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**MODELING AND DYNAMIC
BEHAVIOR OF WIND GENERATION
AS IT RELATES TO POWER SYSTEM
CONTROL AND DYNAMIC
PERFORMANCE**

**Working Group
C4.601**

August 2007



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EXECUTIVE SUMMARY

Background on the Working Group

The CIGRE WG C4.601 on Power System Security Assessment was formed in August 2004, at the CIGRE Session 2004 and was given the charter to specifically look at the following needs in the industry:

1. The design of controls to enhance system security. This includes local device controls as well as system wide area controls and remedial action schemes.
2. Modeling of existing and new equipment required for power system analysis. (In this task it was felt that the most pertinent and timely activity was to look at the modeling and dynamic performance of wind generation systems.)
3. The design of monitoring systems for real time stability evaluation and control.
4. New analytical techniques for assessment of power system security. In addition to advances in computational methods, this includes the development of emerging approaches such as risk-based security assessment and the application of intelligent technologies.

To this end, all of the above subject matters were tackled by the Working Group. More specifically, of the more than one hundred members and contributors to the work, three adhoc groups were developed within the Working Group, each given the task to address one of the first three subject matters above. The fourth task is one that the working group as a whole has presently started on, after having finished the other three tasks. The three completed tasks have resulted in the publication of three CIGRE Technical Brochures. These are:

- CIGRE Technical Brochure on Wide Area Monitoring and Control For Transmission Capability Enhancement (this effort was lead by C. Rehtanz)
- CIGRE Technical Brochure on Modeling and Dynamic Behavior of Wind Generation as it Relates to Power System Control and Dynamic Performance (this effort was lead by P. Pourbeik)
- CIGRE Technical Brochure on Review of On-Line Dynamic Security Assessment Tools and Techniques (this effort was lead by K. Morison)

During the course of the work, in addition to the formally elected WG members a large number of others contributed significantly to these efforts. All have been properly acknowledged. The combined group of members and contributors constituted 125 experts from 25 countries. These included experts from equipment manufacturers, utility engineers, consultants and research organizations around the world. The work on the three Technical Brochures mentioned above was completed in December 2006, with final reviews and approvals before publication occurring in early 2007. Thus, the work took nearly two and a half years to complete.

All three documents constitute timely and valuable information for transmission system planer, operators, reliability organization and engineers in research and consulting firms.

As stated previously, the Working Group is currently working on its last assignments (item 4. above). It is expected that this will be reported on in the near future.

Modeling and Dynamic Behavior of Wind Generation as it Relates to Power System Control and Dynamic Performance

In the past five to ten years, due to the Kyoto Protocol signed in 1997 by 160 industrialized nations, there has been a focused increased in renewable energy sources in the global energy market. None has experienced a faster increase in penetration into the electrical power systems than wind turbine generator systems. This technical brochure is a comprehensive document focused at providing a single source of information for planning engineers in describing the characteristics and performance of wind turbine generators in both distributed and large scale wind farm applications. In addition, the document focuses on presenting recommendations on ways of modeling wind farms for both bulk power system studies and specialized studies. This includes:

- An overview of wind generation and the unique aspects of this type of renewable generation as opposed to more conventional fossil fuel generating plants.
- A description of the unique aspects of control and protection for wind turbine generators and the various types of wind generation technologies.
- A brief overview of the experience of various utilities from around the world with large penetration of wind generation in their system.
- A thorough, yet concise, discussion of the interconnection and operating issues that are unique to wind generation and how the latest generation of wind turbine generators are meeting these challenges (e.g. low-voltage ride-through).
- A discussion on the types of models available for system studies related to the interconnection of wind turbine generators to a utility grid and recommendations on appropriate level of modeling detail for power system analysis. Recommendations and discussion are given on improvements necessary in existing models.
- Discussions are also provided in the appendices, from manufacturers, on field and factory tests pertaining to model assessment and validation.

The document is divided into seven chapters and seven appendices.

Chapter 1 is a brief introduction.

Chapter 2 provides a thorough overview of the application and experience of some of the major utilities around the world with wind generation penetration into the power system. Discussion is provided on the technical performance issues experienced, methodologies employed to rectify these challenges and the future trends for wind generation penetration.

Chapter 3 gives a detailed account of the various wind turbine generator technologies (as well as some emerging ones, with some details differed to an appendix). This includes a comprehensive review of each technology, how they differ from one another, the unique dynamic performance (from a power systems perspective) that each of the technologies display, how the technical challenges (such as fault ride-through systems) are being addressed by manufacturers for each of these designs and what challenges remain.

Chapter 4 presents a full discussion of all the technical issues related to the interconnection of large (10 MW or larger) wind farms to the transmission system. This includes voltage-ride through, reactive power and power factor requirements, voltage control and regulation, controls interaction, harmonic, power quality and frequency control.

Chapter 5 discusses the key technical issues related to small wind farms on distribution systems.

Chapter 6 provides an in-depth overview of modeling of wind farms for both steady-state power flow and time domain dynamic simulations. In addition, recommended generic model structures are presented for all the main wind turbine generator types, including direct connected induction generators, doubly-fed asynchronous generators and units connected to the system through full-rated back-to-back frequency converters. The presentation in this chapter also deals with suitable methods to aggregate wind turbine generators in a wind farm into a simpler model of the collector system, but yet be able to develop a reasonable representation of the wind farm. Extensive discussion is provided on the modeling recommendations for various types of power system studies. This chapter is complemented by several appendices that provided further details on wind turbine generator modeling, including manufacturer specific models, models available in many commercial software programs, modeling wind turbine generators for small-signal rotor angle stability studies, emerging technologies such as the hydrodynamic gear driven wind turbine generator and discussion on model validation efforts by manufacturers.

Chapter 7 summarizes the report and provides a brief overview of remaining challenges in modeling and control of wind generation systems.

Conclusions

Wind generation technology has matured over the past several decades into an economically viable and environmentally favorable source of energy. Today wind generation has become a significant portion of the generation mix in many countries around the world. This document has focused on describing the dynamic performance, behavior and modeling of this generation resource. In general, wind turbine generators tend to be quite different in both mechanical and electrical construction from traditional large thermal, nuclear and hydro power plants. A wind farm of comparable peak megawatt capacity to a large thermal power plant will consist of many tens to perhaps hundreds of wind turbine generators and span over many square kilometers of land or sea. Each wind turbine generator consists of the mechanical turbine, which typically has three rotor blades that can have a diameter in excess of 80 m, that is connected to a small generator through a slender shaft, often with a gear box in between. There are presently four major concepts for the actual generator:

- a conventional, constant speed, induction generator,
- a variable speed induction generator unit with a variable, external, rotor resistance,
- a variable speed unit with a doubly-fed asynchronous generator, and
- a variable speed unit with a fully rated frequency converter connecting the generator to the electrical grid.

Each of these concepts, together with other emerging concepts such as the hydrodynamic gear drive train turbine, have been discussed and explained in detail in this document.

In the early years of wind turbine generator design, the units were mainly designed for application in distribution systems and as distributed resources. Thus, a typical requirement was for the wind turbine generators to disconnect from the system following a major system disturbance. Presently, most wind farms are of the tens to hundred megawatt range and are connected to major transmission systems. Thus, the expectation is for these generating units to help support the system during major disturbances. With the application of modern wind turbine generator technologies (and occasionally other supplemental devices such as static var compensators etc.) it is possible to build wind farms capable of riding through voltage transients caused by typical transmission system faults and disturbances, and having adequate reactive reserves and automatic controls to provide voltage regulation at the point of interconnection.

Of course, the intermittent nature of the energy source (wind) is not controllable, thus this presently still constitutes the major challenge facing operating systems with large amounts of wind generation. Active power control systems have been proposed for wind generators that allow their contribution to frequency and/or tie-line regulation, but this is always at the expense of wasted wind power if no means of energy storage is available.

The exact amount of wind generation that may be incorporated into a system before the burden of operation becomes excessive (usually called maximum penetration of wind power) is highly system dependent, since it is affected by the weather patterns of the region, the type of installed generation capacity in the system, the available power transmission capacity of the system with its neighbors and the contractual obligations governing these interconnections. The unique and unambiguous determination of such penetration limits is still an open question.

Much progress has been made, particularly with research and development in the science of wind generation forecasting but significant additional work remains in this area as well as considerations related to the potential of marrying wind generation with energy storage technologies that could help with active power regulation as mentioned above.

Detailed discussion and generic models for modeling wind turbine generators have been provided in this document. From a modeling development perspective the key item that requires further work is model validation. Although, as documented here mainly in the Appendices, many of the manufacturer specific models have been validated by the respective manufacturers, work remains to be done to validate the generic types of models presented in chapter 6 against field recordings of wind turbine generator response. Through such work, further refinements to the generic model structures may become evident and necessary, such as the behavior of certain doubly-fed asynchronous machine designs, which incorporate active crowbar controls during and immediately after system faults due to the rotor crowbar circuits being engaged and disengaged (this does not apply to all designs of doubly-fed units).

Further research on the participation of wind generation in primary frequency control, including methods for energy storage, as well as on standards to specify wind power penetration limits is in progress. These and other research subjects concerning the integration of wind farms into power systems can be found in the literature.

CIGRE WORKING GROUP C4.601 ON POWER SYSTEM SECURITY ASSESSMENT

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List of Acronyms and Terminology

ac	alternating current
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
dc	direct current
DFAG	Doubly-Fed Asynchronous Generator (a more commonly used misnomer is doubly fed-induction generator)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission (USA)
GW	Giga Watts
HV	High-Voltage
HVDC	High-voltage dc
IPP	Independent Power Producer
LVRT	Low Voltage Ride-Through
ms	milliseconds
MSEPS	Multi-Scheme Ensemble Prediction System
MV	Medium-Voltage
MVA	Mega Volt-Amperes
MVar	Mega Volt-Amperes Reactive
MW	Mega Watts
NEMMCO	National Electricity Market Management Company (Australia)
NERC	North American Electric Reliability Council (USA)
OEL	Overexcitation Limiter
OLTC	On-Load Tap Changer
PCC	Point of Common Coupling
PI	Proportional-Integral
PLC	Programmable Logic controller
PLL	Phase Lock Loop
PNM	Public Service Company of New Mexico
POI	Point of Interconnection
PSD	Power Spectral Density
pu	per unit (system of units used in electrical calculations)
PWM	Pulse Width Modulation
RFP	Request For Proposal
RTU	Remote Terminal Unit
s	seconds
SCR	Short Circuit Ratio
SSR	Subsynchronous Resonance
STATCOM	Static Compensator (IGBT or IGCT voltage source converter based design)
SSTI	Subsynchronous Torsional Interaction
SVC	Static Var Compensator (thyristor based design)
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity (Europe)
UPS	Uninterruptible Power Supply
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator

CHAPTER 1

INTRODUCTION

The Kyoto Protocol is a legally binding document signed by 160 industrialized nations¹ on 11th December 1997. The aim of this protocol is the reduction of six greenhouse gases (CO₂, CH₄, N₂O, HFCs, PFCs, SF₆) by year 2008 to 2012. The original protocol required a collective reduction among these nations of 5.2% in greenhouse gas emissions. Since the emissions by some countries actually increased after the signing of the protocol, when compared to year 2000 emission levels the actual required reduction is roughly 10%. This among other reasons is one of the primary driving forces behind an increase in renewable energy generation globally. Wind energy is one of the most mature of the various renewable energy technologies² and has recently gained much favor in North America, Europe, Australasia and other parts of the world.

Wind energy resources have dramatically increased over the past decade. At the end of 2005 the total installed capacity of wind generation in Europe was up to 40.5 GW (www.ewae.org). Presently, there is an estimated 11.6 GW of installed capacity of wind generation in the USA (www.awea.org). The installed capacity of wind generation in Australia nearly doubled from a total installed capacity of 380 MW by the end of 2004 to 708 MW by the end of 2005 (www.auswea.org).

Due to the rapid growth in wind generation, and the fact that it now constitutes a significant portion of the generation mix in many power systems around the world, there is an imminent need to better understand the dynamic behavior of this technology and to be able to faithfully model and represent it in power system studies. It is vital to the electric power industry to have a concise source of information that defines the distinctive characteristics of wind generation and how its impact on system performance is to be assessed through proper modeling and analysis. This document is aimed at meeting these needs. These needs are driven by the fact that wind generation has some unique characteristics as compared to conventional fossil fuel generation stations.

1. Wind farms are composed of large numbers of turbines spread out across a geographical area much larger than a typical fossil fuel plant. The combined total peak generating capacity of the wind farm may be equivalent to that of a single steam turbine or heavy-duty gas turbine.
2. Wind farms can be quite remote from load centers. For example, particularly in Europe, many of the new wind facilities are aimed at offshore sites.
3. Since the source of the energy is wind, the production of electrical power from a wind farm is intermittent by nature.
4. Conventional fossil fuel, nuclear and large hydro generation power plants all employ synchronous electrical generators. In contrast, wind generation technologies utilize a variety of different types of electrical generators varying from squirrel-cage induction generators to wound rotor asynchronous machines fully or partially coupled to the grid through back-to-back voltage source frequency converters.

Power system studies can be, but are not limited to, analyses of the following nature:

¹ See <http://www.iitap.iastate.edu/gcp/kyoto/finalagree.html>

² Here we are referring to modern renewable technologies such as wind, photovoltaic, etc. Hydro generation is of course a well established form of renewable generation that has been utilized from the very onset of polyphase ac power systems – the world's first hydro generation power station was built by the Westinghouse Company at Niagara Falls to serve the city of Buffalo, New York. This project was completed in 1895, based on the designs and patents of Nikola Tesla.

- The study of the impact of proposed new generating facilities on an existing power system.
- The study of system small-signal and/or transient stability.
- The study of large system frequency disturbances.
- The study of reactive/voltage stability of a power system.

In all of the studies mentioned above there is a need for an appropriate level of modeling detail. Some require a greater focus on the electrical components of the system and power plants while others require as much attention be given to appropriate modeling of the mechanical systems of power plants. For wind turbine generation technologies, both the electrical and mechanical controls are quite unique and different from other types of generation. This document deals with modeling both the mechanical and electrical components in a wind farm, at a level of detail appropriate for power system studies.

The layout of the document is as follows:

- Chapter 2: Presents an overview of the global experience with wind generation from various utilities and system operators.
- Chapter 3: Presents an outline on the various types of wind generation technologies and gives a description of their unique characteristics.
- Chapter 4: Presents some of the integration and operational issues related to wind generation and how these may be addressed by the latest developments in the state-of-the art technology. This chapter is focused on issues related to the integration of large wind generation facilities (tens to several hundred megawatts) being interconnected directly to the transmission grid.
- Chapter 5: Presents an outline of integration and operational issues related to the interconnection of small/distributed application of wind generation.
- Chapter 6: Presents a detailed account of modeling and the present status of model validation of wind generation technologies for power system studies
- Chapter 7: Summarizes the material presented in this report and highlights the key conclusions. Recommendations are given on the level of modeling detailed required for power system studies as well as needed future work in model development.
- A number of appendices are provided at the end of the document, which complement the material presented in the main chapters of the document.

CHAPTER 2

GLOBAL PENETRATION AND EXPERIENCE WITH WIND ENERGY AND FUTURE TRENDS

2.1 Introduction - Wind Energy Conversion

Wind energy has been in use for centuries. Originally, wind turbines (or wind “mills”) were used for pumping water, grinding grain and other such agricultural activities. The first known windmills were developed for the tasks of grain-grinding and water-pumping – the earliest designs were of a vertical axis system developed in Persia (Iran) around 500-900 A.D [1]. The first windmills to appear in Europe were of a horizontal design, and the Dutch set out in the 1390s A.D. to refine this design.

In the past two decades, technological advancements have made it possible to utilize wind energy for the production of electricity. Given that the fuel source (wind) is inexhaustible and free, the urge to utilize this resource is clear.

Figure 2-1 shows a diagrammatic representation of a wind turbine.

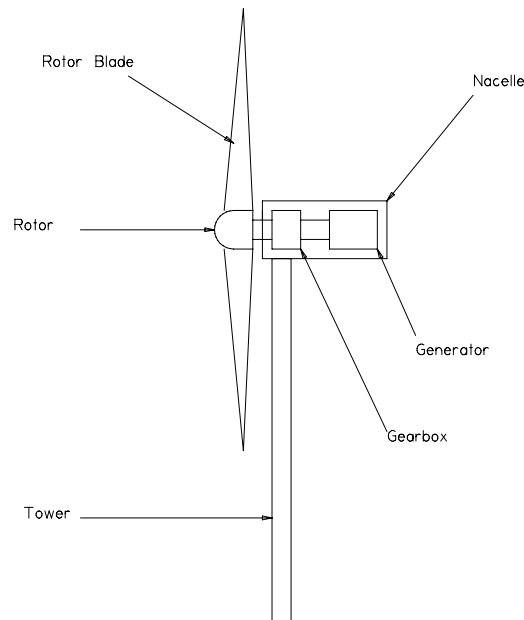
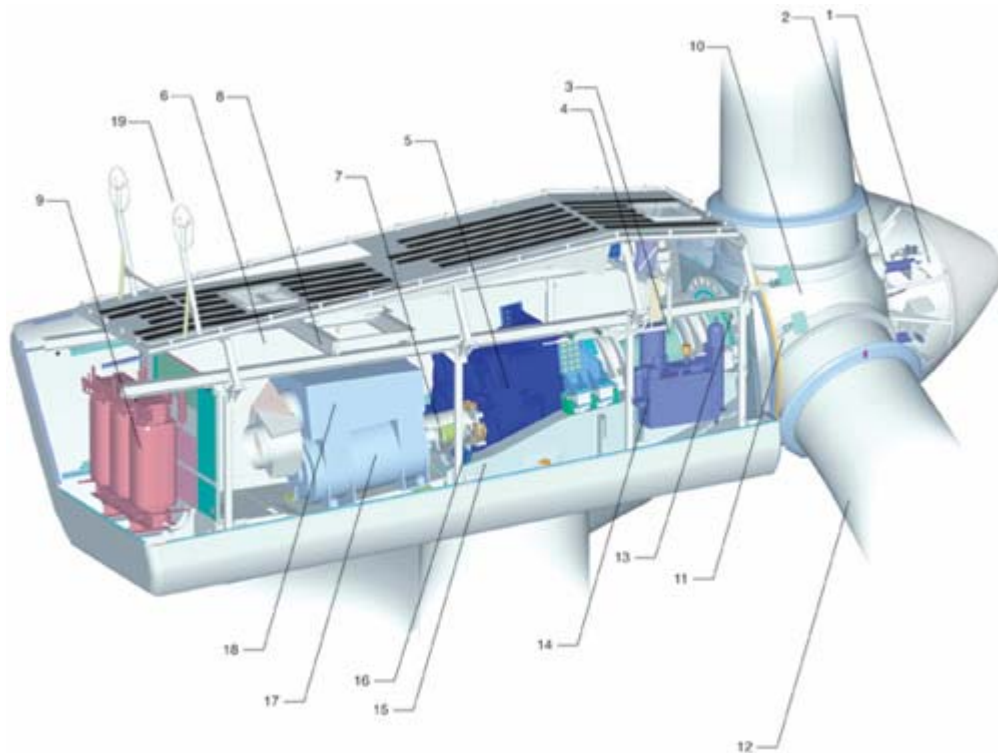


Figure 2-1: Wind turbine [2].



- | | | |
|--------------------------------------|-------------------|--------------------------|
| 1. Hub controller | 7. Parking break | 13. Rotor lock system |
| 2. Pitch cylinder | 8. Service crane | 14. Hydraulic unit |
| 3. Main shaft | 9. Transformer | 15. Machine foundation |
| 4. Oil cooler | 10. Blade hub | 16. Yaw gears |
| 5. Gearbox | 11. Blade bearing | 17. OptiSpeed™ generator |
| 6. VMP-Top controller with converter | 12. Blade | 18. Ultra-sonic sensors |

Figure 2-2: Detailed diagram of the components of a wind turbine (Source: Vestas, www.vestas.com).

Figure 2-1 is a generic diagram showing the main parts of a wind turbine, the rotor blades, the nacelle, a gearbox and a generator (note: not all wind turbine designs use a mechanical gear, see Chapter 3 for more details.). Figure 2-2 is a more detailed picture of the components in an actual wind turbine system. Electronic controls and other ancillary equipment, such as a step up transformer, associated with the unit may be mounted either in the nacelle (as shown in Figure 2-2) or at the base of the tower. Most modern turbines use a three blade design and point upwind. As the wind blows over each blade it causes lift much like on an airplane wing, thus causing the turbine to rotate. The electrical generator extracts this mechanical power and converts it to useful electrical power. The gearbox is the mechanical transition between the rotor blades, often rotating at ten to twenty rounds per minute and the generator rotating fifty to hundreds of times faster. Some modern wind turbine designs are gearless.

The theoretical maximum efficiency of a wind turbine is given by Betz's law [3]. This law states that a lifting rotor can at most extract 59.3% of the energy from an air stream. In practice, modern designs can achieve efficiencies in the order of 40%. For a wind turbine there is no single efficiency since the efficiency of the turbine is a function of the wind speed. Thus, often performance coefficients are quoted as a function of wind speed; that is, the ratio of power extracted to power available in the wind at a given wind speed. In the early 1980's a typical wind turbine had a rotor diameter of 10 meters and would generate in the order of 25 kW. Modern wind turbines such as the Vestas V82, GE 1.5MW and Vestas V90 have rotor diameters of 70 to 90 meters and generate between 1.5 to 3 MW. In addition, wind turbines designed primarily for offshore applications, where winds are more prevalent, presently have reached ratings of 4.5 MW. When deployed in a wind farm, the typical spacing between

adjacent wind turbines is between 3 to 5 rotor diameters (depending on the actual farm layout). Thus, the modern wind farm, which may consist of 50 to 100 turbines, will span several square kilometers of land (or sea).

An important concept is the expected energy output of a typical wind turbine (or farm) over an annual period. This is often expressed as the *capacity factor* of the wind turbine (or farm). The capacity factor is defined as:

$$\text{Capacity Factor} = \frac{\text{Actual annual energy produced}}{\text{Energy produced if wind turbine (farm) was at full capacity for the entire year}}$$

The capacity factor of a wind farm depends on the design and performance of the wind turbines and the wind profile at the site the turbines are located.

A reasonably economic capacity factor may range from 0.25 to 0.3. Anything above 0.3 would be a good site. For land wind farms, it is rare to find sites with a capacity factor much higher than 0.3 to 0.35. Offshore sites, on the other hand, tend to have higher capacity factors and typically range from 0.35 to 0.45.

The typical time frame between commencement of work on construction of a wind farm and full operation of the farm is 12 months [4]. In comparison, the development of conventional power plants and/or transmission assets may typically take several years. Thus, without proper and advanced planning, wind generation assets may grow in a system so rapidly as to not allow adequate transmission reinforcements to be implemented in time to facilitate their interconnection.

2.2 Worldwide Penetration of Wind Generation and Expected Future Trends

2.2.1 North America

The North American Continent presently has an estimated 11.6 GW of installed wind generation. A list of current wind farm projects (and proposed projects) in the US may be found at the American Wind Energy Association website (www.awea.org). The leading regions for wind generation installations are California, Texas and the Midwest (particularly Minnesota and Iowa).

2.2.1.1 New Mexico

The eastern plains of New Mexico have been identified as having the potential for significant development of commercial-scale wind-driven electricity generation. While other areas in the state are also recognized as having potential for wind power development, the eastern one-third demonstrates the most promise, in terms of availability of wind resource. Preliminary indications support an estimate of wind energy development potential in eastern New Mexico of 6000 MW and possibly twice that amount¹. Currently, New Mexico has 497 MW of grid-connected (204 MW to the eastern grid and 293 to the western grid) wind generation that has been installed or is under construction.

The eastern portion of the New Mexico transmission grid is relatively undeveloped. Presently, the only Western Electricity Coordinating Council (WECC) transmission facilities in the eastern portion of the state consist of two long 345kV transmission lines that tie the WECC to Southwest Power Pool (SPP) via two 200 MW High Voltage dc (HVDC) converter stations.

In 2003, Public Service Company of New Mexico (PNM) successfully interconnected a large wind farm ("New Mexico Wind Energy Center" or "NMWEC") to its transmission system in

¹ New Mexico Electricity Transmission Task Force Report dated December 29, 2004.

eastern New Mexico. The NMWEC is located inside the PNM North American Electric Reliability Council (“NERC”) certified control area. As a control area operator, PNM is required to maintain sufficient resources to regulate frequency and balance generation to net load/schedule in accordance with NERC control performance standards. The NMWEC is a 204 MW wind farm, which represents approximately 10.5% of PNM’s on-peak control area load and 18.2% of PNM’s off-peak control area load for 2004. For PNM’s native load, this represents approximately 13.1% of on-peak load and 29.61% of off-peak load for 2004. This is the largest wind energy penetration level in any control area in North America. The NMWEC is widely recognized in the industry as an example of successful wind generation interconnection and integration with the transmission grid. During the large generator interconnection process, PNM conducted extensive technical analyses as part of the System Impact and Facility Studies for the NMWEC. These studies identified the need to implement first of its kind low-voltage ride through and other state of the art performance features.

Within the PNM control area, the intermittent nature of the NMWEC creates an impact on both the PNM generation and transmission operations, particularly in regard to the moment-to-moment following of load due to wind generation fluctuations. It has been a challenge for PNM to integrate this highly intermittent wind energy production on its small, but highly geographically dispersed transmission system. PNM has met this challenge. However, due to the small size of the PNM control area and limited resources available for regulation, PNM may have difficulty meeting reliability standards should further intermittent resources develop on its system. PNM has pending in its interconnection queue requests for an additional 1000 MW of wind resources.

PNM has several generating units on its system equipped with automatic generation control (AGC). These units include both coal and gas units. These units have a finite ability to effectively provide sufficient AGC to manage wind power variability. Despite a surplus of installed generation capacity in the Southwest region, generation equipped with AGC for regulation use is not in abundant supply in the southwest power market, and regulating capacity is generally not available as a market commodity.

2.2.1.2 Electric Reliability Council of Texas

The Electric Reliability Council of Texas, Inc. (ERCOT) is one of eight Regional Reliability Councils in North America². ERCOT serves about 85% of the electrical load in Texas. The 2003 summer peak hourly demand in ERCOT was 59,996 MW. The overall generation capacity is approximately 70,000 MW. Generation resources consist of nuclear; conventional coal, natural gas, and fuel oil; simple cycle combustion turbines and combined cycle power plants; hydro; and other sources such as wind energy. An important characteristic of ERCOT is that it is completely located in the state of Texas, and has no synchronous connections to other reliability regions. There are two back-to-back dc ties connecting ERCOT to another reliability region and a back-to-back dc tie to Mexico. The total capacity of the dc ties is about 856 MW

Modern wind farms began making their appearance on the ERCOT grid in the mid to late 1990s. From these small beginnings a few years ago, things have changed substantially. The amount of wind generation installed in 2006 is about 2500 MW, and the amount of wind generation currently under development (as of summer, 2006) is about 2300 MW³ based upon public information. There is no indication that the development of wind generation in ERCOT will stop any time soon.

As significant wind generation rapidly became a reality in ERCOT, several issues quickly became apparent. These included transmission line capacity, voltage regulation, and the lack of an adequate wind model for dynamic simulations.

² <http://www.nerc.com/regional/>

³ ERCOT CREZ Analysis Report, 12042006.

Most wind generation is located in far west Texas in areas that are sparsely populated. The transmission system in that part of the state was sized for the local load before the wind farms were built. The sudden addition of relatively large amounts of wind generation in the past few years has resulted in localized inadequate transmission capacity for handling the wind generation in some instances. Substantial transmission construction has been underway for several years to alleviate the congestion.

The nearest large load center to the largest concentration of wind farms is about 360 circuit miles (580 km) away. For much of that distance, the transmission system consists of four 345 kV circuits. During light loading conditions, high voltages are often encountered at some wind farms. Conversely, under heavy loading conditions, and especially during fault conditions, the wind farms may experience low voltage conditions. Considerable work has been done to reduce these voltage fluctuations.

To address the wind model issue, ERCOT hired in 2003 a contractor to develop models for all wind machine types then currently installed in ERCOT. These models have been successfully used in several stability studies. Because wind generation technology is developing so rapidly, maintaining a current library of wind models is a continuing challenge.

While there are always several concerns for a power system the size of ERCOT, at the present, three appear to be of greater concern for wind generation. They are the ability of the wind generator to ride-through voltage and frequency excursions, the wind machine response to system oscillations, and as the percentage of wind generation increases, the effect that large wind generation output swings might have on the system.

As mentioned above, voltage can vary considerably in the area of greatest wind generation concentration. While considerable progress has been made to reduce the voltage variations, faults in particular can still reduce the voltage over a large area in west Texas. While not particularly common, sudden loss of large amounts of generation has occurred in ERCOT. During either voltage or frequency excursions, the sympathetic loss of large amounts of wind generation would be detrimental to the system.

The total circuit distance from far west Texas to far south Texas is approximately 800 miles (1290 km). Under some conditions, slow damping of oscillations has been observed. The extent to which this slow damping could affect wind generation in ERCOT has not been fully explored.

At least two issues emerge as the amount of wind generation becomes substantial in ERCOT. Since wind generation does not exhibit governor action in response to frequency deviations, it is possible that the quantity of responsive reserve required to maintain the system may be affected. As mentioned, ERCOT has very limited connection to the rest of North America. As the amount of wind generation increases to a large percent of the total in ERCOT, the sudden loss of large amounts of wind generation becomes a concern. It becomes important to quantify the amount likely to be lost in a short period of time. These are issues that need to be carefully explored as wind generation in ERCOT increases.

2.2.1.3 Canada

Canada has seen a tremendous growth in installed wind energy capacity with an average annual growth of 35% in the past five years. As of July 2006, there was 1049 MW of installed capacity across Canada with approximately 1500 MW of projects that are under construction or have secured power purchase agreements.

Wind plants that have been installed in Canada during the past few years tend to be large (50-150 MW) and connected to the transmission system (69-230 kV). This trend is expected to continue except in Ontario where the provincial government's Standard Offer Program should encourage significant wind interconnections on the distribution system.

The following sections discuss the regional wind activity in Canada in more detail.

British Columbia

British Columbia is a hydro dominated province (84% by capacity). The British Columbia Transmission Corporation (BCTC) was formed in 2003. BCTC is a member of the WECC and NERC, by virtue of its interconnections to the US, and WECC standards are applied when evaluating generator interconnection proposals.

There is a very large wind resource in the province. A recent study estimated that British Columbia has at least 5,000 MW of readily-exploitable wind energy potential, sufficient to provide electricity for over 1.5 million households. Of this, approximately 3,500MW is located onshore in three sites – the Peace, Northern Vancouver Island and the Northern British Columbia Coast - with the remaining 1,500 MW at offshore sites. The Peace River region is of particular interest, with existing transmission infrastructure, a good wind resource, and existing hydro generation.

The BC government has set a voluntary target for electricity distributors to purchase at least 50% of new power supply from local clean renewable energy sources.

Six wind projects were reviewed in BC's 2006 renewable generation call for tender for at least 2500 GWh/year of firm energy. Fifty-three (53) separate projects were submitted that represent approximately 1800 MW of total capacity or 6500 GWh. Contracts were awarded in July to Independent Power Producers for 29 hydro, three wind, two biomass, two waste heat and two coal/biomass. Once developed, the projects will result in the acquisition of more than 7000 GWh/year by 2010. The three wind projects have a total capacity of 325 MW.

BCTC has conducted studies on wind integration into the province⁴.

Alberta

Alberta is the only province in Canada that has a deregulated competitive wholesale market. Transmission and distribution are regulated monopolies with the Alberta Electric System Operator (AESO) responsible for the planning and directing of the operating system. The province runs a competitive market dominated by coal and gas fired generation. The AESO is implementing the Department of Energy's June 2005 policy paper that outlines plans to address a number of issues including the increased uptake of wind and concerns over generation adequacy.

The AESO has conducted studies on wind integration and subsequently introduced a wind Grid Code in 2004: (<http://www.aeso.ca/transmission/302.html>). The wind power facility technical requirements attempt to treat wind generators the same as other generators while recognizing differences in technologies.

The Alberta government is aiming for 3.5% of total electricity supply from new renewable sources by 2008, most of which will be wind. Alberta currently has 283MW of operational wind and 244MW under construction. An additional 2775 MW of wind capacity has applied to the AESO for interconnection to the grid.

There is about 12,000 MW of conventional generation installed (coal, gas and hydro) and a system peak load of 9580 MW (2005). There have been no reliability concerns identified with the currently installed 283MW of wind.

The AESO has recently chosen, at least temporarily, to limit wind power development to 900 MW of capacity so that potential issues associated with wind power variability can be thoroughly examined. A wind variability study was undertaken that examined 225, 895, 1445

⁴ P. Pourbeik, "Wind Farm Integration in British Columbia – Stages 1 & 2: Planning and Interconnection Criteria", ABB Report Number: 2005-10988-2.R01.3, March 28, 2005, and P. Pourbeik, "Wind Farm Integration in British Columbia – Stage 3: Operational Impact", ABB report Number: 2005-10988-2.R02.2, work performed for and sponsored by BC Transmission Corporation, reports available at www.bctc.com/the_transmission_system/engineering_reports_studies/.

and 1994 MW of wind power development. Studies indicate that there are operational and reliability impacts for penetration levels above 900 MW. Historical data is indicating that a large percentage of the installed and/or anticipated wind power in the province will ramp up or down over a very short period of time (under 3 hours). The AESO is leading stakeholder consultation regarding possible mitigation measures that could result in increasing the 900 MW threshold.

One mitigating measure already being researched with stakeholders is wind power forecasting.

Saskatchewan

Saskatchewan is a coal dominated market (50%) with most of the other generation from gas (25%) and hydro (25%) all by capacity. SaskPower (and subsidiary Northpoint Energy Solutions) is the dominant vertically integrated utility, retains control of transmission system operation, and has strong environmental targets.

The province currently has a target for 5% of electricity to come from wind energy which amounts to about 200MW. Support for renewables is present via a “Green Power Portfolio” of “Environmentally Preferred Power”. Qualifying projects must sell all energy to SaskPower.

Saskatchewan currently has 172MW of operational wind including the Centennial Wind Farm, a 150MW project, and the biggest in Canada, in the south west of the Province. SaskPower currently has a call for 45 MW of environmentally preferred power. Thirteen wind projects were received and are being evaluated.

Manitoba

The peak load of Manitoba Hydro is approximately 4200 MW and the installed generating capacity is 5700 MW. Nearly 70% of the power is generated from three hydraulic stations on the Nelson River in northern Manitoba. This power is transmitted over a distance of 900 km via HVDC transmission to the major load centre of Winnipeg.

Manitoba is usually a net exporter and has a strong position as a supplier of green power. Most export is currently to the US, although there are plans for a significant increase of green power export to Ontario, which may involve at some point new hydro capacity specifically to serve Ontario. Like most other hydro dominated provinces, and despite the current “over-capacity”, Manitoba has needed to import energy from outside the Province in recent times during abnormally dry years, to meet its export commitments.

Despite plenty of green hydro capacity, the provincial government has a desire to develop the province’s natural resources including wind. On November 21, 2005, the Manitoba government and Manitoba Hydro released an invitation for expressions of interest from proponents that have potential wind power projects of more than 10 MW and up to 1000 MW. In addition to the large wind projects, another 50 MW may be set aside for the development of smaller, community based projects. The expression of interest response deadline was February 24, 2006. Approximately 10,000 MW in proposals were received from proponents. This has translated to 4300 MW of wind interconnection requests currently in the Manitoba generator interconnection queue, which exceeds the current peak load.

The first 99 MW wind farm in Manitoba was placed in-service in March 2006. In spite of a relatively strong connection point on the 230 kV system, production limit capability and power order ramping (20 MW/minute) were required. In addition, the wind plant is cross tripped following a breaker failure to avoid exciting poorly damped power oscillations in the wind plant.

Ontario

Ontario’s generation is a mix with nuclear providing 37% of electrical capacity followed by hydro, coal, gas and oil supplying most of the rest. The Ontario government recently directed

the Ontario Power Authority (OPA) to work with the Independent Electricity System Operator (IESO) to develop a plan to replace coal generation with cleaner supply for environmental and health reasons.

As part of the plan to ensure reliable supply while achieving desired emission reductions, a series of Requests for Proposals (RFPs) were initiated. Two of the RFPs were directed to renewables – this included a 300 MW RFP in 2004 followed by release of a further RFP for 1,000 MW in spring 2005. Five wind projects totaling 355 MW were selected from the first RFP, and eight wind projects totaling 955 MW were selected from the second RFP. Currently, three of the thirteen wind RFP projects are in service, providing approximately 210 MW. The remaining projects are expected to be in-service over the next 2½ years.

Currently, the OPA has initiated a “Standard Offer Contract” program to encourage connection of smaller generators, 10 MW or less, using clean and renewable resources. All of these projects are expected to connect to distribution systems. This program is expected to add an additional 1,000 MW over the next 10 years.

The IESO is also working with the OPA and the Canadian Wind Energy Association to assess the impacts of integrating a substantial amount of wind into Ontario’s power system by the year 2020. This study will provide a better understanding of the wind generation’s capacity and energy contribution as well as insight into system impacts that may arise from wind’s inherent variability.

Québec

The province of Québec has vast wind energy potential. Though wind energy generation in 2006 only accounts for 0.5% of installed capacity in the Québec control area, the penetration rate of wind energy generation should attain 10% in 2013.

Six wind plants with a total capacity of 212 MW are already in operation and 11 new projects totaling 1,275 MW are under development in the Gaspé Peninsula. These wind plants are scheduled to be commissioned from 2006 to 2012.

The load for the Gaspé Peninsula ranges from 400 MW to 1,200 MW. The Gaspé regional system consists of a radial system rated 315 kV and less, extending over 700 km east of the province’s capital (Québec City). It is connected to Hydro-Québec’s bulk transmission system at Lévis substation, south of Québec City. Since it does not include any other generating stations, the regional system has a very low short-circuit level and experiences frequent voltage variations. A fault near Lévis substation would cause a drop in voltage over the entire regional system.

Experience has shown that the wind turbines in the first wind plants would trip during disturbances. Such behavior, even when foreseeable, was considered to be unacceptable early on by Hydro-Québec TransÉnergie (Transmission Division of Hydro-Québec), which adjusted its requirements with respect to wind plants in 2004 (http://www.hydroquebec.com/transenergie/fr/commerce/pdf/eolienne_transport_en.pdf), and requires a level of performance on par with conventional generating stations, i.e. that wind plants:

- Remain in service during frequency and voltage variations;
- Remain in service during different types of faults such as a three-phase faults resulting in a voltage of 0 V for at least 9 cycles (150 ms) and during the time required to restore voltage after the fault has been eliminated;
- Offer automatic voltage regulation with a power factor of 0.95 on the switchyard’s high-voltage side.

The integration of 1,275 MW of additional wind energy generation in the Gaspé region requires the construction of new lines in the region and the replacement of a large number of protection and telecommunication systems in order to reduce the fault clearing time and, in so

doing, decrease the exposure time of wind plants to voltage drops. Simulations using recent models of wind turbines provided by the developers (and manufacturers) show that no dynamic compensation equipment is required given that the wind turbines selected.

Because of its configuration, Hydro-Québec's system must contend with various electrical phenomena that are not of the same magnitude in the large meshed power systems of Europe and North America⁵.

In fact:

- Hydro-Québec's power system is not synchronized with neighboring systems;
- The main hydroelectric generating stations (85% of total generation) are located to the north, 1,000 km from the load centers, which are mainly found in the south, near Montréal and Québec City;
- The bulk transmission system is made up of very long 735-kV transmission lines (11 x 1,000 km) and a 450-kV HVDC line (1,000 km) divided into two long corridors that connect the main hydroelectric generating stations to the load.
- The minimum load (13,000 MW in the summer) only represents 35% of the system's peak annual load (37,000 MW in the winter).

As a result, during disturbances, Hydro-Québec's network may have to deal with transient and dynamic instability as well as voltage and frequency instability.

A new call for tenders for 2,000 MW of wind power was launched in October 2005 and another one is expected in 2007. The new generation will be put into service in the next decade for a total of almost 4,000 MW in wind power generation for the province of Québec. This capacity accounts for 10% of the annual peak load and 30% of the minimum load. Given such a penetration rate, Hydro-Québec has done everything possible to ensure that wind power generation is integrated in such a way that power system security and reliability are not affected.

Thus, in 2005 Hydro-Québec TransÉnergie added a requirement aimed at specifying expectations during frequency variations to the requirements adopted in 2004, which mainly involved specifying expectations regarding the behavior of wind plants during voltage variations. As a result, future wind plants will have to be equipped with a frequency control system capable of making an inertial contribution comparable to that of conventional generating stations during significant drops in frequency. Major frequency drops occur mainly in summer, during periods of minimum load. However, Hydro-Québec TransÉnergie does not expect to use wind plants to contribute to its operating reserves in the near future.

Integrating a large amount of wind generation also has an impact on power system control. As Hydro-Québec's power system is isolated, it cannot count on neighboring systems to help it compensate for fluctuations in wind energy generation. Balancing is ensured by the hydroelectric generating stations north of the province. Since the required power has to be transported over the long lines of the bulk transmission system, the power system controller wishes to limit substantial fluctuations whenever they can be anticipated.

To this end, the increase and decrease in wind plant generation should be in line with the ramp rates imposed by the power system controller during critical times of day, i.e. during daily load increases and decreases. In addition, wind turbines will have to be shut down gradually when the ambient temperature nears the turbines' minimum operating temperature of -30°C. All of the systems required will help the wind plants to be harmoniously integrated into Hydro-Québec's power system.

⁵ Note that the Québec system is an electrical island since it is connected to the rest of the North American electrical system only through asynchronous HVDC transmission systems.

New Brunswick

Generation in New Brunswick is mixed with roughly 40% oil, 20% hydro, 15% nuclear with the rest mainly coal and gas by capacity. The electricity industry is partly separated and regulated with New Brunswick System Operator controlling the transmission grid. There is a possibility that a “Maritimes” market may be created in the future and this may well result in the New Brunswick System Operator (NBSO) becoming the Independent System Operator. The New Brunswick market has been opened to competition and operates on bilateral contracts.

The New Brunswick government set a renewable energy of 33% to be achieved by 2016.

There is no wind connected at present but there is interest in contracting wind through an RFP process. An RFP for 400 MW of wind was issued in 2005 (40 MW per year for 10 years). Thirty-five proposals were received and are under review. Load following and balancing are expected to be a challenge when integrating 400 MW as the peak load is 3200 MW and the summer light load is 1000 MW.

A 20 MW wind project on Grand Manan Island has recently gained a power purchase agreement.

Most of New Brunswick’s best wind resource is located along the coastal areas where access to the grid is more likely to be via 69kV radial systems and hence NBSO foresees voltage regulation as a likely key issue requiring assistance from wind farms.

NBSO does not at present have any specific wind interconnection requirements, but rather identifies any requirements through the System Impact Study as is common in other provinces. NBSO is currently working with CanWEA on a detailed wind integration study, similar to that being undertaken in Ontario.

Prince Edward Island

Prince Edward Island lies off the New Brunswick coast and is connected to the New Brunswick system via two 138kV submarine cables with 200MW total capacity. In order to be able to continue to meet the peak load with one cable out of service, Maritime Electric installed a 50 MW light oil fired combustion turbine in 2005. Maritime Electric supplies 90% of PEI load and is regulated under traditional cost of service regulation.

Most of the electricity used in PEI is generated in New Brunswick. The oil fired generation on the island is used mainly in a standby and peaking role.

Prince Edward Island has 14MW of wind power in operation and a proactive policy to develop wind to diversify supply. Targets are 15% renewable energy supply for 2010 (which will require approximately 60MW of wind power) and options are being examined for 100% renewable energy supply by 2015.

Nova Scotia

Nova Scotia is another smaller Maritimes market. Coal is dominant at about 43% capacity with oil and gas (25%) and hydro (17%).

Nova Scotia Power Inc (NSP) is the dominant vertically integrated utility and is regulated by the Nova Scotia Public Utility and Review Board.

A mandatory Renewable Portfolio Standard is to be established to foster renewable development. In 2004, 31 MW of wind was contracted and was built in 2005 with contracts in progress for about double this. A target of 5% renewable supply by 2010 has been set, which will require approximately 100 MW of wind.

The issues of concern for Nova Scotia include:

- the ability to curtail wind generation

- low voltage ride through
- voltage control
- voltage flicker, as much of the interest in wind project development is in areas with relatively weak radial 69 kV lines (flicker has been an issue for the first wind farm in the Province).

Newfoundland and Labrador

Newfoundland and Labrador Hydro is a crown corporation, owned by the Province of Newfoundland and Labrador. Newfoundland and Labrador Hydro generates, transmits and distributes electrical power and energy to utility, residential and industrial customers throughout the province. The company has a total installed capacity of 7289 MW of generation including the 5428 MW Churchill Falls Hydroelectric Generating Station located in Labrador. Newfoundland and Labrador Hydro operates two transmission networks: one in Labrador connected to Hydro Quebec and one on the Island of Newfoundland which is electrically isolated from the North American grid. As well, Newfoundland and Labrador Hydro operates 22 isolated systems in rural areas along the coast of Newfoundland and Labrador.

From a wind development perspective, the Province of Newfoundland and Labrador can be viewed as having three distinct opportunities, the Island of Newfoundland, Labrador, and the Isolated Diesel Systems as described below:

Island of Newfoundland:

The province of Newfoundland and Labrador has a world class wind resource with a resource potential for many 100's of MW on the Island alone. On the Island, wind offers the potential to meet future load growth requirements and to displace oil fired generation. However, the Island electrical system is not connected to the North American grid and as such, there exists technical and economic factors that work to limit the amount of wind power that can be integrated into the Island system.

In December 2005, Newfoundland and Labrador Hydro issued a request for proposals for the supply of 25 MW of wind power to the Island of Newfoundland with a projected in-service date of 2008. This will be the first large-scale wind farm for the Island of Newfoundland. The project will provide valuable operating experience regarding the integration of the technology into the Island system and further define the opportunities for wind as a future generation source for the Island.

Labrador:

In Labrador, wind offers the potential to not only supply the domestic market, but also the larger North American market. Newfoundland and Labrador Hydro is currently assessing the potential for large scale wind developments in Labrador.

Isolated Diesel Systems:

Newfoundland and Labrador Hydro operates 22 isolated systems that are served almost exclusively by diesel engine powered generators. The opportunity for wind power in these communities is to provide an alternative to and to displace diesel fuel consumption. While diesel is a relatively costly means to produce electricity, there remains a number of barriers to the widespread penetration of wind in diesel powered electrical systems. The relatively small electrical load limits the economies of scale impacts that have been realized in wind projects elsewhere. In addition, diesel powered communities are often remote from infrastructure which contributes to higher cost wind turbine installation and operation and maintenance costs. Also, wind-diesel integration technology is relatively immature and much needs to be done to realize the opportunity.

In the fall of 2004, on the island of Ramea, which is situated on the south coast of the island of Newfoundland, energy was produced from the first medium penetration wind farm in Canada. The Ramea wind demonstration project consists of six wind turbines of 65 kW each. In 2005, approximately 10% of the electrical energy consumed in Ramea was produced from wind.

The Government of Newfoundland and Labrador is currently developing a comprehensive Energy Plan that will outline, among other things, the policy's that will govern how the Province's vast wind resource will be developed. That plan is expected to be released in the fall of 2006.

Yukon, Nunavut and NW Territories

These are large sparsely populated Northern provinces with fragmented and islanded grids. The Yukon is hydro dominated (89% by capacity); NW Territories is split between hydro and diesel, whereas Nunavut is entirely local diesel supplied.

Yukon Energy Corporation and Yukon Electric Company Ltd are the relevant (vertically integrated) utilities and system operators. North West Power Corporation is the dominant (vertically integrated) utility in NW Territories, Nunavut Power Corporation in Nunavut. No market restructuring is likely as the markets are so small.

Wind in Yukon is less than 1 MW with no substantial installed capacity in the Northwest Territories or Nunavut. There is however strong interest throughout the territories, driven by high electricity costs.

2.2.2 Europe

Europe has hitherto been the leader in utilizing wind energy (www.ewea.org). Germany, Spain and Denmark are the leading countries with wind farm installed capacity. In Denmark, wind energy supplies nearly 18% of the national energy needs [5] – the installed capacity is roughly 70% of the nations peak load.

Of all the utilities world wide, the German utility E.ON and the Danish utility Eltra⁶ arguably have the most mature planning and interconnection standards with respect to wind turbine generation. To add to this list, recently EirGrid, which is the electric system operator in Ireland, also recently came out with comprehensive reports and grid codes related to wind generation interconnection, in 2004.

Proposals for wind farms continue to grow in Europe, with projected realistic potential for wind energy in Europe being some 343 TWh/annum [6].

2.2.2.1 Denmark

In Denmark, the high-voltage (HV) transmission system is presently separated into two synchronous areas that are not electrically connected to each other⁷. The HV transmission system is defined as the network with a rated voltage above 100 kV and is operated by Energinet.dk, the Transmission System Operator (TSO) of Denmark for electricity and gas. The western part of the country contains 400 kV and 150 kV meshed transmission systems with ac connections to the UCTE⁸ synchronous area to the south and HVDC connection to the Nordel synchronous area to the north. The eastern part of Denmark contains 400 kV and 132

⁶ Energinet.dk is the result of a merger between Eltra, Elkraft System, Elkraft Transmission and Gastra. The merger took place on 24 August 2005 and became retrospectively effective from 1 January 2005 (www.energinet.dk).

⁷ Commissioning of an electrical connection between Western and Eastern Denmark - The Great Belt Link, is planned for the year 2010.

⁸ The Union for the Coordination of Transmission of Electricity. This is the association of transmission system operators in continental Europe.

kV meshed transmission systems with ac connections to the Nordel synchronous area (Sweden) and an HVDC link to Germany (the UCTE synchronous area).

In relation to wind power, the western and the eastern parts of Denmark have different degrees of wind power penetration and experience different problems. Specific wind power issues for the western and the eastern part of Denmark will be given in separate sections, whereas common issues are in common sections.

Wind Generation in Western Denmark

Table 2-1 gives the generation mix, load numbers and interface capacity for Western Denmark. The primary power plants are thermal, coal- or gas-fired units. A significant part of the power generation comes from local wind turbines and combined heat and power (CHP) units. A 160 MW offshore wind farm was commissioned at Horns Rev A (HRA) and connected to the 150 kV transmission system. In 2004, the installed wind power capacity corresponded to about 33% of the generation capacity of the area and wind generation accounted for about 22% of the electric energy consumption of Western Denmark. Through ac lines, the system is interconnected with Northern Germany dominated by nuclear and thermal power plants and rapidly growing wind power and, through HVDC links, to Norway and Sweden with hydro power plants.

Table 2-1: Generation mix, load range and interface capacity for Western Denmark, 2004 [7].

	MW	GWh
Primary power plants	3,516	12,951
Local CHP units	1,593	6,839
Local wind turbines	2,379	4,875
Offshore wind farm Horns Rev A	160	
Consumption		21,246
Maximum load	3,639	
Minimum load	1,281	
Capacity export to the UCTE	1,200	
Capacity import from the UCTE	800	
Capacity export to Nordel	1,440	
Capacity import from Nordel	1,460	

At present, the most sites on-land with good wind conditions are already occupied by the existing local wind turbines. Increase of the wind power incorporated on sites on-land may happen by replacing the existing smaller wind turbines with the newer and more efficient wind turbines. This replacement effort may provide up to 350 MW more local wind power in the whole country. This major replacement effort is expected to happen in Jutland, the continental part of Western Denmark.

Increase of the wind power to be commissioned in Western Denmark will therefore come from the large offshore wind farms. The commissioning of the second offshore wind farm, Horns Rev B (HRB), with a rated power of 215⁹ MW, will take place by the year 2009. The contractor is the Danish company Energy E2. Figure 2-3 shows the future development for wind power in Western Denmark. Future incorporation of wind power in Denmark will be regulated by the market mechanisms. As expected, the largest part of wind power will be commissioned in the western part of the country.

Wind Generation in Eastern Denmark

The primary power plants in Eastern Denmark are coal-fired. The system is interconnected through the ac submarine cables to Sweden dominated by nuclear and hydro power plants.

⁹ 200 MW in commercial wind turbines, plus 15 MW in experimental wind turbines.

Table 2-2 presents the generation mix, load numbers and interface capacity in Eastern Denmark.

A significant part of the power consumption is still covered by the central power plants. The largest location of the local wind turbines, about 240 MW installed power capacity, is at the island of Lolland, just south of the main island of Zealand. A 165 MW offshore wind farm was commissioned at Nysted Offshore Wind Farm (NOWF) and connected to the 132 kV transmission system of Lolland. In 2004, the installed wind power capacity corresponded to about 14% of the generation capacity and wind generation accounted for about 12% of the electric energy consumption of Eastern Denmark.

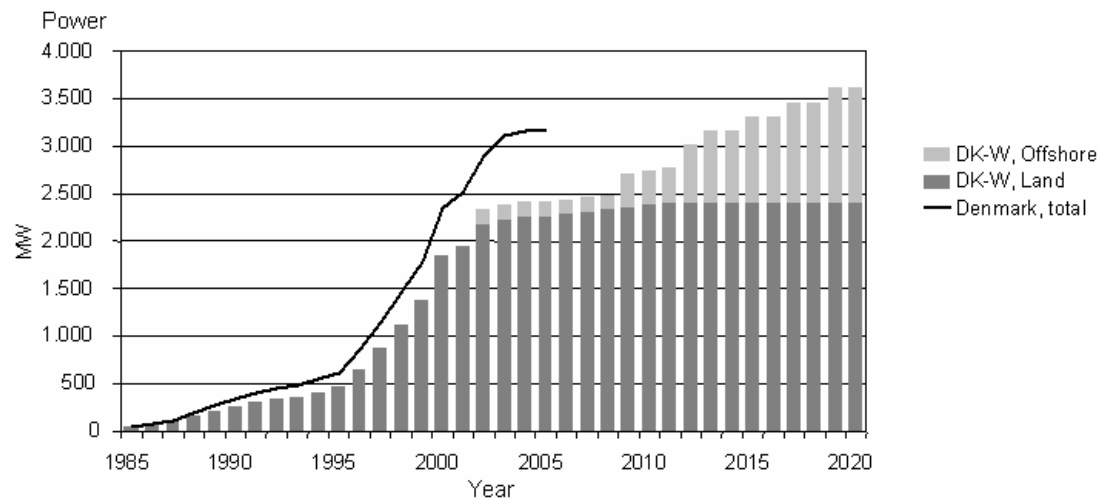


Figure 2-3: Present and expected wind power incorporation in Western Denmark.

