3 mHz. The largest recorded rate of frequency decline was -227 mHz/sec. Some examples of frequency events data for the WI are shown in Figure 3-31, Figure 3-32, Figure 3-33, and Figure 3-34 for cases of large loss-of-generator events with and without following oscillations, a "double dip" frequency event, and a loss of load trip, respectively.

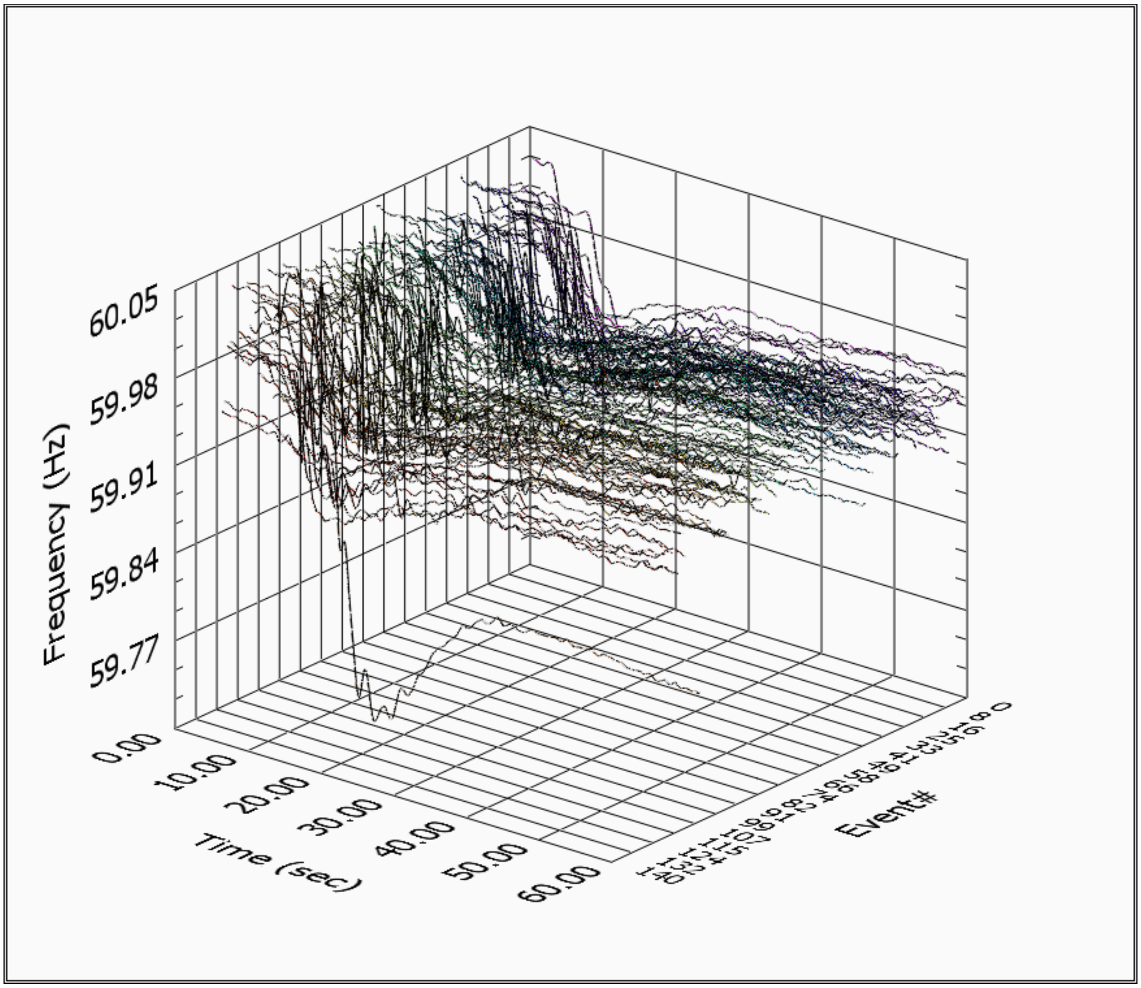


Figure 3-30. WI low-frequency events measured at the NWTC since June 2011.

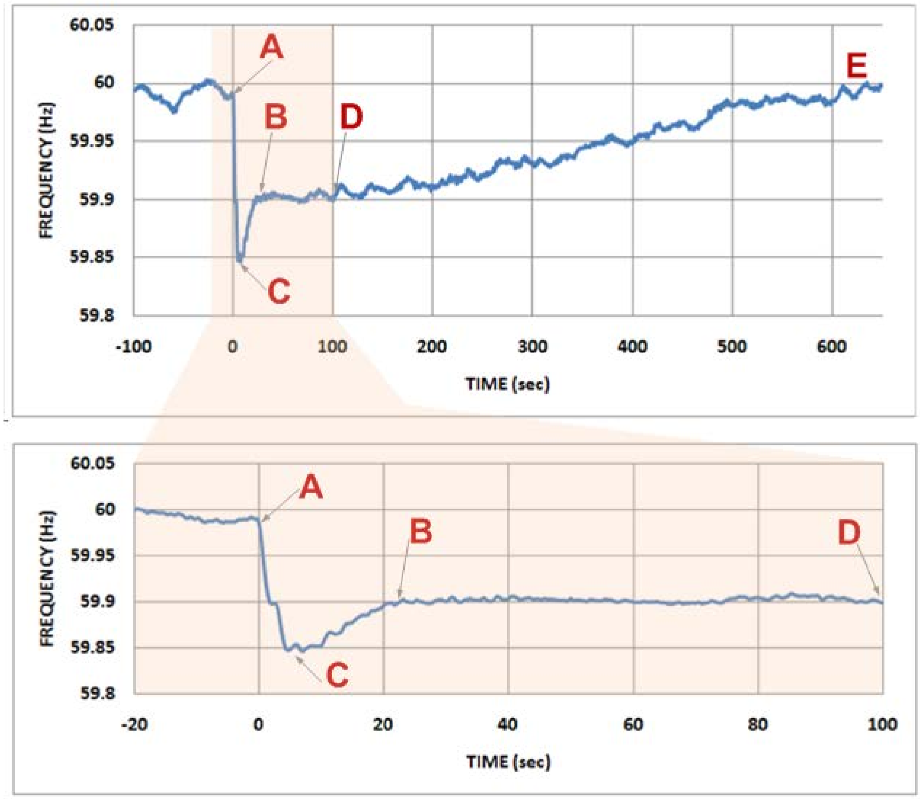


Figure 3-31. Typical WECC frequency response (August 6, 2011 at 11:19 am).

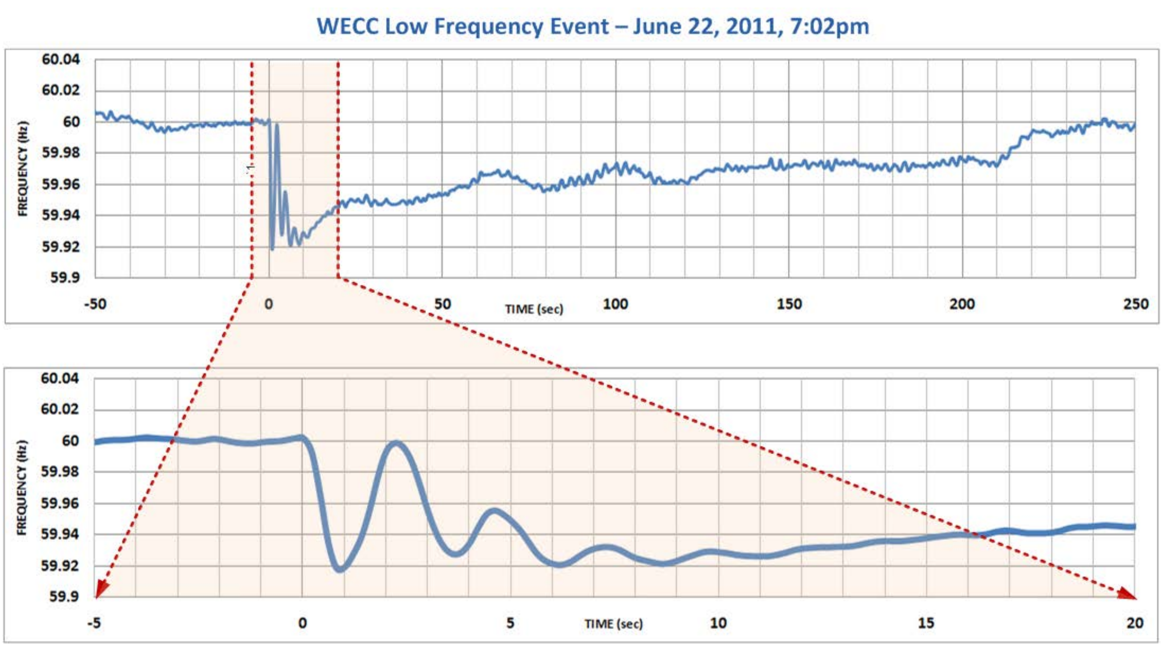


Figure 3-32. Example of WECC event with oscillations.

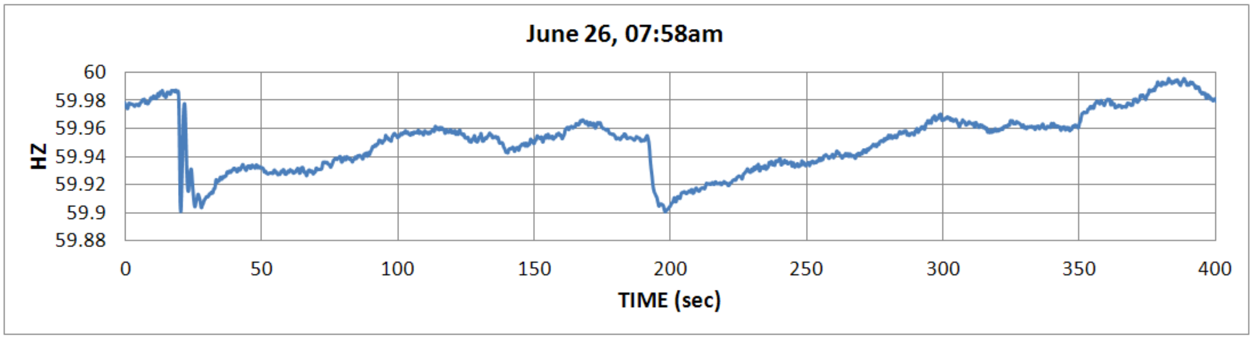


Figure 3-33. WECC "double dip" event.

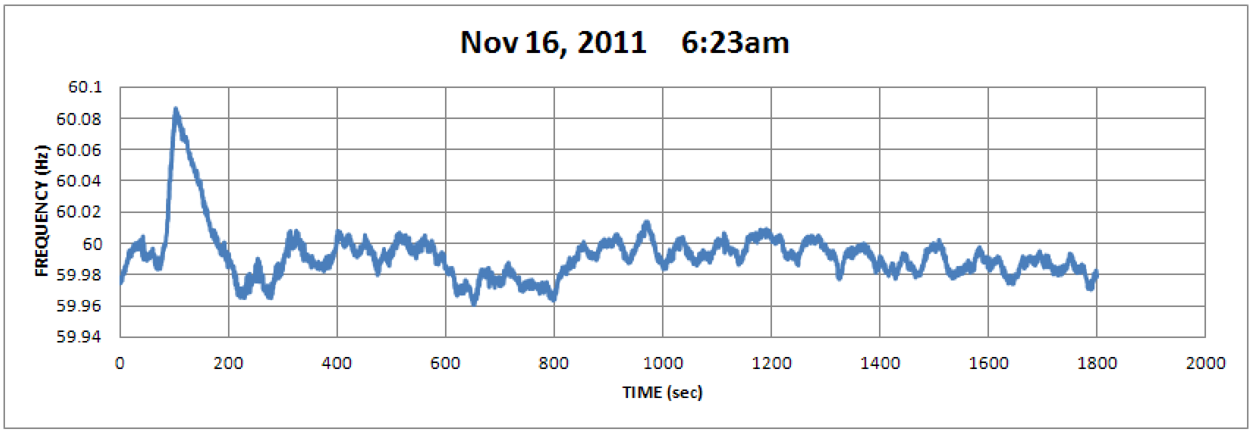


Figure 3-34. Example of WECC over-frequency event.

The large data set of WI frequency events offers a wealth of information with a great variety of frequency response performance characteristics. In Figure 3-35, we present a loss-of-supply event on the EI. Note that the frequency recovery in the EI is quite different than in the WI. The frequency nadir and settling frequency are about the same in the EI, mostly due to the large amount of inertia on the system. In some cases, the EI also has experienced a "lazy L" response. This refers to a decline in frequency after the system has already reached its settling frequency [4]. This is due primarily to a withdrawal of PFC action from governors on the system.

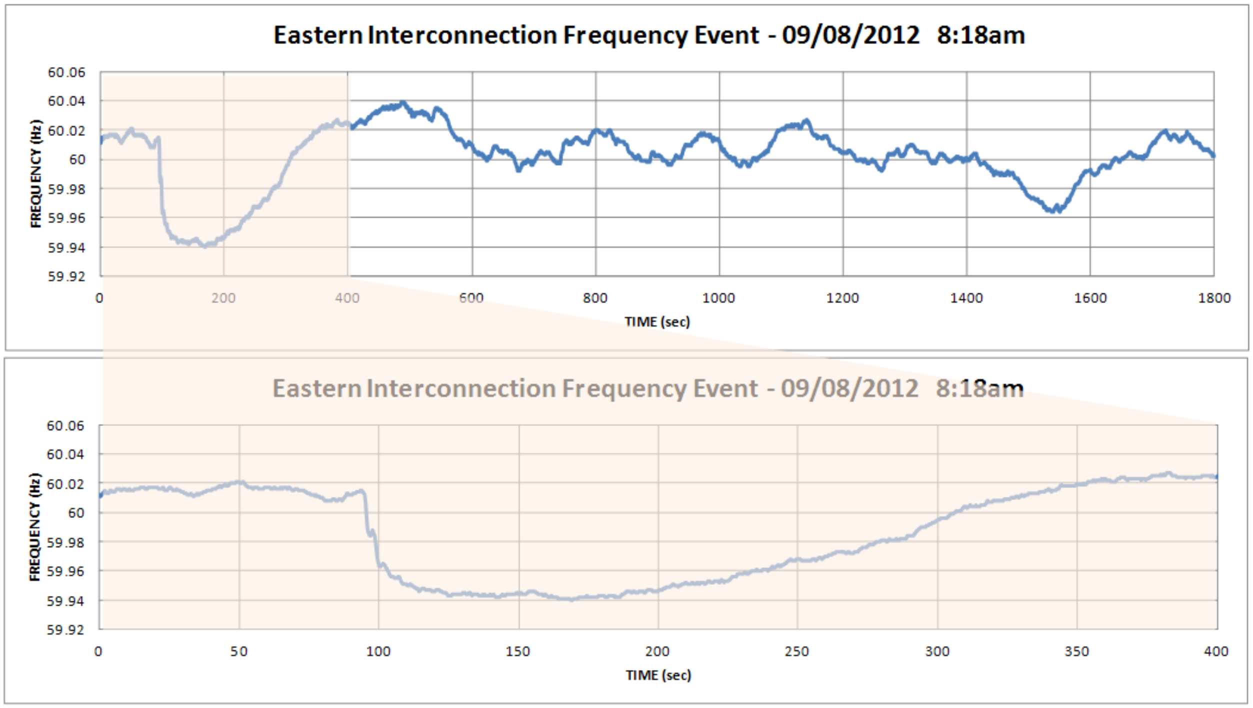


Figure 3-35. Example of EI under-frequency event.

A distribution of frequency nadirs (point C) and settling frequencies (point B) for about 120 events on the WI captured during the 2011–2013 time period are shown in Figure 3-36. Both parameters have non-symmetric distribution with the highest peaks at around 59.91 Hz and 59.93 Hz, respectively. Figure 3-37 shows the relationship between the nadir (point C) and settling frequency (point B) for the same events.

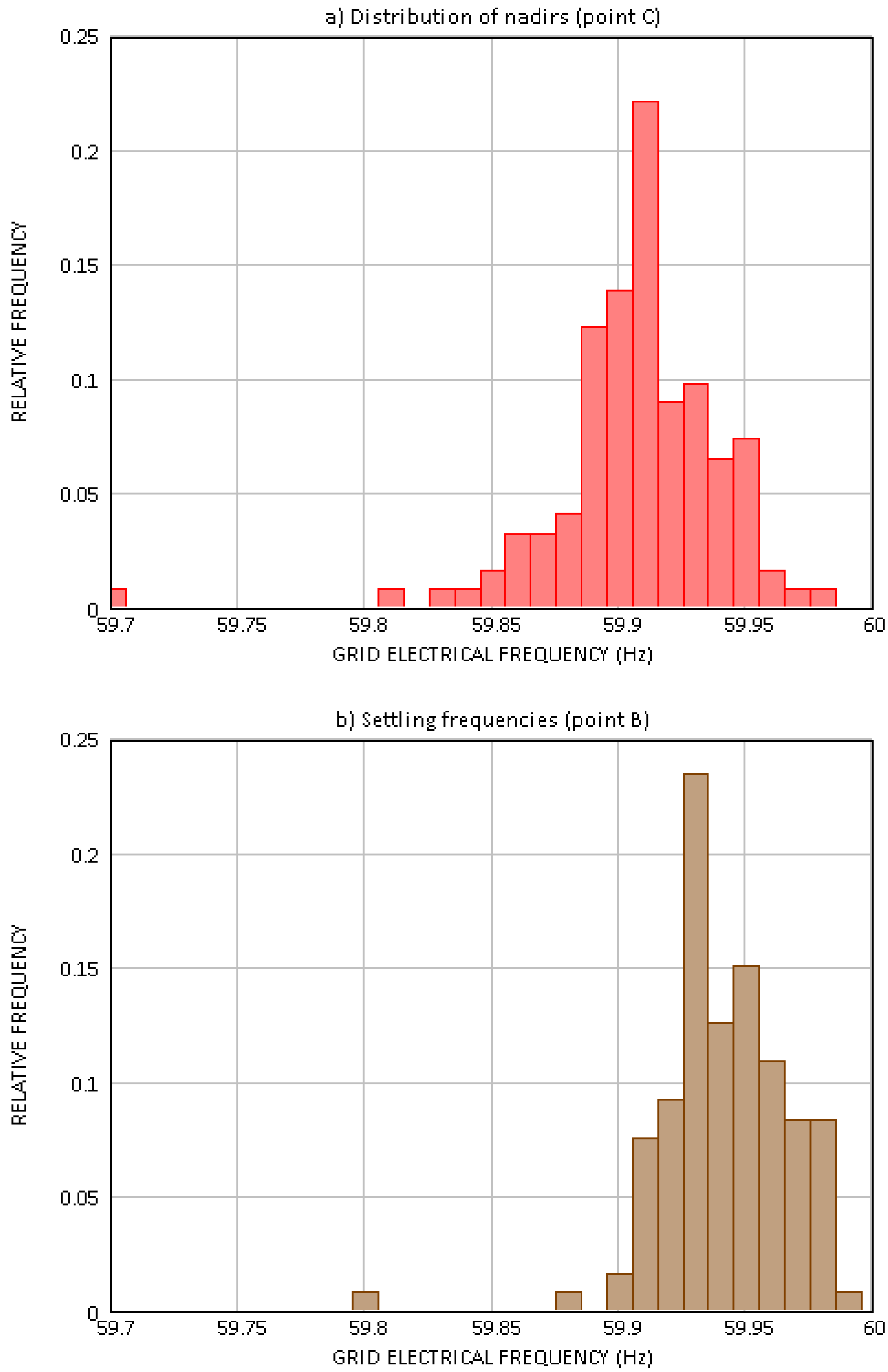


Figure 3-36. Distribution of low-frequency event data.

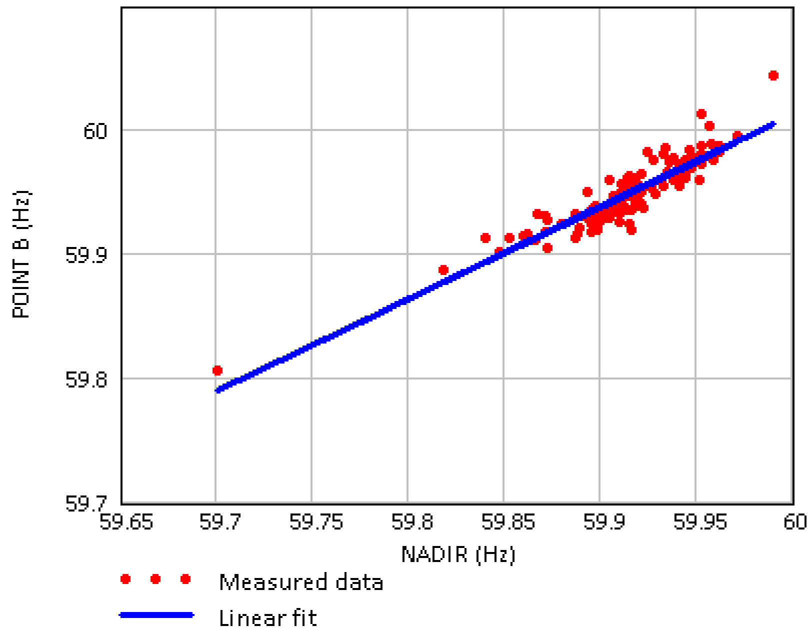


Figure 3-37. Relationship between nadir (point C) and settling frequency (point B).

