

A Comprehensive Frequency Control Framework for High Penetration of Wind

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Degree

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The dissertation is dedicated to my wonderful family

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Abstract

The increased penetration of wind will have significant impact on power system frequency response and brings new challenge to traditional power system frequency framework. With converter interface, the wind unit's rotor inertia is effectively decoupled from the system, causing a reduction in inertial response. Moreover, the replacement of conventional synchronous generators with governors also reduces primary control capability. It is expected non-conventional technologies can be used to help improve the frequency response, such as wind turbine generators, energy storage systems, high voltage DC transmission system (HVDC) and demand response. Wind turbine generators especially variable speed wind turbine generators such as doubly-fed induction generators (DFIG) have the potential to increase or decrease the output active power to improve frequency response if controlled properly, and the capability of DFIG can be as similar as conventional generators. Demand side can take actions as well through collectively controlling the thermostatically controlled loads which have the potential to shift active power consumption for a short period of time without compromising consumer's efforts.

This dissertation proposed a comprehensive control framework to allow for high penetration of wind by coordinating DFIG and controllable loads to provide adequate frequency response. The DFIG can be operated in different operating modes with switching among the different modes achieved by modifying reserve inputs. The DFIG is designed to provide adequate inertial response support. To overcome the secondary frequency drop, a dynamic demand control (DDC) strategy is introduced to coordinate with DFIG control. The joint effect of DFIG control and DDC will improve the frequency response from the time-scale of inertial response through primary frequency control. A user-defined DFIG model is developed. The effectiveness of the proposed control framework is verified through

case studies on a 181-bus WECC system with 50% wind penetration and demonstrated in CURENT large-scale test bed as well. The simulation results verify that the proposed control framework can allow DFIG to provide frequency support from time-scale of inertial response and ensure an adequate primary frequency response through corporation of TCLs.

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Chapter 1

Introduction

1.1 Background and Research Objectives

The modern electric power grid should include adequate resources, to reliably meet customers' demand and energy requirements [1]. The generation and load within a power grid should maintain balance at all time. Significant imbalances may lead to abrupt frequency deviations, stability problems or even widespread system blackouts [2]. System frequency as an indicator to distinguish balance and imbalance operating conditions is required to be controlled well during the whole time. Nowadays, the power system is undergoing significant changes. Renewable generation resources such as wind and solar are gradually replacing conventional synchronous generators. And wind energy has even become one of the fastest-growing energy sources in the world. As shown by [3], the total wind capacity worldwide has reached 54 GW by 2017 (as shown in Figure 1.1). As studied by [2], wind is also expected to provide approximately 20% of total electricity in the US by 2030.

Wind energy has both environmental and economic advantages. For example, wind energy is a free, unlimited clean fuel source, which will reduce the greenhouse gas emissions comparing to conventional fossil fuel sources such as coal and natural gas [4]. A single 1.5 MW wind turbine could displace 2,700 metric tons of CO_2 per year which is also equivalent to plant 4 square kilometers of forest every year [5]. Moreover, wind energy is space efficient that can be built on existing farms or ranches which will greatly boost the economy in rural areas [6]. However, wind power is not dispatchable and highly affected by weather

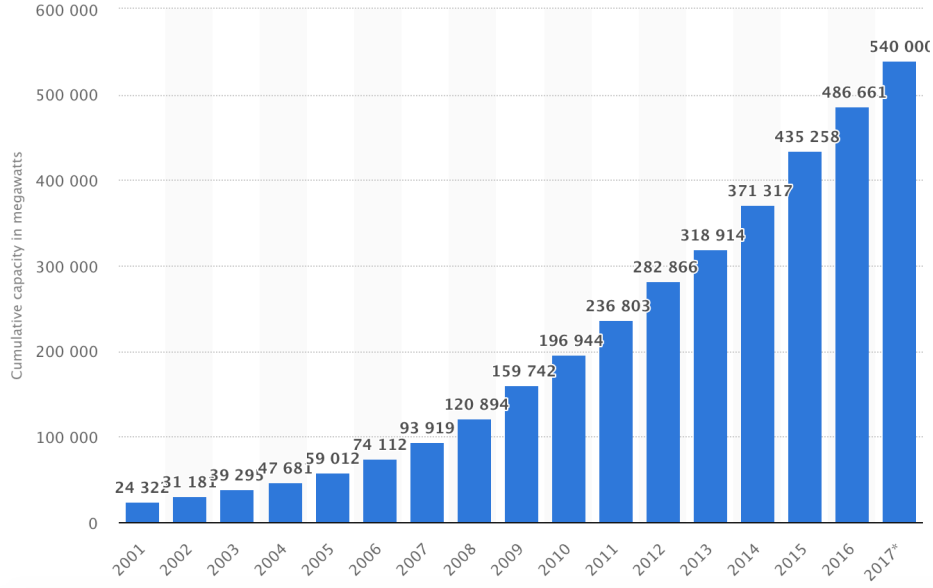


Figure 1.1: Installed wind capacity over the world (GWEC)

conditions [2]. And the intermittent nature of wind power may bring new challenges to power system frequency control [7]. On the one hand, if the random varying output of wind power cannot be balanced quickly, it will lead to a wider range of frequency fluctuation [8]. Several smoothing strategies have been proposed to suppress the power and frequency fluctuation caused by high penetration of wind such as in [9], [10] and [11]. On the other hand, the unacceptable frequency excursion due to the deterioration of inertial and primary frequency response following a large disturbance can threaten system security.

Generally, at the beginning of a disturbance, all the synchronous generators automatically start to release or absorb kinetic energy of the rotating mass, this characteristic is called inertial response. As the frequency deviation exceeds certain limit, turbine-governor will be activated to adjust the output of prime movers, which is primary frequency control [12], however, if this action cannot bring frequency back to the nominal value, secondary frequency control or automatic generation control (AGC) will take over to drive system back to the nominal value. As the wind penetration increases, more thermal units are being replaced by fixed or variable speed wind turbine generators. With high efficiency, variable speed wind turbine generators such as DFIG are more popular compared to fixed speed wind turbine generators in recent years. The variable speed capability is provided by controlling the

back-to-back AC/DC/AC power electronic converter which quickly controls the wind unit's output to its pre-disturbance value, thereby effectively decoupling the rotor inertia from the system [12]. This results in a reduction of inertial response after a contingency. Moreover, the replacement of conventional generators also reduces primary frequency response due to reduced governor actions. Thus, not only the rate of change of frequency (ROCOF), but also the frequency nadir and settling frequency will be lower, which may even trigger under frequency load shedding (UFLS) relays. According to [13] and [14], Electric Reliability Council of Texas (ERCOT) and Western Interconnect (WECC) have both reported deficiency in frequency response due to an increase of wind penetration.

Conventionally, synchronous generators serve as the major contributor to frequency control. Still, it is also expected that unconventional technologies such as wind turbines, High Voltage DC transmission system (HVDC), energy storage and demand response can provide a similar frequency control function as conventional generators [15]. The survey in [15] demonstrated these unconventional technologies do have the potential to provide relatively fast frequency response. For example, the speed change of synchronous generators is usually limited to between 1.0 p.u to 0.95 p.u and only 9.75% of the kinetic energy can be drawn, but asynchronously coupled wind turbine generator such as DFIG can allow its speed to drop from 1.0 p.u to 0.7 p.u., so the potential kinetic energy drawn from DFIG could be much greater than that from conventional generators [16]. In addition to the generation contribution, demand can participate in frequency control. Conventionally, under frequency load shedding (UFLS) is activated when generation-load imbalance is severe and cannot be remedied quickly using fast acting generation [17][18]. In recent years, enabling demand response to provide fast frequency response has been studied extensively. This can be achieved through controllable loads, such as, Thermostatically Controlled Load (TCL), that have the capability to shift power consumption for a short period of time without compromising end-user comfort [17].

The objective of this research work is to develop a proper control framework to utilize these non-conventional technologies such as DFIG-based wind turbine generators and TCLs to provide grid frequency support to facilitate a higher penetration of wind generation in the future power system. The control approach within the framework should provide the similar

function as conventional generators, with the aim of mitigating frequency stability problem and improving the inertial and primary frequency response. The coordinated control strategy is expected to provide frequency support from the time-scale of inertial response through primary frequency control. And the proposed approach should be effective for large-scale power system application.

1.1.1 Dissertation Outline

This dissertation is organized in following chapters:

In chapter 2, the conventional power system frequency control framework is introduced firstly. Then the impact of high penetration of wind integration on the system frequency response is discussed. The literature related to the recent efforts that are put to mitigate the frequency control challenges are presented. The widely used wind turbine generator modeling approach, i.e, positive sequence wind turbine generator model is discussed.

In chapter 3, the characteristics and performance of two predominantly used wind turbine generator models are compared and evaluated with various control strategies under different system operating conditions. The limitation of positive sequence wind model is discussed especially for weak system studies.

In chapter 4, a quantitative control approach for DFIG to improve inertial response is presented in the time scale of inertial response. The application of this approach is introduced and some issues related to similar inertial emulation approaches are discussed.

In chapter 5, a power reserve control approaches for DFIG is introduced to help improve primary frequency response. The comprehensive control framework for DFIG to improve frequency response from the time scale of inertial response through primary frequency control is formulated.

In chapter 6, the method to coordinate multiple DFIG units and the aggregated thermostatically control loads to guarantee adequate primary frequency response is presented. Several sectional frequency and time indexes (SFTIs) and are proposed to realize the coordination. The preliminary test of the coordinated control framework is described and results are discussed.

Chapter 7 described the development of the user-defined DFIG model, the development and benchmark of the test system. Case studies and simulation results with large-scale power system model is presented. Large scale test beds at CURENT are also used to asses the performance of the proposed control framework.

1.1.2 Summary of Contributions

The contribution of this work is summarized as follows:

- In the time scale of inertial response, a novel power surge based temporary power injection (TPI) method is proposed for DFIG to provide adequate inertial response. The contribution of each DFIGs under different operating conditions is quantified based on estimation of maximum extricable energy with consideration of operational constraints to guarantee rotor and converter security.
- In the time scale of primary frequency control, a tip-speed-ratio adjustment based power reserve control (PRC) method is proposed to help improve primary frequency response and mitigate the secondary frequency dip. The maximum reserve margin and the transient active power injection is estimated to ensure rotor security. The operating points can be adjusted up and down to support both under-frequency and over-frequency event.
- The proposed two control modes (TPI and PRC) together with maximum power point tracking (MPPT) are formulated into one control framework. Thus, it can be easily integrated into existing DFIG control system with no additional actuators required.
- A dynamic demand control (DDC) strategy is presented and coordinated with DFIG TPI control. The joint effect of DFIG control and DDC will ensure an adequate primary frequency response. To quantitatively assess the adequacy of the frequency response, several sectional frequency and time indexes (SFTIs) are proposed and used as the trigger to activate control actions across a range of time-scales.
- A user-defined positive sequence DFIG model is developed in OpenModelica for implementing the proposed control framework and used for real-time simulation

in ePHASORsim. A base-case 181-bus Western Electricity Coordinating Council (WECC) system with 0% wind penetration are developed in ePHASORsim and benchmarked with the original system in PSS/E. And a 50% wind penetration scenarios is created with developed user-defined DFIG models.

- The proposed DFIG control framework is successfully implemented and demonstrated on Large-scale Testbed (LTB) at Center for Ultra-Wide-Area Resilient Electric Energy Transmission Networks (CURENT).

Chapter 2

Literature Review

2.1 Overview of Power System Frequency Control

To ensure secure operation of power system, it is required generation and load are balanced closely moment by moment. Any types of imbalance will be indicated by the frequency deviation from the nominal. Off-nominal frequency can impact the reliability of the system. For example, it may damage the equipment, overload transmission lines, and degrade the quality of product delivered to the end users [19]. In traditional power system frequency control framework, once detecting the frequency deviation, a series of control mechanism is applied to adjust the generators' output to maintain frequency within a narrow range. A typical frequency response following a generator trip event is presented by Figure 2.1.

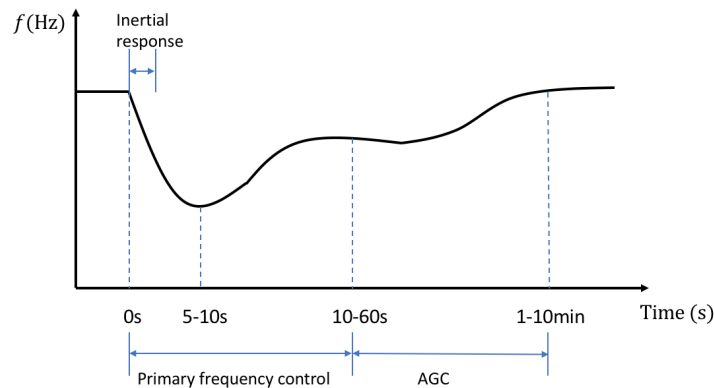


Figure 2.1: Typical frequency response after a generator trip event

From the moment the imbalance occurs to the moment that the frequency is fully stabilized, the frequency control mechanisms can be divided into three stages characterized by the time frame in which each mechanism involves [20].

At the beginning of the under-frequency event, all the synchronous generators and motors automatically start to release kinetic energy of the rotating mass, this characteristic is called inertial response. The inertial response provided by online synchronous generators or motors will reduce the ROCOF but can only last for several seconds. As rotor speed slows down, turbine-governor senses the speed reduction and is activated to adjust the output of prime movers to stabilize the rotor speed, which is called primary frequency control. Governor operates with a droop characteristic and the response of each generating unit is only determined by its droop characteristic and a local frequency measurement so it is a fully local autonomous response [21]. A typical diagram of turbine-governor model with droop coefficient R is shown in Figure 2.2.

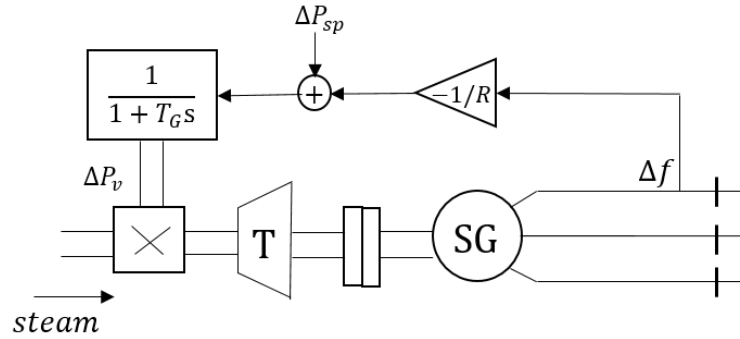


Figure 2.2: Diagram of speed governor

The local primary control action based on droop characteristic is not sufficient to restore the system frequency, especially in an interconnected power system. Therefore, secondary frequency control is accomplished by employing AGC at area level [1]. The AGC process is performed in a control center remote from generating units [22]. AGC signal is assigned in selected generating units in each area economically according to the results of economic dispatch [23]. AGC has two main objectives [24]:

- to match area generation to area load, to regulate interchange power flow with the schedules as well as to restore the system frequency back to the nominal value.

- to distribute the changing loads among generators so as to minimize the operating costs subject to additional constraints

The AGC control performance is highly dependent on how the participant generating units would respond to AGC signals. The North American Electric Reliability Council (NERC) introduced two control performance standards 1 and 2 (CPS1 and CPS2) to achieve the optimum AGC performance [25]. In each area, the supplementary control loop computes the Area Control Error (ACE) and adds it to the primary control loop through a dynamic controller [26]. In practice, the dynamic controller is usually a simple integral (I) or proportional-integral (PI) controller. The ACE must be filtered before being used in case it exceeds the threshold within a time interval [27]. The control logic of a simple AGC for each area is showed in Figure 2.3.

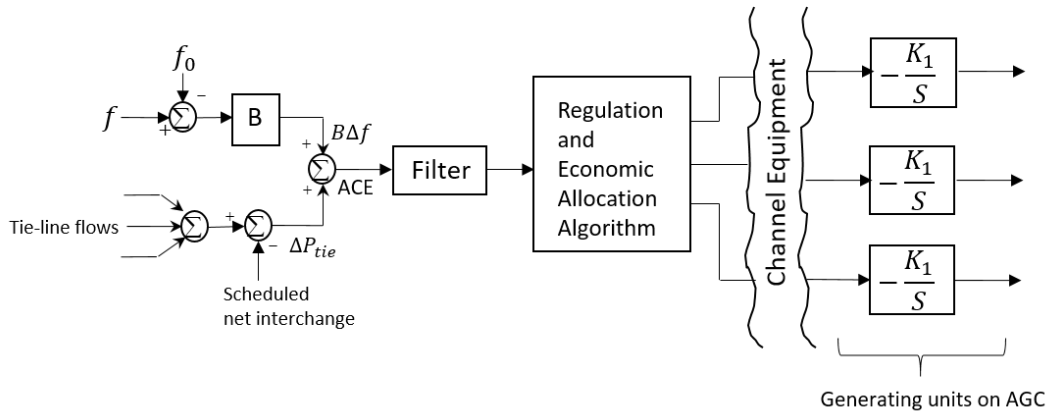


Figure 2.3: AGC control logic for each area

Tertiary control is mainly for rescheduling additional resources to maintain an adequate secondary control reserve in a relatively longer time-scale (10-min to hours) [28]. According to [29], The time frames associated with each control mechanism are summarized in Table 2.1 .

Table 2.1: Traditional power system frequency control time frames

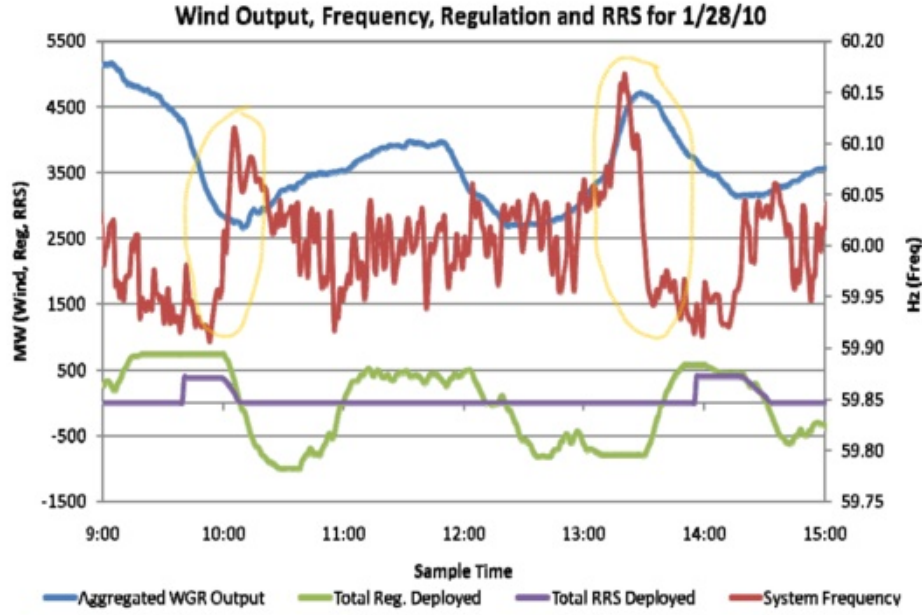
Control	Time Frame	Ancillary Service
Primary Control*	10 – 60s	Frequency Response
Secondary Control	1 – 10min	Regulation
Tertiary Control	10min–hours	Imbalance/Reserve

* Inertial response is within primary control time frame

2.2 Frequency Control Challenges with High Penetration of Wind

The large-scale wind penetration brings significant impacts and technical challenges on power system operation. The wind farms are usually distributed over large areas which are far away from load centers [30]. To accommodate these large amount of power generation, new long-distance transmission capacity is required. Besides, the outputs of wind power are highly dependent on weather conditions. Extreme weather condition may results in large portion of active power imbalance within a few minutes which brings in new uncertainty and variability to the generation output [31]. It is especially difficult to maintain active power balance due to the intermittent and non-dispatchable nature of wind power since the variation of wind power generation has to be balanced quickly with other types of generation units [32]. Conventional generators are the main sources to handle the variability of renewable resources right now by ramping up and down based on wind forecasting. In the future power system, with more conventional generators being replaced by wind generation, the conventional generation may be insufficient to provide the required reserve. In this condition, for transmission system operators (TSO), the variability of wind becomes increasingly difficult to manage as penetration level increases [30]. If the random varying output of wind can not be balanced quickly, it will lead to a larger range of frequency fluctuation. Figure 2.4 demonstrates a real-world example of frequency fluctuation caused by abrupt wind variation in Texas Interconnection [33]. Sudden incline and decline of frequency can be observed and the range of frequency fluctuation can be as large as 0.25 Hz. In this case, sufficient reserve must be in place to cover the expected variations of wind power to maintain a desired reliability level [34] [35].

Conventional fossil fuel generation power plants employ synchronous generators, but the widely used modern wind turbine generators (Type-III and Type-IV) are integrated with grid through power electronic-based converters. The converter control can instantaneously adjust the electrical torque on the generator so that the active power delivery is independent of the rate of change of terminal bus angle (also viewed as bus frequency) [15]. In other words, these converters effectively decouple the wind units from the grid and do not inherently



Source: ERCOT (2010).

Figure 2.4: Frequency fluctuation caused by rapid wind variation in Texas Interconnection

provide rotating inertia to the grid. This results in the reduction of the inertial response following a large disturbance, i.e., generator trip event. A comparison study is conducted in [36] with two recorded frequency disturbance events at high load and low load periods under a generator trip event to demonstrate the impact of inertia on the frequency response as shown in Figure 2.5.

To evaluate the frequency response performance and the frequency control capability after disturbance in different time-scales, three metrics are generally considered in practice.

- ROCOF: a metric that is used to assess the speed of frequency decline/incline
- Frequency nadir: maximum post contingency frequency excursion point
- Primary settling frequency: the stabilized frequency due to governor response

From Figure 2.5, we can see that the ROCOF is increased from 0.027438 Hz/s to 0.066403 Hz/s from the high inertia case to low inertia case which means a similar active power imbalance (represented by MW loss) creates a steeper frequency decline [37]. This decline will be more severe during light load period due to online synchronous generators switching

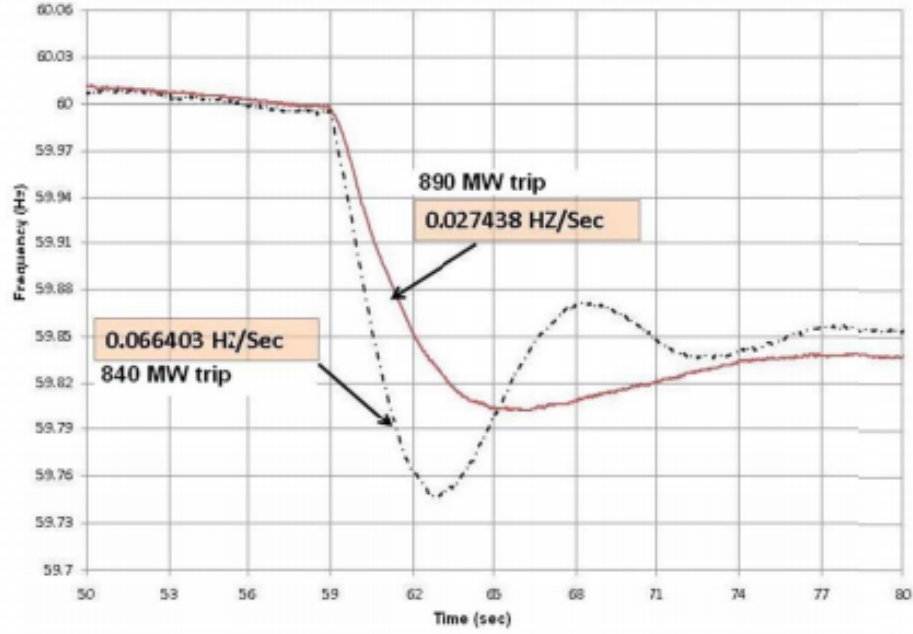


Figure 2.5: Inertial response comparison for ERCOT region

off. Another reason for this observation result is that more conventional generators are replaced by wind generation. The replacement of conventional generators also reduces the capability of governors and affects the quantity of responsive reserve. Thus not only the ROCOF but also frequency nadir and settling frequency will be lower, which leads to a reduction of primary settling frequency. The reduced frequency nadir may even trigger under frequency load shedding (UFLS) relays and threaten system's security. In Ref [7], the authors analyzed the impact of wind power on load frequency control with different wind penetration levels. It reached a conclusion that with more wind power integrated (higher penetration), there will be a larger frequency deviation after the disturbance. The frequency deviation needs to be restricted to a safe limit, this will limit the penetration of wind to a certain level.

2.3 Efforts to Overcome Frequency Control Challenges

Extensive efforts have been made to overcome the above-mentioned frequency control challenges. Additional flexibility must be presented to effectively compensate the wind power variation caused by forecast errors or other uncertainties. This type of flexibility

can have different forms, such as increased ramp rates, and increased amounts of operating reserves [38]. New load frequency control methodologies have been proposed to suppress the wind variation and maintain frequency balance mainly using conventional generators. In [39], a model predictive control (MPC) based frequency regulation approach is proposed to reduce the frequency fluctuation by taking into account the limitations on tie-line power flow, generation capacity and generation ramp rates. While in [40], a flatness-based approach is applied to AGC for multi-machine systems. Simulation results on a reduced Northeast Power Coordinating Council (NPCC) system has verified that with the proposed approach, the range of frequency excursion due to the wind output variation is narrowed down comparing to conventional PI-based approach. Acquiring reserve from conventional generators requires sufficient flexible online capacity which will impose a higher cost. Non-conventional energy sources can be a possible alternative to provide a more flexible margin. For example, [41] shows under-scheduled wind generators can provide a flexible dispatch margin and the additional reserve being held can be utilized to mitigate forecast errors in the real-time operation. Besides, recent advances in electric energy storage technologies provide an opportunity for integration of energy storage system (ESS) to reduce the variability of wind generation [42, 43, 44]. A feed-back based control strategy to integrate a battery energy storage system (BESS) with a large wind farm is proposed to smooth out the intermittent power from the wind farm in [42]. And a dual-layer BESS control strategy is proposed to mitigate wind farm fluctuations and prolong BESS operational lifetime at the same time by optimizing the power allocation among different BESS battery units.

To allow for a higher level penetration of wind with limited frequency excursions after contingencies, one solution is to utilize the capability of fast acting resources to provide fast frequency response to compensate the reduced inertial and governor response. The best candidate will be the variable speed wind turbine generator (VSWTG) itself. This gives rise to an interest in developing control strategies to enable VSWTG to provide fast frequency control support after the contingency event. In [45], the authors provided an overview of modern turbine control strategies and investigated the trends of wind frequency control from industry point of view. The authors in [46] performed a comprehensive review on industry design, recent research activities and national technical requirements on VSWTG frequency

control related issues. The authors in [47] reviews recent control strategies for VSWTG to provide frequency support with focus on detailed controller description and implementation.