In Eastern Denmark, some increase of the wind power on sites on-land may come from replacing the existing, small wind turbines by the newer and larger ones, as described in the previous section, and also from using new sites on the islands of Lolland and Falster characterized by good wind conditions.

The main increase of wind power to be commissioned in Eastern Denmark will come from construction of new large offshore wind farms. The commissioning of the second offshore wind farm, Rødsand Offshore Wind Farm (ROWF), with a rated power of 215¹⁰ MW, was announced by the Danish Energy Authority. As expected, the commissioning will take place by the years 2008-2010.

Table 2-2: Generation mix, load levels and interface capacity in Eastern Denmark for 2004 [8].

	MW	GWh
Primary power plants	3,837	9,441
Local CHP units	642	2,559
Local wind turbines	578	1,709
Nysted Offshore Wind Farm (Rødsand)	165	
Consumption		14,262
Maximum load	2,665	
Minimum load	~ 750	

¹⁰ 200 MW in commercial wind turbines, plus 15 MW in experimental wind turbines.

Capacity export to the UCTE	550
Capacity import from the UCTE	550
Capacity export to Nordel	1,700
Capacity import from Nordel	1,300

Wind Technology in Denmark

There are about 5,000 local wind turbines in Denmark. Most of the local wind turbines are fixed-speed with conventional induction generators. About 4,500 of these wind turbines presently are rated below 0.5 MW. As stated above, wind generation is expected to increase significantly once these smaller units are replaced with newer and larger units.

The large offshore wind farm HRA has eighty 2 MW pitch-controlled, variable-speed wind turbines with doubly-fed asynchronous generators from the Danish manufacturer Vestas Wind Systems.

The large offshore wind farm NOWF has seventy-two 2.3 MW active-stall, fixed-speed wind turbines with induction generators from the manufacturer Siemens Power Generation (former Bonus Energy).

Technical Specifications

The local wind turbines commissioned before July 2004 have been operated according to the technical recommendations of the Danish Electricity Supply R&D (DEFU) such as KR 111 [9], (www.defu.dk). According to the technical recommendations KR 111, the local wind turbines must disconnect from the grid for grid protective reasons when the grid voltage remains below 0.7 pu for more than 0.5 s. At least 4,500 local wind turbines in Denmark follow these recommendations.

The large offshore wind farms connected to the Danish transmission network before 2004 must comply with the Technical Specifications TP98-328b [10], (www.energinet.dk). The large offshore wind farms must maintain uninterrupted operation at a short-circuit fault subject to the transmission grid. This requirement is today called the ride-through capability. In normal grid operation, the large offshore wind farm must be reactive power neutral with the transmission grid at the connection point. The reactive power control of the wind farm must be available for the TSO at grid disturbances. The large offshore wind farm must also contribute to the active power balance and to the frequency control within a defined range.

In 2004, the Danish TSO formulated two new specifications for grid connection of the electricity-producing wind turbines. Technical Specifications TF 3.2.5 [11] deal with connecting wind turbines to the power network at voltages above 100 kV (the HV transmission network), whereas Technical Specifications TF 3.2.6 [12] was written for wind turbines connected to the power network at voltages below 100 kV (local distribution networks). These two specifications can presently be found at www.energinet.dk. The specifications TF 3.2.5 will primarily apply to the large offshore wind farms that will be commissioned in the years to come, since these are to be connected to the HV transmission system. The specifications TF 3.2.6 will primarily apply to the replacement wind turbine generators likely to replace the existing smaller wind turbines connected to the distribution network.

Wind and Power Forecasts (Western Denmark)

Accuracy of wind and active power forecasts is essential for improving the power balance in Western Denmark [13]. The installed amount of the wind power is so huge that an error in the wind forecast by 1 m/s results in an error in the active power prediction of 320 MW, which is significant compared to the size of the system. Figure 2-4 gives examples of an accurate and a less accurate wind power forecasts for the Western Danish power system. The existing wind forecast models have to be improved in several ways:

- Day-to-day forecasts must be improved as the amount of grid incorporated wind power is significant and still increasing.
- Hour-by-hour forecasts to comply with the power balances and planned operation of the central power plants, planned power transits via Western Denmark and consumption.

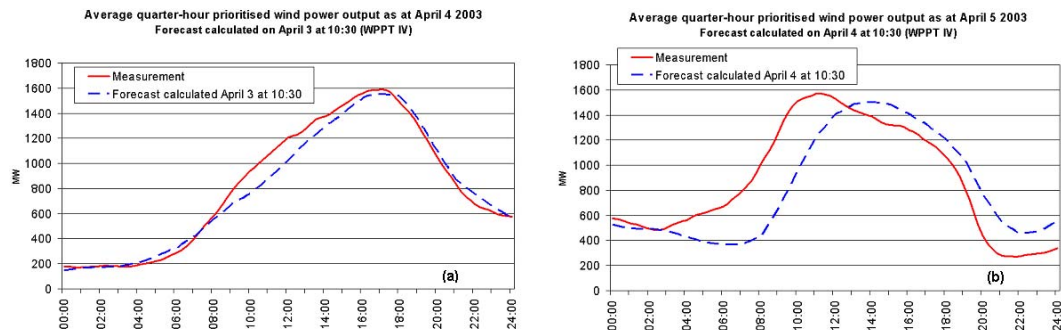


Figure 2-4: Active power forecast from wind power in Western Denmark: (a) a good forecast, (b) a not so good forecast.

A real-time prediction system for wind power has been running in Energinet.dk since 1997. This system used the wind power prediction tool (WPPT) from the Institute of Mathematical Modeling (IMM), Technical University of Denmark, together with meteorological forecasts from the Danish Meteorological Institute (DMI). As an alternative forecasting tool to WPPT, an in-house developed forecasting tool has been used. However, these two models may produce different forecasts of wind power at times, because both the prediction tools apply the meteorological data for forecast lengths from 6 to 48 hours that may have a random variation in the prediction quality from day to day. The magnitude of this prediction error can also change significantly over a few hours.

A need for accuracy improvement of the real-time prediction tools was demonstrated during a storm in Denmark on 7 to 9 January 2005. Figure 2-5 illustrates the wind and the active power generation (predicted and actual) during the storm. The prediction was that maximum active power would be generated by the wind turbines. However, the local wind turbines started to trip when the wind speed exceeded 20 m/s. The Horns Rev offshore wind farm also tripped as the wind speed exceeded 25 m/s. Prediction inaccuracy resulted in a difference between the expected and the actual power production of about 1,800 MW, when the wind speed reached its maximum (about 30 m/s). This resulted in an immediate need for power reserves.

Energinet.dk also undertook an attempt to look into an area in meteorology that deals scientifically with the day-to-day variations in the predictability of the atmosphere: Ensemble forecasting. In 2002, Energinet.dk funded a research project on ensemble forecasting at University College Cork (UCC), Ireland.

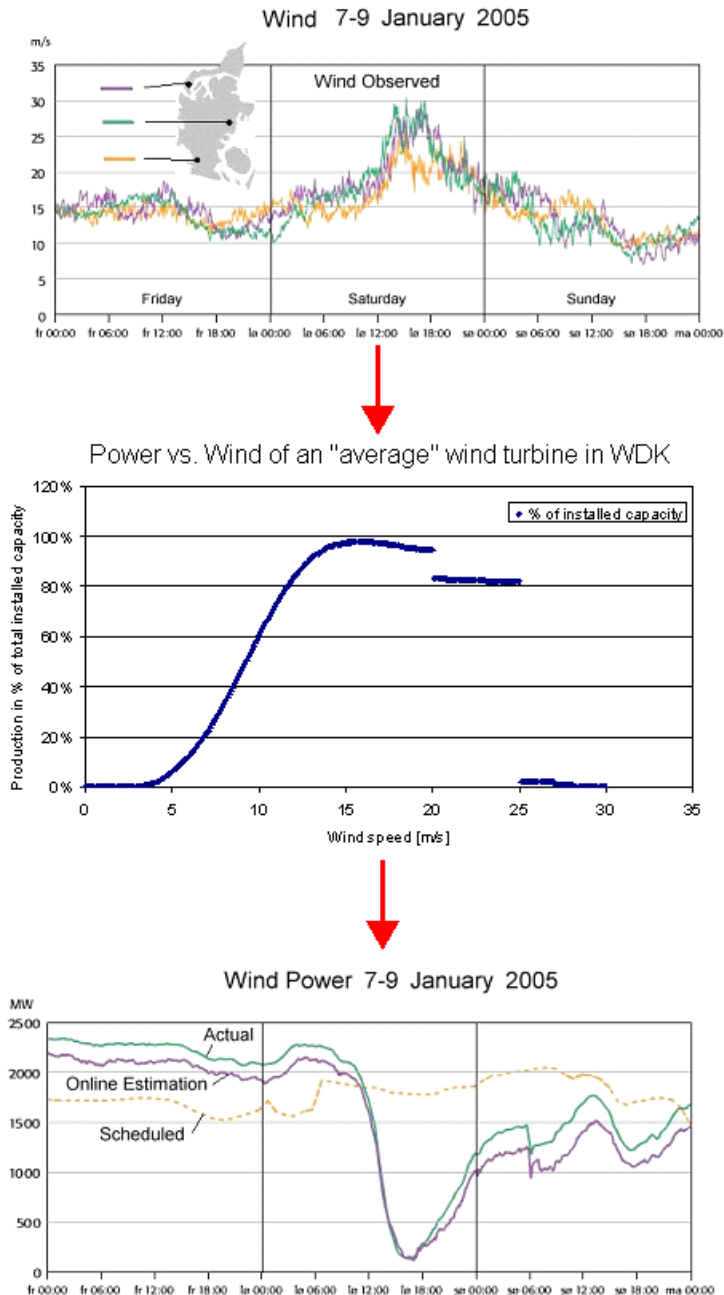


Figure 2-5: Wind and power generation from wind turbines in Western Denmark during a storm in January 2005.

The real-time version of the MSEPS (Multi-Scheme Ensemble Prediction System) application is named MELTRA, because it has been developed in close cooperation between Eltra, the former TSO of Western Denmark, and the research company WEPROG (www.weprog.com). MELTRA consists of 75 ensemble members and a graphics package for visualization of the forecasts. The system generates 3-day forecasts every hour and consists of around 6000 forecasts per day. Half of the forecasts are carried out as nested forecasts in higher resolution. The forecasts are converted into probabilities and, in combination with observations, provide the best possible forecasts of wind power. The MELTRA ensemble system is run on a 92 processor Linux cluster. The resolution in the meteorological model is 45 km with a finer 5 km nested grid covering Denmark. Figure 2-6 shows an example of forecasted wind power production (in percent of installed capacity) from the MELTRA prediction system calculated at 12:00 on 19 March 2004.

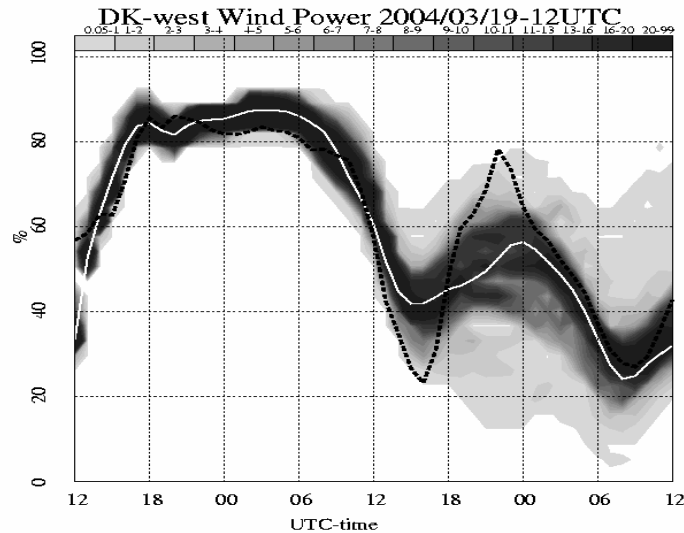


Figure 2-6: 48-hour load factor prediction for wind power for Western Denmark calculated at 12:00 on 19 March 2004. Probability distribution is indicated by grey colors. Dark grey indicates high density of ensembles, narrow bandwidth of results and small uncertainty of wind power production; light grey indicates low density and large bandwidth of results and large uncertainty of production. The white curve represents the average prediction and the black dotted curve the measured production [13].

The major benefits of the real-time experience with the MELTRA system have been:

- Averaged over one year, the implemented ensemble technique has a potential of at least 20% better forecasts of wind power compared to a single forecast.
- Most periods with high wind power output (>70%) and low uncertainty were predicted accurately up to two days ahead.
- Periods with low wind power and low uncertainty are also predicted accurately.
- Uncertain periods are only rarely predicted with too much or too low uncertainty.

The ensemble technique is also better in predicting wind power for single sites or smaller areas than a single forecast.

Issue of Short Term Power Balance (Western Denmark)

Wind power is characterized by fluctuations of the produced active power due to the fluctuating nature of the wind and wind fronts passing areas with incorporated wind turbines. In the offshore wind farm Horns Rev A (HRA) in Western Denmark, the active power fluctuations can be much more intense than ever seen on the aggregated wind power production on land [14]. Figure 2-7 shows such intense power fluctuations observed at the connection point of the HRA, the 150 kV substation Karlsgaarde. For the given summer day in 2003, the maximum (measured) power reaches 120 MW at Horns Rev. The measurements at the point of interconnection to the transmission system for HRA have shown that the active power of the offshore wind farm can change by up to 100 MW in 15 to 20 minutes. In part, this can be explained by the large amount of wind power concentrated within a relatively small area (about 25 km²) resulting in a stronger correlation of the power outputs from the turbines in the farm. Clearly, such intense power fluctuation is also associated with the specific wind behavior at Horns Rev.

Similar power fluctuations as from the Horns Rev offshore wind farm have been observed on dispersed wind turbine sites on land [14] and also at the large offshore wind farm NOWF in Eastern Denmark [15]. However, the total active power of the dispersed wind turbines is smoother, because these wind turbines are scattered throughout the country. This gives a

small correlation between the total power outputs of the different local wind turbines, which may eliminate the fluctuations that last from tens of minutes to one hour.

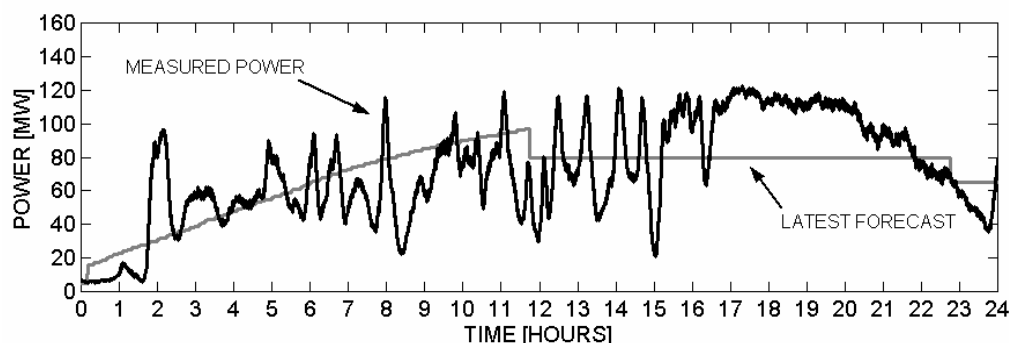


Figure 2-7: Measured power and forecast for the Horns Rev A offshore wind farm on a summer day in 2003 [14].

The planned active power supply from the offshore wind farm HRA is based on wind forecasts transferred to active power forecasts. The first active power forecast is made a day ahead, but can be updated during the day. The active power supplied from the offshore wind farm HRA forms part of the power supplied from a group of power plants available to the Power Balance Responsible Player (PBRP). The PBRP controls the active power from this group of the power plants according to the latest power forecast in a way to comply with the planned total power production. For the given summer day in 2003, the latest power forecast is shown in Figure 2-7. The deviations between the power forecast – the planned active power to be supplied, and the total active power from the HRA are injected into the transmission system of Western Denmark. In the case of the HRA, such power deviations form power fluctuations with the period range from 15 minutes to one hour. These power fluctuations can even be distributed to the neighboring transmission systems, for example the UCTE synchronous area. As defined, positive power imbalance means that the actual power production from HRA is less than planned.

Commissioning of the second offshore wind farm, Horns Rev B (HRB), just 5 km from the existing offshore wind farm HRA will presumably increase the intensity of the active power fluctuations and deviations within a one hour period. A close location of two wind farms will introduce a strong correlation between the power fluctuations at the wind farms.

Besides the power fluctuations and deviations introduced by the Horns Rev wind farm, the deviations from the planned power generation, demand and exchange to Scandinavia contribute to the total deviations in the power exchange between Western Denmark and the UCTE synchronous area.

Furthermore, the power flow of Western Denmark is superimposed by a large transit due to the geographical location between the two large, but different, ac power systems [13]. To the North, the active power exchange has a 15-minute resolution, and the settlement of the power exchanged between Western Denmark and the Nordel synchronous area is arranged as the net power exchanged hour by hour. At the border to Germany to the South, the active power exchange on this border follows a schedule with a 5- minute resolution.

The issue is to keep the power generation, including the power import, in balance to the power consumption including the power export in Western Denmark and to keep the power exchange between Western Denmark and the UCTE synchronous area at the planned power exchange. Only small deviations in the range of approx. ± 50 MW from the planned power exchange may be acceptable [13, 14]. Compliance with the planned power exchange between Western Denmark and the UCTE synchronous area makes it necessary that the Danish wind power and the other sources of the power imbalance be brought into balance with the same or a better resolution. The challenge is to operate the system with large internal power

deviations and different resolution of the exchange schedules on the interconnections to achieve the common goal of the active power balance and the reliable power transport between the Nordel and the UCTE synchronous areas.

The studies performed by Energinet.dk have shown that the target of ± 50 MW can be reached applying the western Danish Area Grid Controller accessing the secondary control on the central power plants of Western Denmark and the HVDC connections with the Nordel synchronous area [14]. In the studies, the second offshore wind farm at Horns Rev was obliged to comply with the power gradient limit of $+5$ MW/min. Figure 2-8 presents the resulting active power deviations at the Danish-German border without any control versus with the use of the western Danish Area Grid Controller. Here, the central power plants were separated into two groups performing slow and relatively fast secondary control, respectively. The HVDC connections were able to provide almost instantaneous power control on demand, but within a limited range. It has been found that the use of the fast power control of the HVDC connections will be essential for keeping the power deviations within the desired range. However, the net hour-by-hour settlement model used in the Nordel area may conflict with the requirement for fast power control of the Danish wind power provided by the HVDC connections and Nordel's hydro power [13].

The studies and the experience of the Danish TSO Energinet.dk show that the Danish power system has a sufficient amount of regulating power to compensate for intense active power fluctuations from the HRA. Application of the net hour-by-hour settlement model for the active power exchange through the HVDC links with the Nordel synchronous area will require better and more intense use of domestic regulating power (thermal). With incorporation of the second offshore wind farm at Horns Rev, the regulating power reserves of Western Denmark, as those are controlled presently, will be exhausted and insufficient.

Revision of the present settlement agreement and access to the fast power control of the hydro power plants in the Nordel synchronous area may be an additional option for keeping active power balance in Western Denmark. Better utilization of the domestic regulating power resources is also vital. This includes better utilization of local CHP units, activation of load control according to the agreements with selected customers, activation of the power control of the large offshore wind farms, avoiding making "clusters" of large offshore wind farms, etc. Establishment of the Great Belt Link will make it possible to utilize the regulating power control incorporated in the eastern part of Denmark to work together with that established in Western Denmark.

Issue of Voltage Fluctuations (Eastern Denmark)

The Horns Rev offshore wind farm has variable-speed wind turbines equipped with doubly-fed asynchronous generators. In such generators, the active and the reactive power are controlled independently from each other (see section 3.2.6). Therefore, significant active power fluctuations at Horns Rev do not lead to fluctuations of the reactive power or the grid voltage at the point of interconnection with the grid.

The NOWF offshore wind farm has fixed-speed wind turbines equipped with conventional induction generators [15]. With such generators, the active power supply and the reactive power absorption are strongly coupled together. Thus, active power fluctuations result in similar fluctuations in reactive power absorption. Therefore, insufficient dynamic reactive compensation may affect the grid voltage in the transmission network of Eastern Denmark.

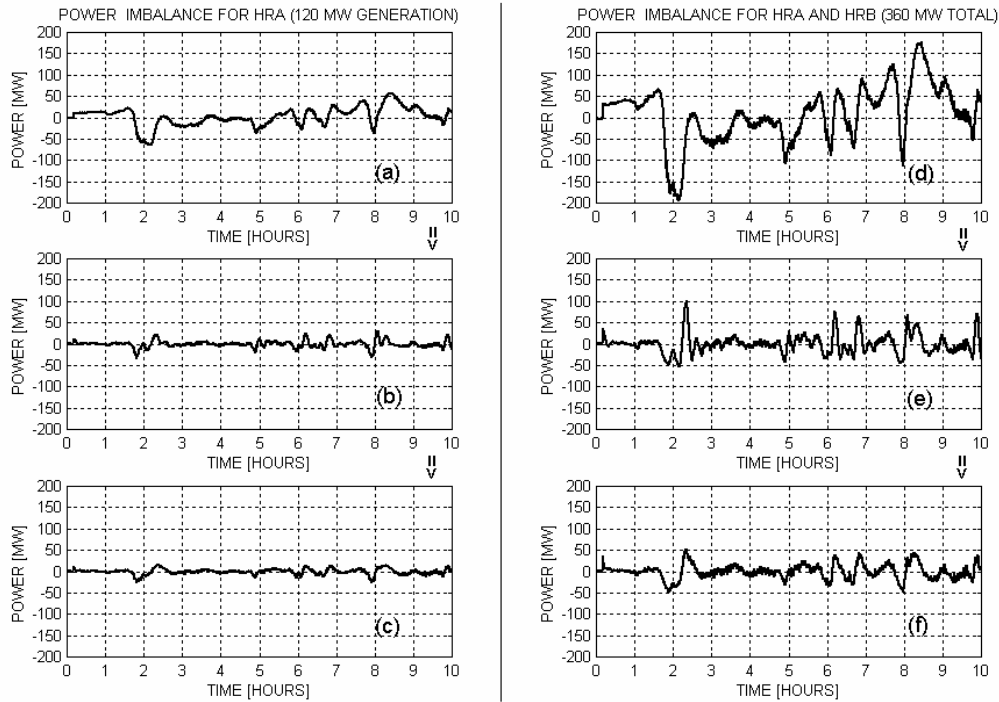


Figure 2-8: Computed power deviations caused by the Horns Rev A wind farm on a summer day in 2003: (a) no control is applied to minimize such deviations, (b) secondary control of primary power plants is applied, (c) as previous and also with access to the fast power control of HVDC links. Computed power deviations after commissioning of the Horns Rev B offshore wind farm: (d) no control is applied, (e) the HRB is subject to a power gradient limit of 5 MW/min. together with use of secondary control of primary power plants, (f) as previous plus access to the fast power control of HVDC connections [13].

The NOWF offshore wind farm is connected to the 132 kV substation Radsted in the transmission network of the Danish island of Lolland. This is the periphery of the eastern Danish transmission network, whereas the central power plants and the main consumption are located at the main island of Zealand, which has a strong transmission system. Prior to the commissioning of the NOWF offshore wind farm in the year 2003, the submarine cables between Zealand and Lolland were reinforced [15]. This was done in order to increase thermal ratings in the grid and enabling the grid to handle full production at the wind turbines during outages in the grid. The reinforcements did, however, only increase the short-circuit level marginally, which is why the voltage in this area is still sensitive to reactive power fluctuations.

Figure 2-9 shows the active power fluctuations at NOWF resulting in the grid voltage fluctuations at the 132 kV substation Radsted on a summer week in 2004. Usually, the active power production is below 100 MW and, then, the voltage variations are relatively small. However, in the periods with high active power generation, there are significant voltage dips - this occurs on day 4 of the week shown in Figure 2-9.

Such voltage fluctuations can be distributed to the other parts of the transmissions system [15]. Figure 2-10 shows the voltages at the two substations during a winter week, 2005. The first substation is Radsted, which is the 132 kV connection point of the NOWF offshore wind farm and distant from the 400 kV grid. The second is the substation Spanager, which is close to the strong 400 kV backbone grid. Notice that the voltage fluctuations at Radsted are considerably larger than those at Spanager.

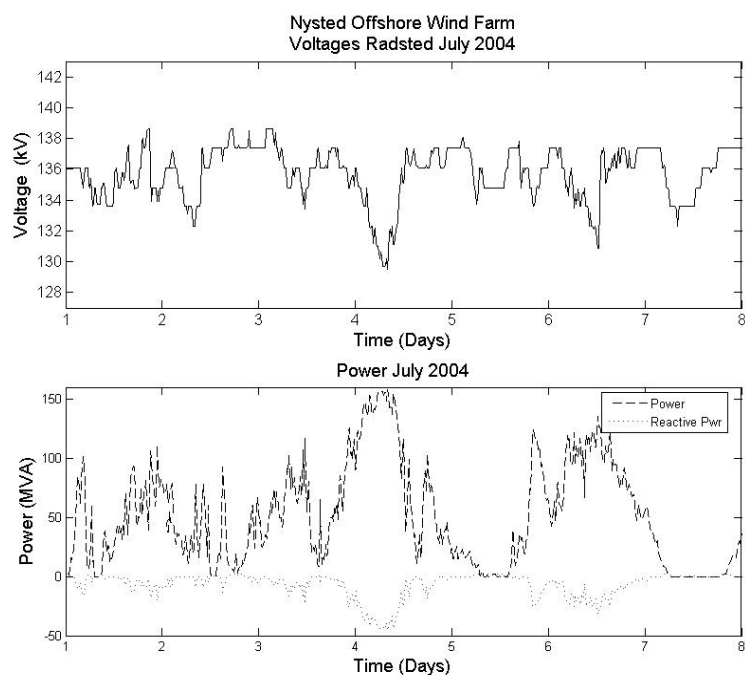


Figure 2-9: First week of July, 2004: The voltage in Radsted (top) and active/reactive power exchange between the NOWF offshore wind farm and the transmission system at Radsted (bottom) [15].

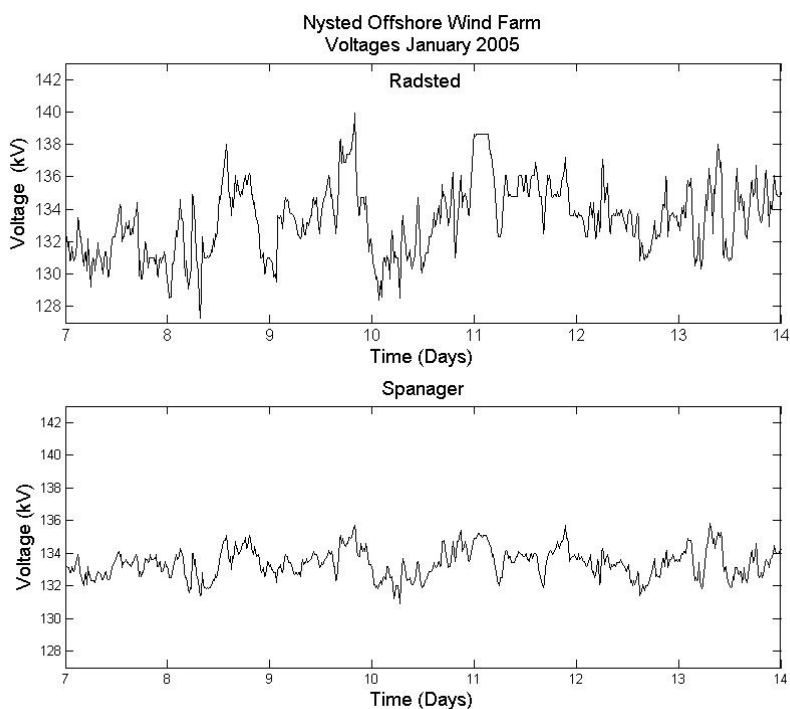


Figure 2-10: A winter week, 2005: Voltage in Radsted (top) and in Spanager (bottom) [15].

A Static VAR Compensator (SVC) is being considered for installation at the 132 kV substation Radsted to reduce such undesired voltage fluctuations [15]. The contractor is the power distribution company SEAS-NVE. The SVC unit will be delivered from the manufacturer Siemens and have a rating of +80/-65 MVar.

Modeling and Ride-Through Capability

Modeling of the electricity-producing wind turbines and evaluation of the ride-through capability of the large offshore wind farms are very relevant issues for short-term voltage stability [16]. Energinet.dk has developed, implemented and validated the simulation models of different wind turbine concepts that are relevant for investigations of short-term voltage stability of the Danish transmission system. Typically, validation is performed in cooperation with the wind turbine manufacturer.

The local wind turbines are represented as fixed-speed, equipped with induction generators. The local wind turbines may disconnect from the grid when the monitored parameter exceeds the relay setting.

The Horns Rev A offshore wind farm has a pitch-controlled, variable-speed wind turbines equipped with doubly-fed asynchronous generators. Energinet.dk implemented the dynamic model of the wind farm and its controller in cooperation with the manufacturer Vestas Wind Systems and the consulting company Elsam Engineering on behalf of the power company Elsam. The wind farm model is validated from the measurements of Vestas Wind Systems from full-scale validation cases performed on simple test grids.

Recently, Energinet.dk had an opportunity to validate the large wind farm model from a short-circuit fault registered in the transmission system. The wind farm was producing 90 MW when a single-phased, short-circuit fault occurred at the 150 kV transmission line between Herning and Sdr. Felding. Energinet.dk monitored the voltage and the current in three-phases at the substation Karlsgaarde which are plotted in Figure 2-11(a). Then, Energinet.dk performed computations with the use of the complete transmission grid model including the central power plants, the consumption, the local wind turbines, the local CHP units and the dynamic model of the HRA. The simulation results are plotted in Figure 2-11(b). The measured and the simulated figures are in good agreement.

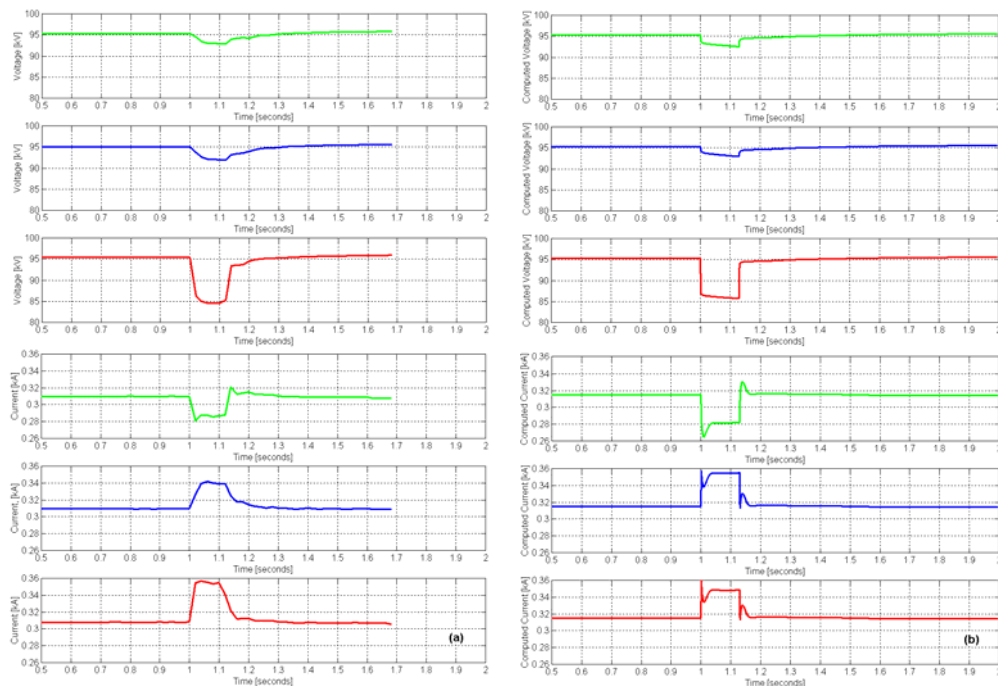


Figure 2-11: Voltage and current in three phases at the 150 kV substation Karlsgaarde: (a) measured with 10 ms sampling and (b) simulated.

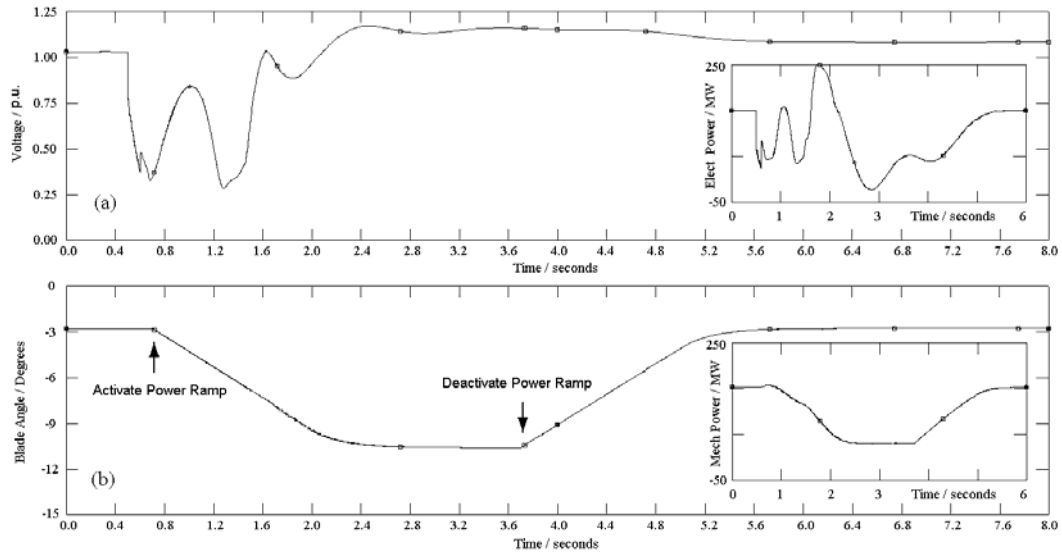


Figure 2-12: Ride-through operation using the power ramp control: (a) voltage and active power as insertion, (b) blade-angle control and mechanical power as insertion.

The large central power plant located at the city of Esbjerg, the large CHP unit in the city of Herning and a number of other smaller CHP units and local wind turbines connected nearby the substation Karlsgaarde were also in operation at the moment when the short-circuit fault occurred. Besides a validation of the wind farm model, this provided also a successful validation of the given part of the Danish transmission grid model, because the monitored voltages and the currents were influenced by the entire power grid of this area. Monitoring of grid events and post-mortem simulations are a part of the transmission grid model validation program carried out by Energinet.dk.

The Nysted offshore wind farm has active-stall-controlled, fixed-speed wind turbines equipped with induction generators. The dynamic model was previously validated by measurements in cooperation with the wind turbine manufacturer Siemens Power Generation (former Bonus Energy) [17].

Due to a significant amount of the induction generator based wind power on Lolland, this power grid may show a tendency to voltage collapse when subject to a three-phased, short-circuit fault [18]. To improve the short-term voltage stability, the power ramp control is applied to the NOWF offshore wind farm [16, 19]. The power ramp control implies that the large wind farm is ordered to reduce the mechanical power of the wind turbine rotor from an arbitrary level down to 20% of its rated power in less than 2 s [10]. The power ramp control stabilizes operation of the large offshore wind farm leading to voltage restoration. Figure 2-12 illustrates operation of the large offshore wind farm with application of the power ramp at a severe short-circuit fault. The power ramp is realized with the use of active-stall control of the wind turbines.

2.2.2.2 Wind Power Development in Greece

Greece has a large wind potential, however, only 1.7% of the total energy demand of 2003 was met by wind generation [20]. The mainland of Greece is served by the Hellenic Interconnected Transmission System with installed capacity close to 11000 MW. In the Interconnected system 405 MW of wind generators have been installed up to 2005. Due to the geographical distribution and their size (15 to 30 MW installed capacity) the wind farms are mostly connected to the high voltage network through HV/MV substations.

In many islands that are not interconnected to the mainland, the wind penetration is more significant. For example, Crete is the largest autonomous system in Greece with 660 MW of installed thermal capacity running on imported oil fuel. The installed wind farms capacity is

81 MW and their production accounts for the 10% of the annual energy demand. The instantaneous power penetration has reached 39% [20].

After the Kyoto Protocol, Greece, as a member of the European Union follows the European policies concerning greenhouse gas emissions. The state target for Greece is 20.1% of renewable energy source penetration in electricity production and considerable incentives are provided to these renewable generation sources, such as satisfactory fixed feed-in tariffs, investment subsidies, guaranteed access to the grid, long-term contracts, etc. [21]. As a result, applications by Independent Power Producers (IPPs) for more than 13,000 MW of wind farms located in the Greek mainland have been filed to the Regulatory Authority for Energy. More than half of the applications (total 6,700 MW) refer to three specific areas of high wind potential in the Greek mainland [22], namely the Evia island, the Southeast of the Peloponnese peninsula and the Thrace region, as shown in Figure 2-13.

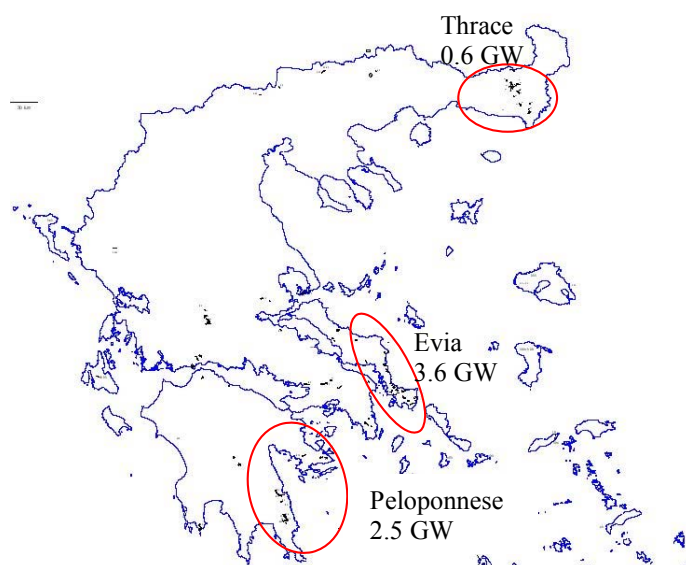


Figure 2-13: Geographical distribution of applications for wind farms in Greece.

The areas of interest share some similar characteristics: they have significant local thermal generation and they are connected to the bulk transmission system through congested transmission corridors of the 150 kV transmission network. Although there are specific plans for reinforcing the network in order to alleviate constraints and accommodate future wind farms, new transmission projects face environmental and financing constraints resulting in considerable delays. Also, environmental constraints and some contradictions of the legal framework are causing further delays in the installation of new Wind farms. Thus, even though there are about 3260 MW of wind farms approved by the Regulatory Authority, the actual penetration is still very limited.

Special Operating Practices for Wind Power In Greece

In Greece, the Hellenic Transmission System Operator (HTSO) has adopted a special operational practice in order to increase the wind power penetration into the windy area of Thrace in the North East part of Greece. The main concept is the introduction of “interruptible contracts” and the continuous monitoring and control of the power flow through the congested corridors by issuing a setpoint to each wind farm to reduce its production, whenever system security is endangered. This practice implies both regulatory and technical amendments [22].

Figure 2-14 depicts the transmission system in the region. The existing generation comprises a combined cycle power plant at Komotini. The maximum capacity of this plant is 480 MW while its technical minimum is 280 MW. The region of Thrace is connected to the transmission system through four overhead transmission lines through the boundary bus of

Iasmos; the thermal limit of each line is in the order of 170 MVA during summer and 200 MVA during winter. The wind penetration is limited by the available transfer capacity from Thrace to the system; static security is the limiting factor. The Komotini power plant is usually bidding successfully in the power market and therefore Thrace is usually an exporting area. Moreover, for large portions of time, it is a “must-run” unit since it is necessary to provide local voltage support. Under these conditions, the possibility of adjusting local thermal power generation, in order to increase wind penetration is not considered, because of the impact this would have on the electricity market (increased uplift costs). Furthermore, the Komotini power plant contributes to the Automatic Generation Control and the provision of this ancillary service is sometimes very important for the quality of the entire system operation.

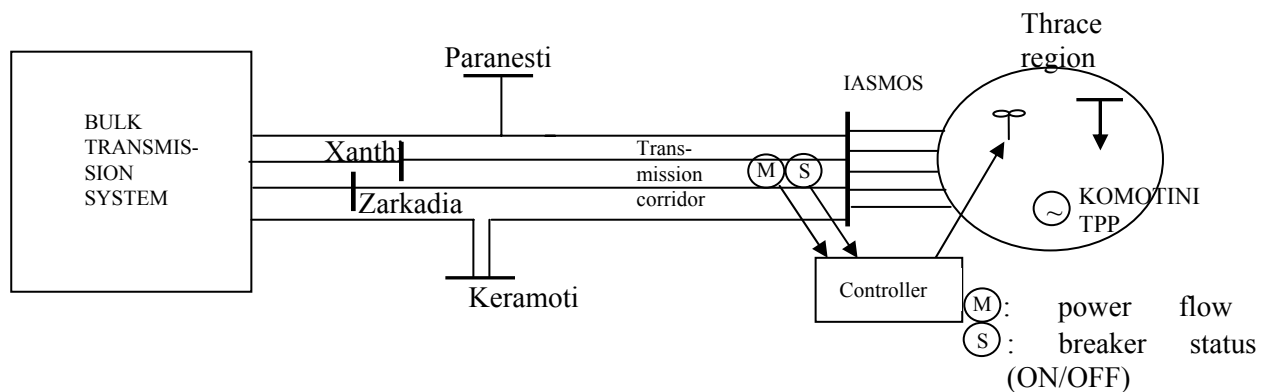


Figure 2-14: Schematic diagram of system configuration

HTSO should guarantee the absorption of all the power produced by the wind farms installed in the country. According to the existing planning practices, the maximum wind power penetration in the area should not exceed 100MW. The application of “interruptible contracts” allowed HTSO to double this limit without compromising system security, or the IPP’s economic feasibility.

From the regulation point of view, the new practice is based on “interruptible contracts” for wind generators; these contracts allow the system operator to curtail the power production of wind farms when security constraints are violated. In this framework a new Ministerial Decree has been issued in 2003 which allows HTSO to violate the “priority in dispatch” rule for renewable energy sources by curtailing power output of wind farms with “interruptible contracts” when necessary; it also sets the mutual obligations between the HTSO and IPPs.

The control is based on the continuous measurement of the total power flow from Thace to the bulk transmission system through the corridor. The control concept is applied according to the following rule: “the power flow through the interconnecting lines is not allowed to exceed a predefined security limit”. This limit is calculated so as to respect the N-1 security criterion according to the Grid Code regulations. If this limit is violated, the controller sends setpoints to the wind farms with interruptible contracts to reduce their production and consequently the power flow through the congested corridor by the necessary amount. These setpoints represent the upper limit of the power output by each wind farm that can be securely injected into the grid. The necessary power reduction is to be shared by all wind farms with interruptible contracts.

The control scheme [23] is implemented using an autonomous system comprised of Programmable Logic Controllers (PLCs) communicating to each other through two different and independent telecommunication lines. Two independent PLCs (main and backup) are installed at the boundary substation to monitor the operating status and the power flow through the interconnection lines and implement exactly the same algorithm. One PLC is

installed at each substation where wind farms with interruptible contracts are connected, in order to provide the necessary interface to the wind farm supervising control system. In each wind farm the respective PLC collects real time data, transmits the limiting setpoints (if any) to the wind farm supervising control system and communicates with the PLCs installed at the boundary substation. In addition to the above described autonomous control system, the supervision and control of the wind farm by the Energy Control Center is always enabled via the existing Remote Terminal Units.

The operation of the control system will be monitored by the Control Center through the SCADA for security and settlement purposes. Whenever a wind farm does not comply for reduction according to the setpoint issued by the control system, the dispatchers are alerted with an alarm and they should communicate (via telephone) with the authorized wind farm personnel to execute manually the command. In cases of an emergency the wind farms that did not comply with the commands will be disconnected from the grid using the remote control facilities of the SCADA.

In all cases the control system operation and the wind farm response is recorded in the EMS databases for settlement purposes. The wind farms that did not comply with the reduction commands are penalized and furthermore, the power injected to the grid above the issued setpoints is not remunerated. Also, the curtailed energy by each wind farm is recorded since it must not exceed 30% of wind farms annual potential according to the Ministerial Decree.

2.2.2.3 Wind Energy in Spain

The history of wind energy in Spain is marked by a rapid growth from its beginning, with a yearly growth of installed capacity in the last 10 years that averages 57%. Currently the total installed wind power capacity is 11,000 MW (peak demand $\approx$ 45,000 MW) this represents 80% of the installed renewable power and 55% of the generation under the special regime framework (RES and cogeneration). This represents 15% of the total installed power, and 7.8% of the total energy production during 2005.

This growth is motivated by several factors:

- The approval in 2005 of the Strategic Renewable Energy Resources that sets the objectives of Renewable contribution of 12.1% of Primary Energy consumption and 30.3 % of Electric Energy consumption by 2010 (this means an estimate wind power installed of 20.2 GW)
- Strong social support: Central and Regional Administrations and environmentalists support it.
- Generation companies and other promoters are interested in this business.

Spanish Wind Integration Features

These are some of the main problems and features of the Spanish Experience:

- **Strong decoupling between wind production and system needs.** From a seasonal point of view, wind generation tends to increase in winter time and decrease in summer time (Figure 2-15).

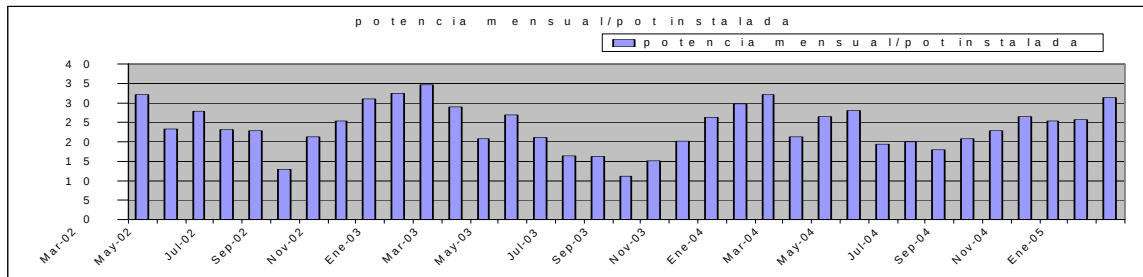


Figure 2-15: Wind Energy Production / Installed Capacity (Monthly Average)

However, no pattern has been identified for short time periods. Therefore there is no guarantee that the wind generation follows the demand curve. In fact, as shown in Figure 2-16, for an example day of operation, it can even follow a reversed profile.

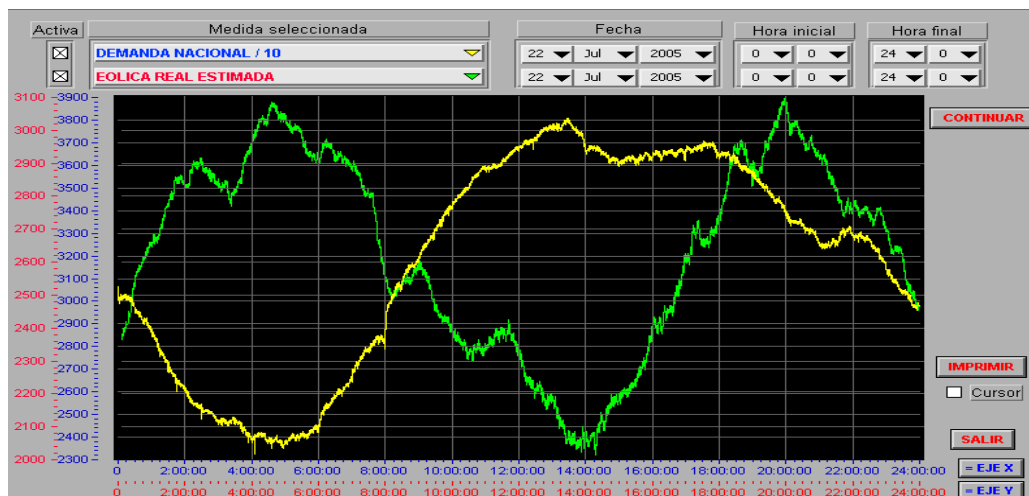


Figure 2-16: Real estimated demand (yellow) versus real estimated wind power supply (green).

- **High variability and gradients in wind generation.** The Spanish TSO (REE) has developed a wind power forecast tool called SIPREOLICO. This tool is under continuous improvement and combines wind speed forecast (HIRLAM model), geographical and technical information of wind farms, power versus wind speed curves and historic production databases (statistical treatment). As a result it provides an hourly forecast for the next 48 hours with real time updating.

The quality of this forecast diminishes with an increasing time horizon. Figure 2-17 shows the average forecast errors versus the forecast horizon. This diminishing accuracy of forecasts, together with the potential for steep generation gradients (up to 1000 MW/h) result in an Additional Tertiary Reserve requirement and an increase in Deviation Management Requirements.

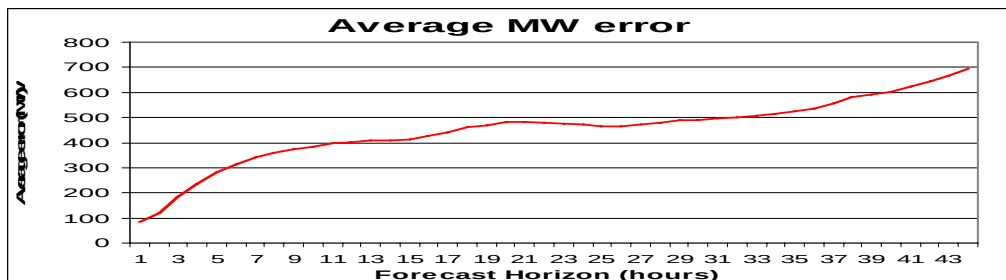


Figure 2-17: Average Error versus Forecast Horizon.

- **Sensitivity to voltage dips (generation trip).** Presently only 49% of the installed wind generation has a ride-through capability for voltage dips of up to 10% (i.e. voltage dips down to 0.9 pu), and only 43% can ride-through voltage dips of up to 15% (i.e. voltage dips down to 0.85 pu). This lack of adequacy results in strong wind generation loss due to equipment faults (see Figure 2-18).

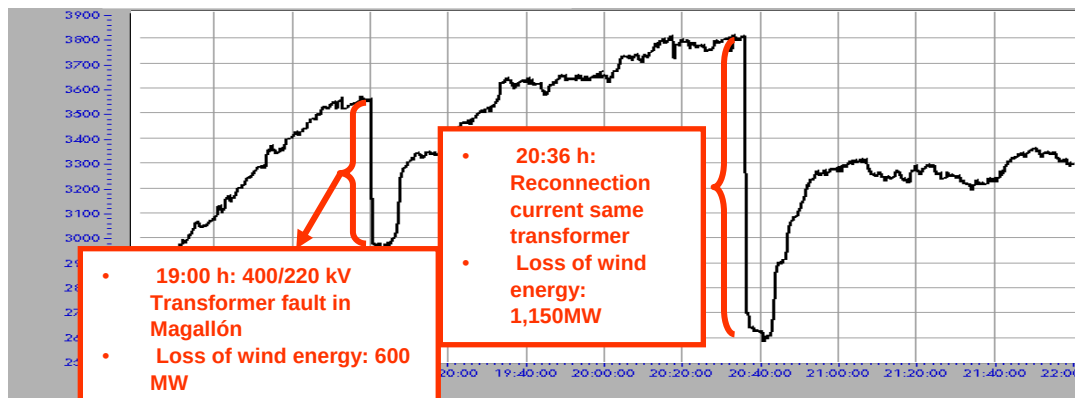


Figure 2-18: Loss of wind generation due to incident in transformer AT-1 400/220 kV in Magallón 1/8/2005.

These incidents lead to a significant deviation in scheduled power interchange with France that has to be recovered according to UCTE rules. The RCP mechanism (Peninsular Shared Secondary Regulation) is responsible for recovering the interchange program with UCTE (see example in Figure 2-19).

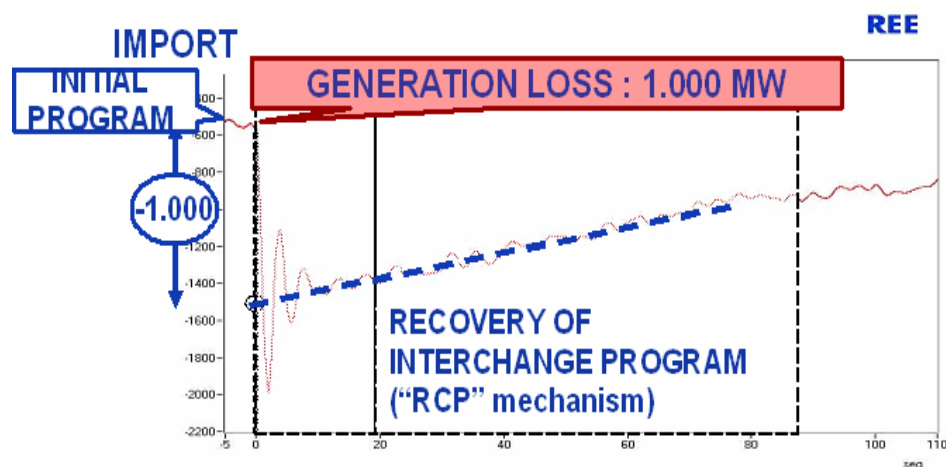


Figure 2-19: Example of RCP Mechanism.

Operating Practices

To minimize these problems REE carries out several Operating Practices.

- **Technical Requirements for Wind Power.** The most relevant is the P.O 12.3 (Operational Procedure) concerning the Fault ride through capability. The procedure establishes the basis for proper behavior of wind turbines during voltage dips. This is shown in Figure 2-20.

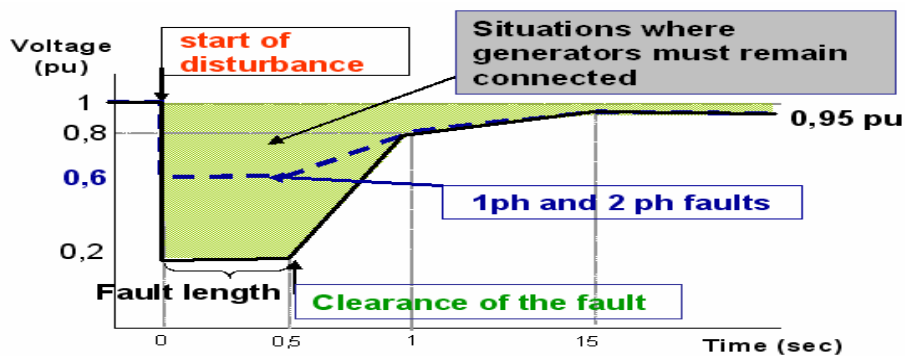


Figure 2-20: Power consumption (P,Q) during the fault and recovery is allowed 150 ms after the fault & 150 ms after fault clearance.