Frequency data was also analyzed continuously for about three months in 2013 (March–June). The distribution of frequency data measured at 0.2-s sampling intervals is shown in Figure 3-38. This symmetric distribution can be predicted using a normal distribution function as shown in Figure 3-38 using the standard deviation $\sigma = 0.019$ and mean $\mu = 60.002$.

$$f(\mu, \sigma, x) = \frac{1}{\sigma\sqrt{\pi}} e^{-\frac{(x-\mu)^2}{2\sigma^2}}$$

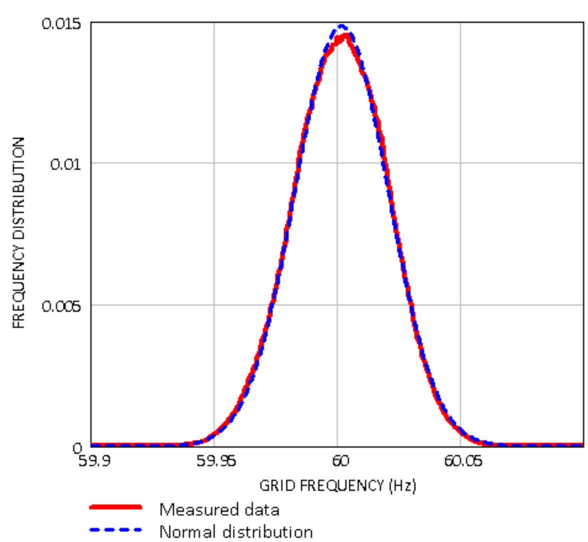


Figure 3-38. Distribution fitting for continuous frequency data.

3.3 Role of Wind Power on Frequency Response of an Interconnection

The ability of a power system to maintain its electrical frequency within a specified range is a crucial element in maintaining a reliable and secure power system. An interconnected power system must have adequate resources to respond to a variety of contingency events to ensure rapid restoration of the balance between generation and load. The combined response of PFC and inertia is essential to arrest electrical frequency changes on an interconnection before triggering UFLS relays. In extreme cases, large deviations in frequency may result in triggering generation protection relays or machine damage, or unstable frequencies that could potentially lead to a blackout.

The frequency response of an interconnection is the aggregated result of PFC from all resources on the power system, including the natural load response. It is typically measured in MW/0.1 Hz, which measures the MW response provided for a 0.1-Hz steady-state frequency deviation. Other metrics that focus more on the frequency nadir have also been recently proposed [1]. The frequency response with high levels of variable generation to sudden, large imbalances between generation and load has been a focal point of many studies both nationally and internationally [1]–[2],[20]. Currently, most variable energy resources like wind power typically do not provide PFC. These technologies are controlled by and interface with the grid using power electronics. As such, not only are they asynchronous, but the MW output of the unit is tightly controlled and maintained at a fixed value for given operating conditions. Thus, they do not inherently provide inertial control. Lower system inertia as a result of increased renewable penetration will cause increased rates of change of frequency immediately following a disturbance. Lower amounts of PFC caused by the displacement of conventional generators with active governors by variable generation will cause greater steady-state frequency deviations.

In the United States, recent studies have suggested that frequency response has been declining during the last several years [22]–[23]. Some potential reasons for this include generators that operate in modes that do not offer PFC (e.g., sliding pressure mode) and blocked governors [24]–[25]. Other reasons may include institutional reasons [26] and electricity market designs (see Section 2 and [27]). Such a decline may translate to a decrease in bulk power system reliability. In particular, the EI has been experiencing a steady decline of approximately 60 MW/0.1 Hz to 70 MW/0.1 Hz over the past two decades [23]. An IEEE task force report studied the issue with great detail and developed a number of conclusions and recommendations [28]. These concerns prompted further industry-wide efforts by the North American Electric Reliability Corporation (NERC) and the regional reliability entities to broaden understanding and increase transparency by highlighting mitigation efforts to ensure adequate frequency response. The FERC Frequency Response Initiative sets a number of objectives to comprehensively address the issues related to frequency response [29]. Such objectives include a) clearer identification of frequency-related reliability factors, b) improvements of frequency response metrics, and c) assessing impacts of emerging technologies, including inverter-coupled renewable energy generation. The proposed BAL-003-1 standard would set a minimum frequency response obligation for BAs within an interconnection and means for measuring their response [30]. The standard requires sufficient frequency response from the balancing area (BA) to maintain interconnection frequency within predefined bounds. A systematic approach to identifying frequency response that is useful for operating a reliable system with increased amounts of variable renewable generation is presented in [1]. It also confirmed the validity of using frequency response as a predictive metric to assess the reliable operation of interconnected systems.

A frequency response study for the U.S. EI is described in [4] and was intended to create a meaningful baseline model for the EI for examining its frequency response to investigate the possible impacts of large amounts of wind generation. Among other useful results, this EI study demonstrated the benefits of wind power providing PFC.

A typical wind power plant appears to the grid as a substantially different generation source than a conventional hydro or thermal power plant. Without special controls, a wind power plant does not participate in PFC. Further, inverter-based WTGs (i.e., Type 3 and Type 4 units) do not, without special controls, provide any inherent inertial control. In this section, we present a detailed study of wind providing these two control features—PFC and inertial control—and illustrate some of the impacts related to applying both control strategies and how they might work best together. In contrast to previous studies, the focus of this work is more on the different effects of each of these controls on the large, interconnected system response and how the two controls can complement each other.

Many researchers and wind turbine manufacturers have proposed different designs that allow wind power plants to provide capabilities similar to PFC and inertial control, for example [31]. The work reported here is described in [3] and [16], in which the impacts of wind power providing inertial control and PFC are investigated on the WI to understand the impacts on the interconnection's frequency response. We demonstrate that these controls from WTGs, if tuned properly, can significantly improve the frequency nadir during disturbances. PFC from WTGs can be tuned to provide response similar to governor droop characteristic and can significantly improve the frequency nadir as well as settling (steady-state) frequency. This work uses many methods and assumptions used in a similar simulation study [2] and evaluates frequency impacts at varying penetration levels, varying control strategies from the wind plants, the response of different generation technologies at these different levels, and the impact of frequency response from varying levels of participation from conventional plants with high wind power penetrations.

3.3.1 Overview of Frequency Response Metrics

In this work, we adopted a similar approach to frequency response metrics as that described in [2], and now a part of the BAL-003-1 NERC standard. Consider a real frequency event that took place in the WI on August 6, 2011. This event started after a large generation loss at t = 0 sec, as shown in Figure 3-39. The point A frequency value is the pre-disturbance frequency and is calculated as an average of frequency values from t = 0 to t = -16 [30]. The grid frequency started declining immediately because of an imbalance between generation and load. The initial ROCOF was about -63 mHz/sec, and is determined by the total amount of inertia in the interconnection. The PFC of conventional generation with active governors starts to respond immediately after the frequency decline passes beyond their governor deadband thresholds. The characteristics of system inertia and PFC determine the lowest frequency (nadir), which is shown as point C in Figure 3-39. The important characteristics are the system inertia, amount of PFC available, and the response speed of PFC. Point C must be higher than the highest set point for UFLS within an interconnection. Measuring the level of point C based on what large, credible disturbances the interconnection plans for helps determine the amount and characteristics of PFC that are needed to arrest frequency decline above the first stage of UFLS.

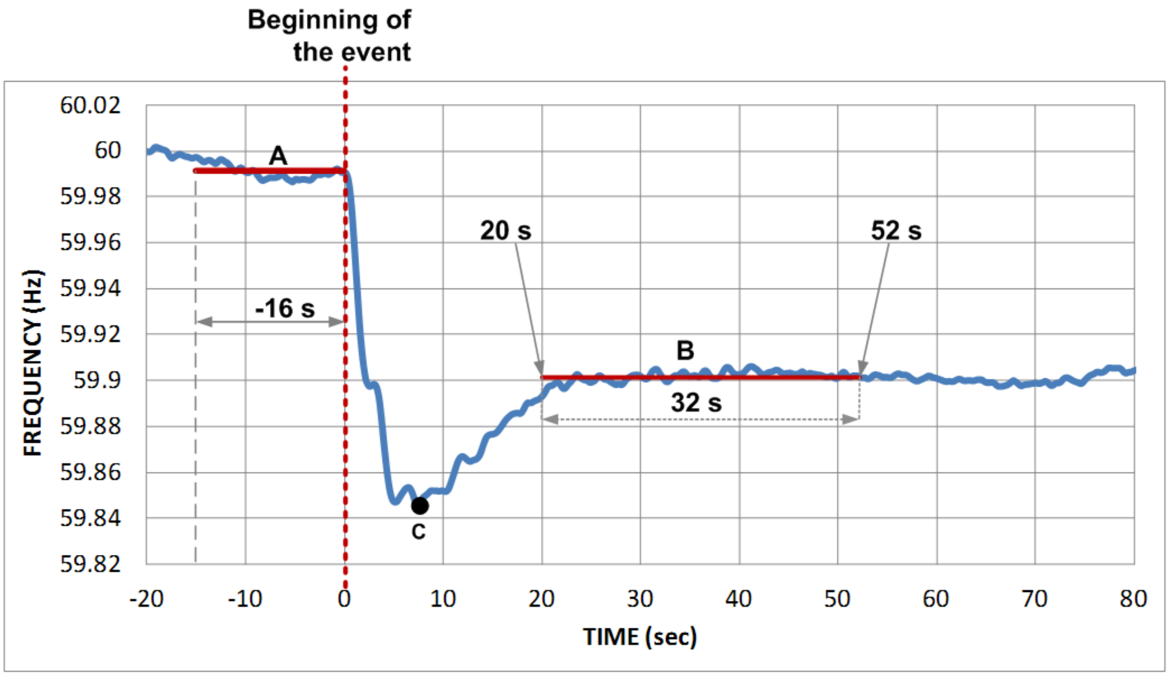


Figure 3-39. Description of frequency response metrics.

Once the frequency decline has been arrested, continued delivery of PFC will stabilize frequency at a steady-state settling level (point B). This point at which frequency is stabilized is often referred to as the settling frequency. Point B is determined by averaging the frequency values from a period of 32 s, starting at t = 20 s after the disturbance [30].

The work presented in this section is focused on assessing the impact of wind generation on the frequency response of the WI. We study the following cases with wind as usual without any frequency response capabilities, as well as allowing wind to have combinations of inertial and PFC capabilities. The following frequency metrics are used in the study:

1. Initial rate of decline of frequency, or ROCOF
2. Value of frequency nadir (point C)
3. Transition time between beginning of disturbance and frequency nadir (transition time from point A to point C)
4. Value of settling frequency (point B)
5. Transition time between frequency nadir and settling frequency (transition time from point C to point B).

According to [30], the Interconnection Frequency Response Obligation (IFRO) is calculated from statistical observations of many events similar to the one shown in Figure 3-39. Various parameters, such as the ratio of point C to the point B (CB_R), are used in IFRO calculations. For the WI, BAL-003-1 requires IFRO = -840 MW/0.1 Hz [30].

3.3.2 Description of U.S. Western Interconnection

WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the WI. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

WECC is geographically the largest and most diverse of the eight regional entities that have a delegation agreement with the NERC. WECC's service territory extends from Canada to Mexico, and includes all or portions of 14 western states (see Figure 3-40).

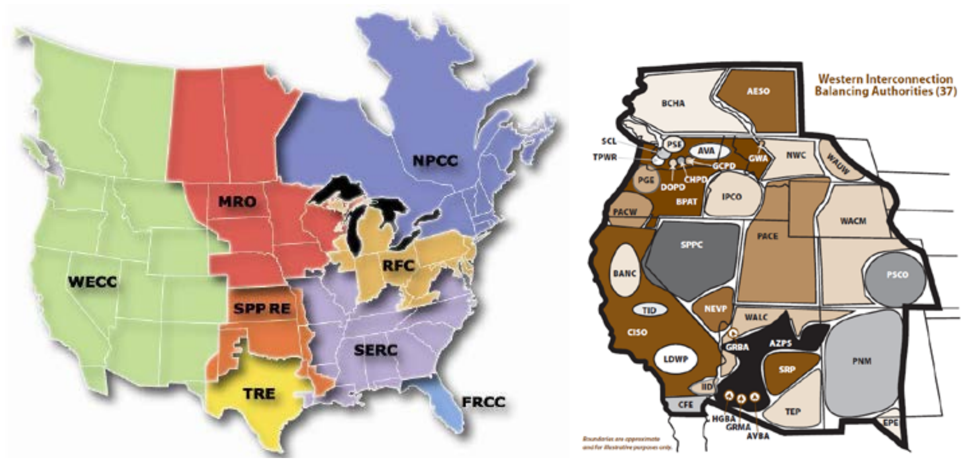


Figure 3-40. WECC geographical footprint and map of BAs. ***Image from WECC***

There are 37 BAs within WI boundaries. These BAs continuously balance their control areas' net scheduled interchanges with their actual interchanges by dispatching generation used for regulation, thus helping the entire interconnection in regulating and stabilizing frequency.

The 2012 peak demand in the WI is estimated to be around 149 GW. The WECC generation on-peak capacity by fuel type is shown in Figure 3-41. There was more than 10 GW of installed wind power capacity in the WI in 2011. The addition of a substantial amount of wind power plants in the future is a subject of heightened concern in terms of frequency response. As discussed, without special controls, a wind turbine does not participate in the regulation of grid frequency. When a large amount of wind power displaces conventional synchronous generation, the mix of the remaining synchronous and frequency responsive fleet changes and could potentially impact overall frequency response.

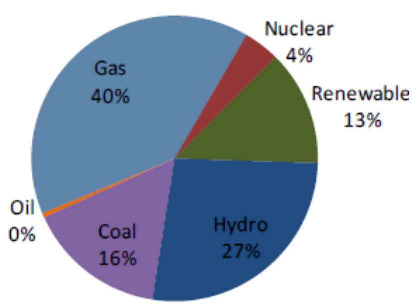


Figure 3-41. WECC on-peak capacity by fuel type.

3.3.3 Base Case Development and Modeling Assumptions

The purpose of this study is to investigate the overall frequency response of the WI with different levels of variable wind generation with enabled inertial control and PFC using the GE Positive Sequence Load Flow (PSLF) dynamic simulation software. For this purpose, it was decided to use one of the PSLF base cases developed under the guidance of the Transmission Expansion Planning Policy Committee (TEPPC). In particular, the TEPPC 2022 light spring load base case (model 22lsp1s) with approximately 15% wind power penetration was selected as a basis for simulating future penetration scenarios. This particular base case under light spring load conditions throughout the WI and renewable penetrations is consistent with state renewable portfolio standard requirements for 2022. Generation, load, and transmission topology are based on conditions modeled in the TEPPC 2022 common case [32]. It should be noted that the results presented here are hypothetical, so they do not claim to represent the actual present or future response of the North American WI. This is a research study with the goal of identifying what behavior might be realistically expected.

It is important to note that this modeling study does not address any changes to the transmission network that will take place at higher penetration levels. Instead, we adopt an approach of replacing the existing conventional power plants with wind power plants to achieve the desired penetration levels without transmission upgrades. At the snapshots of time represented in these cases for different penetration levels, the portion of generation coming from wind power was in accordance with the results of the Western Wind and Solar Integration Study Phase 1 (WWSIS-1) [33]. WWSIS-1 examined three different wind and PV power scenarios to obtain 30% penetration across the WI footprint. For this study, it was decided to base wind power location assumptions on the “In-Area Scenario,” in which each state meets its target using best in-state resources so no additional interstate transmission is needed. The other two WWSIS-1 scenarios (“Local Priority” and “Mega Project”) required different levels of interstate transmission. In addition, the “Mega Project” scenario located most of the wind power in a few best wind-resource areas, causing localized frequency response from wind power.

Three different wind penetration scenarios were studied in WWSIS-1. The level of installed wind capacity for these scenarios is different for different regions in the WI. The total installed wind capacities used in WWSIS-1 are 33.24 GW, 42.9 GW, and 75.39 GW for 10%, 20%, and 30% penetration cases, respectively.

Table 3-1 shows rated wind power capacity installed in each state for 10%, 20%, and 30% penetration in accordance with WWSIS-1. These numbers have been used as a guideline for developing penetration scenarios for this study. The approach in this study is to replace the conventional generators with the wind power plant according to the regional rate somewhat equal to what is listed in the table.

Table 3-1. WWSIS-1 In-Area Scenarios

Area	Wind Rating (MW), 10% case	Wind Rating (MW), 20% case	Wind Rating (MW), 30% case
Arizona	3,600	7,350	11,220
Colorado East	2,040	3,780	5,640
Colorado West	300	600	900
New Mexico	1,080	1,920	2,790
Nevada	2,340	4,680	7,050
Wyoming	930	1,620	2,340
COB	90	90	180
Idaho East	660	660	780
Idaho Southwest	750	750	1,500
Montana	780	780	1,050
N. California	5,610	5,610	11,790
Northwest	6,540	6,540	12,930
S. California	7,110	7,110	14,490
Utah	1,410	1,410	2,730
Total	33,240	42,900	75,390

The selection of conventional thermal units that are displaced by wind power plants is based on the approach to put new wind power plants at existing large, fossil-fueled (steam) unit plants. During this high-wind spring period, these wind power plants operate within the range of 50% to 60% of rated capacity. Such an approach gives an approximate but reasonable distribution of loadings on the wind power plants in the WI.

The scenarios for this study were developed for four penetration cases using Equation (3-3) for replacing conventional plants with wind power plants:

Total Wind Capacity = Penetration % x Western Electricity Coordinating Council Total Load (MW)/0.56 (3-3)

This rule is based on an average 56% capacity factor for the wind power plants. The 56% capacity factor is based on the average capacity factor for all wind power in the WI during the lowest demand hour, as described in [2]. This approach is different from the re-dispatch methodology used in [2] that implemented the 2/3 to 1/3 rule (which means that for every 3 MW of additional wind power production, there is a 2-MW reduction in thermal unit commitment and a 1-MW reduction in thermal unit dispatch). This rule was based on the Multi-Area Production Simulation (MAPS) modeling used in [33]. In this study, we simply replaced conventional thermal units with wind power plants. This approach is a simplistic way of emulating the retirement of steam units because of Environmental Protection Agency (EPA) regulations. Clearly, detailed transmission planning and dispatch consideration are an absolutely essential part of actually planning a system. This should be a greater focus in future frequency response studies.

The total light spring load in the TEPPC 2022 base case is approximately 113 GW, so the total wind power nameplate capacities for each penetration case used in this study can be calculated using Equation (3-3). Table 3-2 shows the nameplate capacities and generation level by wind power for each penetration case.

Table 3-2. Wind Power Nameplate Capacities and Current Generation Level

Wind Penetration Case	Total Wind Nameplate Capacity, GW	Generation Level, GW
15% base case	23	17.92
20%	41.65	22.5
30%	60.34	33.76
40%	80.45	45.19
50%	101.67	56.89

The breakdown of wind generation by turbine type for the TEPPC 2022 base case (15% penetration) is shown in Table 3-3.

For the purpose of this work, all Type 3 and Type 4 generic models were replaced with GE dynamic models for doubly-fed induction generator and full-size power-converter-based wind turbines as implemented in the PSLF dynamic simulation program [20]. These models were developed and validated specifically for the latest GE WTGs and include an inertial control scheme and APC emulator for PFC. The Type 1 and Type 2 wind power plants were not replaced by the GE dynamic model, so a small number of Type 1 and Type 2 WTGs were still present in all simulated cases.

Table 3-3. TEPPC Base Case Wind Generation by Type

Wind Turbine Model	Total Nameplate Rating (GW)	Current Output (MW)	% of Current Output out of Total Current Generation
Type 1 (wt1g)	0.5	425.8	0.3%
Type 2 (wt2g)	1.5	1479.6	1.3%
Type 3 Generic (wt3g)	5.4	4145.7	3.5%
Type 4 Generic (wt4g)	15.6	8631.7	7.4%
Type 3 and Type 4 GE Model (gewtg)	4.9	3238.5	2.8%

All simulations were conducted using the PSLF simulation tool. Each interconnection has a target resource contingency protection criteria based on the largest N-2 loss-of-resource event. For the WI, that would be the loss of the two largest generating units in the Palo Verde nuclear facility totaling 2,625 MW [34].

Additional details on the development of a base case for this study are described in [3]. The simulations performed investigated the sensitivity of various APC parameters of wind generation on the performance metrics discussed above. In particular, the sensitivities to wind power providing only PFC or only inertial controls were investigated at 20%, 30%, and 40% penetration levels. In [16], we present cases with combined inertial and PFC response by wind power for various wind power penetration levels up to 50%.

A wind turbine must operate in curtailed mode to provide enough reserve for PFC response during under-frequency conditions. Under normal operating conditions with near-nominal system frequency, the control is set to provide a specified margin by generating less power than is available from the unit. The reserve margin (or headroom) determines what is specified as the operational point of a wind turbine. In all the simulations where the wind plants provided PFC, 5% of headroom is kept available.

The inertial control provides a synthetic inertial control capability for wind turbines, emulating inertial control similar to conventional synchronous generators, for large under-frequency events. The response is provided by temporarily increasing the power output of the wind turbines in the range of 5% to 10% of the rated turbine power by extracting the inertial energy stored in the rotating masses. This quick power injection can benefit the grid by essentially limiting the rate of decline of frequency at the inception of the load/generation imbalance event.

Another characteristic that influences system frequency behavior is the fraction of generators with active governor control. This fraction (K_t) is a primary metric for expected performance first introduced by Undrill in [35]. The exact definition of K_t is not standardized. For this report, we conducted simulations to show the impact of K_t in the WI simulations using the following definition:

$$K_t = \frac{MW\ Generation\ Capability\ of\ Conventional\ Units\ with\ Governor\ Response}{Total\ MW\ Capability\ of\ Conventional\ Generation} \tag{3-4}$$

The lower *Kt* corresponds to the smaller fraction of generation providing PFC. Note that all synchronous machines will still provide inertia regardless of the K_t value. The 15% base case has a number of enabled governors that corresponds to K_t = 55%.

Table 3-4 provides a summary of the simulations performed to investigate the sensitivity of various APC parameters of wind generation on the performance metrics discussed above. For each simulated case, the grid frequency was calculated at 10 key 500-kV buses in the WI. For visual clarity, only the average of 10 frequencies is shown in the plots.