In summary, the existing VSWTG frequency control approaches can be divided into two categories: one is to introduce a support function as a supplementary control loop, adding to the VSWTG power reference to improve inertial response and the other is to de-load wind turbines to help with primary frequency control. In the time scale of inertial response, three types of strategies have been utilized characterized by the shape of the support function: df/dt response; Δf response; and fixed trajectory response [48]. The work reported in [49] introduced an additional supplementary controller proportional to the derivative of system frequency to emulate the natural inertial response (df/dt response). However, df/dt is sensitive to measurement error and noise [12]. The work in [12] modifies the supplementary control signal to be proportional to the frequency deviation to achieve a greater contribution from the wind turbines (Δf response). Similarly, the work in [50] shows droop control (Δf response) can provide a similar response as the synthetic inertia control. Simulations are also performed to determine the optimal set of parameters for droop control. It can be verified that both df/dt and Δf response are scenario-based, the response shape depends on the system frequency measurement f and the control gains. Ref. [50] also reveals the fact that the effects of different control strategies are highly replied on the composition of the power system so that the parameter tuning is crucial especially for high wind penetration condition. Ref. [51] proposed a systematic theoretical analysis to find the largest deadband to preserve the frequency limits. Ref. [52] examined the inertial response delivery capability for DFIG with different wind speed. The existing approaches fall short in identifying how best to coordinate multiple DFIGs under different operating conditions to ensure an adequate inertial response. Different from df/dt response and Δf response, the shape of the fixed trajectory is not determined by the frequency disturbance but is based on a power surge function. The power surge function can be various types, such as the kinetic discharge function shown in [16] and the temporary frequency control function (TFCF) shown in [53]. However, the power surge amount must be carefully quantified to avoid violating operational limits [54]. Besides, after the inertial response period, the rotor speed needs to be restored to optimal speed which may even bring a secondary frequency dip

to the system if the active power injection is too large or the recovery time is too long. In [48], the authors identified the delayed frequency recovery problem and proposed a genetic algorithm (GA) based gain scheduling method to get an optimal inertial response for each specific system conditions.

The support for inertial response mentioned in the previous is temporary that can only last for several seconds and it has no impact on primary settling frequency, in [55], on the other hand, the authors propose de-loading the wind turbine through pitch angle control to provide reserve for primary frequency support. Similar ideas can also be found in [56] and [57]. Frequently adjusting pitch angles can increase mechanical switching and losses. Instead of manipulating pitch angle, rotor speed adjustment based method can also be used to deload the VSWTG. The investigation in [58] and [59] de-load the wind turbines through rotor angle control to improve overall primary frequency response. Both of the studies in [58] and [59] mainly focus on the control application for small test systems. The authors in [60] modifies the previous de-loading method and formulated an optimization problem to optimize the steady-state de-loaded operating point, so that the de-loading margin can be reduced. Under the de-loading conditions, the delayed frequency restoration can be avoided. However, the capability of rotor speed based control for improving the primary frequency response is limited by the maximum rotor speed limit. The usage of energy storage system (ESS) together with DFIG control has a promising effect to mitigate the secondary frequency dip brought by DFIG inertial control. A coordination strategy between ESS and DFIG is presented in [61], a small ES with a power rating of approximately 10% of that of the DFIG is installed adjacent to the DFIG. So that the frequency response is effectively improved and the secondary frequency dip is avoided.

The aggregated response of under-scheduled wind generators has the capability to participate in secondary frequency control similar as conventional generators if the reserve is adequate. And the idea is to operate wind turbine generators under set-point control to follow operators' command or AGC command to provide ancillary service. Several control strategies have been proposed for this purpose [62, 63, 64]. In [65], the coordination of wind turbine generators and conventional generators are achieved by letting conventional generators be aware of the power imbalance at the beginning of disturbance through implementing an

additional injection signal. The authors in [66] propose to operate the wind farm under the command of AGC. The controllability of wind turbines under either rotor speed based set-point control or pitch angle based set-point control is evaluated and the simulation results show that the aggregate response of VSWTG is able to follow the AGC command under the intermittent wind condition.

For decades, generation side controllers, e.g., governors, have been used to stabilize the frequency of power system [67]. Conventionally, load based control approach such as under frequency load shedding (UFLS) is only activated when generation-load imbalance is severe and can not be remedied quickly using fast acting generation [68]. As the amount of intermittent renewable generation increases and the proportion of flexible conventional generating unit decreases, there is also a possibility that demand side can take a more active role in the frequency control of the power system [67]. Technically, controlling the frequency from demand side is possible and has some advantages. Firstly, the response time of demand response can be very quick. Generation side controllers usually recover the system frequency in a couple of minutes, while demand response can reduce the time to tens of seconds as shown by [69]. Secondly, demand control is more flexible compared with UFLS since it can be activated with a small frequency drop and has a wider range of threshold [68]. Thirdly, demand response reduces the required amount of reserve and the system operational cost since a large amount of load can emulate the droop characteristic of conventional generator.

In recent years, enabling demand side to provide fast frequency response has been studied extensively. This is achieved by interacting with controllable loads, such as, Thermostatically Controlled Load (TCL) that has the capability to shift power consumption for a short period of time without compromising end-user's comfort level [68]. The work in [70] proposed to adjust the instantaneous power consumption of TCL to respond to frequency deviation for the first time back to 1980s and patented the concept of Frequency Adaptive Power Energy Re-scheduler (FAPER). Later on, Pacific Northwest National Laboratory (PNNL) developed a so-called Grid Friendly Appliance controller in the grid-wise test-bed project [71], which was based on the design of FAPER-like controllers. This type of controller is to be fitted into individual appliances as energy users which can modulate their own power consumption accordingly over a certain range of time without changing final energy consumption [71]. A

distributed load controller for autonomous renewable energy system is developed by Taylor in [72]. Each appliance uses a micro-controller in which the software embedded measures the system status, such as the frequency and the frequency change rate, and takes these two as the inputs to a fuzzy logic load control system. The distributed nature of the control scheme ensures that if one load controller fails or is disconnected, the rest of the system can continue to function adequately [72]. The approach was tested in an island power system with a small number of water-heating loads. In [73], Trudnowski assumes that the frequency response appliances will form a linear modulation of the load, taking the frequency error as the input to enable autonomous control and eliminate the need for expensive communications using highly distributed switching actions. It has been proved to be feasible according to the simulation results of case studies. The authors in [68] explored how the demand-side could contribute to primary frequency control using a decentralized approach and argues that the two-way communication is not essential and the demand can respond to the frequency error in a manner similar to the generators. It should be pointed out that frequency control from demand-side must rely on loads that can be easily switched on/off. Heating, cooling and pumping devices which can handle short interruptions can satisfy that requirements. According to [70], 20% of the loads in US are heating and cooling loads which can switch on and off to make a contribution to frequency control.

The control approach introduced above are based on lumped linear power system model, which might be inaccurate if considering the transient dynamics of a complex power network. In [69], the authors proposed a hierarchical decentralized framework to enable a systematic design of demand-side frequency control based on a general non-linear multi-machine power system and also considered device constraints. And the work in [74] showed the capability of dynamic demand control in supporting both primary and secondary frequency control with a detailed time-domain simulation approach.

One important issue that must be studied well about demand-side frequency control is the frequency oscillation caused by the simultaneous responses of smart appliances upon a frequency contingency. In [67], Mohammad et al. proposed a new distributed control paradigm by randomizing frequency responses of smart appliances to solve the frequency oscillation problem. The smart appliances participating in frequency control monitor the

system frequency independently over random time instants and respond according to a simple frequency threshold based on on/off load control policy. And they also point out the average frequency recovery time, the average number of responded smart appliances over time and the probability of frequency overshoot are the main characters that will impact the randomized response of the appliances on system frequency. Ref. [75] focused on enabling frequency responsive appliances to track a targeted power consumption profile that could be used for primary frequency control and the designed controller can avoid frequency oscillations in a relatively longer time-scale.

2.4 Modeling of Wind Turbine Generators

Wind generation has unique features in comparison with convention fossil fuel generation [76]. It is essential to understand the distinctive characteristic of wind generation and its impact on power system dynamic studies through modeling and analysis [76]. The accuracy of system performance studies relies on the fidelity of the underlying models [77]. Thus proper steady-state and dynamic wind turbine generator models are required to perform the interconnection studies. There are generally four types of wind turbine generators in use today for different applications:

- Type I: Induction generator based wind turbine generator with fixed speed
- Type II: Induction generator based wind turbine generator with variable rotor resistance
- Type III: Doubly-fed induction generator based wind turbine generator with variable speed
- Type IV: Full converter based wind turbine generator with variable speed

The structures of each types of wind turbine generators are summarized in Figure 2.6. Type-I and Type-II are fixed speed wind turbines with conventional induction generators, the rotor speed is a fixed speed determined by the grid frequency. These types of machine absorb reactive power from the grid so it is required to have capacitor bank to provide reactive

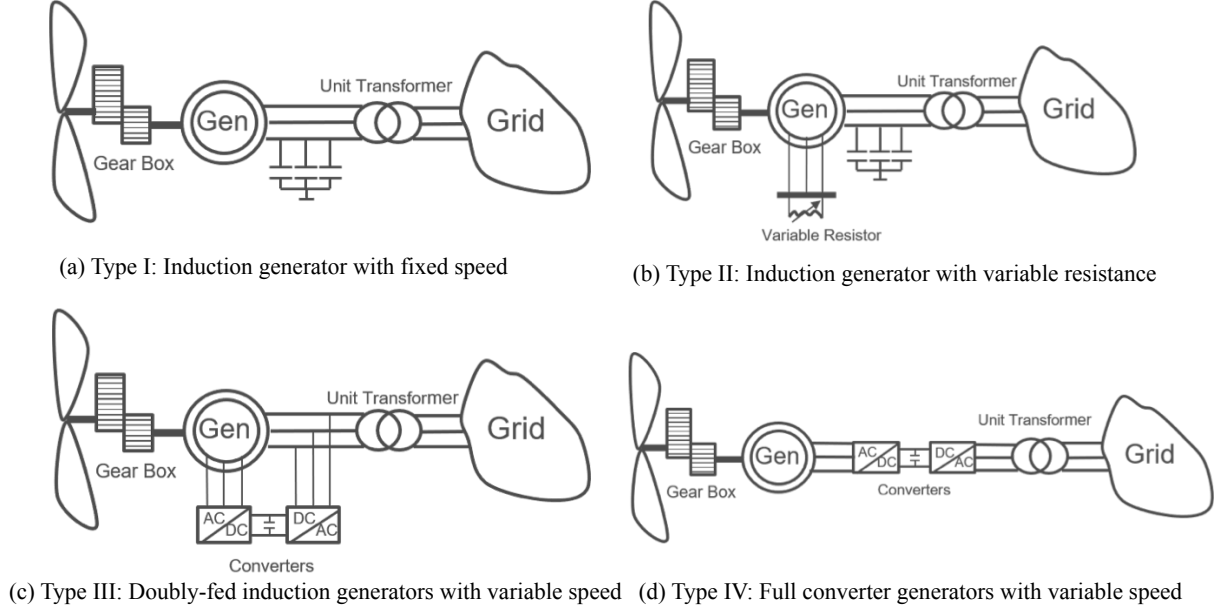


Figure 2.6: Four types of common wind turbine generators.

power compensation [78]. Type-III and Type-IV are variable speed wind turbines with either doubly-fed induction generator or a synchronous generator connected with a full back-to-back frequency converter. Comparing to fixed speed wind turbine generator, the variable speed turbines are able to capture greater energy with advanced active and reactive power control capability. Besides, the fixed turbine will directly translating the power fluctuation into the grid, while variable speed turbine can absorb some of the fluctuations by storing the mechanical energy [76], thus variable speed turbine has better power qualities. Between those two variable speed wind turbine generators, DFIG holds over 60% of market share which is more popular and more suitable for providing controlled frequency support [79].

2.4.1 Positive Sequence DFIG Model

The complete positive sequence DFIG model can be roughly divided into four major functional blocks including generator and converter model, electric control model, wind turbine model including aerodynamic model and drive-train model, pitch control model and an optional wind farm level plant controller as indicated in Figure 2.7.

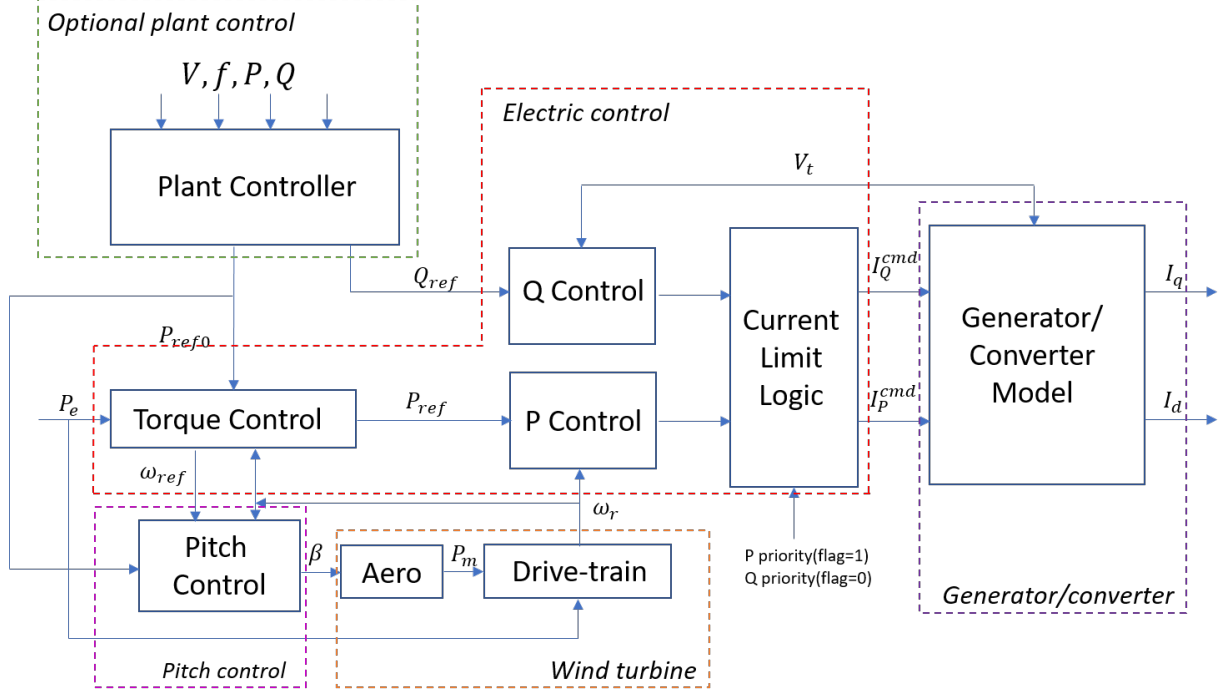


Figure 2.7: Overall structure of positive sequence DFIG model.

2.4.2 Generator and Converter Model

In the positive sequence representation, the generator/converter model is the equivalent of the generator and field converter, and serves as the interface connecting the wind turbine generator to the grid. Due to the fast response of the converter, the flux dynamics are neglected to get a faster response to a higher level control command [80]. The generator is modeled as a controlled current source, while the decoupled active current I_P and the excitation current I_Q determine the required active/reactive power injection to the grid. Two first-order low-pass filters with a time constant of $T_g = 20$ ms will represent the converter control systems [66]. The equations of the generator/converter model can be expressed as [81]:

$$\begin{aligned} \frac{dI_Q}{dt} &= \frac{-1}{T_g}(I_Q^{cmd} - I_Q) \\ \frac{dI_P}{dt} &= \frac{1}{T_g}(I_P^{cmd} - I_P) \end{aligned} \quad (2.1)$$

$$\begin{bmatrix} I_d \\ I_q \end{bmatrix} = \begin{bmatrix} \cos \delta & \sin \delta \\ \sin \delta & \cos \delta \end{bmatrix} \begin{bmatrix} I_P^{lim} \\ I_Q^{lim} \end{bmatrix} \quad (2.2)$$

$$I_P^{lim} = I_P P_g^{lim} \quad (2.3)$$

$$I_Q^{lim} = \begin{cases} I_o^{lim}; & (I_Q - I_c) < I_o^{lim} \\ I_Q - I_c; & (I_Q - I_c) \geq I_o^{lim} \end{cases} \quad (2.4)$$

$$I_c = \begin{cases} 0; & V_t \leq V_o^{lim} \\ K_{hv}(V_t - V_o^{lim}); & V_t > V_o^{lim} \end{cases} \quad (2.5)$$

$$P_g = I_P V_t$$

$$Q_g = -I_Q V_t \quad (2.6)$$

$$I_{inj} = I_d + jI_q$$

where I_P and I_Q are the active and reactive current, I_d and I_q are the d-axis and q-axis current, I_P^{lim} and I_Q^{lim} are the active and reactive current limits, I_P^{cmd} and I_Q^{cmd} are the active and reactive current commands, V_o^{lim} and I_o^{lim} are the voltage and current limits for high voltage compensation, I_c is the total compensation current, and K_{hv} is the high voltage compensation gain.

2.4.3 Electric Control Model

The electric control model determines the amount of active/reactive power the wind turbine generator should deliver to the grid through active/reactive current control loop as shown in Figure 2.8 and 2.9.

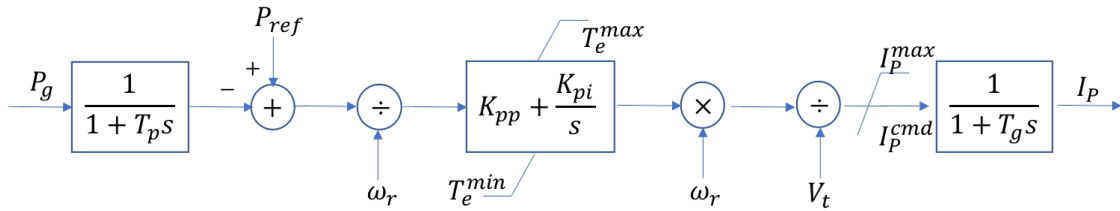


Figure 2.8: Active power control loop of DFIG

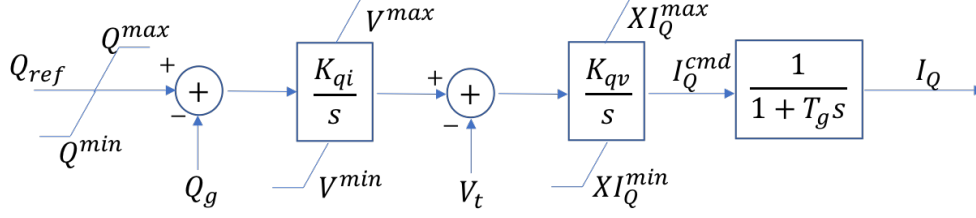


Figure 2.9: Reactive power control loop of DFIG

The electric control model can be divided into two sub-models with a converter current limit logic to limit the active/reactive current within converter ratings. Since the active and reactive power control loop are decoupled, both of them can be externally controlled by the wind farm level controller. One PI controller and one integral controller are utilized to regulate the active and reactive power and follow the P/Q set-points provided by the wind farm level plant controller.

2.4.4 Wind Turbine Model

Aerodynamic Model

The aerodynamic model is used to compute the wind turbine mechanical power P_m extracted from a wind turbine. The expression of P_m is:

$$P_m = \frac{1}{2} \rho A C_p(\lambda, \beta) V_w^3 \quad (2.7)$$

where C_p represents the power coefficient. Three types of C_p functions can be used to represent the power coefficient depending on the required level of details [82]. In this work, a most accurate three-dimensional aerodynamic model instead of simplified low-dimensional generic aerodynamic model is considered to design the DFIG active power controllers. Then C_p can be represented by a function of tip-speed-ratio λ and pitch angle β :

$$C_p = 0.22 \left(\frac{116}{\lambda_i} - 0.4\beta - 5 \right) e^{\frac{-12.5}{\lambda_i}} \quad (2.8)$$

and

$$\frac{1}{\lambda_i} = \frac{1}{\lambda + 0.08\beta} - \frac{0.035}{\beta + 1} \quad (2.9)$$

The tip speed ratio λ is the ratio between the tip speed $V_{tip} = \omega_r R$ and the wind speed V_w :

$$\lambda = \frac{V_{tip}}{V_w} = \frac{\omega_r R}{V_w} \quad (2.10)$$

For a given wind speed, there exists a corresponding optimal rotor speed used to determine the maximum potential power with maximized C_p . The equations above show that the input to the aerodynamic model is the wind speed V_w , pitch angle β and rotor speed ω_r . And the output is the mechanical (shaft) power P_m . The parameters used in (2.7) - (2.10) can be found in [83].

Drive-train Model

The mechanical drive-train model takes the input of P_m from aerodynamic model and the P_e measurement from machine terminal. In this research work, the gear box is assumed to be stiff and the one-mass drive train model is considered. The shaft dynamic can be represented as:

$$\frac{d\omega_r}{dt} = \frac{1}{2H_t}(P_m - P_e) \quad (2.11)$$

2.4.5 Pitch Control

The generic pitch angle controller includes a pitch angle control loop to limit rotor speed to prevent over-speed and a pitch compensation loop to limit the active power order. The block diagram is shown in Figure 2.10.

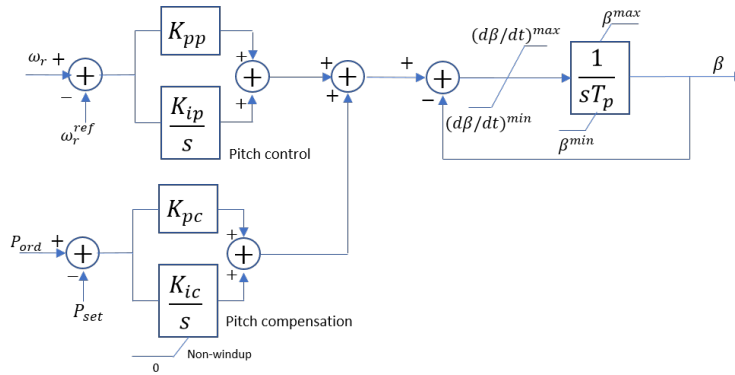


Figure 2.10: Block diagram of pitch control

The pitch angle control is rate-limited and the response of pitch angle control is relatively slow compared to the electric control. The DFIG is assumed to be operated in partial loaded condition (below rated) throughout this work, thus the pitch angle is kept as optimal (in this case is zero) and pitch control is assumed not activated during frequency support period.

2.4.6 Aggregate Wind Farm Model

A typical wind farm usually consists of tens to hundreds of wind turbine generators with each of them connecting to different feeders through step-up transformers and collector systems. Then the voltage is stepped up from the collector system level to the transmission grid level through a substation transformer [76]. This single aggregate equivalent wind farm model is shown in Figure 2.11 and will be used in the case studies in Chapter 7.

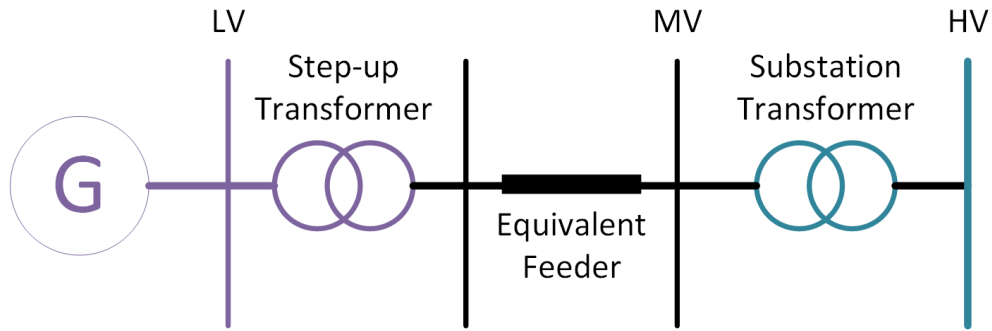


Figure 2.11: Aggregate representation of a wind farm

Chapter 3

Wind Turbine Generator Modeling Considerations for Stability Study of Weak System

Different types of power system studies require different level of modeling details. The existing approaches that are widely used for modeling wind turbine generators (WTG) for power system studies mainly fall into two categories: an electromagnetic transient (EMT) model and a generic positive sequence phasor (PS) model. The EMT analysis involves the detailed representation of components to ensure that models are accurate and valid [81]. This model covers a wide frequency-band-width requiring greater computational efforts which may not suitable for large-scale power system applications. Existing generic models developed for large-scale system planning and stability study are usually positive sequence models. These models are valuable since they are well-understood and portable across multiple software platforms [84]. However, in order to make the models generic and flexible enough to cover a sufficiently wide range of possible control strategies, PS model also has limitations [84]. For example:

- PS model usually considers dynamics approximately in the range of 0.1 Hz to 3 Hz. All converter high-frequency controls run in kHz range are simplified and modeled as algebraic

- The converter phase-lock loop (PLL) is usually neglected due to its very fast response rate
- PS model assumes the inner current control loops are fast enough to reach targeted reference value, thus the detailed representation of converter models can be ignored

The time scale of frequency control and stability study usually ranges from milliseconds to minutes. The inner current control loop is fast enough to track the set-point in milliseconds, this types of dynamics will not impact the system frequency response thus can be neglected. Thus, positive sequence model is valid for frequency response study. However, it may not valid for severe fault condition especially in weak system condition. In this chapter, the characteristics and performance of two predominantly used wind turbine generator models, i.e. positive sequence model and EMT model, are compared and evaluated with various WTG control strategies under different system operating conditions.

3.1 Comparison of Multiple Wind Turbine Generator Models

3.1.1 Positive Sequence Model

In this chapter, the Type-IV wind turbine generator model is used for comparison study. The wind farm representation, the generator and converter model and the electrical control model for positive sequence representation is similar as Type-III wind turbine generator model which are introduced in Chapter 2. The difference exists in the fact the Type-IV does not included the Pitch control, Torque control and Aerodynamic model that are shown in Figure 2.7 in Chapter 2. In this model representation, depending on the input reference to the electric control model, various reactive power control options can be selected, such as, local Q-control, local V-control, constant Pf-control and Q/V control. In this work, voltage control (V control) is considered as the main control approach for wind turbine generator operation. A current limiter module is used to prevent injected current exceeding rated value according to requirements.

If the control mode is set as P-priority:

$$\begin{aligned}
I_Q^{max} &= \min(VDL1, \sqrt{I_{max}^2 - I_{Pcmd}^2}) \\
I_Q^{min} &= -I_Q^{max} \\
I_P^{max} &= \min(VDL2, I_{max}) \\
I_P^{min} &= 0
\end{aligned} \tag{3.1}$$

If the control mode is set as Q-priority:

$$\begin{aligned}
I_Q^{max} &= \min(VDL1, I_{max}) \\
I_Q^{min} &= -I_Q^{max} \\
I_P^{max} &= \min(VDL2, \sqrt{I_{max}^2 - I_{Pcmd}^2}) \\
I_P^{min} &= 0
\end{aligned} \tag{3.2}$$

where $VDL1$ and $VDL2$ are piece-wise linear curves defined by the users. I_P^{max} and I_Q^{max} are the maximum active/reactive current limit during low voltage events.

3.1.2 EMT-type Model

The Type-IV EMT-type wind model assumes a synchronous generator connected to the grid through back-to-back frequency converters, with a stator side converter (MSC) and a grid side converter (GSC). Depending on the size of the wind turbine, a MSC can be either a diode rectifier or a voltage-source converter (VSC), while GSC is typically a VSC.