- **Wind penetration Studies.** Several studies have been performed in order to identify technical limits for wind power production. These studies have helped the Spanish TSO to establish technical requirements for wind farms and explore alternative operating measures. The results of these studies depend on the percentage of adequacy of current generators according to the PO 12.3 criteria.
- **Wind power control center.** The installation of a control center dedicated to the operation in real time of wind generation has provided REE the capability to receive real time information from wind farms. Furthermore it allows REE to send wind farms operation instructions. CECRE is a Control Center, integrated within REE's control structure, dedicated to wind generation and other Special Regime generation. Therefore, the TSO has a direct link with generating control centers to monitor and give control instructions, although it does not control directly generation units according to the scheme shown in Figure 2-21 (see also Figure 2-22).

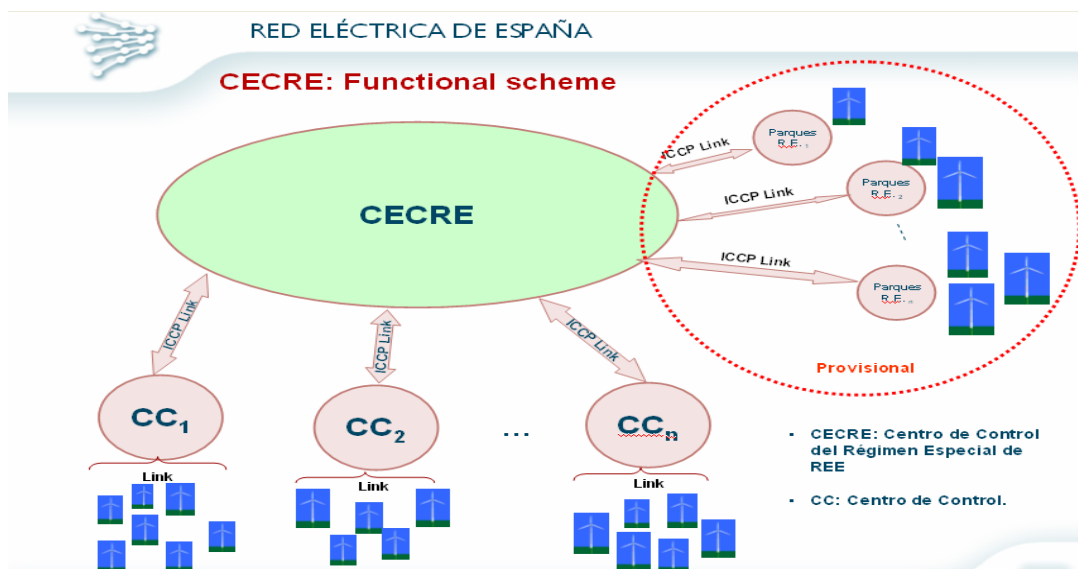


Figure 2-21: CECRE's functional scheme.

All instructions from CECRE to the wind farms are generated every 10 minutes by the GEMAS computing program in order to maximize wind power production while satisfying system security criteria. Under emergency conditions, wind generation would be reduced to a set point based on an algorithm that maximizes wind generation that can be produced in a secure way in case of an incident caused by a system fault.

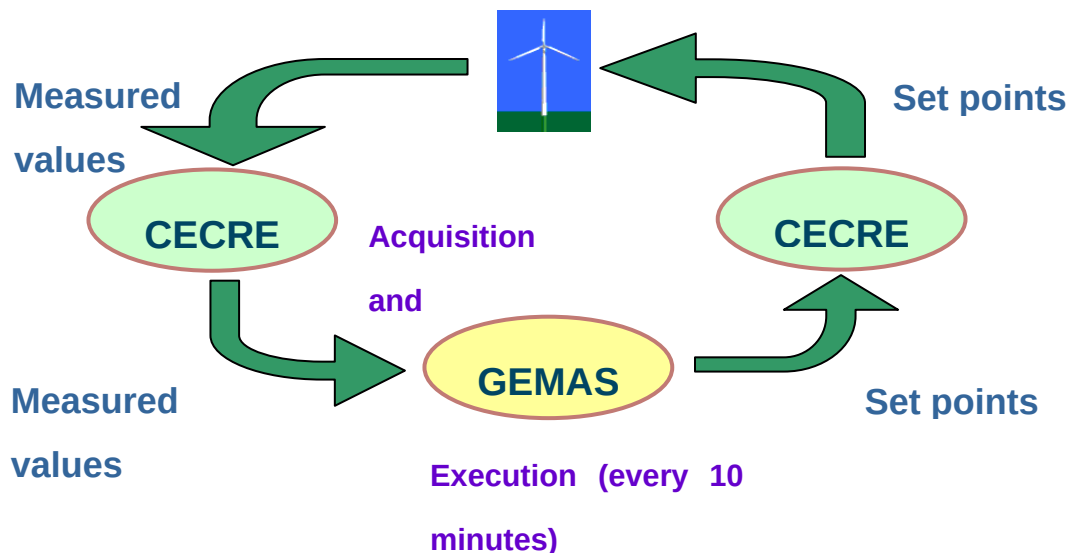


Figure 2-22: Relation among CECRE, GEMAS and Plants.

2.2.2.4 Ireland [24], [25]

The number of wind turbines connected to the Irish electrical power systems has been increasing rapidly over the last number of years (Figure 2-23). By June 2006, 611 MW of wind generation was connected to the Republic of Ireland's power system (10.7% of the total installed capacity in the country). Until October 2004 some 80% of all installed capacity was connected to the distribution system, and the balance to the transmission system. With the connection of new off-shore wind farms, an increasing proportion of wind generation is being connected to the transmission system.

Thus, at the beginning of 2005 36% of wind generation was connected to the transmission system, while by the end of 2006, this figure will grow to 42.7% [26] and is estimated to reach 47.4% in 2007.

In Figure 2-23, 'Historical data' refers to total installed capacity at the end of a particular year, 'Planned data' applies from the perspective of 2001, and 'Scheduled data' for years 2004 - 2008 includes all connected wind farms and wind farms signed and scheduled to be completed at the end of the corresponding year.

There are three main reasons for the significant increase of wind generation penetration into Irish power network:

- Ireland has signed the Kyoto Protocol and in order to contribute to meeting its obligations is supporting wind generation.
- The Directive 2001/77/EC of the European Parliament and the Council of 27 September 2001 on the proportion of electricity produced from renewable energy sources has set a target for EU states, that 22% of Europe's electricity needs should be produced from renewable sources. To meet Ireland's target, 13.2% of the primary electricity needs should come from renewable sources by 2010.
- Commercially viable wind power turbines have become available on the market.

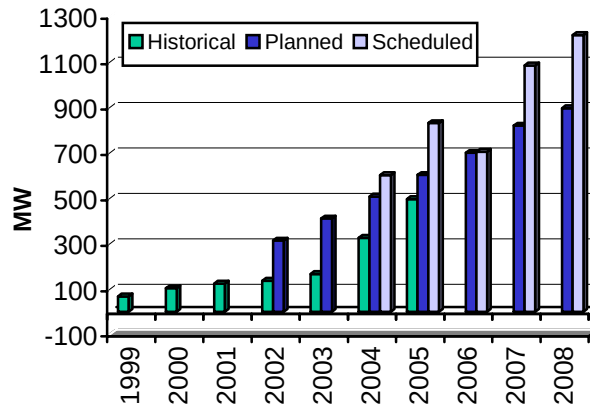


Figure 2-23: The dynamics of wind farms connection both to distribution and transmission networks in Ireland at the end of year.

As wind penetration level increases, it is necessary for system operators to assess the impact of wind generation on system regulation and dynamic stability. The rate of increase of wind generation was such in Ireland, that a “moratorium” was placed by the Commissioner on Energy Regulation in the end of year 2003 [26]. It was lifted after six months. During the moratorium an analysis of the possible impact of the increased wind generation penetration on the grid was conducted. The Grid Code was modified to accommodate wind generation, respecting the interests of both wind energy producers and the transmission system operator, who is responsible for the security and stability of the power system.

Characteristics of Wind Power Generation in Ireland

The majority of Ireland’s wind farms are located in the West of Ireland, based on the wind resources available. Such a spread of wind generation in Ireland leads to more variable power output patterns of the whole wind power plant with very little ‘smoothing effect’ due to geographical spread of wind farms.

Figure 2-24 shows a record of the total wind generation output in the Republic of Ireland in 2005. The actual wind generation output never exceeds 95% of the total installed capacity, and 95% of time generates less than 80% of its installed capacity. Power output distribution as a percentage of the installed capacity is shown in Figure 2-25. The median value of such power output is 26%. It means that for 50 % of time, wind power output is greater than 26.5% of the installed capacity. The yearly median wind power output (capacity factor) varies yearly from 31% to 34% and averages at 32.3% (compared to 20% in Germany [27]).

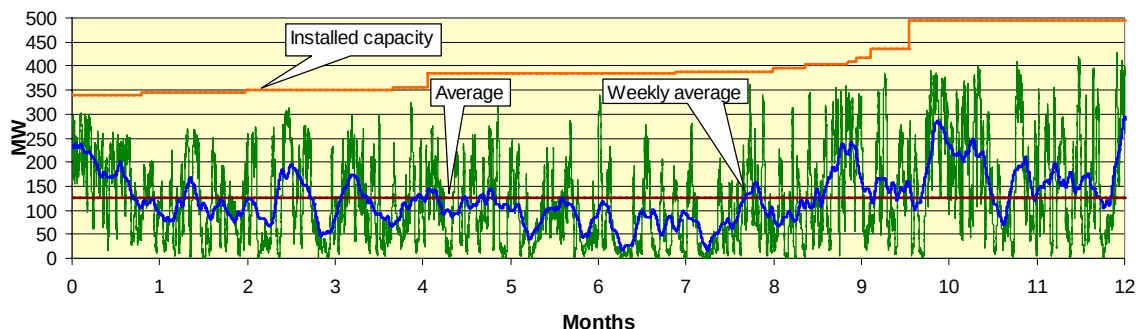


Figure 2-24: Total wind power generation from all Irish wind farms for the year 2005.

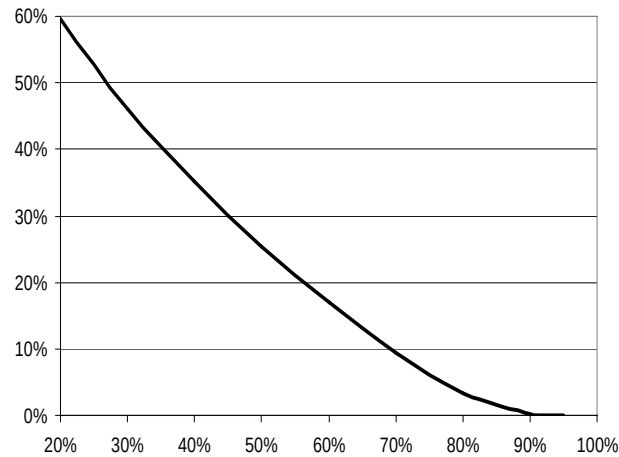


Figure 2-25: Wind power distribution in years 2001 – 2005.

Wind Power Station Connection to the Grid

At present, in the Irish electricity system the four main types of wind turbine generators are in use. That is, constant speed conventional induction generator wind turbine generators, variable speed full-converter wind turbine generators, variable speed doubly-fed asynchronous wind turbine generators and variable speed wind turbine generators with wound rotor induction generators with variable rotor resistance (see chapter 3 for a more detailed explanation of these technologies).

In order to accommodate wind generation on the Irish power transmission system, a grid code was developed to address the following main issues:

- Fault ride through,
- Frequency response,
- Voltage and reactive power capability, and
- Communication.

The details of the above requirements, as specified by the grid code, may be found in [28], [29], [30] and [31]. Figures 2-26, 2-27 and 2-28 summarize some of these requirements.

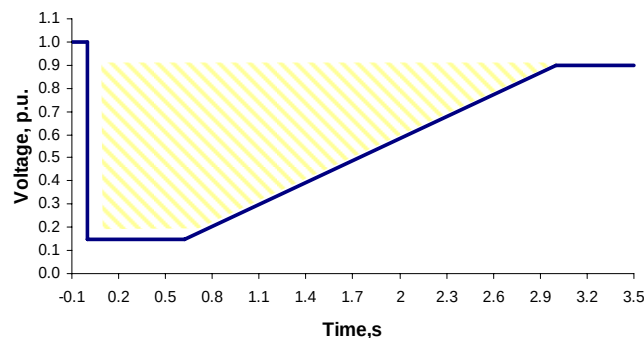


Figure 2-26: Fault Ride-Through capability of wind farms

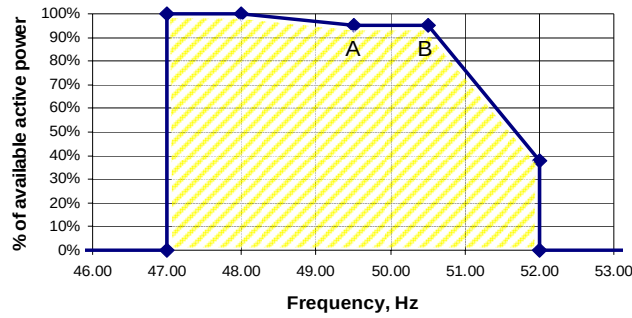


Figure 2-27: Frequency response capability of wind farm.

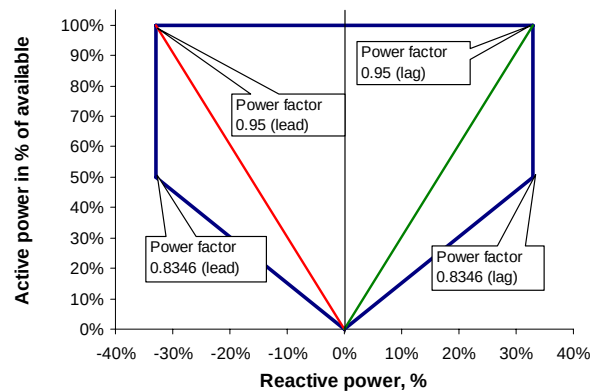


Figure 2-28: Required wind farm reactive capability as measured at the point of interconnection.

In terms of communications, the wind farm is required to make available at the TSO's remote terminal units the following signals:

- Grid connected transformer tap positions,
- Voltage at the grid connected transformer low voltage terminals,
- Active power output (MW) at the low voltage side of the grid connected transformer,
- Reactive power output (MVar) at the low voltage side of the grid connected transformer,
- Voltage regulation system set-point (in kV),
- On/Off status indications for reactive power devices, and
- MV Circuit-breaker position indications.

System Operation with Increasing Wind Power Generation

It is not possible to predict wind generation output with 100% accuracy. In year 2004, only 80% of all forecasts were made within 85% accuracy and in 6% of cases, wind forecast accuracy was less than 75%. The National Control Center (NCC) utilizes a two-day ahead wind forecast when producing the dispatch for the following day, but the NCC operator has the wind forecast updated every 6 hours (Figure 2-29). Eventually he/she has to select the tactic of dealing with the wind output forecast uncertainty based on these sometimes contradictory curves, his/her experience and other sources of information like meteorological maps.

Some interesting results related to the estimated share of wind power in future years, derived from a systematic analysis carried out using an extrapolation of 2003-2005 wind power output patterns, are as follows:

- The installed capacity of wind generation is likely to increase from 3.06% of the total installed capacity in 2003 to about 20% in 2010.
- The maximum percentage of wind power generation could rise from 7% of the total instant system generation in 2003 to 54% in 2010; 99.9% of the time, wind power generation was less than 6.3% of the total instant system generation in 2003. It grew to 16.7% in 2005 and is forecasted to increase to 50% in 2010.
- Fifty percent of the time wind power generation was more than 1.5% of the total instant system generation in 2003 and is forecasted to increase to 11.5% in 2010.
- The maximum hourly change of wind power output is approximately 33% of the total installed wind power generation capacity.
- During some 15-minut periods the net change of wind generation could exceed 25% of the total installed capacity.
- Maximum 6-hour net change of wind power output constitutes about 40% of the total installed wind power generation capacity, increasing from 2.4% of the total instant system generation in 2003 to 16% of the total instant system generation in 2010.

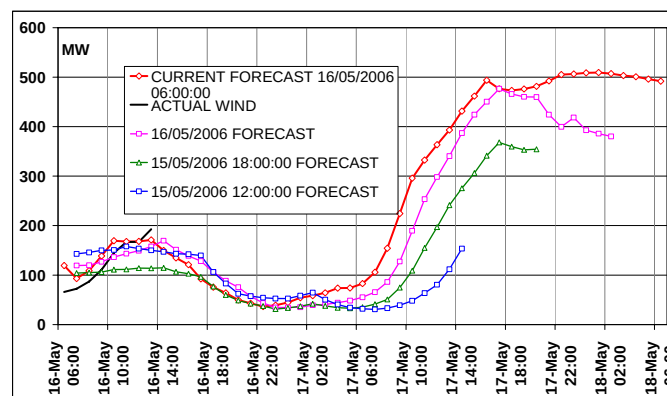


Figure 2-29: Wind forecast screen in NCC.

2.2.3 Asia and Australasia

2.2.3.1 Wind Generation in Japan

The total installed capacity of wind generation in Japan has shown a rapid growth recently and reached 1,078 MW in March 2006, approximately 0.6% of total generation capacity (Figure 2-30).

In 2003, the government introduced the Renewable Portfolio Standard requiring electric utilities to use a certain amount of renewable energy and also set the installation target of 3,000 MW in wind energy by 2010.

Possible influence of wind power on Grid

Wind resources in Japan are unevenly distributed across the country. Power systems in Japan generally have the following features:

- many nuclear power stations exist (about 20% of total generation capacity)¹¹;
- control areas are loosely interconnected as a longitudinal system that essentially contains no loop flow to prevent cascading outages across control areas and available transmission capacity of tie-lines between control areas is relatively small.

¹¹ Load-following operation of nuclear power stations is not conducted.

These features have resulted in particular concerns about the impact of wind power on generation system planning, operation and control along with other technological problems.

Some utility companies thus published ceilings of total capacity of wind turbines connected to their control areas. In determining the ceilings, the aspects described below have been examined.

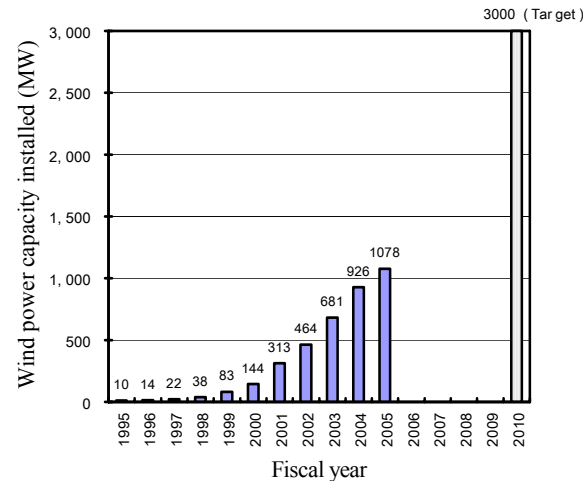


Figure 2-30: Wind power capacity installed in Japan.

Deficiency of Load Frequency Control capacity:

Load fluctuations with periods up to 20 minutes have been compensated mainly with thermal power plants through Load Frequency Control (LFC) in Japan. Increasing wind generation causes problems in LFC because LFC capacity is limited especially during light load periods in the nighttime. That is, LFC will not be able to adjust the fluctuation of wind power output within 20 minutes when the magnitude of fluctuation becomes greater than LFC capacity. This constraint imposes ceilings on the maximum capacity of wind generation to be installed in the system.

For example, Tohoku EPCO estimates this problem is possible if the total wind generation capacity in its control area exceeds 520 MW since its minimum load is 6,300MW.

Figure 2-31 illustrates the relationship between fluctuation and LFC capacity. As shown in the figure, if LFC capacity is limited, maximum total fluctuation will be deduced within permissible control error. The maximum capacity of wind power can be deduced using estimated magnitude of wind power fluctuation within 20 minutes.

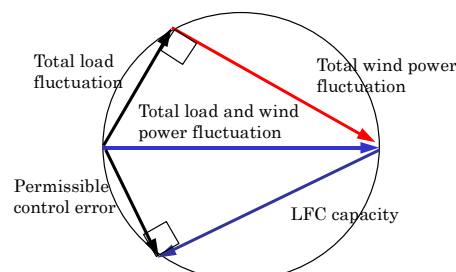


Figure 2-31: Schematic of relation between fluctuation and LFC capacity.

Deficiency of controllable generation during light load periods:

Figure 2-32 illustrates deficiency of controllable generation capacity of longer than 20 minutes during light load periods. The figure depicts that the aggregated output of base load plants (nuclear, run-of-river hydro etc.) and incremental output of thermals (providing

secondary reserve) must exceed total demand minus wind power output, otherwise (typically under light load conditions) curtailment of wind generation is necessary.

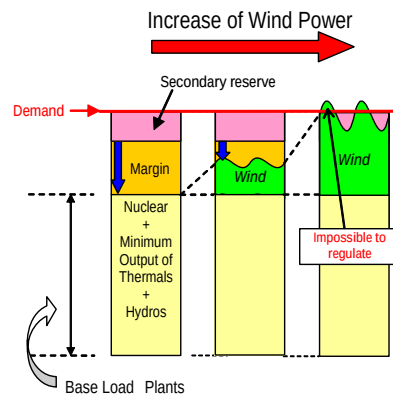


Figure 2-32: Deficiency of controllable generation

Balancing power tangent of wind power output:

Reserve power – that is, its magnitude and ramp rate – can be insufficient to balance both output fluctuations of wind power and electricity demand (Figure 2-33); this can occur, for example, at morning rise or evening drop of electricity demand.

Hokkaido EPCO estimates this situation can possibly occur, during morning rise from a minimum of 2,400 MW, when the total capacity of installed wind generation in their control area exceeds 250MW.

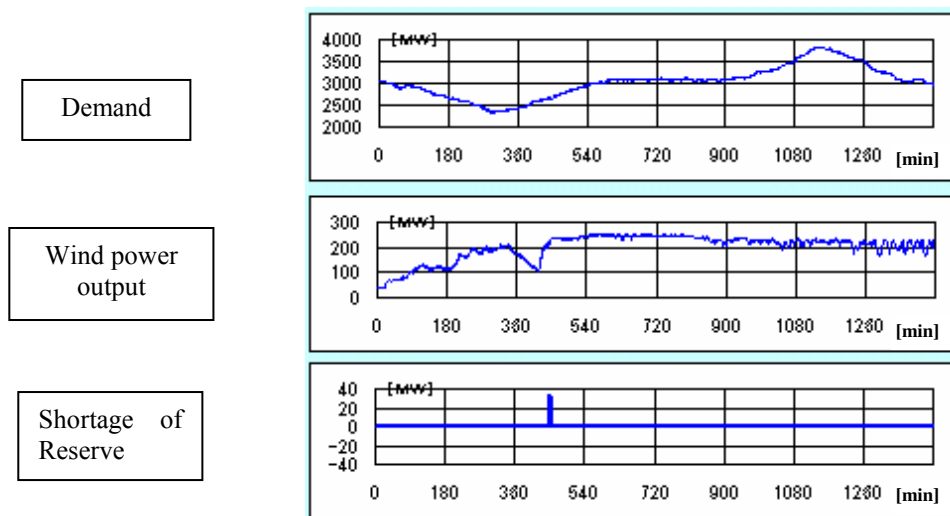


Figure 2-33: An example of shortage of reserve power at a morning rise.

Challenges under discussion for increasing wind power penetration

The following measures have been discussed to increase the level of wind power penetration in to the electricity grid and further discussions have continued:

- Further accumulation and analysis of output data from wind power generations facilities;
- Curtailment or Disconnection from grid during light load periods;
- Utilization of interconnection between control areas;
- Utilization of battery energy storage;

- Development of wind power forecasting method suitable for Japan.

Control systems using battery energy storage technology have been developed to reduce the fluctuation of wind generation. Some projects with battery systems are going to be put into business operation in the Tohoku control area within a few years.

2.2.3.2 Wind Power in Australia

In the eastern and southern states of Australia, electricity production is traded through the National Electricity Market (NEM). The National Electricity Market Management Company (NEMMCO) is responsible for administering the market and overall power system security management. In relation to wind farm development, the various network owners (Network Service Providers, or NSPs) enter into Connection Agreements with the wind farm owners – amongst other things, these Connection Agreements specify particular connection point technical performance requirements that the wind farm must meet.

There are two main categories of generation in the NEM: scheduled and non-scheduled. Synchronous generators that are greater than 30MW in size (and some smaller ones) are generally scheduled, which means that they are dispatched through a central dispatch process. The dispatch process provides a lowest cost generation dispatch while maintaining operation of the electricity grid within technical limits. Generator scheduling and dispatch occurs every 5 minutes. Intermittent generation such as wind power is normally non-scheduled and is, therefore, treated as negative load in the centralized dispatch systems.

Installed wind farm capacity

As of October 2006, there was 617MW of installed wind farm capacity in the NEM. Of this, South Australia has the largest installed wind farm capacity of 388MW. These installed capacities should be compared against a total NEM installed (scheduled) generation capacity of 42GW, of which 3.5GW is in South Australia.

A 10 year forecast of wind generation (and co-generation) installation was commissioned by NEMMCO for long term forecasting purposes – this is on the NEMMCO website [32].

Wind generation variability

From a market and operational perspective, one of the aspects of wind power generation that is expected to become more significant with greater amounts of installed wind capacity is the variability of the supply and its effect on the dispatch processes. The effect of short term supply variability on ac interconnector flows will be monitored and, if necessary, measures will be put into place so that interconnector flow limitations are not breached.

Accurate wind forecasting is expected to assist greatly in this regard. In an attempt to encourage a higher uptake of wind generation, the Federal Government of Australia has committed to fund the development of a new wind generation forecasting system. NEMMCO has entered into an agreement with the Government to facilitate the selection and implementation of the system, which aims to forecast the output from wind farms more accurately.

The system's requirements include:

- a system to forecast wind in the range from five minutes (as a forecast of actual wind power generation) to two years (in terms of a probability distribution of wind power in any hour on any day); and
- facilities to support the continuous improvement of the forecasting algorithms, with an emphasis on accuracy.

This will benefit the market, generally, by reducing errors in forecasting the required scheduled generation dispatch and assist in the maintenance of ac interconnector flows.

The delivery of the project is targeted for early 2008. In the interim, NEMMCO has contracted for the procurement of short term wind generation forecasting services (5 minutes to 40 hours) from a third party provider, prior to the commencement of the Federal Government funded wind generation forecasting system.

Operational issues

With current levels of installed wind capacity, operational issues tend to be local only. For example, there are some local voltage limitations in some areas in South Australia, so of the 388MW of installed capacity the maximum power that can be generated is 290MW.

Given the possibility of much larger levels of wind generation installation in South Australia, up to 1200MW assuming all license applications result in those wind farms being built, NEMMCO was requested by the South Australian regulator to advise on possible power system security implications. In February 2005, NEMMCO commissioned a series of studies to be undertaken (by DlgSILENT) to understand the possible impacts that large scale integration of wind power could have on the South Australian power system.

The scope of this work was to review how large amounts of wind generation could affect the stability performance of the power system, in order to determine:

- what future operational and power system security issues could arise;
- in broad terms, the extent of these impacts; and
- whether there may be a fundamental limit to the amount of wind generation that could be supported.

The scope of the work was limited to power system stability only, and focused on stability issues that could affect wide areas of the South Australian power system. Local issues would be dealt with on a case by case basis, and was beyond the scope of the study.

The study found that 800MW of wind generation (and up to 1200MW under some conditions) would not lead to any need to change operational practices or augmentation of the network. Beyond 800MW, there may be a need, under some conditions:

- to change these operational practices. This may include, for example, applying operational constraints on wind generation, including operational constraints in the scheduled generation dispatch process, or the procurement of additional voltage control ancillary services in South Australia; or
- augment the network.

It was also recognized that the increased generation capacity would be a driver for network development to increase the ability for South Australia to export power. For any network augmentation to proceed, it would need to be developed and justified via the normal transmission planning processes.

A summary report for this study is included on the NEMMCO website [33]. Further work is being carried out to refine the modeling of reactive power support in the South Australian system and to include likely future network augmentations which may affect the conclusions.

Wind farm Technical Standards

In March 2005, a Wind Energy Policy Working Group (WEPWG) recommended a review of technical requirements for the connection of non-scheduled intermittent generation (primarily wind farms). One of the recommendations was for an urgent review of the technical standards for connection of intermittent generation.

The main issues with the current framework were the:

- technical requirements are expressed in terms that cannot be applied to all generation technologies and, as a result, technologies such as wind generation are excluded from

compliance with some technical requirements. For example, many technical requirements were specific to:

- synchronous generating units, but no equivalent requirement was included for asynchronous units; and
- scheduled generating units, where the technical requirement should have also applied to non-scheduled units.
- requirements for provision and dissemination of information such as mathematical plant models are inadequate as they do not apply to all generation technologies. This required special conditions to be applied to wind farm owners to provide the types of models that all registered synchronous generator owners must provide.
- negotiation framework for access by generation to the network needs is inadequate in that it is unclear in some areas, does not cover all technical requirements and precludes use of alternative technologies to meet the requirements. This results in longer and costlier negotiations and inefficient investment in plants where a lower cost alternative is available but not permitted.

NEMMCO was requested to convene an industry-based Technical Standards Reference Group (TSRG) to assist NEMMCO with the review and the development of changes to the National Electricity Rules (“the Rules”). The TSRG also considered comment from wind turbine manufacturers on the proposed technical requirements, and these were taken into account in the proposed changes.

The proposed Rule changes were submitted to the Australian Energy Market Commission for consultation and approval in February 2006. As of October 2006, this was undergoing consultation [34].

Requirements for provision of wind models

Dynamic models, suitable for power system studies, must be provided by the prospective wind farm owner. In this case a “model” may include an encrypted model in a suitable format (e.g. compiled PSS/E® FLECS code), but must also include a full block diagram of the model.

Models are required by NEMMCO and the NSPs for:

- Connection Applications – design of a new facility, which involves design of the connection requirements and ensuring that the new facility is able to perform adequately under the Rules. This is a model based on early design parameters. NEMMCO has published general guidelines for connection applications on its website [35] that includes requirements for model provision.
- Registration – prior to electrical connection and commissioning, NEMMCO must be satisfied that the new facility meets its performance requirements, using the latest design model. It is expected that this model will reflect how the plant will be commissioned.
- Operation – system security assessment of performance under fault (and other disturbance) conditions.

After commissioning, model validation tests must be carried out on all new generators to confirm the model and the model parameters. The model and its parameters must be verified by test within 3 months after commissioning.

NEMMCO has published two guidelines for the provision and validation of wind farm models:

- “Wind Farm Model Guidelines and Checklist” [36]. This document:

- o describes the technical requirements for a dynamic wind farm model;
 - o describes the information that must accompany a suitable dynamic model; and
 - o provides a checklist of requirements and information that must be provided with a model
- “Wind Farm Validation Test Requirements” [37]. This document:
 - o describes the requirements for validation tests; and
 - o the accuracy requirements for a model derived from those tests

As the NEM also allows for open access and transparency for connection to the networks, model information must also be made available to prospective generation developers, so that they can carry out their own design for submission of a Connection Application to the NSPs and NEMMCO. NEMMCO has an obligation to provide model data to registered NEM participants for planning and operational purposes. This information includes network and dynamic model data. This has resulted in significant difficulties with obtaining wind farm models, due to the possible release of sensitive and commercial intellectual property.

In order to preserve intellectual property in the wind turbine design, in some cases a model has been offered by the manufacturer and wind farm owner that has been simplified from another, more accurate and detailed model. While NEMMCO prefers full model disclosure, such a model can be accepted, provided that:

- a broad range of confirmation studies are carried out of the type required for a connection application, specific to the proposed wind farm site, against the more detailed model;
- the confirmation studies result in accuracy between the two models at least equivalent to the accuracy requirements described in the “Wind farm model guidelines and checklist” [36];
- the conclusions drawn in the studies are in good agreement;
- the comparison report is provided to NEMMCO and the NSP, and both NEMMCO and the NSP agree that the comparison is satisfactory;
- validation tests on the wind farm are carried out by the wind farm owner to confirm both models.

As of October 2006, only one such validated model has been accepted by NEMMCO. Other wind farms are in the process of developing such a model or reviewing the results of validation tests.

2.3 Summary

This chapter has presented a discussion on global wind generation penetration and current experience from utilities and system operators from around the world. Figures 2-34 to 2-37 provide a summary of the amount of wind generation installed capacity in the various regions of the global, as discussed above.

In summary, the following general observations are pertinent and common to all regions:

- Whether due to the signing of the Kyoto Protocol or a general increase in public awareness and concern for environmental impact, renewable resources, particularly wind generation, is quickly becoming a significant (approaching or greater than 10% of installed generation capacity in almost all regions) portion of the generation mix.

- The intermittent nature of this energy source has posed significant challenges in the operation of the power grid, particular with respect to load following, frequency regulation and voltage regulation as they relate to system security. These challenges become significant once the level of wind generation, within a control area, increases beyond a certain amount (Note: this number depends highly on the system characteristics and the strength and capacity of interconnections to neighboring systems). Most of these challenges have been or are being addressed through the application of new technological improvements, the enforcement of grid codes that require system upgrades or operational flexibility of the wind farms (e.g. through application of dynamic reactive compensation devices, voltage ride-through etc.) and greater understand of the resource through forecasting tools and historic data. Issues such as fault ride-through and voltage regulation are the most readily addressed by technology applications (e.g. dynamic reactive compensation devices and more sophisticated controls).

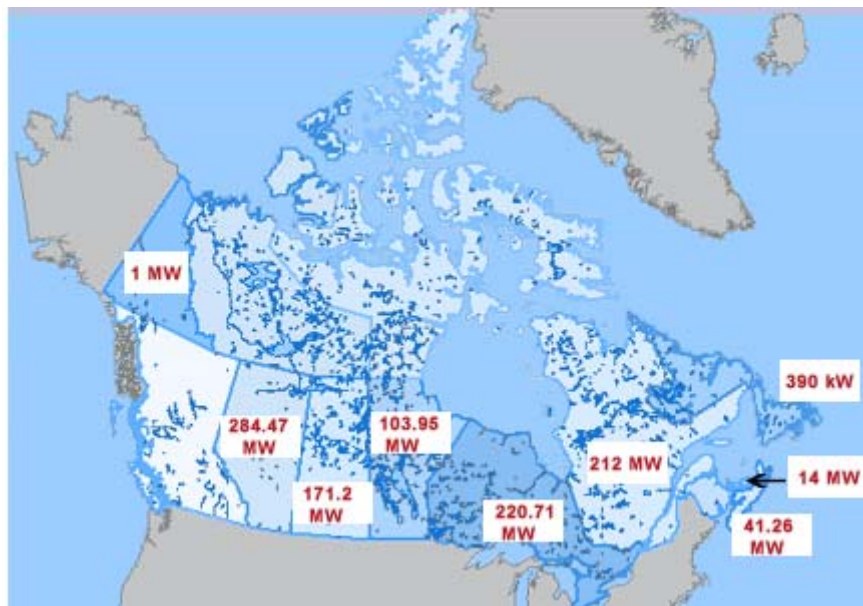
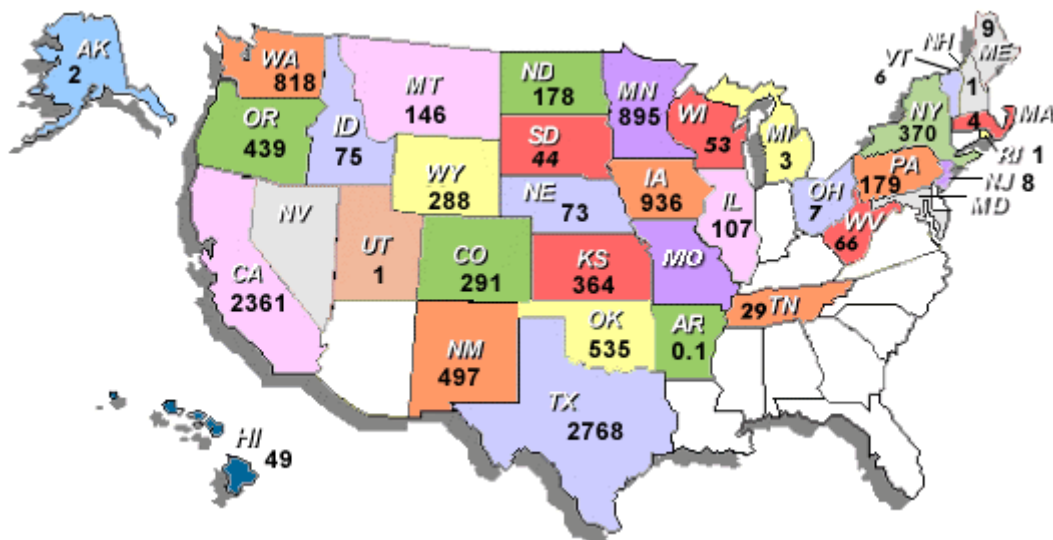


Figure 2-34: Wind generation installed capacity in Canada, a total of 1,439 MW as of 2006 (Courtesy of Canadian Wind Energy Association, www.canwea.com; © CANWEA 2006).



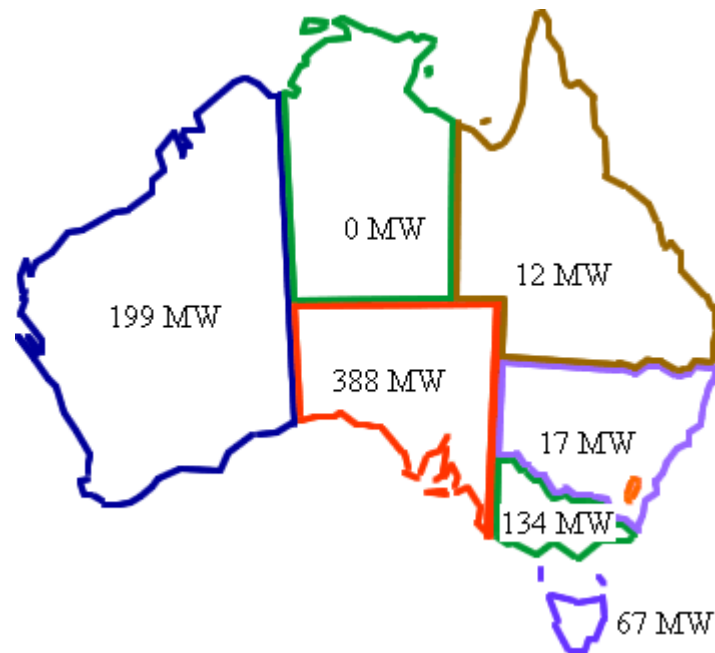


Figure 2-36: Wind generation installed capacity in Australia, a total of 817 MW as of 2006 (Courtesy of the Australian Wind Energy Association, www.auswea.com.au; © AUSWEA 2006).

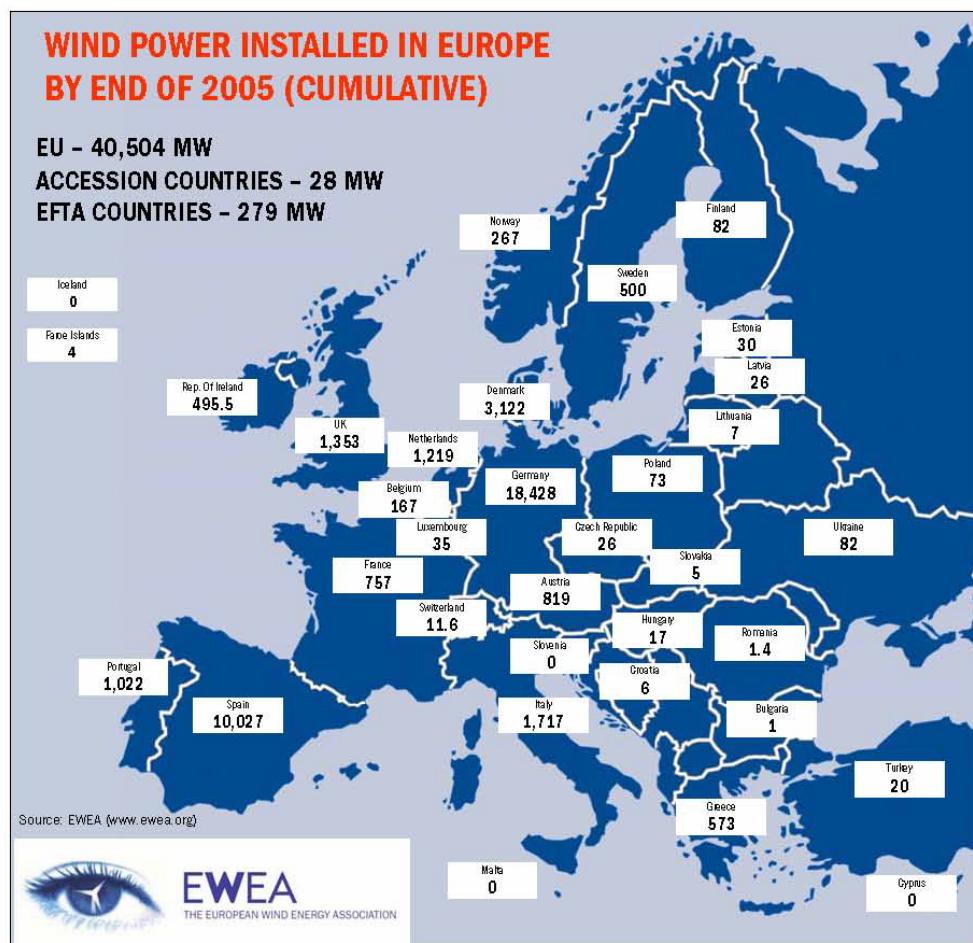


Figure 2-37: Wind generation installed capacity in Europe, at total of 40,894 MW as of 2005 (Courtesy of the European Wind Energy Association, www.ewea.org; © EWEA 2005).

- Finally, a key and common theme has been the constant need for better understanding of the dynamics of wind turbines and the availability of suitable models for incorporation into power system studies. This includes the need for models that are generic enough as to not invoke proprietary restrictions in disseminating them amongst stakeholders within the membership of a reliability council or utility group who are commonly engaged in performing system impact and planning studies.

The remaining chapters of this document aim to address some of these concerns above, particularly focusing on providing greater explanation of the dynamic behavior of the various wind turbine technologies, the models currently available and proposed model structures and needed improvements.

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WIND TURBINE GENERATOR TECHNOLOGIES

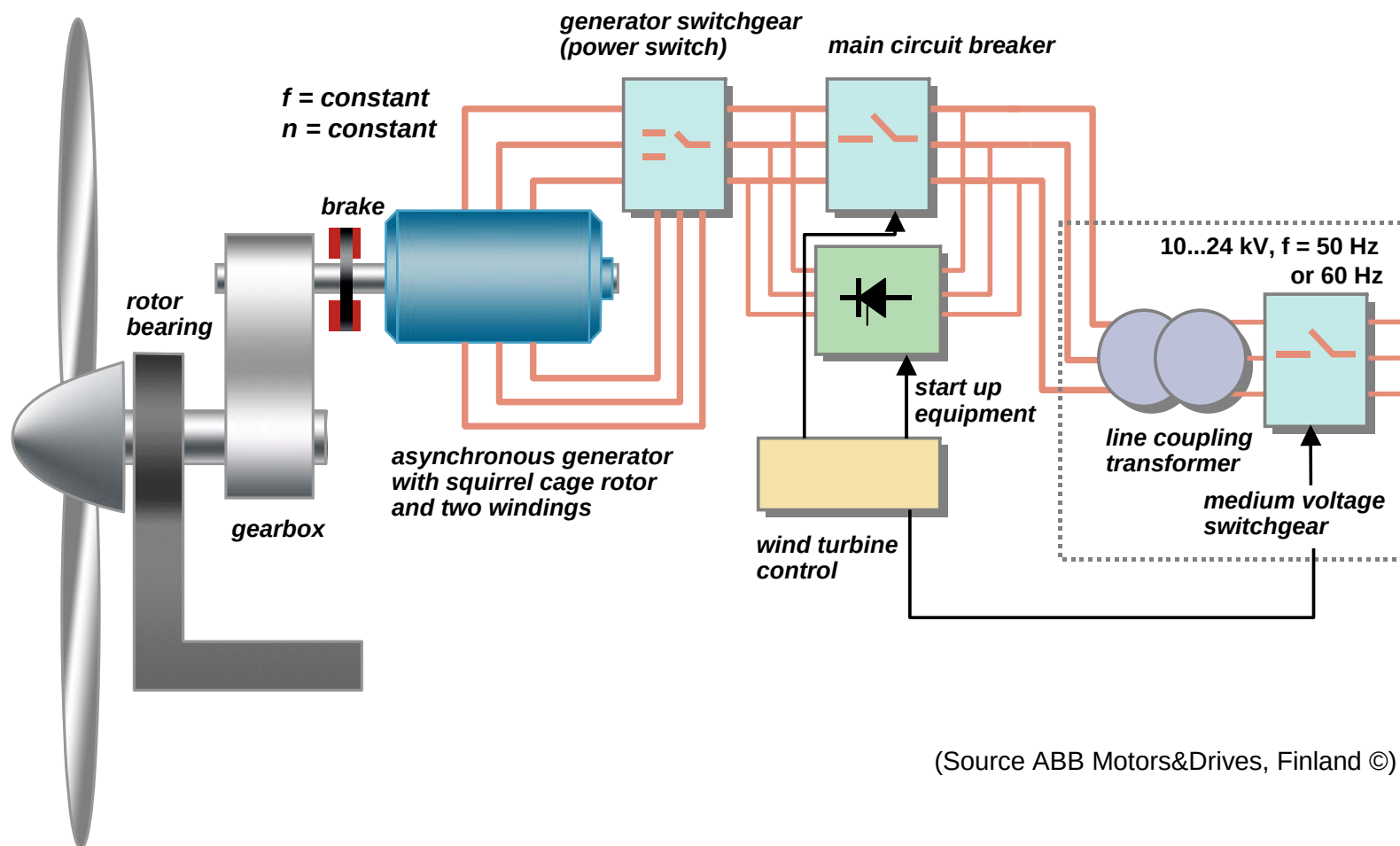
3.1 Introduction

Wind turbines are manufactured by many companies around the world. There are essentially three major types of wind turbine designs:

1. Constant speed turbines
2. Variable speed turbines
3. Gearless turbines

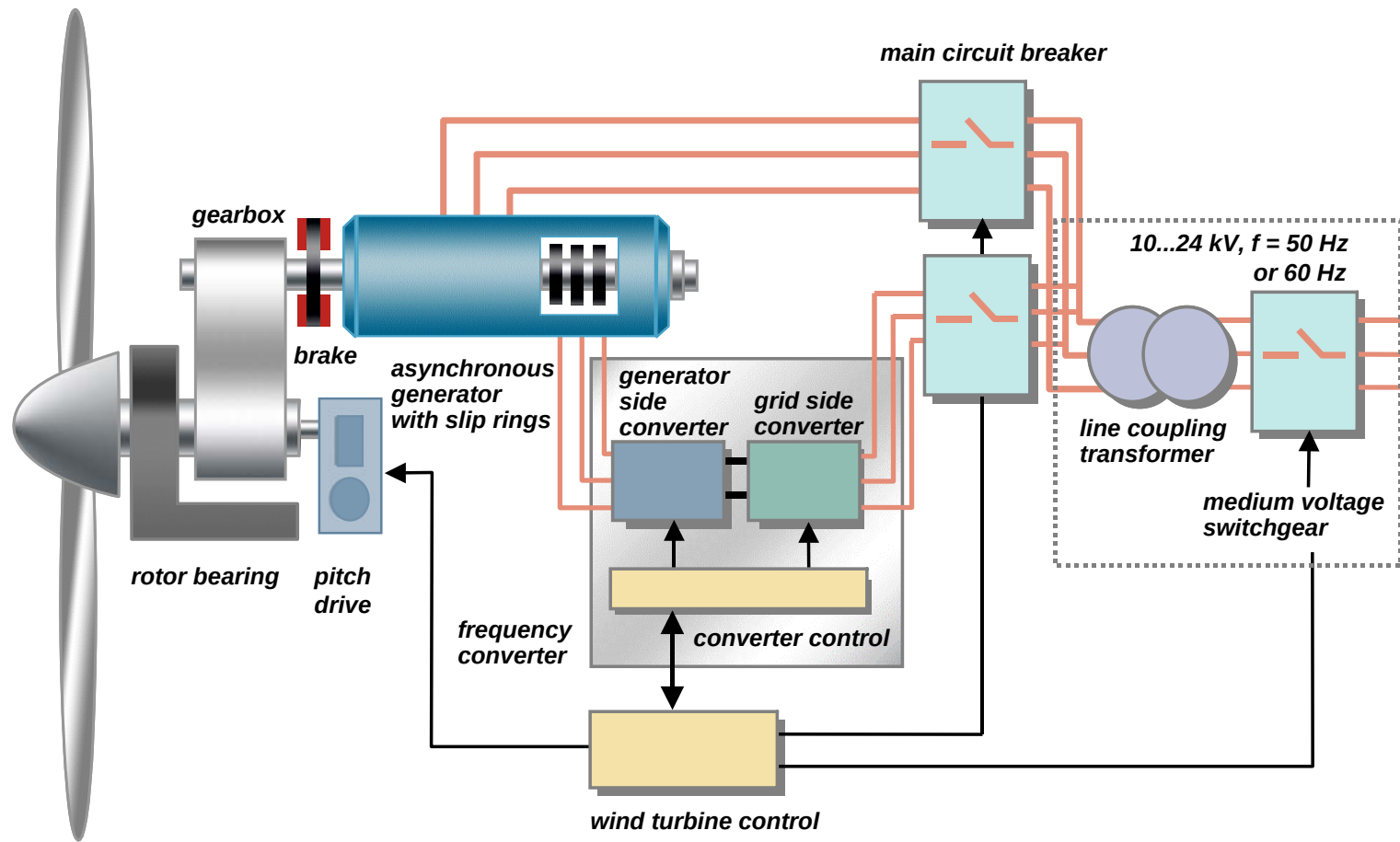
Figures 3-1 to 3-4 show some example electrical layouts for these major designs. As shown in the figures, constant speed turbines employ conventional induction generators while variable speed designs are based either on doubly-fed asynchronous generators¹ or conventional generators connected to the grid through a full back-to-back frequency converter. Gearless turbines typically use conventional or permanent magnet generators connected to the grid through a full back-to-back frequency converter.

¹ In this report we use the terminology ‘doubly-fed asynchronous generator’ instead of the more widely used term ‘doubly-fed induction generator’. These terms both refer to the same type of machine, however, it is felt that the former of the two terms is a more accurate statement of the machine design. This is because the magnetic field in the machine is not sustained by induction but rather by an alternating field voltage.



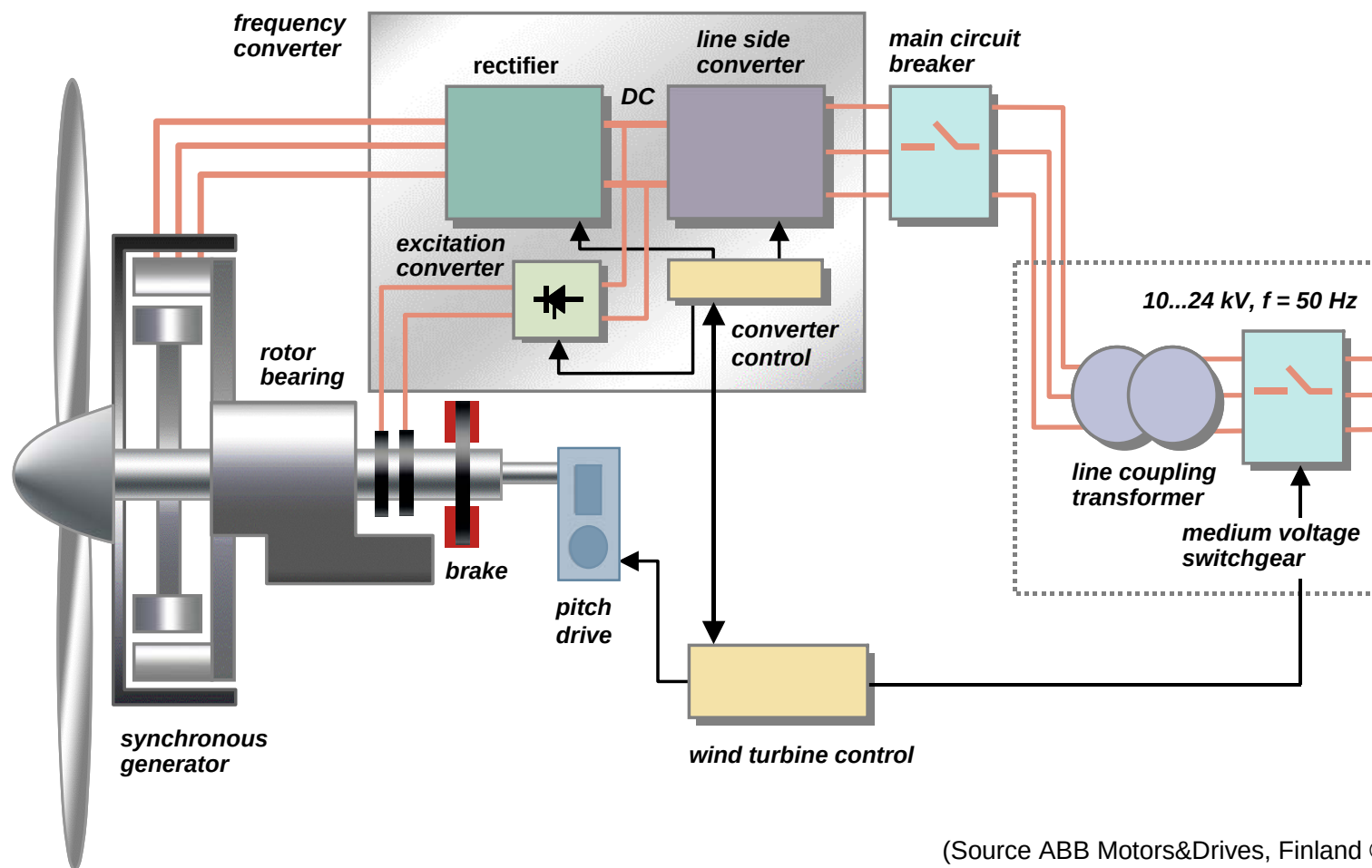
(Source ABB Motors&Drives, Finland ©)

Figure 3-1: Conventional induction generator. Constant speed drive.