Table 3-4. Simulations Performed

Case	Simulation Scenarios			
15% 20% 30% 40% 50%	No inertia, no PFC[a]	Inertia only	PFC only (5% headroom; 4% droop)	Inertia + PFC (5% headroom; 4% droop)
50%	No inertia, no PFC, K_t=60, 50, 40%	Inertia only, K_t=60, 50, 40%	PFC only (5% headroom; 4 droop), K_t=60, 50, 40%	Inertia + PFC (5% headroom; 4% droop), K_t=60, 50, 40%

3.3.4 Simulation Results

3.3.4.1 Impact of Wind Penetration Levels and APC Strategies on Frequency response

Figure 3-42 through Figure 3-46 show simulated frequency response for five different wind power penetration levels (15%, 20%, 30%, 40%, and 50%), and different APC strategies from the wind power fleet.[4] As shown, the increase of wind power penetration has a visible impact on the performance metrics: the frequency nadir and settling frequency decline with penetration levels for the base case (blue plots) as a result of non-frequency responsive wind power replacing the responsive conventional generation.

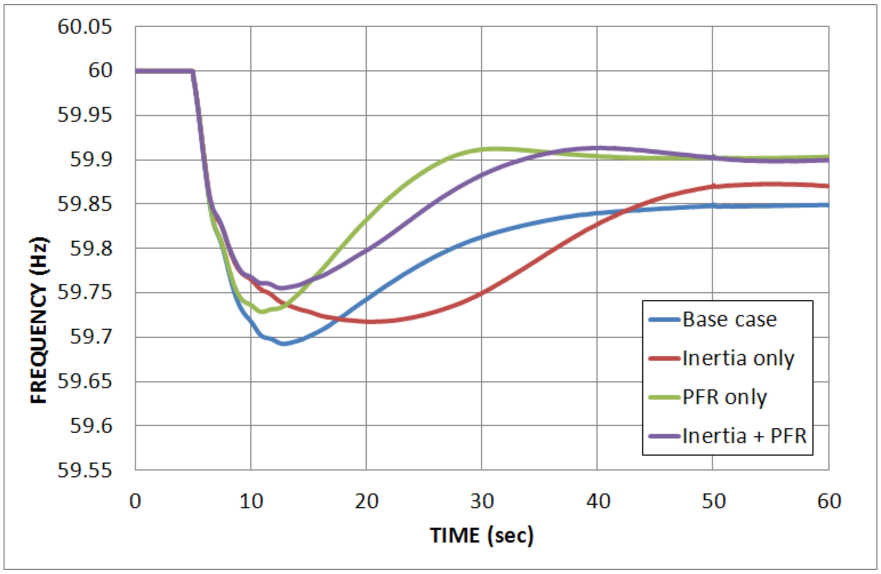


Figure 3-42. WI frequency response for 15% wind power penetration.

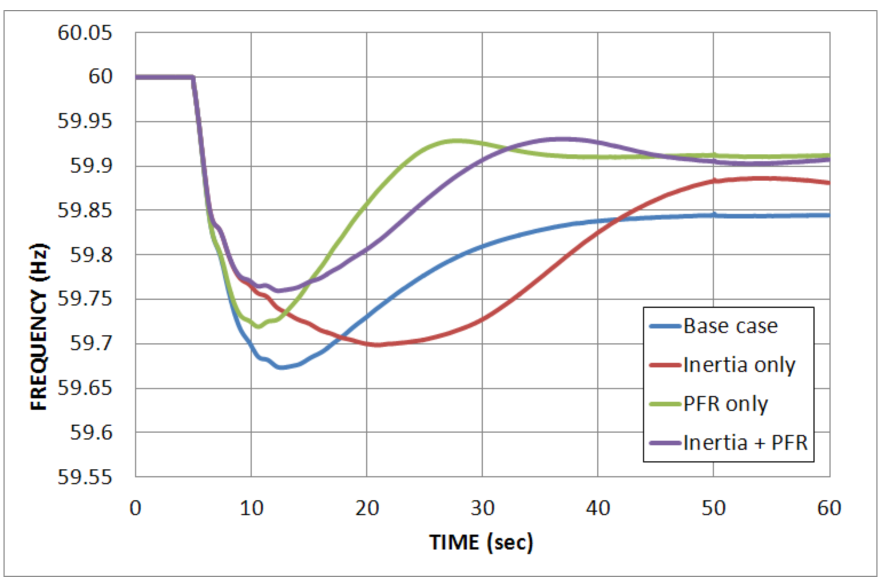


Figure 3-43. WI frequency response for 20% wind power penetration.

[4] Primary frequency response (PFR) and primary frequency control (PFC) are used interchangeably.

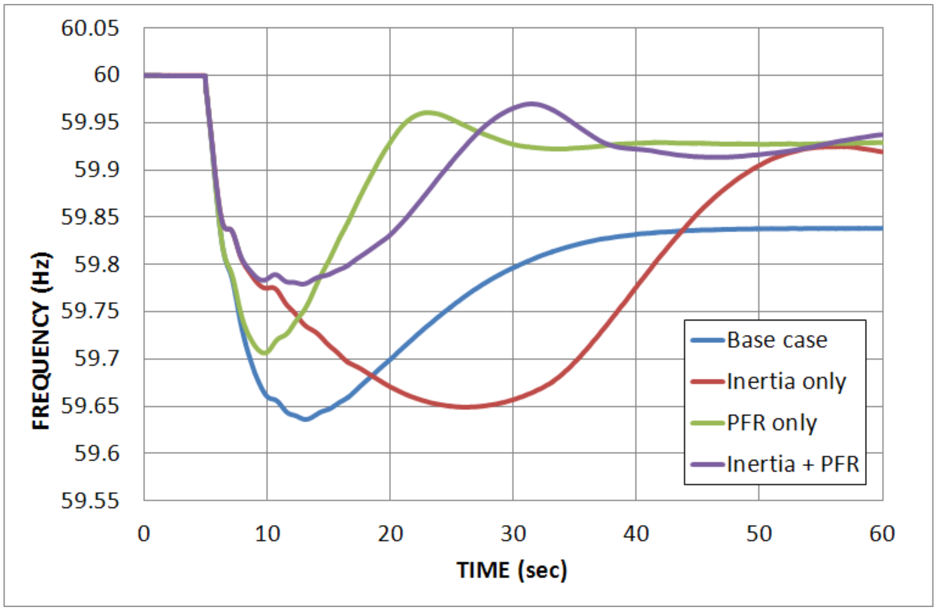


Figure 3-44. WI frequency response for 30% wind power penetration.

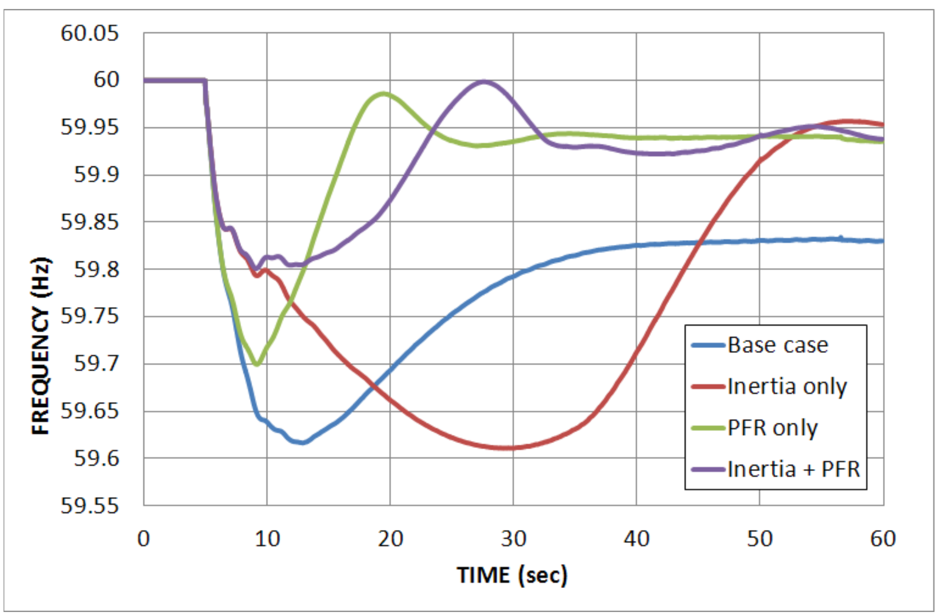


Figure 3-45. WI frequency response for 40% wind power penetration.

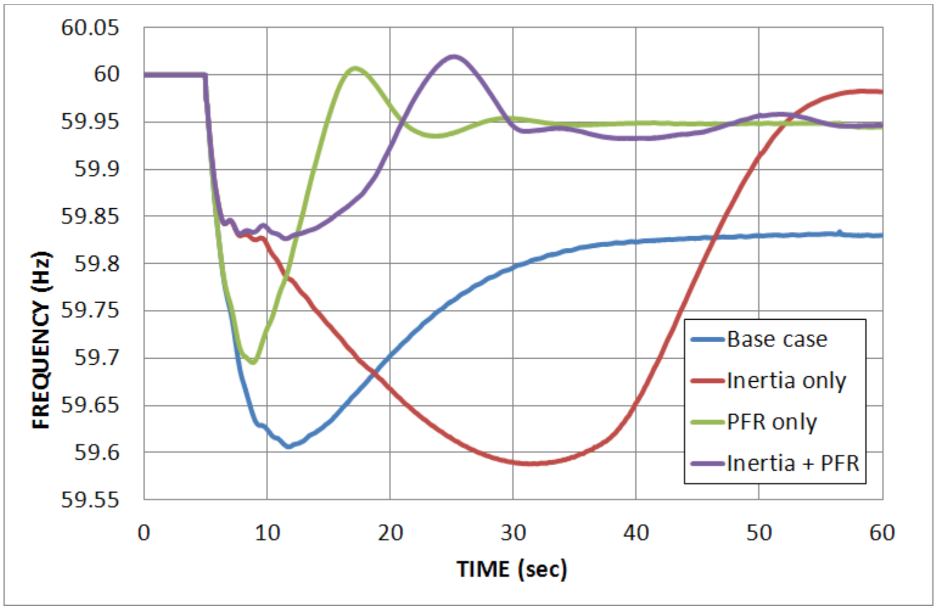


Figure 3-46. WI frequency response for 50% wind power penetration.

Further analysis of Figure 3-44 through Figure 3-46 reveals the impact of different APC strategies. The inertial control by wind power (red trace) shows a marginal improvement in frequency nadir compared to the base case for lower penetration levels (Figure 3-42 through Figure 3-44). At higher penetration levels, the frequency nadir is essentially the same as the base case at 40% penetration (Figure 3-45), and is lower than the base case at 50% penetration (Figure 3-46). The nadir transition time also shifts farther and farther right with increasing penetration levels. This is because inertial control alone only helps reduce the initial rate of frequency decline, which comes at the expense of slowing down wind turbine rotors. Because of this slowdown, the wind turbines depart from their maximum power point, thus creating a deficiency of active power (a period of underproduction relative to the initial pre-fault operating point), and resulting in slower frequency recovery time. In addition, as shown in Figure 3-42 through Figure 3-46, the recovery is of oscillatory nature with overshoots and takes longer to settle at a steady-state frequency (i.e., there is a longer transition to point B).

On the other hand, enabling the PFC feature creates visible improvement in frequency response, resulting in better nadir and higher steady-state frequency, as shown in Figure 3-42 through Figure 3-46 (green trace). The frequency nadir of the PFC-only case does not change significantly with penetration levels because of the same 5% headroom in all simulation scenarios. However, it is consistently higher than the base case nadir for all penetration cases. The recovery of frequency is almost as fast as in the base case, with some oscillatory behavior depending on penetration level. The biggest improvement is in the settling frequency level, which in the 50% case increases from 59.84 to 59.95.

Combining inertial control and PFC gives the most superior performance (magenta trace in Figure 3-42 through Figure 3-46). This control strategy results in a significantly higher frequency nadir with a somewhat slower recovery time compared to the PFC-only case.

Figure 3-47 shows the consolidated results of the simulations and the impact on frequency nadir for all penetration cases and wind power control strategies. Combining inertial and PFC for wind power results in a frequency nadir that is constantly increasing with penetration level (magenta trace in Figure 3-47), and has the best nadir performance at any wind power penetration level compared to other control strategies. Another conclusion (mentioned earlier), also shown in Figure 3-47, is that providing inertial control only does not give significant improvements compared to the base case (note that in this case all wind resources are below rated wind speed, and this result may differ if a percentage of wind plants are operating at above-rated wind speed). In fact, starting at approximately 36% to 37% wind power penetration, inertial control leads to lower frequency nadir compared to the base case. One important conclusion from Figure 3-47 is that the wind power inertial control by itself is not a significant contributor to frequency nadir improvements on the interconnection level, especially at higher wind penetrations; however, the impact of inertial control on nadir performance is highly beneficial when it is combined with PFC.

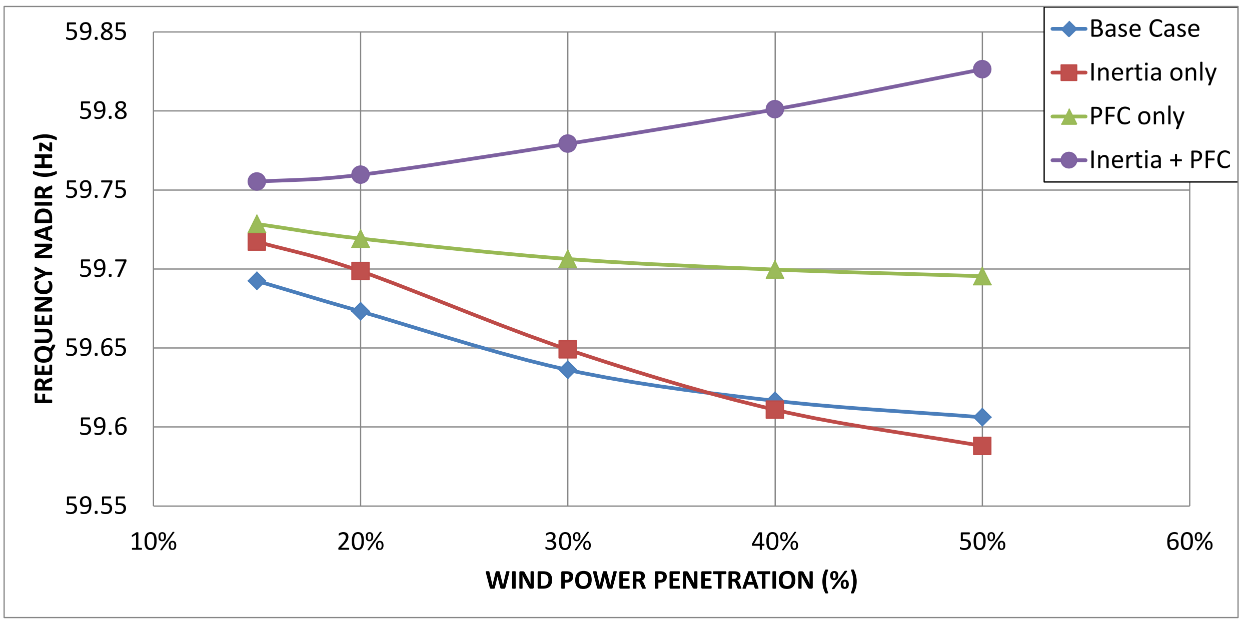


Figure 3-47. Impact of wind power controls on frequency nadir.

It is important to note that, despite the significant decline in frequency nadir for the base case, as wind power penetration increases (blue trace in Figure 3-47), it still stays above the highest UFLS setting of 59.5 Hz in the WI after the loss of the two Palo Verde units. The highest wind power penetration level, 50%, is still approximately 0.11 Hz above the UFLS setting. However, it is conceivable that some extreme conditions were not envisioned in the study that may result in unsatisfactory performance. In this regard, the advanced controls by wind power can help provide improved frequency response and reliability of the power system. Advantages of inertial control by wind power can be more obvious in smaller island systems experiencing inertia response deficiencies caused by high levels of inverter-based variable generation. In such an island system, the wind power inertia may play an important role in arresting the initial rate of change of frequency. The role of wind power inertia in island systems is a subject of separate study and will be investigated in future work.

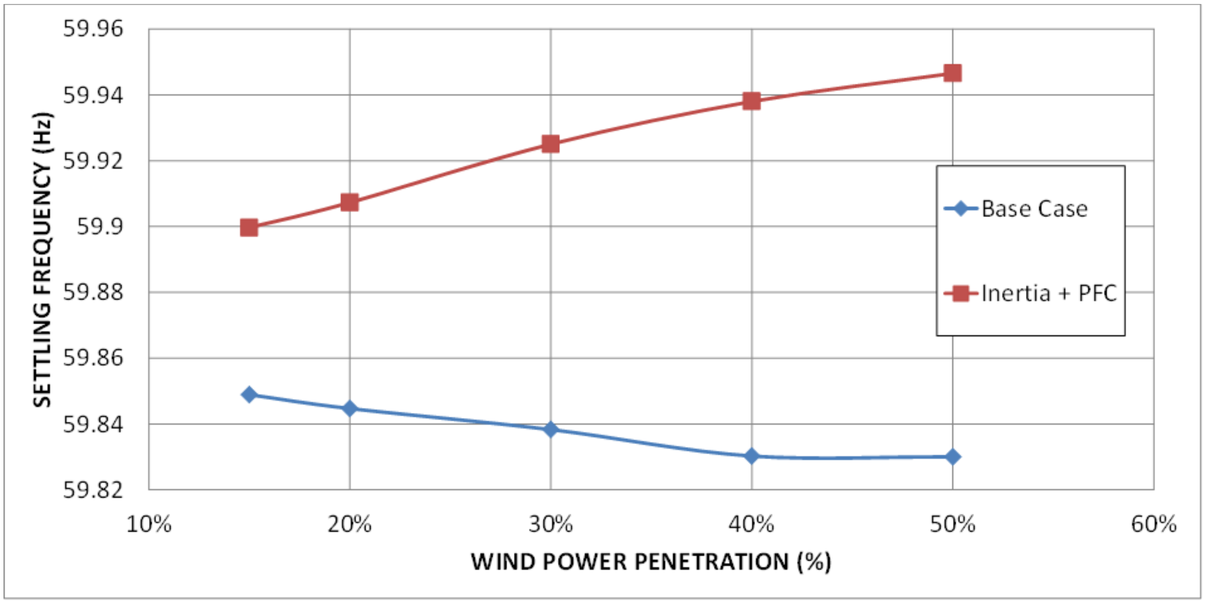


Figure 3-48. Impact of wind power controls on settling frequency.

The impact of wind power control on settling frequency is shown in Figure 3-49. The combination of inertial and PFC results in significant improvements in settling frequency at all penetration levels. Similar to frequency nadir, the settling frequency also increases with penetration level when wind power provides control. The frequency response of the WI was calculated from these settling frequencies and is shown in Table 3-5. Both MW/0.1 Hz and CB_R metrics show sufficient improvements in the overall frequency response of the WI. It is worth noting again that both metrics improve with penetration level when wind power provides a combination of inertial and PFC during the contingency event.

Table 3-5. Impact on WI Frequency Response

Case	Base Case		Inertia + PFC	
	MW/0.1 Hz	CB_R	MW/0.1 Hz	CB_R
15%	1737	2.035	2616	2.439
20%	1690	2.105	2830	2.592
30%	1623	2.250	3500	2.944
40%	1546	2.259	4232	3.208
50%	1544	2.317	4908	3.247

3.3.5 Impact of Wind Power Penetration Levels and APC Strategies on Generation Response

The APC provided by wind power will have a profound impact on the frequency response of conventional generation. Such an impact will become more obvious at higher penetration levels. The performance impact for selected WI conventional units during the same event is shown in Figure 3-49 through Figure 3-53. These figures allow for estimating the evolution of frequency response by combined-cycle, combustion, hydro, and nuclear units, respectively, depending on wind power penetration level and APC strategy provided by wind power.

A closer look at Figure 3-49 through Figure 3-51 reveals significant reduction in the active power output of single thermal and hydro units for the cases in which wind power was providing only PFC or a combination of PFC and inertial controls. These units were selected to represent a typical response of conventional generation units for each fuel type. The power contribution from each unit type was calculated as a percentage of its installed capacity, and increases with wind power penetration level for a base case (blue trace) when all frequency response is provided by the conventional fleet. The magnitude of power contribution by conventional units is higher when wind power is providing only inertial control (red trace). This is because conventional units must provide additional energy to compensate for periods of underproduction by wind power caused by the deceleration of wind turbine rotors. However, PFC and combined controls provided by wind power reduce the burden of frequency response by conventional units significantly, as shown in Figure 3-49 through Figure 3-53 (green and magenta traces).

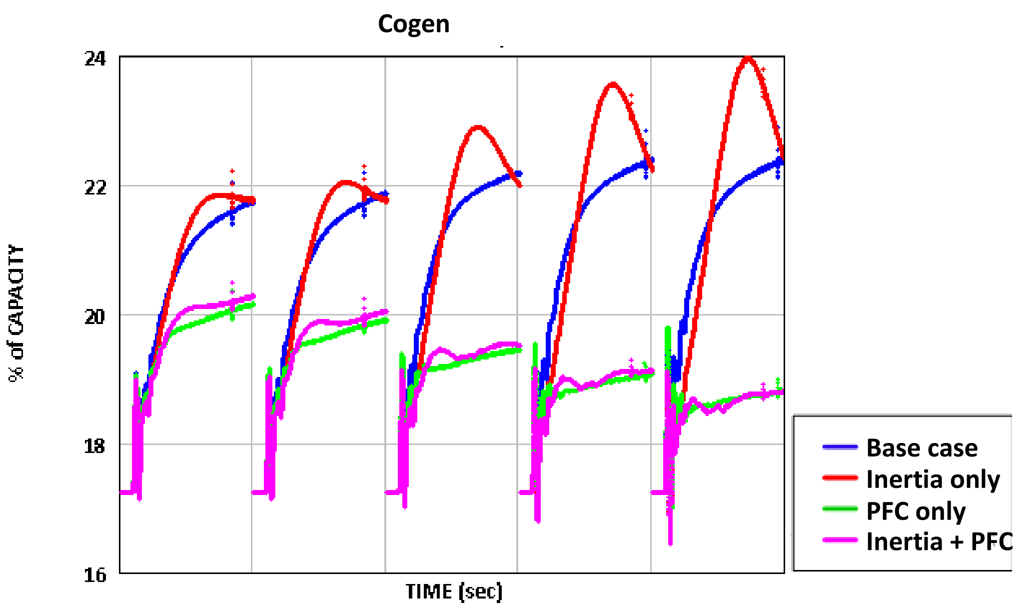


Figure 3-49. Frequency response contribution from cogen unit.