Wind Farm Representation

Similar to positive sequence representation, the EMT wind farm model is also represented by an aggregated model of multiple WTGs and wind turbine transformers with an equivalent collector grid model and wind farm controllers as shown in Figure 3.1.

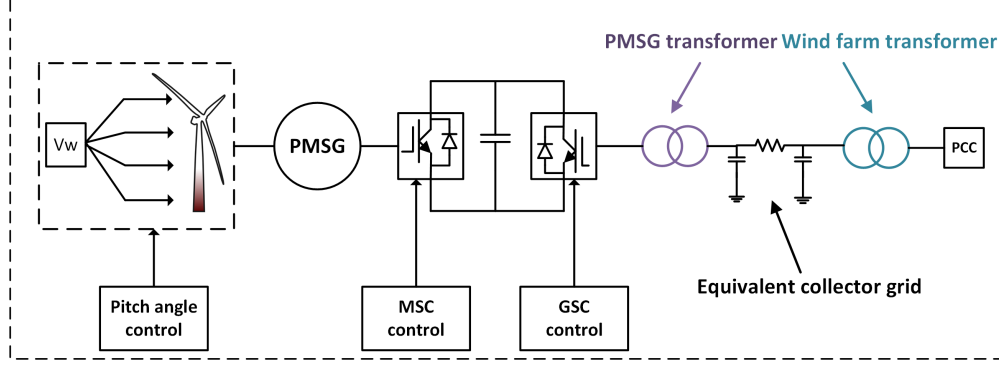


Figure 3.1: Wind farm representation in EMT model

Converter model

Two types of converter models are predominantly used in EMT study. One option is a detailed model (DM) with one IGBT switch, two non-ideal diodes and Pulse Width Modulation (PWM) model. The PWM receives three-phase reference voltages from converter control and generates the pulse pattern for the six IGBT switches by comparing the voltage reference with a triangular carrier wave. The other option is an average value model (AVM) which avoids IGBT switching by modeling a controlled voltage source on the AC side and controlled current source on the DC side to replicate the average response of switching devices. The controlled voltage source on the AC side is:

$$v_{ac} = v_{abc}^{ref} \frac{V_{dc}}{2} \quad (3.3)$$

where v_{abc}^{ref} is the three-phase reference voltage obtained from converter control. If neglecting the converter losses, the power equation is:

$$V_{dc} I_{inj} = \sum_{j=a,b,c} v_{source,j} i_{ac_j} \quad (3.4)$$

By combining (3.3) and (3.4), the controlled current source I_{inj} on the DC side is found from:

$$I_{inj} = \frac{1}{2} \sum_{j=a,b,c} v_{ref_j} i_{ac_j} \quad (3.5)$$

In contrast to positive sequence converter model, the phase-locked loop (PLL) can be modeled in detail in EMT model to provide the angle reference for the voltage and current coordinate transformations. The closed loop nature of PLL provides stability and error rejection for angle estimation [85]. The classic PLL diagram is shown in Figure 3.2.

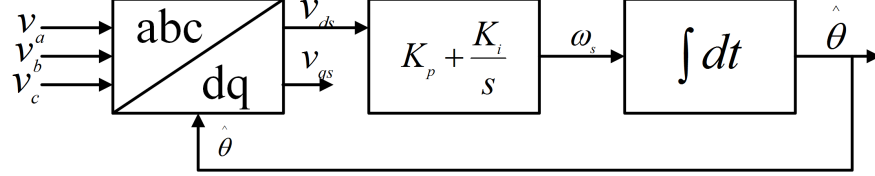


Figure 3.2: PLL structure diagram

Electrical Control Model

In EMT model, the control of a WTG is achieved by controlling the MSC and GSC using vector control approach, which decouples the active and reactive control loop. The MSC is operated in the stator flux reference frame while GSC is operated in the stator voltage reference frame. The d- and q- axis current of the MSC are used to control active and reactive power outputs of the PMSG. The q-axis current of GSC is used to control reactive power and the d-axis current is used to maintain DC bus voltage. Both of the GSC and MSC involves two control loops, namely, the outer control and inner control loops. The outer loop provides the reference dq-frame current (i.e. I_{qg} , I_{dg} , I_{qm} and I_{dm}) in a relatively longer time-scale. The inner loop is the fast control loop used for generating modulated switching pattern. EMT model also employs the current limiter module to prevent over current. If the priority is given to the active current, it has:

$$I_{qr}^{lim} = \sqrt{I_{max}^2 - (I_{dr}^{lim})^2} \quad (3.6)$$

with $I_{dr}^{lim} = 1.0$ p.u, else if priority is given to reactive current to fulfill fault ride through (FRT) requirements, it has:

$$I_{dr}^{lim} = \sqrt{I_{max}^2 - (I_{qr}^{lim})^2} \quad (3.7)$$

with $I_{qr}^{lim} = 1.0$ p.u, where I_{qr}^{lim} , I_{dr}^{lim} and I_{max} are the limits for q-axis, d-axis and total MSC currents, respectively.

Protection Scheme

In addition to the regular dc resistant chopper controls, the EMT model also incorporates the protection system including over/under voltage protection relays and over-current protection for GSC and MSC. The wind unit will be disconnected when the voltage enters trip region and will stay connected when the voltage is below the high voltage ride through and above the low voltage ride through region. The overall modeling structure of EMT wind model is shown in Figure 3.3.

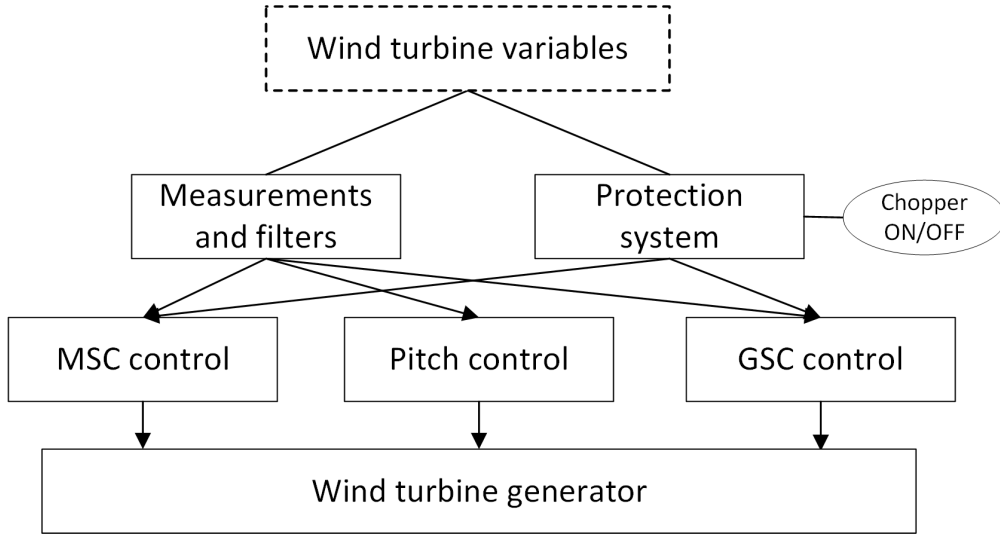


Figure 3.3: Overall structure of wind model in EMT

3.2 Benchmark System Development

In the case study, a 9-bus benchmark system is developed for both the positive sequence stability software program and the EMT software program. The one-line diagram of the developed system in positive sequence simulation software is shown in Figure 3.4 and the corresponding system in the EMT simulation platform is shown in Figure 3.5.

The system includes nine buses with an equivalent grid connected to Bus 21 and a wind farm connected to Bus 11. The equivalent grid can be regarded as an infinite bus. The wind

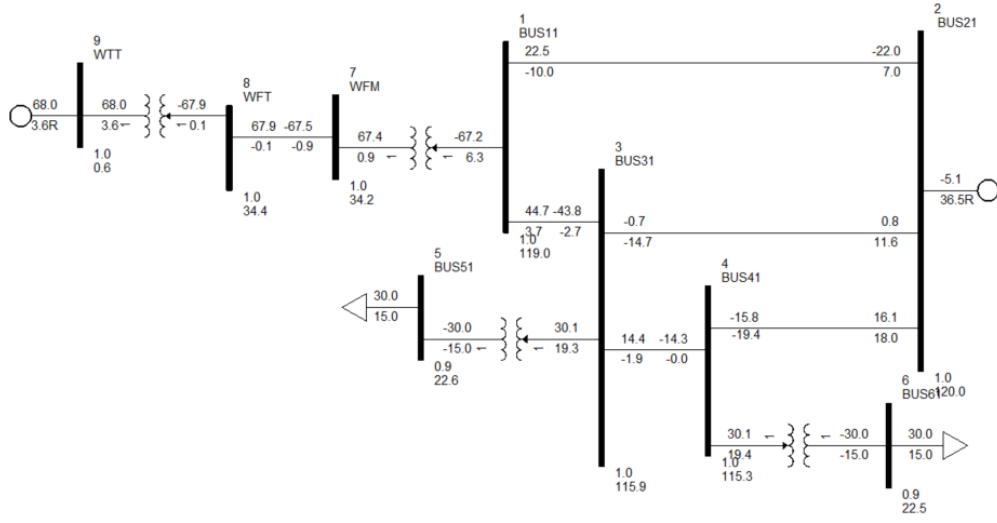


Figure 3.4: 9-bus benchmark system with WTG in positive sequence representation

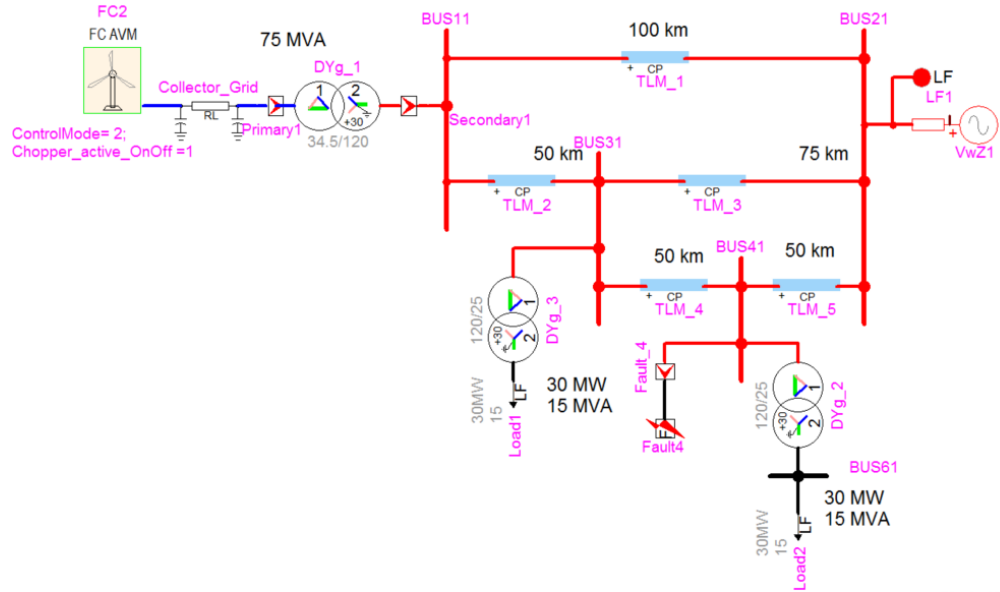


Figure 3.5: 9-bus benchmark system with WTG in EMT representation

farm consists of 34 2MW WTG with max/min Var limits specified by 0.95 power factor and is connected to Bus 11 through a 34.5kV/120kV step-up transformer. The 34.5kV collector grid is represented with an equivalent pi circuit.

3.3 Evaluation of System Strength by Short Circuit Ratio

The short circuit ratio (SCR) is an important indicator to quantify the strength of an electric power system. SCR is defined as the ratio of the interconnected grid's short circuit MVA to the MW rating of the interconnecting generator [86]. For the system shown in Figure 3.4, the SCR of the system with integration of WTG is calculated as:

$$SCR = \frac{S_{min}}{S_{wpp}} \quad (3.8)$$

where S_{min} is the minimum fault level at wind power plant without this wind power plant (MVA), and S_{wpp} is the rating of the interconnecting wind power plant (MW).

In this case study, the equivalent grid connecting to Bus 21 is modeled as constant voltage source (and infinite bus) behind impedance. Thus the strength of the system can be modified through adjusting the voltage source impedance. Based on Equation (3.8), two scenarios with a relatively large SCR representing a strong system and a relatively small SCR representing weak system are developed to evaluate the model performance. The SCR of the two scenarios and the corresponding parameters of the generators are shown in Table 3.1.

Table 3.1: Source parameters and corresponding SCR

Case Number	SCR	H_{sys}	D_{sys}	R_{source}	X_{source}
Case 1	5.21	5.0000	1.5000	0.0000	0.0250
Case 2	2.51	5.0000	1.5000	0.0069	3.0000

3.4 Case Study and Simulation Results

3.4.1 Evaluation of Model Performance with Various System Strength

The positive sequence WTG model is implemented for the benchmark system described as before for the positive sequence simulation software and the EMT model is implemented for the same system but for the EMT simulation platform. Since there is no protection module available in positive sequence software, any tripping or protection scheme in EMT is disabled for both of the scenarios. Before running time domain simulation, the power flow result has been verified and kept consistent across the simulation platforms. Wind speed is set as 15m/s and the wind farm is operated with unity power factor (i.e. $Q_{ref} = 0$). The following two system conditions are considered to compare the response the models.

- Scenario I: WTG with local voltage control in strong system ($SCR > 3$)
- Scenario II: WTG with local voltage control in weak system ($SCR < 3$)

A three-phase fault is applied between Bus 11 and Bus 61 at 1s in all six fault conditions and cleared at 1.2 s so the fault duration is 12 cycles. The active/reactive power and terminal voltage of WTG in strong system are plotted in Figure 3.6 through Figure 3.9.

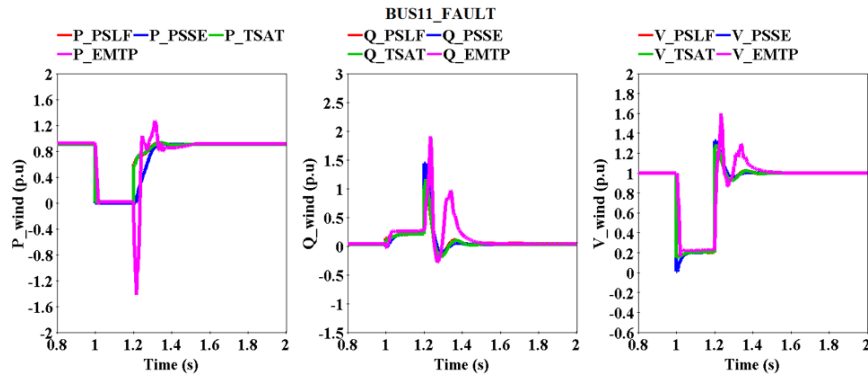


Figure 3.6: Output of WTG with 3-phase fault on Bus 11 for strong system

And the plots of the similar fault but in the weak system condition are shown in Figure 3.10 through Figure 3.13. From the simulation results shown above, the following observations can be summarized:

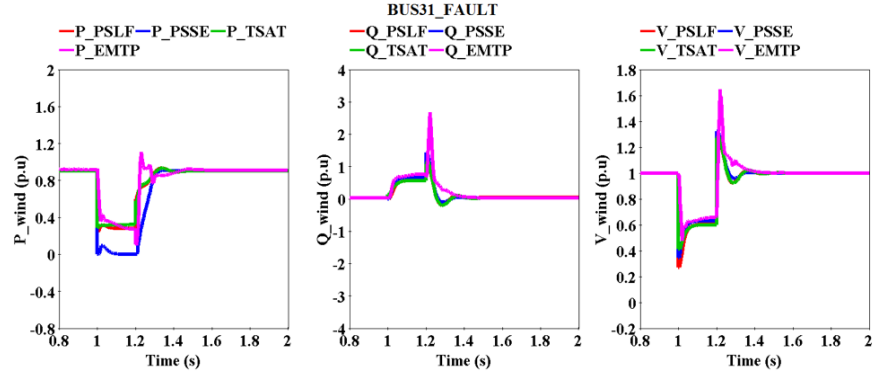


Figure 3.7: Output of WTG with 3-phase fault on Bus 31 for strong system

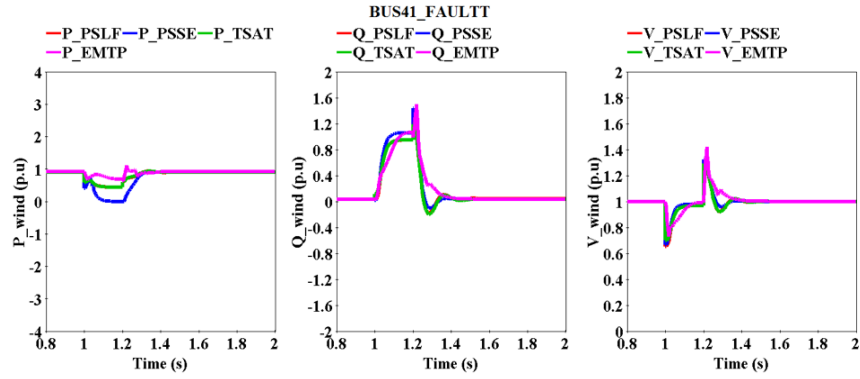


Figure 3.8: Output of WTG with 3-phase fault on Bus 41 for strong system

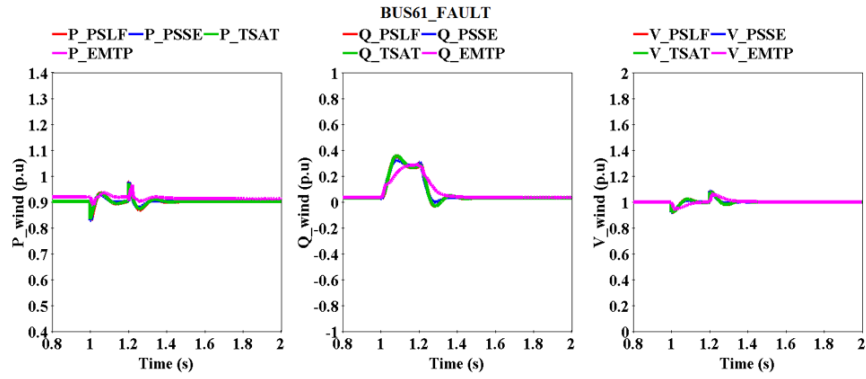


Figure 3.9: Output of WTG with 3-phase fault on Bus 61 for strong system

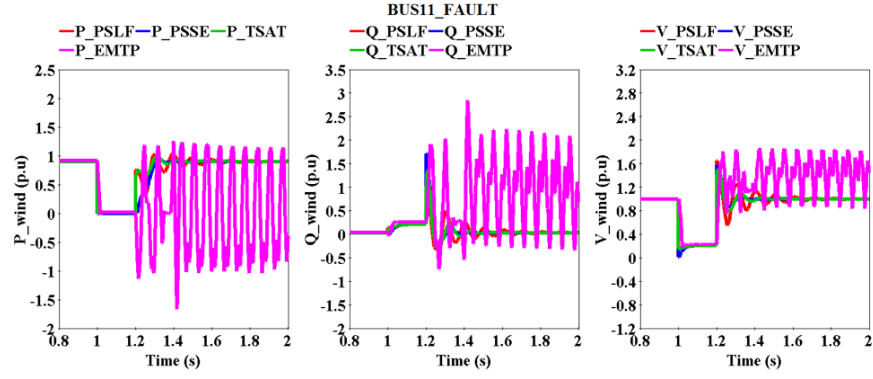


Figure 3.10: Output of WTG with 3-phase fault on Bus 11 for weak system

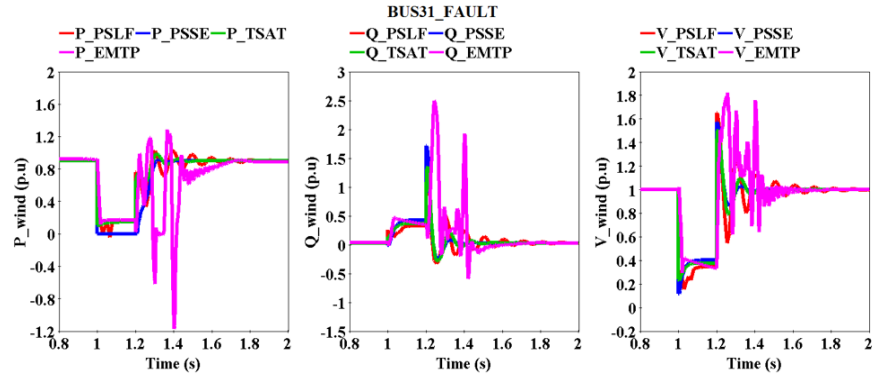


Figure 3.11: Output of WTG with 3-phase fault on Bus 31 for weak system

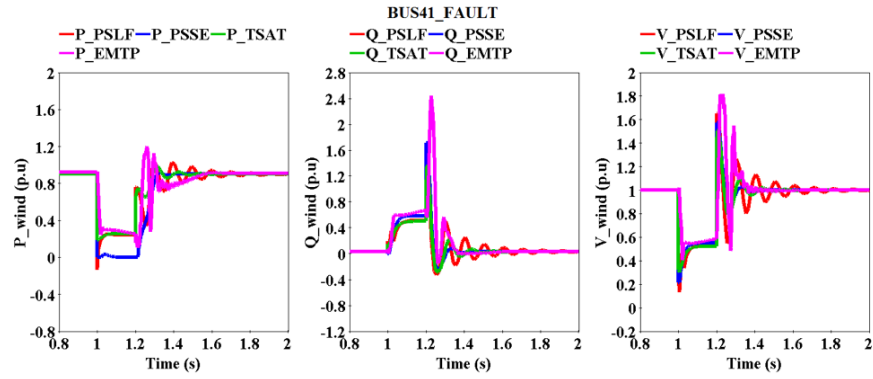


Figure 3.12: Output of WTG with 3-phase fault on Bus 41 for weak system

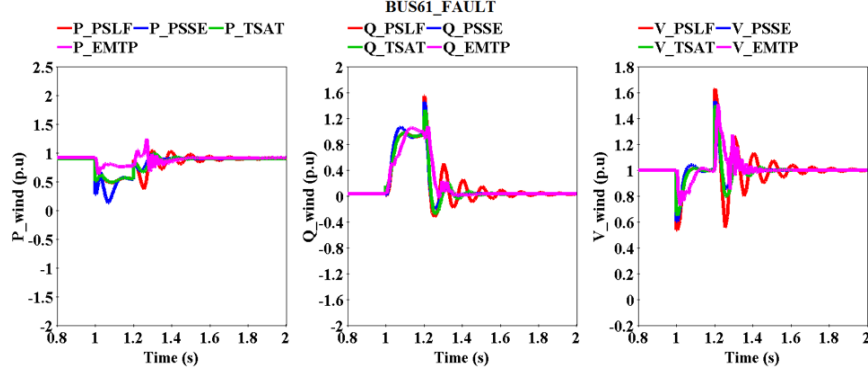


Figure 3.13: Output of WTG with 3-phase fault on Bus 61 for weak system

- In the strong system, the WTG with the voltage support function has the capability to respond to system fault and at the same time inject reactive current to help support voltage. The dynamic response of the positive sequence models in different positive sequence simulation platforms are identical, and is consistent with the EMT model response as well.
- In the weak system, the dynamic response of the EMT model differs from the positive sequence model. EMT model shows instability of PLL while the positive sequence model does not.

3.4.2 Limitations of Positive Sequence Model in Weak Systems

Based on the above figures it is observed that the positive sequence model may not be able to represent accurately the response of WTG when studying a weak system due to simplification of the converter models. As shown in Figure 3.14, a scaled version of Figure 3.10, due to the large voltage angle shifts, the PLL has a hard time to track the voltage angle reference, which may lead to instability of PLL and the WTG fast inner control loop. While in the positive sequence model, the PLL has been neglected, only the low voltage active current management logic is used to approximate the response of PLL during voltage drop, the instability issue during current injection to low voltage faults cannot be captured.

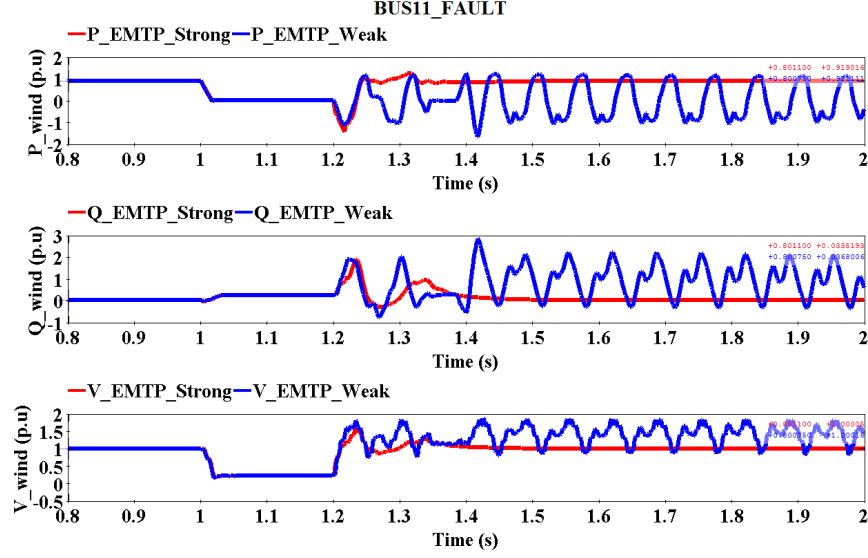


Figure 3.14: Comparison of response for strong and weak system

3.5 Conclusion

In this chapter, a preliminary comparison study on dynamic performance of two types of wind turbine generator models: positive sequence model and EMT-type model are performed. The case study and simulation results show that even while the positive sequence model is simple and well-developed, it is not sufficient to reveal the true transient response, especially in weak systems. The positive sequence model can not capture PLL and the fast inner loop instability due to simplification of converter settings. Keeping the capability of positive sequence simulation software while adding a more detailed RES model, i.e., a hybrid positive sequence and EMT model, is required. A hybrid simulation approach connecting the EMT model with a large scale positive sequence simulation platform is necessary for this types of study.