(Source ABB Motors&Drives, Finland ©)

Figure 3-2: Doubly-fed asynchronous generator. Variable speed drive.



(Source ABB Motors&Drives, Finland ©)

Figure 3-3: Gear-less synchronous generator with back-to-back frequency converter.

3.2 Wind Turbine Control Philosophies

The power extracted from wind by a wind turbine may be given by the equation

$$P = \frac{1}{2} \rho v^3 \pi r^2 C_p(\lambda) \quad (1)$$

where

P = mechanical power

ρ = air density

v = wind speed

r = wind turbine rotor radius

C_p = coefficient of efficiency

λ = tip-speed ratio (i.e. the ratio of blade tip speed to wind speed)

It is clear that air density, the speed of the air and the radius of the wind turbine rotor are not controllable. Thus, to maximize energy output from a wind turbine, based on (1), the only parameter that can be controlled is the coefficient of efficiency (C_p). As mentioned in section 2.1, the theoretical maximum value of C_p is 0.593 (Betz's Law). In practice, C_p values close to 0.4 are achievable.

For a given blade pitch and rotation speed, C_p is a non-linear function of wind speed and will peak at a given turbine tip-speed to wind speed ratio (called the 'tip-speed ratio'), and will drop off again to zero at higher tip-speed ratios. A good wind site may have an average wind speed ranging around 7 to 10 m/s. Very high wind speeds occur seldom and also tend to put significant stress on the turbine. Thus, the turbine would be typically designed to extract the maximum amount of wind energy possible at wind speeds between 10 to say 15 m/s, and to start to spill away some of the power at wind speeds in excess of 15 m/s until they shut-down at relatively high wind speed – typically, in excess of 20 to 25 m/s. That is, a mechanism is required to control the turbine power once wind speeds increase beyond a certain amount, in order to avoid increasing the turbine power above its rating. To achieve this necessitates a form of power control on the turbine. There are two main different ways of achieving wind turbine power control:

- (i) fixed-speed designs that typically use stall, and
- (ii) variable speed designs that typically use dynamic blade pitch-control.

3.2.1 Stall and Active-Stall for Fixed Speed Wind Turbines

Fixed speed wind turbines, which typically used conventional induction generators, are in general controlled by stall or active-stall design. For turbines that have a capacity of around one megawatt or less, stall is used. For the larger turbines, active-stall is used since the higher power levels require some pitch control to prevent excessive turbine stress.

With stall design the blades of the wind turbine are bolted to the hub at a fixed angle. The blades are aerodynamically designed such that as the wind speed increases the blade shape gradually begins to yield turbulence and thus eventually results in stalling the blades. The coefficient of efficiency (C_p) is designed to peak around the expected average wind speed for typical sites, and then gradually drops off until the unit stalls at high wind speeds. The advantage of this design is that it avoids mechanical moving parts and some of the controls and other complexities associated with pitch control. Thus, these units are typically cheaper than an equivalent size variable speed

system. There are significant challenges to perfecting the aerodynamic design of a stall system. Sudden changes in wind speed (such as a gust) will translate into sudden changes in turbine torque and generator output. This requires more robust design of the drive train. Also, if such units are used in very weak grid connections they may result in more significant voltage flicker.

For larger turbines (1 MW and up) a variation of this concept is used called active-stall. With active-stall the blades of the turbine do have a pitch control mechanism. At low wind speeds pitch control of the blades is used similar to that of pitch controlled systems. Even though the unit is rotating at constant speed, by changing the blade pitch at lower wind speeds C_p can be changed and thus turbine efficiency improved. At high wind speed, when the machine has reached its rated output, active-stall allows much better control of the turbine than passive stall. If the wind speed increases suddenly, active-stall systems will pitch the blades in the opposite direction than pitch-controlled machines – that is, they increase the angle of attack into the wind in order to force stalling of the blades much quicker.

3.2.2 Pitch-controlled Turbines

If the coefficient of efficiency were to be kept relatively constant over the operating range of the turbine, then it would be possible theoretically to capture the maximum amount of wind energy. This can be achieved by maintaining essentially a fixed tip-speed ratio [1]. This can be achieved several ways such as adjusting the turbine speed as a function of wind speed or programming the turbine output as a function of turbine speed based on a preprogrammed power-speed curve that leads to maintaining a fixed tip-speed ratio. In practice, it is often difficult to obtain a good and reliable measurement of wind speed (since the anemometer sits behind the rotor on the nacelle and thus the wind speed being measured by it is distorted). Thus, a typical design used is shown in Figure 3-5. Based on a measurement of the rotor speed, the power converter is controlled to adjust the electrical power output of the unit to follow a predefined power-speed curve. This preprogrammed curve is based on manufacturer calculations that will essentially maintain a fixed tip-speed ratio and thus optimize energy conversion.

Variable speed turbines such as doubly-fed asynchronous generators and full converter units use pitch-control. The other advantage of these systems is that they produce greater power quality with less likelihood of flicker. This is because during a short lived wind gust the rotor speed increases and thus absorbs some of the fluctuation in power in the form of stored mechanical energy rather than directly translating the power fluctuations onto the grid with fixed-speed systems.

3.2.3 Fixed-speed versus Variable Speed Turbines

As discussed above, one of the motivations for variable-speed pitch-control systems is the ability to capture greater wind energy. In Reference [2], through calculations, the authors show that a variable speed system can capture more energy over time than a fixed speed design. In answer to such claims some fixed speed designs actually employ active stall (explained above) or dual-speed, dual-wound machines – that is, the stator of the generator can be switched between a smaller rated 6-pole stator winding for low wind speeds and a higher rated 4-pole winding for higher wind speeds. In these ways the machine's efficiency is somewhat improved at lower wind speeds. In the end the cost of electricity production is determined by many factors, and is not just a function of the energy captured by the wind turbines. Energy production costs depend also on initial capital cost, projected life span of the wind farm, reliability of the machines, operating and maintenance costs and other factors. Thus, it has in general been hard to truly verify if one design is superior to the other over the lifetime of a wind farm [3], and so all of the above designs have persisted in the market. In the long run, however, as power electronic equipment become more

reliable and less expensive it is expected that variable speed systems may start to dominate the market.

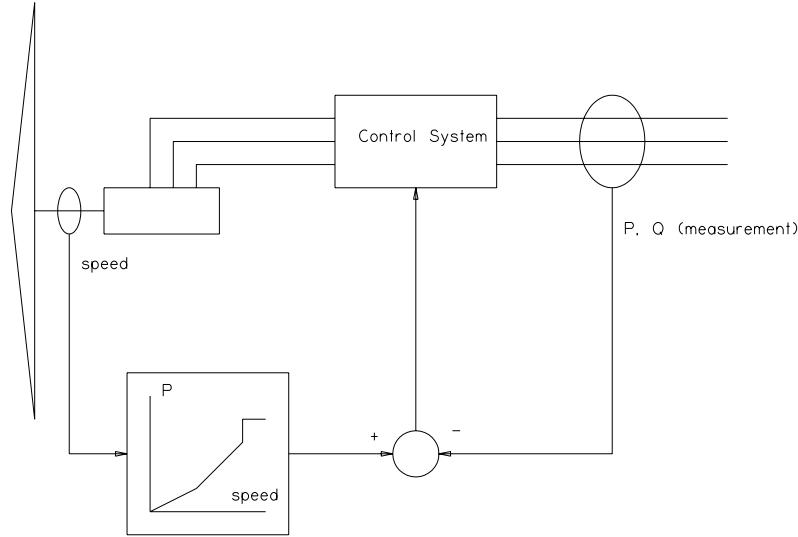


Figure 3-5: Control strategy for variable-speed turbines [4].

3.2.4 Stability of variable-speed control

As previously stated, it is usually quite difficult to obtain a good and reliable measurement of wind speed and, therefore, variable speed control is typically based on a measurement of the rotor speed. Knowing the optimal tip speed ratio and the corresponding maximum coefficient of efficiency (C_p) of the wind turbine, one can deduce the output power, which corresponds to a certain value of the rotor speed so that the tip speed ratio is optimal (ABC curve in Figure 3-6). This results in a predefined optimal power-speed curve. The wind turbine controller deduces the electrical output power by means of this curve and the rotor speed measurement.

The electric power (and torque) thus follows the optimal power – rotor speed curve, while the mechanical power and torque are determined by the wind turbine characteristic curves.

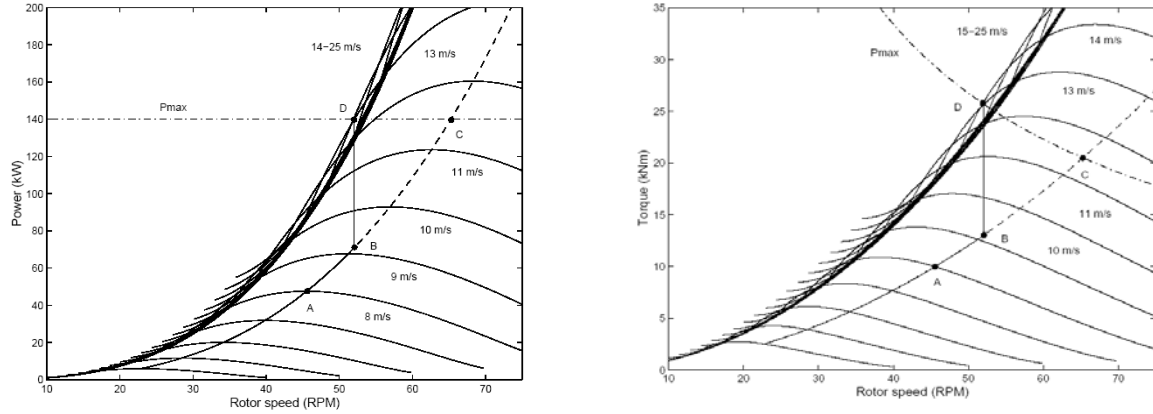
Assuming equilibrium on a point between A and B, the stability can be deduced by assuming small deviations [5]. Let us consider the situation depicted in Figure 3-7.

While the system is at equilibrium at point “a”, the wind speed increases abruptly to V_{w2} . Right after this disturbance, the rotor speed has not changed and thus the electromagnetic torque is kept by the controller equal to T_a , while the mechanical torque is $T_b > T_a$. However, as the rotor accelerates, the mechanical torque decreases, while the electromagnetic torque is increased following the maximum C_p curve. Eventually, the system finds a new equilibrium at point “c”, i.e. it remains on the maximum C_p curve. We can deduce the stability condition for this type of variable speed wind turbine control as:

$$\frac{\partial T_e}{\partial \omega} > \frac{\partial T_m}{\partial \omega} \quad (1)$$

Applying a similar analysis to the constant power part of Figure 3-6 (curve CD) it is easy to deduce that a controller trying to keep the active power at its maximum by specifying the

electrical torque based on the speed measurement will be unstable, because condition (1) is violated. Thus the CD part (constant power equal to rated) of the optimal speed-torque curve is implemented by the pitch controller (see previous subsections).



(a) Power – rotor speed

(b) Torque – rotor speed

Figure 3-6: Mechanical power (torque) – rotor speed characteristic curves with wind speed as parameter and optimal power (torque) – rotor speed curve.

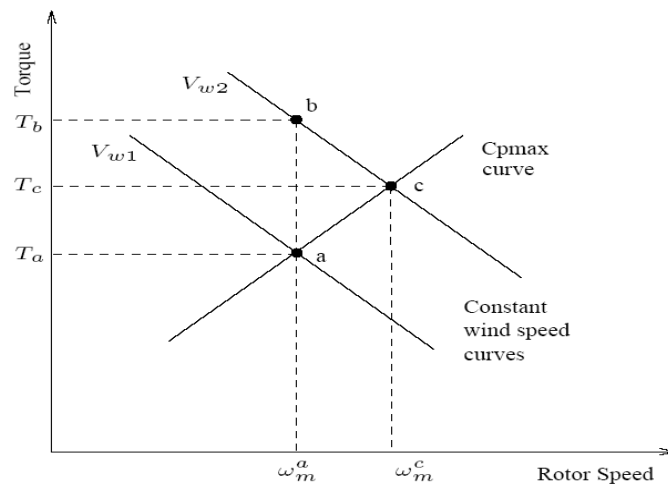


Figure 3-7: Stability of maximum C_p tracking – wind speed deviation

3.2.5 Conventional Induction Generators

The conventional induction generator is essentially a constant speed system. Though the electrical generator speed may vary by a fraction of a percent to a percent as the machine goes from low load to high load, from a mechanical stand point the machine essentially operates at a constant speed. Figure 3-1 shows an example of this system. The soft-start thyristor-controlled converter is used to start the machine with minimal impact on system voltage. Once the unit is connected to the grid, it runs essentially as a super-synchronous induction generator (see Figure 3-8).

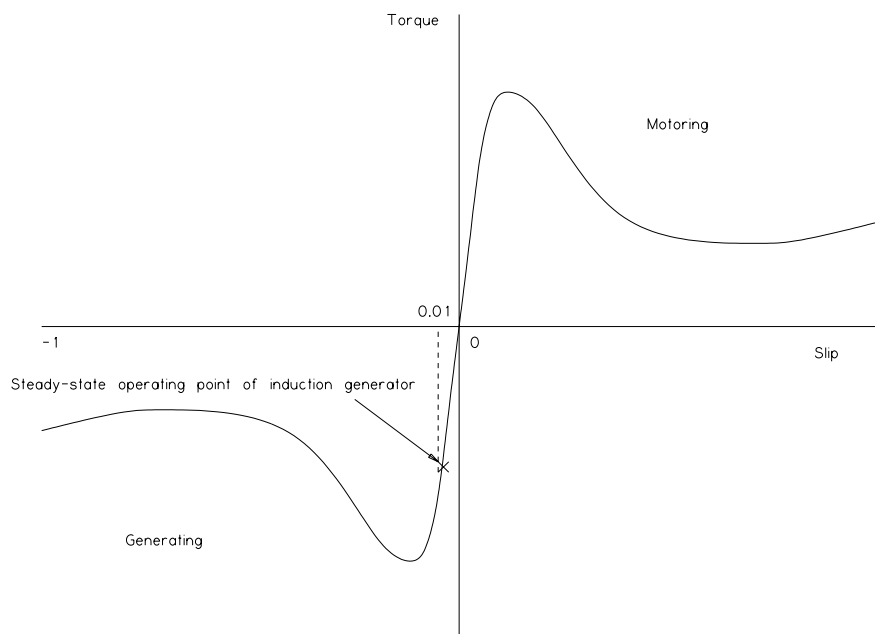


Figure 3-8: Induction machine torque speed curve [4].

Conventional induction generators, similar to induction motors, absorb reactive power from the system. This reactive power essentially sustains the rotating magnetic field in the air gap between the cage rotor and the stator windings. Manufacturers supply switched capacitor banks at the turbine that are switched based on the machine kilowatt output. Thus, the effective power factor of the machine is kept at or very close to unity, when operating at or above rated voltage. Moreover, some manufacturers provide the added option of placing a thyristor based dynamic VAr device at the turbine for additional and smoother VAr control, or dynamic VAr devices can be placed at the substation level.

One of the issues discussed in this report is that of low-voltage ride-through. This is the ability of the wind turbine to ride-through a grid disturbance. Up to the late 1990's and early 2000's, most wind turbines were connected at the distribution level. Thus, it was common practice to disconnect the turbine from the system following a system fault. As an example, for conventional induction generators it is typical for the units to disconnect from the system if the voltage at the terminals of the machine falls below 70 to 80% for more than 100 ms. On most transmission systems this would mean a high probability that the wind turbine would disconnect for any nearby system fault.

In the case of conventional induction generators, the reason for this tripping is that upon fault inception the electrical power falls to a low value (zero for a bolted 3-phase fault). This results in the turbine speeding-up. Thus, if the turbine is not disconnected after a certain time it may exceed its pullout torque and become unstable (similar to an induction motor stalling, except here the units speed increases uncontrollably since it is running as a generator). This is depicted graphically in Figure 3-9. We start at the steady-state operating point A. Upon inception of the fault/disturbance, due to the effective change in the unit's electrical torque speed curve (as a result of voltage depression) we move to point B. Now the unit starts to accelerate because mechanical torque is greater than electrical torque, and thus may go to point C at which point the

unit could go unstable, if the electrical torque upon fault clearing is less than the turbine's mechanical torque (and is on the left side of the torque-speed curve beyond the break-down or sometime called 'pull-out' torque – the peak of the curve). Therefore, under voltage protection is installed to disconnect the unit from the system for low-voltage conditions.

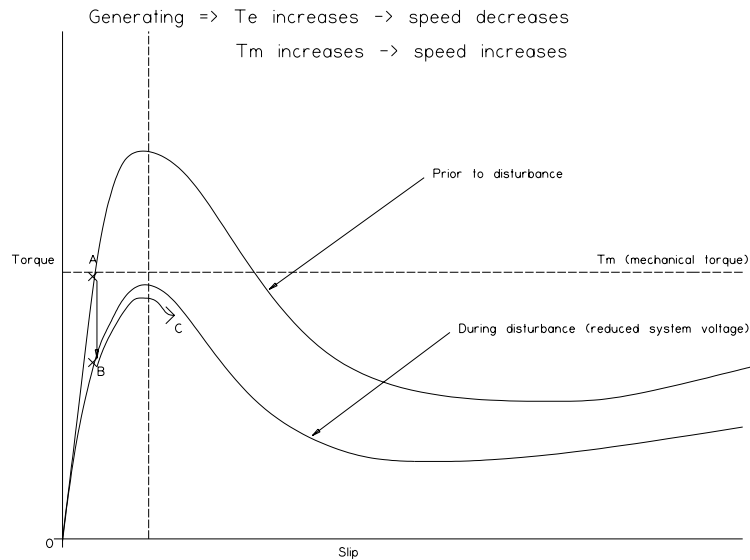


Figure 3-9: Behavior of a conventional induction generator during a disturbance [4].

Most wind turbine manufacturers now offer a low voltage ride-through package. This was originally driven by European requirements, and more recently similar requirements in Northern America. This is achieved by a combination of modified blade pitch control algorithms (that help to remove some of the mechanical power following fault inception) and applying uninterruptible power supplies (UPS) at the turbine to keep the controls running during the fault. In addition, smoothly controlled dynamic reactive power sources such as an SVC or STATCOM may sometimes be required to provide additional support upon fault clearing to ensure proper voltage recovery.

3.2.6 Doubly-Fed Asynchronous Generators

One of the most common variable speed turbines is the doubly-fed asynchronous generator (DFAG). One design is shown in Figure 3-2. This design employs a series voltage-source converter to feed the wound rotor of the machine. By operating the rotor circuit at a variable ac frequency one is able to control the mechanical speed of the machine. In this design the net power out of the machine is a combination of the power coming out of the machine's stator and that from the rotor (through the converter) into the system. When the unit is operating at supersynchronous speeds real power is injected from the rotor, through the converter, into the system. When the unit is operating at subsynchronous speeds real power is absorbed from the system, through the converter, by the rotor. At synchronous speed, the voltage on the rotor is essentially dc and there is no significant net power interchange between the rotor and the system.

Most designs tend to supply reactive power to the system through the machines stator by effectively changing the d-axis excitation on the rotor. A vector control strategy is used, where the rotor current is split into d-axis (flux producing) and q-axis (torque producing) components. Each component is then controlled separately. The d-axis component is controlled in order to

regulate the machine power factor, while the q-axis component is controlled in order to keep the electrical torque of the machine constant. It is possible, however, to also provide reactive power through the converter with a four-quadrant voltage source converter design. By employing this feature in the line side converter the wind turbine generator line side converter can essentially act as a STATCOM and supply or absorb reactive power to or from the system even when the actual wind turbine generator is not running and disconnected from the system. Providing this feature, though, will typically mean additional cost.

The fact that rotor currents are tightly controlled (kilohertz) means that the controls have the ability to, within limits, hold electrical torque constant (as opposed to the relation between torque and angle in synchronous machines). Thus, rapid fluctuations in mechanical power can be temporarily “stored” as kinetic energy, thus improving power quality.

As in the case of conventional induction generation, older designs of DFAGs would disconnect from the system during a close in fault. In the case of earlier DFAG designs, one might say they were more sensitive to system fault and would disconnect from the system in a much shorter time frame than conventional induction generators (within milliseconds, if the system voltage dropped below about 70%). Unlike the case of conventional induction generation, however, the process leading to separation might not be readily apparent from dynamic simulation results. The concern in DFAG is the fact that large disturbances will lead to large initial fault currents, both in the stator and in the rotor as well. These high initial currents will, of course, flow through the rotor-side converter. Due to low voltages at machine terminals during a disturbance, the stator-side converter is limited in its ability to pass power to the grid. Consequently, the additional energy goes into charging the dc bus capacitor and thus the dc bus voltage rises rapidly, depending on the design of the converter controls. This may give rise to protection acting to short-circuit the capacitor (via a crowbar) in order to protect the converter power electronic components (see Figure 3-10) [6]. In the past, when the crowbar circuit fired, the unit would be disconnected from the system.

The newer generations of doubly-fed asynchronous generators are now supplying low-voltage ride-through, achieved through changing the control and protection philosophy of the voltage-source converter. One example is the use on an active crow-bar circuit, which is described in the following subsection.

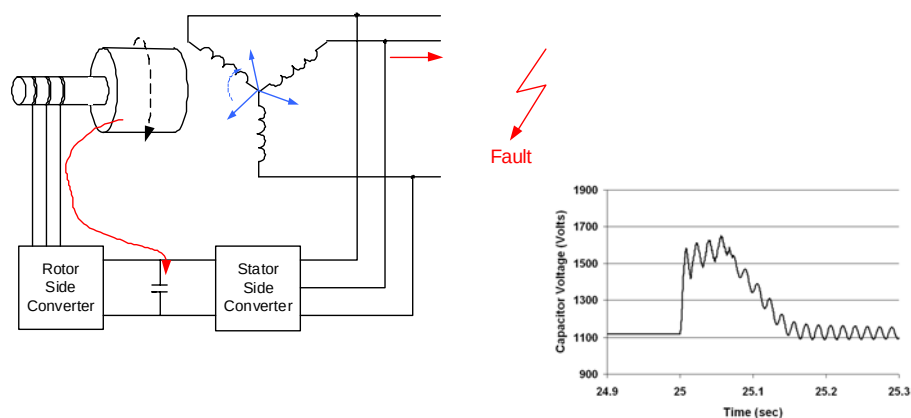


Figure 3-10: Tripping of old DFAG designs [4].

3.2.6.1 Doubly-fed Asynchronous Generator Low-Voltage Ride-Through Using Active Crowbar

Active crowbar means a crowbar with a semiconductor switch that can in addition to turning on of the crowbar also switch it off. Typically the active crowbar consists of a diode bridge and an IGBT-transistor as a fully controlled semiconductor switch, Figure 3-11.

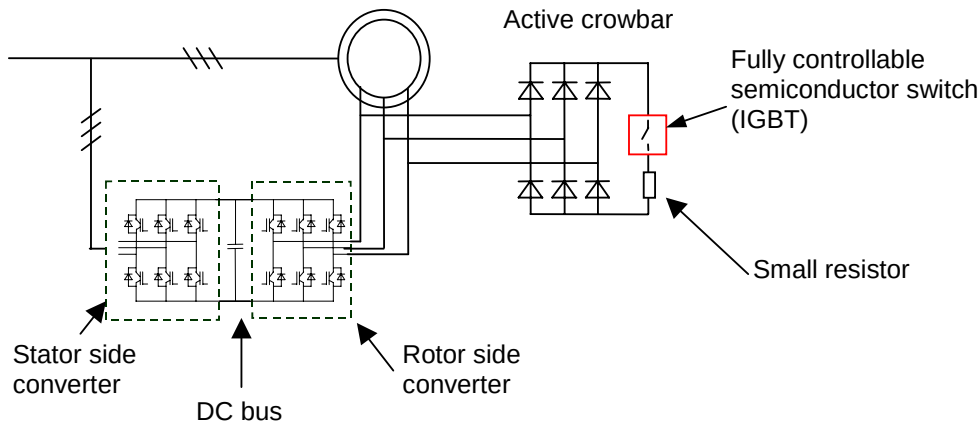


Figure 3-11: Doubly-fed generator with an active crowbar.

It is common to have a resistor with a small resistance value in series with the transistor in order to limit the inrush current in the rotor when the crowbar is conducting.

The ride through sequence for a symmetric three-phase voltage dip starts when either the rotor current or the dc bus voltage increases above the tripping limit. In order to protect the converters and the dc bus capacitor from excessive voltages and currents, the crowbar transistor will be turned on and all the transistors of the rotor side converter will be turned off. As a result the rotor current is diverted to flow via the crowbar.

When the crowbar conducts the generator behaves much like an ordinary asynchronous induction generator that has a small external rotor resistor (roughly equivalent to 2/3 of the crowbar resistor's resistance per phase). Thus, after about a 10 to 15 ms initial burst of reactive power to the grid the generator starts to consume reactive power. The active power depends on the generator slip. If the generator speed is above the synchronous speed it will continue to produce some power to the grid. If the speed is lower than synchronous speed the generator starts to consume active power. However, due to the low stator voltage the active and reactive power of the generator are quite low although the stator currents are high.

Due to the low impedance of the crowbar circuit and low stator voltage the generator flux reduces rapidly. The currents in the stator and rotor similarly decrease. Typically after 60 to 100 ms the measured crowbar current indicates that the transient has decayed enough for the rotor converter to be able to control them again. The dc bus voltage has also decreased to normal levels because the stator side converter has fed the extra energy stored in the dc bus capacitor to the grid.

In the next step the crowbar transistor is turned off. The rotor current is then turning back to the rotor side converter. The transistors of the rotor side converter are still blocked, but the rotor current finds its way through the diodes that are parallel to the transistors. If the voltage induced in the rotor is now lower than the dc bus voltage, the rotor current will rapidly decrease to zero.

The stator current is similarly reduced to a low value. After the rotor current has been close to zero long enough to be sure that the transient is over, the rotor side converter can be started again.

If, however, the rotor current does not decrease fast enough, the dc bus voltage may rise to the tripping level again. Then the crowbar is retriggered and a new turn-off attempt is made when the dc bus voltage has decreased back to normal again. Thus, in severe voltage dips the crowbar may conduct several times before the rotor current is finally cut out.

When the rotor side converter has been successfully started, the rotor side converter can control the generator to produce reactive and active power to the grid. Typically the rotor side converter will start 80 to 150 ms after the beginning of the dip and rated generator current is available 200 to 400 ms after the beginning of the dip. The increase of the generator current has to be slow enough especially when the voltage in the grid during the dip is close to zero, because then the magnitude and phase angle of the voltage on the generator terminals will be largely defined by the generator itself, a situation that may cause loss of synchronism with the grid.

When the fault causing the voltage dip is cleared, the grid voltage will increase. This change will induce another transient in the generator stator and rotor. However, the circuit breaker will break the fault current in each phase when the phase current is near zero. Thus, the grid voltage increase is not as fast as the decrease has been. In many cases the resulting transient is so low that the crowbar is not triggered at all. The generator's active and reactive power can then be controlled according to the grid code requirements without delay. If the transient triggers the crowbar, the generator will start typically 50 to 100 ms after the triggering instant.

One example of a ride-through measured in a factory test is shown in Figure 3-12.

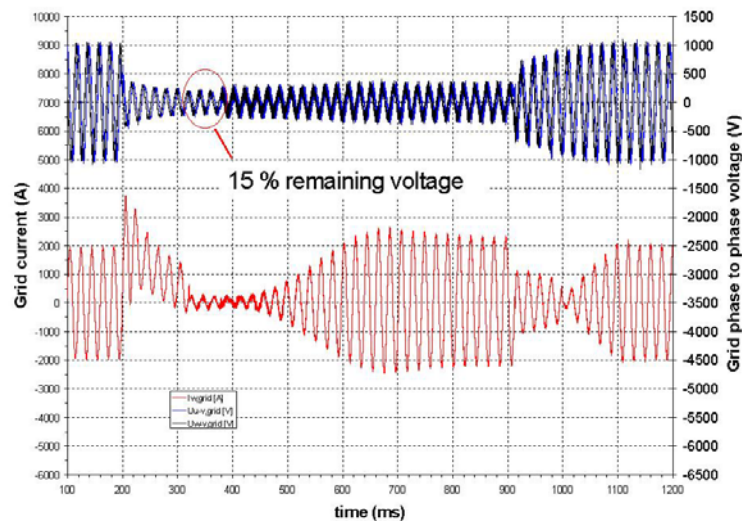


Figure 3-12. Measured ride-through of a doubly-fed generator with an active crowbar.

For unsymmetrical (that is, single- and two-phase) faults the ride-through of a doubly-fed generator is more difficult. The reason is the negative sequence in the grid voltage that is caused by the unbalance of the phase voltages. The negative sequence rotates in the other direction than the rotor and thus has a high slip value around 2 pu. Due to this high slip even a rather small negative sequence component in the stator voltage can induce in the rotor a voltage that is higher than the dc bus voltage. Because there are diodes parallel to the transistors in the rotor converter, the rotor circuit will feed current to the dc bus even when the rotor side converter's transistors are blocked.

In contrast to the decaying transient caused by a symmetrical three-phase fault, the negative sequence will continue to exist until the asymmetric fault is cleared. Thus if the unbalance is high enough the rotor current will continue to boost the dc bus voltage up and cause repeating sequence of turn-ons and -offs of the crowbar. The active crowbar will then be operating much like a chopper that controls the dc bus voltage.

Typically the rotor converter cannot be started during the dip if the negative sequence component in the stator voltage is greater than 30 to 50 % of the rated voltage.

When the fault is cleared, the rotor side converter can control the generator in a normal way if it has succeeded to start during the dip. If the crowbar is still on, the crowbar will be turned off first and then the rotor side converter is started in a normal way.

There are several other alternative designs for a doubly-fed converter ride-through. One alternative is to dimension the rotor side converter to be able to handle the inrush current. Because the stator side converter cannot handle the power fed to the dc bus from the rotor when the grid voltage is close to zero, a transistor controlled resistor ("braking chopper") is needed to dissipate the extra energy in the dc bus. Naturally the required higher current rating of the rotor side converter increases the cost of the equipment.

Another alternative has semiconductor switches in the stator that temporarily disconnect the stator from the grid when a high current transient is detected. The main drawback of this scheme is the addition to the complexity of the circuit and the extra losses in these switches that decrease the efficiency of the generator during normal operation.

3.2.7 Other Designs

3.2.7.1 Full Converter Units

Presently, the major supplier of full converter units is Enercon. Other manufacturers are starting to pursue units of this design. These units have dominated the German market, with perhaps three quarters of the wind turbine generators in Germany being of this design from Enercon.

The concept in this case is to generate power using either a conventional generator² with a dc field or a permanent magnet generator. This has two basic advantages:

1. It allows for a gearless design. This avoids the mechanical complexity of gears and hydraulics. The generator is directly coupled to the turbine and spins at whatever rotational velocity as required. The electrical frequency of the generator output is then converted by a back-to-back frequency converter to the grid frequency (50 or 60 Hz). With gearless designs, typically, the generator has a significantly larger diameter to

² The commonly used term is to say that a "synchronous generator" is used since the generator design is similar to conventional fossil fuel plants. Also, such generators operate such that the induced rotating magnetic field (produce by the current induced in the stator winding) rotates at the same speed (in synchronism with) the field winding on the rotor. More commonly, though, the term "synchronous generator" is associated with the fact that such generators operate in synchronism system wide. That is, all synchronous generators in conventional power plants rotate in synchronism establishing a common system frequency. Thus, in this section we have used the term "conventional generator" to identify the design with a common conventional synchronous generator, but have dropped the term "synchronous" to avoid connotations of synchronous operation with the system, since in fact these units do not operate in synchronism with the system frequency. In stead the back-to-back fully rated converter, converts whatever the output frequency of the generator is (which may vary over the operating range of the unit) to the system frequency on the system side. None-the-less, throughout this report, in this context both terms "conventional generator" and "synchronous generator" refer to the same generator design.

accommodate a large number of pole pairs (e.g. the Enercon E112, which is a 4.5 MW unit, has a generator with 84 poles).

2. Through the use of a frequency converter the full electrical output of the generator can be converted from a wide range of frequencies to grid frequency. This means that the wind turbine generator may operate at a wide range of speeds.

In addition, with the use of a voltage-source converter the grid side converter (or sometimes referred to as inverter) can independently control real and reactive power. In this way the electrical grid and the generator are decoupled. These features allow for greater flexibility and easier control for providing:

- 1) low-voltage ride through, and
- 2) voltage regulation and reactive power control at each turbine.

To achieve low-voltage ride-through the line side converter (or inverter) can stop gating the IGBTs if the voltage falls to excessively low levels and be essentially on stand-by to re-start once the fault clears. On the generator side, the converter (or rectifier) can be by-passed and the stator made to feed into a braking resistor to prevent excessive over speed. In addition, since the generator does not directly see the low network voltages during such an event there is no large transient rotor or stator currents produced in the machine. Voltage regulation is easily achieved with a voltage-source converter through controlling the relative phase and magnitude of the voltage phasor produced by the voltage-source converter as compared to the grid voltage phasor. This concept is no different than that already used in STATCOM and voltage-source HVDC systems.

The Enercon design discussed above is a gearless design. Other manufacturers (e.g. GE) are pursuing the full-converter design with a speed reduction gear between the turbine and generator.

Full-Converter Units Using Induction Generators

It is also possible to use the full-converter concept with a conventional squirrel-cage induction generator. In this case one might refer to such units as full-converter induction generator units. Siemens Power Generation presently manufactures this type of wind turbine generator. With these units the generator is a simpler design. However, the other difference between this design and the design mentioned above is in the frequency converter. This design requires a voltage-source converter both on the generator and grid side, since the machine requires reactive power to maintain the flux in the machine. However, with the full-converter design using conventional generators, typically the generator side converter is a line commutated rectifier – this is a simpler converter module. In summary, while one design has a cheaper generator design, the other has a cheaper generator side converter design.

These units can easily ride-through a grid disturbance. This is done by blocking (stop gating) the IGBTs on both the generator and grid side converter for severe faults. Over speed on the machine can be prevented by rapid pitch control [7, 8, 9] and a braking resistor can be used to discharge the dc link capacitor if necessary [8].

The Siemens design has a gear box between the turbine and generator.

3.2.7.2 The Vestas Opti-Slip® Design

Another variable speed design concept is one that is primarily produced by one manufacturer, Vestas. Vestas refers to this design as Opti-Slip®. In this design the generating unit again is a conventional induction generator with one modification; the rotor is fitted with a variable external resistance. This resistance is controlled using power electronics. By varying the rotor resistance the torque-speed curve of the unit can be modified and thus allow stable operation of the

conventional induction generator for a great range of speeds. At full-load, the unit can typically operate between 2% to 10% slip. This is quite a larger range than a standard convention induction generator, which typically sees a change in speed of only a fraction of a percent from no-load to full load. However, the speed range is still smaller than other variable speed designs such as the doubly-fed unit and the conventional generator (synchronous generator or PMG) with a full-converter. These latter units can have operating speed ranges from -30 to +30% slip. Typically, the turbine is operated between 2% to 5% slip. Then in the event of a short wind gust, the turbine can still increase its speed up to say 10% slip and thus absorb some of the additional energy in the form of stored energy in the shaft. In this way this design, much like other variable speed designs, can offer better power quality with lesser short term power fluctuations that may lead to flicker.

These variable rotor-resistance units are still essentially an induction generator with no field excitation. Thus, they absorb reactive power from the system and required additional shunt compensation in the form of switched capacitor banks and/or static var systems to compensate for the reactive power consumption at full-load. These units can also be supplied with low-voltage ride-through. Similar to conventional induction generators this is achieved through a combination of modified blade pitch control algorithms (that help to remove some of the mechanical power following fault inception) and applying uninterruptible power supplies (UPS) at the turbine to keep the controls running during the fault. In addition, smoothly controlled dynamic reactive power sources such as an SVC or STATCOM may sometimes be required to provide additional support upon fault clearing to ensure proper voltage recovery. In addition, the rotor current transient during severe voltage dips is often controlled to protect the power electronics in the rotor circuit by switching the rotor resistance to its maximum value. This has the added benefit of flattening out the machine's torque-speed curve and thus making it less likely to go unstable during a disturbance. However, capturing this phenomenon in a model can be challenging

3.2.7.3 Wind Turbine Generators Using Permanent Magnet Generators

Mitsubishi Heavy Industries, Ltd. (MHI) developed a 2000kW wind turbine (MWT-S2000) using a permanent magnet synchronous generator in 2003 [10]. The overview and specifications of this MWT-S2000 are shown in Figure 3-13 and Table 3-1.



Figure 3-13: MWT-S2000 turbine.

The shape of the wind turbine (Table 3-1 and Figure 3-14) was determined based on considerations of transportation and installation restrictions, and the strength of IEC Class I to withstand typhoons. In particular, due to severe traffic limitations in Japan (tunnels and

pedestrian bridges), the diameter of the synchronous generator was limited to 4.2 m or less. The turbine is a variable speed, gearless, permanent magnet wind turbine generator. The generator is essentially a conventional generator. MHI chose the gearless structure for better reliability by simplifying the structure in order to apply to offshore wind power generation in the future. The generator design can overcome fluctuations in generated power, which is the weak point in wind power generation.

Table 3-1: Specifications of MWT-S2000

Model	MWT-S2000
Rated output (kW)	2000
Generator type	Permanent magnet generator
Rotor diameter (m)	75
Tower height (m)	60
Rotating speed (rpm)	8 - 24
Rated wind speed (m/s)	13.0
Cut-in wind speed (m/s)	2.5

In gearless design, the rotating speed of the generator is lower, and there is a need to compensate by expanding the diameter and increasing the number of poles. European manufacturers solve these problems by employing large disk type generators, but in Japan transportation of such structures is impossible. By the following joint design efforts with Mitsubishi Electric Corporation, the large capacity generator has been successfully completed with a diameter of less than 4 m.

- Potent neodymium magnet (10 times more powerful than ferrite).
- Reinforced cooling by mechanical draft.
- Opposing configuration of rotor and generator (Figure 3-14).

The electrical frequency of the generator output is converted by a back-to back converter to the grid frequency.

The first unit of the MWT-S2000 was installed on the dike of the Gushikawa Power Station of Okinawa Electric Power Company on January 2003 (Figure 3-13). The trial run started in February, it was transferred to the client at the end of March, and commercial operation began in April.

In the trial run there was little output fluctuation. In performance evaluation, satisfactory results were obtained.

3.2.7.4 Truly Synchronous Units – Emerging Technology

Another concept is that of using a synchronous generator that is directly coupled with the electrical grid. This technology is not yet prevalent but is indeed promising. It requires the ability to have a variable gear ratio between the wind turbine rotor and the generator. In Appendix C a detailed presentation is provided of one such design.

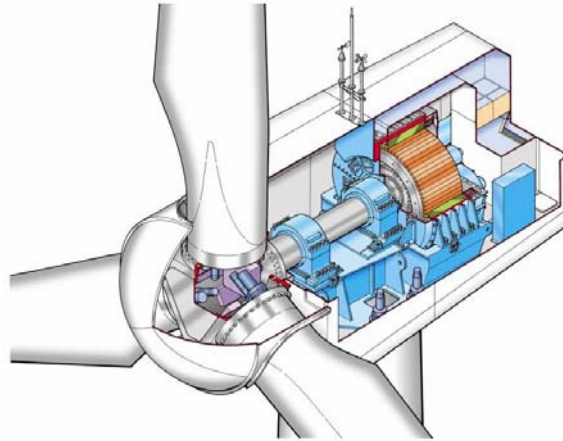


Figure 3-14: Cross-section of the MWT-S2000 turbine.

3.3 Summary

This chapter has presented a thorough, yet concise, discussion on the major types of wind turbine generators, the unique features of each design and a general discussion on their controls and dynamics. What is clear is that wind turbine generators are quite unique as compared to conventional generating plants. A wind farm is built up of many tens (to a hundred) wind turbine generators, as opposite to a single large generating unit in a conventional fossil-fuel, hydro or nuclear power plant. Furthermore, there are a variety of electrical generator designs and the way in which they are connected to the grid. Thus, from a modeling and simulation stand point it is necessary to develop at least four generic models (i) conventional induction generator, (ii) doubly-fed asynchronous generator, (iii) full-converter units and (iv) wound rotor induction generators with variable rotor resistance. Furthermore, some guidance is necessary on methodologies for aggregating units for the purposes of modeling wind farms in a power system model. These issues will be discussed in the following chapters.

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INTERCONNECTION AND OPERATIONAL ISSUES RELATED TO LARGE WIND FARMS

4.1 Introduction

The bulk of the installed capacity and experience with wind turbine generation has been primarily in Europe and the US. In addition, three European nations Denmark, Germany and Spain together account for almost 80% of the European installed capacity of wind generation. It is thus not surprising that Denmark, Germany and Spain have led the way in terms of setting standards for planning and interconnection of wind farms to utility grid systems. Ireland recently has followed this trend with putting out a number of comprehensive documents on wind interconnection standards, in 2004. In North America, the Alberta Electric Systems Operator (AESO) in Canada was the first region to adopt an explicit wind generation interconnection standard that was published in November, 2004 (www.aeso.ca). More recently other regions such as the British Columbia Transmission Corporation (www.bctc.com) and Hydro Quebec have also studied or adopted wind interconnection standards.

The American Wind Energy Associations (AWEA, www.awea.org) also recently made a proposal to the Federal Energy Regulatory Commission (FERC) to implement a national standard for wind generation interconnection. Based on this proposal from AWEA, FERC proposed a set of interconnection standards for wind generation in 2005 (www.ferc.gov). The North American Electric Reliability Council (NERC) also commissioned a wind generator task force to look at reliability issues specific to wind generation. The task force was started in February 2005. Recently, NERC, FERC and AWEA collaborated in amending FERC's original interconnection standard proposal – details may be found on the FERC website (www.ferc.gov). E.ON, the German utility to first come out with a now famous “E.ON” curve (see Figure 5-9, in Chapter 5), has also recently made some modifications to its standard¹.

The International Electrotechnical Committee (IEC) has published a number of standards for design and specification of wind turbines. These standards, however, are more aimed at the turbine manufacturers for specifying design standards and techniques for measuring and demonstrating performance criteria. The Institute of Electrical and Electronic Engineers (IEEE) recently published a standard (IEEE Std 1547) on the interconnection of distributed resource. This standard is for generating facilities with an aggregated total capacity of 10 MVA or less. Appendix G provides a discussion of this standard.

In this chapter we will discuss some of these issues related to wind generation integration, with the intent of clarifying the technical issues, how they have and continue to be resolved. The intent here is neither to challenge nor make recommendations related to interconnection standards, but rather to simply discuss these technical issues and how they relate to system dynamic performance. In latter chapters of this document recommendations are given on proper modeling approaches to ensure that the various aspects of modern wind turbine technologies are adequately represented for system studies.

¹ E.ON Grid Code – High and Extra High Voltages – Status 1. April 2006 (<http://www.eon-netz.com/Ressources/downloads/ENENARHS2006eng.pdf>)

4.2 Interconnection and Operational Issues from a Technology and Modeling Perspective

4.2.1 Voltage Ride Through

Once large wind farms started to be connected to the bulk transmission network, one of the issues identified in Europe and latter in the USA was the need for voltage ride-through (also referred to as low-voltage ride-through and fault ride-through). Since historically wind turbines had been connected to distribution systems, it was common practice to trip the turbine in the event of a significant system disturbance that lead to a large dip in voltage – this is because often distribution systems are fed by radial lines and leaving the wind farm connected after a disturbance may lead to islanded operation that can lead to unsafe overvoltage conditions.

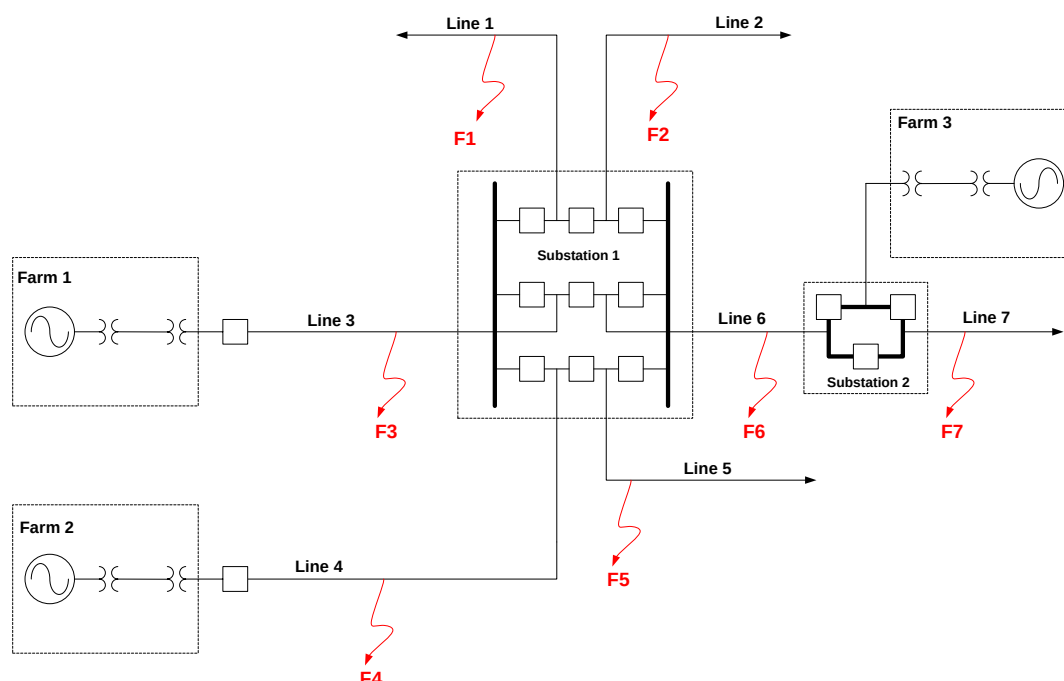


Figure 4-1: A hypothetical system with wind generation.

It is now widely accepted that for large wind farms connected to the bulk transmission system, it is expected that the wind turbines should be able to ride through a normally cleared single or multi-phase fault that occurs at the transmission voltage level (not within the wind farm collector system). To illustrate the point consider Figure 4-1, of a hypothetical system. In this case, if a fault were to occur at F3 or F4 it is clear that wind farms 1 or 2, respectively, would be essentially disconnected from the system and thus would not be expected to ride-through the disturbance – for these disturbances wind farm 3 should remain connected to the system. However, for all the other faults shown (F1, F2, F5, F6 and F7) it is quite reasonable to expect that all three wind farms ride-through the fault while line relays clear the particular faults. Otherwise, one might experience the loss of several hundred megawatts of generation together with the loss of the faulted line. This would further aggravate the problem and lead to potential stability concerns system wide. This is particularly true if a single disturbance should lead to a total loss of wind generation equal to or greater than the single largest generating facility on the system – most systems will carry enough spinning reserve to accommodate for the forced outage of the largest unit on the system.

The leading wind turbine manufacturers do presently offer voltage-ride through packages able to carry the wind turbine through a severe transmission disturbance – see section 3.2 (chapter 3) for more details.

Furthermore, it is often required that the wind turbine be able to withstand a momentary overvoltage transient during various switching events. This too can be accommodated by modern wind turbine voltage-ride through augmentations. It should be noted, however, that older generation wind turbine technologies that are already in-service cannot necessarily be retrofitted with voltage-ride through capability. To ensure voltage-ride through, it may be necessary to install more modern equipment.

4.2.2 Reactive Capability and Voltage Regulation

As with all other forms of large generation interconnected to the bulk transmission network, there is a need for real-time voltage regulation. There are really two time frames of concern:

1. voltage regulation and recovery for the few seconds following a major system disturbance, and
2. voltage regulation during normal system operating conditions (over the minutes to hours time frame)

For voltage regulation and recovery following a major grid disturbance there are two basic needs. Firstly, to ensure that the generating facilities remain on-line and secondly that they help in restoring system voltages. This can be achieved by all the various wind turbine technologies but exactly how it is achieved depends on the type of wind turbine technology. For machines with rotor excitation (e.g. doubly-fed asynchronous generators or conventional generators/permanent magnet machines with full-converters) the machine will have reactive capability (leading and lagging) – for full-converter units this is provided if the line-side converter is a voltage source inverter. Thus, if the unit is able to ride through a disturbance, and if the necessary control and protection modifications have been made to ensure fault ride-through then the individual machines will respond to produce the required reactive power to restore voltage once the fault has been cleared. There is one slight caveat to this in the case of some DFAG generators. As explained in chapter 3, during a severe close in fault the protections on some designs of DFAG converter controls will engage a crowbar circuit to short the rotor circuit. The crowbar is removed and the unit resumes DFAG operation once the fault has cleared and rotor transient currents subsided. As such, there may be a brief period following fault clearing where the crowbar has not yet disengaged. During this period the unit is running essentially as an induction generator (or motor depending on its initial operating conditions prior to the fault); thus it will be consuming some reactive power from the system during this brief period (between fault clearing and when the crowbar circuit disengages). Thus, depending on the power system short circuit strength in the vicinity of the wind farm, the size of the wind farm and the delay associated with disengaging the crowbar circuit after a disturbance there may be a need for some added dynamic VAr compensation – although in most cases such a need is unlikely (see section 6.2.1.2 for a more detailed discussion). This is not necessarily true of all DFAG designs.

With a conventional induction generator (which absorbs reactive power from the system in order to maintain its internal flux) a combination of switchable shunt capacitors (for steady-state power factor correction) and fast-acting dynamic shunt compensation (such as SVC or STATCOM technologies) can be used to result in a smooth and quick voltage recovery following a disturbance.

The second issue is that of voltage regulation over the longer term as wind power fluctuates and the system is required to adjust to maintain a well regulated voltage profile. There are a number of devices that act to regulate voltage:

1. Switched shunt capacitors (automatically and manually controlled)
2. On-load tap changing (OLTC) transformers
3. Any dynamic reactive capability available in the wind turbine generators or the wind farm (from the individual units or substation SVC/STATCOM etc.).

Once again with wind turbine technologies such as doubly-fed asynchronous generators or full-converter units (provided they have adequate reactive capability) closed loop control can be put into place to help regulate system voltage and thus compensate for voltage fluctuations that may otherwise occur with variable wind generation. This is available from manufacturers. Similarly, with the application of smoothly controlled dynamic var compensation (such as SVC or STATCOM) together with conventional induction generators a similar performance can be easily achieved (again this has been demonstrated in the field by manufacturers of conventional wind turbine generators). In both these cases, since the response time of an SVC/STATCOM or that of the converter controls on a doubly-fed machine or full-converter unit is quite fast, such controls can be easily coordinated with OLTCs and switched shunt capacitor banks, which typically act many seconds to tens of seconds after a deviation in system voltage. However, if the system were to solely rely on OLTCs and switched shunt capacitor banks, the regulation in system voltage may become coarse and may require continuous switching of capacitors and stepping of transformers leading to greater maintenance on these devices and more variability in system voltage (since switched capacitor banks and OLTCs can only effect discrete changes in voltage).

4.2.3 Controls Interaction

Torsional Interaction:

Under the banner of torsional interaction, there are two potential concerns that have been discussed in detail in the literature for conventional thermal turbine-generators. Subsynchronous resonance (SSR) and subsynchronous torsional interactions² (SSTI).

Subsynchronous resonance is a phenomenon whereby series compensation of a transmission lines leads to electrical resonance frequencies in the subsynchronous frequency range that can thus lead to destabilizing modes of mechanical torsional vibration on the turbine-generator shaft that fall in the frequency range of the electrical resonance (for more detail on the phenomena of SSR the reader should refer to the many texts and papers on this subject such as [1, 2]). Such resonance is less likely to affect wind turbines since the typical torsional mode for a wind turbine is quite low (around 1 to 4 Hz). As such, it would be quite unlikely that the level of series compensation in a system would be high enough to result in an electrical resonance that would interact with such a mechanical frequency (Note: that the electrical resonance needs to be in the range of $f_o - 1$ to $f_o - 4$ Hz, where f_o is the system nominal electrical frequency.). The bigger concern is that of self-excitation, see section 4.2.7 below. Thus, some analysis and discussions with the wind turbine manufacturer on a case by case basis is prudent when installing wind farms near series compensated lines.

The phenomenon of SSTI was first observed for the Square Butte HVDC project in 1976 [3]. Subsynchronous torsional interactions (SSTI) is the phenomenon by which controls associated with transmission equipment, such as SVC [4] or HVDC [3], may introduce negative damping torques in the frequency range associated with the torsional mechanical modes of oscillation of nearby thermal turbine-generating units. Again, due to the relatively low frequency range for torsional modes of wind turbine, this may not be a concern in most cases, however, where wind farms are closely couple to a HVDC system some analysis to ensure that controls and/or torsional interaction do not occur is prudent. Such analysis will typically require detailed three-phase models for both the wind farm and the HVDC system. A good recent publication on the subject of torsional issues related to wind turbine generators is [5].

² SSTI is sometimes more generally referred to as device dependant subsynchronous oscillations.

Control Instability:

The second possible interaction phenomenon is simply the potential for interactions between the wind turbine controls and controls of other nearby transmission or generation equipment. For example, the DFAG based designs often incorporate a farm wide central control system to regulate voltage at the substation. This is essentially a centralized controller that regulates the voltage at the substation connecting the farm to the grid. The high side (or low side) voltage on the substation transformer together with a current compensation signal are fed into a proportional-integral (PI) regulator, which compares the measured voltage (plus current compensation) to a reference signal. The error is fed in to the PI regulator. The regulators output is fed to the power factor reference input of all wind turbines in the farm. Thus, effectively this centralized controller adjusts the power factor of all the wind turbines in the farm on a continuous basis in order to regulate (within the capability of the farm) the bus voltage at the interconnection point. If there are any other regulating devices nearby (e.g. power plant, SVC, HVDC etc.) that are attempting to regulate the same point, steps need to be taken to ensure the two control systems do not hunt or interact with each other. Often it suffices simply to provide an appropriate level of droop into the regulator through the use of the current compensation setting.

Transient Torque Issues:

The third potential for adverse interactions is system phenomena that may expose the shaft of a wind turbine to cyclical and significant transient torque pulsations. For example, nearby arc furnaces, or high-speed re-closing on a transmission line emanating from the wind farm substation, or repeated commutation failures on a HVDC link connecting the wind farm to the ac system.

If there are nearby equipment that can expose the wind turbine to such repeated transient torques, as a first step, some simple transient stability analysis may be performed to estimate the expected step change in the electrical torque on a wind turbine generator due to the electrical event. Then the wind turbine generator manufacturer must be consulted to identify if the observed level of transient torque is a concern, if the wind turbine were exposed to such a recurring transient torque. Based on consultation with the wind turbine manufacturer, more detailed analysis may be required to assess if a potential problem exists and how it may be remedied.