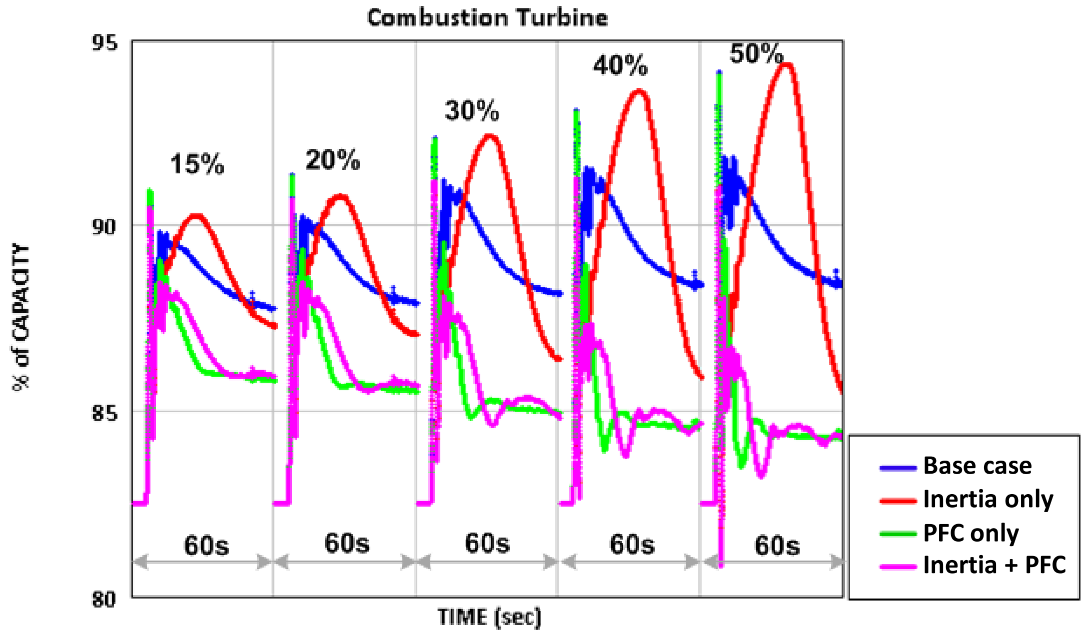


Figure 3-50. Frequency response contribution from combustion unit.

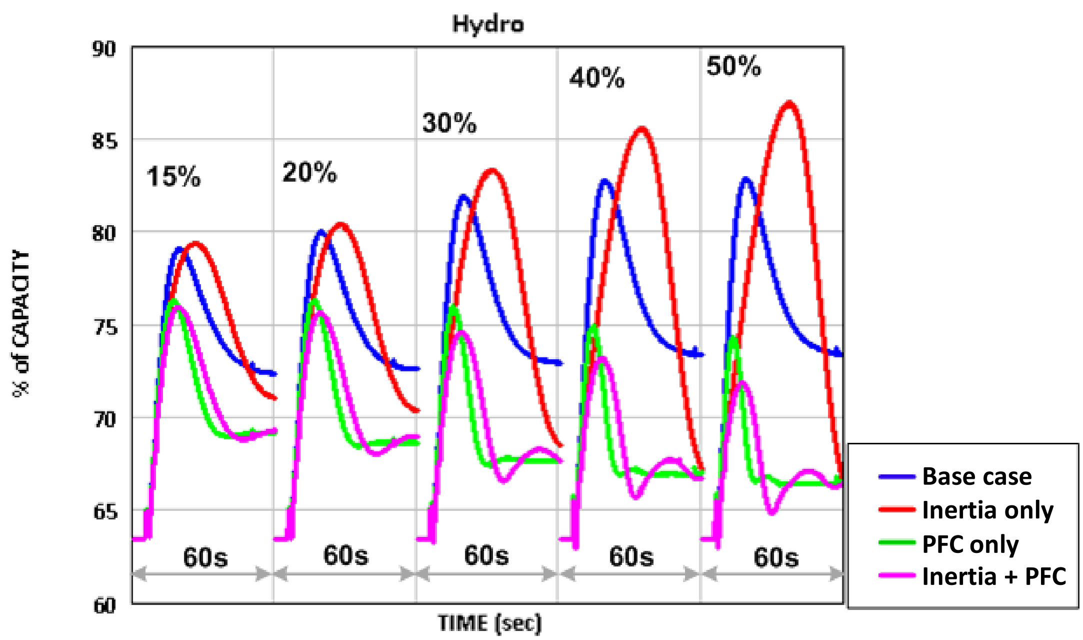


Figure 3-51. Frequency response contribution from hydro unit.

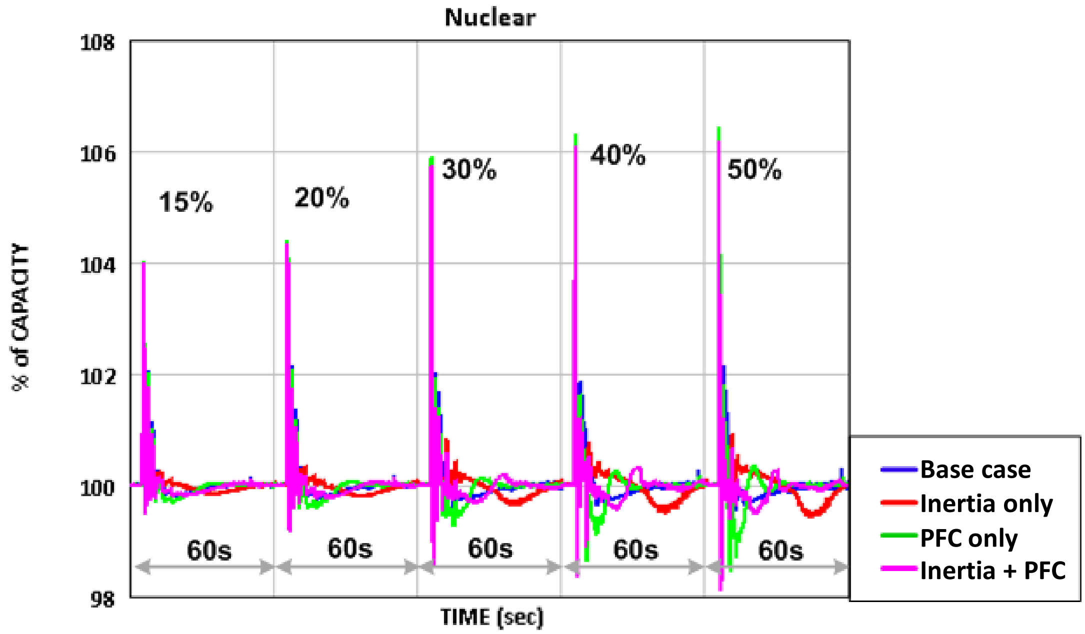


Figure 3-52. Frequency response contribution from nuclear unit.

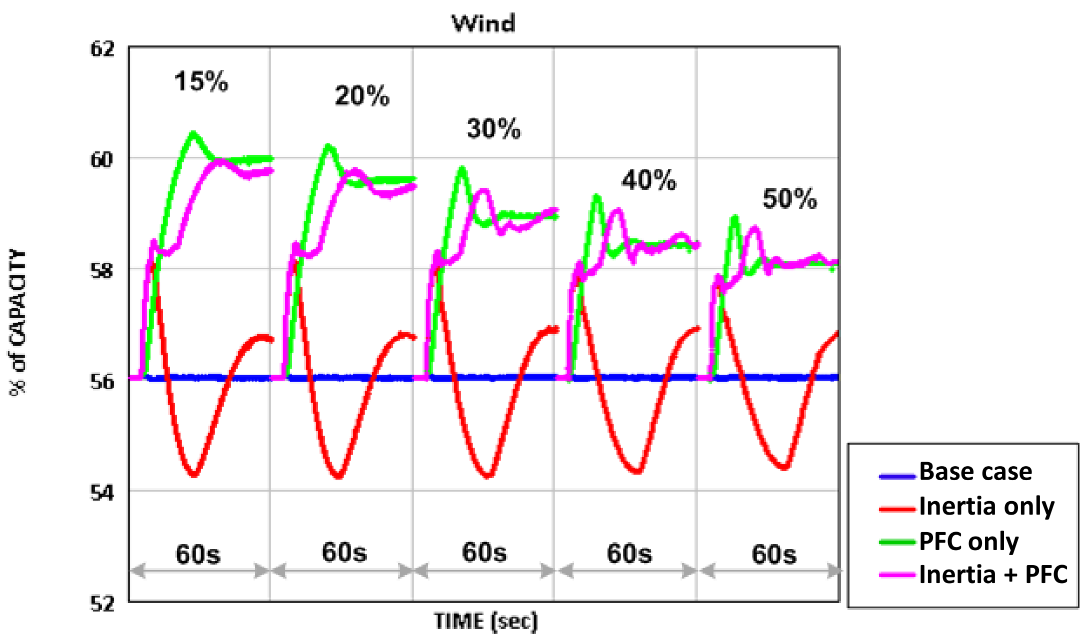


Figure 3-53. Frequency response contribution from wind power.

The impact on nuclear units is less obvious (Figure 3-52), because in this modeled case the nuclear power was not providing any PFC. The response of nuclear plants is only inertial and is not associated with governor response. The magnitude of such inertial response by synchronous generators is determined by the initial rate of change of the frequency immediately following generation loss.

The impact of wind power control strategies on the power output of the selected wind power plant is shown in Figure 3-53. The active power magnitudes do not change significantly with penetration when wind power is providing only inertial response (red trace in Figure 3-53). They do change, however, in the cases in which wind power is providing PFC or combined inertial control and PFC (green and magenta traces). In fact, the burden of frequency response on individual wind power plants decreases with penetration level because such response is spread among a larger number of wind power plants that are online.

It is important to note that the results presented here do not consider the economic impact of curtailing wind power to have 5% reserve margin to provide PFC. Based on the results above, such controls tend to improve the PFC of the system. Further analysis on providing rules during unit commitment or economic dispatch procedures can help ensure sufficient response at minimal cost (see Section 2.2).

3.3.6 Impact of Conventional Generation Frequency Response Participation

It was mentioned earlier that the simulated frequency nadir of the WI stays above the highest UFLS setting even at 50% wind power penetration with wind power providing no frequency response. Further simulations were conducted to determine the impact of K_t (as specified in Section 3.3.3) on frequency nadir. Simulations demonstrated that even for the 50% wind power penetration case, it takes $K_t = 40\%$ for the frequency nadir to go below the UFLS setting of 59.5 Hz. This finding is illustrated in Figure 3-54, in which the frequency response of the WI at 50% wind power penetration was simulated for different values of K_t. (UFLS features were disabled in these simulations.)

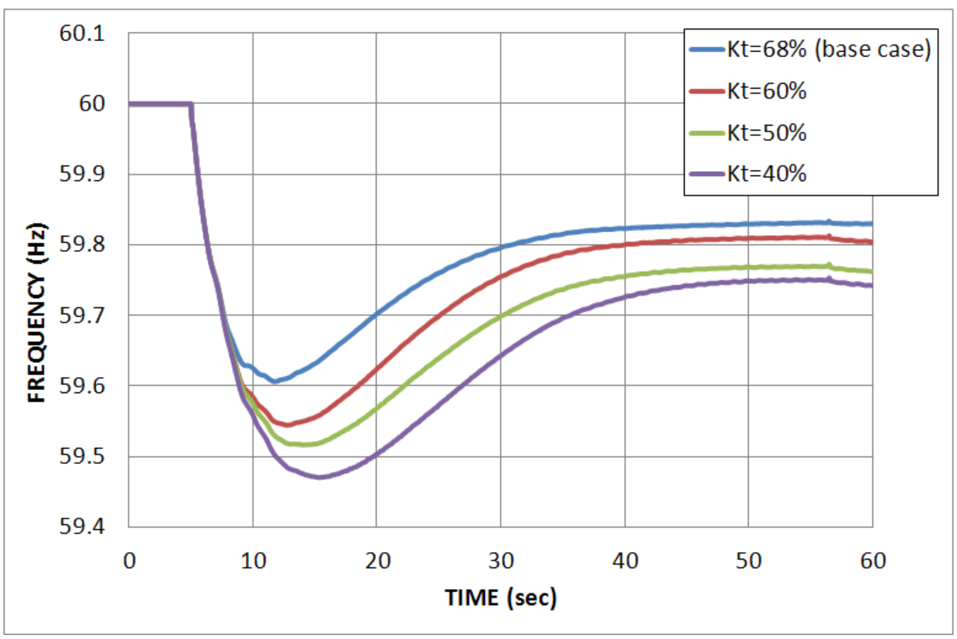


Figure 3-54. Impact of K_t for 50% penetration case (wind providing no APC).

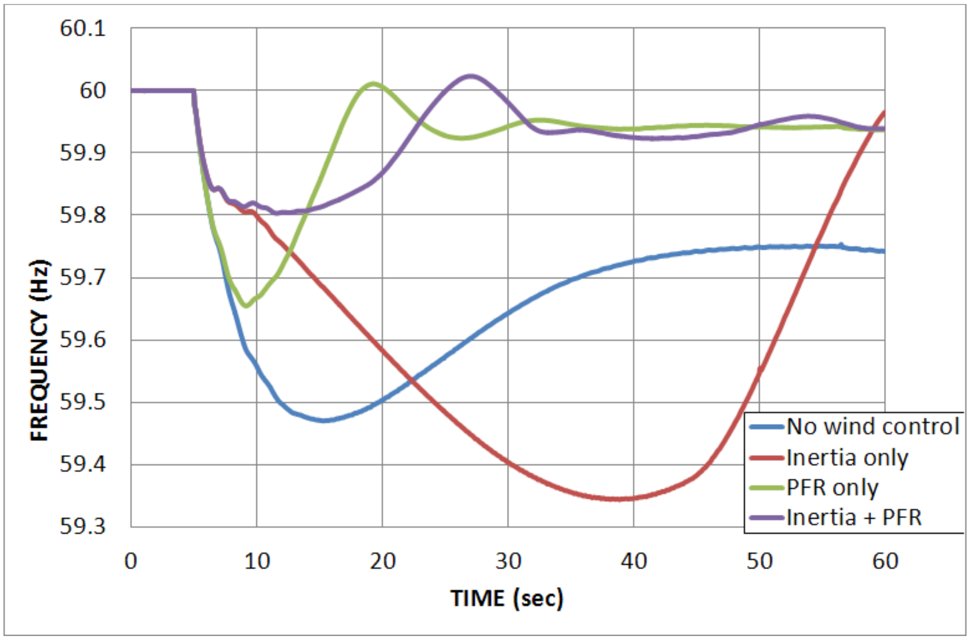


Figure 3-55. Impact of wind power controls (50% penetration and K_t = 40%).

As a next step, we conducted simulations for the case with 50% penetration and K_t = 40% to evaluate the impact of wind power APC strategies on frequency response of the WI with reduced governor response by conventional units. The results of these simulations are illustrated in Figure 3-55. The inertia-only control (red plot) demonstrates significantly lower performance compared to the base case when wind power was not providing any frequency response (blue trace). Such a high level of wind power penetration combined with fewer governor-enabled conventional generators causes a much deeper frequency nadir, slower nadir transition and recovery time, and potentially a large overshoot during frequency recovery. This simulation used the default model parameters for wind power inertial control. The inertial control from wind can be somewhat modified by further tuning these control parameters. Such parameter tuning is beyond the scope of this study and is the subject of future work.

On the other hand, both PFC and combined controls (green and magenta traces) show significant improvements compared to the base case. In particular, the combined control shows the most superior performance, resulting in a shallow nadir and fast recovery time. This hypothetical simulated case demonstrates the capability of wind power controls to provide frequency response under conditions with reduced PFC capabilities by conventional generation (K_t = 40%) at extremely high levels of wind power penetration, when wind power can assist in ensuring UFLS relays are not triggered.

3.4 Summary and Conclusions

The above insights on the impacts on frequency response performance under various penetration levels of wind power are by no means comprehensive. They are, however, an attempt to provide additional contributions to ongoing industry-wide discussions on the topic of frequency response of power systems with larger penetrations of variable generation and how providing APC from wind power can provide benefits to frequency performance and system reliability. Models that correctly simulate the power electronic controls of each wind turbine type are needed to correctly reflect the total system performance. An understanding of frequency behavior is needed to understand the ways in which these plants might have to respond in the future with these controls. The simulation effort was conducted specifically to investigate the frequency response of the WI after a large loss of generation to see if it was in danger of reaching levels that could trigger UFLS. Many factors and constraints (both technical and economic) affect the operation of the power system with high levels of wind generation. The depth of frequency excursions followed by generation loss can be improved by inertial and/or PFC controls of WTGs. The industry is concerned about having inadequate frequency response in light of this changing generation mix because of the increasing penetration of variable generation and planned retirements of fossil-fueled generation. Currently, the PFC from generation sources is not technology neutral. To consider all options toward improving the frequency performance, the industry needs to research, develop, and demonstrate newer and less familiar sources to provide frequency support and analyze how they contribute to the system response—and how that system response supports power system reliability.

The focus of the research presented in this report was to assess the impact of different APC strategies on the frequency response of an interconnection with a high level of wind power penetration. Inertial control and PFC from WTGs can be tuned to improve the frequency response of the system and can become an additional source of flexibility for power system operators. Further research on the proper tuning of this flexible control is needed to understand how WTGs can better support power system reliability.

Most of the simulations on the WI showed that even with high penetrations of wind power, when wind power is not providing APC, the system is not in significant danger of reaching frequency levels that trigger UFLS (exception being at very low conventional generation participation, or low *Kt* levels). This is the primary metric that has been studied in almost all the studies analyzing the frequency response performance, including that in Section 3.3 of this report, and in [1]–[2],[4],[29]. All simulations generally study a large disturbance with constant wind power for about a 30-second timeframe to ensure the system reaches the steady-state settling frequency. What these studies have not analyzed is how the deployment of both primary and secondary reserve control can interact with each other, which can lead to a better understanding of further reliability issues due to the variability and uncertainty of wind power in addition to the displacement of frequency-responsive units when wind power does not enact controls. Studies also have not understood how wind power can provide both primary and secondary frequency control simultaneously to help avoid reliability issues. This lack of longer-term dynamic modeling was discussed briefly in [1]. We believe this interaction must be studied to further the analysis of sufficient frequency control on an interconnection.

Another topic that was ignored in many of the previous studies—including this one—is the effects of the network during disturbance events. Understanding the stability of the transmission system during transient events with significant penetrations of wind power without controls, as well as understanding how wind power can help support transient stability with properly tuned controls, would be a significant contribution to the research to further evaluate power system reliability. For instance, analysis of how wind power plants can provide damping controls and the proper way to model this control is a research topic that warrants further study.

Finally, although not addressed in this report, we simply note that both inertial control and PFC as provided by wind generation are inherently stochastic. This is because the wind resource is highly variable. As such, future work will need to assess the impact of the stochastic nature of this resource when provided by wind power as opposed to inertial control and PFC provided by conventional generation, which are generally deterministic in nature.

References

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4 Controller Design, Simulation, and Field Testing

The final task of this report studies new active power control (APC) system designs and their performance using both numerical computer simulations and field tests. The focus of this work is on the development and testing of new controller designs that are capable of simultaneously actively de-rating, following an automatic generation control (AGC) command, and providing primary frequency control (PFC). Furthermore, this task evaluates the structural loading induced by the various APC designs. The controllers are designed in an environment (Simulink) that can be directly ported to the 3-Bladed Controls Advanced Research Turbine (CART3) for field testing at the National Wind Technology Center (NWTC). These controllers have been studied extensively in simulation and have been successfully tested in the field. Due to the higher presence of inertial control in commercial applications, and the team's agreement that inertial control is likely not the significant reliability need for the large interconnected systems of the United States (see Section 3), the team focused the controls work on PFC and AGC. The design process and simulation results have been published or have been accepted for publication [1]–[4].

The primary goal of traditional wind turbine control systems is to maximize power extraction up to the rated power of the turbine, where the goal becomes to regulate power capture at the rated value, often using a gain-scheduled proportional-integral (PI) pitch controller, which we will refer to as a "baseline pitch controller" [5]. In below-rated operation, these controllers typically attempt to maximize energy capture by keeping the blades pitched at the maximum aerodynamic power capture angle β_* and controlling the generator load torque τ_g to maintain the maximum power capture tip speed ratio λ_*, which is a particular ratio of blade tip speed to wind speed [5]. The controller tracks λ_* by commanding the generator torque to balance the steady-state aerodynamic torque using a well-known feedback control law $\tau_g = k_* \Omega_g^2$, where Ω_g is the measured generator shaft speed and the feedback constant k_* is determined by the aerodynamic properties of the rotor [6]. Providing APC services with wind energy requires modified control systems that can control the active power output to levels as directed by system frequency or system operator needs.