Chapter 4

Quantitative Control Approach for DFIG to Improve Inertial Response with Guaranteed Rotor Security

4.1 Maximum Power Point Tracking (MPPT)

The regular operation mode for DFIG in partial loaded zone is based on the widely used MPPT strategy as shown in Figure 4.1. For a given wind speed V_w , there exists a corresponding optimal rotor speed ω_r^{mppt} to extract the maximum potential power P_m^{mppt} with maximized power coefficient from the wind turbines. Then the curve connecting each maximum power point is the MPPT curve. For a measured rotor speed ω_r , the active power reference of DFIG in regular operation mode can be represented by:

$$P_{ref}^{mppt} = \begin{cases} \frac{1}{2}\rho A \frac{R^3}{\lambda^3} C_p(\lambda_{opt}, \beta=0, 0) \omega_r^3 = k_{opt} \omega_r^3, & \text{if } \omega_r < \omega_r^{max} \\ P^{max}, & \text{if } \omega_r \geq \omega_r^{max} \end{cases} \quad (4.1)$$

During frequency disturbance, the active power reference remains unchanged, the active power output of DFIG will quickly go back to the reference value under the fast control action of AC/DC/AC converters which decouples the rotor inertia from the system. Thus,

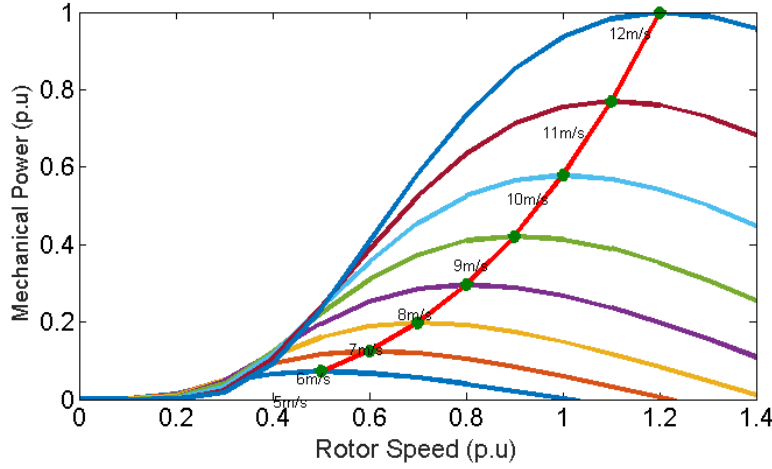


Figure 4.1: Maximum power point tracking reference curve

the DFIG will not contribute to frequency response in this mode. The MPPT strategy is well documented in, e.g., [87], so details will not be discussed further here.

To couple to rotor inertia to the system, chapter 2 reviews the existing DFIG control approaches for improving inertial response within the traditional DFIG control framework. A general idea is to introduce a injection signal ΔP as a supplementary control loop, adding to the VSWTG power reference as shown in Figure 4.2. The injection signal can either be proportional to the ROCOF or frequency deviation or based on a pre-programmed fixed trajectory curve.

With ΔP added to the initial active power reference P_{ref}^{mppt} , due to fast response of converter control action, the electrical power output will quickly increase to $P_{ref}^{mppt} + \Delta P$, but turbine aerodynamic power will remain near P_m . Referring to Equation (2.11) in Chapter 3, the active power mismatch between P_m and P_e will force the rotor speed to decelerate and the stored kinetic energy will be released. It can be observed that the more injected active power the lower the rotor speed, the active power injection should be carefully designed to avoid stalling the rotor. Moreover, DFIGs in different operating conditions (with different wind speed) will have different rotor speed reduction capability. Then the following two questions need to be solved in order to utilize multiple DFIGs to provide inertial response.

1. How to quantitatively design the active power injection to maximize a DFIGs contribution without violating operational constraints?

2. How to coordinate multiple DFIGs under different operating conditions to provide an adequate inertial response?

This chapter investigates these two questions and proposes a possible solution - a quantitative control approach referred as temporary power injection (TPI) for DFIG to provide fast frequency response with guaranteed rotor security. First, the maximum power injection for a given DFIG is identified based on wind turbine maximum extricable energy and the minimum allowable rotor speed. Then a coordination scheme is presented for DFIGs with different wind speed to deliver an adequate response.

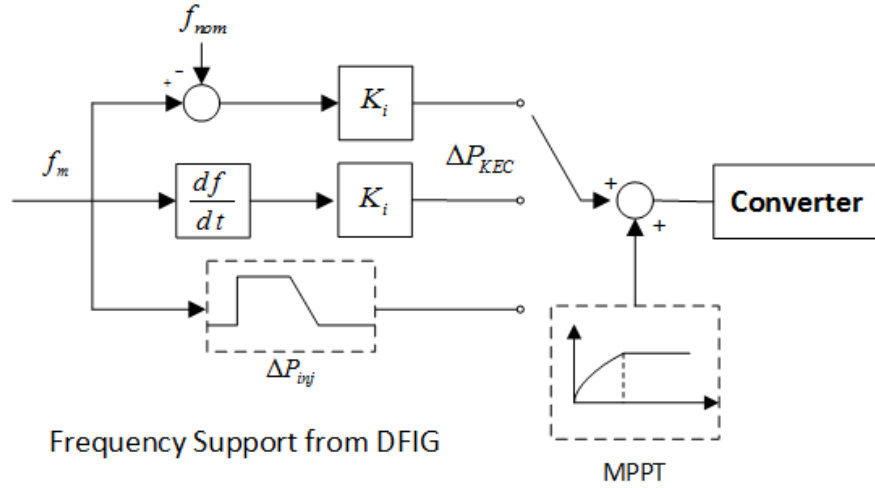


Figure 4.2: Three types of DFIG inertial support

4.2 Temporary Power Injection (TPI)

During normal operation, DFIG still operates under MPPT. During frequency disturbance, the MPPT mode is bypassed, the TPI mode is activated to inject excess active power ΔP_{del}^{tpi} from the wind turbine and the ΔP_{del}^{tpi} is added to the initial active power reference P_{ref}^{mppt} . With no reserve allocated, the DFIG on TPI mode is expected to only provide temporary frequency support, the active power output will finally return to maximum power point, and thus, the overall response should include a short over-production period and a recovery period as shown in Figure 4.3 to allow for rotor speed restoration.

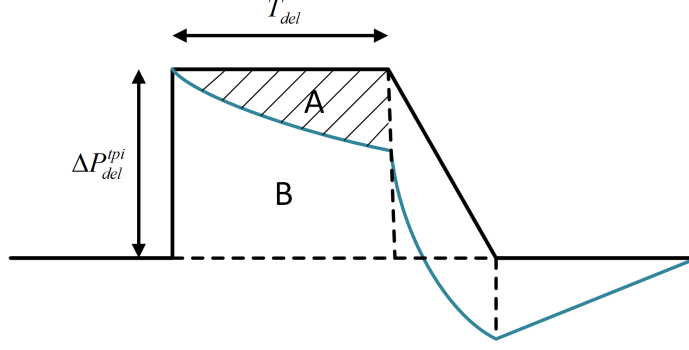


Figure 4.3: Active power injection for TPI

The more energy extricated from wind turbines, the more injected active power DFIG can provide and the more reduction the rotor speed. To avoid stalling the rotor we propose to calculate the exact amount of power injection based on estimated maximum extricable energy with consideration of operating constraints.

4.2.1 Maximum Active Power Injection with Guaranteed Rotor Security

From energy point of view, the energy balance for DFIG in TPI mode can be expressed as follows [20]:

$$\Delta E_{aero} - \Delta E_e - \Delta E_{loss} - \Delta E_{kic} = 0 \quad (4.2)$$

where ΔE_{aero} is the aerodynamic energy variation (due to reduction of P_m), ΔE_e is the electric energy variation, ΔE_{loss} is the energy losses, ΔE_{kic} is the kinetic energy variation. Assuming wind speed is constant during a temporary power injection period T_{del} :

$$\Delta E_{aero} = \int_0^{T_{del}} \Delta P_m dt = KV_w^3 \int_0^{T_{del}} \Delta C_p dt \quad (4.3)$$

Approximating ΔC_p as the first two terms of Taylors series yields [20]:

$$\Delta C_p = \frac{\partial C_p}{\partial t} \Big|_{t=0} t + \frac{\partial^2 C_p}{\partial t^2} \Big|_{t=0} \frac{t^2}{2} \quad (4.4)$$

Further assuming the rotor speed deviation is constant, while $d\omega_r/dt = \text{const}$, the partial derivative of the power coefficient in (4.4) can be approximately expressed as:

$$\begin{aligned}\frac{\partial C_p}{\partial t}|_{t=0} &= \frac{\partial C_p}{\partial \lambda} \frac{\partial \lambda}{\partial \omega_r} \frac{\partial \omega_r}{\partial t}|_{t=0} = \frac{R}{V_w} \frac{\partial C_p}{\partial \lambda} \frac{\partial \omega_r}{\partial t}|_{t=0} \\ \frac{\partial^2 C_p}{\partial t^2}|_{t=0} &= \left(\frac{R}{V_w}\right)^2 \frac{\partial^2 C_p}{\partial \lambda^2} \left(\frac{\partial \omega_r}{\partial t}\right)^2|_{t=0} + \frac{R}{V_w} \frac{\partial C_p}{\partial \lambda} \frac{\partial^2 \omega_r}{\partial t^2}|_{t=0}\end{aligned}\quad (4.5)$$

Combining (4.3), (4.4) and (4.5) and considering the integration time T_{del} :

$$\begin{aligned}\Delta E_{aero} &= \frac{1}{2} K R V_w^2 \frac{\partial C_p}{\partial \lambda}|_{t=0} T_{del} \Delta \omega_r \\ &+ \frac{1}{6} K R^2 V_w \frac{\partial^2 C_p}{\partial \lambda^2}|_{t=0} T_{del} \Delta \omega_r^2\end{aligned}\quad (4.6)$$

where

$$K = \frac{1}{2} \rho A = \frac{1}{2} \rho \pi R^2 \quad (4.7)$$

Also, the kinetic energy variation is:

$$\Delta E_{kic} = \frac{1}{2} J (\omega_{r2}^2 - \omega_{r1}^2) \quad (4.8)$$

and the electric energy variation is:

$$\Delta E_e = \int_0^{T_{del}} \Delta P_{del} dt = \Delta E_{del} \quad (4.9)$$

The energy losses variation can be approximately expressed by mechanical losses as:

$$\Delta E_{loss} = (1 - \eta) \Delta E_{aero} \quad (4.10)$$

where η is the energy efficient. Thus, combining (4.2), (4.6), (4.8), (4.9) and (4.10), the overall energy delivered during power injection period can be expressed as:

$$\begin{aligned}
\Delta E_{del} = & \left(\frac{\eta}{12} K V_w^2 \frac{\partial C_p}{\partial \lambda} \Big|_{t=0} - J \frac{\omega_r(0)}{\omega_s^2} T_{del} \right) \Delta \omega_r \\
& + \left(\frac{\eta}{36} K V_w^2 \frac{\partial C_p}{\partial \lambda} \Big|_{t=0} + \frac{\eta}{216} K V_w \frac{\partial^2 C_p}{\partial \lambda^2} \Big|_{t=0} \right. \\
& \left. - \frac{J}{2\omega_s^2} T_{del} \right) \Delta \omega_r^2
\end{aligned} \tag{4.11}$$

Equation (4.11) reveals the relationship between the delivered energy ΔE_{del} , the rotor speed deviation $\Delta \omega_r$ and the delivery time T_{del} . By specifying T_{del} and allowable maximum rotor speed deviation $\Delta \omega_r^{max}$, the maximum extricated energy and the corresponding power injection ΔP_{del} can be calculated as:

$$\Delta P_{del} \approx \frac{\Delta E_{del}(\Delta \omega_r^{max}, T_{del})}{T_{del}} \tag{4.12}$$

Note when applying the calculated maximum power injection, the actual energy released by DFIG is smaller than calculated. As shown in Figure 4.3, the supplementary power reference is represented by the black curve, but the true response curve is shown in blue. The response reduces the rotor speed (the $k_{opt}\omega_r^3$ term in (4.1)), and thus, reduces the power reference and tapers off the ideal inertial response [52]. A similar observation is obtained in [52]. While the calculation is conservative, this can guarantee the rotor speed of DFIG always remains higher than the minimum allowable limit, and no additional rotor speed protection scheme is required.

A DFIG rotor speed response example with $V_w = 9.4$ m/s and the minimum allowable rotor speed $\omega_r^{min} = 0.7$ p.u is shown in Figure 4.4 to illustrate the conservative nature of the result. It can be verified that with the calculated maximum active power injection signal, the actual rotor speed is reduced to 0.73 p.u with a margin from the minimum allowable rotor speed limit.

Another constraint that must be taken into consideration when calculating the maximum active power injection is the converter limit (here assumed to be 20% above the rated as $P_g^{lim} = 1.2$ p.u). Finally, the maximum power injection of a DFIG on TPI mode at a given

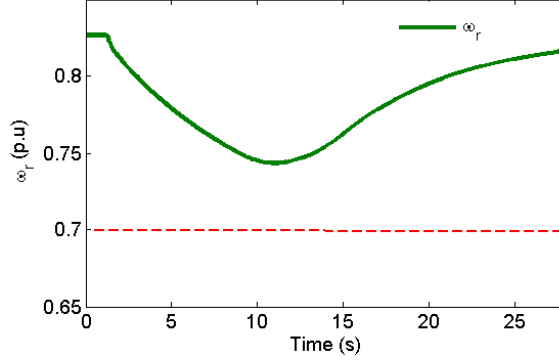


Figure 4.4: Illustrative example of conservative nature of TPI

wind speed V_w can be expressed as:

$$\Delta P_{del}^{tpi}(V_w)|_{max} = \Delta P_{del}^{max} = \min(\Delta P_{del}, P_g^{lim} - P_0(V_w)) \quad (4.13)$$

where $P_0(V_w)$ is the initial operating point of DFIG with wind speed V_w .

Figure 4.5 shows an example of the allowable maximum active power injection for DFIG under various wind speed V_w given different delivery time T_{del} . It can be seen that for a given wind speed, the larger the delivery time, the smaller the maximum active power injection capability. For a given delivery time, the active power injection capability for DFIG first increases and then decreases as wind speed increases. This is due the joint effect of rotor speed limit and converter overload limit. Figure 4.5 can be saved as a look-up table and used as a criteria for on-line selection of DFIGs for delivery of inertial response.

4.3 Coordinated Control Framework for Multiple DFIGs to Provide Adequate Inertial Response

4.3.1 Sensitivity Measure of Frequency Nadir to Active Power Injection

Consider the low-order frequency response model shown in the Figure 4.6.

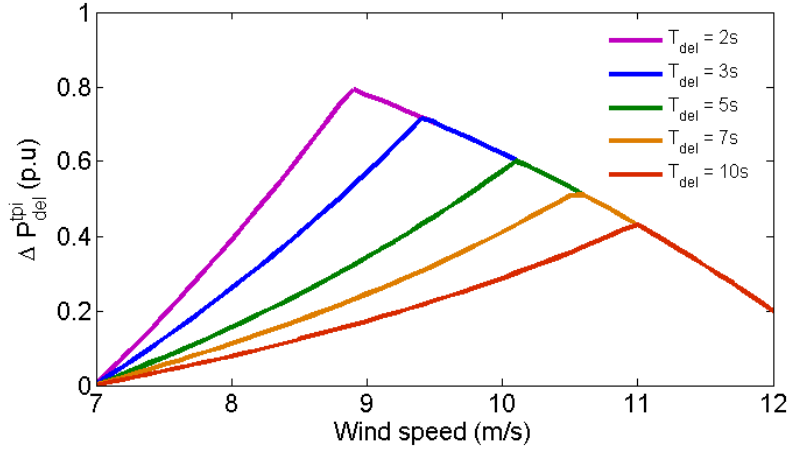


Figure 4.5: Maximum power injection curve for TPI

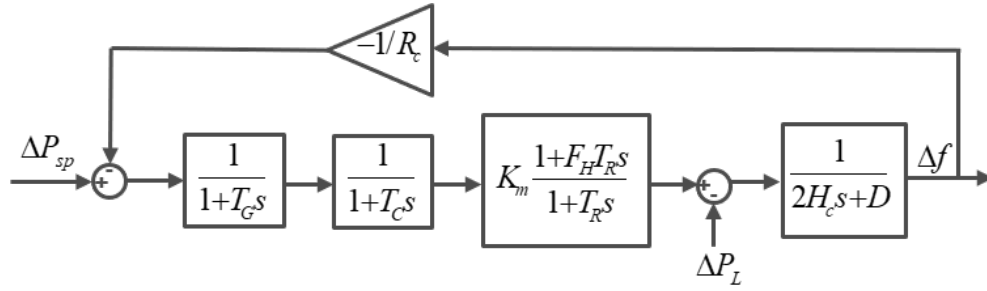


Figure 4.6: Low-order power system model.

The frequency nadir of this system is given by:

$$f_{na} = f_b \left(1 - \frac{R_w}{K_m + D R_w} [1 + \alpha e^{-\xi \omega_n t_n \sin(\omega_t t_n + \phi)}] \Delta P_L \right) \quad (4.14)$$

The parameters and the notations of the variables are given in Chapter 6. It can be verified that the overall net injected active power ΔP to the system has a near linear relationship with the system frequency nadir f_{na} . This relationship is further verified by a detailed transient simulation result of a nonlinear power system with a generator trip event as shown in Figure 4.7.

The above analysis indicates the sensitivity measure of frequency nadir incremental to the active power change can be assessed by the matrix $S = \partial \Delta f_{na} / \partial \Delta P$ for DFIGs with different wind speed using offline transient simulations. With $\Delta P = \Delta P_{del}^{tpi}|_{max}$, the minimum commitment number (u) of DFIGs to meet the minimum frequency nadir improvement

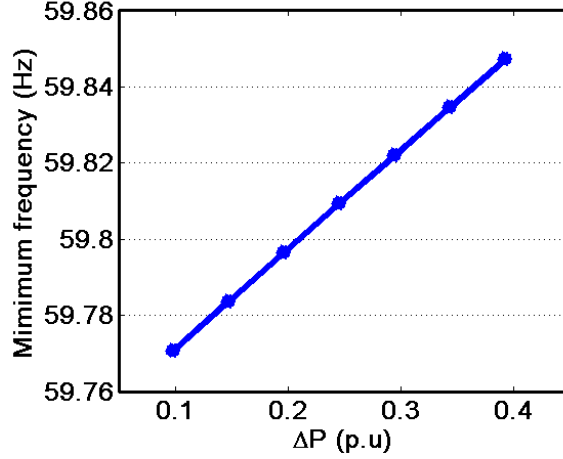


Figure 4.7: f_{na} varies with ΔP

requirement Δf_{na}^{min} can be computed for each possible under-frequency events by solving the unit commitment problem as:

$$\begin{aligned}
& \text{minimize} && u \\
& \text{subject to} && \Delta f_{na}|u \geq \Delta f_{na}^{min}, \\
& && \Delta f_{na} = S * \Delta P, \\
& && u \in [0, 1]
\end{aligned}$$

4.3.2 Overall Offline Schedule and Online Selection Scheme

The proposed coordination framework includes two levels: wind farm level set-point generation and wind turbine level set-point tracking. It is assumed that the short term wind speed prediction is available every 5-min and updated every 1-min. The sensitivity matrix S , the maximum power injection $\Delta P_{del}^{tpi}(V_w)|_{max}$ for TPI can be obtained and stored in a database offline. During on-line operation, the minimum number of DFIGs on TPI that need to provide frequency support is scheduled at the beginning of each 5-minute scheduling period. Once the frequency deviation out of the specified dead-band is detected, the on-line process activates the scheduled DFIGs to ensure the frequency nadir be above the specified threshold. The updated power reference is then calculated for wind turbine level set-point

tracking. The overall flow-chart of the off-line schedule and on-line selection is shown in Figure 4.8.

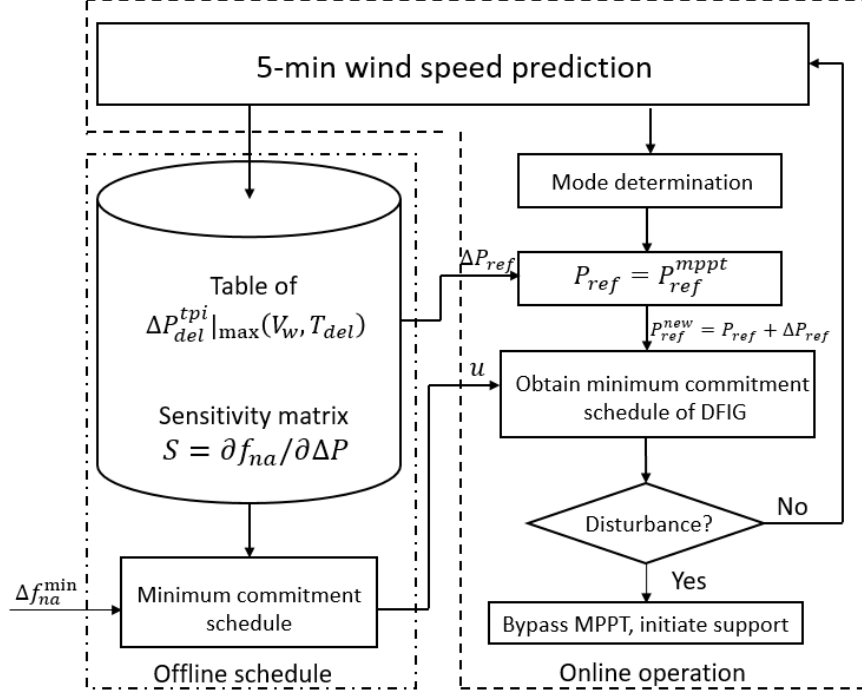


Figure 4.8: Flowchat of proposed control approach

One PI controller and one integral controller are utilized in the wind turbine level to regulate the active and reactive power and follow the P/Q set-points provided by the wind farm level. Here we assume the DFIG is operated under unity power factor in which case the reactive power set point is set as 0.

4.4 Issues of Inertial Emulation Approaches

TPI mode assumes DFIG is still operated in MPPT mode without reserve during normal operation. Since there is no reserve allocated, the rotor speed needs to be restored back to MPPT mode after delivery period so it only improves the frequency nadir and ROCOF and has no impact on the steady-state settling frequency. Besides, during recovery period the DFIG will absorb the active power from the grid and may have a delayed frequency recovery

(secondary frequency dip) problem. The amount of secondary frequency dip can be reduced if increasing the recovery time. Similar issue can be identified with other types of inertial emulation approaches (i.e., Δf response). The secondary frequency dip can only be avoided when DFIG is in reserve mode or compensated by other types of resources such as energy storage or demand response.

4.5 Conclusion

This chapter presents a quantitative control approach for DFIG to provide fast frequency response by incorporating a supplementary power surge function to the existing MPPT reference. The approach considers the trade-off between maximum contribution of DFIG and the DFIG rotor security. The supplementary power surge amount is carefully designed considering maximum active power injection capability of each DFIG and the converter overload limits. And rotor limits can be maintained without additional actuator for rotor speed protection.

Chapter 5

Power Reserve Control for DFIG to Improve Primary Frequency Response

The quantitative TPI approach introduced in the previous chapter only improves ROCOF and frequency nadir with no support for primary frequency control. And the secondary frequency dip due to the rotor recovery will become more severe in the condition of higher wind penetration with more conventional generators being forced offline, when the reduced governor actions may not be sufficient enough to recover the primary settling frequency and brings new burden to the secondary frequency control. The secondary frequency dip can only be avoided when DFIG is in reserve mode or compensated by other types of resources. Operating DFIG in reserve mode is not prevalent in today's market since it requires sacrificing wind power plant revenue from energy sales. However, PRC can an alternative option for wind producers to comply with interconnection standards while the revenue loss can be compensated by participating in regulation markets [55] [88].

This chapter proposed a PRC approach for DFIG to mitigate the secondary frequency dip and at the same time improve the primary settling frequency. By estimating the transient active power injection amount, and the maximum reserve margin. The rotor security of DFIG is guaranteed and the operating points can be adjusted to support both under-frequency and over-frequency events.

5.1 Power Reserve Control (PRC)

PRC requires DFIG operating in a non-optimal (de-loaded) mode so a certain amount of generating margin can be saved to allow contribution to primary or secondary frequency control. The root source of PRC is through the reduction of the power coefficient C_p . According to (2.7) and (2.10) in Chapter 2, PRC can be achieved by either adjusting rotor speed ω_r or blade pitch angle β . Figure 5.1 shows the power reserve options in PRC mode with respect to ω_r and β for different wind speed. In zone 2 where the rotor speed of DFIG is below the maximum speed limit, both pitch angle control and rotor speed control are achievable to maintain a certain level of reserve. While in zone 3, the rotor speed of DFIG already reaches the maximum limit, only pitch angle control is feasible to adjust the reserve levels.

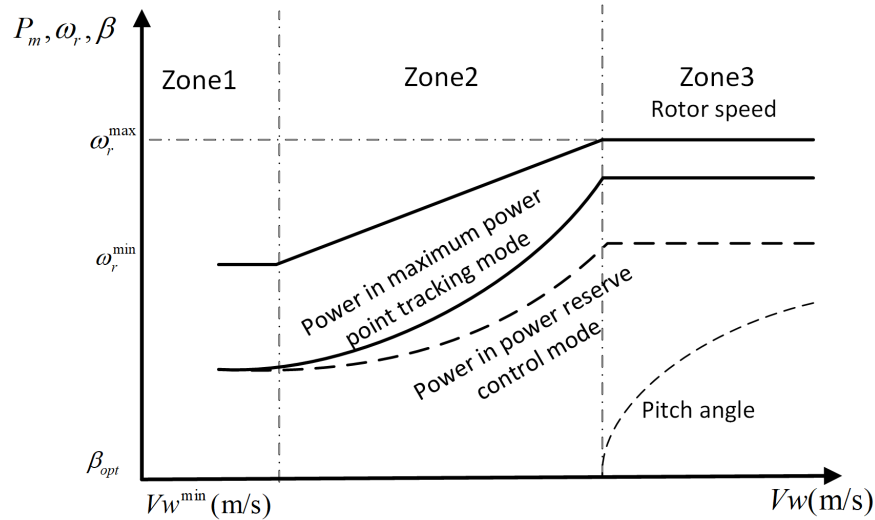


Figure 5.1: Power reserve control options for DFIG

Pitch angle control is slow and frequent adjustment of pitch angles can increase mechanical switching and losses. In practice, the good wind sites usually have an average wind speed around 7 m/s to 10 m/s and very high wind speeds seldom occur [76]. Actually, the wind speed of DFIG in zone 2 has a higher probability density according to the study in [89]. Thus, rotor angle based PRC is preferable and is considered as a first option when wind speed is in zone 2 in this work. The pitch angle is kept at optimal and pitch control is only initiated when wind speed is high to prevent over-speeding [59].

When wind speed is in zone 2, either allowing rotor speed to be higher than the optimal value (green curve in Figure 5.2) or lower than the optimal value (turquoise curve in Figure 5.2) will reduce power coefficient; however, under-speeding based PRC may reduce the small signal stability while over-speeding based PRC can actually improve the small signal stability as studied by [90]. Accordingly, only over-speeding based PRC is considered in this work.