4.2.4 Harmonics

In general there are two ways in which harmonics can be generated by wind turbine generators:

- (1) due to saturation in electrical machines
- (2) due to harmonic injection by power electronic equipment

The first item is no different than that of any other electrical generator. The manufacturer of the electrical machine must build their units to comply with the industry standards (IEEE/ANSI in North America and IEC in Europe and other regions of the world).

The second cause may come from one of two sources. Harmonic injection by soft-start thyristor based converters typically used in conventional induction generator designs. The requirement here is that the wind turbine manufacturer should ensure that their design conforms to the applicable standards. The second is by variable speed designs that use frequency converters, such as the doubly-fed asynchronous generators or the full-converter designs. Once again, the requirement would be to ensure that the manufacturers design complies with the applicable standards. Typically, with the variable speed designs the frequency converters are voltage-source converter technologies. This means that the designs are typically based on pulse width modulation (PWM). These converters will mainly generate high order harmonics (several kHz) – see also discussion on harmonics in chapter 5.

In designing the collector system for the wind farm, there may be a concern when interconnecting to a weak node in the system. The concern is that with the charging capacitance on underground cables (typically used in wind farm collector systems) and/or fixed or switched capacitor banks on the collector system, harmonic resonance may occur and thus give rise to significant voltage distortion. In addition, there may be a potential for voltage magnification on the shunt capacitor banks near the wind turbine generators (e.g. at 600 V) when switching higher voltage capacitors on the collector system or at the substation level. The harmonic resonance issue can be resolved by judicious design and/or application of filters. If voltage magnification is deemed possible, solutions might be to minimize the switching surge due to the high voltage capacitor banks by applying synchronously switched breakers. Alternatively, surge arresters may be applied at the lower voltage capacitor banks to protect them. Thus, during the design of the wind farm electrical system these and other equipment application issues should be reviewed to ensure proper design and integrity of the entire wind farm electrical system.

4.2.5 Power Quality

The main power quality issue related to wind turbine generators is that of voltage flicker. In the USA and Canada, the IEEE Standards are adopted. The main documents that deal with this issue are IEEE Standard 519-1992 and IEEE Standard 141-1995.

The IEC Standard 1000-3-7 is a more comprehensive standard on flicker limits, and is used in Europe. IEC Standard 61400-21 describes methods for actually measuring flicker performance for wind turbines.

4.2.6 Short Circuit Impact

The short circuit impact of wind generation depends on the type of generator. For example, full converter designs (i.e. designs where a conventional generator connected to the wind turbine is connected to the grid through a back-to-back frequency converter, see Figure 3-4) will not significantly contribute to system fault current. On the other hand, all other designs such as conventional induction generators and doubly-fed asynchronous generators may be treated in the same way as other rotating machines. That is, the short circuit current may be calculated based on the unit's subtransient and transient impedances. Due consideration must be given to the fact that conventional induction generators have no excitation system, and thus their contributions to short-circuit levels may decay rapidly (although larger units will exhibit in general slower decays) and thus depending on the protection clearing time their short circuit contribution at the time of fault clearing may be quite small. For doubly-fed asynchronous generators, depending on design, the manufacturer should be consulted on their fault contribution – e.g. if the active crowbar circuit on the rotor engages during a close in transmission fault then the effective reactance of the machine changes during the fault and this needs to be taken into consideration when calculating fault current contribution.

In general, for conservative results, the short circuit calculations may be dealt with in a similar way as with other rotating machinery, taking care not to include wind turbine generators with full converter designs. Full converter designs essentially control the current output of the line side converter (inverter) and thus even during a fault the current output from the inverter is not significantly higher than its rated current output (though some designs may have higher short-term current ratings to allow for reactive boosting). To calculate the fault current at the point of interconnection, both the generator step-up transformer and substation transformer winding configurations need to be taken into consideration (i.e. Y – delta transition).

4.2.7 Self-Excitation

Self-excitation is a pure electrical resonance that occurs between the inductance of an induction machine and a series capacitance [6]. Such self-excitation may be caused by two sources:

1. The application of series capacitors on a radial transmission line(s) feeding a wind farm with induction generators (note: even doubly-fed asynchronous generators are susceptible).
2. Islanding that leads to a substantial amount of induction generator wind generation remaining in the island feeding primarily capacitive load (such as shunt capacitors used for power factor correction and voltage support).

In the case of series compensation, the potential for self-excitation exists for induction generators [5]. For doubly-fed asynchronous generators, since they are variable speed machines, a potential for self-excitation may also exist when the generator is operating at a significant slip frequency. Such analysis needs to be performed using system and machine models that capture the frequency dependence of network parameters that is programs that represent network elements with differential equations rather than a constant impedance matrix. Note: electrical resonance phenomena such as self-excitation and SSR are unlikely to be a concern with full-converter units since they are electrically decouple from the network by the back-to-back frequency converter.

4.2.8 Inertial Response and Primary Frequency Control

Another concern related to large proliferation of wind generation, particularly in islanded systems where the installed capacity of wind generation may be a very large portion of the total generation (e.g. 25% or more), is that of inertial response and primary frequency control. Following a major disturbance that results in a large load/generation imbalance in a system (e.g. losing a major inter-tie that import/exports power, loss of a large generating plant or loss of a large portion of load) the system frequency will start to vary. The initial rate of decline (rise) of the system frequency as a result of a large generation (load) loss will be determined by the combined inertia of the remaining generating facilities in the system. For conventional fossil fuel, hydro and nuclear generating facilities this inertial response is typically in the range of 1.2 MWs/MVA (for small aero-derivative turbines) to as much as 7 MWs/MVA (for large heavy-duty gas turbines). This is a well-known physical phenomenon for synchronous generators.

For conventional synchronous generator plants the balance between electrical and mechanical power is kept by the primary turbine governor. If a disturbance, such as the loss of a large generating source occurs (or the loss of an importing line resulting in islanding a system) then the system frequency will start to decline. The initial rate of decline is determined by the megawatt imbalance and the total system inertia. Whereas conventional synchronous generators inherently add inertia to the system, this is not necessarily true of all wind turbine generators. Conventional, direct connected induction generator based wind turbine generators will add some inertia to the system, however, doubly-fed and full-converter units do not unless specifically designed to do so [7]. This can be readily understood by considering the physics of the phenomenon. For conventional synchronous generators, when a sudden loss of generation occurs then electrically this is replaced by a sudden draw of additional electrical power for the remaining units on-line. This is essentially an immediate electrical response. Since there is no subsequent immediate change in mechanical power, this results in a draw of power out of the stored energy in the rotating turbine-generator shafts – hence the decline in frequency. Clearly, the initial rate of change of frequency is then determined by the total power imbalance and the effective (collective) inertia of the system. Then in the impending seconds following the disturbance, those units with regulating capability will start to increase their mechanical power (as their primary turbine-governors respond) and the system frequency decline is arrested and settles down at a final value based on the effective system droop.

In the case of wind turbine generators the response is different. For direct connected conventional induction generators there is some inertial response. However, for doubly-fed asynchronous units and full-converter units, unless specifically designed to do so, there is no

inertial response. This is a consequence of the control action of the power electronics. For these units the converters are designed to regulate the power output of the unit tightly and extremely quickly. Thus, the electrical output of the unit is kept constant throughout such disturbances and there is no effective inertial response. There are proposed techniques, however, for augmenting the converter controls to emulate inertial response [7]. It remains to be seen how these can be effectively implemented in the field.

Similarly, wind turbine generators do not contribute to primary frequency control. One example of where such functionality has been demonstrated on a wind farm is the Horns Rev off-shore wind farm in Denmark (see section 2.2.2.1). In this wind farm, the manufacturer (Vestas) demonstrated various control features one of which is a reserve capability. That is, it is possible to operate the wind farm to maintain, for example, a 5% reserve margin that may be called upon during a frequency decline. That is, the wind farm maintains a 5% margin between the power it generates and the actual power available in the present wind conditions. This of course means that the amount of megawatt reserve varies with the wind profile and is not constant. One could then ask that the margin kept be a megawatt margin. In either case there are clear commercial consequences as well since the amount of power kept in reserve is not utilized. This tends to suggest that in large interconnected systems it may make more economic sense to maintain reserves on more conventional and traditionally responsive units such as hydro and thermal plants. Nevertheless, in small and islanded systems where wind is likely to be a major portion of the generation mix these issues of inertial response and primary frequency control require careful consideration and further development of the suited control strategies.

4.3 Voltage Stability Considerations

Fixed speed wind turbines are basically conventional induction generators. Conventional induction generators consume reactive power and similar to induction motors are prone to instability at low voltage due to insufficient pull-out torque, as explained in section 3.2.4. This type of unstable behavior is driven by induction machine loss of equilibrium and is known as short-term voltage instability [8].

When constant speed wind turbines are used, the problem of short-term voltage instability is one of the usual barriers limiting wind power integration. This type of voltage instability is not likely to happen unless the voltage support provided by local synchronous generators is lost or reduced. The latter is usually the result of rotor current limitation brought about by the Overexcitation Limiter (OEL) of the local synchronous machines [9].

Since variable speed wind turbines (doubly-fed and full-converter units) are able to regulate their reactive power generation, they have a beneficial effect in terms of short-term voltage stability, similarly to static compensators (STATCOM) and static var compensators (SVC). The following example illustrates this reasoning.

Figure 4-2 depicts the one-line diagram corresponding roughly to the South Evia region in Greece. The system consists of two local conventional plants (140 MW each), 19 wind farms with 200 MW total rated capacity equipped with fixed speed wind turbines and two local loads. Two equivalent parallel 150 kV transmission lines connect the local network to the mainland. All 6 substations are equipped with on-Load Tap Changer (OLTC).

The stability of the system is checked for the following double contingency:

- loss of one of the synchronous generators (G1) ($t=10$ s)
- one of the two interconnection lines trips (at $t=50$ s after the OLTCs have regulated the MV side of the transformers),

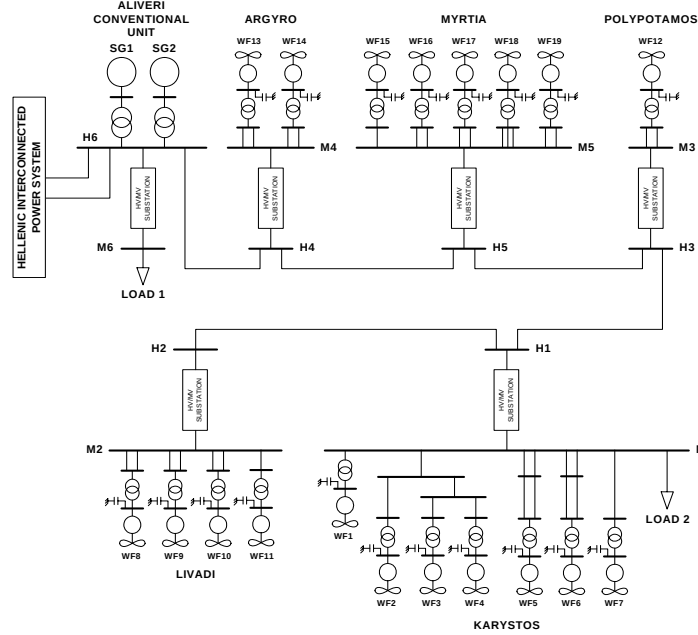


Figure 4-2: One-line approximate diagram of South Evia power system.

The dynamic response of the system was simulated in three cases:

- All wind farms are equipped with conventional induction generators
- One wind farm (WF8) is equipped with DFAG with voltage control
- One wind farm (WF8) is equipped with DFAG with power factor control

The wind speed is assumed to be constant during the simulation. In order to investigate short-term voltage instability, the instantaneous rotor current limit of the synchronous generators was taken low enough for the system to be unstable in case (a). This is done as an academic exercise and does not reflect the degree of security of the actual power system.

The voltage instability is clear from the voltage response of Figure 4-3a (solid line, curve corresponding to case (a)). It can be seen that the replacement of just one wind farm (of 15 MW rating) with variable speed wind turbines renders the system stable. The same result could be achieved by adding a Static Var Compensator (SVC), or a STATCOM.

A similar case study, but with full converter units is presented in [10]. The system studied (see Figure 4-4) consists of a local conventional power plant with a synchronous generator rated at 140 MW and two large wind parks of 100 MW (WP1) and 50 MW (WP2) nominal capacity. Consider the operational point at which the wind parks and the local conventional generator produce their nominal power. The system exports active power and imports reactive power from the interconnection. In the simulated contingency, one of the two interconnection lines is tripped 5 s after the beginning of the simulation.

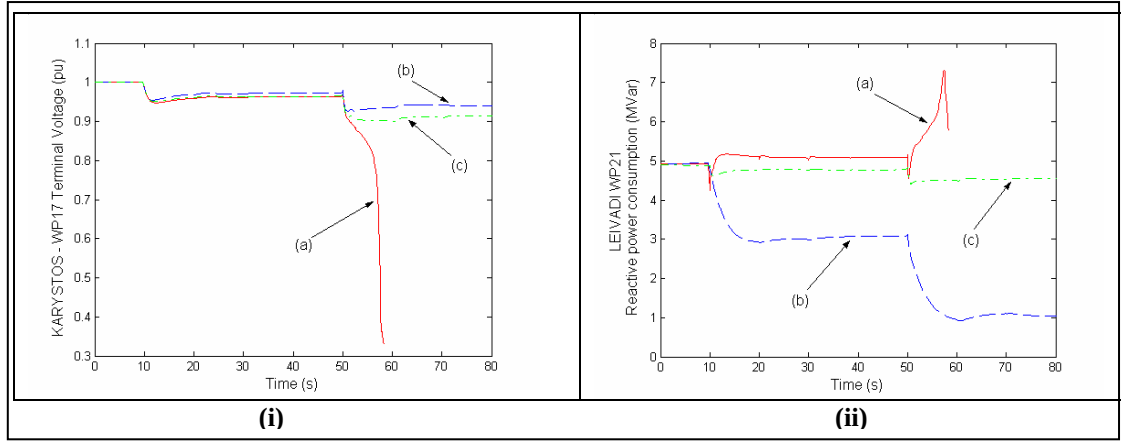


Figure 4-3: (i) Terminal voltage at WP17, and (ii) reactive power consumption of WP21. Case (a) all wind parks are equipped with conventional induction generators, (b) one wind park (WF8) is equipped with DFAG with voltage control, and (c) one wind park (WF8) is equipped with DFAG with power factor control

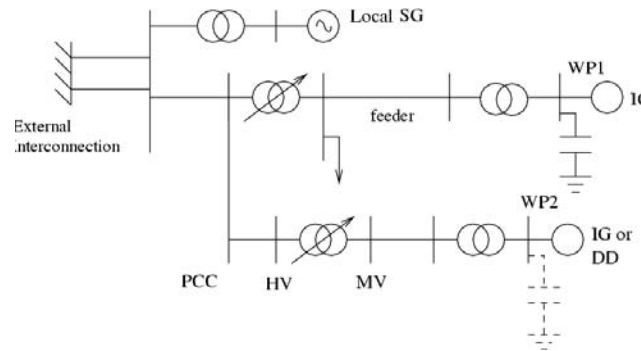


Figure 4-4: Small interconnected network.

In all cases it is considered that WP1 is an older installation consisting of constant speed induction generators. The system response to the disturbance is simulated under three different configurations for WP2:

- WP2 is also equipped with constant-speed induction generators.
- WP2 is equipped with direct drive conventional generators with the inverter regulating the network power factor at unity.
- WP2 is equipped with direct drive conventional generators with the inverter regulating the network terminal voltage (a proportional voltage controller is assumed).

Again, case (a) is unstable, as seen in Figure 4-5a, due to local synchronous generator excitation current limitation. Simulating the same contingency in cases (b) and (c) shows that, if direct drive conventional generators are used in WP2, they need to exercise voltage control in order for the system to be stable as shown in Figure 4-5b.

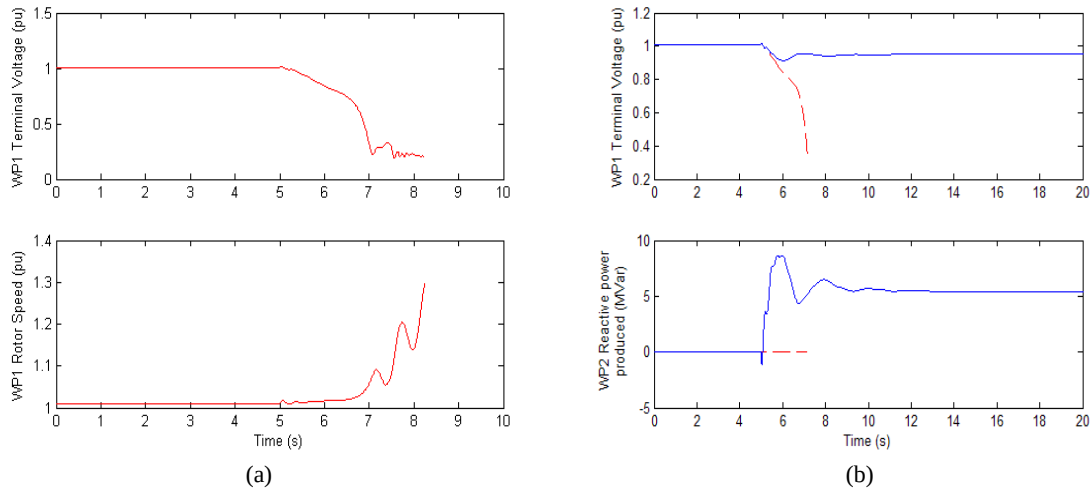


Figure 4-5: (a) Voltage collapse and induction generator overspeed (b) WP1 terminal voltage and WP2 reactive power production for constant power factor control mode (dashed red line) and network voltage control mode (solid blue line).

This small example illustrates that wind penetration can be drastically increased in voltage stability constrained networks, provided that adequate provisions are made for voltage control and reactive power support.

4.4 Summary

In this chapter a presentation has been provided of the key dynamic performance issues related to wind turbine generation integration into a transmission system. These issues are pertinent for large wind farms (tens to hundreds of megawatts) that are connected to the extra high voltage transmission grid. Of the many technical issues related to dynamic performance, the three main issues are:

- **Fault-Ride Through** – For present designs this is now addressed by all the major wind turbine manufacturers.
- **Reactive Capability and Voltage Regulation** – Depending on the type of wind turbine generator, this concern can be addressed either through the wind turbine generators themselves (e.g. doubly-fed, full-converter, etc. units) or through the combination of the capability of the turbine-generators and additional controlled shunt compensation (e.g. SVC, STATCOM, synchronous condensers etc.).
- **Frequency Control and Inertia** – This is perhaps the most challenging technical issue at present. Though some demonstration farms have been commissioned that allow primary frequency regulation (by keeping a delta between actual megawatts generated as compared to available megawatts based on available wind), there are still technical and commercial issues to be resolved. Also, for small systems the effective inertial response of the system can be significantly degraded by the addition of large amounts of wind generation. Both these issues, particularly for small and islanded systems, require further development of control strategies for adequate response and carefully study on a case by case basis.

As discussed, most of these issues have or are being addressed with the application of new technologies such as control modifications (sometimes combined with the need for smoothly controlled dynamic reactive sources such as SVC, STATCOM or synchronous condensers) for providing fault-ride through and supplemental controls and equipment for providing reactive support and voltage regulation. In this chapter, the details of interconnection requirements and policies have deliberately not been discussed as such issues are beyond the scope of this document.

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INTERCONNECTION AND OPERATIONAL ISSUES RELATED TO SMALL/DISTRIBUTED GENERATION APPLICATION OF WIND FARMS

5.1 Introduction

The penetration of Distributed Generation (DG) resources (wind turbines, photovoltaics, fuel-cells, biomass, micro-turbines, small hydroelectric plants etc., ranging from sub-kW to multi-MW sizes) in distribution grids is increasing world-wide. The drive for cleaner energy sources, the economic opportunities presented for investors in the deregulated electric industry environment and the potential benefits for utilities (peak-shaving, congestion alleviation, reduction of losses, better asset utilization etc.) are contributing to this trend [1].

Although there always exists important regulatory and business issues concerning the integration of DG in the grids, technical considerations are often viewed as a critical factor affecting the development of new installations [2]. To facilitate the technical evaluation process for the interconnection of new DG installations, without compromising the operating and safety requirements of the grid, suitable disturbance limits have been adopted and simplified evaluation methodologies are applied by utilities (e.g. [3-9]). It is also important that the interconnection requirements (power quality considerations, fault ride-through capability, anti-islanding detection etc.) not only influence the economic viability of a particular DG investment, but also act as a driving force for the design of components with improved operating characteristics. A typical example is the uniform adoption of PWM voltage-source converters at the grid side of all modern DG sources and the implementation of sophisticated anti-islanding schemes in small DG sources connected to the LV network (e.g. [10, 11]).

In this chapter fundamental considerations are first discussed, regarding the grid-interconnection schemes used in practice. Then a framework of technical criteria and requirements is presented, which permits the efficient evaluation of new DG installations. The focus here is on medium voltage (MV) connected DG/wind turbines. From a modeling perspective, for dynamic simulations, the same models as presented in chapter 6 of this document may be used. Thus, in this chapter the focus is on dynamic performance issues that are of particular relevance in DG applications of wind farms. That is, slow and fast voltage variations, flicker, power quality and harmonic emissions. Other important considerations, such as interconnection protection requirements, are briefly discussed, whereas the critical issue of the fault level contribution of DG ([12]) is not dealt with here. The interconnection criteria and guidelines presented are based on the extensive set of IEC power quality standards (part of the IEC 61000 series of EMC publications). They reflect the evaluation practices adopted in [9], which are similar in concept to the practices of several other European utilities.

5.2 Interconnection Schemes

DG installations are connected to the distribution grid using arrangements not essentially different from those used for consumers, as shown in Figure 5-1. Most important is the differentiation between the actual connection point (CP) and the Point of Common Coupling (PCC). The latter is defined as the closest node to the DG, where other users are (or may be) connected and it may differ from the physical point of connection, when the installation is interconnected via a dedicated (“direct or radial”) line segment, as shown in Figure 5-1.

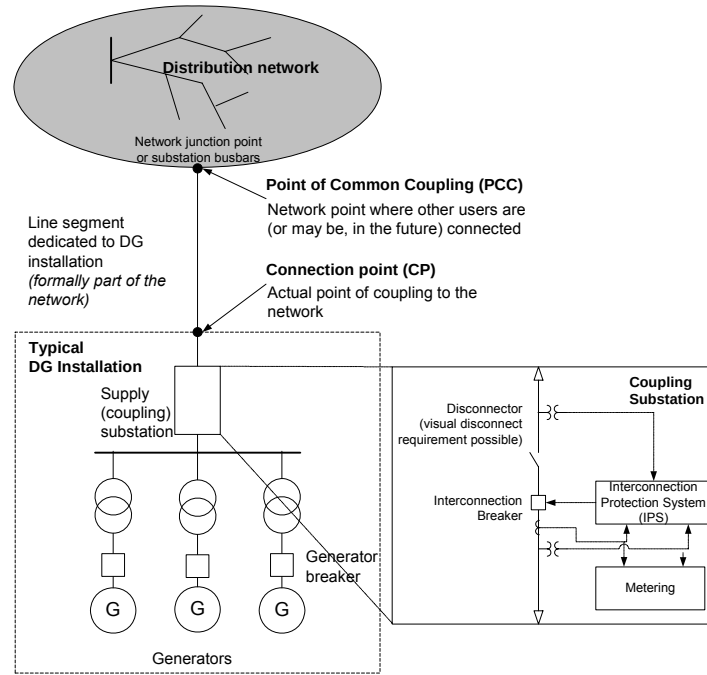


Figure 5-1: Connection Point (CP) and Point of Common Coupling (PCC).

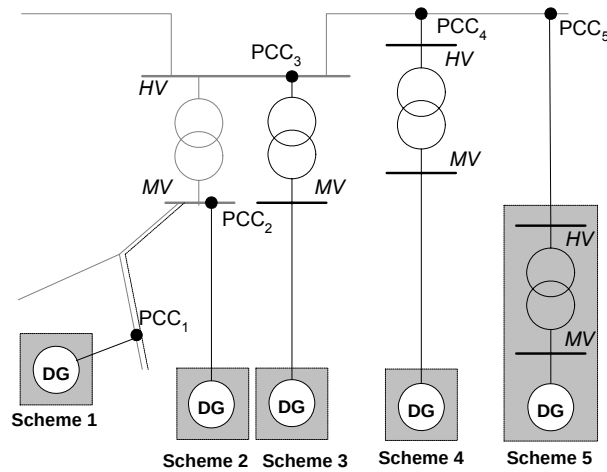


Figure 5-2: Alternative interconnection schemes for a DG installation (MV and HV network) and associated PCCs. Grey/black line for existing/new parts of the network.

The most common schemes for the interconnection to the MV and high voltage (HV) grid are illustrated in Figure 5-2. The numbering of these five schemes corresponds to increasing DG capacity, fault-level at the PCC and cost and time of construction for the interconnection works. For smaller installations, which may be connected to the LV network (e.g. <100 kW), cases 1, 2 and 5 of Figure 5-2 are the basic alternatives (HV/MV substations being replaced by MV/LV ones).

In Scheme 1 the DG station is connected to an existing distribution feeder, via an extension to the existing line. In this case reconductoring (e.g. conductor upgrade) to increase the thermal rating of the line may be necessary (dashed black line in Figure 5-2). In Scheme 2, a dedicated ('direct') line connects the DG station directly to the MV busbar (where the PCC is now located). When this is not possible or acceptable, an upgrade of the existing substation by adding an additional substation transformer may be required (Scheme 3). If this is not possible, a new HV/MV substation has to be built, either under/near an existing HV line, whereupon the DG station is connected at the MV level (Scheme 4), or within the premises of

the DG installation (Scheme 5). In the latter case, an extension of the HV line is needed (often a radial single-circuit line, to keep costs down) and the station becomes a user of the HV network, unlike all the other schemes, where the station is a MV network user. Large stations, of the order of tens of MW and above, are connected directly to the HV grid.

Selecting the appropriate interconnection scheme is often a complicated economic and technical decision, which takes into account:

- The existing network infrastructure
- The cost of grid reinforcement and extension works
- The cost of power and energy losses on the interconnecting network
- Possible implications in the construction of major grid works (e.g. environmental permits for new HV lines)
- Technical criteria and requirements, related to power quality, fault level, protection etc., which are presented in more detail in the following sections.

5.3 Overview of Technical Requirements

The interconnection of DG sources to the grid is often regarded as a potential source of power quality disturbances and appropriate requirements and evaluation methodologies are applied. In general, they comprise two distinct stages. First, the expected disturbance is calculated at the Point of Common Coupling (PCC)¹ because of a specific DG installation. Then, suitable limits are applied to ensure that the expected disturbance level does not adversely affect other users of the network. Following the IEC 61000 definitions [13], *planning levels* are generally used as disturbance limits. Power quality phenomena taken into consideration are slow (steady-state) voltage variations, fast voltage changes, flicker and harmonic emissions.

Beyond the power quality issues, additional considerations and requirements include the following:

- Network capacity: Ratings of all network components must be sufficient to handle the power of the DG station.
- Short circuit capacity: DG source contribution should not lead to exceeding the design fault level of the network. This issue is dealt with in more detail in [12].
- Switching and protection equipment: All DG installations are equipped with suitable interconnection protection, to enforce disconnection upon detection of abnormal grid conditions.
- Effect on network signaling systems: User equipment should not interfere with the operation of public network signaling systems (e.g. attenuate or amplify signals of the acoustic frequency ripple control systems).

5.3.1 Slow Voltage Variations

The statistical nature of voltage variations is recognized today and relevant norms have been issued, such as the European Norm EN 50160, [14], which imposes statistical limits, in the sense that a small probability of exceeding them is acceptable. However, checking the conformity against statistical limits at the planning stage calls for elaborate procedures, such as probabilistic load flow techniques (e.g. [15, 16]). Such an approach is relatively difficult to apply, would require data usually unavailable in practice and completely defies the objective of simplicity and efficiency in the evaluation. For this reason, utility directives for the connection of DG adopt simpler and more straightforward procedures. The evaluation

¹ Dedicated interconnection lines are formally a part of the grid. For this reason, disturbance limits may also be enforced for the point of connection (CP) as well, albeit more lenient than for the PCC.

procedure presented in the following utilizes 10-min average values of the voltage and can be applied in two stages.

At a first stage, the maximum steady-state voltage change $\varepsilon(\%)$ at the PCC is evaluated using the following simplified relation and compared to a limit:

$$\varepsilon(\%) \cong \frac{100}{U_n^2} (R_k P_n + X_k Q_n) \leq 2\% \quad (1)$$

where P_n and Q_n are the DG rated (or maximum continuous) active and reactive powers, and $Z_k = R_k + jX_k$ the network short-circuit impedance at the PCC.

The 2% limit in equation (1) is typical (e.g. [8, 9]) and relatively strict, since this is a “first stage” evaluation and, further, this limit is allocated to a single user, whereas the voltage level is determined by the aggregate effect of all connected consumers and generators.

In practical situations, equation (1) will yield a voltage increase, due to the active power flow on the resistive part of the network impedance, which may be significant in case of weak grids. For this reason, slightly inductive power factor values are usually preferred ($Q < 0$).

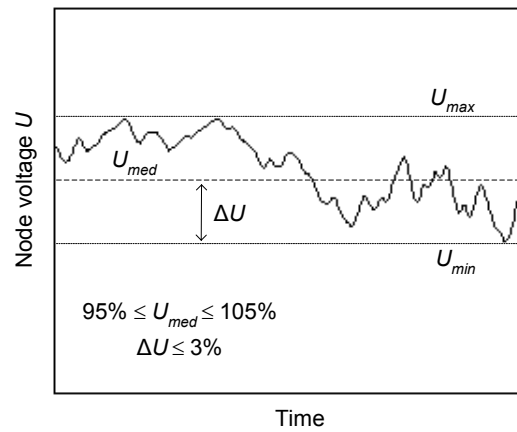


Figure 5-3: In the top part of the diagram, the concept of maximum/minimum and median node voltage in steady state is diagrammatically shown. In the bottom half of the diagram, the acceptable region of maximum and minimum node voltage is defined.

Since voltage variations are the aggregate effect of generating facilities and network loads, a second stage, more detailed evaluation involves load flow calculations in the network, taking into account the actual network configuration and loads. By solving the load flow for the 4 combinations of max/min load/generation, the maximum and minimum voltages, U_{max} and U_{min} , are determined for each node (usually, min load/max generation yields maximum voltages and max load/min generation minimum voltages). These voltages must then be appropriately bounded. In [9] the following requirements are set for the steady state voltage of all nodes (Figure 5-3, top part of the diagram):

- The median voltage of any node k should lie within $\pm 5\%$ of the nominal voltage, a requirement dictated by the off-load tap changer of the MV/LV distribution transformers ($\pm 5\%$ regulation, in steps of 2.5%):

$$0.95 \cdot U_n \leq \frac{U_{min,k} + U_{max,k}}{2} \leq 1.05 \cdot U_n \quad (2)$$

- The variation of the voltage around its median value should not exceed $\pm 3\%$ of the nominal, so that the LV network voltage deviations remain within $\pm 8\%$ (planning limit), after the median deviation is corrected by the fixed taps:

$$\frac{U_{\max,k} - U_{\min,k}}{2} \leq 0.03 \cdot U_n \quad (3)$$

The requirements expressed by equations (2) and (3) determine the region of acceptable maximum and minimum node voltages illustrated in Figure 5-3 (bottom part of the diagram), against which the load flow results are compared.

In the four load-flow calculations proper account must be taken of the voltage regulating means of the network (on-load tap-changers of HV/MV transformers, line voltage regulators, capacitor banks), which normally operate on time scales of 30 s-1 min or longer and therefore affect the steady-state (10-min average) values. Further, when dealing with sources with adjustable power factor (synchronous generators, PWM converters), this has to be accounted for in the load flow calculations.

5.3.2 Rapid voltage changes – Flicker

Rapid voltage changes occur within the 10-min averaging interval used in the definition of *slow voltage variations*, typically on a time scale between half a period (10 ms at 50 Hz) and a few seconds. They are induced either by switching operations in the DG installation (usually start/stop operations of equipment) or by the variability of the output power during normal operation (e.g for wind turbines).

In the case of rapid voltage changes, both their magnitude and the resulting flicker emissions should be limited. Measures of the flicker emissions are the short-term, P_{st} , and long-term, P_{lt} , flicker severity indices ([17-19]).

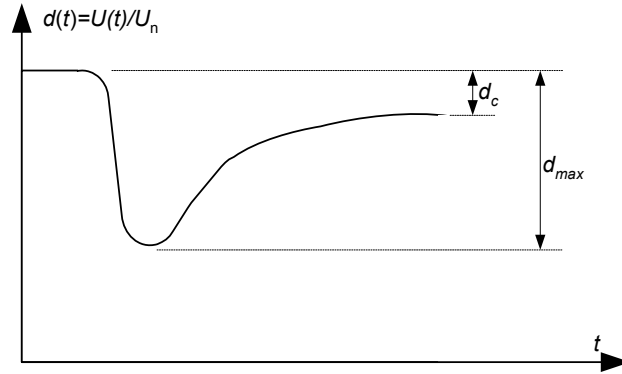


Figure 5-4: Fast voltage change pattern and characteristics.

Regarding switching operations, the limits imposed depend on the voltage level (LV or MV) where the installation is connected, the size of the equipment and the frequency of the operations. Taking into account the requirements of the relevant IEC documents, [20-23], the limits of Table 5-1 can be set for the relative (%) voltage change (see also Figure 5-4).

An evaluation of the expected voltage change at the PCC at the cut-in of a DG unit is given by:

$$d_{\max} (\%) = 100 \cdot k_U (\psi_k) \frac{S_n}{S_k} \quad (4)$$

Table 5-1: Magnitude limits for rapid voltage changes

		Frequency of switching operations, r (h^{-1} : per hour, d^{-1} : per day)		
LV		$r > 1 \text{ h}^{-1}$	$2 \text{ d}^{-1} < r < 1 \text{ h}^{-1}$	$r < 2 \text{ d}^{-1}$
	Steady-state change, d_c	$\leq 3 \%$		
	Maximum change, d_{max}	$\leq 4 \%$	$\leq 5.5 \%$	$\leq 7 \%$
MV		$r > 10 \text{ h}^{-1}$	$1 \text{ h}^{-1} < r \leq 10 \text{ h}^{-1}$	$r \leq 1 \text{ h}^{-1}$
	Steady-state change, d_c	-		
	Maximum change, d_{max}	$\leq 2 \%$	$\leq 3 \%$	$\leq 4 \%$

where $k_U(\psi_k)$ is the voltage change factor, defined for wind turbines in IEC 61400-21, [24], and included in their test certificates as a function of the angle ψ_k of the short-circuit impedance Z_k of the grid. Suitable values of k_U for installations with synchronous generators are discussed in [25]. For simplified calculations, k_U can be set equal to the ratio of the equipment starting current to its rated current, ranging from less than 1 to higher than 8, depending on the type of equipment and the starting method used.

Equation (4) is applied for the single unit in the power station, which creates the largest disturbance. Summation rules for simultaneous switching of equipment need not be applied, due to the very low probability of coincident events.

For the case of wind turbines, flicker emissions resulting from switching operations can be calculated as ([24, 27]):

$$P_{st} = \frac{18}{S_k} \left(\sum_{i=1}^N N_{10,i} (k_{f,i}(\psi_k) \cdot S_{n,i})^{3.2} \right)^{1/3.2} \quad (5)$$

$$P_{lt} = \frac{8}{S_k} \left(\sum_{i=1}^N N_{120,i} (k_{f,i}(\psi_k) \cdot S_{n,i})^{3.2} \right)^{1/3.2} \quad (6)$$

where N is the number of generators operating in parallel, $S_{n,i}$ the rated capacity and $k_{f,i}(\psi_k)$ the flicker step factor of unit i (defined in [24]). $N_{10,i}$ and $N_{120,i}$ are the maximum number of switching operations that can take place in a 10-min and a 120-min interval for unit i . If the flicker factor is unavailable, the flicker has to be evaluated either by the shape characteristics and the frequency of the disturbance (IEC 61000-3-3, [20], provides useful guidance), or by simulation using a software implementation of the flickermeter algorithm of IEC 61000-4-15, [19].

The following rule is commonly applied for the summation of flicker due to switching operations (used for P_{lt} as well):

$$P_{st} = \sqrt[3]{\sum_i P_{st,i}^3} \quad (7)$$

where the exponent may also be 3.2, instead of 3.0, as in equations (5) and (6).

During normal operation, voltage changes resulting from fluctuations of the DG output power may create flicker problems, a well-known fact for wind turbine generators, [26-29]. According to IEC 61400-21, the expected flicker emissions of wind turbine generators can be assessed using the flicker coefficient, $c(\psi_k, v_a)$, dependent on the average annual wind speed, v_a , at the wind turbine installation site and the grid short circuit impedance angle, ψ_k :

$$P_{st} = P_{lt} = c(\psi_k, v_a) \frac{S}{S_k} \quad (8)$$

For the total flicker emissions of a wind farm comprising N wind turbines, the following relation is used:

$$P_{st} = P_{lt} = \frac{1}{S_k} \sqrt{\sum_{i=1}^N (c(\psi_k, v_a) \cdot S_{n,i})^2} \quad (9)$$

where the flicker summation in normal operation is performed applying a quadratic summation rule.

Limits for flicker emissions are the same for normal operation and switching. At the LV level, limits stipulated in IEC 61000-3-3 are $P_{st} \leq 1$ and $P_{lt} \leq 0.65$. At the MV level, the determination of limits is left to the utilities, which set the *planning levels* for their grids. Indicative values for planning levels in MV systems, according to IEC 61000-3-7, are $P_{st} \leq 0.9$ and $P_{lt} \leq 0.7$. The allocation of these global limits to individual installations is made according to the principles presented in the next section for harmonics (equations similar to (10) and (12) are applied).

5.3.3 Harmonics

The increasing use of power electronics at the front end of many DG types (variable speed wind turbines, photovoltaics, microturbines etc.) poses harmonic control requirements for their connection to the grid. Several national and international standards and recommendations are available today (e.g. [30-33]), to elaborate appropriate evaluation procedures. In this section, an approach based on the IEC set of standards is presented, which comprises three basic steps: First, the definition of acceptable voltage distortion limits (planning levels), second, the allocation of global harmonic voltage limits to individual users (producers or consumers) and third, the determination of the corresponding current distortion limits for a specific installation.

For LV systems specific compatibility levels are given in IEC 61000-2-2, [34], which also serve as planning levels, and are included in Table 5-2. At higher voltage levels (MV and HV), it is the responsibility of the utility to determine the compatibility levels in its network and then define appropriate planning levels. For reference purposes, Table 5-2 summarizes indicative planning levels from IEC 61000-3-6.

Table 5-2: Planning levels for LV, MV and HV networks (IEC 61000-3-6, [33])

Odd harmonics $\neq 3k$				Odd harmonics $= 3k$				Even harmonics			
Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)			Order h	Harmonic voltage (%)		
	LV	MV	HV		LV	MV	HV		LV	MV	HV
5	6	5	2	3	5	4	2	2	2	1.6	1.5
7	5	4	2	9	1.5	1.2	1	4	1	1	1
11	3.5	3	1.5	15	0.3	0.3	0.3	6	0.5	0.5	0.5
13	3	2.5	1.5	21	0.2	0.2	0.2	8	0.5	0.4	0.4
17	2	1.6	1	>21	0.2	0.2	0.2	10	0.5	0.4	0.4
19	1.5	1.2	1					12	0.2	0.2	0.2
23	1.5	1.2	0.7					>12	0.2	0.2	0.2
25	1.5	1.2	0.7								
>25	0.2+	0.2+	0.2+								
	$1.3 \cdot \left(\frac{25}{h}\right)$	$0.5 \cdot \left(\frac{25}{h}\right)$	$0.5 \cdot \left(\frac{25}{h}\right)$								
THD: 8 % at LV, 6.5 % at MV, 3% at HV											

MV systems

The coordination of harmonic emission control at the different voltage levels (LV, MV and HV) of a power system requires that distortion transmitted from one level to another be taken into account. Hence, the distortion limit G_{hMV} , available to all installations connected to the MV system, is ([33]):

$$G_{hMV} = \sqrt[3]{L_{hMV}^3 - (T_{hHM} \cdot L_{hHV})^3} \quad (10)$$

where L_{hMV} and L_{hHV} are the MV and HV planning levels for harmonic order h (from Table 5-2) and T_{hHM} the harmonic transfer coefficient from HV to MV level (ranging from below 1.0 to more than 3.0); a is the exponent of the harmonic summation rule:

$$U_h = \sqrt[a]{\sum_i U_{hi}^a} \text{ or } I_h = \sqrt[a]{\sum_i I_{hi}^a} \quad (11)$$

IEC 61000-3-6 suggests $a=1$ for $h<5$, $a=1.4$ for $5 \leq h \leq 10$ and $a=2$ for $h>10$, since harmonics of higher orders tend to have random phase angles.

From G_{hMV} , the voltage distortion limit E_{Uhi} for an individual installation can then be determined, in proportion to its rated power, $S_{n,i}$:

$$E_{Uhi} = G_{hMV} \sqrt[a]{\frac{S_{n,i}}{S_t}} = G_{hMV} \sqrt[a]{S_i} \quad (12)$$

where S_t is the «total capacity» of the network (e.g. equal to the rated MVA of the feeding transformer). S_i can also be interpreted as the total capacity of the *distorting* equipment in the network, to avoid over-pessimistic results.

It is common practice in harmonic studies to regard the connected equipment as a harmonic current source (although this may not be correct in certain cases, e.g. voltage source converters), whereas the limits discussed previously refer to the harmonic distortion of the system voltage. In order to relate these quantities, the system harmonic impedance Z_h at the PCC is needed. Then:

$$U_{hi} = Z_h \cdot I_{hi} \leq E_{Uhi} \Rightarrow I_{hi} \leq E_{Ihi} = \frac{E_{Uhi}}{Z_h} \quad (13)$$

where U_{hi} and I_{hi} are the h -order harmonic distortion of the voltage and current due to installation i and E_{Uhi} , E_{Ihi} the respective limits allocated to this installation.

For MV systems no standardized reference impedance is available and the harmonic impedance Z_h has to be evaluated for each specific network. For a purely inductive system (no shunt capacitance):

$$Z_h \approx h \cdot X_k \quad (14)$$

where the fundamental frequency inductive component X_k of the short circuit impedance at the PCC is evaluated from:

$$X_k = \frac{U_n^2 \sin \psi_k}{S_k} \quad (15)$$

However, since this is not a realistic assumption, a simplified approach can be established ([33]) with reference to Figure 5-5, where all network capacitance is aggregated at the MV busbars and any possible resonance in the HV system is ignored. The capacitance in Figure 5-5 accounts for the first order parallel resonance with the upstream system (but not for possible higher order resonances). If all resistances and system loads in Figure 5-5 are ignored, the resonant frequency f_r and the respective harmonic order h_r (not necessarily an integer) are given by

$$f_r = f_1 \sqrt{\frac{S_{kS}}{Q_c}} \Rightarrow h_r = \frac{f_r}{f_1} = \sqrt{\frac{S_{kS}}{Q_c}} \quad (16)$$

where S_{kS} is the short circuit capacity at the MV busbars of the HV/MV substation and Q_c is the total capacitive reactive power of the MV network. A rough and conservative estimation of Z_h is then given by the “envelope impedance curve” of IEC 61000-3-6, shown in Figure 5-6. The resonant amplification factor, k_r , of the system impedance at the PCC typically varies

between 2 and 5 in public distribution networks, depending mainly on the damping effect of the system load. A discussion on the application of this method is provided in [35].

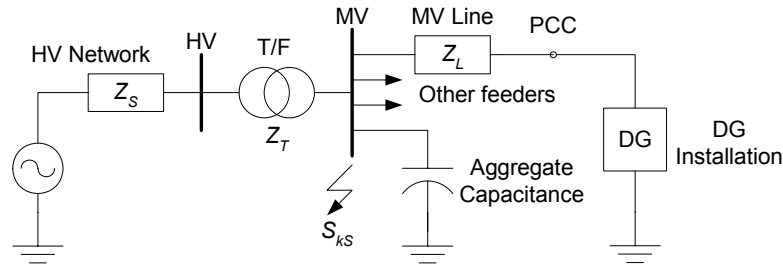


Figure 5-5: MV network equivalent for simplified harmonic analysis ([33]).

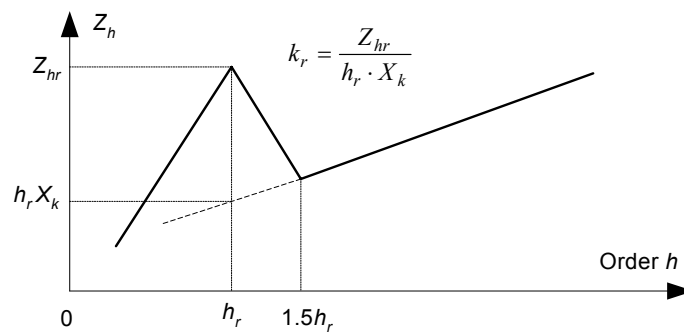


Figure 5-6: System harmonic impedance approximation, using the «envelope impedance curve» ([33]).

For installations with filters or significant PFC capacitance, in more complex networks or when resonant conditions exist in the HV network, the approach presented above is not suitable. Manual computation of Z_h is possible in certain cases but the application of harmonic load flow software is recommended.

The procedure described, although heavily simplified by research standards, may already be complicated enough for application in practical situations. To further facilitate the evaluation of low distortion equipment at the MV level, without resorting to the procedure described above, a “Stage 1” requirement may be formulated. Using equations (13)-(15) and the definition of the resonant amplification factor, k_r , from Figure 5-6, it is derived:

$$U_{hi} \approx k_r \cdot h \cdot \frac{U_n^2}{S_k} \cdot \sin \psi_k \cdot I_{hi} \leq E_{Uhi} \quad (17)$$

For the “Stage 1” evaluation, a conservative approach is adopted. The resistive part of Z_k is ignored ($\sin \psi_k=1$) and the limit E_{Uhi} is deduced from the planning levels L_{hMV} (or G_{hMV}) in proportion to the ratio s_i ($a=1$ in equation (12)). Then, from equation (17):

$$\frac{I_{hi}}{S_i} \leq \frac{L_{hMV}}{k_r \cdot h \cdot U_n^2} = M_{hMV} \Rightarrow \frac{I_{hi}}{S_i} \leq M_{hMV} \cdot S_k \quad (18)$$

The limit M_{hMV} in equation (18), expressed in A/MVA, is then directly evaluated using the nominal voltage of the network and assuming an appropriate value for k_r ($k_r=5$ would be a conservative approach). Such a simplified evaluation is adopted in [6, 9]. If equation (18) is not satisfied, a more detailed evaluation has to be conducted, as discussed previously.

LV systems

The principles outlined in the previous section for MV systems are also applicable to the LV level. However, for LV systems IEC 725, [36], establishes a reference system impedance, permitting thus the direct determination of harmonic current limits. IEC 61000-3-2 provides limits for equipment with rated current ≤ 16 A/phase (Class A). For DG units with rated current between 16 and 75 A/phase, the limits of IEC 61000-3-4 are applicable, when connected to a PCC where the short circuit ratio is higher than 33. For DG installations with rated current higher than 75 A per phase, the Stage 1 evaluation procedure used for MV installations (equation (18)) can be applied, using as emission limit:

$$I_h \leq M_{hLV} \cdot \frac{S_k}{\sin \psi_k} \quad (19)$$

where M_{hLV} is the harmonic current limit per MVA of S_k . ψ_k is taken into account, because of the predominantly resistive character of the LV networks. M_{hLV} values can be derived based on equation (18).

5.4 Interharmonics and higher order harmonics

The evaluation procedures outlined above cater for harmonic orders $h \leq 40$ (IEEE Std. 519, [31], provides limits up to the 50th order), which is sufficient for line-commutated converters, as well as for voltage-source converters with a low switching frequency. However, the increasing utilization of fast switching PWM converters has extended the harmonic frequency spectrum well beyond 2 kHz, where limits and standardized evaluation methodologies are still unavailable. Due to the lack of relevant standards and experience in this range, a conservative approach is often adopted. In [6, 7, 9], a strict limit is set on the voltage distortion due to higher order and interharmonic components:

$$U_h \leq 0.2 \%, h > 40 \text{ or } h \text{ non-integer}$$

which is in line with the interharmonics planning level suggested in IEC 61000-3-6.

An issue related to harmonics is also the possible interference of DG installations with mains signaling, such as ripple control systems². Such systems usually operate in the range 100 to 500 Hz (up to 2-3 kHz) by injecting a voltage signal of higher frequency on the power frequency voltage waveform. To ensure no interference, the injection of harmonics or interharmonics from the DG installations should be minimized at the ripple control frequency and its sidebands at frequencies differing by twice the fundamental frequency.

5.5 Interconnection Protection Requirements

The DG-utility interface protection is primarily intended to ensure the safety of other users of the network and of utility personnel and it should be properly coordinated with other protections of the grid. The protective functions incorporated therein may differ considerably, depending on the size, voltage level, type of DG equipment and the operation and protection scheme of the network. A comprehensive overview for small DG stations is provided in [37].

The primary function of the interconnection protection (besides fault detection via overcurrent relays) has always been the detection of islanding situations and the immediate disconnection of the generating equipment. Islanding has been extensively studied for PVs connected to the LV network and islanding detection and protection schemes have been proposed, tested and gradually implemented in commercial products, [10, 11]. In case of DG installations utilizing synchronous generators, islanding is a serious concern, too. If induction generators are used, the possibility of self-excited operation exists and such situations have been encountered in practice. An example is shown in Figure 5-7, recorded on the Greek island of Chios, where

² Ripple control systems are used in Europe to send signals over the power line in order to change tariffs, turn on street lighting and other control applications. They comprise of low amplitude voltage signals of a few hundred Hz.

about 5 MW of wind power are connected to a 20 kV line, which includes a 20 km section of submarine cable, [38]. The opening of the feeder circuit breaker resulted in a voltage swell in the isolated part, sustained for about 15 sec (the wind turbine over-voltage protection was set high, due to the high normal operation voltage).

Typical minimum protective functions of the interconnection protection system are over-/under-voltage and over-/under-frequency, as shown in Figure 5-8. Zero-sequence (residual) voltage relays are also stipulated in many cases (depending on the MV network neutral earthing arrangements and step-up transformer connections). In Table 5-3, two groups of indicative relay settings (Type A and Type B) are provided and discussed in the following.

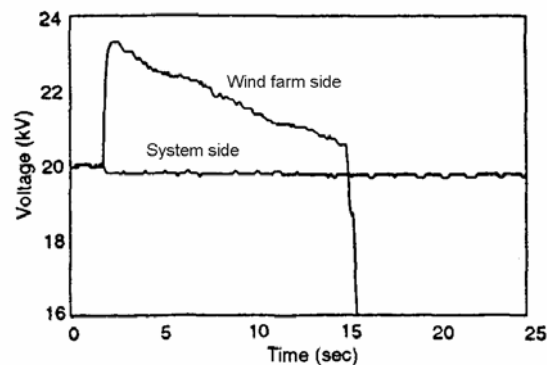


Figure 5-7: Recorded voltage during the isolated operation of a feeder with significant wind power, following the opening of the circuit breaker at its departure ([38]).

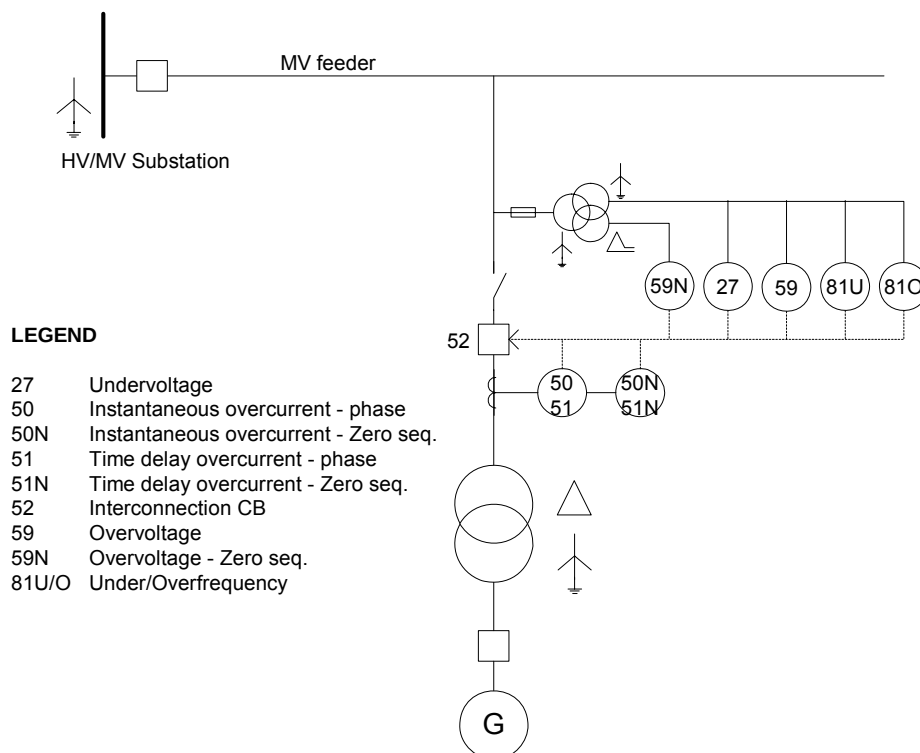


Figure 5-8: Basic functions of the interconnection protection system.

Table 5-3: Indicative settings for the interconnection protection relays.

Relay	Settings Type A	Settings Type B
-------	-----------------	-----------------

	Threshold	Delay	Threshold	Delay
27	$0.85 \cdot U_n$	0.3 s	$0.80 \cdot U_n$	1.2 s
59	$1.10 \cdot U_n$	0.3 s	$1.15 \cdot U_n$	1.2 s
81U	49.5 Hz	0.3 s	47.5 Hz	1.2 s
81O	50.5 Hz	0.3 s	51.5 Hz	1.2 s

Strict settings are needed in the voltage and frequency protection, to achieve sensitive islanding detection, as well as fast disconnection of DG sources in lines with fast reclosing schemes (ensuring disconnection before reclosing, to prevent unacceptable stresses, [39]). These requirements are fulfilled by the settings Type A in Table 5-3. The 0.3 s activation time is short enough to ensure disconnection before the first reclosing of the feeder breaker (approximately 0.5 s after initiation of the fault). At the same time, it is also long enough to avoid tripping by voltage dips due to faults on adjacent feeders, cleared in the first reclosing cycle (with instantaneous overcurrent relays, dips last approximately 0.1-0.15 s). Transfer-trip schemes can also be used between the line and the DG breaker, a solution considered for relatively large installations.