Over the past decade there has been an increasing level of interest from both industry and academia in researching wind power's provision of APC. Numerous wind turbine manufacturers have patented APC or APC-related designs since 2010. While the exact methodology of most industry technologies is proprietary, their capabilities are documented within their patents. General Electric's "GE WindCONTROL" [7] includes a suite of wind turbine APC systems that can de-rate the turbine or plant to specified power set-points, provide primary frequency control (PFC), and provide inertial emulation. Siemens has a patent for an APC system that has similar capabilities, enabling a wind turbine or wind farm to emulate governor PFC and ramp power up or down in response to grid frequency deviations [8]. De-rating and power-tracking APC systems have also been patented by Vestas [9] and Mitsubishi [10]. Experience from utility companies, such as Xcel Energy, has shown that a wind plant responding directly to the area control error (ACE) can provide exceptionally fast regulation responses and offer excellent ACE compliance [11].

Wind turbine APC has also been a focus of research performed in academia and elsewhere, investigating methods of implementing various frequency response and/or AGC regulation services and the effects and implications of wind turbines providing (or not providing) these services. The provision of up- and down-regulation services through wind plant APC has been demonstrated [12] to represent a situation where wind plant owners can simultaneously increase their own profitability while perhaps enhancing grid reliability. Miller and Clark provide a suite of proposed active power controllers including AGC, PFC, and inertial control [13]. Tarnowski et al. also explore the capabilities of wind turbines to provide a range of APC services [14]. In [15], the research focuses on the impact of providing frequency control from wind turbines. Methods for providing primary response are further explored in [16]. Providing de-rating by operating at higher-than-optimal tip-speed ratios is a method that has been explored recently in [17]–[18]. This method forms the basis for the most recent control system that has been developed in this report.

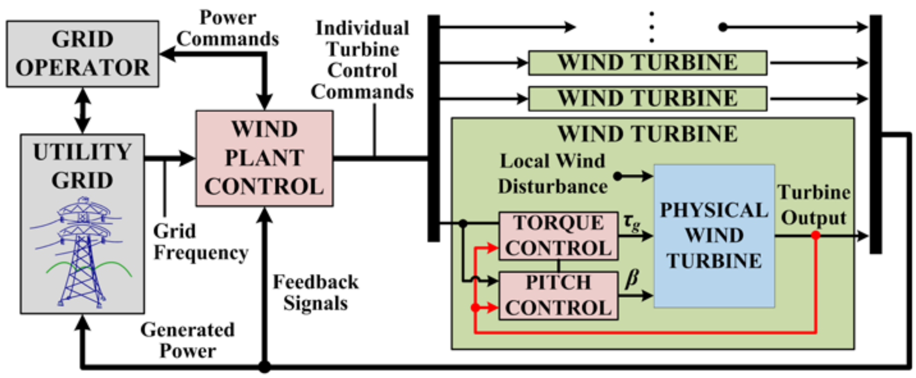

Figure 4-1. A schematic that shows the communication and coupling between the wind plant control system, individual wind turbines, utility grid, and the grid operator.

Two control systems have been developed and tested to implement APC on wind turbines that are capable of tracking a power reference signal. These control systems are designed to actuate the generator torque τ_g and the collective blade pitch angles β to track the desired power reference commands. The control systems are assumed to have access to grid frequency measurements and the ability to receive power commands from an external operator, referred to here as the grid operator for simplicity. The communication and coupling between the wind plant APC system, individual turbines, the grid operator, and the grid can be seen in Figure 4-1. It should be noted that the control systems presented here are for individual turbines, and the wind plant control system passes the power reference commands and frequency measurements to each turbine controller.

This section of the report is organized as follows. Section 4.1 summarizes the results of augmenting an initial control system with a dynamic droop curve to generate alternative PFC responses. Section 4.2 highlights the development of a new control system that is more straightforward and flexible than previously developed control systems. Section 4.3 focuses on the field tests with the new control system at the NWTC. Section 4.4 provides concluding remarks. For further details, see the full papers including [2]–[3] for Section 4.1, and [4] and [25] for Section 4.2 and 4.3. A general tutorial of APC strategies of wind power for the control systems audience can be found in [1].

4.1 Alternative Droop Curve Implementation for Primary Frequency Controller Design

4.1.1 Overview of Filtered Split Controller (FSC)

The first control system is adapted from a controller developed during the prior phase of this project, and described in [3]. This controller is designed to track an absolute power reference signal (i.e., with units of watts). This controller will be referred to as the filtered split controller (FSC), as it uses a band-pass and a low-pass filter to divide the power tracking control authority between the generator torque controller and blade-pitch controller, respectively. The FSC generator torque controller follows the traditional baseline control trajectory described in [5] at low frequencies, but is combined with a band-pass filtered perturbation torque command that is calculated to extract the commanded power for the given rotor speed. A lookup table is used to determine where the power command lies on the steady-state operating trajectory, and the corresponding rotor speed is low-pass filtered and used as a variable set point for the baseline gain-scheduled PI pitch controller, similar to the fixed set-point pitch control system defined in [5]. With this method, the control system uses the slower blade-pitch actuation to perform steady-state power regulation and the higher bandwidth torque actuation to provide a more rapid response to the power commands.

4.1.2 Augmenting FSC Control System with Droop Curves for PFC

A new methodology of using droop curve concepts with the FSC controller is proposed in [2]. Droop curves typically relate deviations in electrical frequency to a corresponding change in active power output in a governor for conventional synchronous generators. A wind turbine control system with a droop curve can allow for participation in PFC if measurements of grid frequency are available. This allows PFC power commands to be synthetically generated and passed to the control system, enabling an automatic response to changes in grid frequency in addition to active power set points requested by the grid operator, as long as there is sufficient power available from the wind and the turbine stays within the designed power limits. The research presented in [2] focuses on using static and dynamic droop curves with various parameters on a single wind turbine and analyzing the tradeoffs between the structural loads induced on the turbine and the grid frequency response after a loss-of-generation event when there are multiple wind turbines providing a PFC response on an island utility grid. The dynamic droop curves (DDCs) had variable slopes and deadbands that became more aggressive in response to greater rates of frequency change, so long as the rate of change of frequency (ROCOF) and the frequency perturbation had the same sign. The performance of the APC system is compared when using two different DDCs and three static droop curves (SDCs). The five droop curves are detailed in [2]. There are three DDC cases considered, each described by three parameters: ROCOF thresholds, slope range, and deadband range. The ROCOF thresholds parameter describes the range of ROCOF for which the slope and deadband are linearly interpolated between the bounds of the corresponding bounds of the slope range and deadband range, respectively. The three DDC cases have the following parameters: DDC1 has ROCOF thresholds of 5 – 10 mHz/second and slope range of 5 – 2.5%, DDC2 has ROCOF thresholds of 1 – 5 mHz/second and slope range of 5 – 2.5%, and DDC3 has ROCOF thresholds of 5 – 10 mhz/second and slope range of 7.5 – 5%. All three cases have deadband ranges of 50 – 0 mHz.

4.1.3 Individual Turbine Simulations

Simulations at the individual turbine and grid level were carried out to evaluate the performance of multiple droop curves combined with the FSC APC system. Individual turbine tests were carried out using the FAST wind turbine response simulation code developed by NREL [19]. The simulations used five 600-second stochastic wind fields, each with a mean wind speed of 18 m/s, and each including a single under-frequency event. The results were averaged over the five simulations for each droop curve considered. Data from an under-frequency event, measured during a disturbance on the Electric Reliability Council of Texas (ERCOT) grid, was used as the electrical frequency input. The effect of the droop curve and controller on the turbine was measured in terms of the damage equivalent loads (DELs) that were induced on the turbine components during the simulations. DELs are a standard metric for comparing fatigue loads in wind turbine components [19].

Varying the parameters of the static droop curves affected the intensity of the induced structural loads. Compared to a constant power baseline case, augmenting the power reference with a droop curve increases the structural loads on the turbine when using any of the droop curves. The more aggressive SDC2 response to the frequency event, characterized by the 2.5% droop curve with no deadband, had the effect of increasing all of the measured DELs relative to SDC1, as the SDC2 droop curve causes the power reference to change more dramatically compared to the SDC1 case. The effects on DELs of using the dynamic droop curves are more complex than those caused by the two static droop curves. In general, the DDC cases have induced DELs to levels between those induced by the SDC cases. It should be noted that the increases in DELs when the wind turbine is providing PFC are significantly amplified because the grid frequency events occurred every 600 s during the simulations.

4.1.4 Grid Simulation Results

A simple simulation of a power grid represented as a single bus was used to analyze the effects of the APC controller in coordination with conventional generation during a frequency event. The system includes hydro, wind, and steam turbine generating plants producing 40%, 15%, and 45% of power, respectively. Figure 4-2 shows the grid frequency for simulations where the non-reheat steam turbine (5%) abruptly goes offline at time $t = 1000$ s. In the "no wind" case, the wind plant is replaced with a steam turbine. When the wind plant is operating with its normal ”baseline” control system set to simply track a constant power reference, the frequency response is worse due to the reduced amount of conventional generation providing frequency response. It should be noted that this effect assumes that wind fully decommits another generating plant (a steam turbine in this case).

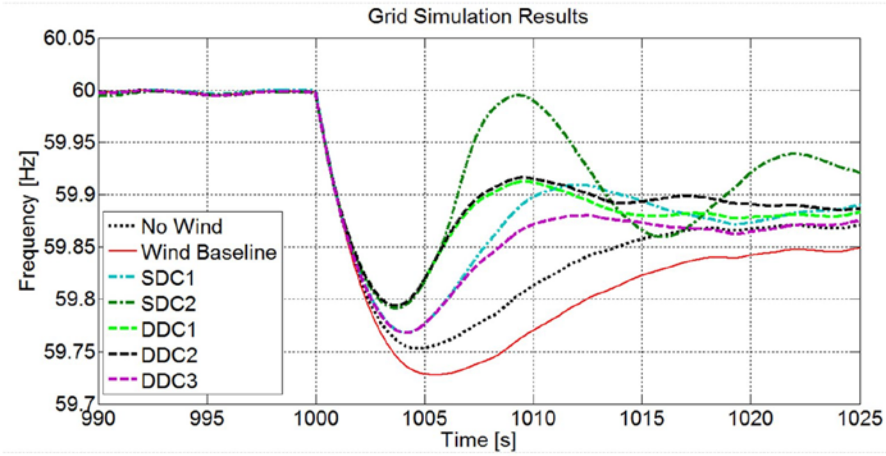

Figure 4-2. Simulation results from a single bus power system. At $t = 1000$ s, 5% of generating capacity goes offline. The system response with all conventional generation is compared to the cases when there is a wind plant at 15% penetration without wind plant control or with the droop curve and APC system configurations.

The aforementioned FSC APC system was simulated in the grid model using the same droop curves used for the individual turbine simulations. It can be seen in Figure 4-2 that the frequency response is affected when the APC system is augmented with the static droop curves. The smallest deviation from nominal frequency is achieved with the SDC2 case, but this also causes large, undesirable oscillations as frequency recovers to nominal. The SDC1 case results in improved frequency response over both the "no wind" and baseline wind cases. At the nadir, the grid frequency has deviated further from nominal than in the SDC2 case, but there are no oscillations during the recovery in the SDC1 case. Figure 4-2 shows that the use of dynamic droop curves results in improved performance in all three cases over both the "no wind" and baseline simulations. Additionally, in the DDC1 and DDC2 simulations, the grid frequency recovery is improved compared to the SDC1 simulation and is comparable to the initial recovery of the SDC2 simulation. The improved grid response to loss of generation achieved in the DDC1 and DDC2 cases comes at the cost of generally higher induced structural loads on the turbine compared to the SDC1 case. However, these dynamic droop curve cases offer a general decrease in structural loads when compared to the SDC2 simulation. Similar simulation studies will be carried out with newer control designs and higher fidelity grid models in order to validate the results shown here.

4.2 Development of a New Wind Turbine Active Power Control System

4.2.1 Overview of Torque-Speed Tracking Controller

The second control system, which will be referred to as the Torque-Speed Tracking Controller (TTC), uses the standard PI pitch controller (to regulate the turbine speed at rated value) and tracks the power commands through the torque controller, as described in [4]. The torque controller can directly track the desired power command when the turbine is operating at rated speed because the blade pitch controller regulates the turbine speed, and the generated power is the product of the generator torque and generator speed $P_g = \tau_g \Omega_g$. The torque controller uses a modified version of the standard generator torque feedback control law to track the power commands when operating below rated speed. The torque controller achieves the de-rating in below-rated-speed operation by operating the turbine at a higher-than-optimal tip-speed ratio, which also stores kinetic energy in the rotor that can be extracted in the case of an under-frequency event. The TTC is capable of operating in three de-rating modes, can provide PFC, and can track a time-varying AGC power command, as long as the power commands do not exceed the power available from the wind. The TTC APC system was analyzed thoroughly via simulation and ported to the CART3 for field testing in the 2012/2013 wind season at the NWTC (September 2012 through April 2013). A test plan was developed and the CART3 control system was augmented for operator control of the APC testing (see Section 4.3). The field testing produced important data on the performance of the various APC services through wind turbines, as well as information about the induced loading on turbine components as a result of providing APC through the use of the extensive sensors installed on the CART3.

The TTC controller is designed with three de-rating modes, which are depicted in Figure 4-3:

- **Mode 1 –** Absolute power set-point, where the turbine will produce maximum power up to the desired power set-point
- **Mode 2 –** Absolute power reserve, where the turbine keeps a specified amount of power as reserve power capacity below the power available in the wind
- **Mode 3 –** Percentage reserve, where the turbine will capture a certain percentage of the power available in the wind.

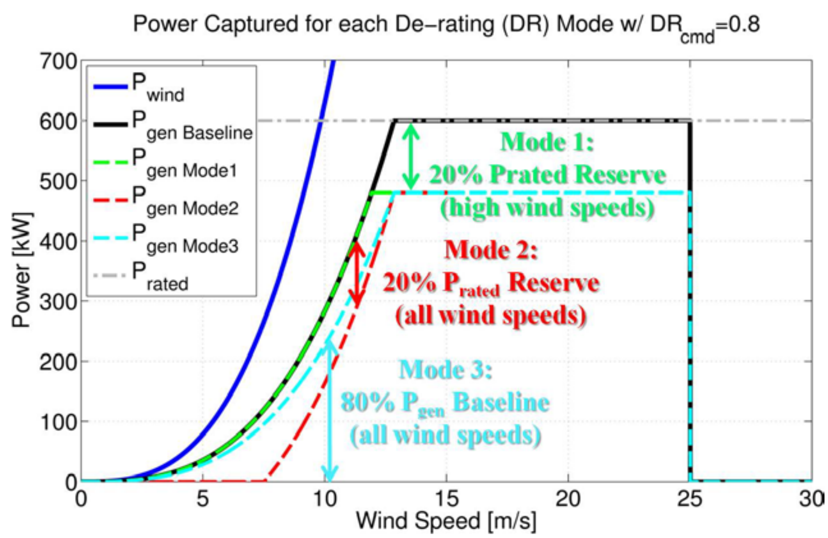

Figure 4-3. A depiction of the steady-state power commands in each de-rating mode when a de-rating command of $Dr_{cmd} = 0.8$ is used.

To implement de-rating modes 2 and 3, an estimate of the power available in the wind must be obtained. This is done by utilizing a simple wind speed estimator to estimate the rotor effective wind speed, and calculating the power available from this wind. The wind speed estimator uses a straightforward method of determining the aerodynamic torque based on the measurements of high-speed shaft torque τ_{hss}, blade pitch β, generator speed Ω_g, and generator acceleration $\dot{\Omega}_g$, which are common feedback signals for wind turbine control systems. The wind speed is calculated based on a torque balance equation and a characterization of the rotor power coefficient produced with NREL's WT_Perf rotor analysis code [21] using the method described in [22]. The wind speed estimate is low-pass filtered to avoid unstable feedback coupling when the power commands are based on the estimated wind speed, therefore affecting the control of the turbine states.

A block diagram of the TTC wind turbine control system can be seen in Figure 4-4. This control system is designed to be capable of receiving step power reference commands so that the controller can handle commands with any rate of change. The total power commanded from the turbine is the de-rating power command plus the AGC and PFC power commands. The TTC control system uses two different methods to track the power commands depending on whether or not the pitch control system is actively regulating the turbine to rated speed, dividing the control system operation into two regions: rated speed operation and below-rated speed operation.

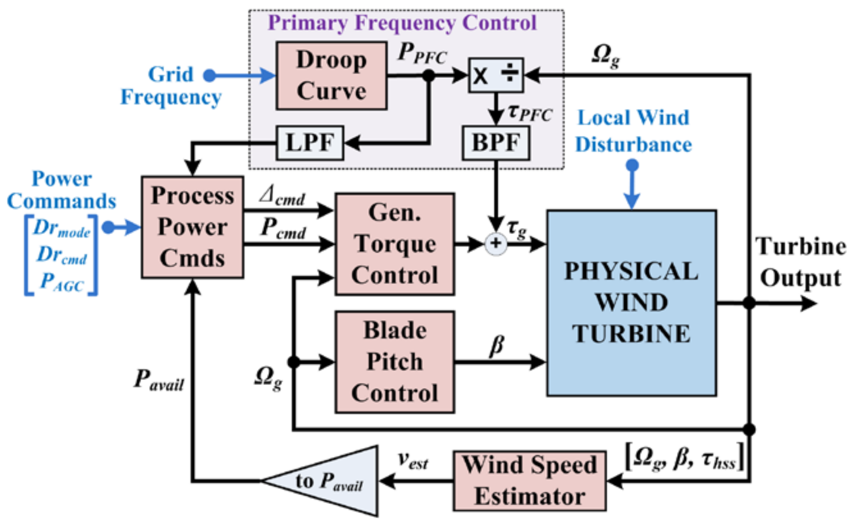

Figure 4-4. A block diagram of the TTC APC wind turbine control system with a wind speed estimator. The “Power Command” inputs Dr_{mode} and Dr_{cmd} determine the method and level of de-rating, and P_{AGC} is a power command that is an additive perturbation to the de-rated power. The control system can also provide PFC by processing the measured grid frequency in the "Primary Frequency Control” block, using a droop curve to generate the PFC power command P_{PFC} that is split using a low-pass filter (LPF) and band-pass filter (BPF).

TTC Below-Rated Speed Operation

The control system de-rates the wind turbine in below-rated speed by varying the generator torque to obtain a sub-optimal tip-speed ratio (TSR). The blades are kept at β_* when operating below rated speed because the blade pitch actuator used is the baseline pitch actuator, which operates to prevent the turbine from exceeding rated speed. A method of de-rating the turbine in this manner was presented in prior research, where the turbine operates at a higher than optimal tip-speed ratio. As seen in Figure 4-5, there are two rotor speeds that can achieve a particular de-rated power level for a given wind speed. The higher of these speeds is chosen so that there is more inertia stored in the rotor. This allows for a better PFC capability to under-frequency events by extracting some of the additional kinetic energy of the rotor, which slows the turbine to operate at a higher power coefficient, as described later in this report. Though the fundamentals of this method are presented in prior research, those studies focus on the inertial/primary controls with a constant power de-rating command from a power electronics viewpoint and do not consider practical speed limitations and interactions between the torque and pitch controllers. Prior studies also do not consider how to transition from one de-rated value to another.

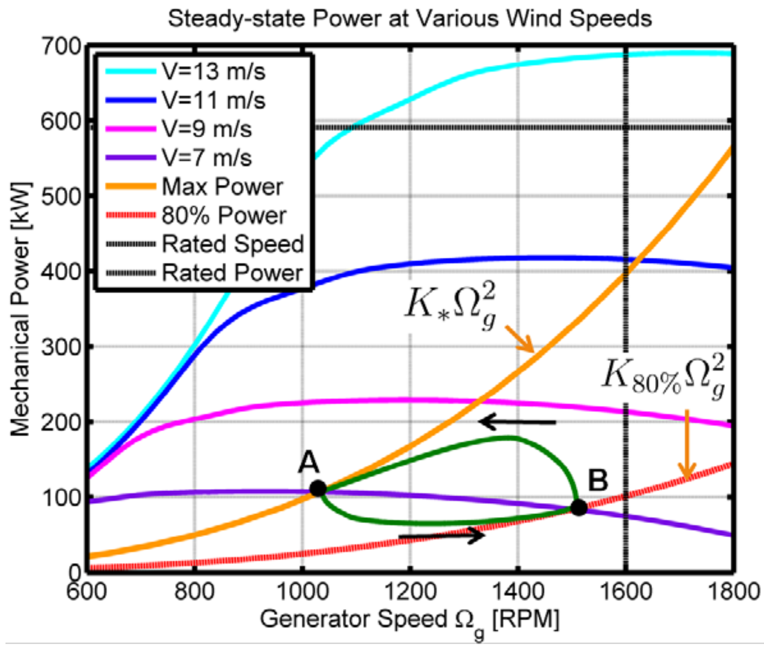

Figure 4-5. Various steady-state power capture curves for given wind speeds at β_*. The "Max Power" curve is the trajectory of the turbine that achieves maximum power capture for each wind speed by controlling the generator torque to be $\tau_g = k_*\Omega_g^2$. The "80% Power" curve is the trajectory that leaves 20% reserve power via rotor speed control and can be achieved by controlling generator torque as $\tau_g = k_{80\%}\Omega_g^2$. The dark green curves (and corresponding arrows) show the turbine trajectories during transitions between 80% and 100% power at a constant wind speed of 7 m/s.

It can be seen in Figure 4-5 that for each percentage delta (mode 2) de-rated power level, a different torque feedback gain k_{Dr} must be used to control the generator torque as $\tau_g = k_{Dr}\Omega_g^2$, as shown for the "Max Power" and "80% Power" trajectories. A lookup table is generated to determine the appropriate feedback gain for a given percentage delta de-rating power command signal. The feedback gain is then low-pass filtered to avoid rapid torque actuation. The turbine will follow these trajectories until it reaches rated speed.