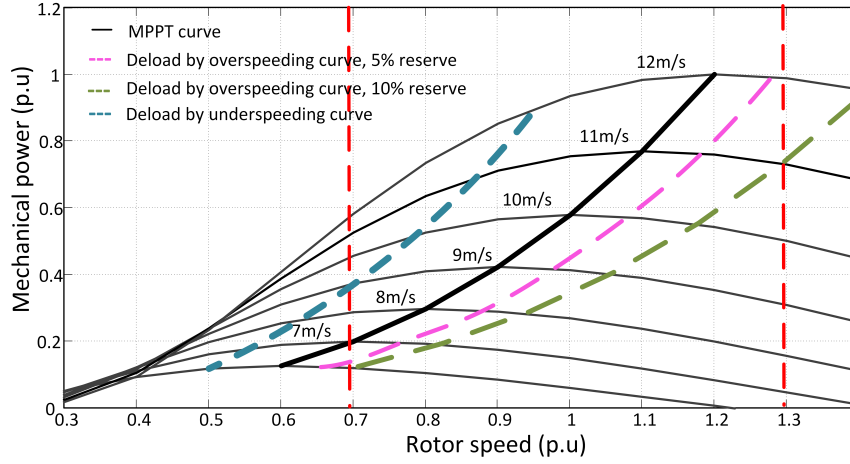


Figure 5.2: De-loading option for DFIG

5.1.1 Transient Active Power Injection Limit

Different from TPI in which the supplementary active power injection requires a recovery period to restore rotor speed back to optimal speed, the power injection function for PRC only requires a step change as shown in Figure 5.3.

Take the under-frequency event as an example, the dynamics of the PRC control loop can be described as Figure 5.4.

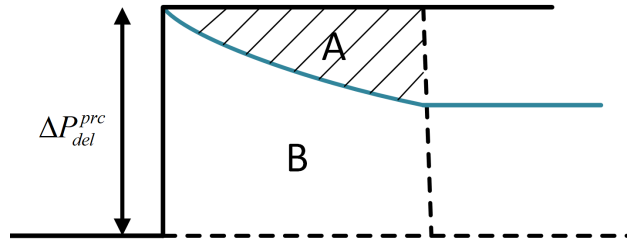


Figure 5.3: Transient active power injection for PRC

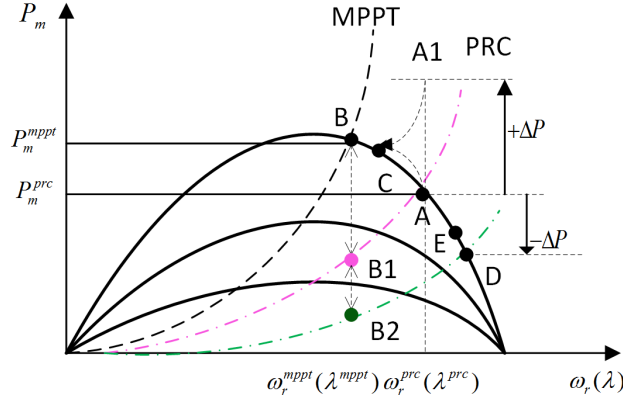


Figure 5.4: Control loop dynamics of PRC.

Initially, DFIG is operated under over-speed condition with P_m^{prc} (point A) during normal operation with reserve p . With the supplementary step change function, the electric power P_e will quickly increase to point A1 while P_m is still remains as point A. The mismatch between P_m and P_e will reduce the rotor speed, which is equivalent to reduce the tip-speed-ratio λ and increase the power coefficient C_p . After the transient period, P_e will finally reach a new equilibrium point C when $\Delta P_m = \Delta P_e$, and the active power difference between C and A will effectively contribute to primary frequency control.

With very large transient active power injection, both mechanical torque and electrical torque would have the same sign of the derivative with respect to the rotational speed if the operating point moves to the left of point B. Thus it may have slow speed transient to lead to unstable condition. So in this case, the step function ΔP for PRC should be limited to avoid continuous rotor speed reduction to avoid the operating point C moving to the left of the MPPT point B (the under-speeding condition). Figure 5.5 and Figure 5.6 demonstrated the necessity of limiting the step function ΔP .

From Figure 5.5, we can see the transient active power injection is small, both mechanical torque and electrical torque are able to find the equilibrium point eventually, it will not have any stability problem. And the rotor speed finally goes back to the MPPT reference speed. However, for the case with very large injection as shown in Figure 5.6, the wind turbine reaches an unstable condition because the operating point moves to the left of B where the mechanical torque and electrical torque would have the same sign of the derivative.

The parameters used in both cases are listed in Table 5.1.

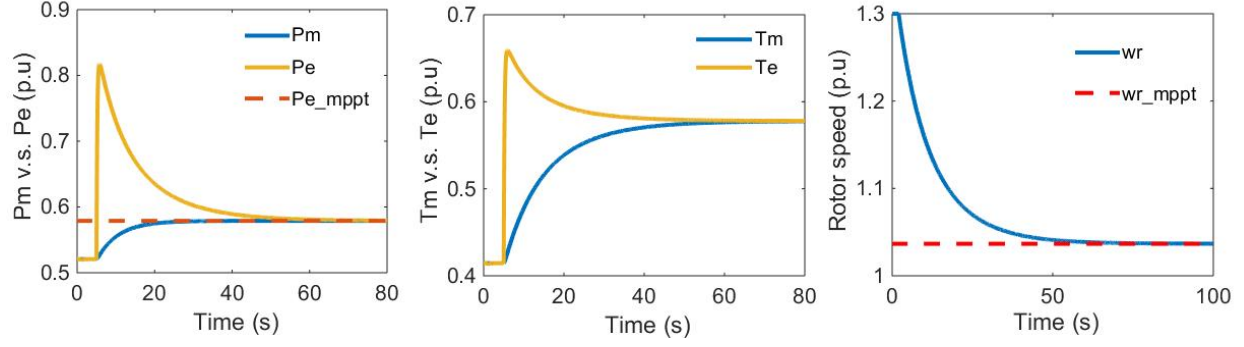


Figure 5.5: PRC with small injection

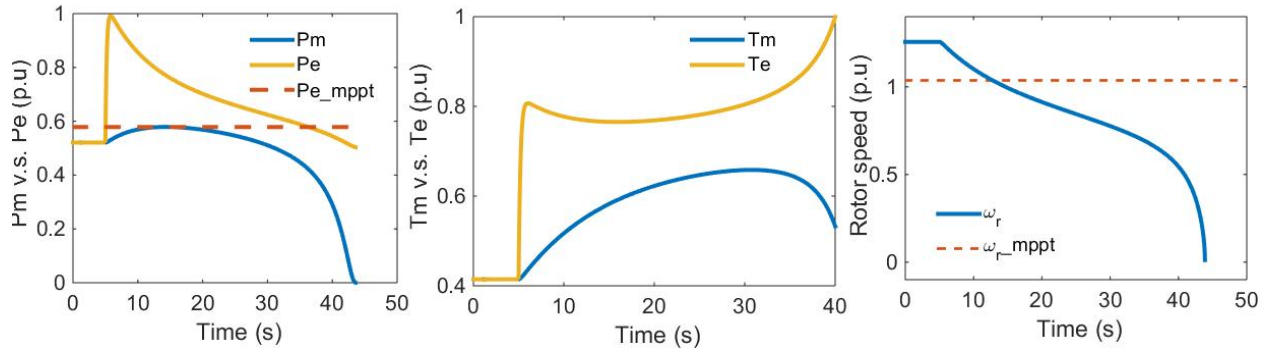


Figure 5.6: PRC with large injection

Based on (2.10) in Chapter 2, (2.7) can be rewritten as:

$$P_m^{mppt} = \frac{1}{2} \frac{\rho A R^3}{(\lambda^{mppt})^3} C_p^{mppt} (\omega_r^{mppt})^3 = K^{mppt} (\omega_r^{mppt})^3 \quad (5.1)$$

$$P_m^{prc} = \frac{1}{2} \frac{\rho A R^3}{(\lambda^{prc})^3} C_p^{prc} (\omega_r^{prc})^3 = K^{prc} (\omega_r^{prc})^3 \quad (5.2)$$

Due to the p reserve, there is:

$$P_m^{prc} = (1 - p) P_m^{mppt} \quad (5.3)$$

And combining (5.1), (5.2), (5.3), there is:

$$(\omega_r^{mppt})^3 = \frac{K^{prc}}{(1 - p) K^{mppt}} (\omega_r^{prc})^3 \quad (5.4)$$

The maximum active power injection ΔP_{del}^{prc} for PRC can be determined by the power difference between point B (MPPT point) and point B1 (minimum rotor speed limit for

PRC), which can be represented by:

$$\begin{aligned}\Delta P_{del}^{prc}|_{max} &= K^{mppt}(\omega_r^{mppt})^3 - K^{prc}(\omega_r^{mppt})^3 \\ &= \frac{K^{mppt} - K^{prc}}{(1-p)K^{mppt}} P_m^{prc}\end{aligned}\tag{5.5}$$

Table 5.1: Operating conditions with different ΔP

Variables	Small ΔP	Large ΔP
Wind speed	10 m/s	10 m/s
P_e in MPPT mode	0.5788 p.u	0.5788
P_e in 10% reserve mode	0.5207	0.5207
ω_r in MPPT mode	1.0015	1.0015
ω_r in 10% reserve mode	1.256	1.256
Maximum ΔP_{del}^{prc}	0.3148 p.u	0.5 p.u (>0.3148 p.u)

5.1.2 Maximum Reserve Level Estimation

Besides the transient active power injection limitation, the initial rotor speed in over-speeding condition should be kept within the maximum rotor speed limit. In this condition, the power reserve level should be maintained between minimum reserve level ($p = 0$) and the maximum allowable reserve level ($p = p^{max}$). For a given wind speed V_w , the maximum available active power from a wind turbine can be expressed as:

$$P_m^{mppt} = \frac{1}{2}\rho AC_p(\lambda^{mppt})V_w^3 = K_w C_p^{mppt}\tag{5.6}$$

If keeping p reserve, then the available active power is:

$$P_m^{prc} = \frac{1}{2}\rho AC_p(\lambda^{prc})V_w^3 = K_w C_p^{prc}\tag{5.7}$$

where λ^{mppt} and C_p^{mppt} are tip-speed-ratio and power coefficient in MPPT mode, while λ^{prc} and C_p^{prc} are the tip-speed-ratio and power coefficient in PRC mode. The reserve level (in p.u) can be expressed as:

$$\Delta P_R = P_m^{mppt} - P_m^{prc} = \frac{1}{2}\rho AV_w^3 \Delta C_p = K_w \Delta C_p = p * P_m^{mppt}\tag{5.8}$$

where $K_v = \frac{1}{2}\rho AV_w^3$. The relationship between ΔC_p and $\Delta\lambda$ can be approximately determined if $C_p(\lambda, \beta)$ characteristic is known. Since pitch angle remains unchanged ($\beta = 0$), ΔC_p can be approximated by 4th order polynomial function of $\Delta\lambda$ without losing accuracy as shown in Figure 5.7, and there is:

$$\Delta C_p(\Delta\lambda) = \sum_{i=0}^4 \alpha_i \Delta\lambda^i \quad (5.9)$$

The coefficients α_i are given in Table 5.2.

Table 5.2: ΔC_p coefficients α_i

	$i = 4$	$i = 3$	$i = 2$	$i = 1$	$i = 0$
α_i	-9.5e-05	0.0023	-0.021	0.00085	0.0001

Then combining (5.8) and (5.9), the power reserve percentage p can be expressed as:

$$p = \frac{\Delta P_R}{P_m^{mppt}} = \frac{1}{C_p^{mppt}} \sum_{i=0}^4 \alpha_i \Delta\lambda^i \times 100\% \quad (5.10)$$

Equation (5.10) demonstrates the relationship between power reserve percentage p and the tip-speed-ratio incremental $\Delta\lambda$ regardless of wind speed, thus the power reserve amount can be adjusted by varying λ . This relationship can be further verified in Figure 5.7.

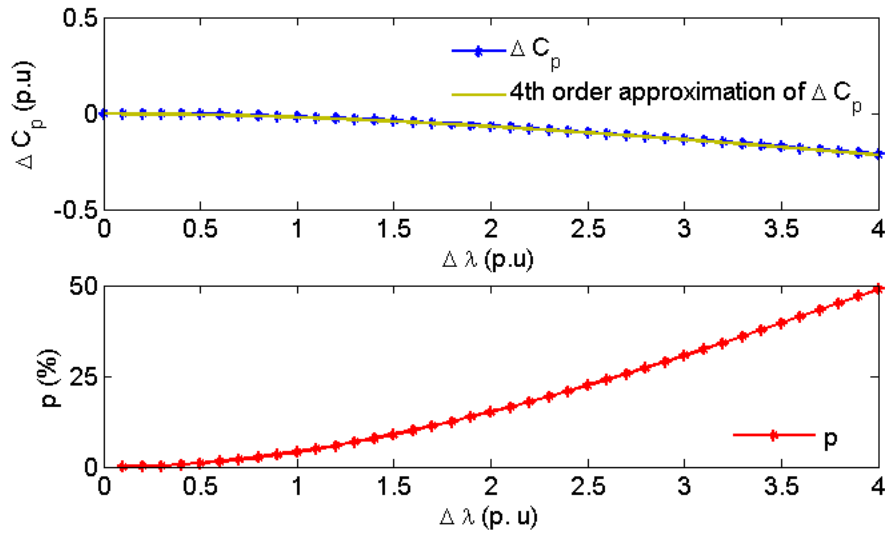


Figure 5.7: Power reserve vs. tip speed ratio deviation.

Utilizing a short-term wind speed prediction V_w^{pre} , and the maximum allowable rotor speed deviation ω_r^{max} , the maximum reserve level (in percentage) can be estimated by:

$$p^{max} = \frac{1}{C_p^{mppt}} \sum_{i=0}^4 \alpha_i (\Delta\lambda^{max})^i \times 100\% \quad (5.11)$$

where

$$\Delta\lambda^{max} = \frac{\omega_r^{max} R}{V_w^{pre}} - \frac{\omega_r^{mppt} R}{V_w^{pre}} \quad (5.12)$$

The maximum available reserve level will be compared with the power reserve requirement at the wind farm level, the smaller reserve amount will be maintained at the wind turbine level during normal operation. If the reserve is less than the maximum reserve margin (red dotted straight line on the right of Figure 5.2), the operating point can be adjusted either towards more reserve (green curve in Figure 5.2) or less reserve (black curve in Figure 5.2). Thus, it is possible to provide support in both under-frequency and over-frequency events.

In summary, $\Delta P_{del}^{pre}|_{max}$ and p^{max} could be used to limit the supplementary active power injection amount and the reserve level to ensure rotor security in PRC mode for under-frequency event. Similar with under-frequency event, when DFIG is required to participate in over-frequency event, the rotor speed will increase towards more reserve point (point D) and further reduce the power coefficient. After the transient period, P_e will reach a new equilibrium point as point E. And the reduction of the active power from A to E will drive the frequency towards a value much closer to nominal frequency. Note that for over-frequency event, the capability of PRC is also limited by p^{max} . To further reduce the active power of DFIG, pitch angle should be increased to reduce power coefficient.

5.2 Comprehensive Frequency Control Framework for DFIG to Improve Frequency Response

The previous introduced flow-chart in Chapter 4.3 can be updated to consider all the three operating modes: MPPT, TPI and PRC mode as shown in Figure 5.8.

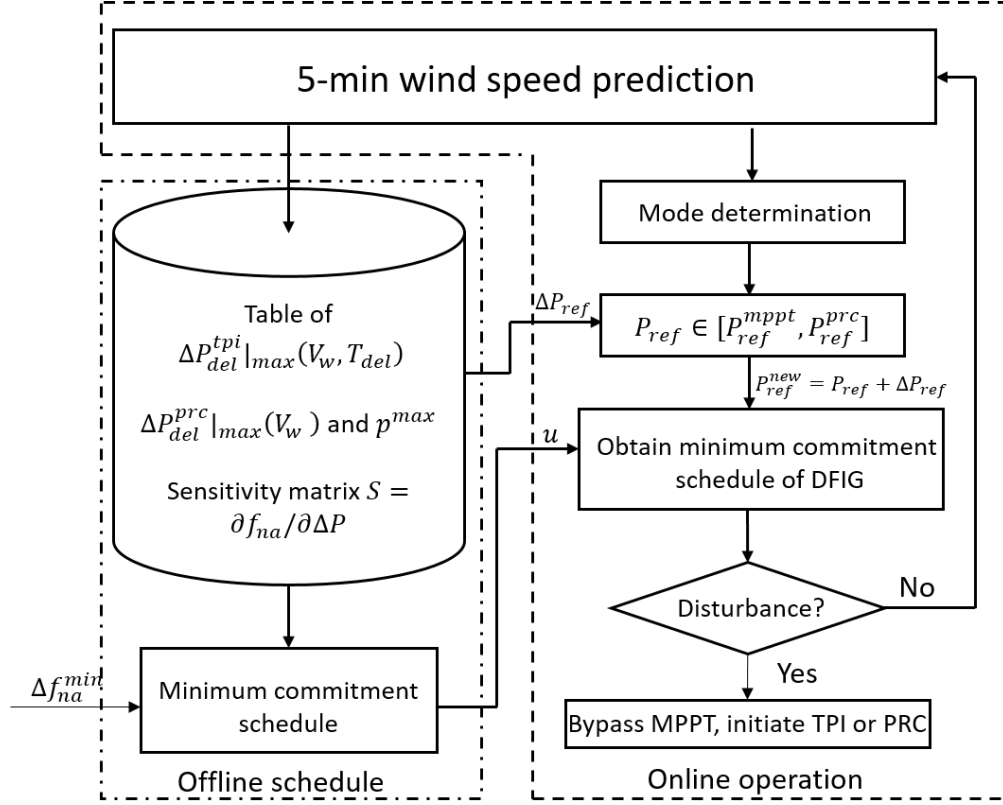


Figure 5.8: Flowchat of proposed control approach

The overall framework includes two levels: wind farm level set-point generation and wind turbine level set-point tracking. The control diagram is shown in Figure 5.9. It is assumed that the short term wind speed prediction is available in every 5-min and updated every 1-min. Then the sensitivity matrix S , the maximum power injection $\Delta P_{del}^{tpi}(Vw)$ for TPI, and the maximum power injection $\Delta P_{del}^{prc}(Vw)$ for PRC together with the maximum allowable reserve p^{max} can be obtained and stored in a database. The minimum number of DFIGs on TPI or PRC that need to provide frequency support is scheduled at the beginning of each 5-minute. Once the frequency deviation out of the specified dead-band is detected, the on-line process activates the scheduled DFIGs. The power reference is then calculated in the supervisory level while the set-point tracking is achieved by local level controllers.

Chapter 6

Fast Frequency Response Support From DFIG with Auxiliary Dynamic Demand Control

A general low-order power system model is considered in this chapter for theoretical analysis of frequency response with high penetration of wind [91]. A multi-machine system can be represented by the low-order power system model without losing much accuracy as studied by [92]. It is assumed all generators with turbine governors can be lumped into a single unit with inertia constant H_c and regulation droop constant R_c , while all loads are lumped into an equivalent load with a damping factor D [1]. The block diagram of the system is shown in Figure 6.1.

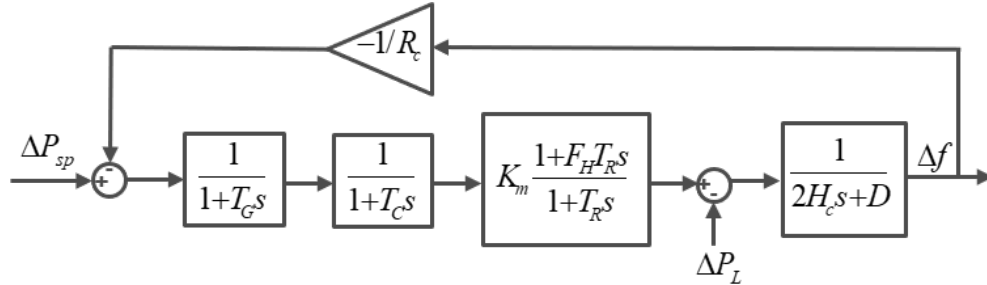


Figure 6.1: Low-order power system model.

The power balance for frequency control analysis is given by [1]:

$$2H_c s \Delta f(s) + D \Delta f(s) = \Delta P_t(s) - \Delta P_L(s) \quad (6.1)$$

with

$$\begin{aligned} \Delta P_t(s) &= T_{gt}(s) [\Delta P_{sp}(s) - \frac{1}{R_c} \Delta f(s)] \\ T_{gt}(s) &= \frac{K_m(1 + F_H T_R s)}{(1 + T_R s)(1 + T_G s)(1 + T_C s)} \end{aligned} \quad (6.2)$$

$\Delta P_t(s)$ represents the mechanical power deviation, $\Delta P_L(s)$ is the load deviation, Δf is the frequency deviation, $\Delta P_{sp}(s)$ is the secondary frequency control set-point deviation, $T_G(s)$ is the turbine governor transfer function, s is the Laplace transform operator. A typical set of system parameters is shown in Table 6.1.

Table 6.1: Parameters of the low-order power system model

System parameter	Value
Inertia constant H_c	6s
Damping coefficient D	1 p.u/p.u
Governor time constant T_G	0.5s
Steam turbine time constant T_C	0.3s
Reheat time constant T_R	10s
Mechanical power gain factor K_m	0.95
High pressure turbine fraction F_H	0.3
Governor regulation constant R_c	0.05 p.u/p.u

Different from conventional fossil fuel generation power plants which employ synchronous generators, the widely used modern wind turbine generators typically Type-III or Type-IV are integrated with grid through AC/DC/AC converters. The converter control can instantaneously adjust the electrical torque on the generator so that the active power delivery is independent of the rate of change of terminal bus angle (also viewed as bus frequency) [15]. In other words, these converters do not inherently provide rotating inertia to the grid, thus the equivalent inertia constant is reduced. Assume the system shown in Figure 6.1 is integrated with a DFIG-based wind farm and p represents the total fraction of wind generation that replaces the synchronous generation. With the DFIG operating in MPPT mode, there is no contribution to the overall system inertia. The new inertia constant of the

system with wind integration can then be expressed by:

$$H_w = H_c(1 - p) \quad (6.3)$$

The fraction of equivalent regulation constant that has changed due to the reduction of governor actions can also be represented by p . Then the new regulation constant will be:

$$R_w = \frac{R_c}{1 - p} \quad (6.4)$$

The objective here is to study the inertial and primary frequency response, the effect of automatic generation control (AGC) will be neglected in the time frame of interest, thus $\Delta P_{sp}(s) = 0$. Moreover, the value of T_G and T_C are much smaller than T_R , so that can be neglected for simple analysis [91]. Now consider a step load disturbance $\Delta P_L(s) = \Delta P_L/s$, the frequency deviation can be obtained as [91]:

$$\Delta f(s) = \left(\frac{R_w \omega_n^2}{DR_w + K_m} \right) \left(\frac{(1 + T_R s) \Delta P_L(s)}{s^2 + 2\xi \omega_n s + \omega_n^2} \right) \quad (6.5)$$

where

$$\omega_n^2 = \frac{DR_w + K_m}{2H_w R_w T_R} \quad (6.6)$$

$$\xi = \frac{2H_w R_w + (DR_w + F_H)T_R}{2(DR_w + K_m)} \omega_n \quad (6.7)$$

The frequency nadir of the system with base frequency f_b in the time domain by inverse Laplace transformation is:

$$f_{na} = f_b \left(1 - \frac{R_w}{K_m + DR_w} [1 + \alpha e^{-\xi \omega_n t_n \sin(\omega_n t_n + \phi)}] \Delta P_L \right) \quad (6.8)$$

with

$$\alpha = \sqrt{\frac{1 - 2T_R \xi \omega_n + T_R^2 \omega_n^2}{1 - \xi^2}} \quad (6.9)$$

$$\omega_r = \omega_n \sqrt{1 - \xi^2} \quad (6.10)$$

$$\phi = \tan^{-1} \left(\frac{\omega_r T_R}{1 - \xi \omega_n T_R} + \tan^{-1} \left(\frac{\sqrt{1 - \xi^2}}{\xi} \right) \right) \quad (6.11)$$

Applying the final value theorem, the steady-state frequency deviation is:

$$\Delta f_{ss} = \lim_{s \rightarrow 0} s \Delta f(s) = \frac{R_w \Delta P_L}{DR_w + K_m} \quad (6.12)$$

and the initial ROCOF is calculated as:

$$\left. \frac{df}{dt} \right|_{t=0} = \frac{\alpha R_w \omega_n \Delta P_L}{DR_w + K_m} \sin \phi = \frac{\Delta P_L}{2H_w} \quad (6.13)$$

Figure 6.2 shows the frequency response of the system with wind penetration p . The values of the three metrics that are introduced in Chapter 2 are summarized in Table 6.2.

Table 6.2: Frequency response assessment by three metrics

Penetration Level	2H (p.u/p.u)	R (p.u/p.u)	ROCOF (Hz/s)	f_{na} (Hz)	f_{ss} (Hz)
p = 0%	12.0	0.0500	-0.1747	59.7868	59.8998
p = 10%	10.8	0.0556	-0.1941	59.7652	59.8891
p = 20%	9.60	0.0625	-0.2183	59.7391	59.8762
p = 30%	8.4	0.714	-0.2495	59.7062	59.8597
p = 40%	7.2	0.833	-0.2909	59.6639	59.8381
p = 50%	6.0	0.100	-0.3389	59.6073	59.8085

From Figure 6.2 and Table 6.2 together with (6.8), (6.12) and (6.13), for this particular system, several observations can be made as the wind penetration increases:

1. The system overall inertia is reduced which leads to a higher ROCOF as indicated by (6.13).
2. With reduced governor actions, overall regulation constant increases causing a reduction of the primary settling frequency as indicated by (6.12).
3. The joint effect of reduced inertia and governor action drives the frequency nadir lower (in the example from 59.7868 Hz to 59.6073 Hz), this may be low enough to trigger UFLS relays.
4. The overall active power injection change (either from generation side or from demand side) has a near linear relationship with f_{na} , ROCOF and the settling frequency f_{ss} .

Any positive active power injection will help improve the frequency response and the improvement can be quantified by evaluating these three metrics.

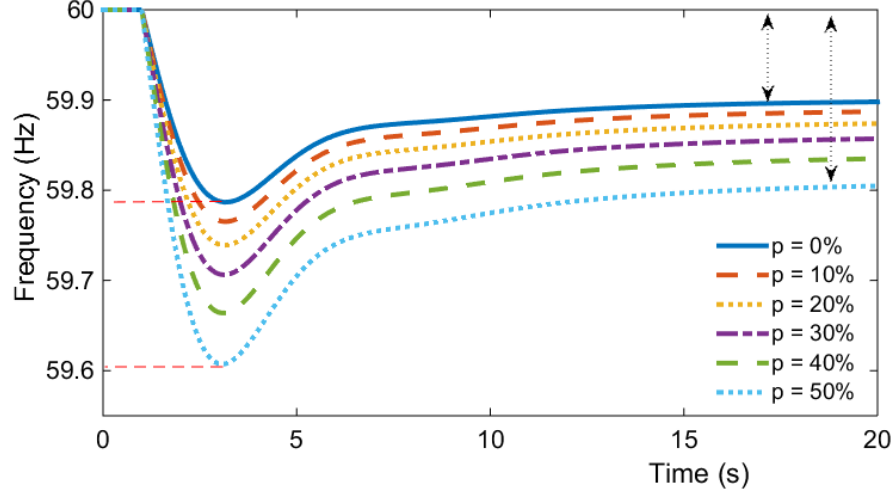


Figure 6.2: Frequency response with increasing wind penetration

As introduced in Chapter 4, the DFIG with inertial support function still operates normally under MPPT, the rotor speed needs to be restored to the optimal speed indicated by MPPT curve. The rotor speed restoration process will absorb active power from the system which will cause a secondary frequency dip. The higher the scheduled improvement, the larger the secondary frequency dip. This can only be avoided if the DFIG is on reserve (deloaded) mode or compensated by other resources. Moreover, as studied in Chapter 5, the contribution of DFIG with rotor speed based power reserve control is limit by its rotor speed limit and the transient maximum power injection limit. The support may not be sufficient to ensure an adequate primary frequency response. In this case, additional support from other types of sources (such as controllable loads) is needed to not only mitigate the impact of the rotor speed restoration but also ensure an adequate primary frequency response if the reserve is adequate.