Fast activation times, however, lead to increased “nuisance” trips of the DG station, which may pose a threat to the stability of systems with high levels of DG penetration. In such cases, maintaining generation capacity in operation during critical disturbances takes precedence over other considerations, leading to the adoption of less sensitive protection settings. The Type B settings in Table 5-3, applicable for DG stations connected to the MV network of island grids, ensure adequate ride-through for voltage sags due to faults cleared by inverse-time overcurrent relays of the feeder breakers. They are also much less sensitive to temporary voltage and frequency excursions, common in small isolated power systems.

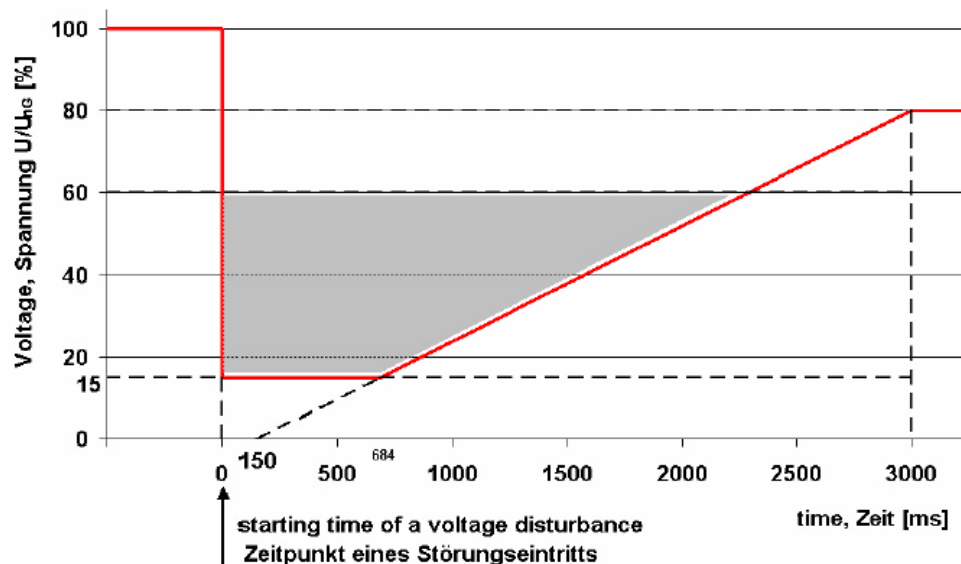


Figure 5-9: Voltage sag immunity requirements imposed to large wind farms by a German utility (E.ON. Netz GmbH, [40])³.

Adopting less sensitive protection settings to maintain generation capacity in operation during critical disturbances, also imposes requirements for the fault ride-through capability of DG units. A characteristic example is the requirement first imposed by the German utility E.ON.

³ Note: This standard has recently been modified by E.ON, see E.ON Grid Code – High and Extra High Voltages – Status 1. April 2006. (<http://www.eon-netz.com/Ressources/downloads/ENENARHS2006eng.pdf>).

to all large wind farms connected to its system, that their generators should ride through all voltage sags lying above the magnitude-duration characteristic of Figure 5-9, [40, 41]. In addition, in all countries experiencing high DG penetrations (mainly wind power), the grid codes now impose strict requirements on all stations connected to the grid (initially only for HV level installations, now gradually for the MV level as well), in order to assure that they actively assist the grid, by properly regulating their output active and reactive power, both in normal operation and during contingencies [42]. For such requirements to be met, the design of the DG units themselves has to be revised (fast action of pitch controllers, moderate over-speed allowance, possibly incorporation of storage at the DC-link, installation of SVCs at the generator terminals for conventional induction generators etc.).

At present, this discussion is relevant for large DG installations connected to the HV and MV level. In the case of LV installations, the functional requirements for the utility interface concentrate mostly on the islanding detection, which in general is the responsibility of the manufacturer to provide as an integrated part of the equipment. The protection functions of LV DG equipment will be heavily revised in the medium- or long-term, due to the increasing momentum of the “Microgrid” concept, i.e. the possibility for parts of LV networks with sufficient distributed generation to intentionally isolate and operate autonomously from the main grid ([43-45]).

5.6 Summary

The chapter includes a presentation of important technical considerations for the interconnection of distributed generation resources to distribution networks. Technical requirements and assessment criteria are presented for power quality related issues, including steady state and rapid voltage variations, flicker and harmonic emissions, which are suitable for practical application. These criteria and procedures are largely based on the set of relevant IEC publications, as well as on current utility practice.

It is certain that the technological advancements will call for continuous update of the evaluation methodologies. For instance, active front-end converters, with load balancing, flicker cancellation and active filtering capabilities, may soon find their way into commercial DG equipment, such as wind turbine generators. The operating paradigm of distribution networks with significant DG resources will also evolve, towards an “active” network principle. Further, apart from the core technical issues, it is also certain that other market and regulatory factors will affect critically the degree of future DG penetration and the criteria and requirements for their integration.

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MODELING WIND TURBINE GENERATORS FOR POWER SYSTEM STUDIES

6.1 Introduction

As presented in previous chapters, wind generation is steadily increasing in installed capacity around the world. Understanding the dynamic performance of this generation source and how it should be modeled for various power system studies is essential. In this chapter the modeling of wind turbine generators (WTG) will be discussed in detail both for steady-state and dynamic studies. The focus will be on recommended modeling practices and proposed generic model structures for power system studies. The chapter is further supplemented by Appendices at the end of the report that provided detailed descriptions for manufacturer specific models and modeling required for specialized analysis.

6.2 Modeling of Wind Turbine Generators and Wind Farms for Steady-State and Dynamic Studies [1]:

6.2.1 Modeling Various Types of Wind Turbine Generators

In chapter 3, the various types of wind turbine generators (WTG) were discussed. In essence there are four major types; these are shown in Figure 6-1. Each type requires a different means of modeling.

6.2.1.1 Modeling WTG for Steady-State Analysis

For power flow analysis ideally conventional and variable rotor resistance induction generators should be modeled using the equivalent circuit of an induction machine (see Appendix E for a discussion of this approach). However, most commonly used positive-sequence based programs do not necessarily have such functionality. Thus, it is a reasonable compromise to model the WTG as a P, Q bus with constant reactive power (Q) equal to the amount being absorbed at the real power (P) level being studied. For example, a typical conventional induction generator will have a power factor of 0.9 pf. Thus, a WTG operating at full-load of say 1.65 MW would be modeled as a P, Q bus with $P = 1.65$ MW and $Q = -0.799$ MVar. In reality the reactive consumption of the units will change some if the terminal voltage drops below nominal (based on the characteristics of the machine), however, in the absence of a steady-state equivalent circuit model of the unit a constant Q representation is perhaps adequate – especially since per typical planning criteria the system voltage should be maintained at $\pm 5\%$ of nominal voltage. Alternate static representations of an induction machine based on the steady-state equivalent circuit can be found for example in [2] – such models clearly required more data, but have the advantage that reactive power consumption is a function of active power and terminal voltage. Figure 6-2 shows this equivalent circuit (reproduced with permission from [2]).

Once the WTG has been modeled, the shunt capacitors at the turbine compensating for the WTG reactive consumption should also be explicitly modeled. It is not acceptable to make the gross approximation of combining the shunt capacitor and WTG into a lumped model for the whole unit as a P, Q bus at unity power factor. Although, the shunt compensation at the unit may provide adequate reactive power to fully compensate for the unit's reactive consumption (and is controlled through switching increments of shunt capacitors to regulate the units effective power factor between no-load to full-load), this is not an appropriate model since it is only true at 1.0 pu system voltage. Once the unit is, for example, at full-load and all the shunt compensation in-service, as the voltage starts to change from 1.0 pu the reactive output of the shunt capacitors will vary as the square of voltage while that of the WTG will essentially remain constant. Thus, modeling the unit as a unity power factor P, Q bus can give quite optimistic results with regard to steady state voltage.

For doubly-fed asynchronous generators (DFAG) and full converter units that have voltage source converters, the units may be modeled as a P, V (i.e. specified megawatt level and voltage) bus with appropriate VAr limits. This is because both these types of unit have reactive capability. It should be noted, however, that the full converter design becomes a constant current device (rather than a constant power device) when it reaches its limit. As such, the actual VAr limit will change linearly with voltage once the unit is at limit. To model this accurately the device needs to be modeled as a current source once at limit in power flow. Such a feature is likely not easily available in most power flow simulation program (unless one changes the unit to a constant current negative load at its limit).

Note: in steady-state analysis the aim should be to design the system in such a way to ensure that the steady-state voltages (pre and post-contingency) meet planning reliability standards. For most regions this means voltages should not deviate, in steady-state, by more than +/- 10% of nominal (this ten percent variation criterion is typically applied for contingency conditions). Most modern wind turbines will operate continuously within such a bandwidth of system voltage variation and so typically low/high voltage tripping of wind turbines does not need to be simulated for steady-state analysis. Nonetheless, the planning engineer needs to be aware of the off-nominal voltage trip settings of the wind turbine-generator controls.

Table 6-1: Summary of power flow models [1].

WTG Type	Model	Shunt Compensation	Generator Transformer
Conventional IM	P, Q bus; $Q = \text{const.}^1$	Explicitly model shunt capacitor	Typically, $X_t = 6\%$ on transformer rating
Variable Rotor Resistance IM	P,Q bus; $Q = \text{const.}^1$	Explicitly model shunt capacitor	Typically, $X_t = 6\%$ on transformer rating
Doubly-fed asynchronous Generator	P,V bus; $Q_{\min} \leq Q \leq Q_{\max}$	Inherent in machine, typical power factor +/- 0.95 pf (or better)	Typically, $X_t = 6\%$ on transformer rating
Full Converter	P,V bus; $Q_{\min} \leq Q \leq Q_{\max}^2$	Typically, inherent in inverter capability (+/- 0.95 pf or better)	Typically, $X_t = 6\%$ on transformer rating

1. The reactive consumption of an actual induction generator will vary as the voltage drops, but to properly model this one would need an equivalent circuit power flow model of an induction machine, which is not available in some programs.
2. Provided the converter is a voltage-source converter the unit will have reactive capability. However, at its limit this is a constant current not a constant VAr device. Thus, once at limit a P, V model is not exactly correct – once again this may be a limitation of some simulation tools.

6.2.1.2 Modeling WTG for Dynamic Analysis

There are a number of components that contribute to the dynamic behavior of a WTG. These are:

- Turbine aerodynamics
- Turbine mechanical controls (i.e. pitch control or active-stall control)
- Shaft dynamics
- Generator electric characteristics
- Electrical controls (such as converter controls, switching of shunt capacitor banks etc.)

- Protection relay settings
- Measurement equipment (such as filters in the transducers for measuring terminal voltage, PLLs etc.)

Most simulation programs capture all of these to some extent (see Appendices B, D and E). Figure 6-3 illustrates the components of the WTG.

The model structure for the aerodynamics, turbine controls and protection systems for all of the various WTG will essentially be similar. The parameters will clearly be different from one manufacture to the other. In the case of stall controlled units there is no turbine blade pitch control (active-stall units do have blade pitch control). For constant speed units, blade pitch will be used to regulate power instead of speed on variable-speed units. The shaft dynamics may be modeled as a single equivalent mass or as is often done these days as two masses; one mass represents the rotor/blades and the second represents the electrical generator. In the case of a two mass model care should be taken to properly represent the damping coefficient between the two masses for otherwise the amount of oscillation between the two masses will be over exaggerated. In general, modeling the shaft as a two mass system is recommended, particularly for connections to weak systems where the perturbations in the generator speed will readily translate into voltage fluctuations on the system and can thus affect system dynamic performance. Finally note that in the case of the full converter design since the generator and power system are essentially decoupled by a full back-to-back converter, ideally perturbations in the generator speed will not be seen on the system since the line side converter can be appropriately controlled in order to maintain a fixed frequency output regardless of variations in the speed on the generating unit. Thus, in this case modeling the shaft dynamic from the perspective of power systems analysis becomes less critical.

Some comments are pertinent with regard to modeling the electrical generator:

- **Conventional Induction Generator:** For this type of machine the generator may be modeled in the same way as an induction motor. Such models are readily available in power system simulation programs. Typically, the equivalent circuit parameters provided by manufacturers for use in modeling these units are appropriate only for modeling the machine using a single-cage model (i.e. transient fluxes only). This can be pessimistic for simulation of severe fault conditions since such models have a tendency to over estimate the current drawn by the machine after fault clearing. A two-cage model (including subtransient behavior and saturation) is preferred [3]. None-the-less, given that most power system simulations are still performed with rather optimistic load models (i.e. static polynomial ZIP models) the use of a slightly pessimistic machine model might be a reasonable compromise. Another important aspect of these designs is blade pitching for active-stall designs during a severe disturbance. Some manufacturers will pitch the blades during a severe disturbance in order to remove some of the mechanical power off of the turbine and thus reduce the level of overspeed to help the recovery of the unit [4]. This does impact the rate of voltage recovery after a fault is cleared and can indeed improve voltage recovery [5, 6].
- **Variable Rotor Resistance Generator:** Again this design may be represented using induction machine models. In this case, however, it may be pertinent to model the variable rotor resistance. In practice the machine tends to operate up to a slip of roughly 5% at peak load. Then in the event of sudden wind fluctuations it can increase (decrease) its speed roughly up to another 5% to absorb (release) some of the energy into the shaft and thus minimize second to second fluctuations in power providing better power quality. Also, during a severe voltage dip the rotor resistance is switched to its maximum value to prevent excessively high rotor currents.

Increasing the effective rotor resistance also has the added benefit of flattening out the motor torque-speed curve thus making its recovery after fault clearing easier.

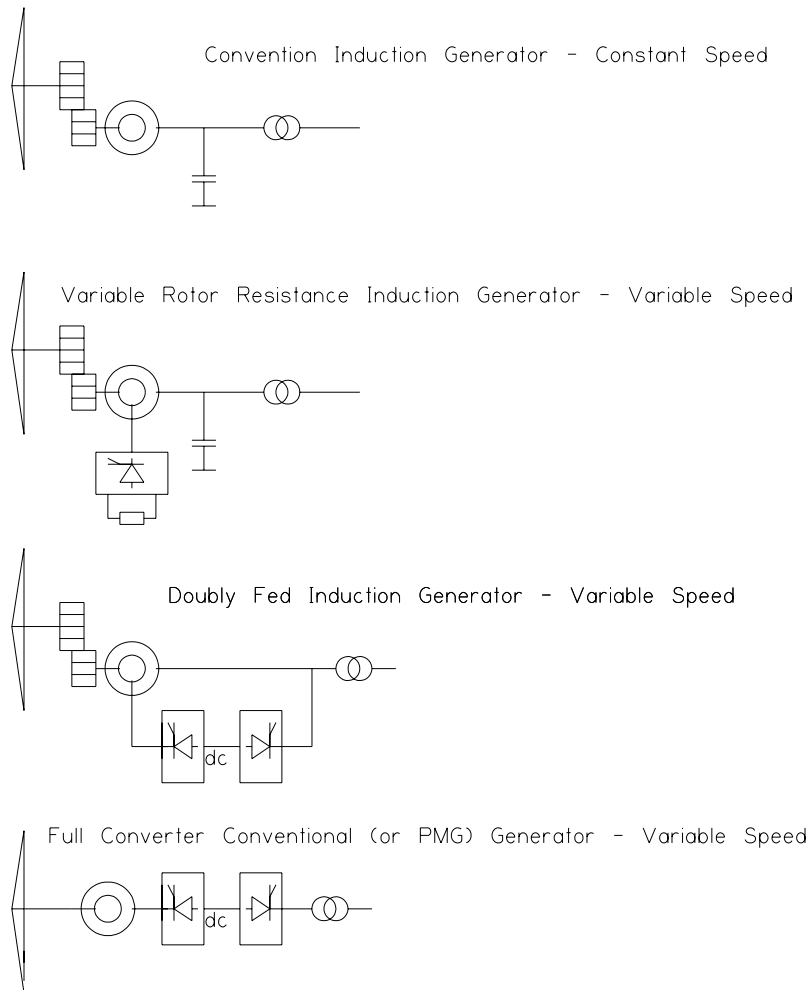


Figure 6-1: Summary of various turbine technologies [1].

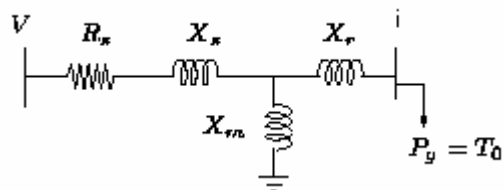


Figure 6-2: Steady-state representation of induction machine [2].

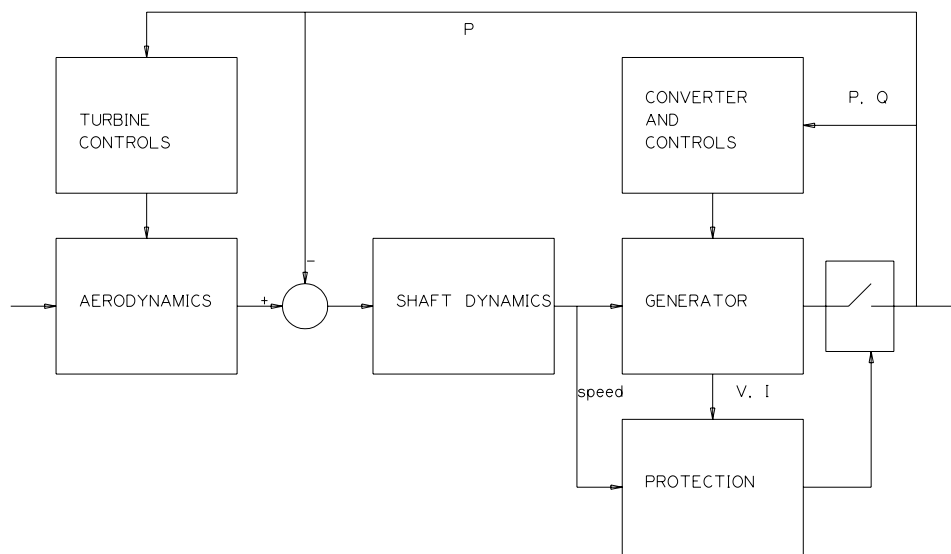


Figure 6-3: Components of a WTG model [1].

- Doubly-fed asynchronous generator:** With these units one needs to capture the behavior of the generator and converter since both are connected to the system. Also, when modeling the shaft as a two mass system adequate damping should be added to the model to account for the active damping loop often implemented in the converter controls to improve damping of the torsional mode between the generator and turbine rotor. A seldom captured (in some commercial programs) behavior of the unit is what happens during and immediately following a disturbance for certain designs. Some designs of doubly-fed units, for relatively close in faults (as explained in section 3) the rotor side converter will use a crowbar (essentially short circuit the rotor) to protect the power electronics from high transient currents and thus voltages. Once the rotor crowbar is engaged in this way the unit essentially becomes an induction generator (or motor if it was operating at a subsynchronous operating point). Even with active crowbar systems that disengage the crowbar circuit after the fault has cleared, this is not done immediately. There may be a short period of time between the fault clearing and the crowbar circuit disengaging. As such, during this time depending on the initial operating condition of the DFAG the unit may absorb significant amounts of both real and reactive power from the system. For example, if the unit were generating a small amount of power and thus operating at say 0.15 pu slip then immediately after the fault clears and the crowbar is still engaged the unit will be essentially an induction motor running at a relatively high slip and thus absorbing megawatts and megavars. On the other hand if the unit were at peak load then once the fault clears and the crowbar circuit has not yet disengaged the unit will be an induction generator running at very high slip possibly -0.2 to -0.3 pu and thus may be absorbing a significant amount of reactive power, depending on the effective resistance of the crowbar circuit. This phenomenon may have an effect on the system voltage recovery in weak systems, but to our knowledge is not presently captured in the widely used positive-sequence based programs. It may not, however, be appropriate to capture this phenomenon using positive-sequence simulation tools. The time period between fault clearing and the crowbar circuit disengaging is typically between five to a few tens of milliseconds, and so for positive-sequence simulation tools this may not be significant. However, this point needs to be clarified by manufacturers in future model development activities (see subsection 3.2.6.1 for more details). Note: the above discussion is only pertinent to units that impose a

crowbar strategy for fault ride-through. There are different ways to achieve this. For example in the Vestas VCS AGO2 solution the crowbar is seldom engaged for grid faults – typically the rotor inverter can withstand the high current due to grid faults and a chopper in the DC-link consumes the active power to limit the DC-link voltage.

- **Full converter units:** For full converter units the most important component from a system perspective is proper emulation of the dynamic behavior of the line side converter (or sometimes called inverter). Typically, in the event of a remote disturbance or fault the line side converter will quickly control the converter current to its rated (or short term) current rating – thus, the unit at its limit becomes a constant current device. Typically, the active current (real power component) will be the first priority and reactive current will contribute up to the maximum allowed (i.e. maximum current magnitude limit of the converter). For close in faults where the voltage is severely depressed the converter may block and stop gating the IGBTs (or IGCTs). During this time the generator side converter can feed into a resistor to minimize the overspeeding of the WTG. Once the fault clears the converters will quickly go back into operation.

6.2.2 Wind Farm Modeling for Steady-State (Power Flow) Analysis

Table 6-1 in the above subsection provides a summary of how to model the various WTG in power flow analysis. The question is how to extend this to modeling an entire wind farm. The wind farms being designed and proposed these days are often of the order of several tens to hundreds of megawatts in capacity. This means the wind farm has tens to sometimes nearly a hundred WTGs. Each unit has a dedicated step-up transformer that raises the unit's terminal voltage (typically 600 to 690 V) up to the collector system voltage (typically 20 to 34.5 kV). Then groups of WTG are connected in a loop or radial line and then connected to a feeder. These feeders are then all collected together at a single (or sometimes a few) substation. At the substation the voltage is stepped up from the collector system level to the transmission system level through a substation transformer. For detailed design and analysis of the collector system it is necessary to model this entire network in some form, particularly when studying the potential for harmonic or other resonant phenomenon. For the study of resonant phenomenon a three-phase harmonic power flow analysis and/or frequency scanning analysis would be necessary.

For power system studies where we are more interested in the effect that the wind farm may have on the transmission grid, modeling the details of the entire collector system may be too exorbitant. Thus, lumped models need to be used for power system studies. In general the approach should be to group WTGs. For example, if we are to model a 10 MW wind farm which consists of eleven 900 kW units then it may be appropriate to lump the whole farm into a single lumped model as shown in Figure 6-4. If the wind farm were 100 MW with five groups of twenty turbines being fed to the common substation through five feeders, then we could model the whole farm with five lumped models, etc. For system impact studies, it is typical practice to model the whole farm by a single equivalent model such as that shown in Figure 6-4, since we are only interested in the impact of the facility on the system and not in the collector system design. The model should not be reduced any further since we then risk not capturing properly the effective reactive and real losses through the substation transformer etc. Also, as mentioned earlier the shunt compensation in the case of conventional induction generators should be explicitly modeled rather than over simplifying the model. The case study in section 6.4 below provides an example of more detailed aggregation techniques.

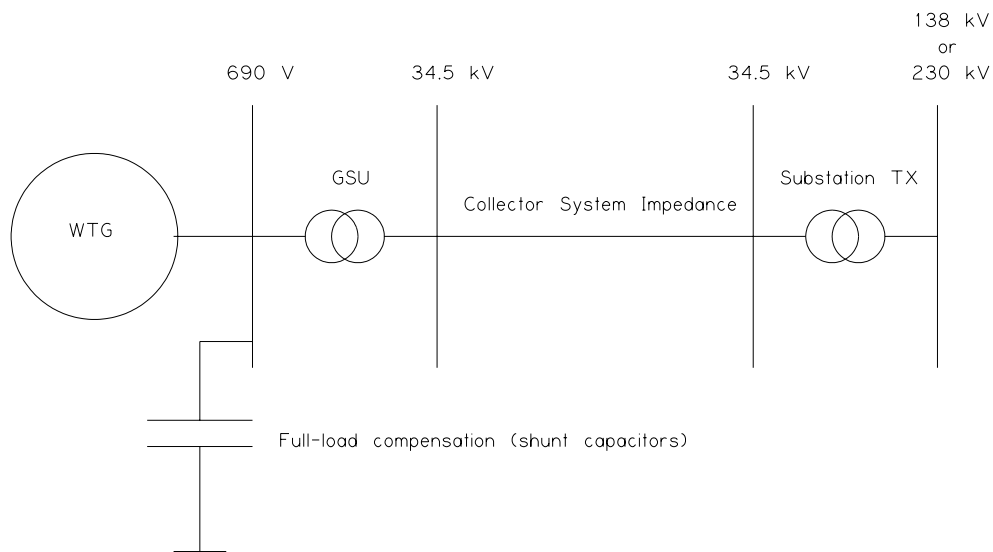


Figure 6-4: Model of conventional induction generator WTG. The GSU impedance is assumed to be 0.06 pu per turbine on the MVA base of the turbine. The substation transformer impedance is modeled based on manufacturer data; otherwise a typical impedance of 8 to 10 % on unit oil-air (OA) rating may be used. The effective collector system impedance may be calculated by creating a Thevenin equivalent of the collector system; typically this is of the order of 0.025 pu on the total MVA base of the wind farm. Note: if the collector system is primarily underground cables, then the effective charging should also be modeled and can be significant [1].

6.2.3 Wind Farm Modeling for Transient Stability Time-Domain Analysis

For power systems transient stability simulations the common practice is to model the wind farm as a single equivalent machine as shown in Figure 6-4. Again to model many tens to a hundred individual units can be unmanageable for simulation work, particularly when the details of the collector system are not known during the initial study stages. Since on a per unit system models may be easily scaled, one need only scale the MVA rating of a single WTG model to use it to represent the entire farm.

It should be noted, however, that this aggregated approach does not necessarily imply that it is adequate to represent a large wind farm by a single equivalent generator for all cases. It is quite clear that for larger wind farms with multiple feeders (which will in many cases be of unequal length) the response of individual turbines or groups of turbines within the farm will likely be different to a system disturbance. This is even more so if different stages of the wind farm use different turbine generator technologies (e.g. half the farm is DFAG and the other half conventional induction machines). Thus, it may make sense or be necessary, for more detailed studies, to model the wind farm using a number of equivalent machines representing groups of turbines at the end of major feeders within the farm, particularly if different WTG technologies have been utilized in the wind farm.

One example of aggregation is given below in section 6.4 and another methodology for several wind farms connected to the same substation through different feeders, as well as the limitations of the technique in providing accurate stability limits is reported in [7].

6.2.4 More Detailed Modeling for Other Types of Analysis

For detailed controls interaction studies and studies related to torsional interaction more detailed three-phase equipment level models are typically required. Such models need to be developed in close collaboration with the wind turbine manufacturer and are typically

developed in platforms such as EMTDC/PSCAD[®], EMTP, MATLAB Simulink[®] or DigSILENT[®] (see Appendix E). These models require a detailed representation of the converter and its controls for DFAG, variable rotor resistance and full converter units. Similarly, for studies where the intricacies of the fault ride-through system are being evaluated detailed three-phase equipment level models are required [8] (see also subsection 3.2.6.1 and Appendix E).

6.3 Generic Models for Time Domain Simulations

6.3.1 Generic Models versus Detailed-Manufacturer Specific Models

It is pertinent to first present a brief discussion of the use of generic models versus more detailed (and manufacturer specific) models. In spirit, this discussion is applicable to any power system component (synchronous generators, SVC, STATCOM, HVDC etc.).

The purpose of generic models, which constitute a generic structure based on physical principles, as opposed to detailed (typically 3-phase) component level and often manufacturer specific equipment models is to facilitate a means of performing power system studies that often incorporate tens of thousands of models. The aim is to have a simple yet comprehensive enough model structure to be able to faithfully capture the most important dynamics aspects and then by simply changing appropriate parameters (e.g. inertias, impedances, gains etc.) to facilitate emulation of different manufacturer designs.

Of course, such generic models have their limitations. When studies are focused on improving or assessing details of equipment design, such generic models are typically not adequate. For example, when evaluating the detailed performance of fault-ride through systems (see section 3.2.6.1, and to some extent some discussions in Appendix E) 3-phase component level models are necessary. In the end some engineering judgment and consultation among the parties involved (manufacturer, consultants, developer and host utility) are necessary to identify the correct level of modeling detail for each stage of a study. Also, as presented in section 4.2.3, in some cases (e.g. installation of a wind farm near a series compensated line or HVDC converter station) specialized studies may be necessary to evaluate the potential for controls and torsional interactions – again these studies by their very nature demand more detailed equipment level models.

The models discussed in this subsection are intended for time-domain, dynamic simulations of wind turbine generators for the purpose of power system stability studies. In such studies, the time frame of interest is typically a few seconds to tens of seconds following a disturbance and the power system network is represented by a constant positive-sequence impedance matrix. Thus, such simulation tools are intended for looking at system wide oscillations and phenomena such as between many generators spread out on the system (inter area modes of rotor oscillation) or frequency instability or fast and slow voltage decay. Thus, these power system models are limited to a bandwidth of up to 2 Hz or so, because the network model is static and not adequate for studies that go outside this range. For local control interactions between controllers that are in the same substation or very close by and thus not affected by the network impedance (e.g. potential interactions between the automatic voltage regulator on a generator and that of a nearby SVC) this can also be studied provided the respective control models are of high enough fidelity and so perhaps the range of simulation bandwidth for such local phenomena may be extended to 10 to 20 Hz. It is within this context that the model structures below are recommended. Furthermore, during such simulations, typically it is assumed that the wind speed is constant for the duration of the simulation.

6.3.2 Typical Model Structures and Modeling Guidelines

The main types of wind turbine generators are those shown in Figure 6-1. Each requires a different model structure for dynamic simulations. However, there are common components

to all these units. The most suitable approach to modeling is a modularized approach (similar to conventional power plants). Namely, to develop a model for each WTG component:

- Turbine mechanical controls (i.e. pitch control or active-stall control) and aerodynamics
- Shaft dynamics
- Generator electric characteristics
- Electrical controls (such as converter controls, switching of shunt capacitor banks etc.) and protection
- Measurement equipment (e.g. time lag associated with voltage measurement transducers, where they are significant)

Of these modules, the turbine mechanical controls and shaft dynamics are essentially the same in structure for all the four wind turbine types, with the following specific exceptions:

- For fixed speed turbine the pitch controller controls power and has power feedback, while for variable speed units it typically controls speed and has speed feedback.
- For conventional induction generator one needs to capture the power ramp down and back up following a disturbance that is implemented by some manufacturers – see discussion in section 3.2.5 and Figure 2-12 and related discussion.

The proposed generic block diagram for the turbine aerodynamics, pitch control system and shaft dynamics is thus given in Figure 6-5.

The generic mechanical model in Figure 6-5 has the following features. A non-windup proportional-integral (PI) regulator acting on the error between actual and reference mechanical power (for fixed speed turbines) or actual and reference speed (for variable speed turbines). The actual power (speed) is as measured/derived from the turbine-generator output. The reference power (speed) is defined by the user. In the case of variable speed turbines, the reference speed is defined as a function of power output by the manufacturer, e.g. see cubic function in Figure B-4 of Appendix B for one manufacturer (see section 3.2.2 for reasoning behind this). The additional signal *pitch_comp* is for pitch compensation used in some designs – typically this is ignored (for one example, see Figure B-4 in Appendix B). The parameters in the block diagram are defined in Table 6-2.

The bottom part of Figure 6-5 shows how the pitch control model interacts with the rest of the turbine-generator model. First, mechanical power (P_m) is calculated as a function of the three input variables pitch angle (β), wind speed (V_w) and rotor speed (ω). This function is equation (1) in section 3.2. It can be implemented as described in Appendix B, section B.4.8 and Appendix E, section E.3.1.8 (typical parameters are also provided in Appendix B for one manufacturer). The mechanical power and electrical power are then inputs to the shaft dynamics equation. If the shaft is modeled as a single mass (generally not recommended), this is the simple well know shaft dynamics equation (see e.g. [9]). Alternatively, this can be easily extended to the two-mass and spring-constant model of the shaft (see Appendix A, equations (38), (39), (40) and (43) or Appendix B, Figure B-5). As explained in section 6.2.1, to fully capture the dynamics of the turbine-generator this two mass model approach is recommended (for further evidence see Appendix A).

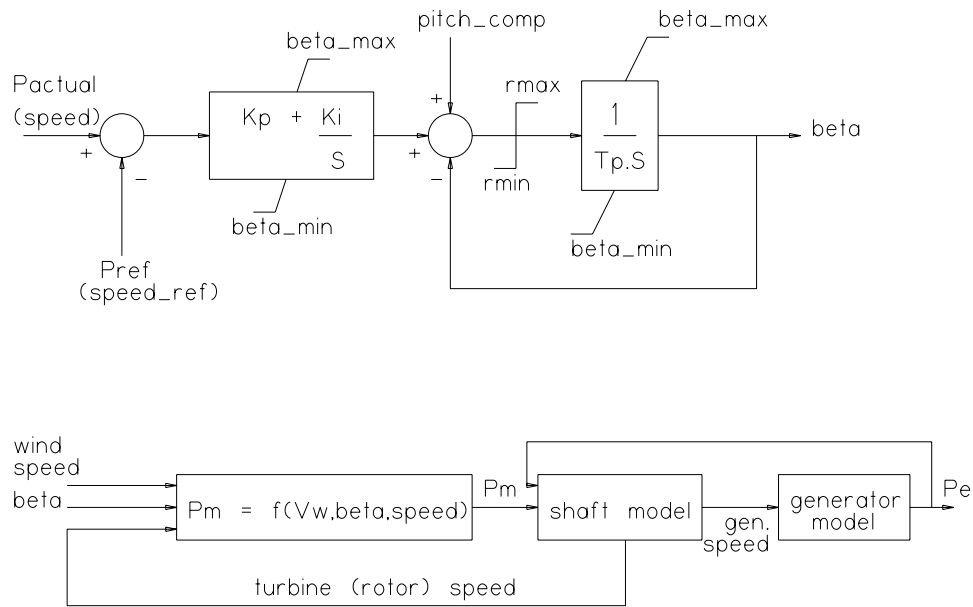


Figure 6-5: Generic model of pitch control and mechanical system. Note: speed in the top figure refers to the speed of the generator – typically, measured generator speed is what is used in this control loop and so if a two mass shaft model is used, the generator speed should be used for the feedback signal in this control loop. In the bottom portion of the figure speed in the function for developed mechanical power is the rotor speed of the turbine.

Table 6-2: Parameters for pitch control.

Parameter Name	Description	Typical Range
Kp	Proportional Gain	50 - 200
Ki	Integral Gain	10 - 50
rmax	Maximum rate of increase of pitch angle	5 – 10 degrees/sec
rmin	Maximum rate of decrease of pitch angle	-5 – -10 degrees/sec
Tp	Actuator time constant	0.3 – 1 second
beta_max	Maximum pitch angle	20 – 30 degrees
beta_min	Minimum pitch angle	0 degrees
beta	Pitch angle	Output of model

Modeling the pitch-control system is important for power system studies. This is particularly true for conventional induction generator machines. This is because, following a disturbance the speed deviation of the machine will determine the operating point of the electrical generator along its torque-speed curve and thus its real and reactive power injection (see section 3.2.5). To suitably capture these aspects the action of the pitch control system should be modeled as it will have a noticeable impact on the power output and speed deviation of the machine. Furthermore, some manufacturers will implement a fast ramp down in power during a severe system disturbance followed by a slow ramping back up of power (see e.g. Figure 2-12, section 2.2.2.1). Again, it is important that this be emulated (e.g. by a forced ramp on beta that overrides the pitch controller) since it will significantly affect the dynamic recovery of the wind turbine generators and system voltage. Considering the discussion in section 3.2.5, if the turbine power is ramped down following a major disturbance this will tend to reduce the chance of the turbine overspeeding beyond its pull-out torque and thus becoming unstable and tripping, and it would also reduce the amount of reactive compensation needed to maintain stability.

The electrical generator, shown as a block in Figure 6-5, may then be modeled as follows:

1. For conventional induction machines the differential equations for representing the machine dynamics are well known, as given by equation (1) in Appendix E.
2. For doubly-fed asynchronous machines, one may use the approach provided in Appendix A (which is particularly relevant to small-signal stability studies) or for transient stability analysis the approach presented in Appendix B (Figure B-4 and B-5) or Appendix E. As discussed in section 6.2.1.2, for certain designs this machine becomes effectively an induction machine once the rotor side converter crowbar circuit engages during close in faults. To better capture the real and reactive power injection of the machine during this period, in positive-sequence programs this phenomenon could be captured by switching to a conventional induction machine model (item 1 above) during the fault, with the appropriate rotor resistance. This approach is followed for instance in [10]. This, however, may lead to numerical integration problems for fix-time step integration routines if a sufficiently small enough integration time step is not chosen. Also, some designs may not employ this type of crowbar action. For example, for the Vestas VCS AGO2 solution (see Appendix F) the crowbar is seldom engaged for grid faults – typically the rotor inverter can withstand the high current due to grid faults and a chopper in the dc-link consumes the active power to limit the dc-link voltage. If such Vestas designs are modeled by this crowbar approach it will not show a realistic performance of the unit.
3. For full-converter units, for transient stability analysis, as seen from the power system the most relevant response is the behavior of the line-side converter. This may be modeled as shown in Figure 6-6. In this simplified generic model, for use in positive-sequence simulation programs, the machine side converter and mechanical characteristics of the wind turbine may be neglected and the mechanical power (power command P_{cmd}) assumed to be constant. Alternatively, a model of the mechanical system may be connected at P_{cmd} or this variable may be varied according to a lookup table during simulation of disturbances to emulate the action of the pitch control and machine side converter which will reduce the mechanical power by both pitching the turbine blades and feeding excess power into a braking resistor, respectively. The model allows simulation of constant power factor operation (setting mode to 0) or voltage regulation (mode set to 1) for four-quadrant voltage source converters with this control mode. The time constants T_t , T_q and T_p represent lags in the voltage measurement and Q and P command control loops, respectively. V_t is the machine terminal voltage from the network solution. The reference voltage (V_{ref}) is set by the user (or initial power flow solution). The maximum and minimum power levels ($P_{max}/0$ and Q_{max}/Q_{min}) define the unit's ratings. The block *Trans* represents the algebraic transformation of the real and reactive current command (I_p and I_q) into the effective current injection into the network – this is calculated based on the network voltage phasor at the secondary of the converter transformer. The current phasor I_t is then injected into the network. The limit i_{max} acts on the current phasor (I_t) magnitude, and is based on the maximum current rating of the line side converter – this limit may be made a function of terminal voltage (e.g. to emulate extinction of injected current for periods when the converter will stop gating due to severe voltage depression, typically $V_t < 0.2$ pu). Similarly, the current limits I_{pmax} and I_{qmax} act on the real and reactive current commands, respectively, and may be made a function of terminal voltage. Thus, as with the DFAG (see Appendix B) the dynamics of the converter current control loops (which are in the kilohertz range) are neglected and assumed to be instantaneous for the purposes of power system studies.

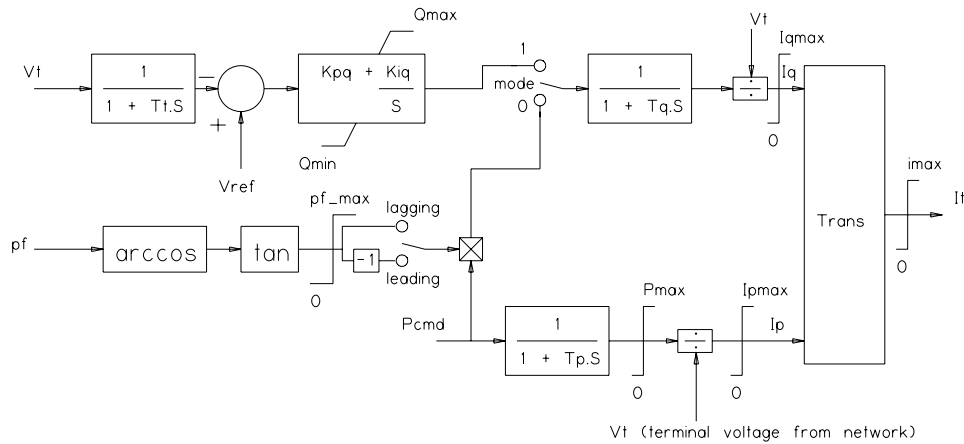


Figure 6-6: Generic model of full-converter wind turbine generator (line side converter).

6.3.2.1 Modeling the Protection Systems

For the purposes of power system simulations, the protection systems such as voltage-ride through (over- and undervoltage trip settings), overfrequency and underfrequency trip settings can be implemented as logic statements. Namely, based on the network solution the terminal voltage and network frequency at the machine terminals can be calculated. Thus, a set of logic statements are typically specified that will trip (disconnect the turbine-generator model from the network) the wind turbine generator if the settings are violated. The trip points should be provided by the manufacturer. Care should be taken, however, in simulating network frequency. Often this is calculated based on the rate of change of bus voltage phasor angle. In the event of a close in fault, this can lead to erroneous results due to the abrupt drop of voltage to a small value. Care must be taken to appropriately filter the signal to avoid emulating erroneous trips due to what may appear as a sudden spike in frequency.

6.4 A Case Study: Wind Farm Modeling for Network Analysis – Simulation Work and Validation

In this section, a method for dynamic modeling of wind farms is presented. This method takes into account the dynamic behavior of the wind turbine itself, i.e. by a dynamic two-mass model of a fixed-speed turbine attached to an induction generator model [11]. It is also shown how the internal network of a wind farm can be modeled by simple cable equivalents. To validate the wind turbine and wind farm model, simulation results are compared with measurements.

6.4.1 Models of Wind Turbine and Wind Farm

6.4.1.1 Wind Turbine Model

The wind turbine model is implemented in the PSS/E® power system simulation program [12]. Figure 6-7 shows a schematic diagram of the model. The model comprises a fixed-speed wind turbine and is capable of performing passive pitch (fixed pitch angle), active pitch or active stall control.

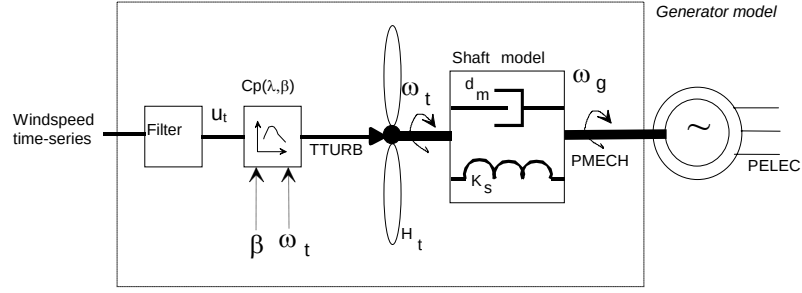


Figure 6-7: Schematic diagram of the wind turbine model

The input to the wind turbine model is (measured) wind speed (time-series) and the output is mechanical (shaft) power which is the input to the induction generator model (CIMTR3 in PSS/E®). The model is made up of an aerodynamic part, including the pitch control, and a mechanical two mass shaft model. The aerodynamic model is based on a two-dimensional look-up table of turbine efficiency coefficients (C_p) as a function of the tip speed ratio (λ) and pitch angle (β). A filter converts the single point input wind speed to an equivalent wind time series, $u_t(t)$, in order to provide a simplified representation of the spatial wind speed distribution and resulting cyclic torque variations.

The model can also be operated in fixed-torque mode. In this mode, the turbine torque (TTURB in Figure 6-7) is constant, corresponding to the mechanical power (PMECH) needed to produce the electric power (PELEC) specified in the load flow calculation (in PSS/E® as in most other power system simulation tools, a solved load flow case needs to be established prior to running dynamic analyses).

A further description of the model is given in [11].

6.4.1.2 Wind Farm Model

When modeling a group of wind turbines (wind farm) as one large wind turbine, the per-unit values of a single wind turbine are kept and scaled values applied for rated power (S), shunt capacitors (Q) and rotor radius (R) according to:

$$\begin{aligned} S_{wf} &= S_N N_{wt} \\ Q_{wf} &= Q_{wt} N_{wt} \\ R_{wf} &= R_{wt} \sqrt{N_{wt}} \end{aligned}$$

Subscript wt applies to a single wind turbine, whereas wf applies to wind farm.
 N_{wt} = number of wind turbines at the wind farm

This approach corresponds to modeling the wind farm as a large, single wind turbine assuming that the power fluctuations from all the wind turbines coincide. This is unlikely, thus the filters for determining $u_t(t)$ (i.e. the resulting wind speed, after filtering) use R_{wt} instead of R_{wf} and the variation of $u_t(t)$ is scaled according to

$$u_{t,wf}(t) = u_{avg} + \frac{u_t(t) - u_{avg}}{\sqrt{N_{wt}}}$$

Thus, the model takes into account (to a certain degree) the coincidence effect of the wind farm (i.e. the power fluctuations of a wind farm are relatively smaller than of a single wind turbine).

6.4.1.3 Internal Network Equivalent

The simplest way to model a wind farm is to model the whole farm as a single generator and connect it directly to a high voltage bus. This, however, does not take into account the reactive power contribution from the internal (e.g. 22 kV) grid of the wind farm or the power losses (active and reactive) of the generator transformer (e.g. a 0.69/22 kV transformer). The

size of the internal grid can be considerable (10 – 20 km) and thus may give a significant contribution to the reactive power balance.

The method, proposed and described in this work, is based on modeling an equivalent for each radial of the wind farm. Each equivalent consists of a single generator model, representing the total number of generators connected to that radial, and a cable giving similar response as the original cabling of the radial. The cable between the common 22 kV bus and the first point of common coupling (PCC) of each radial is modeled with its actual parameters (e.g. a 400 mm² Al cable), but for the remains of the radial equivalent impedances are estimated as follows:

The common 22 kV bus is modeled as a swing bus. Each radial is modeled explicitly with the correct distance between the points of injection (i.e. the wind turbines), and each of the wind turbines inject maximum active power (e.g. 2.0 MW) and no reactive power (i.e. $Q = 0$ MVar). The voltage, active and reactive power at the first PCC is noted. Then a new model is made, where the cable between the common 22 kV bus and the first PCC is modeled as it is (with the actual parameters). The impedance of the cable from the first PCC to the equivalent generator is chosen such that the values of voltage, active and reactive power at the first PCC are similar to the corresponding values from the full modeling of the radial. Figure 6-8 illustrates the method.

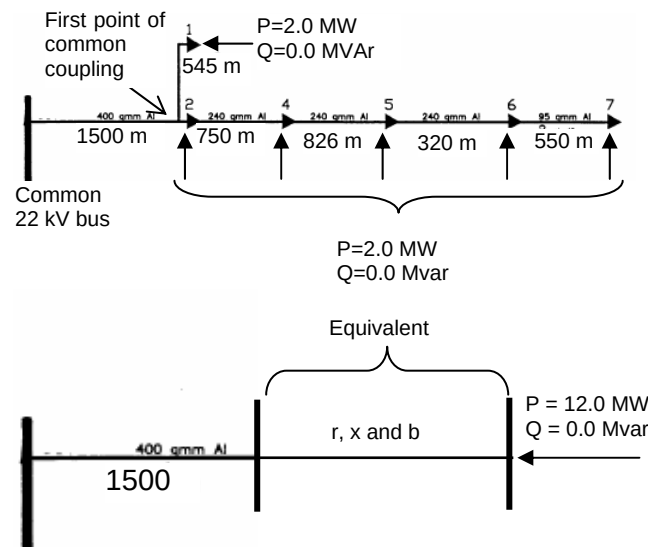


Figure 6-8: Illustration of the wind farm internal network model.

To complete the modeling, a 0.69/22 kV transformer (the size of which corresponds to the aggregated size of the generator transformers for the radial in question) is placed between the generator model and the injection bus. Thus a model of a single radial is as shown by the single-line diagram in Figure 6-9.

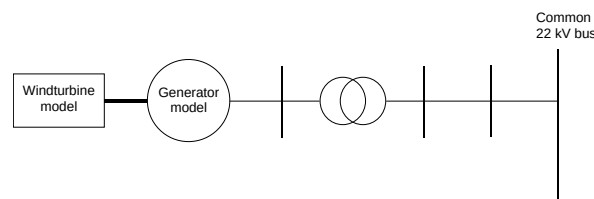


Figure 6-9: Schematic diagram of a single radial model.

6.4.1.4 Model Verification Against Measurements

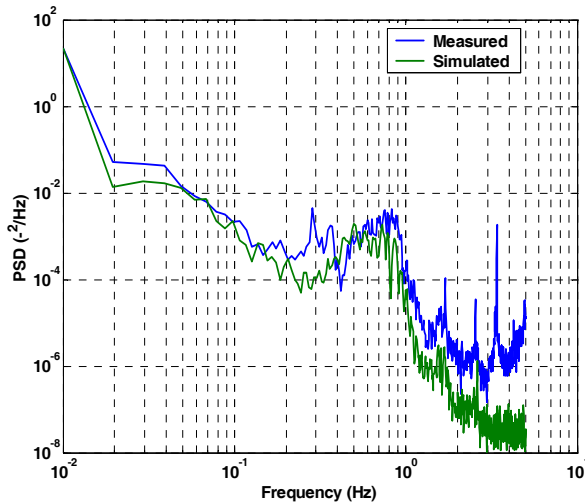
Measurements from a wind farm with twenty 2 MW fixed speed, active stall controlled wind turbines were used for validating the model. The measurements include 10-minutes time-

series with simultaneous 10 Hz registrations of wind speed in front of one wind turbine, active power from one wind turbine and active power from the whole wind farm.

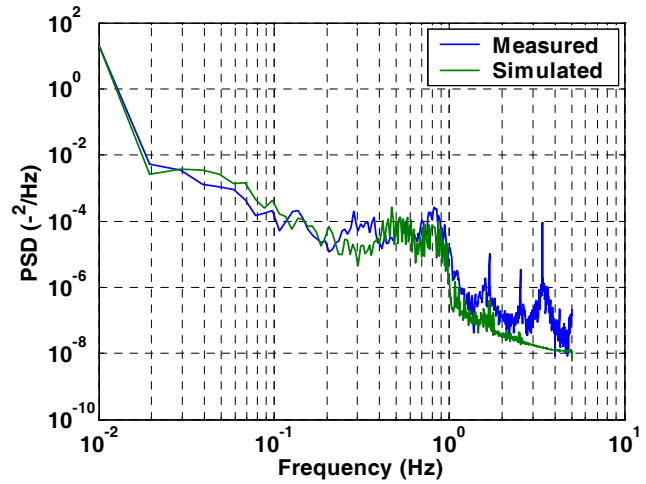
The measurements are taken during continuous operation of the wind farm, and for a situation without any faults on the grid, hence suitable for validating the model performance with respect to power fluctuations.

The model validation is carried out applying the given data for the wind turbines and a simplified representation of their grid connection. Two simulations are prepared, i.e. one for comparing the wind turbine model simulation results with the measured active power from the single wind turbine, and one for comparing the wind farm model with the measured active power from the wind farm. In both simulations the measured wind speed time-series is applied as input to the model.

Figure 6-10 shows the power spectral density (PSD) of the simulated and measured active power. The peaks of the graphs indicate enhanced power fluctuations. These appear at three times the turbine frequency, i.e. $3p = 0.8$ Hz. and also at 6p, 9p and 12p, and with relative magnitudes being smaller for the wind farm than for the wind turbine. This is all as expected; enhanced power fluctuations from fixed speed three bladed wind turbines will appear at multiples of $3p$ due to the wind speed variations over the turbine blades, and wind farms will provide relatively less fluctuating power as the power fluctuations from the wind turbines are unlikely to coincide.



a) Wind turbine (2 MW)



b) Wind farm (20x2 MW)

Figure 6-10: PSD of measured and simulated power from a 2 MW wind turbine (a) and 20x2 MW wind farm (b).

The good match between the measurements and simulations verifies the dynamic wind turbine model (Figure 6-10a) and the aggregation technique to constitute a wind farm model (Figure 6-10b). The only significant mismatch is the power fluctuation around 0.3 Hz. This is however likely due to a power system oscillation that is not included in the simplified grid model applied for this verification study.

6.4.2 Case Study

Application studies using the developed models are described in [13], [14]. The papers show how the proposed modeling approach makes it possible to include a fairly detailed model of wind farms in a model of a large power system in order to perform numerous dynamic analyses, including transient and voltage stability analysis and voltage quality assessments.

Two large wind farms have been modeled and analyzed. The first (and smaller) wind farm consists of 24 wind turbines each rated at 2.3 MW, thus having an installed capacity of 55.2

MW. The second (and larger) wind farm consists of 20 wind turbines of 2.0 MW each and 47 turbines of 2.3 MW each, a total installed capacity of 148 MW.

Figure 6-11 shows how the 148 MW wind farm is modeled and connected to the bulk power system model. The wind farm consists of 67 wind turbines. The 20 wind turbines rated at 2.0 MW are modeled as four wind turbines with reactive compensation for covering the no-load consumption. The remaining 47 wind turbines are modeled as eight wind turbines, thus the wind farm is modeled as 12 wind turbines. The distance from the wind farm substation to the regional grid is approximately 30 km and the transmission line consists of overhead lines, underground and submarine cables. A switched capacitor bank (two steps) is modeled on the common 22 kV bus. The local load (modeled on the 132 kV bus at the farm) is small ($P, Q \approx 8 \text{ MW}, 2 \text{ MVAR}$), compared with the production capacity of the farm, thus the main part of the produced electric energy is transmitted to the regional grid.

In the simulation model, the wind farm models are connected to a detailed model of a larger (national) power system, consisting of more than 2000 buses and over 500 power plants.

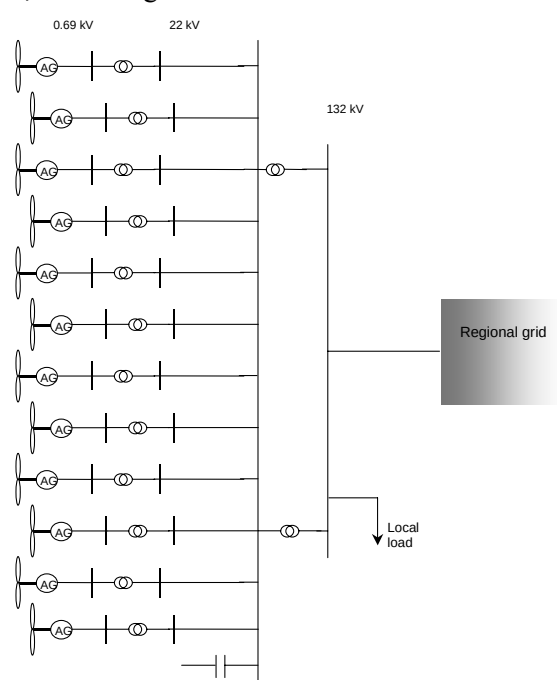


Figure 6-11: Single line diagram (SLD) of the 148 MW wind farm model.