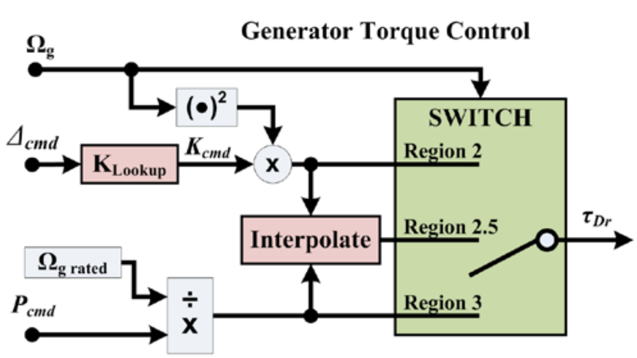

Figure 4-6. A detailed schematic of the de-rating torque controller block.

TTC Rated Speed Operation

Once the turbine reaches rated speed, the blade pitch actuator is enabled to prevent the turbine from exceeding rated speed. To meet the de-rating power set point when operating at rated speed, the torque can be commanded to be the absolute power command divided by the rated speed. The absolute power command is calculated from the de-rating power command and the estimated power available from the wind. The de-rating power command is low-pass filtered to avoid rapid torque actuation. The de-rating power command can be tracked more rapidly than the power command below rated speed, where the torque feedback gain must be changed slowly to avoid large power spikes.

The torque controller switches between below-rated and rated-speed operation by implementing a transition that linearly interpolates between the torque commands of the two operating regions when the rotor speed is between 92% and 97% of the rated rotor speed, similar to the "Region 2.5" as described in [5].

AGC Regulation

The TTC control system is capable of tracking an AGC power command to participate in grid frequency regulation. The AGC power command is viewed as an additive perturbation to the de-rating power command and can be scaled to different participation levels to regulation up and regulation down commands. The AGC participation levels are normalized to the rated power of the turbine when in de-rating mode 1 or 2 and normalized to the power available in the wind when operating in de-rating mode 3.

Primary Frequency Control

In the same way as the FSC controller, the TTC controller is able to perform PFC by using a droop curve. The controller measures grid frequency, and calculates a PFC perturbation power command P_{PFC} based on the grid frequency deviation, droop curve parameters, and rated turbine power. The PFC power command is low-pass filtered, and then added on top of the de-rating power command. The PFC power command is also converted to a PFC torque command, which is band-pass filtered and added directly to the output of the torque controller to allow faster PFC response, as seen in Figure 4-4.

4.2.2 Torque-Speed Tracking Controller Simulation Results

Simulations of the TTC were performed at the individual turbine and grid level. Grid level simulations were performed to show that the TTC control system can successfully provide a PFC to a loss-of-supply event, as seen in Figure 4-7. While more extensive testing and analysis is to be performed, these preliminary results are promising in demonstrating that a wind plant outfitted with a PFC-capable APC control system can provide PFC comparable to a traditional generating utility, such as a natural gas plant. In the simulation case shown in Figure 4-7, enabling PFC in all of the wind plants on the grid improves the grid robustness in response to a loss of generation compared to a case where only natural gas and coal plants provide PFC.

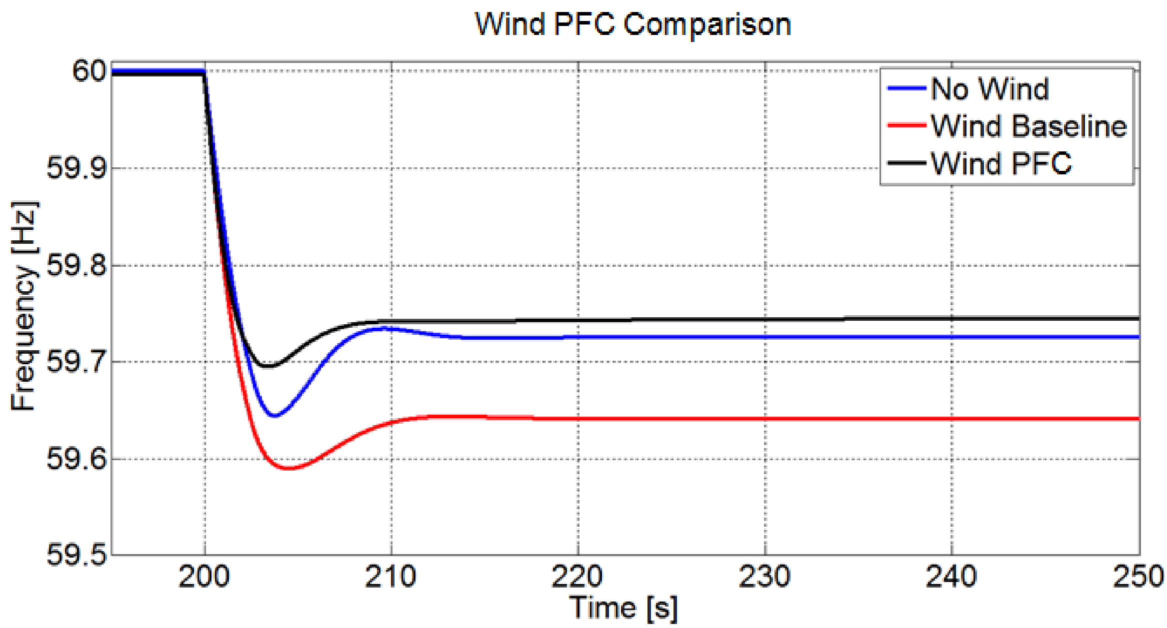

Figure 4-7. A simulation performed on the IEEE Reliability Test System grid model [23] run as an island grid with 56.7% natural gas, 40% coal, and 3.3% nuclear generation for the "No Wind" case. At time 200 s, a single coal plant, which is 5% of total generation, is suddenly disconnected. For the other two scenarios, four wind plants are placed on the grid, comprising 40% of generation. To achieve this, three gas plants are decommitted and two gas plants are de-rated. In the "Wind Baseline" case the wind plants are operating with a traditional baseline control system, and in the "Wind PFC" case the wind plants are using the TTC control system and are de-rated by 10% of their rated power, but are scaled to produce equivalent generation as the "Wind Baseline" case. In the "Wind PFC" case, the wind plant provides PFC and uses a droop curve with a 5% slope.

Individual turbine simulations were performed using stochastic turbulent wind fields to further assess the controller performance and analyze the DELs induced on the turbine components for varying levels of constant de-rating delta set-points. Plots of two of the individual turbine simulations can be seen in Figure 4-8 and Figure 4-9.

The PFC component of the control system is demonstrated in Figure 4-8. A frequency reference signal, comprised of three recorded grid frequency events on the ERCOT grid, is used to generate the PFC power commands. The turbine was simulated with an above-rated turbulent wind field and with a constant de-rating command signal so that the variation of output power due to the PFC can be seen more clearly.

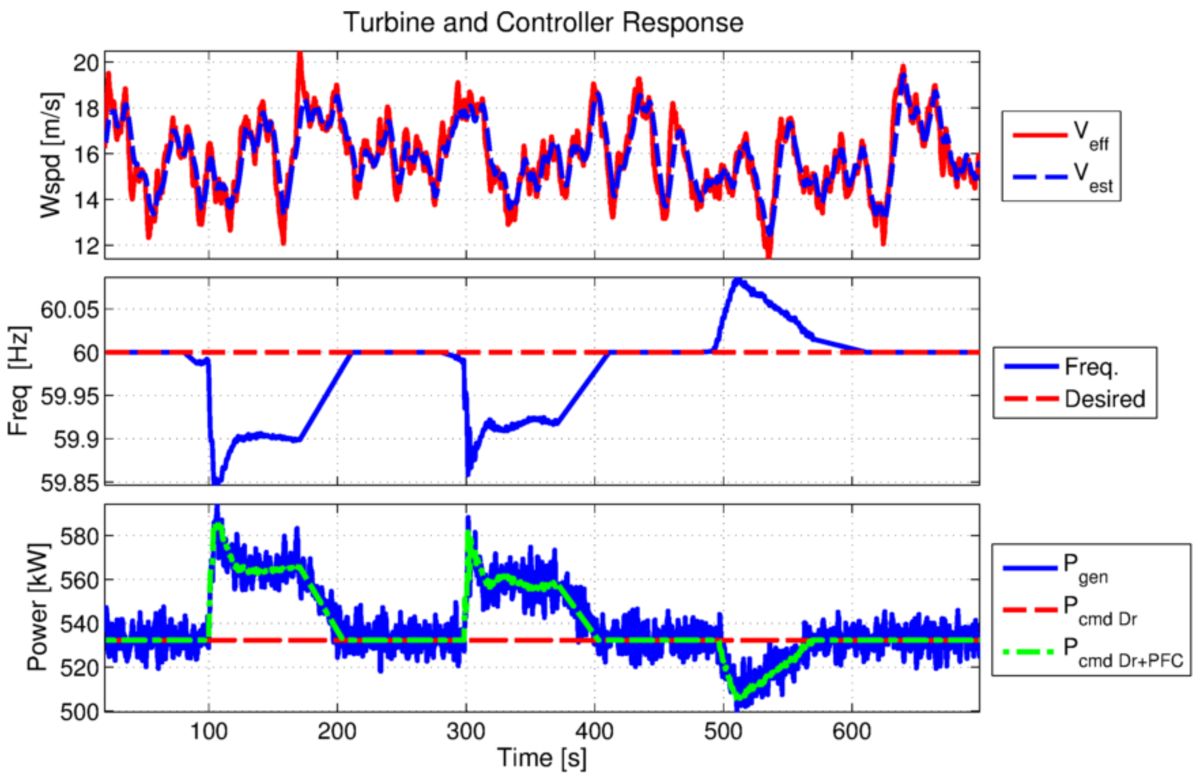

Figure 4-8. Simulation results for a turbulent 16 m/s wind field with a de-rating command of 0.9 in de-rating mode 1, a droop curve slope of 2.5%, and deadband of 17 mHz. Recorded data from grid frequency events were passed into the controller near the 100-, 300-, and 500-second marks to show the PFC.

The control system is also tested when providing both AGC and PFC during simulation performed with an above-rated turbulent wind field, as seen in Figure 4-9. Here the de-rating command is 0.8 as a fixed power set-point and the AGC and PFC power commands are added to this set-point. The power output in the bottom subplot shows that the turbine provides good tracking of both PFC and AGC power commands.

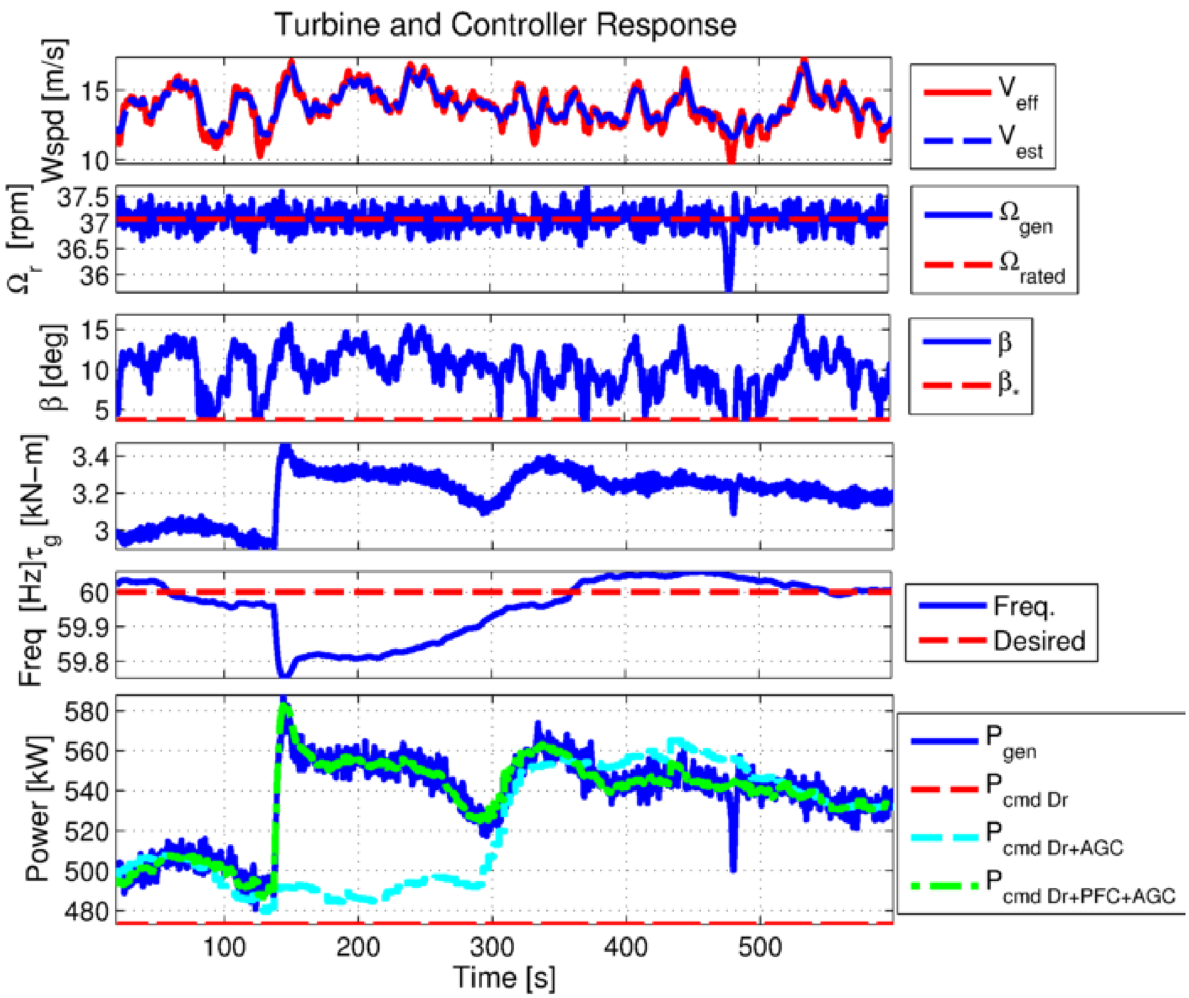

Figure 4-9. A simulation of the turbine and control system with above-rated turbulent winds showing AGC and PFC capability. The control system is operating in de-rating mode 1 with de-rating power command of 0.8. The AGC power commands were derived from the ACE that was recorded at a different time than the grid frequency data that was passed into the controller, which uses a 2.5% droop curve to generate the PFC commands.

The TTC control system is also simulated in FAST to determine the effect of de-rating and participation in regulation on the DELs. These DELs are calculated by simulating the wind turbine with 5 hours of turbulent wind fields and using NREL's MLife post processing code, as described in [24]. The effects of using a de-rating command of 0.9 for each de-rating mode are shown normalized to the baseline maximum power capture control system in Figure 4-10. The results indicate that de-rating commands of 0.9 reduce the DELs for every component under consideration. Figure 4-10 shows these DELs alongside the DELs when AGC participation is 10% both up and down. It can be seen that AGC participation has very little effect on the DELs.

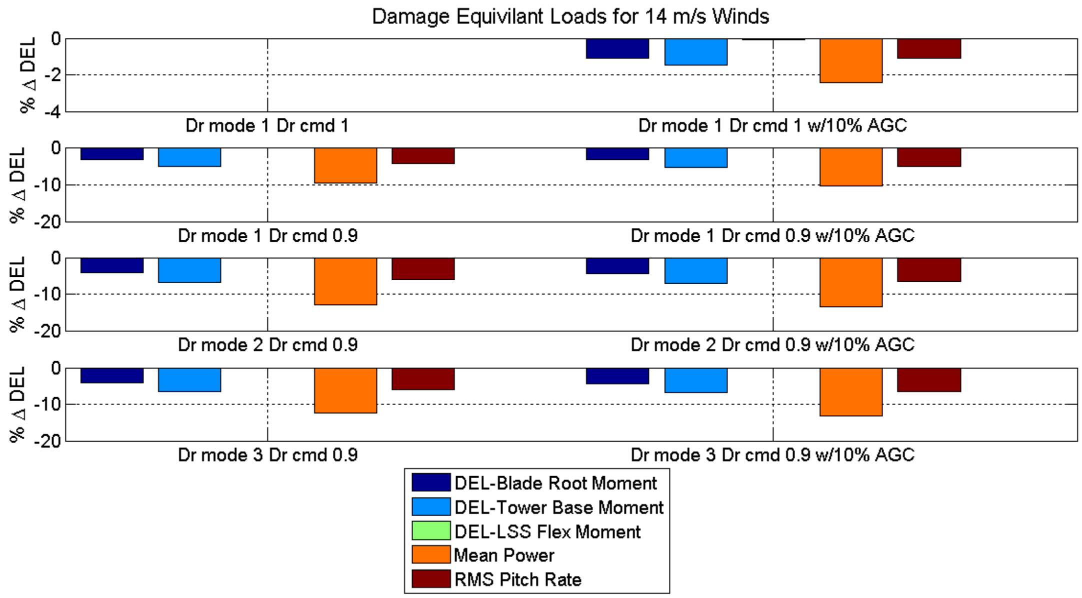

Figure 4-10. The induced DELs on turbine components and induced pitch rates compared to the baseline control system (Dr_{mode}=1 Dr_{cmd}=1 as shown in the top left). The DELs are calculated with MLife [24] using FAST simulation data [20]. The DELs are shown for each de-rating mode with a constant Dr_{cmd} without AGC and with 10% participation in AGC. The participation in AGC has very little impact on the overall DELs. The upper right hand data was generated with no de-rating and 10% participation in regulation down.

4.3 Field Testing

4.3.1 Initial Field Testing

Initial field-testing of APC was carried out on the CART3 wind turbine with the FSC control system. The controller tested was one of the pitch-control strategies proposed in [3]. The controller tracked an artificial power reference command while the turbine operated in rated wind speeds. Figure 4-11 shows the results of this test.

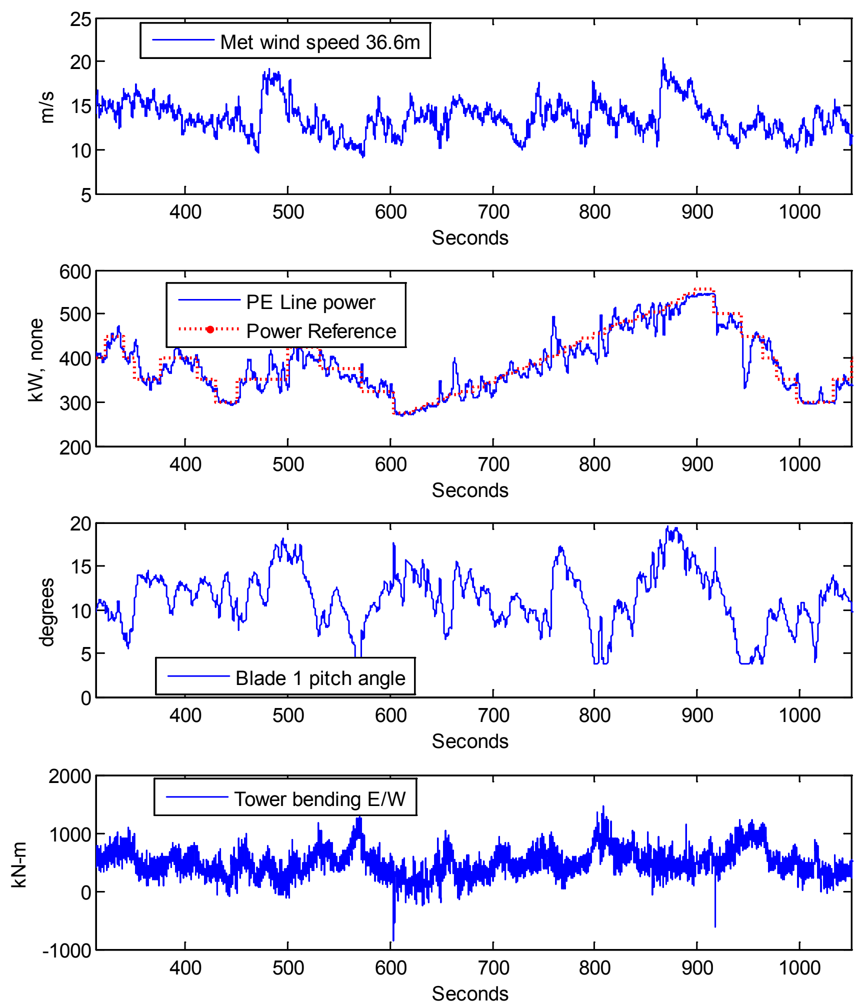

Figure 4-11. Field test data of the FSC APC control system on CART3, showing reasonable trends in power reference following.

This initial test validated the concept of APC control by demonstrating the turbine could follow a power reference. However, further testing was postponed while the second generation of APC controllers (TTC) were being developed and simulated.

4.3.2 Implementing the Controller for Deployment

The field test implementation of the TTC APC wind turbine control system described in Section 4.2 was designed to receive either real-time manual power commands from the operator or read a file of power commands and frequency data that is generated offline. The input data files specify the de-rating mode, de-rating command, grid frequency, droop curve setting, droop curve deadband, and in later tests, an AGC power command. During field testing, the operator may specify at which point of the input file the controller will begin reading after start-up. The manual operation mode was used at the beginning of field testing, to allow for gradual de-rating of the turbine in small steps. The PFC responses can be enabled and disabled online at the discretion of the operator through the use of a switch. Another user variable allows the operator to scale the PFC response, allowing for gradual integration of the PFC capability during initial field tests.

4.3.3 CART3 Field Testing Set Up

With the controller ready for deployment, the next step is to integrate the controller into the supervisory control and data acquisition (SCADA) system for NREL's CART3 wind turbine (see Figure 4-12). The SCADA system has been developed using LabVIEW in order to streamline the process of incorporating various controllers for the CART3 wind turbine. The SCADA runs on a National Instruments real-time controller at 400 Hz. An operator can interact with this controller to give it various supervisory commands, such as the turbine's startup/shutdown command, through a user interface (see Figure 4-13). This user interface runs on a separate computer (not in real time), and communicates to the real-time controller through a TCP Internet Protocol.

Figure 4-12. CART3 wind turbine at the NWTC.