This chapter aims to utilize DFIG to provide fast frequency support in inertial response time-scale and to overcome the shortcomings of DFIG control by incorporating a dynamic demand control (DDC) strategy to obtain the collective response from controllable TCLs. The joint effect of DFIG control and DDC will improve the frequency response from the time-scale of inertial response though primary frequency control. Moreover, the DFIG control

and DDC are formulated into one coordinated framework. To quantitatively assess the adequacy of the frequency response, several sectional frequency and time indexes (SFTIs) are proposed and used as the trigger to activate control actions across a range of time-scales. The coordination between DFIG and controllable loads ensures the adequacy of inertial response and primary frequency response as well.

6.0.1 Fast Inertial Response Support from DFIG

In Chapter 4, a quantitative control approach for DFIG (TPI mode) is proposed to ensure adequate inertial response with guaranteed rotor security. This approach is incorporated here in this chapter to coordinate with thermostatically controlled loads to further ensure an adequate primary frequency response.

6.0.2 Primary Frequency Contribution from Dynamic Demand Control

As suggested by [93], the ideal candidates for demand control must have high power ratings and be able to change the connection state (ON to OFF or OFF to ON) as requested with a low impact on end-user comfort, such as, electric water heaters (EWH) and heating, ventilate and air-conditioners (HVAC). Therefore, in this paper, we consider HVAC as the example to demonstrate the effectiveness of the proposed DDC strategy.

Modeling of HVAC Load

The widely used first-order heat transfer model is considered here for modeling HVAC with a rate of energy transfer P and operation state $S(t)$ [94]:

$$\dot{\theta}(t) = \frac{1}{R_t C_t} (\theta_a - \theta(t) - S(t) R_t P) \quad (6.14)$$

with

$$S(t) = \begin{cases} 0, & \text{if } S(t - \varepsilon) = 1 \text{ and } \theta \leq \theta^{min} \\ 1, & \text{if } S(t - \varepsilon) = 0 \text{ and } \theta \geq \theta^{max} \\ S(t - \varepsilon), & \text{otherwise} \end{cases} \quad (6.15)$$

where $\theta(t)$ is the internal temperature [$^{\circ}\text{C}$], θ_a is the ambient temperature [$^{\circ}\text{C}$], R_t is the thermal resistance [$^{\circ}\text{C}/\text{kW}$], C_t is the thermal capacitance [$\text{kWh}/^{\circ}\text{C}$].

An example of temperature dynamics of this type of HVAC during normal operation is shown in Figure 6.3(a). The parameters used here are obtained from [95]. During normal operation, the temperature is kept within the maximum and minimum temperature limits θ^{max} and θ^{min} . Figure 6.3(b) shows the temperature dynamics and the active power response if switching off the device at 10 minutes and switch it back on at 15 minutes. We can see that temporarily turn off the HVAC for a short period of time, here, 5 minutes, has little effect on the temperature dynamics. In this condition, the collective response of HVACs is able to contribute to primary frequency control if the number of devices available for control is sufficiently large.

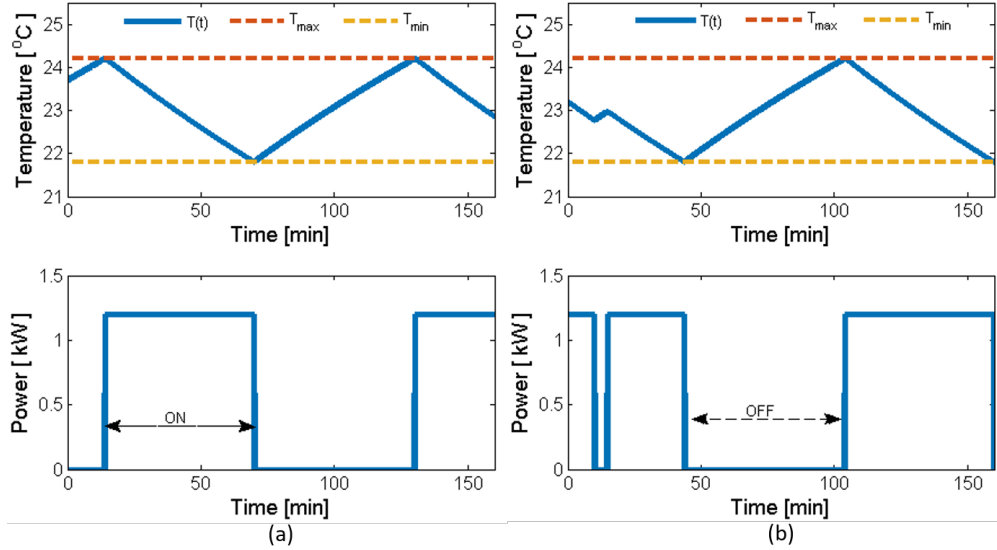


Figure 6.3: Temperature dynamics of HVAC, (a) without DDC (b) with DDC

Dynamic Demand Control

We assume the controllable load reserve is sufficient to satisfy the settling frequency requirement and the primary frequency response can be delivered within time T_{pr} . For the cases when the responsive HVACs are not sufficiently large (i.e., in the cold days), other types of TCLs such as refrigerators, spacing heating and storage water heating can also be promising alternatives to provide the dynamic demand control [17]. From (6.12), to drive the settling frequency back above the settling frequency limit f_{ss}^{min} , the amount of load participating in DDC should be:

$$\Delta P_{ddc} \geq \frac{DR_w + K_m}{60R_w} (f_{ss}^{min} - f_{nom} + \Delta f_{ss}) \quad (6.16)$$

If we assign each individual HVAC controller with a uniformly distributed switching time T_s within $[0, T_{pr}]$, in another words, each device is switched with a uniformly distributed time delay $T_s \in [0, T_{pr}]$. The collective response will be a ramp-down and the control can be fully activated within the response time T_{pr} . The aggregated response of switched HVACs with DDC is depicted in Figure 6.4.

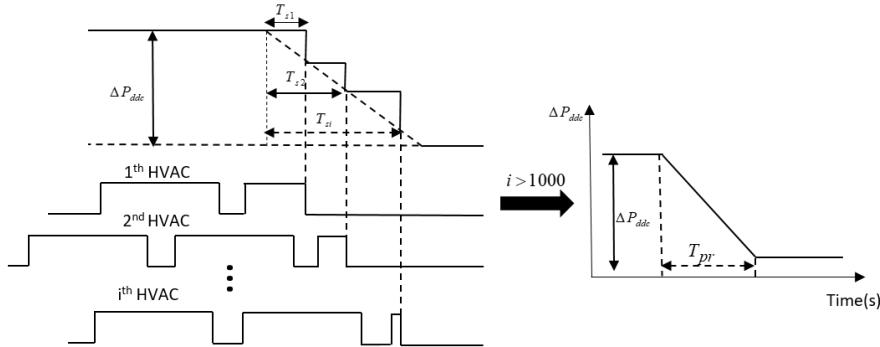


Figure 6.4: Aggregated response of HVACs with DDC

6.0.3 Coordinated Fast Frequency Support Framework

One important consideration for a multi-timescale multi-source coordination scheme is to determine when each contributor should be activated. For this purpose, we propose several

sectional frequency and time indexes (SFTIs) to trigger each control action across a range of time. The proposed SFTIs are listed as follows:

- Frequency dead-band: $f_{db\pm}$
- Minimum allowable frequency nadir: f_{na}^{min}
- Minimum primary setting frequency: f_{ss}^{min}
- Minimum allowable secondary frequency dip : f_{dip}^{min}
- DFIG inertial response delivery end time: T_{del}
- DFIG rotor speed recovery start time: T_{rec}
- Primary frequency response fully activated time: T_{pr}

Note that the minimum allowable frequency nadir should be above the UFLS settings with a security margin away. The values of SFTIs can be determined by system planners to ensure the response delivered is adequate for the specific power system. The overall framework of DFIG control and DDC has offline computation and online operation as shown in Figure 6.5.

Still, it is assumed that the short-term wind speed prediction is available every 5-minute and updated every 1-minute. The sensitivity matrix S and maximum power injection $\Delta P_{inj}^{max}(V_w)$ can be obtained by offline analysis and stored in a database. The minimum number of DFIGs that need to provide fast frequency response is then scheduled at the beginning of each 5-minute interval.

During on-line operation, the system frequency is continuously monitored. For the over-frequency event (i.e, loss of load) with abundant active power, the pitch angle of DFIG can be increased to shed a certain amount of active power of DFIG. In this case, DDC is not activated. The more concerning case, such as, the under-frequency event in which active power is not sufficient (i.e, generator trip event) will be the main focus of this work. Once detecting a under-frequency event, the disturbance amount ΔP_L can be estimated, for example, by the recursive least square algorithm proposed in [96], then the frequency nadir

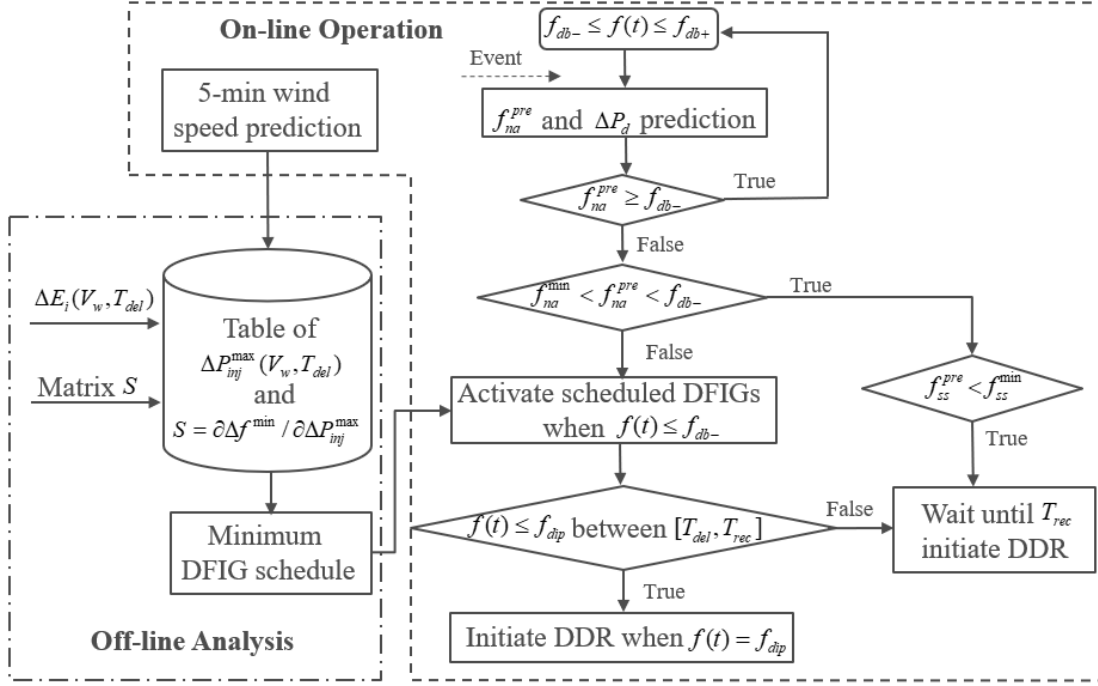


Figure 6.5: Coordinated control strategy for DFIG and DDC to provide fast frequency support

f_{na}^{pre} and the primary settling frequency f_{ss}^{pre} are estimated based on (6.8) and (6.12). With the information of f_{na}^{pre} and ΔP_L , the proposed control requires the following steps:

1. If it is determined that f_{na}^{pre} may reach f_{na}^{min} , then when the measured frequency $f(t)$ is out of the dead-band f_{db-} , the scheduled Dfigures are activated. The inertial support from DFIG is fully activated within T_{del} . The DDC will be based on the frequency measurement after f_{na} by:
 - If at any time, $f(t) \leq f_{dip}^{min}$ in the interval $[T_{del}, T_{rec}]$, then the secondary frequency dip is possible so DDC with ΔP_{ddc} is activated once the frequency passes f_{dip}^{min} and is fully activated within T_{pr} .
 - If $f(t)$ does not lower than f_{dip}^{min} , then the secondary frequency dip is not critical in the time interval $[T_{del}, T_{rec}]$. DDC with ΔP_{ddc} waits until T_{rec} to restore frequency above f_{ss}^{min} .
2. If f_{na}^{pre} will not reach f_{na}^{min} and the settling frequency f_{ss}^{pre} is smaller than f_{ss}^{min} , then DDC will wait until T_{rec} to restore frequency above f_{ss}^{min} within T_{pr}

3. Otherwise, the estimated settling frequency f_{ss}^{pre} is higher than primary settling frequency threshold f_{ss}^{min} , so no support from DDC is required in the primary frequency control time-scale.

6.1 Preliminary Test Cases

We will demonstrate how the proposed control strategy contributes to frequency response under various system conditions. The low order frequency response model with reheated turbines shown in Figure 6.1 is used in this example. Both inertia constant and regulation constant are modified based on (6.3) and (6.4) to represent a scenario with 50% wind penetration. Five DFIGs with wind speed ranging from 7 m/s to 12 m/s are scheduled to provide fast frequency response. The matrix S and ΔP_{inj}^{max} for each wind speed are shown in Table 6.3. The values of the proposed SFTIs for each scenario is defined in Table 6.4.

Table 6.3: ΔP_{inj}^{max} and matrix S under various V_w

DFIG Number	V_w (m/s)	ΔP_{inj}^{max} (p.u/p.u)	S (p.u/p.u)
DFIG1	8.5	0.0018	0.1574
DFIG2	9.83	0.0040	0.1492
DFIG3	10.35	0.0050	0.1487
DFIG4	11	0.0065	0.1549
DFIG5	7.9	0.0011	0.1606

Table 6.4: SFTIs for each scenario

Triggering Metrics	Threshold Values	
Frequency (Hz)	Scenario I	Scenario II
f_{db}	59.95	59.95
f_{na}^{min}	59.65	59.75
f_{ss}^{min}	59.90	59.90
f_{dip}^{min}	59.75	59.75
Time (s)	Scenario I	Scenario II
T_{del}	10.00	10.00
T_{rec}	30.00	30.00
T_{pr}	30.00	30.00

The contingency is a step load change with $\Delta P_L = 0.035$ p.u. The available responsive load is 0.0175 p.u, which consists of 875 HVAC devices with a power rating of 2×10^{-5} p.u.

The minimum allowable rotor speed is $\omega_r^{min} = 0.7$ p.u as suggested by [16]. We assess the frequency response for the following three control strategies:

- 50% wind penetration, with DFIG operated in MPPT without any external control
- 50% wind penetration, with DFIG inertial support control without DDC
- 50% wind penetration, with DFIG inertial control together with DDC

6.1.1 Scenario I: Small scheduled inertial support

As shown in Table 6.4. The first scenario requires a frequency nadir limit $f_{na}^{min} \geq 59.65$ Hz. The frequency response of the studied system without any external support is shown as the solid blue curve in Figure 6.6. The frequency nadir will be lower than f_{na}^{min} , so the minimum number of DFIGs to increase f_{na} by 0.05 Hz is initiated when $f(t)$ is outside the dead-band. The frequency response with external DFIG control is shown as the yellow dotted curve and the frequency response with both DFIG control and DDC is shown as the red dashed curve in Figure 6.6.

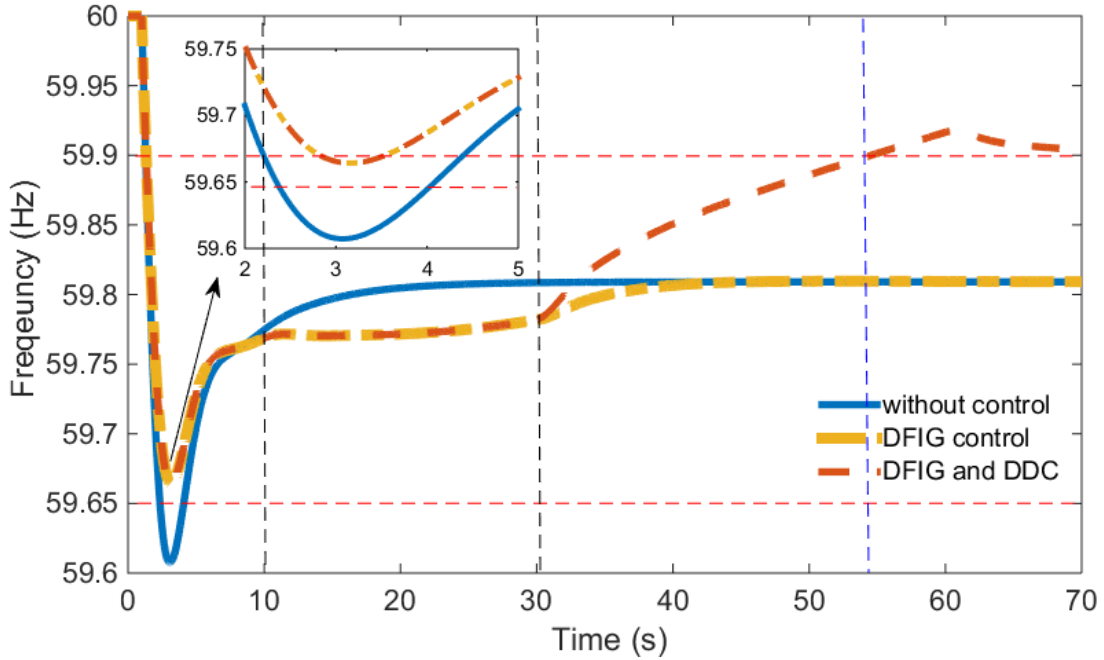


Figure 6.6: Frequency response comparison for scenario I

Simulations verify that the frequency nadir remains above 59.65 Hz. Due to the relatively low Δf_{na} requirement, the secondary frequency dip is not lower than f_{dip}^{min} during the recovery period. Thus, DDC is only activated after T_{rec} . The primary frequency control is fully activated in 30s. The supplementary active power injection of DFIG for Scenario I is shown in Figure 6.7(a) and the rotor speed response is shown in Figure 6.7(b). It can be seen that only DFIG4 switches to support mode to meet the requirement. The rotor speed of DFIG4 remains above the minimum allowable limit $w_r^{min} = 0.7$ p.u.

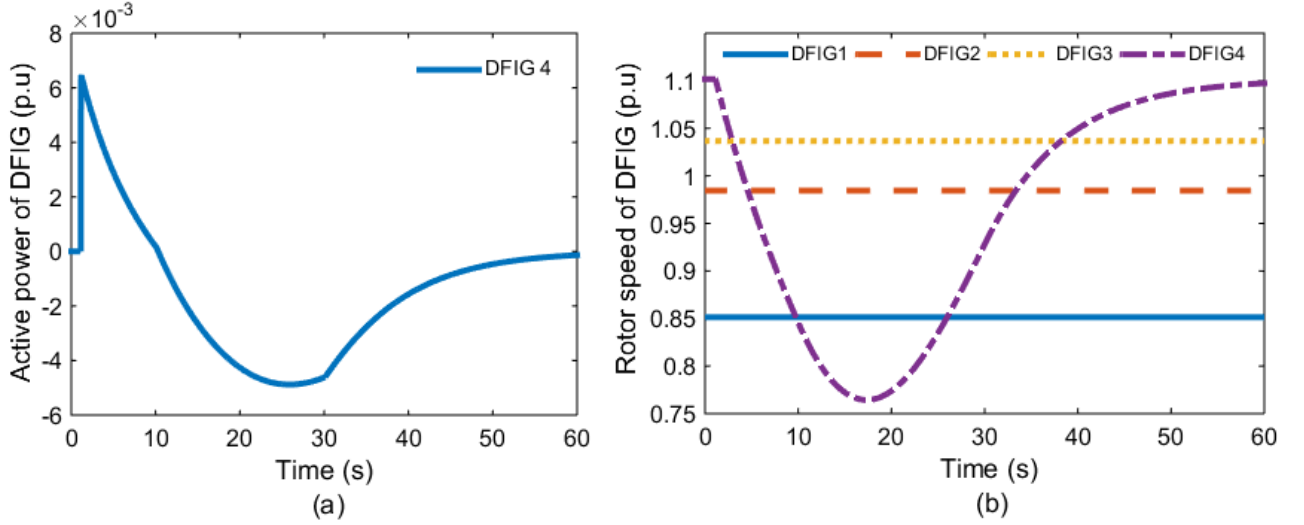


Figure 6.7: Active power and rotor speed for scenario I. (a) active power deviation (b) rotor speed

Increasing the communication delay may degrade the control performance. Figure 6.8 shows the frequency response in face of 100 ms, 1000 ms and 2000 ms communication delay from the moment the disturbance occurs to the moment the DFIG control starts to take actions.

It can be verified that for this particular system, with smaller time delay (less than 1000 ms) the frequency nadir can still be kept above the specific threshold and the control performance does not degrade too much. However, for larger delay time (i.e, 2000 ms) the control performance is degraded seriously. In this case, to ensure a better frequency, the initial scheduled active injection for DFIG could be larger as demonstrated in the next case study. The criteria of control mode switches might be different for different systems. To obtain a 'optimal' response for a particular system, the criteria should be carefully

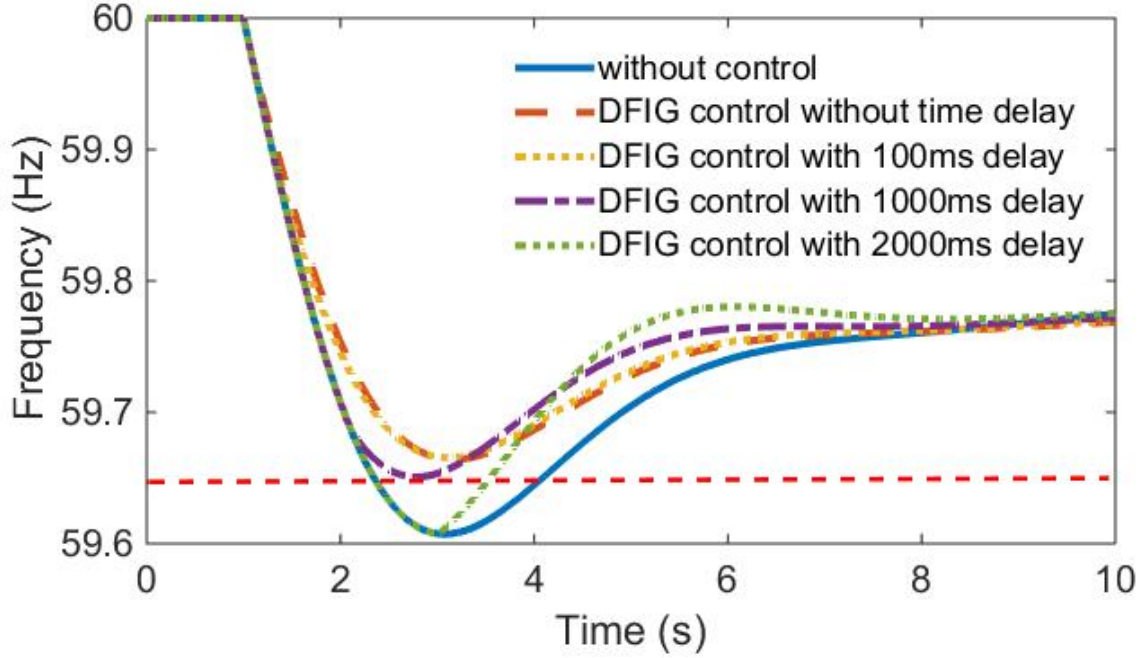


Figure 6.8: Impact of communication delay on control performance

determined by the system planner (operator) based on specific system requirements and offline simulation studies.

6.1.2 Scenario II: Large scheduled inertial support

In this scenario, the minimum frequency nadir requirement is raised to 59.75Hz, the frequency response with DFIG control only is shown as the dotted yellow curve in Figure 6.9. With a relatively large Δf_{na} , the frequency response has a secondary dip which is smaller than f_{dip}^{min} during the recovery period. Thus, DDC is activated when the frequency passes f_{dip}^{min} . The frequency response with both DFIG control and DDC is shown as the dotted red curve in Figure 6.9. Compared to the DFIG control only strategy, the coordinated control is able to mitigate the secondary frequency dip, and restore frequency back above the f_{ss}^{min} sooner than in Scenario I.