6.4.3 Summary

In this subsection a practical approach for modeling wind farms for dynamic power system studies is presented. The wind farm modeling is based on a dynamic two-mass model for a fixed speed wind turbine connected to a model of an induction generator. The wind turbine model has been validated by comparing with measurements. The power spectral density (PSD) of the model, based on simulation results agrees well with the PSD established from measurements.

The wind turbine model is used as a basic building block for wind farm models. The wind farm modeling approach proves to be flexible and relatively simple yet fairly detailed. It has been shown that the model is applicable for transient and voltage stability analyses, as well as long term simulations (for instance for calculation of power quality parameters).

6.5 Manufacturer Specific Models and Model Validation

A discussion of manufacturer specific models has been delegated to Appendices B, C, and F. In addition, in each of these appendices a discussion has been provided on model validation. As indicated, the primary approach to model validation up to the present time has been to

compare various simplified models to more detailed, 3-phase, equipment level models or to factory tests. More work needs to be done in comparing simulated model response to field recorder behavior in wind farms. Manufacturers and entities such as the WECC Modeling and Validation Working Group are presently working towards this end. Wind farm models and model validation are also the main objectives of the work performed in Task XXI, “Dynamic models of wind farms for power system studies” under the IEA Wind implementing agreement [15], [16].

6.6 Summary

This chapter provides a thorough discussion of the modeling of wind turbine generators and wind farms for the purposes of power system simulations performed typically for transmission system planning and operation. Modeling of wind farms for steady-state power flow analysis and time domain stability analysis is discussed and guidelines provided for modeling considerations. In addition, recommendations are provided for generic model structures and block diagrams for modeling the various types of wind turbine technologies. As a brief summary, the following are the key recommendations with regards to wind turbine generator modeling:

- The following four components of the wind turbine generating system should be modeled in stability studies in order to capture all the relevant dynamics (i) the turbine blade pitch controller and basic aerodynamics for translating wind speed and blade pitch into mechanical power, (ii) the dynamics of the mechanical transmission system, (iii) the electrical characteristics of the generator and (iv) the behavior of the protection systems (specifically, voltage-ride through and over- and under-frequency settings) – these may be emulated using logic statements through monitoring of the machine terminal voltage and frequency.
- It is highly recommended that the mechanical transmission system be modeled as a two mass system with the inherent (and sometimes induced by control) torsional damping properly captured. Due to the relatively low shaft stiffness, there is no common mode of oscillations for which the entire shaft oscillates against the system.
- The four basically different types of wind turbine generators (conventional induction generator, induction generator with variable rotor resistance, doubly-fed asynchronous machine and generator coupled with fully rated converter) require different models.
- For detailed investigations of the turbine controls and protection, component level 3-phase models are required. Some examples of this type of modeling are provided in the Appendices and section 3.2.6.1.
- For conventional induction generator units, it is important to model the fast ramping down of mechanical power and subsequent slower ramping back up of power that is effected in some pitch control systems following a major system disturbance. This power ramp will significantly affect the system voltage recovery.

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SUMMARY AND RECOMMENDATIONS

7.1 Overview

Wind generation technology has matured over the past several decades into an economically viable and environmentally favorable source of energy. Today wind generation has become a significant portion of the generation mix in many countries around the world. This document has focused on describing the dynamic performance, behavior and modeling of this generation resource. In general, wind turbine generators tend to be quite different in both mechanical and electrical construction from traditional large thermal, nuclear and hydro power plants. A wind farm of comparable peak megawatt capacity to a large thermal power plant will consist of many tens to perhaps hundreds of wind turbine generators and span over many square kilometers of land or sea. Each wind turbine generator consists of the mechanical turbine, which typically has three rotor blades that can have a diameter in excess of 80 m, that is connected to a small generator through a slender shaft, often with a gear box in between. There are presently four major concepts for the actual generator:

- a conventional, constant speed, induction generator,
- a variable speed induction generator unit with a variable, external, rotor resistance,
- a variable speed unit with a doubly-fed asynchronous generator, and
- a variable speed unit with a fully rated frequency converter connecting the generator to the electrical grid.

Each of these concepts, together with other emerging concepts such as the hydrodynamic gear drive train turbine, have been discussed and explained in detail in this document.

7.2 Performance, Control and Dynamics of Wind Farms

In the early years of wind turbine generator design, the units were mainly designed for application in distribution systems and as distributed resources. Thus, a typical requirement was for the wind turbine generators to disconnect from the system following a major system disturbance. Presently, most wind farms are of the tens to hundred megawatt range and are connected to major transmission systems. Thus, the expectation is for these generating units to help support the system during major disturbances. With the application of modern wind turbine generator technologies (and occasionally other supplemental devices such as static var compensators etc.) it is possible to build wind farms capable of riding through voltage transients caused by typical transmission system faults and disturbances and having adequate reactive reserves and automatic controls to provide voltage regulation at the point of interconnection. The fault ride through capability of some generator technologies has been described in detail in chapter 3 and some of the appendices.

Of course, the intermittent nature of the energy source (wind) is not controllable, thus this presently still constitutes the major challenge facing operating systems with large amounts of wind generation. Active power control systems have been proposed for wind generators that allow their contribution to frequency and/or tie-line regulation, but this is always at the expense of wasted wind power if no means of energy storage is available.

The exact amount of wind generation that may be incorporated into a system before the burden of operation becomes excessive (usually called maximum penetration of wind power) is highly system dependent, since it is affected by the weather patterns of the region, the type of installed generation capacity in the system, the available power transmission capacity of the system with its neighbors and the contractual obligations governing these

interconnections. The unique and unambiguous determination of such penetration limits is still an open question.

Much progress has been made, particularly with research and development in the science of wind generation forecasting but significant additional work remains in this area as well as considerations related to the potential of marrying wind generation with energy storage technologies that could help with active power regulation as mentioned above.

7.3 Modeling Recommendations

In steady-state power flow analysis, a wind farm should be modeled with at the very least a simplified, but full, representation of the collector system. That is, even if lumped into single components, each component of the wind farm should be modeled, namely:

1. the wind turbine generator,
2. any shunt compensation devices at the generator voltage level, or on the collector system and connection substation,
3. the generator step up transformer,
4. the collector system impedance (taking into account resistance, as well as reactance, and susceptance in the case of underground cables), and
5. the substation transformer stepping up the collector voltage to the transmission system voltage.

Proper modeling of all these components is important. Models that represent the entire wind farm as a single unity power factor generator at the transmission bus are inadequate and can grossly misrepresent the actual reactive consumption of the wind farm. Depending on the nature of the study and the electrical distance of the wind farm being modeled to the region of the electrical system under study, a hierarchy of possible models for the wind farm might be considered. From as simple as a single lumped model of all the wind turbine generators in the wind farm together with an equivalent representation of the collector system (modeling each component explicitly but as a lumped total equivalent, see Figure 6-4 in Chapter 6), to a representation consisting of multiple feeders within the collector system with equivalent groups of machines at the end of each feeder, to a detailed representation of the entire wind farm and collector system. Wind farms that utilize different wind turbine technologies will require at the very least a separate equivalent machine to represent each group of different technology wind turbine generators. In these cases one may lump turbine groups (of the same type) fed by individual feeders. Thus, a wind farm consisting of say fifty wind turbines might be represented by five feeders of groups of ten turbines.

The starting point for dynamic simulation is the steady-state power flow model developed for a wind farm. Again the amount of detail will depend on the study. For example, if one is studying localized issues within an electrical power system (e.g. local voltage stability), depending on the electrical network topology it may not be necessary to model in great detail wind farms that are quite remote to this region – such determination relies heavily on the nature of the problem and topology of the system under study. Conversely, for studies in the electrical vicinity of a wind farm (or group of wind farms) it may be desirable to lump fewer machines together and thus represent the wind farm in more detail because the wind farm may have machines scattered over several tens of kilometers and thus the voltage can vary enough throughout the wind farm to affect the number of units that trip on low voltage. This and other factors should be considered, and the level of detail adjusted to support the study objectives.

One final comment is pertinent with respect to power system studies. Most power system studies are presently performed in positive sequence stability programs. In these programs if one is studying system-wide phenomena such as power system oscillations (inter area modes of rotor oscillation), or frequency instability or slow voltage decay etc., then one is limited to

a bandwidth of up to roughly 2 Hz, because the network model is static and not adequate for studies that go outside this range. For example, one cannot study phenomenon such as subsynchronous resonance (SSR) with torsional modes, ferroresonance with electrical equipment etc. in such positive sequence stability programs. On the other hand, if one is looking at control interactions between controllers that are in the same substation or very close by and thus not affected by the network impedance (e.g. potential interactions between the automatic voltage regulator on a generator and that of a nearby SVC) this can also be studied provided the respective control models are of high enough fidelity and so perhaps the range of simulation bandwidth for such local phenomena may be extended to 10 to 20 Hz. It is within this context that the model structures in chapter 6 are recommended. Furthermore, during such simulations, typically it is assumed that the wind speed is constant for the duration of the simulation. For detailed control interaction studies, the study of phenomena such as SSR etc., more detailed equipment level models (in the range of electromagnetic transients as in EMTP type programs) are needed.

As a brief summary, the following are the key recommendations with regards to wind turbine generator modeling:

- The four main components of the wind turbine generating system should be modeled in stability studies (i) the turbine blade pitch controller and basic aerodynamics for translating wind speed and blade pitch into mechanical power, (ii) the dynamics of the mechanical transmission system, (iii) the electrical characteristics of the generator and (iv) the behavior of the protection systems such as voltage-ride through and over- and under-frequency settings.
- It is highly recommended that the mechanical transmission system be modeled as a two mass system with the inherent (and sometimes induced by control) torsional damping properly captured.
- The four basically different types of wind turbine generators (conventional induction generator, induction generator with variable rotor resistance, doubly-fed asynchronous machine and generator coupled with fully rated converter) require different models.
- For detailed investigations of the turbine controls and protection, component level 3-phase models are required.
- For conventional induction generator units, it is important to model the fast ramping down of mechanical power and subsequent slower ramping back up of power that is effected in some pitch control systems following a major system disturbance. This power ramp will significantly affect the system voltage recovery.

Finally, it should be noted that where studies are performed to investigate the effect of wind gusts on wind farm power output some care should be taken to not overestimate the resulting power fluctuation. The spatial distribution of the wind turbines within a typical wind farm will result in a wide enough variation of wind speed at each turbine, such that the collective farm response to a wind gust will be significantly lesser than if one were to simulate all the wind turbines as seeing the wind gust simultaneously. This statement is pertinent to short duration wind gusts. Clearly, severe weather patterns that last for several hours can affect large numbers of wind turbines and wind farms in entire regions causing large fluctuations in wind generation over a several hour period as has been experience on many systems.

7.4 Recommendations for Future Work

From a modeling development perspective the key item that requires further work is model validation. Although, as documented here mainly in the Appendices, many of the

manufacturer specific models have been validated by the respective manufacturers, work remains to be done to validate the generic types of models presented in chapter 6 against field recordings of wind turbine generator response. Through such work, further refinements to the generic model structures may become evident and necessary, such as the behavior of certain doubly-fed asynchronous machine designs, which incorporate active crowbar controls during and immediately after system faults due to the rotor crowbar circuits being engaged and disengaged (this does not apply to all designs of doubly-fed units).

Further research on the participation of wind generation in primary frequency control, including methods for energy storage, as well as on standards to specify wind power penetration limits is in progress. These and other research subjects concerning the integration of wind farms into power systems can be found in the literature.

APPENDIX A

STEADY-STATE AND SMALL-SIGNAL DYNAMIC BEHAVIOR OF DOUBLY-FED ASYNCHRONOUS GENERATORS

This appendix presents a detailed discussion with mathematical derivations, for the steady-state and small-signal dynamic behavior of the doubly-fed asynchronous generator¹ (DFAG). The first section is concerned with model derivation and interpretation. The difference between the synchronous generator and DFAG modeling for stability studies is explained. The second section discusses the DFAG steady-state behavior. Stator and rotor voltage, current and power are given as a function of rotor speed. The third section summarizes results of parametric studies made in the frequency domain. The most influential parameters and variables on the DFAG dynamic behavior are assessed and identified.

A.1 Doubly-Fed Asynchronous Generator Modeling

A.1.1 Conventional dq-Model

The convention adopted in this work for positive current, voltage and flux directions is shown in Figure A-1. By applying the Kirchhoff voltage law to each circuit of Figure A-1, the three-phase DFAG voltage equations are obtained.

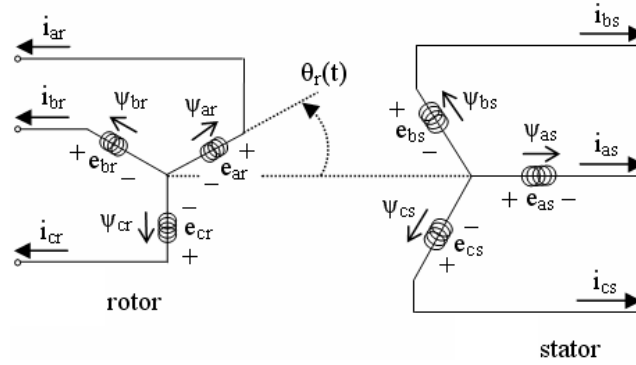


Figure A-1: DFAG stator and rotor three-phase circuits.

Assuming a balanced system and sinusoidal distribution of stator and rotor windings, the machine equations can be written in a two-axis synchronously rotating frame, referred to as the dq-frame [1]. With the power invariant abc-to-dq transformation and the d-axis leading the q-axis [2], the following set of equations is obtained:

$$v_{qs} = -\frac{1}{\omega_{elB}} \frac{d}{dt} \psi_{qs} + \omega_s \psi_{ds} - R_s i_{qs} \quad (1)$$

$$v_{ds} = -\frac{1}{\omega_{elB}} \frac{d}{dt} \psi_{ds} - \omega_s \psi_{qs} - R_s i_{ds} \quad (2)$$

$$v_{qr} = -\frac{1}{\omega_{elB}} \frac{d}{dt} \psi_{qr} + s \omega_s \psi_{dr} - R_r i_{qr} \quad (3)$$

¹ As indicated in Chapter 3, in this report the terminology doubly-fed asynchronous generator is used in lieu of the more commonly used term doubly-fed induction generator (DFIG).

$$v_{dr} = -\frac{1}{\omega_{elB}} \frac{d}{dt} \psi_{dr} - s\omega_s \psi_{qr} - R_r i_{dr} \quad (4)$$

$$\psi_{qs} = L_{ss} i_{qs} + L_m i_{qr} \quad (5)$$

$$\psi_{ds} = L_{ss} i_{ds} + L_m i_{dr} \quad (6)$$

$$\psi_{qr} = L_{rr} i_{qr} + L_m i_{qs} \quad (7)$$

$$\psi_{dr} = L_{rr} i_{dr} + L_m i_{ds} \quad (8)$$

where v , ψ and i stand for voltage, flux linkages and current; the subscripts d and q stand for d- and q-axis components; the subscripts s and r stand for stator and rotor variables; $\omega_s = 1$ pu is the per unit synchronous speed; $s = (\omega_s - \omega_r)/\omega_s$ is the slip; ω_r is the rotor speed; R and L are resistance and inductance; L_m is the mutual inductance; L_{ss} and L_{rr} are mutual inductance plus leakage inductance for the stator and rotor respectively. The factor $1/\omega_{elB}$ ($\omega_{elB} = 2\pi f_s$ [rad/s]) indicates that time is in seconds while all other variables and parameters are in per unit.

Equations (1)-(4) show that stator and rotor voltage in each axis is determined by three terms: a transformer voltage (voltage due to flux change in time), a speed voltage (voltage due to flux change in space), and a resistive voltage drop.

A.1.2 dq-Model for Stability Studies

In power system stability studies the practice is to represent generators by a transient voltage behind transient impedance, as shown on Figure A-2.

This equivalent model is adequate as long as the power delivered to the grid corresponds to the stator power. For the DFAG with back-to-back converters, shown on Figure A-3, the total delivered power is the sum of both stator and grid-side converter power. To account for this in the equivalent model, a current source is added in parallel at the terminal, as shown on Figure A-4. The impedance $\bar{Z}_T$ represents the step-up transformer between the grid-side converter and the stator terminal.

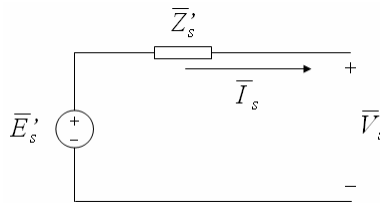


Figure A-2: Conventional generator model for stability studies.

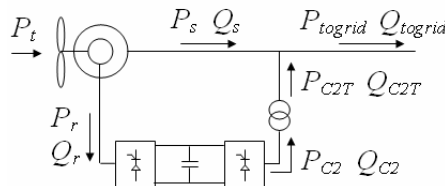


Figure A-3: DFAG with back-to-back converters.

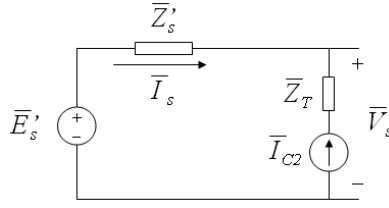


Figure A-4: DFAG model for stability studies.

The DFAG model equations (1)-(8) can be rewritten in terms of the variables shown on Figure A-4 with the following definitions of variables:

$$e'_{qs} = K_{mrr} \omega_s \psi_{dr} \quad (9)$$

$$e'_{ds} = -K_{mrr} \omega_s \psi_{qr} \quad (10)$$

$$L'_s = L_{ss} - (L_m^2 / L_{rr}) \quad (11)$$

$$T_r = L_{rr} / R_r \quad (12)$$

where $K_{mrr} = L_m / L_{rr}$. The variables e'_{qs} and e'_{ds} are proportional to the rotor flux ψ_{dr} and ψ_{qr} respectively. It is shown below that $\bar{E}'_s = e'_{qs} + j e'_{ds}$ can be interpreted as a transient voltage source behind a transient impedance. Substituting (9)-(12) in (1)-(8) gives the following equations:

$$\frac{1}{\omega_{elB}} \frac{d}{dt} L'_s i_{qs} = -R_1 i_{qs} + \omega_s L'_s i_{ds} + \frac{\omega_r e'_{qs}}{\omega_s} - \frac{e'_{ds}}{\omega_s T_r} - v_{qs} + K_{mrr} v_{qr} \quad (13)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} L'_s i_{ds} = -\omega_s L'_s i_{qs} - R_1 i_{ds} + \frac{e'_{qs}}{\omega_s T_r} + \frac{\omega_r e'_{ds}}{\omega_s} - v_{ds} + K_{mrr} v_{dr} \quad (14)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} \frac{e'_{qs}}{\omega_s} = R_2 i_{ds} - \frac{e'_{qs}}{\omega_s T_r} + \left(1 - \frac{\omega_r}{\omega_s}\right) e'_{ds} - K_{mrr} v_{dr} \quad (15)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} \frac{e'_{ds}}{\omega_s} = -R_2 i_{qs} - \left(1 - \frac{\omega_r}{\omega_s}\right) e'_{qs} - \frac{e'_{ds}}{\omega_s T_r} + K_{mrr} v_{qr} \quad (16)$$

$$i_{qr} = -(e'_{ds} / X_m) - K_{mrr} i_{qs} \quad (17)$$

$$i_{dr} = (e'_{qs} / X_m) - K_{mrr} i_{ds} \quad (18)$$

$$\psi_{qs} = -(1/\omega_s) e'_{ds} + (X'_s / \omega_s) i_{qs} \quad (19)$$

$$\psi_{ds} = (1/\omega_s) e'_{qs} + (X'_s / \omega_s) i_{ds} \quad (20)$$

where $R_1 = R_s + R_2$, $R_2 = K_{mrr}^2 R_r$ and $X'_s = \omega_s L'_s$. A convenient way to interpret (13)-(20) is to consider q- and d-axis variables as real and imaginary parts of complex variables. Grouping

$\{(13)-(16)\}+j\{(14)+(15)\}$ and $\{(13)+(16)\}+j\{(14)-(15)\}$ and notating complex variables with an overline, gives:

$$\bar{V}_s = \bar{E}_s' - \bar{Z}_s' \bar{I}_s - \frac{1}{\omega_{elB}} \frac{d}{dt} \left(L_s' \bar{I}_s + j \frac{\bar{E}_s'}{\omega_s} \right) \quad (21)$$

$$\bar{V}_r = \bar{E}_r' - R_r \bar{I}_r - \frac{1}{\omega_{elB}} \frac{d}{dt} \left(j \frac{\bar{E}_s'}{\omega_s K_{mrr}} \right) \quad (22)$$

where $\bar{E}_r' = (s/K_{mrr})\bar{E}_s'$ and $\bar{Z}_s' = R_s + jX_s'$. It is seen that for both stator and rotor circuits, the terminal voltage is equal to a transient voltage source minus a voltage drop across an impedance and minus a term that is only non-zero during transients. Similarly, grouping $\{(17)+j(18)\}$ and $\{(19)+j(20)\}$ gives:

$$\bar{I}_r = j \frac{\bar{E}_s'}{X_m} - K_{mrr} \bar{I}_s \quad (23)$$

$$\bar{\Psi}_s = j \frac{\bar{E}_s'}{\omega_s} + L_s' \bar{I}_s \quad (24)$$

The DFAG equivalent circuit in terms of complex variables can be drawn by considering (21) and (22) in steady-state, as shown in Figure A-5. Obviously, stator and rotor circuit are coupled; the relationships of their interdependence are given by $\bar{E}_r' = (s/K_{mrr})\bar{E}_s'$ and (23).

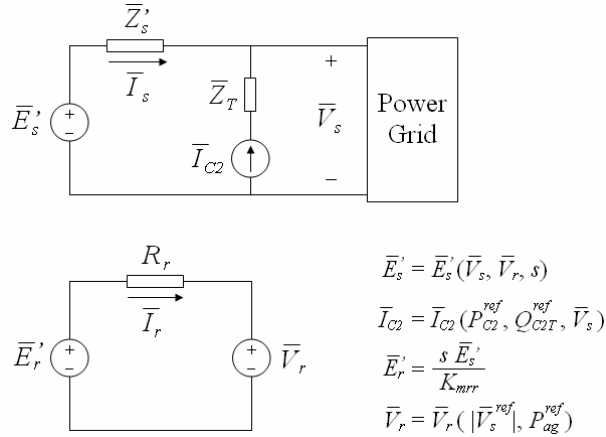


Figure A-5: DFAG stator and rotor model for stability studies.

The equivalent model of Figure A-5 fully and adequately represents the grid connected DFAG, reflecting that total delivered power is the sum of stator and grid-side converter powers. Active and reactive powers are obtained conveniently as real and imaginary parts of the product of complex voltage and current-conjugate, e.g. $P_s = \text{Re}\{\bar{V}_s \bar{I}_s^*\}$ and $Q_s = \text{Im}\{\bar{V}_s \bar{I}_s^*\}$.

The steady-state value of the stator transient voltage $\bar{E}_s'$ (rotor flux scaled and phase shifted) can be obtained from (21)-(23) by eliminating the currents $\bar{I}_s$ and $\bar{I}_r$:

$$\bar{E}_s' = \bar{E}_s'(\bar{V}_s, \bar{V}_r, s) = \frac{\frac{\bar{V}_r}{R_r} + \frac{K_{mrr} \bar{V}_s}{\bar{Z}_s'}}{\frac{1}{jX_m} + \frac{s}{K_{mrr} R_r} + \frac{K_{mrr}}{\bar{Z}_s'}} \quad (25)$$

This equation shows that the stator transient voltage depends on the stator terminal voltage (determined by power flows on the whole power system), the rotor voltage (injected by the rotor-side converter), and the slip (determined by the DFAG mechanical input and electrical load).

In Figure A-5 it is seen that by varying the rotor voltage $\bar{V}_r$, transient voltages and machine currents are changed. In other words it is possible to control terminal voltage and maximize power capture by regulating the injected rotor voltage. This is shown by the relation $\bar{V}_r = \bar{V}_r \left(|\bar{V}_s^{ref}|, P_{ag}^{ref} \right)$ where $|\bar{V}_s^{ref}|$ is the reference terminal voltage magnitude and P_{ag}^{ref} is the airgap reference characteristic that is determined for maximum power capture.

For the grid-side converter (C_2), the current injected to the grid depends on the converter control which is decoupled for active and reactive power. For the active power, the objective is to maintain the dc-link voltage constant. This is achieved by maintaining $P_{C2}^{ref} = P_r$. For the reactive power, the reference value can be fixed arbitrarily. With $Q_{C2}^{ref} = \alpha Q_s$, the portion of reactive power coming from the grid-side converter via the step-up transformer is $Q_{C2T}/Q_{tograd} = \alpha/(1+\alpha)$ where Q_{C2T} is the reactive power at the terminal node (Q_{C2T} equals Q_{C2} minus transformer reactive losses). Choosing $\alpha = 0$ means that the reactive power is fully delivered or absorbed by the DFAG stator, in which case the rating of C_2 is minimized.

A.2 Doubly-Fed Asynchronous Generator Steady-State Analysis

A.2.1 Controllability and Control Objectives

The fact that the DFAG rotor voltage is non-zero, gives the DFAG two additional degrees of freedom. This means that two additional constraints have to be imposed so that the rotor voltage to be injected can be determined. For grid connected wind turbine generators, a sensible choice is to impose a constraint for maximum power capture (airgap power constraint or equivalently electrical torque constraint) and another for voltage control (reactive power constraint).

These objectives can be conveniently achieved by formulating the control of the *rotor-side* converter in a synchronously rotating two-axis reference frame aligned with the stator voltage. In this way, torque and voltage control are decoupled and can be taken care of separately by the two axes.

This alignment with stator voltage is to be contrasted with the alignment along stator flux that is sometimes also suggested for DFAG control. Usually alignment with flux is done for induction motor applications, in which case one axis maintains constant flux while the other regulates the torque for speed control [3]. When stator resistance is negligible these two alignment alternatives are equivalent. However, since for grid connected DFAG the explicit objective is to maintain constant terminal voltage, the alignment along stator voltage is more justified.

For DFAG with a back-to-back converter, the control of the *grid-side* converter has to be coordinated so that the dc-link voltage is constant and the desired sharing of reactive power with the stator is achieved. The reactive power sharing between the stator and grid-side converter can be chosen arbitrarily. For minimum converter rating, no sharing is done and the reactive power delivered to the grid comes only from the stator.

A.2.2 Steady-State Operating Points

Injecting non-zero rotor voltage makes the DFAG conceptually more similar to a synchronous generator than an induction generator. Indeed the operating characteristics of the DFAG and conventional induction generator are completely different. For the conventional induction generator the short circuited rotor requires that the machine operates at strictly

supersynchronous speed as no active power is produced at zero slip (and at subsynchronous speed the machine becomes a motor). For the DFAG the additional two degrees of freedom makes synchronous and subsynchronous operation with power production possible. This is shown below by determining the DFAG operating points as function of rotor speed.

From section A-1, the steady-state equations of the grid connected DFAG can be summarized as:

$$\bar{V}_s = \bar{E}_s' - \bar{Z}_s' \bar{I}_s \quad (26)$$

$$\bar{V}_r = \bar{E}_r' - R_r \bar{I}_r \quad (27)$$

$$P_{ag}^{ref}(\omega_r) = \text{Re}\left\{\bar{E}_s' \bar{I}_s^*\right\} + \text{Re}\left\{\bar{E}_r' \bar{I}_r^*\right\} \quad (28)$$

$$P_{tgrid} = \text{Re}\left\{\bar{V}_s \bar{I}_s^*\right\} + \text{Re}\left\{\bar{V}_s \bar{I}_{C2}^*\right\} \quad (29)$$

$$Q_{tgrid}^{ref} = (1 + \alpha) \text{Im}\left\{\bar{V}_s \bar{I}_s^*\right\} \quad (30)$$

$$\bar{V}_{C2} = \bar{V}_s + \bar{Z}_T \bar{I}_{C2} \quad (31)$$

$$\text{Re}\left\{\bar{V}_{C2} \bar{I}_{C2}^*\right\} = \text{Re}\left\{\bar{V}_r \bar{I}_r^*\right\} \quad (32)$$

$$\text{Im}\left\{\bar{V}_s \bar{I}_{C2}^*\right\} = (\alpha/(1 + \alpha)) Q_{tgrid} \quad (33)$$

Equations (26) and (27) are the voltage equations of the DFAG stator and rotor. Equations (28) and (30) are the two additional constraints required to determine the rotor voltages. Equations (29) and (30) are the total active and reactive power delivered by the DFAG to the grid. Equation (31) is the voltage equation for the grid side converter C_2 . Equation (32) is the active power output of C_2 . Equation (33) is the reactive power output of C_2 minus the transformer reactive losses.

Equation (28) corresponds to the airgap power constraint for maximum power capture (speed control). The reference airgap power is determined from the turbine performance curve so that captured wind power is maximized when the rotor speed ω_r is below a certain threshold, and constant when ω_r is above that threshold. The two operating regimes are referred to as maximum power tracking (MPT) regime and constant power tracking (CPT) regime. Figure A-6 shows $P_{ag}^{ref} = P_{ag}^{ref}(\omega_r)$ with the threshold speed chosen as the synchronous speed $\omega_s = 1$ pu. It is noted that due to mechanical stress and converter rating limitations the actual speed range of the turbine is smaller than that shown on Figure A-6.

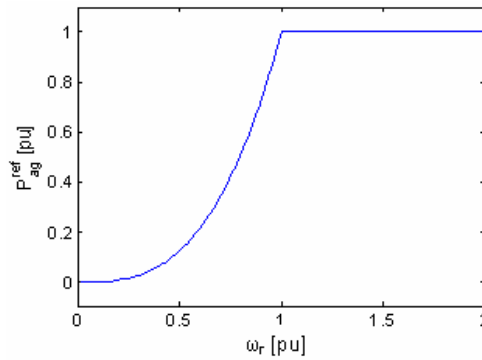


Figure A-6: Reference airgap power as function of turbine speed.

Equation (30) corresponds to the reactive power constraint for voltage control. For open-loop control the reference reactive power level is determined by the initial power flow solution; for closed-loop control it is determined as a function of terminal voltage magnitude error. The parameter α in (30) and (33) can be chosen arbitrarily with $\alpha/(1+\alpha)$ representing the portion of total reactive power coming from converter C_2 through the step-up transformer. This additional degree of freedom corresponds to the reactive power control loop of the *grid-side* converter.

The DFAG steady-state characteristics as function of rotor speed are obtained by solving (26), (27), (28) and (30) for $\bar{I}_s$, $\bar{E}_s$ and $\bar{V}_r$ (which is a system of 6 equations 6 unknowns when considering real and imaginary parts separately) for given $\bar{V}_s$, P_{ag}^{ref} , Q_{logrid}^{ref} and α . Results are shown in the following for $\bar{V}_s = 1$ pu, P_{ag}^{ref} of Figure A-6, $Q_{logrid}^{ref} = 0.1$ pu and $\alpha = 0$.

Figure A-7 shows the steady-state active and reactive power of the DFAG as a function of rotor speed. Positive power flow directions are shown on Figure A-3. It is assumed that the back-to-back converter is a lossless device and the step-up transformer presents only reactive losses, so that the active power delivered to the grid is the sum of stator and rotor active power i.e. $P_{logrid} = P_s + P_{C2T}$ with $P_{C2T} = P_{C2} = P_r$. The parameter α is assumed as zero, so that the reactive power delivered to the grid is the stator reactive power i.e. $Q_{logrid} = Q_s + Q_{C2T}$ with $Q_{C2T} = \alpha Q_s = 0$. Zooming Figure A-7 (b) shows that at synchronous speed, rotor reactive power is zero i.e. $Q_r(\omega_r=1) = 0$ as expected since all rotor variables are dc variables, and rotor active power is negative $P_r(\omega_r=1) < 0$ which is the absorbed rotor power corresponding to resistive losses.

Figure A-8 (a) shows the steady-state rotor voltage magnitude of the DFAG as function of rotor speed. The approximation $V_r \approx |s|V_s$ can be observed. At zero slip ($\omega_r = 1$ pu) the rotor voltage is not zero and there is a dc-current flowing through the rotor resistance. Figure A-8 (b) shows the steady-state rotor and stator current magnitudes of the DFAG as function of rotor speed.

It is seen that in per unit (with common base values) the rotor current magnitude is higher than stator current magnitude. The rotor voltage and current characteristics show the importance of suitable design choice for both the stator-rotor turn ratio n_{sr} and the speed range over which the DFAG is allowed to operate. For smaller rotor currents it is desirable to put more turns on the rotor side; from a mechanical point of view less rotor turns is more advantageous (lighter rotor body). Clearly there is a compromise to be made between the costs of converters, mechanical components and transformers in the rotor circuit design. A good compromise is to use an effective ratio n_{sr} of 1:1 with delta-connected stator windings and star-connected rotor windings [4]. Alternatively, to avoid transformers in the rotor circuit, the ratio n_{sr} can be selected such that the voltage rating of the converters matches the stator voltage at maximum speed [5]. In fact, most manufactured designs of DFAGs (as shown in Chapter 3) adhere to this approach, namely the line side converter connects directly to the stator without any transformation. The only transformer employed is the generator step-up that transforms the stator voltage up to the collector system voltage.

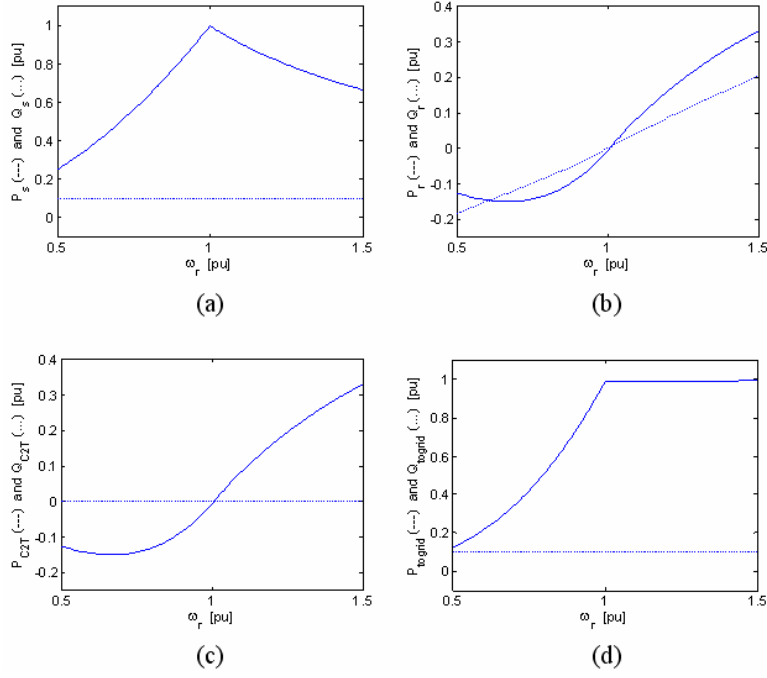


Figure A-7: Steady state active (continuous) and reactive (dotted) power of the DFAG as function of rotor speed: (a) stator power, (b) rotor power, (c) grid-side converter power minus step-up transformer losses, (d) total power to grid.

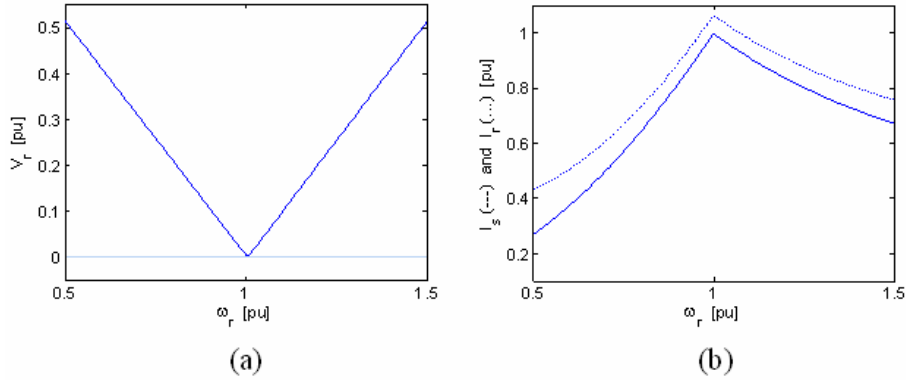


Figure A-8: Steady state voltage and current of the DFAG as function of rotor speed: (a) rotor voltage magnitude, (b) stator (continuous) and rotor (dotted) current magnitudes.

To conclude it can be said that for larger absolute values of Q_{togrid}^{ref} and lower values of $\bar{V}_s$, the currents of Figure A-8 are larger. This is because losses increase with the magnitude of reactive power, and higher currents are required to produce same levels of power at lower voltage.

A.3 Doubly-Fed Asynchronous Generator Small-Signal Analysis

A.3.1 Initialization

System initialization is the calculation of initial steady-state operating point and is required for both time and frequency domain analysis. For conventional synchronous generator models initialization is quite straightforward since the speed is known (synchronous) and only stator power is delivered to the grid. For given output variables (power flow solution), the calculation of input variables can be done by solving successively in the right order the individual algebraic and differential equations (with zero time derivative term) [6].

In contrast, for a DFAG speed is unknown (not necessarily synchronous) and the grid-side converter also feeds power to the grid. The initialization of the DFAG is hence different, requiring simultaneous solution of coupled equations. Figure A-9 shows the DFAG initialization procedure.

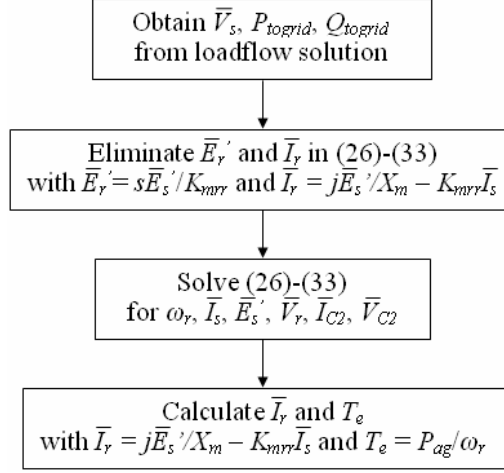


Figure A-9: Step by step initialization of the DFAG.

It is seen that the DFAG initialization does not depend on the type of prime mover used (it could be a motor, gas turbine or wind turbine). For a wind turbine generator, the prime mover is the turbine which has wind speed v_w as its input, pitch angle β as a parameter, rotational speed ω_t as its state variable and mechanical torque T_m as its output. The DFAG initialization gives $\omega_t = \omega_r$ [pu] and $T_m = P_{ag}(\omega_r)/\omega_t$ (losses neglected); hence the input v_w can be obtained from the turbine power equation and performance characteristic (given later in (41) and (42)) for different values of pitch angle.

A.3.2 Small Signal Analysis of DFAG in Open-loop

To understand the inherent dynamics of the DFAG and the influence of parameters, small-signal analysis is done to observe the DFAG modes. To begin, the analysis is done with fixed terminal voltage, fixed rotor voltage, and fixed mechanical torque. Assuming fixed terminal voltage means that the external grid is infinitely strong. Assuming fixed rotor voltage means that the control loop is an open-loop with reference values remaining fixed at the values given by the initialization. Assuming fixed turbine torque means that there is no disturbance from the wind.

Obtaining the state matrix A

The set of differential equations of the studied system is given as:

$$\frac{1}{\omega_{elB}} \frac{d}{dt} L_s' i_{qs} = -R_1 i_{qs} + \omega_s L_s' i_{ds} + \frac{\omega_r e_{qs}'}{\omega_s} - \frac{e_{ds}'}{\omega_s T_r} - v_{qs} + K_{mrr} v_{qr} \quad (34)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} L_s' i_{ds} = -\omega_s L_s' i_{qs} - R_1 i_{ds} + \frac{e_{qs}'}{\omega_s T_r} + \frac{\omega_r e_{ds}'}{\omega_s} - v_{ds} + K_{mrr} v_{dr} \quad (35)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} e_{qs}' = R_2 i_{ds} - \frac{e_{qs}'}{\omega_s T_r} + \left(1 - \frac{\omega_r}{\omega_s}\right) e_{ds}' - K_{mrr} v_{dr} \quad (36)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} e_{ds}' = -R_2 i_{qs} - \left(1 - \frac{\omega_r}{\omega_s}\right) e_{qs}' - \frac{e_{ds}'}{\omega_s T_r} + K_{mrr} v_{qr} \quad (37)$$

$$2H_g \frac{d}{dt} \omega_r = T_{shaft} - T_e \quad (38)$$

$$\frac{1}{\omega_{elB}} \frac{d}{dt} \theta_{tw} = \omega_t - \omega_r \quad (39)$$

$$2H_t \frac{d}{dt} \omega_t = \frac{P_t}{\omega_t} - T_{shaft} \quad (40)$$

Equations (34)-(37) are the generator voltage equations; their derivation has been discussed in section A.1.2. Equations (38)-(40) are the drive-train equations. They show that a two-mass drive train is assumed. The parameters H_t and H_g are the turbine and generator inertia in [s]. The state variables ω_t , ω_r and θ_{tw} are the turbine and generator speed in [rad/s] and shaft twist angle in [rad]. The variables P_t , T_{shaft} and T_e are the turbine power, shaft torque and generator electrical torque in [pu]; their expression are given further below.

The importance of modeling the drive train should be explained. For conventional power plants with synchronous generators the stiffness of the turbine-generator shaft between the generator and turbine and between adjacent turbine segments is much higher in comparison to the equivalent electrical stiffness between the generator and electrical system. This fact results in nearly equal participation of all inertias in the low frequency non-torsional mode (referred to as the “system mode” [1]). The other natural modes are the torsional modes and typically have frequencies higher than 7 Hz [1]. Hence, for studies focusing on low frequency oscillations (0.5 – 2 Hz) the lumped-mass model can be used.

For wind turbine generators however, the shaft connecting the generator and turbine is relatively slender and long and the generator is a much lighter inertia than the turbine [7], [8]. Thus, the stiffness (spring constant) between the two masses (generator and turbine) is actually relatively low and comparable in magnitude to the equivalent electrical stiffness between the generator and electrical system. This would be particularly true for weak systems. Thus, there is no drive-train mode (eigenvalue) in which both the generator and turbine participate equally, as is the case with large thermal turbine-generators (the mode referred to as the “system mode” [1]).

Thus, there is no “system mode” for which the drive-train acts as a lumped-mass, and so a multi-mass drive train *must be* considered. The justification of the two mass drive train is not uniquely the fact that the torsional mode is of lower frequency for wind turbine generators, but solely for the fact that there is no mode in which all inertias participate equally i.e. there is no mode for which the drive train behaves as an equivalent single mass.

There is no need to model the hub and blades with additional masses because the associated modes are either well damped or out of the frequency range of interest [9]. Finally, it should be noted that manufacturers (see section 6.2.1) of DFAG systems often have active damping loops implemented in the machine controls to provide damping for the torsional mode. The effects of such active damping should be taken into consideration in system studies. Such damping loops have not been modeled here.

The mechanical input power P_t in (40) is the portion of wind power that is captured by the turbine:

$$P_t = 0.5\rho\pi R^2 C_p(\lambda, \beta) v_w^3 \frac{1}{S_B} \quad (41)$$

where $0.5\rho\pi R^2 v_w^3$ [W] is the rate of change of kinetic energy associated with the mass of air with density ρ [kg/m³] passing through the area πR^2 [m²] at speed v_w [m/s] [10]. The factor $1/S_B$ where S_B is the base power indicates that P_t is in [pu]. The coefficient C_p known as the turbine performance coefficient reflects the fact that captured power is only a portion of available wind power (theoretical maximum = Betz limit [10]). In practice C_p -curves are provided by manufacturers; for academic purposes numerical approximations may be used [7], [11]:

$$C_p(\lambda, \beta) = c_1 \left(\frac{c_2}{\lambda + c_8 \beta} - \frac{c_2 c_9}{\beta^3 + 1} - c_3 \beta - c_4 \beta^{c_5} - c_6 \right) \dots$$

$$\dots \exp \left(\frac{-c_7}{\lambda + c_8 \beta} + \frac{c_7 c_9}{\beta^3 + 1} \right) + c_{10} \lambda \quad (42)$$

It is noted that (41) is an algebraic equation. For stability studies, turbine dynamical models are generally not used because of their complexity (and disputed reliability [12]). When turbine dynamics are considered the airflow around the blades are modeled using boundary element methods, wake or computational fluid dynamic methods [13], [14]. The computational cost involved is more justified for turbine design purposes.

The shaft torque in (38) and (40) is associated with the stored potential energy in the twisted shaft and losses due to friction:

$$T_{shaft} = k \theta_{tw} + c \left(\frac{d}{dt} \theta_{tw} \right) \quad (43)$$

where k [pu/el.rad] is the shaft stiffness, c [pu.s/el.rad] is the shaft damping coefficient, and $d\theta_{tw}/dt$ is given in (39).

The generator electrical torque in (38) is the airgap power divided by the rotor speed. Since airgap power is output power plus losses i.e. $P_{ag} = P_s + P_r + P_{losses}$ where $P_s = \text{Re}\{\bar{V}_s \bar{I}_s^*\}$, $P_r = \text{Re}\{\bar{V}_r \bar{I}_r^*\}$, $P_{losses} = R_s |\bar{I}_s|^2 + R_r |\bar{I}_r|^2$, the electrical torque is obtained as:

$$T_e = (L_m / L_{rr}) (i_{qs} i_{dr} - i_{ds} i_{qr}) \quad (44)$$

Alternatively, using the variables defined to model the DFAG as a voltage source behind impedance, the airgap power is given as $P_{ag} = \text{Re}\{\bar{E}_s' \bar{I}_s^*\} + \text{Re}\{\bar{E}_r' \bar{I}_r^*\}$ so that the electrical torque is obtained as:

$$T_e = (\bar{e}_{ds}' / \omega_s) i_{ds} + (\bar{e}_{qs}' / \omega_s) i_{qs} \quad (45)$$

Equations (34)-(39) are a set of non-linear differential equations $dx/dt = f(x, u)$ where $x = [i_{qs}, i_{ds}, e_{qs}', e_{ds}', \omega_r, \theta_{tw}, \omega_l]'$ and $u = [v_{qr}, v_{dr}, P_t]'$. For small-signal analysis, these equations are linearized around an operating point. The corresponding linear time-invariant system is given as $d\Delta x/dt = A\Delta x + B\Delta u$ where $A = \partial f / \partial x|_{x0, u0}$ and $B = \partial f / \partial u|_{x0, u0}$.

Base Case

Table A-1 gives the parameter values that are considered as base case. Table A-2 shows the eigenvalues $\lambda = \sigma \pm j\omega$ of the state matrix A for the base case parameters. Table A-3 gives the corresponding time constant τ , frequency of oscillation f_{osc} [Hz], damping ratio ζ , and participation factors p_{ki} .²

² For a state matrix A , the mode associated with the eigenvalue $\lambda = \sigma \pm j\omega$ has time constant $\tau = 1/|\sigma|$ [s], frequency of oscillation $f_{osc} = \omega/2\pi$ [Hz], and damping ratio $\zeta = -\sigma/\sqrt{\sigma^2 + \omega^2}$ [1]. The participation factor of the k^{th} state variable into the i^{th} eigenvalue is defined as $p_{ki} = |\Psi_{ik}| |\Phi_{ki}| / (\sum_{k=1:n} |\Psi_{ik}| |\Phi_{ki}|)$ where Ψ_{ik} and Φ_{ki} are the k^{th} element of the i^{th} mode left and right eigenvectors respectively (normalization so that p_{ki} is a fraction of 1) [15].

Table A-1. Base case parameters.

Turbine	Drive train	DFAG									
$P_{rated} = 2 \text{ MW}$	$n_{gb} = 57.2$	$P_{togrid} = 1 \text{ pu}$	$V_s = 1 \text{ pu}$								
$v_{w,rated} = 12 \text{ m/s}$	$k = 0.3 \text{ pu/elrad}$	$Q_{togrid} = 0 \text{ pu}$	$\omega_r = 1 \text{ pu}$								
$\rho = 1.225 \text{ kg/m}^3$	$c = 0$	$X_m = 4 \text{ pu}$	$n_{pp} = 2$								
$R = 35.4 \text{ m}$	$H_t = 4 \text{ s}$	$R_s = X_m/800$	$L_{ss} = 1.01 L_m$								
$C_p \text{ see } c_1 - c_{10}$	$H_g = 0.1 H_t$	$R_r = 1.1 R_s$	$L_{tr} = 1.005 L_{ss}$								
c1	c2	c3	c4	c5	c6	c7	c8	c9	c10	Cpmax	Lopt
0.5176	116	0.4	0	0	5	21	0.08	0.035	0.0068	0.48	8.1

Table A-2. Base case eigenvalues $\lambda = \sigma \pm j\omega$.

	σ	ω
λ_1	-0.31	3.38
λ_2	-8.01	63.57
λ_3	-16.16	313.31
λ_4	-17.44	0

Table A-3. Base case mode properties.

	τ	f_{osc}	ζ	P_{ias}	P_{ids}	$P_{eas'}$	$P_{eds'}$	P_{or}	P_{etw}	P_{ot}
λ_1	3.2	0.54	0.092	-	-	-	.01	-	.49	.50
λ_2	0.13	10.12	0.125	.02	.01	.01	.47	.46	.01	-
λ_3	0.062	49.86	0.052	.48	.46	.02	.03	-	-	-
λ_4	0.057	0	1	-	.01	.98	.01	-	-	-

The system has four stable modes, three of which are oscillatory modes. The dominant mode (slowest mode) has a very low frequency of 0.54 Hz. The participation factors in Table A-3 show the physical nature of the modes: λ_1 is a mechanical mode associated with turbine and shaft; λ_2 is an electro-mechanical mode associated with rotor q-flux & generator speed; λ_3 is an electrical mode associated with stator currents; λ_4 is an electrical mode associated with rotor d-flux. From the participation factors, it also appears that the modes are decoupled. The frequency of the electro-mechanical mode λ_2 (10.12 Hz) is much higher than that of conventional synchronous generators ($< 2.5 \text{ Hz}$). The reason is that in the present case only one DFAG (MW range) is considered; hence its inertia is much smaller than that of synchronous generator (hundreds of MW range). For studies of whole wind farms with aggregate models it can be anticipated that the frequency of λ_2 is more similar to that of conventional synchronous generator plant.

To show the importance of modeling adequacy, Table A-4 and A-5 show the modes when using the lumped-mass drive train model and generator classical model respectively. Obviously the one-mass drive train model does not replicate the dominant mode correctly, and the generator model without electrical transients does not reproduce the electro-mechanical mode. These observations stress the importance of considering the shaft flexibility and at least the rotor q-flux transient.

Table A-4: Modes for reduced order model with one-mass drive train.

	τ	f_{osc}	ζ	P_{ias}	P_{ids}	$P_{eas'}$	$P_{eds'}$	P_{or}	P_{etw}	P_{ot}
λ_1	0.12	2.72	0.452	.01	-	-	.50	.49	x	x
λ_2	0.063	49.86	0.051	.48	.48	.02	.02	-	x	x
λ_3	0.057	0	1	-	.01	.99	-	-	x	x

Table A-5: Modes for reduced order model with classical generator.

	τ	f_{osc}	ζ	P_{ias}	P_{ids}	P_{vas}	P_{vds}	P_{cor}	P_{etw}	P_{cot}
λ_1	3.1	0.55	0.092	x	x	x	x	-	.50	.50
λ_2	0.004	0	1	x	x	x	x	.99	-	-

Stator Transients

For stability studies of synchronous generators, network electro-magnetic transients and machine stator transients are not included because they are associated with fast and high frequent dynamics that are not of interest. It is therefore useful to check whether DFAG stator transients can also be ignored. In Table A-3, λ_3 is the stator mode. As it is in the high frequency range, with a small time constant and decoupled from the other modes, stator dynamics can indeed be ignored. This means that stator state variables can be considered as algebraic variables i.e. they change instantaneously. When stator state variables are coupled with other states, neglecting them may give significantly different and hence incorrect dynamic behavior. It is therefore useful to check if the decoupling condition holds for reasonable DFAG parameter ranges and operating conditions.

Parametric studies reveal that shaft stiffness has no noticeable effects on the stator mode. However in case of low inertia, low magnetizing reactance (large airgap), and high ratio R_s/X_m , the participation of stator states become significant in the electro-mechanical mode. In the present study, the stator states participation in the electro-mechanical mode exceeds 10% for $H_t \leq 1.3$ s and $L_m \leq 1$ pu, and $R_s/X_m \geq 1/125$.

Effect of initial rotor speed

Since the DFAG may operate at large slip, it is important to study how its dynamic behavior changes with rotor speed. For the different initial rotor speeds and corresponding active power levels of Table A-6, the locus of λ_1 and λ_2 are shown in Figure A-10 (a) and A-11 (a). The corresponding variation of damping ratio and oscillating frequency are shown in Figure A-10 (b) and A-11 (b).

Interestingly, some degree of symmetry can be observed around synchronous speed ($\omega_r = 1$ pu) in the latter Figures. If the slip range is limited to $\pm 10\%$, the change in oscillation frequency is also limited to $\pm 10\%$. At larger slip, the increase in oscillation frequency is steeper.

Table A-6: Investigated initial rotor speeds and corresponding active power levels.

ω_r	sub-synchronous speed							super-synchronous speed						
	0.67	0.74	0.8	0.85	0.89	0.97	1	1.05	1.1	1.15	1.2	1.25	1.3	
P_{tegrid}	0.3	0.4	0.5	0.6	0.7	0.8	1	1	1	1	1	1	1	
	MPT regime							CPT regime						

It can be shown by observing the participation factors that at non-synchronous speed, the electrical states participate more heavily in λ_1 and λ_2 . For $s = \pm 0.3$ the participation of stator states in λ_2 exceeds 8%. Another observation is that at non-synchronous speed, λ_1 becomes an electro-mechanical mode. For the base case (synchronous speed) λ_1 is a mechanical mode with dynamics mainly associated with the turbine and shaft. As slip increases, the contribution of the turbine dynamics in λ_1 decreases, being replaced by that of rotor d-flux and rotor speed dynamics.

The effect of initial rotor speed on λ_3 (stator mode) is shown in Figure A-12 (a). As rotor speed increases, the oscillation frequency of this mode is not affected (imaginary component is nearly constant) and the damping decreases (absolute value of real component decreases); however the scale of the real axis indicates that the effect is not significant.