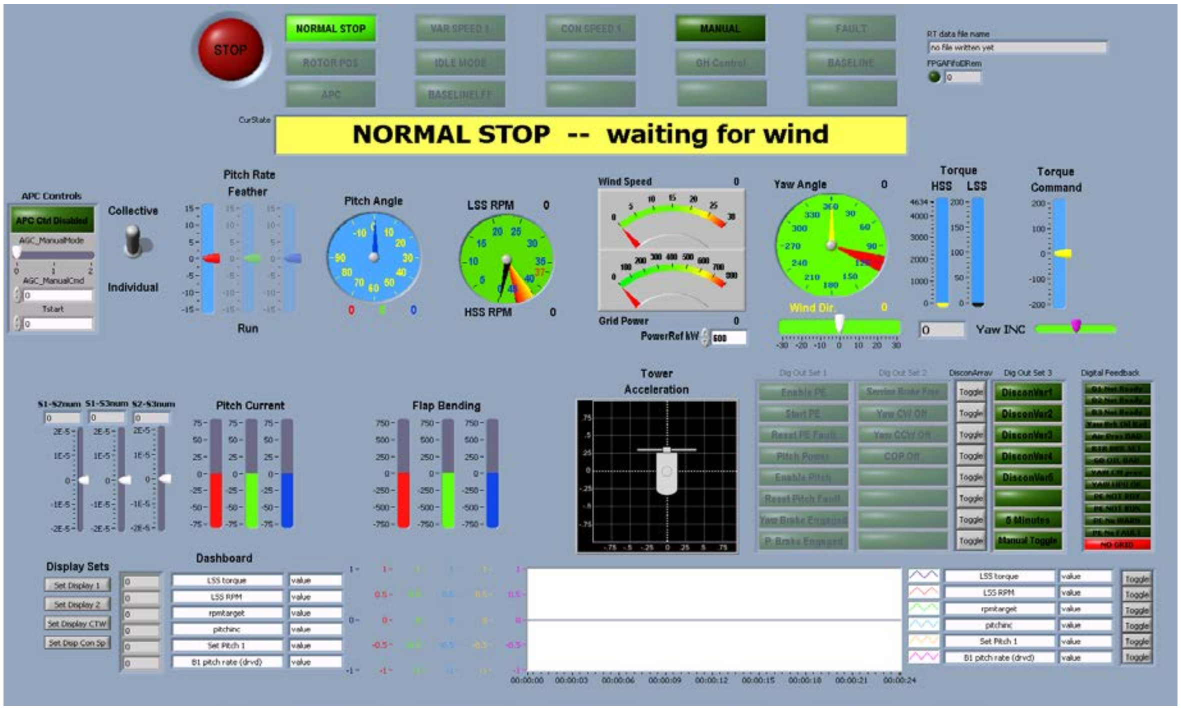

Figure 4-13. The operator user interface for running the APC controller on the CART3 wind turbine. The APC-specific controls have been added to the left side of the user interface.

For the APC project, the user interface has been modified by adding additional features in order to allow the operator to set up the APC controller to run in the desired experiment. These modifications included adding a control for the AGC mode, the AGC command, and a control to start reading the input time-series data at a specified time index. Furthermore, an indicator was put in place on the user interface to display whether or not these inputs are currently being fed into the controller. With these controls in place on the user interface, further modifications needed to be made to enable these control features to be sent to the real-time controller. This was done through the LabVIEW programming environment, and the operator inputs can now be read by the real-time controller.

Following this, a Simulink model of the control system described in Section 4.3.2 must be compiled to a dynamic-link library (DLL) in order to be interfaced into the LabVIEW environment. Once this is done, a suite of simulations are run with the DLL loaded onto the real-time controller. These tests are necessary to ensure that the controller's performance is fast enough to run the wind turbine. Additional checks are made through these simulations to ensure that transitions between the APC controller and the supervisory startup/shutdown controllers are smooth and do not produce any unanticipated loads that could potentially harm the wind turbine.

Once the controller has passed the simulation tests, it is then ready to use with the actual CART3 wind turbine. Field tests are then carried out to collect data in order to determine the effectiveness of the APC system.

4.3.4 CART3 Field Test Results to Date

Field testing of the TTC control system described in Section 4.2 has been underway since November 2012. These tests have thus far focused on tuning controller parameters, analyzing the performance of the PFC response of the controller in different de-rating modes, and evaluating the performance of following an AGC power command in de-rating mode 3.Testing has been performed in both high and low wind speeds.

Tests to date have verified the performance of the wind speed estimator. The wind speed estimator, which has previously not been field tested, is crucial to the performance of the control system when operating in de-rating mode 2 or 3, as it is used to estimate the power available in the wind. This estimate of available power is used by the control system in de-rating modes 2 and 3 to determine the de-rating power command and the feedback gain k_{Dr} in the torque control law. Figure 4-14 shows the performance of the wind speed estimator compared to the wind speed measured at the CART3 nacelle and at a height of 36.6 m on the meteorological tower in front of the CART3.

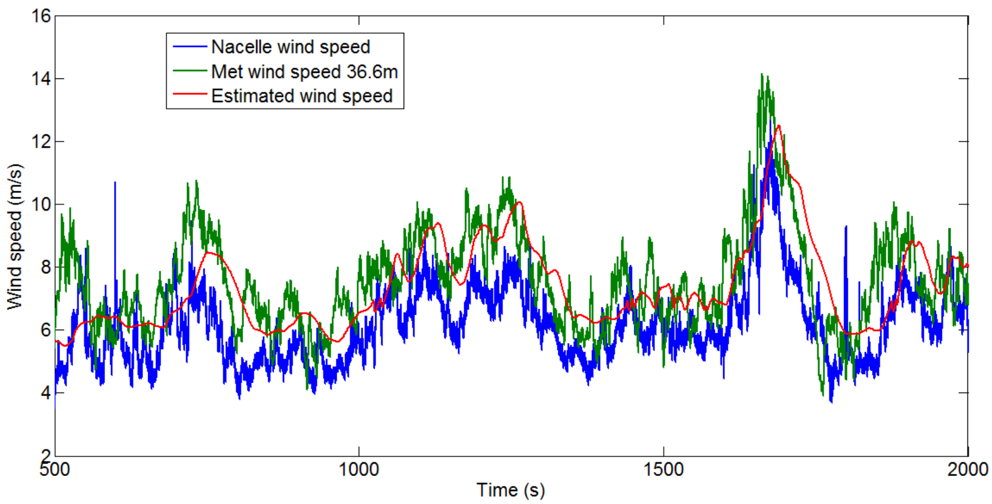

Figure 4-14. Performance of the wind speed estimator in a field test on the CART3.

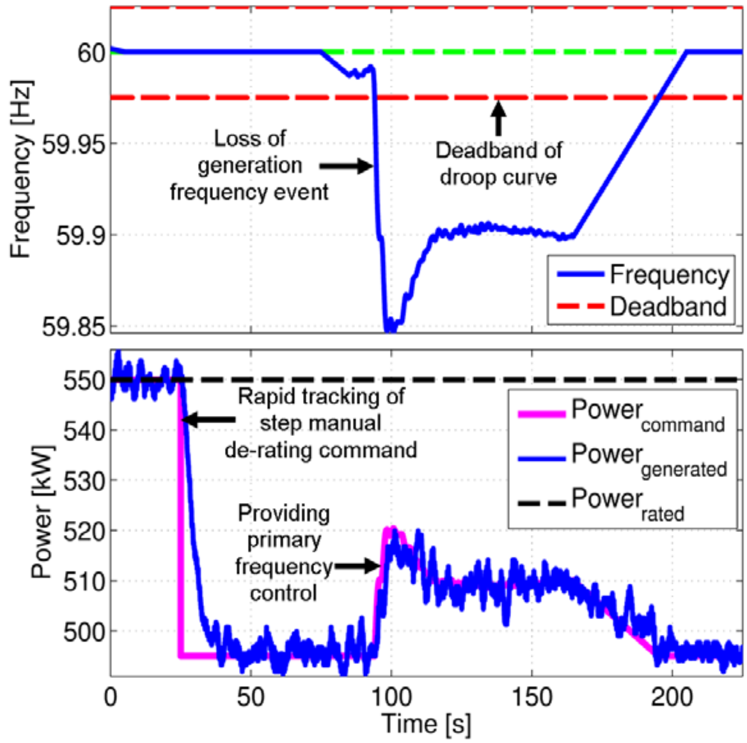

Figure 4-15. Field test data that shows the turbine tracking a step change in the de-rating command followed by a PFC.

Figure 4-15 shows a field test in de-rating mode 1 where the de-rating command is stepped from 1.0 to 0.9 and is followed by a grid frequency event. The turbine is successfully able to rapidly change the power output in response to the power command and provide PFC following the frequency event. As these field tests are performed on a single turbine, the high-frequency fluctuations in the generated power would be smoothed when aggregating the power output of an entire wind plant.

Figure 4-16 shows a field test in which the control system is operating in mode 3, capturing 80% of the power available in the wind and following an AGC command that is scaled to 20% of the power available in the wind. This field test was performed using a higher-bandwidth low-pass filter for the power available in the wind than would be necessary if the control system was implemented over an entire wind plant, rather than attempting to maintain 10% power available reserve with a single turbine.

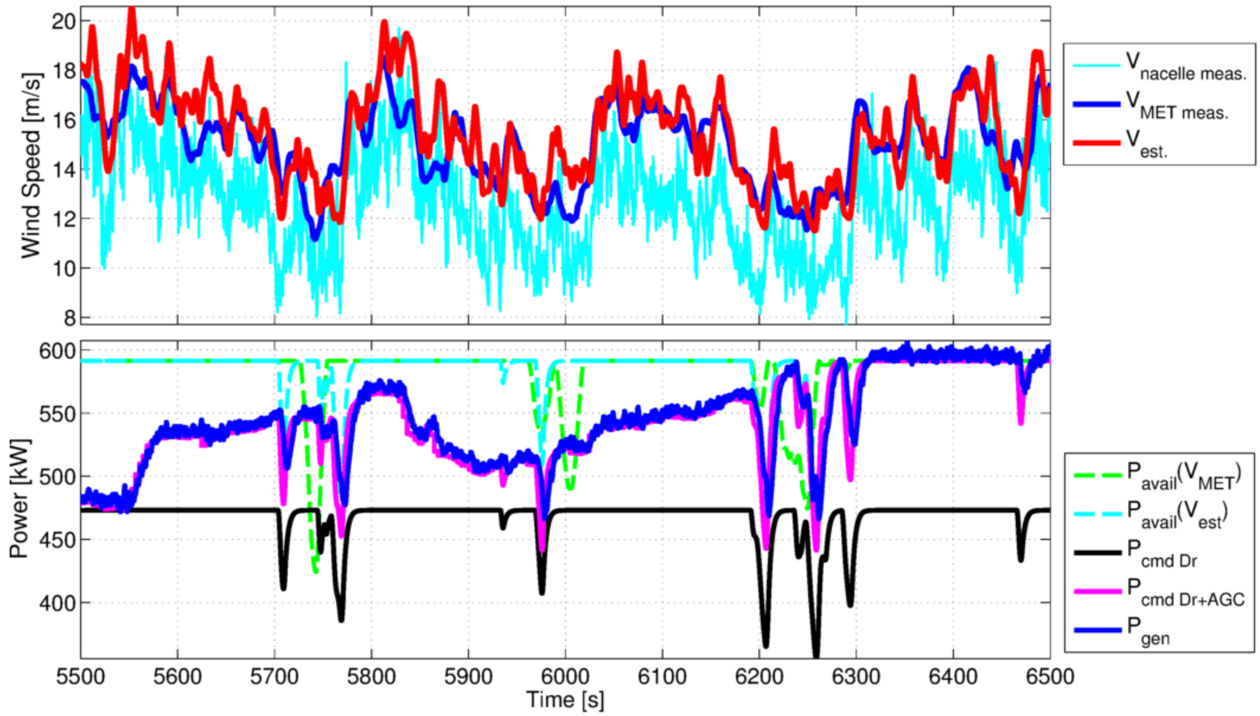

Figure 4-16. A field test in which the control system is operating in de-rating mode 3, de-rating command 0.8, and tracking an AGC power command, which is added to the de-rating power command "$P_{cmd\ Dr}$," resulting in the overall power command "$P_{cmd\ Dr+AGC}$." The estimated wind speed "$V_{est.}$" Is shown with the averaged meteorological tower measurements "$V_{MET\ meas.}$" and the nacelle anemometer measurements "$V_{nacelle\ meas.}$," which are used to calculate the power available "P_{avail}" The rapid changes in the de-rating power command are due to the available wind power dropping below the rated power of the turbine while the controller is in de-rating mode 3. The higher frequency fluctuations in the available power estimate should be filtered out if applied to an entire wind plant.

4.4 Summary and Conclusions

Two control systems were designed to perform de-rating, track power commands, and participate in PFC. The simulations indicated that it is possible for wind turbines to participate in APC and simultaneously improve grid robustness while minimally increasing turbine structural loads. The first of these two designs (FSC) was based in-part on previously performed work. One of the major developments using the FSC design was implementing PFC, and testing this capability in a simplified grid model. Using droop curves to achieve PFC in a control system previously designed to track power commands was first introduced using the FSC controller. The concept of using DDCs, which increase power actuation in response to increasingly negative ROCOF, was further investigated.

The turbine response and the effects on its structural loads were investigated more extensively using the TTC. This control system was designed to be a simple and straightforward method of providing flexible power tracking capability and PFC from wind turbines. The development of the TTC considered the tradeoffs between aggressive power responses and induced structural loads. Results so far have shown that the TTC control system is capable of tracking a de-rating power command, can successfully provide a PFC response, and can rapidly follow an AGC power command, as long as there is sufficient power available in the wind, with negligible impacts on the structural loading.

Simulations showed that de-rating of the turbines to have capacity for PFC provision had beneficial impacts on the DELs. Providing AGC regulation had a negligible effect on DELs as well, regardless of the amount of smoothing of the AGC signal. Future work will include a complex loads analysis to fully investigate the effects of providing PFC on turbine structural loads. To this end, the PFC will be considered an extreme loading event, rather than a fatigue load, and a new IEC extreme load design case will be considered. It is anticipated that considering PFC as an extreme load will show that other extreme loads, such as wind gusts, affect turbine loads much more severely than PFC.

The participation of wind power in the regulation market is also an ongoing research focus. Analysis is underway to determine the "regulation performance score" as determined by the grid operators of a wind turbine participating in regulation. The performance score is an important metric to use because it determines the economic compensation for providing regulation services. Efforts are underway to parameterize the performance score at different wind regimes, de-rating set-points, and AGC participation levels. For now only de-rating mode 1 is being considered because using absolute power set-points is a natural first step for market adoption. Preliminary results show that a wind turbine's capability to rapidly and accurately track a power command signal allow for achieving high performance scores, which lead to better compensation than slower-actuating power plants in the ISO/RTO regions where performance-based compensation is established. The regulation performance score significantly degrades at higher power set-points as the wind speed decreases and the wind turbulence intensity increases, so probabilistic wind forecast models may be used to assess the economic viability of wind plants participating in this regulation market.

Future work will also include more advanced control system and sensing technology developments and simulations. New sensing technology, like LIDAR, will be integrated with the TTC system and will be used to sense wind (and power) conditions in lieu of the wind-speed estimator. LIDAR will be integrated into the control system first in simulation, with aims to use this sensor in future field tests. Wind-plant-wide simulations will also be conducted that consider stochastic, rather than constant, wind speeds across the entire wind plant. Research in developing a wind-plant-scale distributed control system, which takes into account wake effects and turbine interactions, is needed for a more realistic representation of APC from wind power plants. It is likely that the relative error of plants following command signals will be significantly reduced when the command is aggregated across multiple turbines.

Initial field tests have validated the simulation results and have shown the capability of the wind turbine to follow power commands in each de-rating mode, provide a PFC in response to grid frequency event data, and track power reference commands. These tests will continue, further validating improvements and new features of the TTC controller, in an iterative manner. Upcoming field tests will continue focus on the ability of the TTC control system to track an AGC command when operating in de-rating mode 1 with a constant power reference set point, as this is a more realistic scenario for participating in the regulation markets. In conclusion, simulations and field tests have begun to show the effectiveness of advanced APC designs to follow signals from the grid operator or direct frequency signals in a satisfactory manner, with negligible impact on the structural loading of the wind turbine.

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5 Conclusions and Next Steps

Wind turbine simulations and field tests show that wind turbines can provide a satisfactory response for PFC and AGC. Power system dynamic studies show that wind can generally improve reliability when providing PFC and synthetic inertial control. Steady-state models show that wind power can have slight improvements in revenue and reductions in total production costs when providing AGC regulation. Steady-state models also show that a PFC market design can be introduced to ensure that enough PFC is provided, and wind can likely participate in this market to support system reliability, earn additional revenue, and lower production costs to consumers. Finally, control simulations show that providing these PFC and AGC responses will have a negligible effect on structural loading.

An understanding of how wind power can provide APC response is important, as wind turbine generators are a unique resource, much different from conventional thermal or hydro turbines. If manufacturers were to increase their capabilities and market APC to wind owners/operators, and if wind owners/operators were to purchase this control, they would need to be confident that providing this control would not impact the structure of the turbine or its components and thus affect the warranties. Much of the control design work focused on the design of a torque tracking control system. The control explored the tradeoffs between aggressive response and the impact of structural loads. For the responses generally needed for supporting power system reliability, the less aggressive approach can be taken with negligible effect on loading. This control was used to satisfactorily provide both PFC and AGC responses. Additional research focused on dynamic droop curves, which are simulated to understand the response given. The dynamic droop curves would adjust the power response depending on the initial rate of change of frequency to provide superior response when needed, but reduce the response when the need was lower, in order to reduce any loading impacts on the turbines. Notably, the team has coordinated a plan for field testing new controllers, which allows the team to be a single point for independent testing of APC of wind power in the United States, one that researchers, utilities, and manufacturers can continue to collaborate with for further research.

For utilities to allow for higher penetrations of wind on their systems, they must have the confidence that these penetrations will not lead to potential reliability issues. Wind power plants that support the power system rather than undermine it will generally improve wind power’s image in the eyes of utilities and the general public. This study developed the electrical models needed for proper representation of the four types of wind turbines and how they can provide synthetic inertial control and PFC to support power system reliability. This work also analyzed the types of frequency events that occur in the two major interconnections in the United States in order to better prepare for the designs needed and validate the dynamic models. Lastly, the team studied the system frequency performance on the Western Interconnection for instantaneous wind penetrations of up to 50%. The frequency response showed significant degradation on these systems with wind plants providing no control, though they still were not in immediate danger of shedding load during the majority of the largest of disturbances. With wind power plants providing PFC, the response was greatly improved. When providing synthetic inertial control alone, without initial curtailment, below rated wind speeds, and without also providing PFC, the frequency response was not improved. However, with wind power providing combined PFC and synthetic inertial control, the frequency response performance was significantly improved. This study also showed the importance of how grid codes may affect system reliability: according to these results, any grid code requiring synthetic inertial control without PFC may not have desired effects with significant wind power penetrations (depending on wind speed conditions). The study's key takeaway, however, is that wind power can act similar to conventional generation when providing PFC, and support the system frequency response and improve reliability in a similar or in some ways superior manner.

For wind owners/operators to purchase APC from manufacturers, and then curtail power to provide these services when needed, some sort of incentive must be in place. A proper incentive will also drive manufacturers to innovate and improve the technology for superior response. In addition, an incentive, rather than an individual mandate, will likely ensure that utilities, independent system operators (ISOs), and regional transmission organizations (RTOs) receive the flexibility that they need at the lowest cost to consumers. This study found that the lack of incentives for PFC may be one of the most significant reasons that the system frequency response in the U.S. Eastern Interconnection has declined in the past 20 years, when it should have been increasing. Alternatives to avoid disincentives and develop incentives were proposed, and a full ancillary service market design for PFC was introduced. This market design could work for any system and incentivizes all the characteristics needed for superior frequency response. A market for inertia was also studied that was found less critical than the market for PFC, but, if developed, it could reduce the number of instances at which inefficient make-whole payments are used to ensure units are kept online to provide inertia, when these units are not economic for other services. If such a PFC market were designed and implemented, wind could provide tremendous flexibility and potentially earn additional revenue. Finally, the study evaluated how wind could provide AGC regulation in an ISO market. By providing regulation, wind could gain additional revenue and reduce the total production cost on the system by allowing for other units to be at more efficient levels of output.

This study is part of an ongoing effort, with the ultimate goal to show industry the benefits of active power provision from wind power plants. The objective is to show justified economics, improved behavior in the steady-state and dynamic timeframes, and limited impact on the loading of the turbine components—and therefore no impact on life of the machines. The team will continue to develop improvements to the control designs in an iterative process between the designs and field tests. Future work will transition to studying the entire wind plant, implement new tracking devices and study how these devices could help with the control, and see how controls can follow new ancillary services being proposed in the U.S. markets. The team will also perform a comprehensive review of the power system impacts of wind power plants providing these response capabilities, both from the dynamics perspective during symmetrical faults, as well as transient behavior during symmetrical or unbalanced faults. The team seeks to better understand the interaction between primary and secondary frequency control on multi-area systems with and without wind power plants providing both of these controls, and how it impacts reliability compliance measures in the United States. Finally, we plan to help the industry move forward on PFC market design proposals where those market designs make sense, and understand how the additional flexibility of wind power plants can participate in these markets. We believe that these future steps will help achieve the objectives of ensuring industry's confidence in wind power plants providing APC to support power system reliability, and ensuring the confidence of the wind power plants that they can do so without reduction of life to their investments, all while earning additional revenue with properly set market designs.

Appendix A: Detailed Papers

The following papers contain further details on the work described in this report. We recommend those who want further details on specific sections to look for these papers.

Section 2.1:

Ela, E.; Tuohy, A.; Milligan, M.; Kirby, B.; Brooks, D. "Alternative Approaches for Incentivizing Frequency Responsive Reserve." *The Electricity Journal* (25:4); pp. 88–102.