Four DFIGs are switched in to meet the requirement. The active power injection is shown in Figure 6.10(a) and the rotor speed response is shown in Figure 6.10(b). It can be seen the rotor speed of DFIGs are kept above the specific minimum rotor speed limit. The aggregate load response for both scenarios are compared in Figure 6.11, we can see that the switched

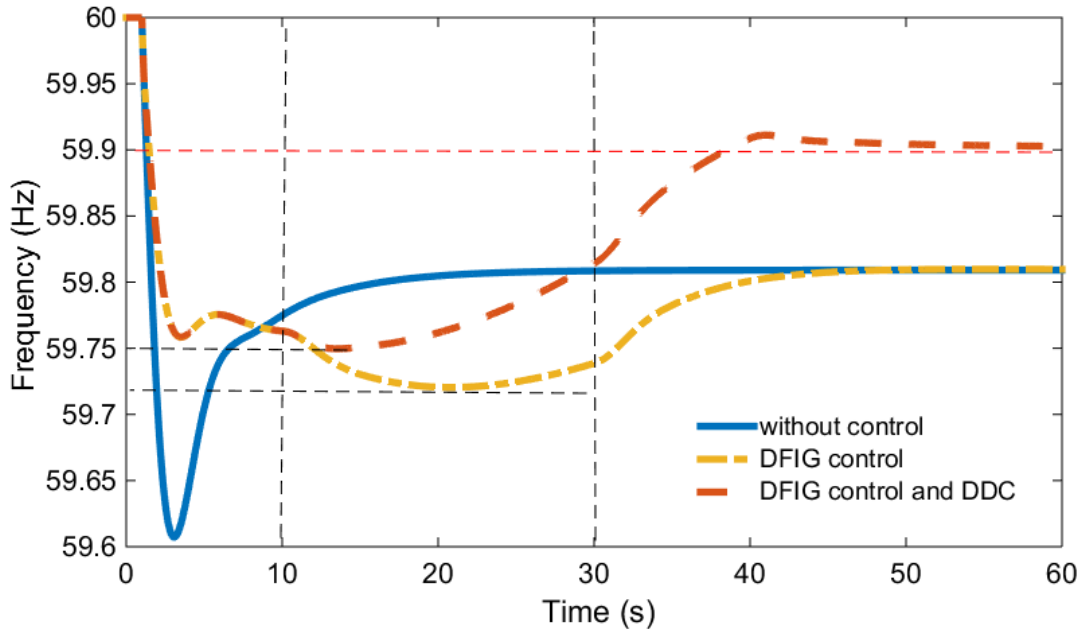


Figure 6.9: Frequency response comparison for scenario II

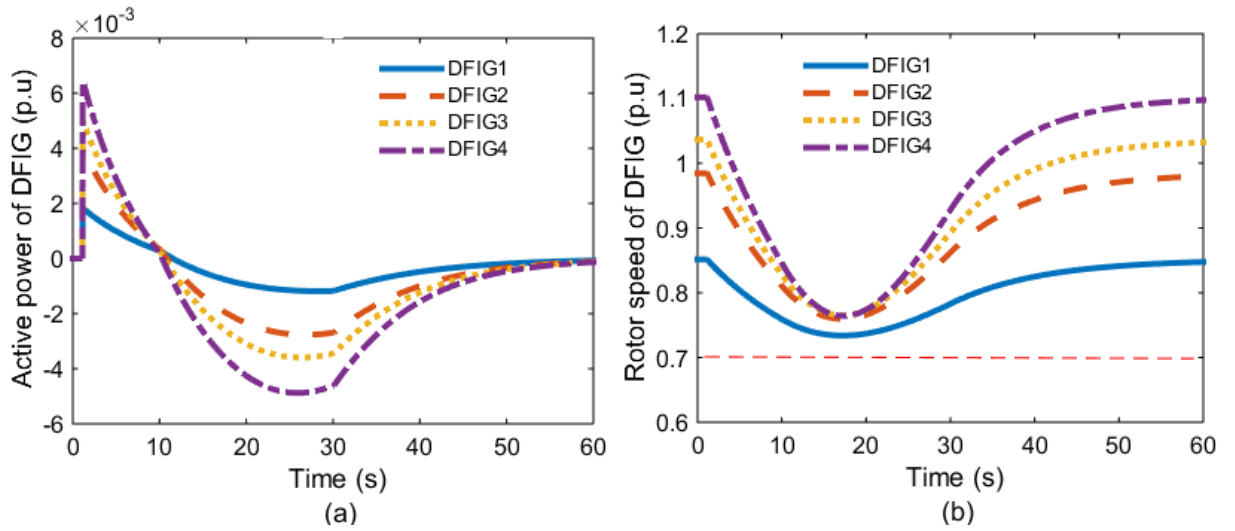


Figure 6.10: Active power and rotor speed for Scenario II. (a) active power deviation (b) rotor speed

time of DDC are different for the two scenarios, but ΔP_{ddc} is identical since f_{ss}^{min} does not change.

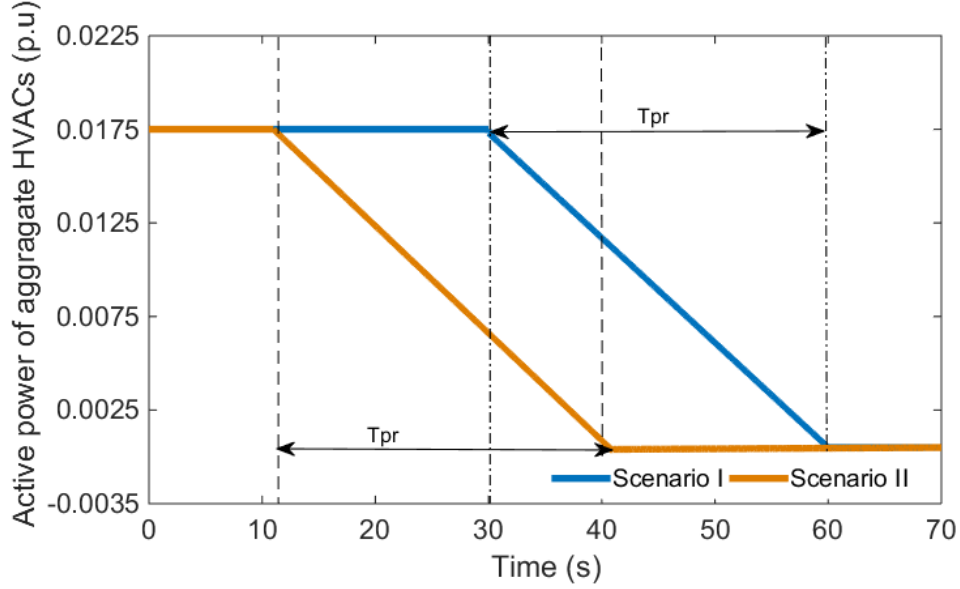


Figure 6.11: Aggregate HVACs active power response for both scenarios

6.2 Conclusion

Existing approaches for DFIG to provide inertial response have no impact on primary settling frequency and may even bring a secondary frequency dip as studied in Chapter 4. A possible solution that enables DFIG to provide reserve for primary frequency control is proposed in Chapter 5. However, the effect of this types of compensation is limited by the maximum reserve amount which is also limited by the maximum allowable rotor speed and the maximum transient active power injection. In some severe cases, it may not be able to ensure an adequate primary frequency response.

In this Chapter, a coordination control strategy is proposed to exploit the capability of both DFIG and controllable loads to jointly provide fast frequency support. The DFIGs are expected to provide adequate inertial response with guaranteed rotor security and DDC is activated to ensure adequate primary frequency response. The proposed control has been implemented in the preliminary small test system. Preliminary simulation results on small scale power system model indicated the proposed coordinated control is effective, and the

frequency response improves for time-scale of inertial response through primary frequency control. The proposed control will be implemented and further tested in the large test system in Chapter 7.

Chapter 7

Test System Development and Case Studies

7.1 Test System Development

7.1.1 Base Case Test System

The objective of this research work is to study large-scale power system frequency response. A reduced 181-bus WECC system is utilized as the base case test system and modified to demonstrate the effectiveness of the proposed framework. In the base case, the reduced WECC system has 31 synchronous machines supplying 40% total generation from 15600-bus planning case of WECC system. The original models are available in the commercial transient simulation software PSS/E. The conventional generators are modeled as round rotor machine GENROU, and each conventional generator is equipped with AC exciter, turbine governor and power system stabilizer to form a GENUNIT. In this work, we use a real-time power system dynamic simulation software ePHASORsim which is developed by Opal-RT to perform the case studies [97]. The ePHASORsim environment has a convenient interface with MATLAB/Simulink and is capable of performing real-time simulation with interactive controls. To represent the same system in ePHASORsim, the original exciter models (ESST3A, ESDC2A) and power system stabilizer model (ST2CUT) are replaced by ESST4B, IEEEEX1 and IEE2ST that are available in the ePHASORsim library. The modified

models are summarized in Table 7.1. The model parameters are adjusted to benchmark with

Table 7.1: Models used in ePHAOSRsim

Generator	Exciter	PSS	Turbine Governor
GENROU	ESST4B	IEEEEST	IEEEG1
GENROU	ESST4B	IEE2ST	IEEEG1
GENROU	EXST1	IEE2ST	IEEEG1
GENROU	IEEEX1	IEE2ST	IEEEG1

the original PSS/E models. The voltage, active power and reactive power response following a generator trip event are compared for ePHASORsim and PSS/E as shown in the Figure 7.1, Figure 7.2 and Figure 7.3.

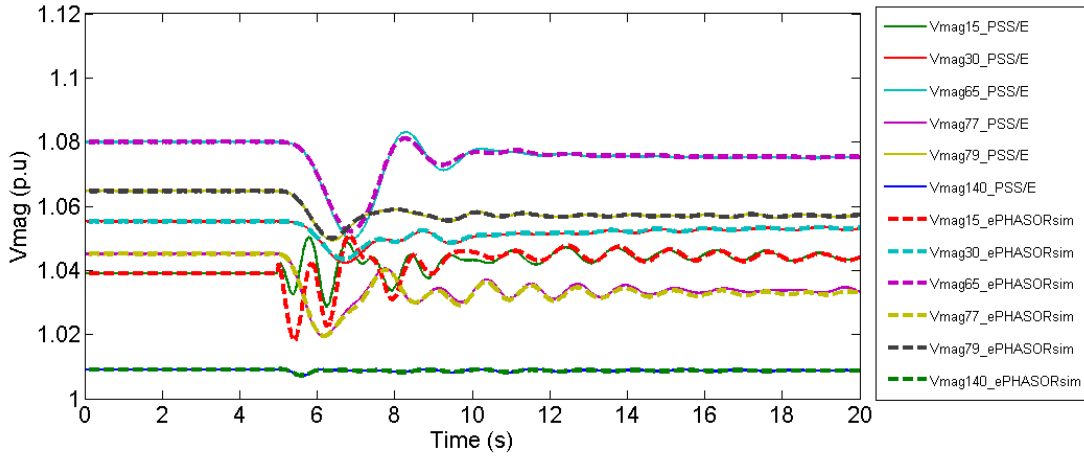


Figure 7.1: Voltage response of WECC system in ePHASORsim and PSS/E.

7.1.2 User-defined Wind Farm Model

The generic wind model are available in most of the commercial simulation software libraries, such as PSS/E. This default model does not inherently have inertial response, thus do not include provisions to represent synthetic inertia capability. And the built-in model assumes a fixed reference power level which is MPPT in the solved power flow case. This is inflexible when modifying initial condition for flexible power reserve control. For these reasons, a user-defined wind model with proper modifications is required. The user-defined model also takes the modular design with five functional blocks by combining aerodynamic and drive-train

models together to form a wind turbine model. The overall model has two-level structure: wind farm level generates the P_{ref} and Q_{ref} and the wind turbine level tracks the generated reference. In this work, the turbine level components are implemented in OpenModelica and compiled as a functional mock-up unit (FMU) and used in ePHASORSim, which is a real-time power system dynamic simulation software with support of functional mock-up interface (FMI) [97].

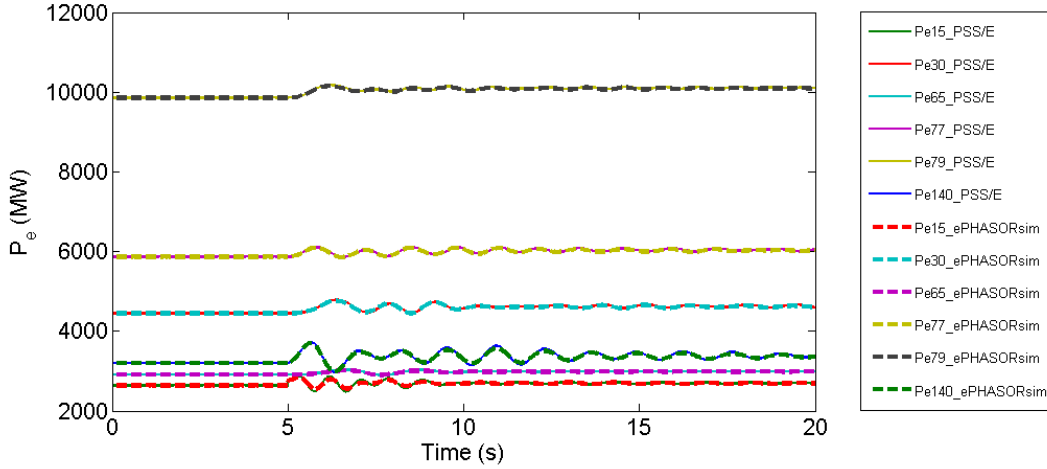


Figure 7.2: Active power response of WECC system in ePHASORSim and PSS/E.

The ePHASORSim environment has a convenient interface with MATLAB/SimulinkTM and is capable of performing real-time simulation. P_{ref} and Q_{ref} are the external control signals obtained from wind farm level set-point generation algorithm. Even though the turbine level is developed in OpenModelica, the wind farm level set-point generation algorithm is developed in a separate module in Simulink. So the switch of control inputs can be easily achieved without modifying the internal model structure. With proper communication and data streaming server, the control action can be remote and interactive. The structure of the user-defined model and the controller interface are shown in Figure 7.4.

7.1.3 WECC System with 50% Wind Penetration

The WECC system introduced previously was modified by integrating DFIG-based wind farms introduced above. The total installed capacity of wind farm is 32.79 GW taking

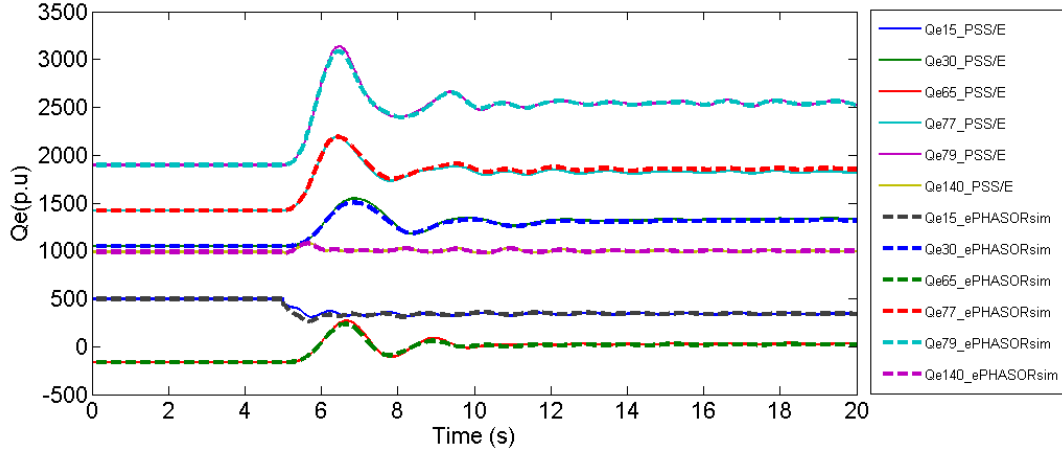


Figure 7.3: Reactive power response of WECC system in ePHASORsim and PSS/E.

approximately 53.4% of total generation of original WECC system to realize a high penetration case. The wind locations are summarized in Table 7.2 and indicated in the one-line diagram in Figure 7.5.

7.2 Case Studies

7.2.1 Case Study I: 50% wind penetration on MPPT with under-frequency event

Two scenarios are considered in this case study. The worst-case generator trip event (2160MW loss) happens at 1s. As shown in Figure 7.6, the blue curve is the response of the studied system without wind penetration, the dotted green curve is the frequency response to the same event with 50% wind penetration while DFIG units are on Mode I - MPPT with no contribution to frequency variation. Referring to Equation (6.12) and (6.13) in Chapter 6, the replacement of the synchronous generators reduces the overall equivalent inertia constant, leads to a higher ROCOF, and causes the frequency nadir to decrease to 59.66 Hz from 59.81 Hz, which is close to the under frequency load shedding limit (59.65 Hz). At the same time, the less effective governor response deteriorates the primary regulation capability, reducing the primary steady state frequency to 59.86 Hz from 59.94 Hz.

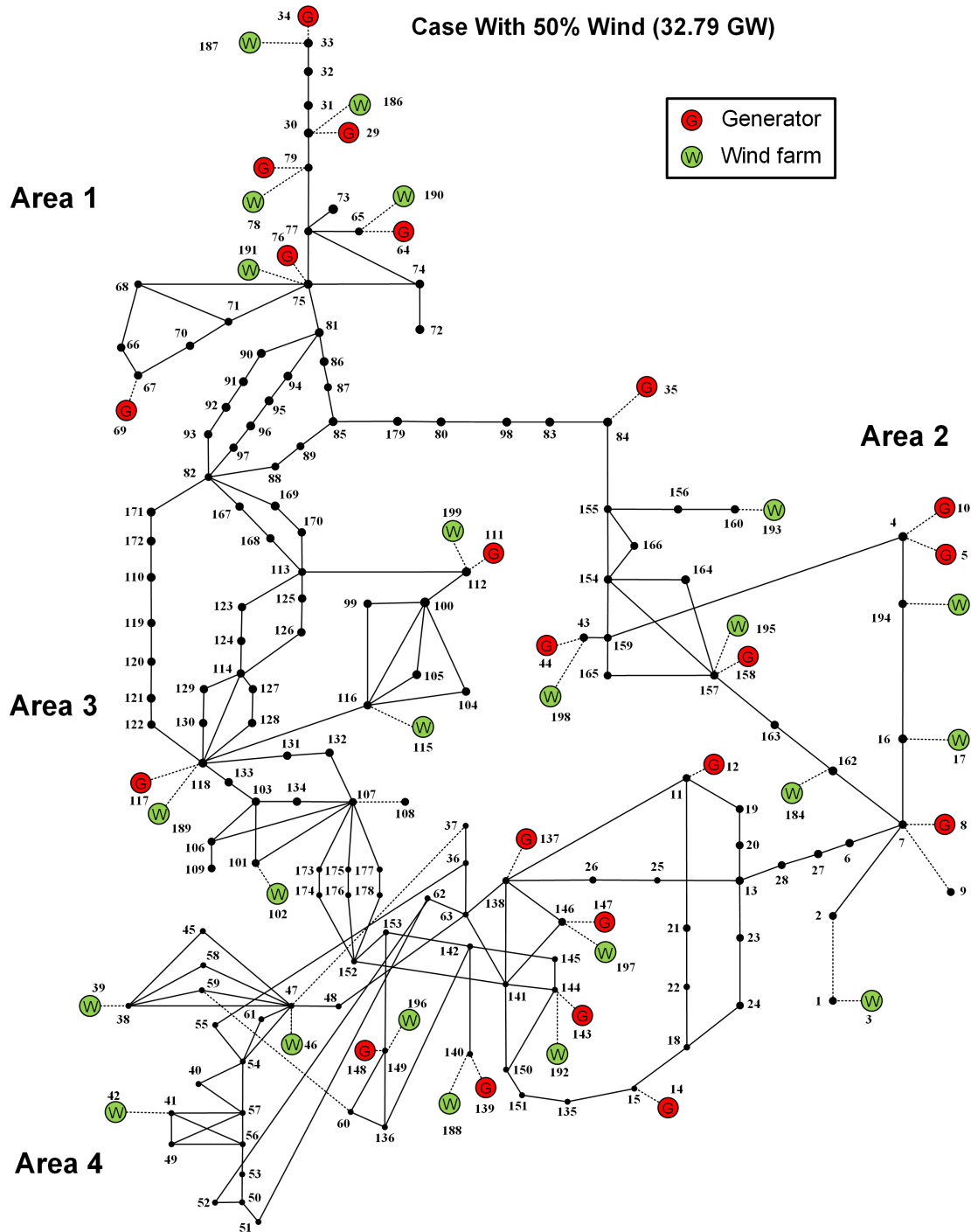
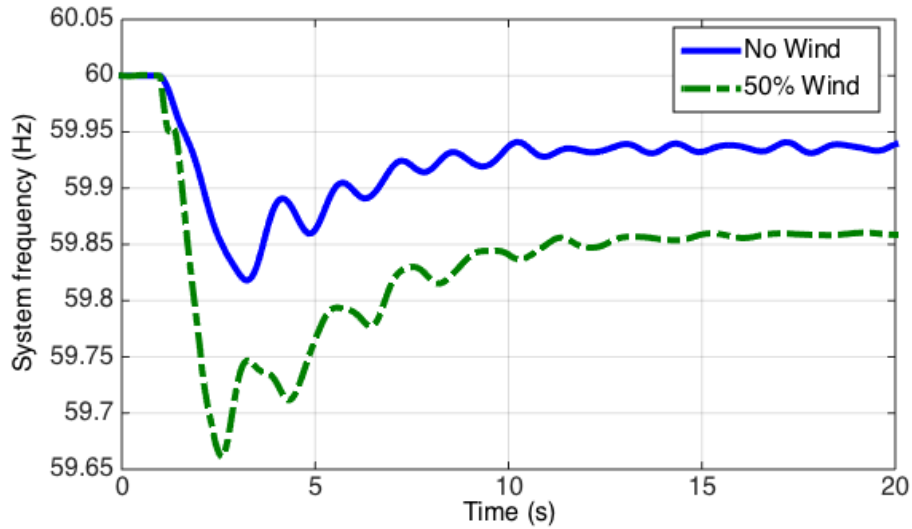


Figure 7.5: WECC system with 50% wind penetration.

Table 7.2: Locations of wind farms in WECC System

Location	Base Case	50% Wind Case
CORNADO	800MW GENROU	801MW DFIG-WF
SJUAN G4	962MW GENROU	961.5MW DFIG-WF
CASTAI4G	200MW GENROU	201MW DFIG-WF
HAYNES3G	325MW GENROU	325.5MW DFIG-WF
OWENS G	110MW GENROU	109.5MW DFIG-WF
TEVATR	594MW GENROU	594MW DFIG-WF
MIRALOMA	445MW GENROU	445.5MW DFIG-WF
NAUGHT	1690MW GENROU	1690.5MW DFIG-WF
CRAIG	1048MW GENROU	699MW DFIG-WF
CANAD G1	4450MW GENROU	2967MW DFIG, 1483MW GENROU
CMAIN GM	4480MW GENROU	2988MW DFIG, 1492MW GENROU
INTERM1G	1780MW GENROU	1188MW DFIG, 592MW GENROU
MONTA G1	2910MW GENROU	1939.5MW DFIG, 970.5MW GENROU
JOHN DAY	5859MW GENROU	3906MW DFIG, 1953MW GENROU
NORTH G3	9860MW GENROU	4926 MW DFIG, 4934MW GENROU
DIABL01	765MW GENROU	382.5MW DFIG, 382.5MW GENROU
ROUND MT	1057MW GENROU	529MW DFIG, 528MW GENROU
TEVATR2	3467MW GENROU	2310MW DFIG, 1157MW GENROU
LITEHIPE	3195MW GENROU	2130MW DFIG, 1065MW GENROU
MOHAV1CC	1680MW GENROU	1119MW DFIG, 561MW GENROU
PARDEE	2200MW GENROU	1467MW DFIG, 733MW GENROU
EMERGY	1665MW GENROU	1110MW DFIG, 555MW GENROU

**Figure 7.6:** Frequency response comparison of no wind case and 50% wind case

7.2.2 Case Study II: 50% wind penetration on TPI with under-frequency event

It is assumed that DFIGs within the same wind farm has the same wind speed and are aggregated into a single unit keeping the same MVA rating as the summation of each DFIG's MVA rating. The wind speed spatial variation across regions is not the focus of this work thus is neglected. To demonstrate the variety of the case studies, five DFIG units at five different locations with wind speed ranging from 7m/s to 12m/s are scheduled to provide frequency support with the same system condition as previous. The delivery time is set as 10s, the sensitivity matrix S and $\Delta P_{del}^{tpi}|_{max}$ for each wind speed V_w are available in the database and are given in Table 7.3.

Table 7.3: $\partial \Delta f_{na}^{min} / \partial \Delta P_{del}^{tpi}|_{max}$, $\Delta P_{del}^{tpi}|_{max}$ under various V_w

Name	V_w (m/s)	$\Delta P_{del}^{tpi} _{max}$ (p.u)	S (Hz/p.u)	P_{pf} (MW)
W3	10.35	0.3347	0.1526	801
W17	9.83	0.2652	0.2089	961.5
W39	7.90	0.0754	0.1259	201
W42	11.00	0.4339	0.0686	325.5
W46	8.50	0.1221	0.2530	109.5

In this case, it is required the frequency nadir threshold is set to be 59.75 Hz to ensure a 0.1 Hz security margin from the UFLS threshold. Considering the same worst-case generator trip event as previous, when the DFIG nearby bus frequency is beyond the dead-band, the minimum number of scheduled DFIG units on TPI support mode are switched in. The frequency response is shown in Figure 7.7 as the blue curve.

In this particular case, two units (W3 and W17 in Table 7.3) are required to meet the 0.1 Hz frequency nadir improvement requirement. Compared to no controlled case (the black curve in Figure 7.7), the initial ROCOF is smaller and the frequency nadir is above the specified 59.75 Hz threshold. It is also noticeable that there is a secondary frequency dip associated with the fact that the rotor speed of the DFIG needs to recover back to pre-disturbance speed after delivery time (10s). This can only be avoided if the DFIG is on reserve mode or compensated by other resources. Still, it can be improved by adjusting recovering time. Figure 7.8 shows the frequency response under the condition of different

recovery time. It can be seen that with the same delivery time the maximum injection amount is the same, when increasing the recovery time, the second frequency dip is reduced but the recovery phase is prolonged. The criteria of control mode switches, such as delivery time and recovery time, might be different for different systems. System planners must ensure that the manner in which energy is delivered and recovered is optimal for the specific system [48].

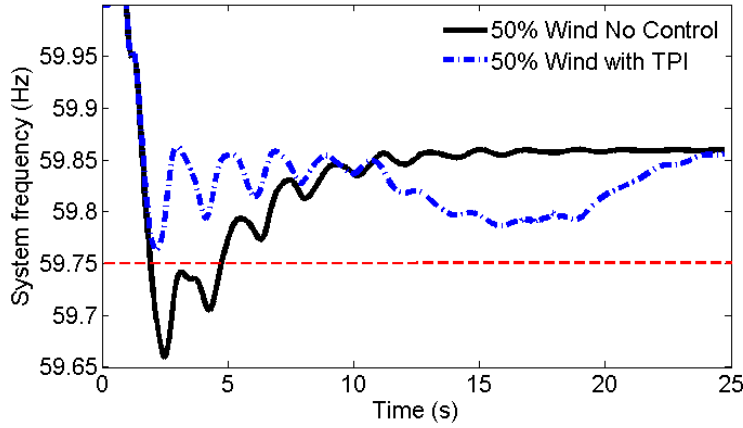


Figure 7.7: Frequency response comparison for MPPT and TPI

The active power of W3 and W17 are plotted in Figure 7.9 as solid blue and pink curve. And the rotor speed of W3 and W17 are plotted in Figure 7.10 as solid blue and pink curve. It can be verified that the rotor speed remains within security range during inertial response delivery period and returns to the maximum power point optimal speed after inertial response delivery period.

To better evaluate the proposed control performance in comparison with the conventional inertial support approach, a conventional power surge method with $\Delta P_{del} = 0.1$ p.u is also included in this case study. The frequency response is compared with the TPI method and shown as the dotted green curve in Figure 7.11. The active power and the rotor speed are compared with TPI in Figure 7.12 and Figure 7.13. The comparison results show that the frequency nadir for conventional power surge control is not guaranteed to be above the required 59.75 Hz and the rotor speed is far away from the minimum allowable speed since it does not suggest the maximum contribution and the response is over-conservative.

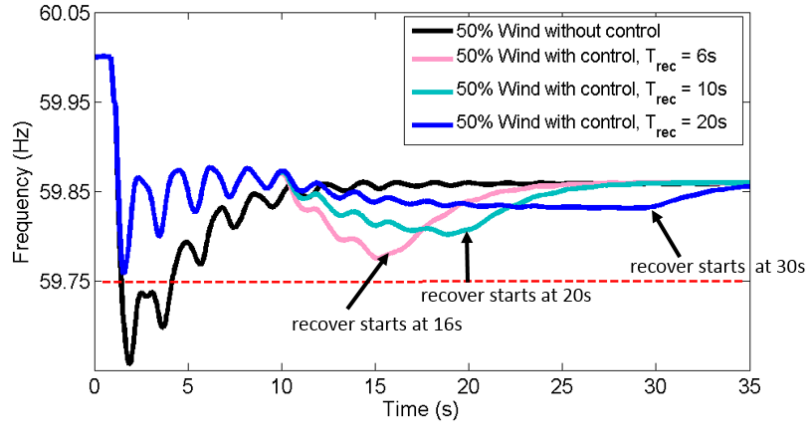


Figure 7.8: Frequency response comparison for TPI with different delivery time

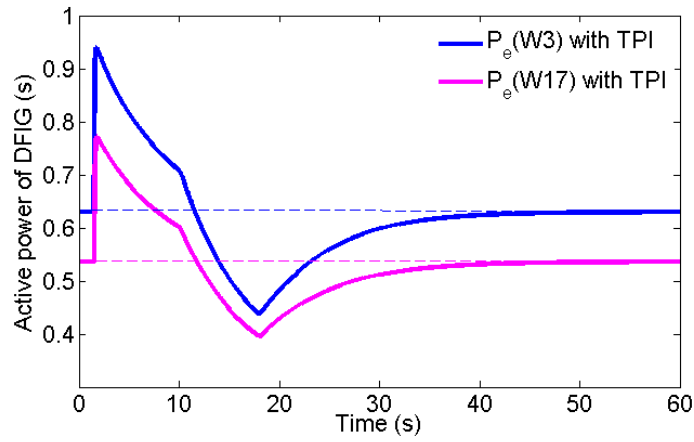


Figure 7.9: Active power of DFIGs under TPI

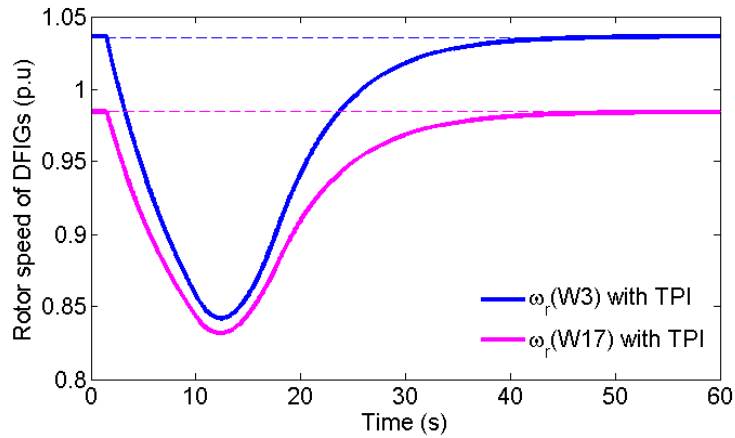


Figure 7.10: Rotor speed of DFIGs under TPI

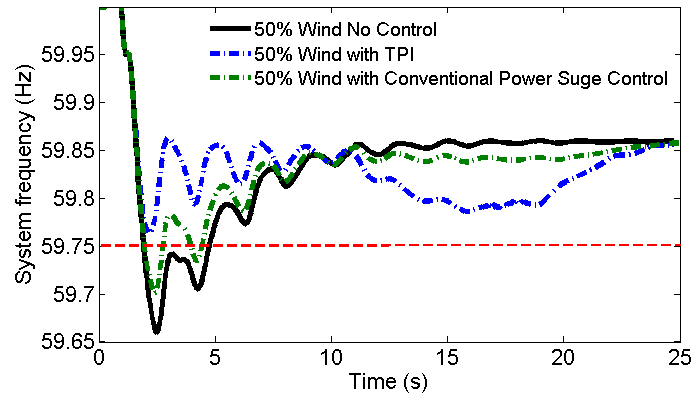


Figure 7.11: Frequency response comparison for TPI and conventional power surge

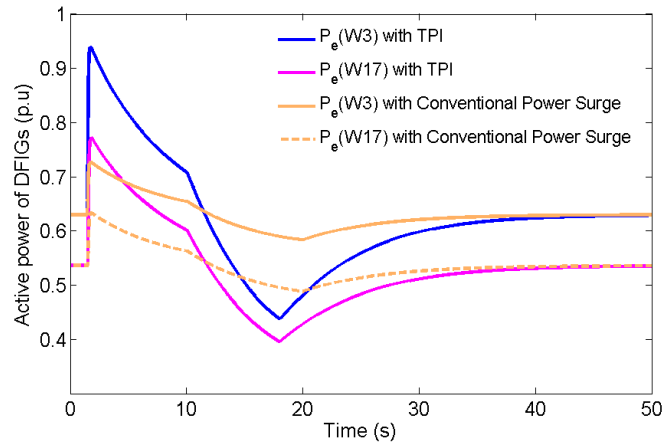


Figure 7.12: Active power of DFIGs for TPI and conventional power surge

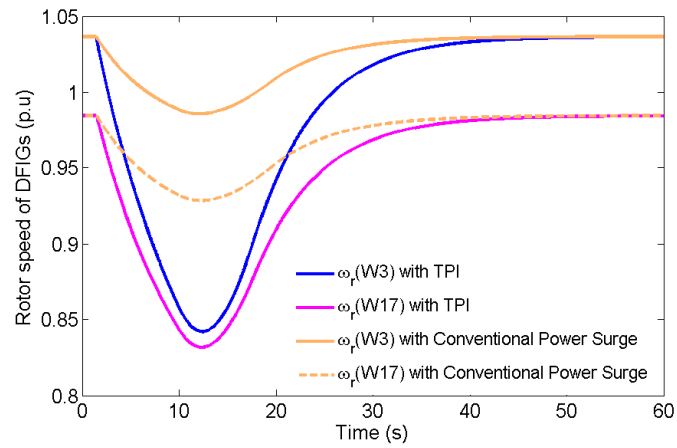


Figure 7.13: Rotor speed of DFIGs for TPI and conventional power surge

7.2.3 Case Study III: 50% wind penetration on PRC with under-frequency event

In this case study, a 10% margin is used for the same five DFIG units during normal operation. Hence, the initial active power of DFIG is lower than the active power in TPI mode as shown as dotted red and green curve in Figure 7.15(a). Also, the rotor speed is increased compared to the optimal rotor speed under TPI mode to achieve the over-speeding condition (dotted red and green curve in Figure 7.15(b)). And the frequency response of PRC is shown as the dotted pink curve in Figure 7.14.

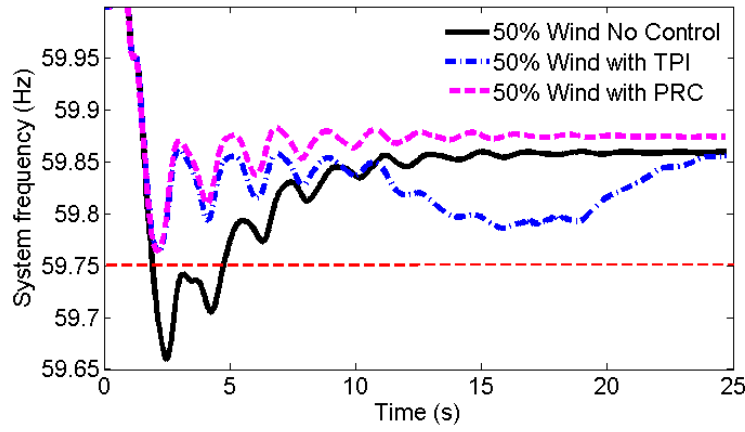


Figure 7.14: Frequency response comparison for TPI and PRC

In this case study, the scheduled active power injection for the same two DFIG units (W3 and W17) on PRC mode is set identical as in TPI mode. Thus, the frequency nadir is the same as the previous case study. However, the secondary frequency dip is avoided and the settling frequency is increased as well. As the power margin moves from 10% to 0%, the active power of the DFIG first increases before reaching the target value. This is due to the fact that the rotor needs to decelerate to release the kinetic energy. The rotor speed will remain at the re-optimized value (above MPPT) and no recovery period is needed, as shown in Figure 7.15(b) for the dotted green and red curves.

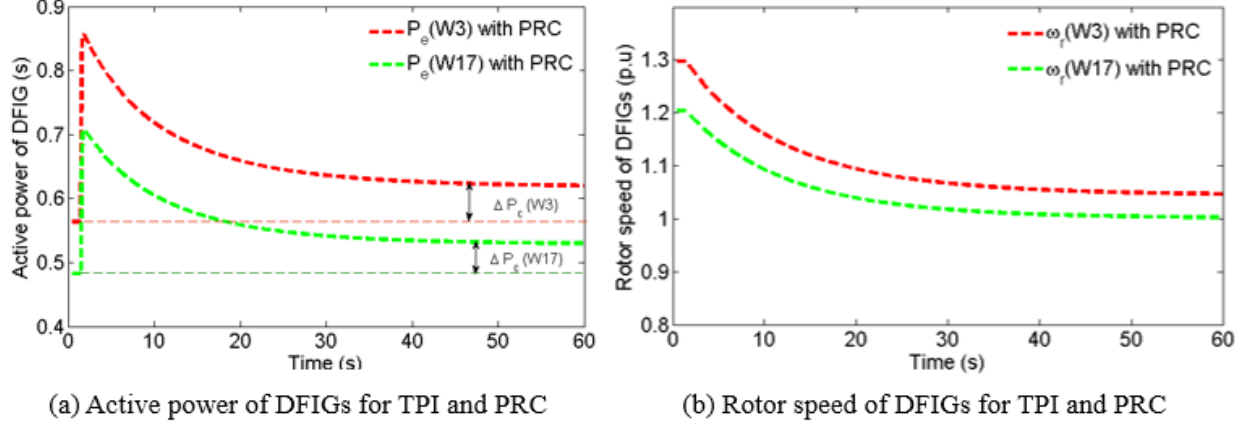


Figure 7.15: Active power and rotor speed of DFIGs for TPI and PRC

7.2.4 Case Study IV: 50% wind penetration on PRC with over-frequency event

If the reserve margin is less than the maximum allowable reserve during normal operation, DFIG in PRC mode has the capability to help with not only under-frequency events, but also over-frequency events. In this case study, we consider a 5% reserve for W17 under the condition of a load reduction event (500 MW) at 1s. The frequency response with and without the proposed PRC controller is compared and shown in Figure 7.16. The corresponding active power and rotor speed are shown in Figure 7.17. It can be verified that the frequency nadir and settling frequency are both improved relative to the no support case and the rotor speed is kept within the maximum allowable limit. The capability of overspeeding based PRC is limited by the maximum reserve level. In this condition, increasing the pitch angle could further reduce the DFIG output active power to improve the frequency response of over-frequency event.

7.2.5 Case Study IV: 50% wind penetration on TPI with DDC

Consider the worst-case generator trip event (2160 MW) as an example. Fig. 7.18 (blue curve) shows the frequency response with 50% wind with DFIG units non-responsive to frequency deviation. In this particular case, the frequency nadir reaches 59.66 Hz which is lower than f_{na}^{min} . The scheduled DFIG units will be switched in to satisfy the f_{na}^{min}

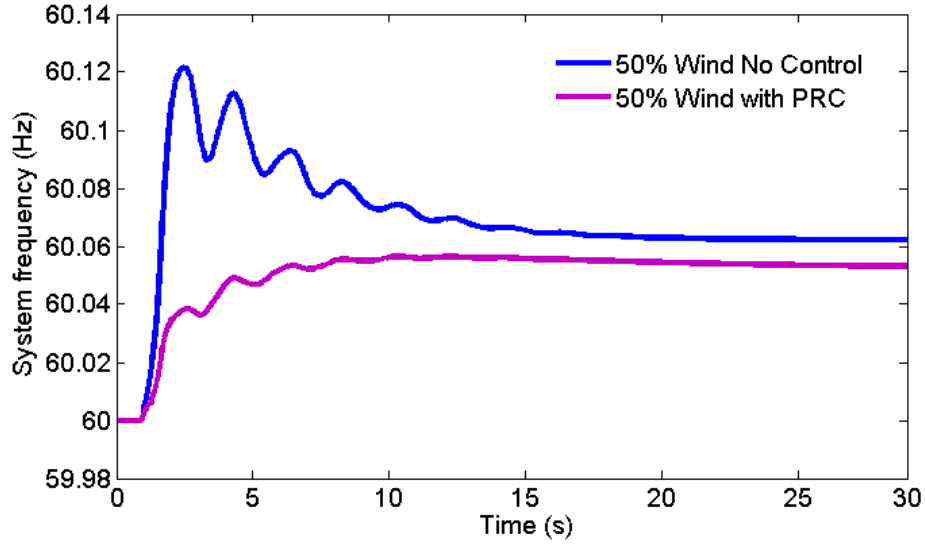


Figure 7.16: Frequency response for PRC with over-frequency event

requirement. The frequency response with DFIG control only is shown as the yellow dotted curve in Fig. 7.18. Since the required minimum secondary frequency dip limit is 59.80 Hz, DDC is activated when $f(t)$ passes f_{dip}^{min} and the settling frequency is above f_{ss}^{min} as shown in Fig. 7.18 as the dotted red curve.

7.3 Large-scale Test Bed Results

The proposed DFIG control framework is also demonstrated on CURENT LTB taking advantage of the real-time capability of RT-Lab real-time simulator. The multi-processor feature of RT-Lab provides a convenient path to separate a complex model into several subsystems, in this way, the parallel operation of each subsystem is able to increase the computational speed to fulfill real-time requirement. The web-base visualization tool is used to show the visualized results. The frequency response of the system at different time are shown in Figure 7.19 and 7.20. In this case, the generator trip event happens at 1s in the red circled area in the visualization contour map (Figure 7.19).

The five DFIG units are operated in TPI mode. The left subfigure in Figure 7.19 is the uncontrolled case, and the right one is the controlled case for simultaneous comparison. At the beginning of the disturbance, the initial ROCOF is smaller for controlled case and

the effect is indicated as the less blue color. As the disturbance effect propagated, it can be verified the frequency nadir in the controlled case is higher than the uncontrolled case, which successfully demonstrated the effectiveness of the proposed control framework from the whole system point of view.

7.4 Conclusion

In this chapter, a comprehensive control framework with three operating modes for DFIG is proposed to improve system frequency response. A temporary power injection mode is presented to ensure adequate inertial response with guaranteed rotor security. And a power reserve control mode is presented to help mitigate the secondary frequency dip and improve the primary settling frequency. If the reserve is less than the allowable maximum reserve, DFIG is able to not only help with under-frequency event, but also contribute to over-frequency event to some extent.

The proposed framework is implemented in 181-bus WECC system with integration of 50% wind penetration using user-defined positive sequence DFIG model. The proposed framework is also demonstrated in CURENT LTB. Both offline and real-time simulation results demonstrate that the proposed control framework is effective and DFIG has the potential to improve frequency response from the time-scale of inertial response through primary frequency control.

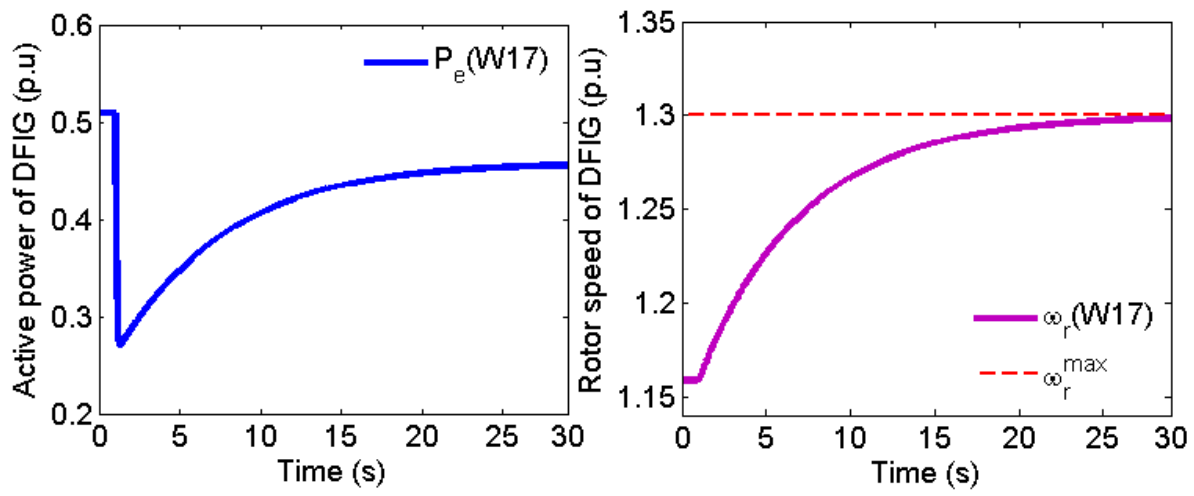


Figure 7.17: Active power and rotor speed response for PRC with over-frequency event

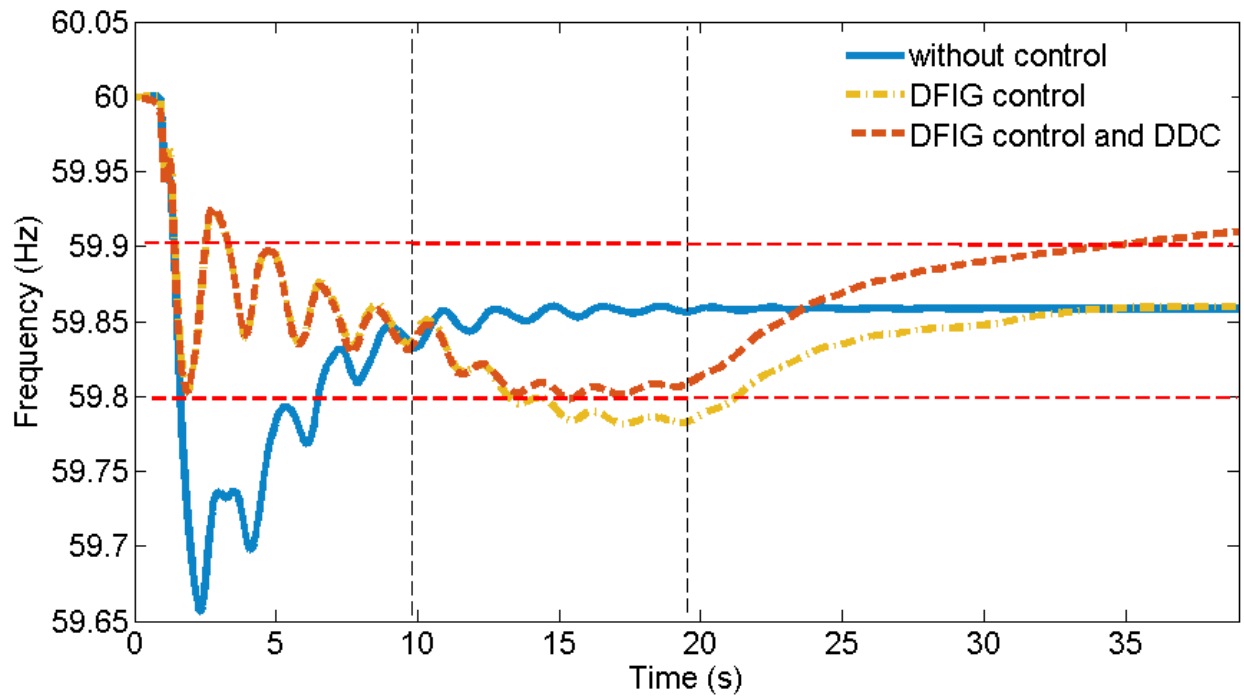


Figure 7.18: Frequency response comparison of WECC system

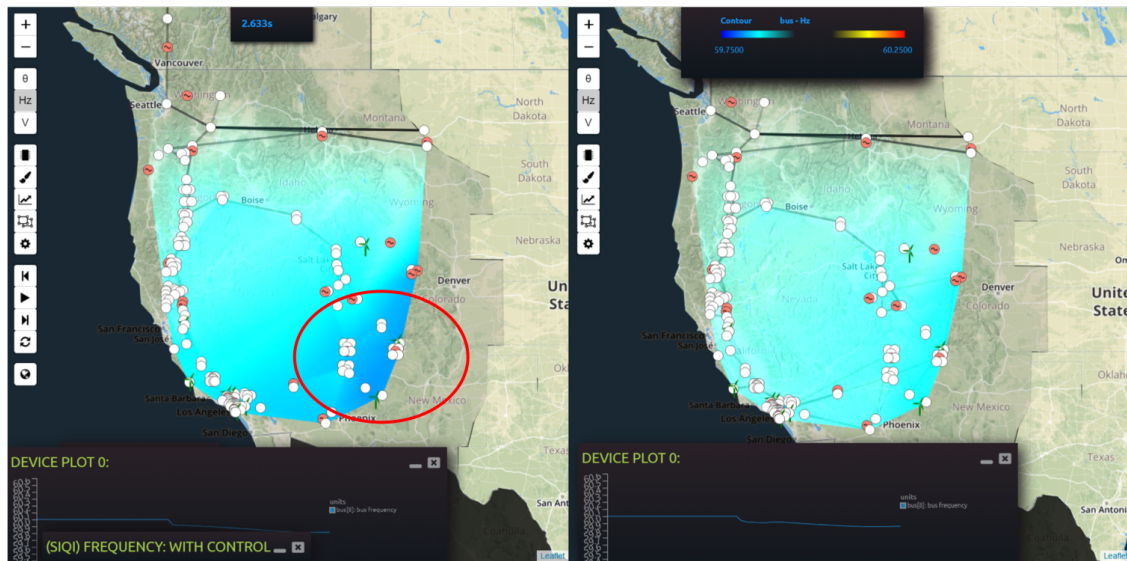


Figure 7.19: ROCOF comparison for uncontrolled and controlled case

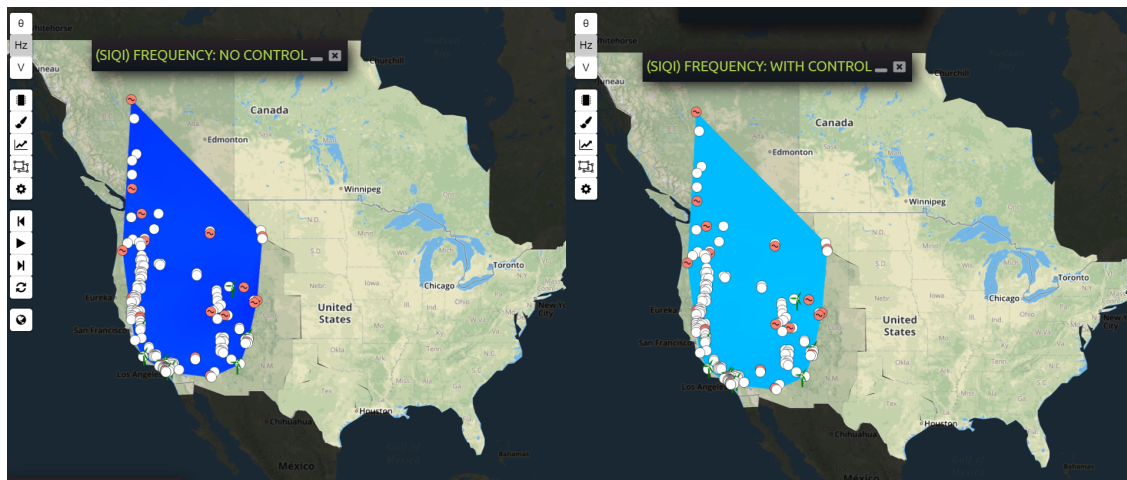


Figure 7.20: Frequency nadir comparison for uncontrolled and controlled case

Chapter 8

Conclusion

The secure operation of power system requires the active power between generation and load be balanced moment by moment. Any types of imbalance will be indicated by the frequency deviation from the nominal. Off-nominal frequency may damage the equipment, overload the transmission lines, and degrade the quality of product delivered to the end users. System frequency as the indicator to distinguish balance and imbalance operating conditions is required to be controlled well during the whole time. In recent years, there is a big trend of integrating high penetration of renewable energy resource such as wind generation. The high penetration of wind brings significant impact and technical challenges on traditional power system frequency control. On the one hand, during normal operation, the wind power output variations due to the abrupt weather changes will lead to a larger range of frequency fluctuations. On the other hand, the replacement of conventional generators by wind units will reduce the inertial response and primary frequency control capability. Extensive research work has been done to overcome the frequency control challenges brought by high penetration of wind. The efforts are made from both conventional generation side and renewable generation side.

This work investigates the potential of DFIG and TCLs for participating in power system frequency control and proposed a comprehensive control framework to improve frequency response from the time-scale of inertial response through primary frequency control. The DFIG control approaches include three operating modes with switching among each operating modes achieved by modifying reserve input up to p percent. In TPI mode,

the maximum active power injection amount is estimated with consideration of rotor speed security limit and the converter overload limit. In PRC mode, the maximum reserve level constrained by maximum rotor speed limit is obtained by estimating the maximum tip-speed-ratio deviation for each specific wind speed condition. And the maximum transient active power injection is estimated to ensure the rotor speed be kept above MPPT point. An offline schedule and online selection scheme is presented to ensure an adequate inertial response delivery with minimum commitment number of DFIG units.

The TPI approach and the other similar inertial emulation strategies only improve the inertial response with no impact on primary settling frequency. And it also has a delayed frequency recovery issue due to the fact that rotor speed needs to recovery back to MPPT point which will absorb active power from the system. Operating DFIG in PRC mode can avoid the secondary frequency dip and help with the primary frequency control but the capability for settling frequency improvement is limited by the DFIG's maximum rotor speed limit. To further ensure the adequacy of primary frequency control, support from demand sides needs to be activated to coordinate with DFIG in the primary frequency control time-scale. Controlling the frequency from demand side can be very quick and more flexible. The controllable loads that can participate in frequency control are usually energy users instead of power users. The energy users have the capability to shift power consumption for a short period of time without compromising end-user's comfort level. The ideal candidates of such controllable loads are thermostatically controlled loads (TCL) such as electric water heaters (EWH) and heating, ventilate and air-conditioners (HVAC).

The control framework for DFIG is extended to include the frequency control capability of controllable loads. And the control design of DFIG and controllable loads can be formulated into one multi-source multi-time-scale coordinated fast frequency control framework in which DFIG can provide the fast and adequate inertial response and the controllable loads can take over the frequency control responsibility in the primary frequency time-scale after the inertial response delivery period. In this way, the secondary frequency dip caused by DFIG rotor speed restoration can be avoided and the primary settling frequency can be kept within a specific range. This requires a coordination strategy to switch control actions and activate each contributors based either on frequency threshold or time interval requirement. To

achieve this, several SFTIs are proposed to help with the control activation and switching. With the support from both DFIG and controllable loads, the requirement of increasing the ramping rate of conventional generators can be released and the burden of secondary frequency control by conventional generators can be relieved to some extent. The control performance is tested in both of the offline 181-bus WECC systems and in CURENT Real-time Large-scale Test Bed.

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