Section 2.2:

Ela, E.; Gevorgian, V.; Tuohy, A.; Kirby, B.; Milligan, M.; O'Malley, M. "Market Designs for the Primary Frequency Response Ancillary Service—Part I: Motivation and Formulation." *IEEE Transactions on Power Systems*, 2013. DOE:10.1109/TPWRS.2013.2264942.

Ela, E.; Gevorgian, V.; Tuohy, A.; Kirby, B.; Milligan, M.; O'Malley, M. "Market Designs for the Primary Frequency Response Ancillary Service—Part II: Case Studies," *IEEE Transactions on Power Systems*, 2013. DOE:10.1109/TPWRS.2013.2264951.

Section 2.3:

Tuohy, A.; Ela, E.; Kirby, B.; Brooks, D. "Provision of regulation reserve from wind power: Economic benefits and steady state system operation implications." *Proc. 11th International Workshop on Large-scale Integration of Wind Power into Power Systems*; 2012, Lisbon, Portugal.

Section 3.1:

Muljadi, E.; Singh, M.; Gevorgian, V. "Fixed-speed and variable-slip wind turbines providing spinning reserves to the grid." *Proc. 2013 IEEE Power and Energy Society General Meeting*; July 2013, Vancouver, BC.

Singh, M.; Gevorgian, V.; Muljadi, E.; Ela, E. "Variable speed wind power plant operating with reserve power capability." *Proc. IEEE Energy Conversion Congress & Expo*; Sept. 2013, Denver, CO.

Section 3.3:

Zhang, Y.; Gevorgian, V.; Ela, E.; Singhvi, V.; Pourbeik, P. "Role of wind power in the primary frequency response of an interconnection." *Proc. 12th International Workshop on Large-scale Integration of Wind Power into Power Systems*; 2013, London, UK.

Singhvi, V.; Zhang, Y.; Pourbeik, P.; Bhatt, N.; Brooks, D.; Gevorgian, V.; Ela, E.; Clark, K. "Impact of Wind Active Power Control Strategies on Frequency Response of an Interconnection." *Proc. IEEE Power and Energy Society General Meeting*; July 2013, Vancouver, BC.

Sections 4.1:

Buckspan, A.; Aho, J.; Pao, L.; Fleming, P.; Jeong, Y. "Combining Droop Curve Concepts with Control Systems for Wind Turbine Active Power Control." *Proc. IEEE Symposium on Power Electronics and Machines for Wind Applications*; July 2012, Denver, CO.

Sections 4.2, 4.3, 4.4:

Aho, J.; Pao, L.; Buckspan, A.; Fleming, P. "An Active Power Control System for Wind Turbines Capable of Primary and Secondary Frequency Control for Supporting Grid Reliability." *Proc. 51st AIAA Aerospace Sciences Meeting Including the New Horizons Forum and Aerospace Exposition*; Jan. 2013, Grapevine, TX.

Appendix B: 1st Workshop on Active Power Control from Wind Power

Workshop Proceedings:
http://www.nrel.gov/electricity/transmission/active_power_control_workshop.html

Workshop on Active Power Control from Wind Power

Thursday January 27, 2011
8:00 – 5:00

Chautauqua, Climbers' Club Room
900 Baseline Road
Boulder, CO 80302

The workshop is aimed at discussing the research needs and state-of-the art of providing active power control from wind turbines and wind plants. In general, the scope of the workshop includes active power control in all forms but in particular we would like to focus on the areas of inertial response, primary control (frequency response), and secondary control (AGC regulation). The workshop will include participants from utilities, ISOs, manufacturers, universities, and other institutions. NREL and EPRI are pursuing a project in this area as well are many universities, utilities/ISOs, and manufacturers. This workshop is aimed at guiding that research. Also, many utilities and ISOs are beginning to evaluate the potential for new standards and policies that relate to these capabilities and therefore it is important that they have available the best information about these capabilities for making these decisions.

8:00 – 8:30 am	Breakfast	
8:30 – 8:45 am	Introduction and workshop overview	Erik Ela, NREL
8:45 – 9:15 am	R&D Objectives of NREL and EPRI Project	Daniel Brooks, EPRI Vahan Gevorgian, NREL
9:15 – 10:15 am	Session 1: ISO/Utilities • *What are the issues concerning them?* • *Do they see the need for active power control capability from wind or other renewables as critical?* • *What concerns or issues do they have with "synthetic" inertial response?* • *What are they requiring today in*	Moderator: Daniel Brooks, EPRI • Sandip Sharma, ERCOT • James Dominick, Xcel • Dale Osborn, MISO • Bob Cummings, NERC

	• *their interconnection standards?* • *What is being discussed as future standards or policies in this area?*	
10:15 – 10:30 am	Break	
10:30 – 11:15 pm	Session 1 (cont)	
11:15 – 12:15 pm	Session 2: Manufacturers • *Cover practical examples of what they have done trying to achieve inertial response and primary and secondary control response.* • *Talk about limitations of the turbines and the power electronics.* • *What are the needs for researchers to complement the work that is being done by the manufacturers?*	Moderator: Pouyan Pourbeik, EPRI • Richard Springer, Vestas • Bob Nelson, Siemens • Nick Miller, GE • Slavomir Seman, ABB
12:15 – 1:15 pm	Lunch	
1:15 – 2:15 pm	Session 2: (continued)	
2:15 – 2:30 pm	Break	
2:30 – 4:00 pm	Session 3: Universities • *Discuss existing and planned research in these areas being done in universities.* • *Discuss the types of future research that is needed.*	Moderator: Ed Muljadi, NREL • Vijay Vittal, Arizona State University • Mohammad Shahidehpour, IIT • Jim McCalley, Iowa State • Mack Grady, U Texas Austin

4:00 – 5:00 pm	Session 4: Group Discussion • *Summarize days discussions to see how R&D can be focused moving forward;* • *Where are the gaps and how do we best utilize R&D dollars for maximum public benefit*	Moderators: Erik Ela, NREL Daniel Brooks, EPRI
5:00 pm	Adjourn	

Appendix C: 2nd Workshop on Active Power Control from Wind Power

Workshop Proceedings:
http://www.nrel.gov/electricity/transmission/active_power_control_workshop_2.html

2nd Workshop on Active Power Control from Wind Power

Organized by the National Renewable Energy Laboratory and the Electric Power Research Institute

May 16, 2013 – May 17, 2013
Renaissance Hotel
Broomfield, Colorado

Day 1: May 16, 2013 7:30 AM – 5:30 PM
Breakfast and badges: 7:30 – 8:30

Introduction: 8:30 – 10:00

Welcome, Introduction and Workshop Purpose– *Charlton Clark, DOE, Erik Ela, NREL*

Frequency control standards and history in the U.S. – *Howard Illian, Energy Mark*

The impact of wind power on frequency control – *Bob Zavadil, Enernex*

Break: 10:00 – 10:30

Primary Frequency Response from Wind Power, the ERCOT experience: 10:30 – 12:00
Moderator – *Walter Reid, Wind Coalition*

History and Background – *Walter Reid, Wind Coalition*

Wind provision of primary frequency control, system operator perspective – *Sandip Sharma, ERCOT*

Wind provision of primary frequency control, manufacturer perspective – *Kaj Skov Nielsen, Siemens*

Wind provision of primary frequency control, wind owner perspective – *Sydney Niemeyer, NRG*

Discussion

Lunch: 12:00 – 1:00

System impacts of wind power with and without APC capabilities: 1:00 – 3:00
Moderator – *Matt Schuerger, Energy Systems Consulting Services*

Frequency response impacts on the Western Interconnection – *Clyde Loutan*, *CAISO*

Eastern Interconnection frequency response study – *Kara Clark, NREL, Nick Miller, GE*

Frequency response sensitivities on the Western Interconnection – *Vikas Singhvi, Pouyan Pourbeik, EPRI, Yingchen Zhang, Vahan Gevorgian*, *NREL*

Hawaiian island impacts – *Robert Kaneshiro*, *HELCO*

Operating an island power system with significant wind generation levels, the technical challenges, and ancillary services adequacy – *Yvonne Coughlin, Eirgrid*

Wind plants on automatic generation control – *Drake Bartlett, Xcel Energy*

Discussion

Break: 3:00 – 3:30

Active Power Control Design: 3:30 – 5:30
Moderator – *Vahan Gevorgian, NREL*

Frequency control concepts – *John Undrill, JMULLC*

Siemens wind power control design – *Kaj Skov Nielsen, Siemens*

GE wind power control design – *Miaolei Shao, GE Energy*

Experience on synthetic inertial response requirements in Hydro Québec – *Noël Aubut, Hydro Québec*

Load implications of active power limitation and delta control – Ali Ghorashi, Garad Hassan

Field testing and loading impacts of active power control tests at the NWTC – *Paul Fleming, NREL, Jake Aho, Andrew Buckspan, University of Colorado*

Discussion

<u>Friday, May 17th, 7:30 – 12:00</u>
Breakfast: 7:30 – 8:30

<u>Incentives, policies and market designs for active power control: 8:30 – 10:30</u>
Moderator – *Charlie Smith, UVIG*

Markets for frequency control – *Howard Illian, Energy Mark*

Primary frequency control market design – *Erik Ela, NREL*

Markets enabling ancillary services from all technologies – *Mary Cain, FERC*

Performance-based pricing – *Alex Papalexopoulos, Ecco International*

Profitability of wind plants providing regulation services – *Brendan Kirby, consultant, Aidan Tuohy, EPRI*

Discussion

Break: 10:30 – 11:00

<u>Closing Panel: 11:00 – 12:00</u>
Moderator – *Daniel Brooks, EPRI*

NERC Frequency Response Initiative – *Bob Cummings, NERC*

Panelists*: Bob Cummings, NERC, Charlie Smith, UVIG, Sandip Sharma, ERCOT, Miaolei Shao, GE Energy, Matthew Burt, RES Americas*

- **Of the issues discussed, what are the most difficult to solve? What are the most crucial?**
- **What are the immediate next steps? What are the long-term initiatives?**
- **What issues are there relating to active power control grid support that were not discussed?**
- **How will these issues change with greater and greater renewable penetrations**
- **How will other new technologies affect these issues (e.g., energy storage, demand response, distributed generation, smart grid)?**

12:00 Adjourn

<u>Optional 1:00 – 2:00</u>

National Wind Technology Center Optional Tour: 1:00 – 2:00

Appendix D: Low-Frequency Event Data, Western Interconnection (2011–2012)

Date	Nadir (Hz)	FA-FC (Hz)	Max +Hz/sec	Min -Hz/sec	Point B (Hz)	Point A (Hz)
6/16/2011	59.8967	0.0989	0.0167	-0.0402	59.9389	59.9899
6/25/2011	59.9125	0.1153	0.0485	-0.0426	59.9544	60.01
7/3/2011	59.9	0.0776	0.0204	-0.0225	59.9299	59.9741
7/14/2011	59.871	0.0961	0.0122	-0.0518	59.928	59.965
7/17/2011	59.918	0.0687	0.0104	-0.0216	59.9548	59.9775
7/30/2011	59.9059	0.0947	0.0261	-0.0374	59.9372	59.9915
8/1/2011	59.9016	0.0847	0.0742	-0.0989	59.9402	59.9855
8/6/2011	59.8462	0.1459	0.0172	-0.0658	59.9021	59.9906
8/10/2011	59.861	0.1541	0.1251	-0.0821	59.9175	60.0098
8/21/2011	59.9128	0.0827	0.0192	-0.0365	59.9622	59.9834
8/29/2011	59.8584	0.1378	0.115	-0.1117	59.9155	59.9923
9/23/2011	59.8961	0.0904	0.0347	-0.0419	59.9297	59.9758
11/2/2011	59.8919	0.0877	0.0135	-0.0459	59.93	59.9774
11/9/2011	59.8856	0.1321	0.0375	-0.0616	59.9323	60.0115
11/16/2011	59.9029	0.0773	0.0633	-0.1268	59.9384	59.9771
11/27/2011	59.8789	0.1066	0.0219	-0.064	59.9256	59.9834
12/6/2011	59.9149	0.0907	0.0189	-0.0379	59.9569	59.9867
12/10/2011	59.9032	0.1149	0.1153	-0.1998	59.9306	60.0157
2/14/2012	59.8963	0.1071	0.0234	-0.0647	59.9311	59.9957
3/14/2012	59.9112	0.0739	0.022	-0.0293	59.9516	59.9769
4/2/2012	59.9089	0.0592	0.0362	-0.0413	59.9265	59.9588
4/3/2012	59.9127	0.0809	0.0183	-0.0395	59.9493	59.9791
4/4/2012	59.918	0.0963	0.0153	-0.0289	59.9575	59.9869
4/6/2012	59.87	0.1584	0.0272	-0.0717	59.9322	60.0244
4/10/2012	59.918	0.0652	0.0537	-0.0404	59.9486	59.9665
4/16/2012	59.9151	0.0649	0.0166	-0.0229	59.9487	59.9658
4/19/2012	59.9145	0.0704	0.0161	-0.0249	59.9642	59.9705
4/20/2012	59.8387	0.1973	0.0331	-0.1274	59.913	60.0337
5/5/2012	59.9124	0.0955	0.0126	-0.0586	59.9496	59.9954
5/7/2012	59.8982	0.0943	0.0214	-0.0332	59.9336	59.9878
5/9/2012	59.8941	0.0846	0.0198	-0.0315	59.9242	59.9736
5/14/2012	59.8946	0.1171	0.0448	-0.0469	59.9369	60.0042
5/18/2012	59.9001	0.0664	0.0217	-0.023	59.937	59.9634
5/22/2012	59.904	0.0827	0.0548	-0.0437	59.9604	59.9841
5/30/2012	59.911	0.0562	0.0263	-0.041	59.9452	59.9654
6/8/2012	59.9086	0.1066	0.115	-0.2016	59.95	60.0112
6/9/2012	59.893	0.0981	0.0777	-0.1606	59.9343	59.989
6/25/2012	59.8977	0.1017	0.022	-0.066	59.9203	59.9897

Date	Nadir (Hz)	FA-FC (Hz)	Max +Hz/sec	Min -Hz/sec	Point B (Hz)	Point A (Hz)
6/26/2012	59.9009	0.0863	0.0855	-0.1621	59.9305	59.9823
6/28/2012	59.9024	0.0806	0.0196	-0.0505	59.9343	59.9776
7/4/2012	59.8167	0.1792	0.0656	-0.0938	59.8886	59.9924
7/10/2012	59.8658	0.1585	0.0147	-0.0242	59.9328	60.0189
7/13/2012	59.916	0.1083	0.1	-0.16	59.9385	60.0124
7/14/2012	59.9431	0.0419	0.0201	-0.0155	59.9655	59.9784
7/21/2012	59.9566	0.0517	0.0871	-0.1024	59.9893	60.013
7/22/2012	59.9419	0.0507	0.0104	-0.0242	59.9727	59.9868
7/24/2012	59.9518	0.0464	0.0231	-0.0199	59.9879	59.99
7/31/2012	59.9396	0.0595	0.05	-0.0755	59.9665	59.9887
8/2/2012	59.9271	0.0545	0.0552	-0.0359	59.9497	59.9714
8/3/2012	59.9515	0.0615	0.044	-0.066	59.9811	60.0076
8/4/2012	59.9469	0.0482	0.0367	-0.0501	59.978	59.9921
8/8/2012	59.9562	0.0734	0.0272	-0.0345	59.9801	60.0248
8/13/2012	59.9706	0.0423	0.0158	-0.0172	59.9953	60.0077
8/17/2012	59.9581	0.0511	0.0225	-0.0316	59.9768	60.0044
8/26/2012	59.9431	0.0698	0.0257	-0.0168	59.9621	60.0058
9/5/2012	59.9399	0.0643	0.0642	-0.0385	59.9581	60.0089
10/1/2012	59.8988	0.0808	0.0251	-0.0289	59.9267	59.9678
10/16/2012	59.9155	0.0754	0.0284	-0.046	59.9365	59.9883
10/18/2012	59.9328	0.0842	0.0317	-0.0455	59.9856	59.9977
10/19/2012	59.894	0.0747	0.0404	-0.0484	59.9187	59.9586
10/29/2012	59.9437	0.0995	0.0127	-0.0283	59.9767	60.036
11/7/2012	59.9554	0.0714	0.0484	-0.0724	60.0044	60.0093
11/11/2012	59.9155	0.0606	0.061	-0.0787	59.949	59.9642
11/13/2012	59.9254	0.0947	0.0231	-0.0578	59.9534	60.0081
11/16/2012	59.9517	0.0631	0.0114	-0.0256	59.974	59.9979
11/21/2012	59.9394	0.0681	0.0266	-0.0291	59.9635	60.0035
11/22/2012	59.9609	0.0383	0.0171	-0.0146	59.9838	59.9962
11/24/2012	59.9399	0.0845	0.0786	-0.1257	59.9731	60.0198
11/25/2012	59.9461	0.0496	0.0298	-0.0432	59.9701	59.9867
11/28/2012	59.9249	0.0941	0.0209	-0.0263	59.9551	60.003
12/9/2012	59.9015	0.0912	0.0929	-0.1754	59.9373	59.9918
12/12/2012	59.906	0.0989	0.0988	-0.194	59.9469	59.9985
1/4/2013	59.945	0.0659	0.0312	-0.0451	59.985	59.997
1/17/2013	59.9147	0.0811	0.0122	-0.0378	59.9563	59.9851
1/28/2013	59.9321	0.081	0.0288	-0.036	59.9559	59.9909
1/31/2013	59.9011	0.0951	0.0969	-0.1848	59.9384	59.9918
2/4/2013	59.9168	0.0878	0.0195	-0.0335	59.9427	59.9955
2/13/2013	59.9367	0.0798	0.0123	-0.0157	59.9776	60.0015
2/27/2013	59.9137	0.0137	0.0127	-0.012	59.9242	59.9252
3/2/2013	59.9237	0.1078	0.0155	-0.037	59.9563	60.0237

Date	Nadir (Hz)	FA-FC (Hz)	Max +Hz/sec	Min -Hz/sec	Point B (Hz)	Point A (Hz)
3/5/2013	59.9088	0.0844	0.0223	-0.0274	59.9415	59.9872
3/14/2013	59.887	0.1022	0.1162	-0.1962	59.9321	59.9804
3/17/2013	59.9504	0.0692	0.0218	-0.0289	59.9609	60.0035
3/20/2013	59.8995	0.0954	0.0235	-0.0544	59.9311	59.9881
3/28/2013	59.9238	0.0976	0.0223	-0.0433	59.9832	60.0118
3/31/2013	59.8924	0.111	0.0358	-0.0442	59.9507	59.994
4/1/2013	59.9215	0.0264	0.0225	-0.0275	59.9386	59.9322
4/5/2013	59.9205	0.0267	0.0347	-0.0285	59.9411	59.9271
4/8/2013	59.9206	0.1043	0.1477	-0.1847	59.9646	60.0167
4/11/2013	59.9365	0.0704	0.0167	-0.0309	59.9607	59.9997
4/12/2013	59.916	0.071	0.0243	-0.0343	59.9626	59.9841
4/15/2013	59.8976	0.0753	0.0267	-0.0406	59.9327	59.969
4/22/2013	59.9406	0.0588	0.0326	-0.0169	59.9562	59.9892
4/26/2013	59.9121	0.1533	0.0914	-0.1277	59.9368	60.0168
4/29/2013	59.8516	0.1764	0.1108	-0.2051	59.914	59.9936
5/6/2013	59.9156	0.022	0.022	-0.0204	59.9206	59.9335
5/7/2013	59.8873	0.1202	0.2348	-0.2269	59.9167	60.0052
5/8/2013	59.952	0.0828	0.0123	-0.0387	60.0133	60.0101
5/14/2013	59.9192	0.0391	0.0146	-0.0117	59.9494	59.9269
5/15/2013	59.935	0.0922	0.024	-0.0381	59.9648	60.0234
5/21/2013	59.9082	0.0862	0.0167	-0.0239	59.9436	59.9851
5/22/2013	59.9112	0.037	0.0248	-0.0162	59.9396	59.9275
5/25/2013	59.9102	0.0743	0.0786	-0.1105	59.9579	59.982
5/26/2013	59.9321	0.1022	0.0112	-0.0361	59.9816	60.0284
5/29/2013	59.9141	0.0813	0.0212	-0.0337	59.9502	59.9959
5/30/2013	59.7	0.2792	0.0538	-0.1821	59.8067	59.9787
5/31/2013	59.924	0.0889	0.0141	-0.0295	59.9556	60.0122
6/4/2013	59.9101	0.0429	0.0246	-0.0146	59.9373	59.9502
6/8/2013	59.9612	0.0825	0.0837	-0.1573	59.9876	60.0033
6/11/2013	59.927	0.0878	0.0231	-0.0269	59.9759	60.0043
6/18/2013	59.9887	0.0835	0.0426	-0.022	60.044	60.0068
6/29/2013	59.8702	0.1609	0.032	-0.131	59.9189	60.028
7/6/2013	59.9044	0.077	0.0208	-0.0276	59.9323	59.9779
7/8/2013	59.9156	0.0623	0.0688	-0.1134	59.9468	59.9735
7/10/2013	59.8712	0.1203	0.0224	-0.0782	59.9052	59.9893
7/15/2013	59.9337	0.0602	0.0195	-0.0197	59.9666	59.985
7/25/2013	59.8651	0.1174	0.0542	-0.0874	59.9119	59.9747
7/30/2013	59.9352	0.1036	0.1159	-0.1315	59.9754	60.0298
8/3/2013	59.886	0.1027	0.017	-0.0602	59.9131	59.9853
8/4/2013	59.888	0.0985	0.1163	-0.1814	59.9212	59.9838
8/8/2013	59.9088	0.0326	0.0175	-0.0183	59.9327	59.9407
8/13/2013	59.9201	0.0394	0.019	-0.0175	59.9507	59.9353