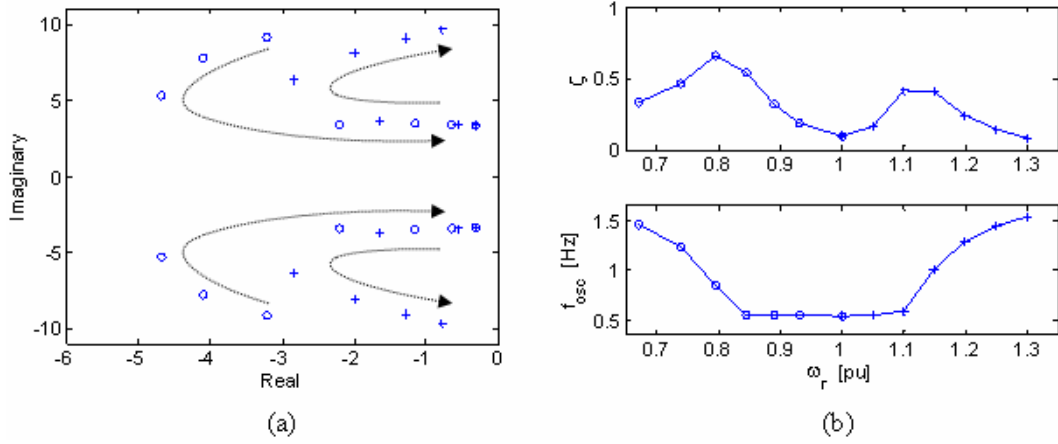


Figure A-10: Effect of initial rotor speed on λ_1 : (a) eigenvalue locus; (b) damping ratio and oscillation frequency. The arrows show the direction of speed increase. The symbols $\circ$, $+$ and $\oplus$ are used for sub-, super- and synchronous speed respectively.

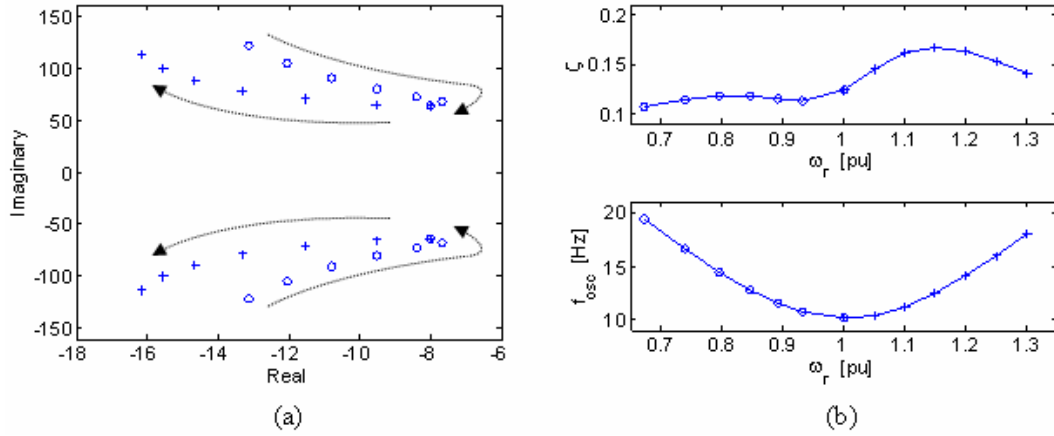


Figure A-11: Effect of initial rotor speed on λ_2 : (a) eigenvalue locus; (b) damping ratio and oscillation frequency. The arrows show the direction of speed increase. The symbols $\circ$, $+$ and $\oplus$ are used for sub-, super- and synchronous speed respectively.

The effect of initial rotor speed on λ_4 (real mode) is shown in Figure A-12 (b). The eigenvalue is furthest away from the imaginary axis at synchronous speed. At non-synchronous speeds, its absolute value decreases dramatically and λ_4 becomes the dominant mode. As λ_4 is real, this means that at larger slip a new steady-state condition is reached after a disturbance at a slower pace (longer rising time).

Effect of terminal voltage magnitude

For the different initial terminal voltage magnitudes of Table A-7, the locus of λ_1 and λ_2 are shown in Figure A-13 (a) and A-14 (a). The corresponding variation of damping ratio and oscillating frequency are shown in Figure A-13 (b) and A-14 (b).

At severely depressed voltage, the mechanical mode λ_1 becomes two distinct real eigenvalues. For the electro-mechanical mode λ_2 , the oscillation frequency decreases significantly with the voltage ($f_{osc} = 2.56$ Hz at $V_s = 0.2$ pu compared to 10.12 Hz in base case). During over-voltages, the dominant mode λ_1 goes closer to the imaginary axis. As λ_1 is a pair of complex conjugates, this means that oscillations are damped out at slower pace (longer settling time).

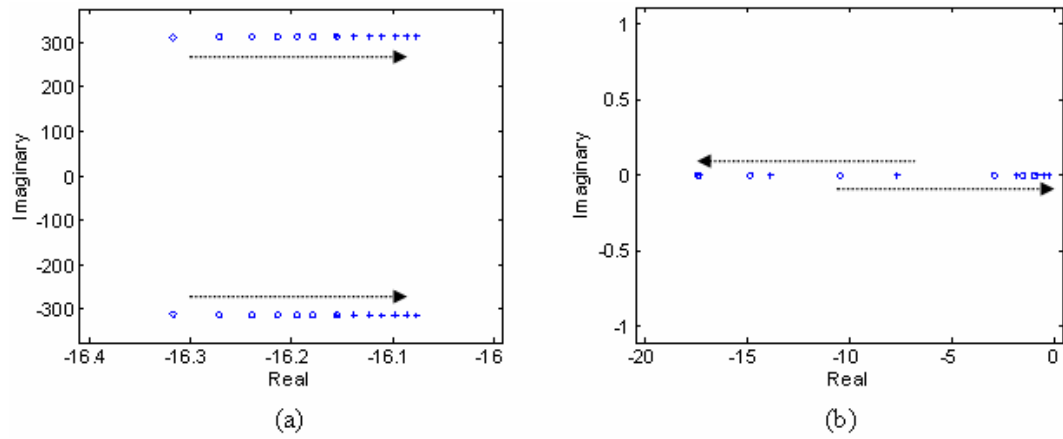


Figure A-12: Effect of initial rotor speed: (a) locus of λ_3 ; (b) locus of λ_4 . The arrows show the direction of speed increase. The symbols $\circ$, $+$ and $\oplus$ are used for sub-, super- and synchronous speed respectively.

Table A-7: Investigated initial terminal voltage magnitudes.

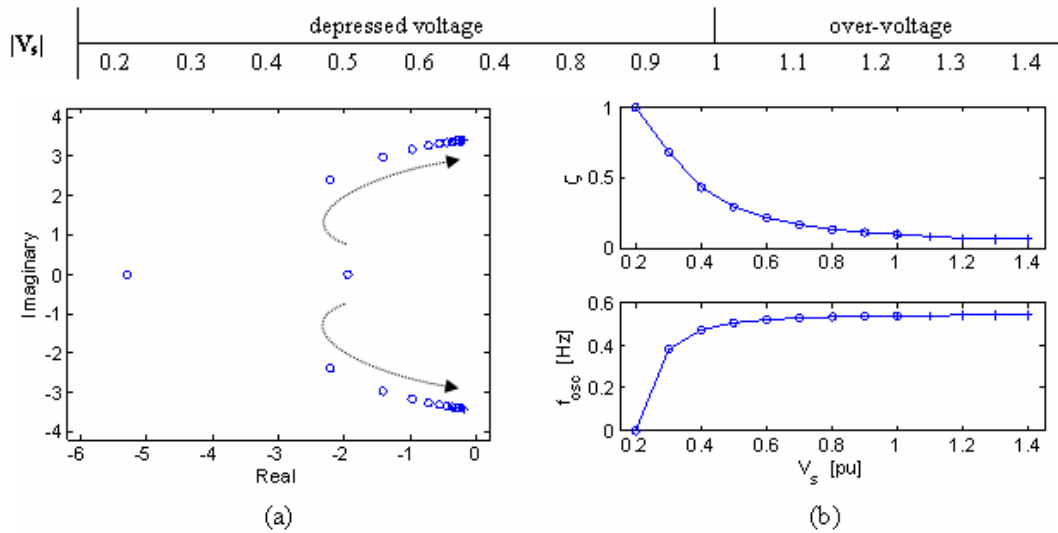


Figure A-13: Effect of initial terminal voltage magnitude on λ_1 : (a) eigenvalue locus; (b) damping ratio and oscillation frequency. The arrows show the direction of voltage increase. The symbols $\circ$, $+$ and $\oplus$ are used for depressed, over- and unity voltage respectively.

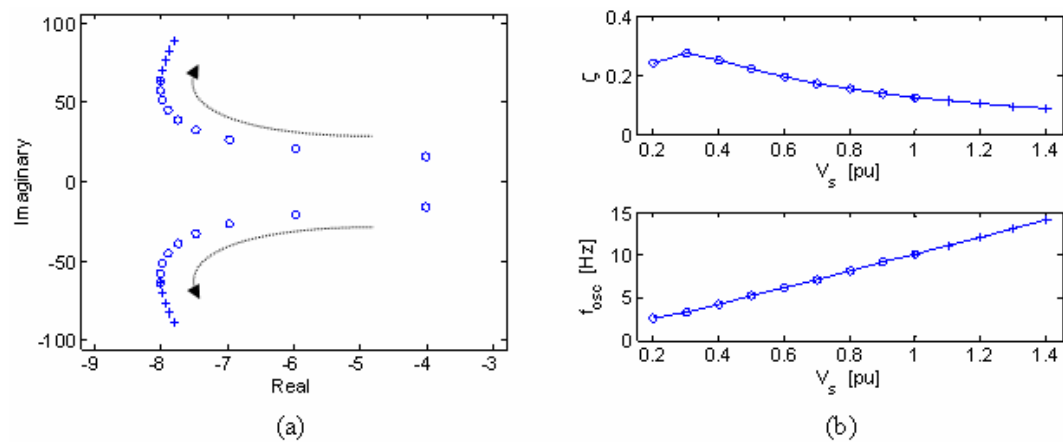


Figure A-14: Effect of initial terminal voltage magnitude on λ_2 : (a) eigenvalue locus; (b) damping ratio and oscillation frequency. The arrows show the direction of voltage increase. The symbols $\circ$, $+$ and $\oplus$ are used for depressed, over- and unity voltage respectively.

It can be shown by observing the participation factors that when the voltage is depressed there is more coupling between the state variables. For $\bar{V}_s = 0.2$ pu the participation of stator states in λ_2 are about 7% and λ_1 becomes an electro-mechanical mode. As slip increases, the contribution of shaft dynamics in λ_1 decreases, being replaced by that of rotor q-flux and rotor speed dynamics.

The locus of λ_3 and λ_4 for the initial voltage levels of Table A-7 are shown on Figure A-15. Noting the scale of the real axis it is seen that the effect of initial voltage magnitude on λ_3 and λ_4 is not significant.

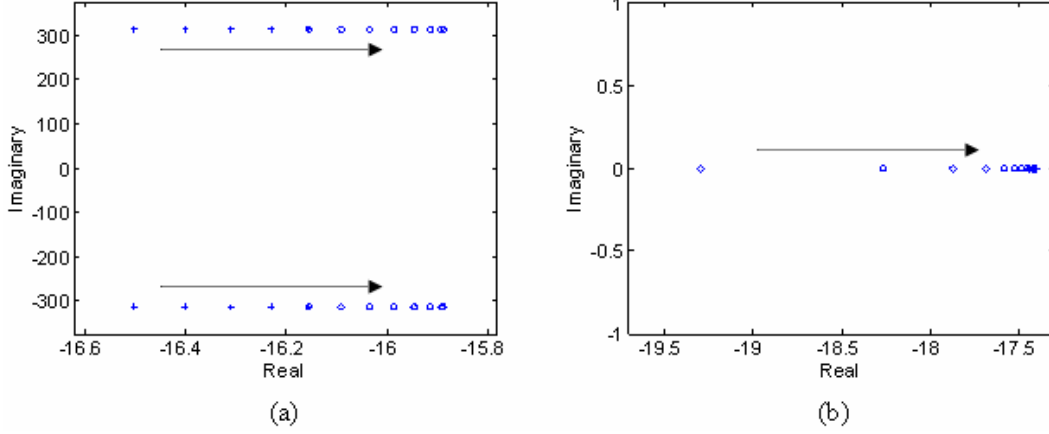


Figure A-14: Effect of initial terminal voltage magnitude: (a) locus of λ_3 ; (b) locus of λ_4 . The arrows show the direction of voltage increase. The symbols $\circ$, $+$ and $\oplus$ are used for depressed, over- and unity voltage respectively.

Effect of external line reactance

In the above discussion the stator voltage has been assumed constant, meaning that the external grid is infinitely strong (zero impedance between DFAG bus and infinite bus). The corresponding system state matrix is $A = \partial f / \partial x|_{x0,u0}$. If however the DFAG is connected to the infinite bus through a finite reactance, the terminal voltage is not constant and becomes an algebraic variable $z = [v_{qs} \ v_{ds}]^T$. If $\partial g / \partial z|_{x0,z0,u0}$ is invertible, where g is the set of algebraic equations describing the power flows over the line, the corresponding system state matrix becomes $A = (\partial f / \partial x|_{x0,z0,u0} - A_g)$ where $A_g = (\partial f / \partial z (\partial g / \partial z)^{-1} \partial g / \partial x)|_{x0,z0,u0}$.

For the external line reactance values of Table A-8, it has been observed that the effect of X_e is only significant for λ_3 (stator mode) and λ_4 (real mode). Figure A-16 shows the root locus and mode properties of the stator mode.

Table A-8: Investigated initial external line reactance values.

X_e	0	0.01	0.025	0.05	0.075	0.1	0.125	0.15
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As X_e increases (i.e. as the external grid is weaker) λ_3 moves towards the right hand plane. For too large X_e the stator mode becomes unstable, requiring closed-loop control or series compensation to reduce the effective X_e . It can also be shown that grid strength does not affect the participation factors. As a result although frequency and damping change, the stator mode remains decoupled from the other modes. For the real mode λ_4 , as X_e increases, it also moves towards the right hand plane but remains negative ($\lambda_4 = -17.44$ for $X_e = 0$ pu, $\lambda_4 = -7.04$ for $X_e = 0.15$ pu).

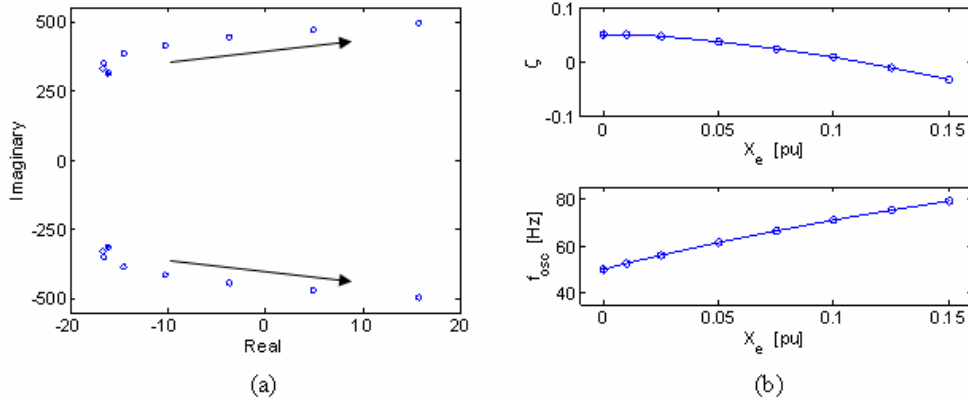


Figure A-16: Effect of initial line reactance value on λ_3 : (a) eigenvalue locus; (b) damping ratio and oscillation frequency. The arrows indicate the direction of increasing X_e . The symbol $\oplus$ is used for the base case ($X_e = 0$).

A.4 Summary and Conclusion

When modeling DFAG it is important to account for the two additional constraints required for the determination of rotor voltage. In grid connected wind turbine generator applications these constraints are formulated for the airgap power (for maximum power capture) and reactive power (voltage control).

For DFAG with back-to-back converters it is also important to represent correctly the contribution of the grid-side converter (C_2) in the power balance. The active power P_{C2} is equal to the rotor active power; the reactive power Q_{C2} or Q_{C2T} can be chosen arbitrarily. If $Q_{C2T} = 0$ the total reactive power delivered to the grid is produced by the stator only and the rating of C_2 is minimized (reactive power required from C_2 is only transformer losses).

For stability studies of wind turbine generators, it is important to model a two mass shaft system due to the relatively low spring constant between the generator and turbine, and the high inertia of the turbine compared to that of the generator. These features result in the fact that there is no “system mode” i.e. there is no mode for which the drive train behaves as an equivalent single mass. The low stiffness of the shaft and the difference in inertias are adequately represented by the two-mass drive train model. It should be noted, however, that manufacturers (see section 6.2.1 and B.4.7) of DFAG systems often have active damping loops implemented in the machine controls to provide damping for the low frequency torsional mode. The effects of such active damping should be taken into consideration in system studies. This active damping has not been modeled here.

Parametric studies with small-signal analysis reveal that for sufficiently efficient DFAG (small airgap and low ratio R_s/X_m) connected to turbines with sufficient inertia, the stator dynamics can be neglected in stability studies because they are not in the frequency range of interest and are not coupled with the dynamics of interest. For DFAG operating at very large slip and severely depressed voltage however, neglecting stator dynamics can be inaccurate.

Initial rotor speed and terminal voltage affect mostly the two slowest oscillating modes of the DFAG. Within a limited speed range ($s = \pm 10\%$) the modal properties do not change significantly. For low voltage level, oscillation frequencies are lower, damping ratios higher and steady state current magnitudes much larger. The grid strength affects mostly the stator mode, which has higher frequency and lower damping for weaker grids. The stator mode may become unstable when the external line reactance is too large.

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APPENDIX B

DYNAMIC MODEL OF GE's 1.5 AND 3.6 MW WIND TURBINE GENERATORS – MODEL STRUCTURE, SIMULATION RESULTS, AND MODEL VALIDATION

B.1 Introduction

This appendix documents the present recommendations for dynamic modeling of wind power plants of GE Energy's 1.5 and 3.6 MW wind turbine generators for use in studies related to the integration of such wind power plants into power grids. The wind turbine model is as detailed as is appropriate for bulk power system studies. The individual dynamic models presented here are specific to GE's wind turbines. Subsequent sections include recommended model structure and data, as well the assumptions, capabilities and limitations of the model. Dynamic performance comparisons with a more detailed model are also included.

It is valuable to put the wind turbine model characteristics in the context of the type of analysis for which the model was developed. First and most important, the model is for positive sequence phasor time-domain simulations – e.g., GE PSLF® or Siemens PTI PSS/E® software programs. Second, it is assumed that the analysis is mainly focused on how the wind turbines react to grid disturbances, e.g., faults, on the transmission system. Third, the model provides for calculation of the effect of wind speed fluctuation on the electrical output of the wind turbine. Details of the actual equipment dynamics have been substantially simplified. Specifically, the very fast dynamics associated with the control of the generator converter have been modeled as algebraic (i.e., instantaneous) approximations of their response. Representation of the turbine mechanical controls has been simplified as well. The wind turbine model is not intended for use in short circuit studies or electromagnetic transient studies.

The wind turbine model is based on design information, test data, and extensive engineering judgment available at the time the model was developed. The model structure and parameter values continue to be updated in order to best reflect the relevant characteristics of the actual hardware, as experience and additional test data are obtained, and so, it is *essential* that model structure and data parameters be confirmed by GE for the specific application for critical evaluations for wind power plant performance.

B.2 Model Overview and Philosophy

B.2.1 Fundamentals

A simple schematic of an individual 1.5 or 3.6 MW wind turbine is shown in Figure B-1. GE's wind turbine generators are unusual from a system simulation perspective. Physically, the 1.5 or 3.6 MW machine is a relatively conventional wound rotor induction machine. However, the key distinction is that this machine is equipped with a solid-state voltage-source converter ac excitation system. The ac excitation is supplied through an ac-dc-ac converter. For the 3.6 MW machine the converter will be connected as shown or to a third winding on the main unit step-up transformer. For the 1.5 MW machine it is connected directly at the stator winding voltage. Machines of this structure are termed 'doubly-fed,' and have significantly different dynamic behavior than either conventional synchronous or induction machines.

The fundamental frequency electrical dynamic performance of GE's wind turbine is completely dominated by the converter. Conventional aspects of generator performance related to internal angle, excitation voltage, and synchronism are largely irrelevant. In practice, the electrical behavior of the generator and converter is that of a current-regulated voltage-source inverter. Like other voltage-source inverters (e.g., BESS or STATCOM), the

wind turbine converter synthesizes an internal voltage behind a transformer reactance, which results in the desired active and reactive current being delivered to the device terminals.

In the case of the doubly-fed machines, the machine rotor and stator windings are primary and secondary windings of the transformer. The rotation of the machine means that the ac frequency on the rotor winding corresponds to the difference between the stator frequency (50 or 60 Hz) and the rotor speed. This is the slip frequency of the machine. In the vicinity of rated power, GE's 1.5 and 3.6 MW machines will normally operate at 120% speed, or -20% slip. Control of the excitation frequency allows the rotor speed to be controlled over a wide range, $\pm 30\%$. The rotation also means that the active power is divided between the stator and rotor circuits, roughly in proportion to the slip frequency. For rotor speeds above synchronous, the rotor active power is injected into the network through the converter. The active power on the rotor is converted to terminal frequency (50 or 60 Hz), as shown in Figure B-1.

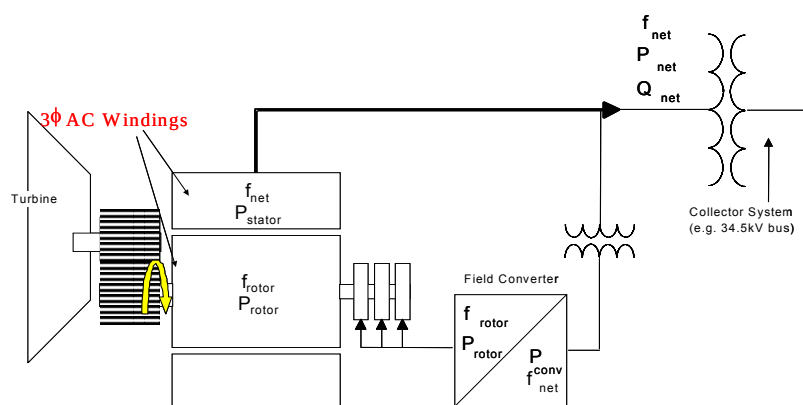


Figure B-1: GE's 1.5 and 3.6 MW Wind Turbine Major Components.

In addition to controlling the rotor speed, the reactive power output of the generator can be controlled by varying the magnitude of the rotor currents. This gives the doubly-fed machine the voltage regulation capability of a synchronous generator but with greater speed of response. The control of active and reactive power is handled by fast, high bandwidth regulators within the converter controls. The time responses of the converter regulators are sub-cycle, and as such can be greatly simplified for simulation of bulk power system dynamic performance.

Broadly stated the objectives of the turbine control are to maximize power production while maintaining the desired rotor speed and avoiding equipment overloads. There are two controls (actuators) available to achieve these objectives: blade pitch control and torque order to the electrical controls (the converter). The turbine model includes all of the relevant mechanical states and the speed controls. The implementation of the turbine model, while relatively complex, is still considerably simpler than the actual equipment. Losses are not considered throughout the model, since "fuel" efficiency is not presently a consideration.

The model presented here describes the relevant dynamics of a single GE wind turbine. However, the primary objective of the model is to allow for analysis of the dynamic performance of groups of wind turbines and their interactions with the bulk power system. Wind power plants with GE's wind turbines normally include a wind power plant management system (WindCONTROL). Currently, the only component of this system is the Wind Volt-Ampere-Reactive (WindVar) control system, which interacts with the individual wind turbines through the electrical controls. Representation of all the individual machines in a large wind power plant is inappropriate for most grid stability studies. Therefore, provisions have been made within the model structure to allow a single wind turbine machine model (suitably sized) to provide a realistic approximation to the way that an integrated

system will behave. The model implementation allows the user access to parameters that might reasonably be customized to meet the particular requirements of a system application.

B.2.2 Overall Model Structure

From a power flow perspective, there are two standard components that need to be included in the power flow setup and are required for initialization of the dynamic simulation program: generator and transformer. These two components use conventional power flow device models, and can be represented in any power flow program.

The implementation is structured in a fashion that is similar to conventional generators. To construct a complete wind turbine model, three device models are used, as shown in Figure B-2:

1. Generator/converter model (Injects real and reactive current into the network in response to control commands and represents low and high voltage protective functions, e.g., low voltage ride through capability.)
2. Electrical control model (includes closed and open loop reactive power controls including the WindVar system)
3. Turbine and turbine control model (mechanical controls, including blade pitch control and power order – torque order in the actual equipment – to converter; over/under speed trips; rotor inertia equation; wind power as a function of wind speed, blade pitch, and rotor speed.)

In addition, user-written models can be used for the following:

- Generator/converter protection model (trips generator for under/over frequency and other application specific special protective functions)
- Wind gust model (varying input wind speed to the turbine model)

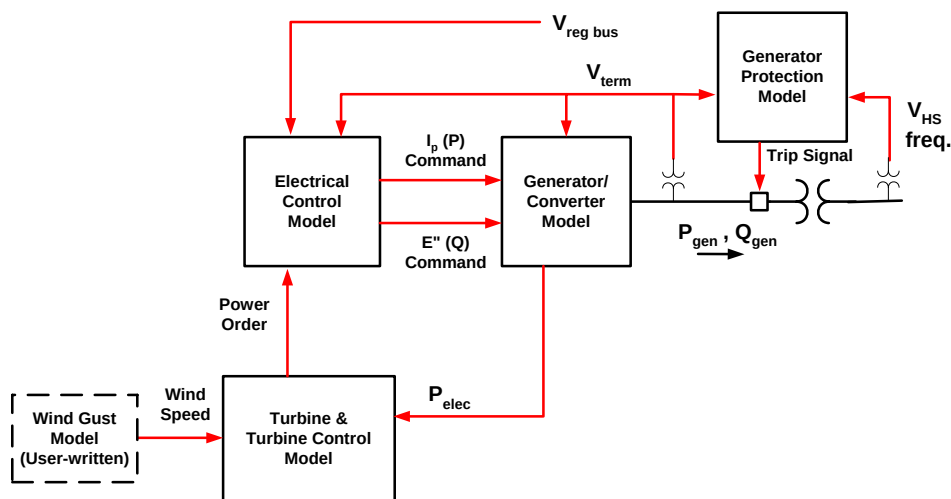


Figure B-2: GE's Wind Turbines Dynamic Model Connectivity

B.3 Modeling for Power Flow

Wind power plants normally consist of a large number of individual wind turbines. The wind power plant model may consist of a detailed representation of each machine and the collector system. Alternatively, the simpler model shown in Figure B-3 is adequate for most bulk transmission system studies. This model consists of a single wind turbine and unit transformer with MVA ratings equal to N times the individual device ratings, where N is the number of wind turbines in the wind power plant (or those considered to be on-line for study purposes). An equivalent impedance to reflect the aggregate impact of the collector system

can be included together with the substation step-up transformer(s). The total charging capacitance of the collector system should also be included. The charging capacitance can be significant since underground cables are often used for the collector system. A third alternative is to model several groups of machines, each represented by a single model, with a simplified representation of the collector system.

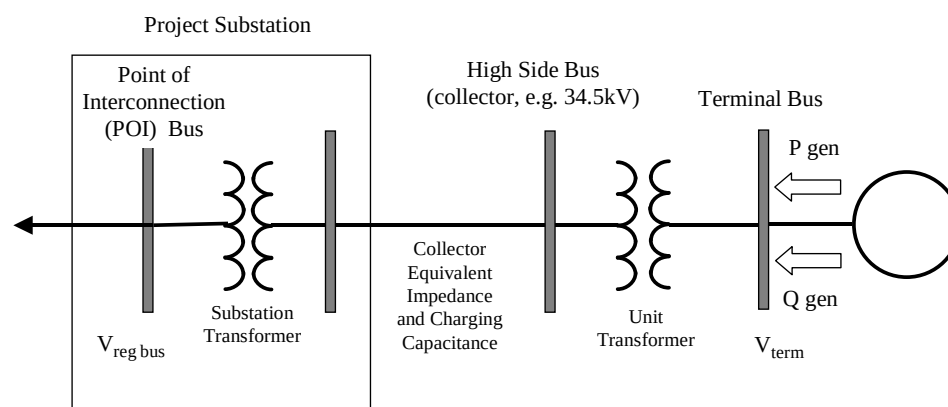


Figure B-3: Load Flow Model

Table B-1: Load Flow Data on GE's Wind Turbine Generators.

	1.5 MW	3.6 MW
Generator rating	1.67 MVA	4 MVA
Pmax	1.5 MW	3.6 MW
Pmin	0.2 MW	0.5 MW
Qmax	0.493 MVar *	2.08 MVar **
Qmin	-0.726 MVar *	-1.55 MVar **
Terminal voltage (60 Hz)	575 V	4160 V
Terminal voltage (50 Hz)	690 V	3300 V
Unit Transformer Rating	1.75 MVA	4 MVA
Unit Transformer Z	5.75%	7%
Unit Transformer X/R	7.5	7.5

* To produce power factor at terminals of 0.95 overexcited / 0.90 underexcited

(Note: Some of GE's 1.5 MW wind turbine generators can go to higher MVar, e.g. 0.9 power factor, overexcited)

** To produce 0.90 power factor at unit transformer high side

The nominal voltage at the generator terminals depends on the wind turbine size and frequency as shown in Table B-1. Table B-1 also shows the generator P_{gen} , Q_{max} and Q_{min} , and typical unit transformer ratings and impedances. Typical collector system voltages are at distribution levels (12.5 kV or 34.5 kV are common in 60 Hz applications, 33 kV in 50

Hz applications). The substation transformer would be suitably rated for the number of machines, with impedance typically around 10%.

The WindVar system is typically structured to measure the voltage at a particular bus, often the point of interconnection (POI) with the transmission system, and regulate this voltage by sending a reactive power command to all of the wind turbines. Line drop compensation may be used to regulate the voltage at a point some distance from the voltage measurement bus. For power flow modeling of the WindVar, the aggregate machine (or each machine) should be set to regulate the remote bus at the desired voltage regulation point.

B.4 Dynamic Model

B.4.1 Generator/Converter Model

This model is the equivalent of the generator and the field converter and provides the interface between the wind turbine and the network. Unlike a conventional generator model, it contains no mechanical state variables for the machine rotor – these are included in the turbine model. Further, unlike conventional generator models, all of the flux dynamics have been eliminated to reflect the rapid response to the higher level commands from the electrical controls through the converter. The net result is an algebraic, controlled-current source that computes the required injected current into the network in response to the flux and active current commands from the electrical control model. The model is shown in Figure B-4.

The converter controls include a phase-locked loop to synchronize the generator rotor currents with the stator. The converter phase-locked loop (PLL) has the effect of establishing a reference frame for the wind turbine voltages and currents. Transiently, θ can change instantaneously during system disturbances, but the rate of change of δ is limited by the PLL logic. Typical values for K_{pll} and $d\delta_{max}$ are 30 and 0.1, respectively, and provide a conservative estimate of the PLL tracking.

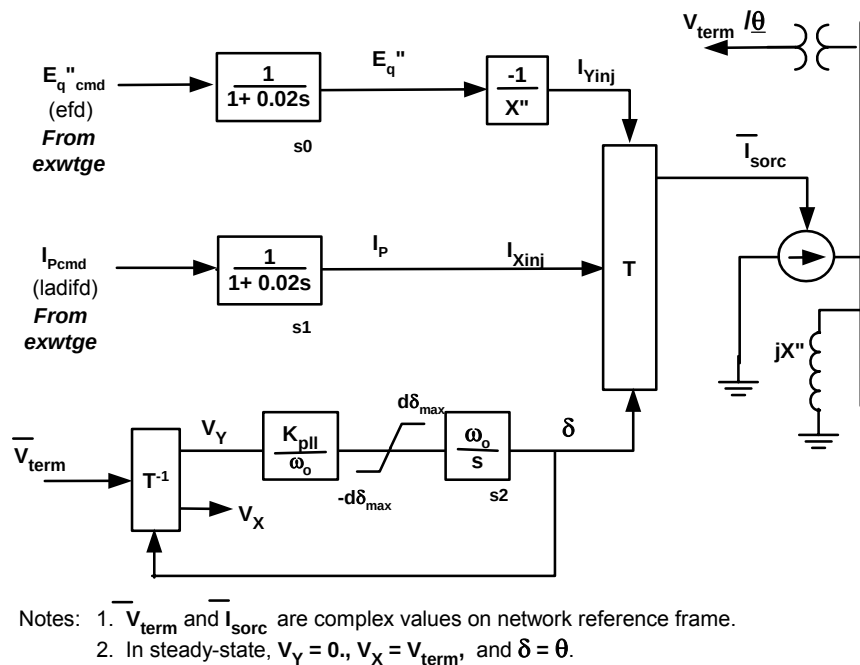


Figure B-4: Generator/Converter Model

The model includes two small time constants (20 ms) to represent lags in converter action. Comparison with more detailed models of the generator and controls has shown that this is an accurate model of the combined behavior of the doubly-fed generator and its rotor converter when the value of X'' is set to 0.80 pu (on the generator MVA rating) for both the 1.5 and 3.6 MW wind turbines. (Note: X'' represents an effective equivalent reactance and is not the

actual subtransient reactance of the doubly-fed induction generator. T represents the generator-network reference frame transformation.)

B.4.2 Electrical (Converter) Control Model

This model dictates the active and reactive power to be delivered to the system based on inputs from the turbine model (P_{ord}) and from the supervisory VAR controller (Q_{ord}). Q_{ord} can either come from a separate model or from the WindVar Emulation function included in the Electrical Control Model. Q_{ord} can also be held constant or determined by a power factor regulator. The model consists of the following control functions: WindVar Emulation, Power Factor Regulator, Electrical (Volt/VAr) Controller, and Open Loop Control Logic (used only on some older systems). The block diagram for the Electrical Control model is shown in Figure B-5.

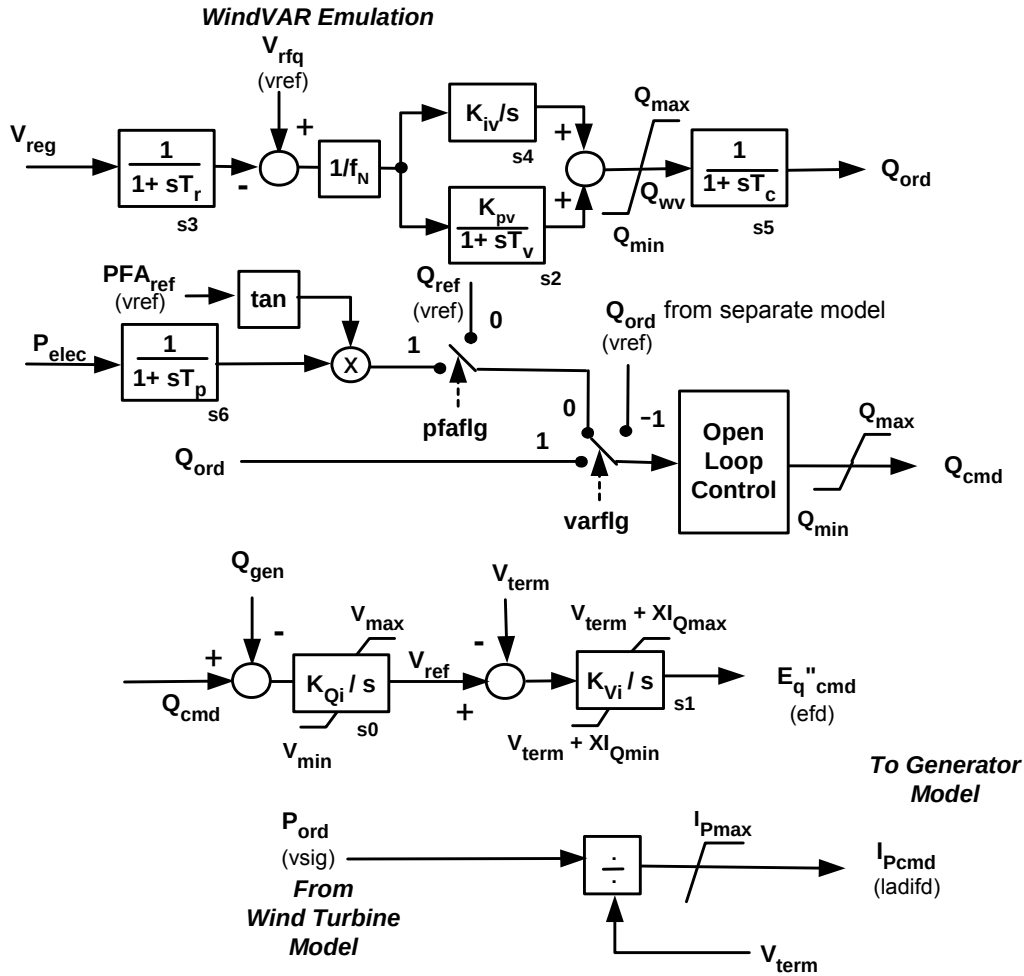


Figure B-5: Electrical Control Model

B.4.3 WindVar Emulation

The WindVar Emulation function represents a simplified equivalent of the supervisory VAR controller for the entire wind power plant. The function monitors a specified bus voltage and compares it against the reference voltage. The regulator itself is a PI controller. The time constant, T_c , reflects the delays associated with cycle time, communication delay to the individual wind turbines, and additional filtering in the controls. The voltage measurement lag is represented by the time constant T_r . Table B-2 gives suggested settings for the WindVar Emulation model. The gains are field adjustable to improve performance and may be adjusted in the model, if necessary. The given values should be suitable for systems with

Short Circuit Capacity of five or more times the wind power plant MW rating. For weaker system, some reduction in the gains may be desirable.

The parameter, f_N , is the fraction of wind turbines in the wind power plant that are on-line. For example, if a case represents a condition with half of the wind turbines on-line, f_N should be set to 0.5. In this case the MVA base of the generator should also be set to one-half of its full value, and the MW capability of the turbine should be set to one-half of its full value. If a wind power plant is represented by more than one wind turbine model, the f_N values of each should be set to the same value.

Table B-2: WindVar Emulator Parameters

(all power quantities are per unit on MVA base – 1.67 or 4.0 MVA)

Parameter Name	Recommended Value	
	1.5 MW	3.6 MW
$T_r(\text{sec})$	0.05	
$T_v(\text{sec})$	0.05	
f_N	1.0	
$T_c(\text{sec})$	0.15	
K_{pv}	18	
K_{iv}	5.0	
$Q_{\max}(\text{pu})$	0.296*	0.52
$Q_{\min}(\text{pu})$	-0.436	0.39

* 0.436 on some of GE's 1.5 MW Wind Turbines

B.4.4 Electrical Controller

The electrical controller model is a simplified representation of the converter control system. This model monitors the generator reactive power, Q_{gen} , and terminal voltage, V_{term} to compute the voltage and current commands $E_{q \text{ cmd}}$ and $I_{p \text{ cmd}}$.

Several options are provided by settings of the **varflg**, **pfaflg**, and **Kvi** parameters, as follows:

- **Operation with WindVar and with North American “volt/VAr” control - varflg = 1, pfaflg = 0, Kqi = 0.1** – This represents the normal configuration for recent and future North American wind power plants, using the WindVar emulator in the model to represent the wind power plant management system.
- **Operation without WindVar and with North American “volt/VAr” control – varflg = 0, pfaflg = 0, Kqi = 0.001** – With the WindVar turned off, Kqi is reduced so that there is slow reset to the desired reactive power and wind turbine terminal voltage control is rapid.
- **Operation without WindVar and with European fast power factor control – varflg = 0, pfaflg = 1, Kqi = 0.5** – This represents the present normal configuration for European wind parks, where a set power factor angle is rapidly regulated by the converter control. Closed loop voltage control is not used on these systems, but is left in the model to approximately represent other means that are used to limit voltage excursions that would otherwise cause unit tripping.
- **Operation with WindVar and with European fast power factor control – varflg = 1, pfaflg = 0, Kqi = 0.5** – This represents the present normal configuration for European wind parks when WindVar is employed. Similar to the North American model except the regulator gain is at the higher value. Pfaflg is set to zero because the signal from the WindVar is a reactive power order, rather than pf angle.

The voltage error, V_{err} , is multiplied by a gain and integrated to compute the voltage command E_{q_cmd} . The magnitude of the gain determines the effective time constant associated with the voltage control loop. E_{q_cmd} is limited according to a time-varying limit that reflects hardware constraints.

The active current command I_{p_cmd} is computed by dividing the power order, P_{ord} , from the wind turbine model, by the generator terminal voltage, V_{term} . The active current command is limited to the short term active current capability of the converter, I_{pmax} .

Table B-3 includes recommended settings for the Electrical Control model. All settings are given in terms of rated MVA.

Table B-3: Electrical Control Parameters for Wind Turbine Generators

Parameter Name	Recommended Value	
	1.5 MW	3.6 MW
K_{Qi}	0.1**	
K_{Vi}	40.0	
Q_{max}	0.296*	-0.436
Q_{min}	-0.436	-0.39
XI_{Qmax}	0.40	
XI_{Qmin}	-0.50	
V_{max}	1.10	
V_{min}	0.90	
I_{pmax}	1.1	

* 0.436 on some of GE's 1.5 MW Wind Turbines

** North American with WindVar; see discussion above for other configurations.

B.4.5 Wind Turbine and Turbine Control Model

The wind turbine model provides a simplified representation of a very complex electro-mechanical system. The block diagram for the model is shown in Figure B-6. In simple terms, the function of the wind turbine is to extract as much power from the available wind as possible without exceeding the rating of the equipment. The wind turbine model represents the relevant controls and mechanical dynamics of the wind turbine. The block labeled "Wind Power Model" is a moderately complex algebraic relationship governing the mechanical shaft power that is dependent on wind velocity, rotor speed and blade pitch.

B.4.6 Turbine Control Model

The lower part of Figure B-6 is the model of the turbine controls. The practical implication of the turbine control is that when the available wind power is above the equipment rating, the blades are pitched to limit the mechanical power (P_{mech}) delivered to the shaft to the equipment rating (1.0 pu). When the available wind power is less than rated, the blades are set at minimum pitch to maximize the mechanical power. The dynamics of the pitch control are moderately fast, and can have significant impact on dynamic simulation results.

The turbine control model sends a power order (actually a torque order) to the electrical control, requesting that the converter deliver this power to the grid. The electrical control, as described in Section B.4.2, may or may not be successful in implementing this power order. The control of turbine speed is quite complex. For modeling purposes, this is approximated by closed loop control with a speed reference that is proportional to electric power output. For power levels above rated, the rotor speed will be controlled primarily by the pitch control,

with the speed being allowed to rise above the reference transiently. The actual control does not use a speed reference or a feedback of power.

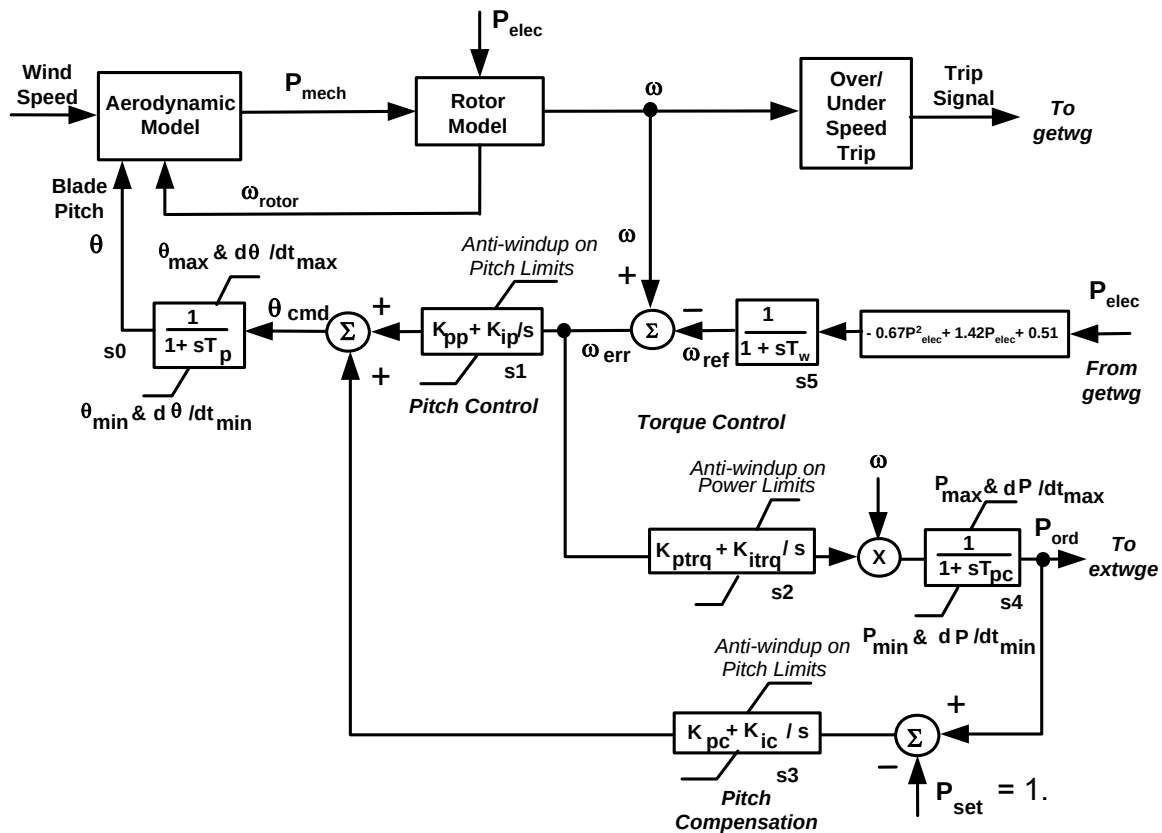


Figure B-6: Wind Turbine Model Block Diagram

In this model, the blade position actuators are rate limited and there is a time constant associated with the translation of blade angle to mechanical output. The pitch control does not differentiate between shaft acceleration due to increase in wind speed or due to system faults. In either case, the response is appropriate and relatively slow compared to the electrical control.

The model reference speed is normally 1.2 pu, but is reduced for power levels below 75%. The speed reference slowly tracks changes in power with a low pass filter time constant of approximately 5 seconds. Note: In the actual controller, the speed reference is not directly a function of power, but the overall effect on the speed/power relationship is similar.

The turbine control acts to smooth out electrical power fluctuations due to variations in shaft power. By allowing the machine speed to vary around reference speed, the inertia of the machine functions as a buffer to mechanical power variations.

The model does not include high and low wind speed cut-out for the turbine. In situations where system performance questions hinge on this behavior, the user can simply trip the machine.

Parameter values for the wind turbine control model are shown in Table B-3. None of these values should be modified by the user unless advised to do so by the manufacturer.

Table B-4: Turbine Control Parameters. The parameter T_w is typically equal to 5 s.
(all quantities are per unit on MW base)

Parameter Name	Recommended Value	Parameter Name	Recommended Value
K_{pp}	150.	$P_{\max}$ (pu)	1.12*
K_{ip}	25.	$P_{\min}$ (pu)	0.1
T_p (sec.)	0.30	$dP/dt_{\max}$ (pu/sec.)	0.45
$\theta_{\max}$ (deg.)	27.	$dP/dt_{\min}$ (pu/sec.)	-0.45
$\theta_{\min}$ (deg.)	0.0	K_{pc}	3.0
$d\theta/dt_{\max}$ (deg./sec.)	10.0	K_{ic}	30.0
$d\theta/dt_{\min}$ (deg./sec.)	-10.0	K_{ptrq}	3.0
T_{pc}	0.05	K_{itrq}	0.6

* This value permits transient excursions above rated power in response to grid disturbances. For running wind ramps above rated wind speed, $P_{\max}$ should be set to 1.00 to prevent steady-state operation above rated power.

B.4.7 Rotor Mechanical Model

The upper part of Figure B-6 includes the rotor inertia equation for the wind turbine rotor. This equation uses the mechanical power from the Wind Power Model and the electrical power from the Generator/Converter model to compute the rotor speed. This part of the model can be extended to include a two-mass rotor model, with separate masses for the turbine and generator, as shown in Figure B-7.

The data for the rotor mechanical model are given in Table B-5. These parameters result in torsional oscillation frequencies of approximately 1.8 Hz for the 1.5 MW unit and 2.6 Hz for the 3.6 MW unit, respectively. The torsional damping coefficient, D_{tg} , is set to approximate the damping provided by a damping function in the controller, which is not included in the model.

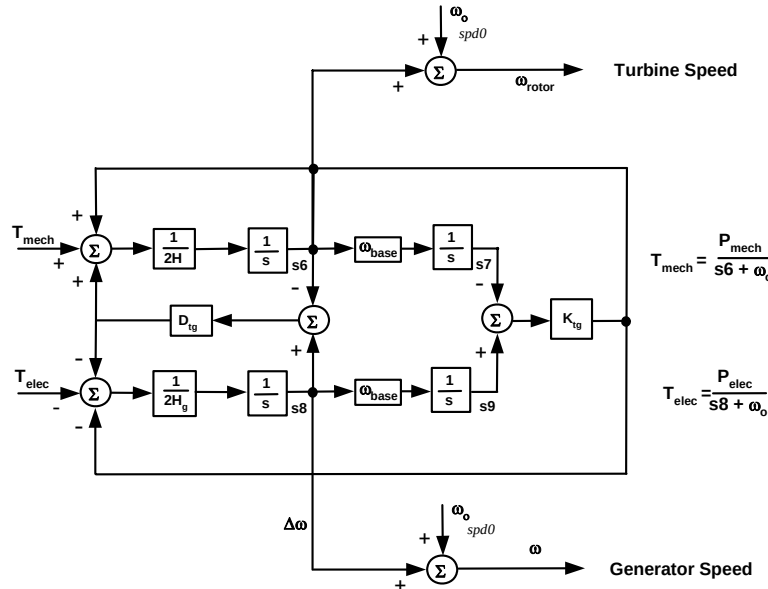


Figure B-7: Two-Mass Rotor Model

Table B-5: Wind Turbine Rotor Mechanical Model Parameters (On turbine MW base – 1.5 or 3.6)

	1.5 MW	1.5 MW	3.6 MW	3.6 MW
	60 Hz	50 Hz	60 Hz	50 Hz

One-Mass Model

H (p.u. torque/ p.u. accel.)	4.94	5.29	5.23	5.74
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Two-Mass Model

H (turbine)	4.33	4.33	4.32	4.32
H _g	0.62	0.96	0.91	1.42
K _{tg} (p.u. torque / rad.)	1.11	1.39	3.16	3.95
D _{tg} (p.u. torque / p.u. speed)	1.5	2.3	1.5	2.3
ω _{base} * (rad. / sec.)	125.66	157.08	125.66	157.08

* nominal generator speed

B.4.8 Wind Power Model

The function of the wind power module is to compute the wind turbine mechanical power (shaft power) from the energy contained in the wind, using the following formula:

$$P = \frac{\rho}{2} A_r v_w^3 C_p(\lambda, \theta)$$

P is the mechanical power extracted from the wind, ρ is the air density in kg/m³, A_r is the area swept by the rotor blades in m², v_w is the wind speed in m/sec, and C_p is the power coefficient, which is a function of λ and θ. λ is the ratio of the rotor blade tip speed and the wind speed (v_{tip}/v_w), θ is the blade pitch angle in degrees. The relationship between blade tip speed and turbine rotor speed, ω_r, is a fixed constant, K_b. The calculation of λ then becomes λ = K_b (ω/v_w). The coefficients given in Table B-6 will result in P_{mech} in pu on the unit's MW base.

Table B-6: Wind Power Coefficients

	1.5 MW	3.6 MW
½ ρ A _r	0.00159	0.00145
K _b	56.6	69.5

C_p is a characteristic of the wind turbine and is usually provided as a set of curves relating C_p to λ, with θ as a parameter. Representative C_p curves for GE's wind turbines are shown in [1]. Curve fitting was performed to obtain the mathematical representation of the C_p curves used in the model:

$$C_p(\theta, \lambda) = \sum_{i=0}^4 \sum_{j=0}^4 \alpha_{i,j} \theta^i \lambda^j$$

The curve fit is a good approximation for values of 2 < λ < 13, which are a suitable for stability simulations. These curves should not be used for energy production or other economic evaluation. Values of λ outside this range represent very high and low wind speeds, respectively, that are outside the continuous rating of the machine.

B.4.9 Wind Speed Model

Wind power fluctuations are relatively complex and stochastic in nature. The wind speed variable is accessible to a user-written model that can be designed to apply various wind

fluctuations, including: step or ramp of wind speed, wind gust following a $(1 - \cos A t)$ shape, and wind speed variations derived from measurements.

B.5 Simulation Results

Representative results for a grid fault are presented in this section using data for 60 Hz, 1.5 MW wind turbines. Results for other models of GE's wind turbines do not differ significantly from these results.

B.5.1 Test System

The test system represents an aggregate model of a wind power plant, which would be suitable for analyzing the response of the wind power plant to grid disturbances (Figure B-8). The system includes a single wind turbine model, representing the aggregation of several machines, an aggregate unit transformer, a 34.5 kV feeder representing the aggregate collector system, and a substation transformer to the system voltage level. Bus 1 (Grid V_{thv}) is an infinite bus.

For the 1.5 MW wind turbine benchmark cases, the wind turbine is rated 33 MVA (30 MW), representing the aggregation of 20 machines. All network impedances are on a 30 MVA base. Results are given for cases with two different system strengths, a relatively strong system with short-circuit current at the Point of Interconnection of five times the wind power plant MW rating and a relatively weak system with a short circuit ratio (SCR) = 2.0.

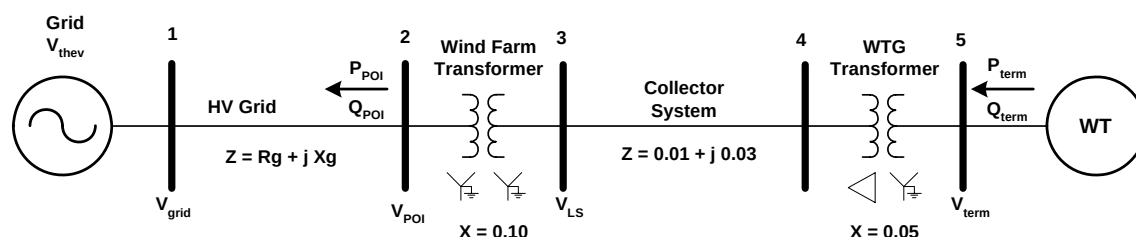


Figure B-8: Benchmark Test System

The power flow initial conditions and wind speed used for all cases, unless otherwise specified, are as follows:

Table B-7: Initial Conditions

	SCR = 5.0	SCR =2.0
Grid Voltage (V1)	1.02	1.05
Rg, Xg	0.04 + j 0.2	0.1 + j 0.5
Wind Turbine Voltage (V5)	1.04	1.04
Wind Turbine Power (Pterm)	30	30

B.5.2 1.5 MW Wind Turbine Grid Fault Simulation Results

B.5.2.1 Grid Fault Simulation

Figures B-9a and B-9b show the response of the wind turbine model to a grid fault for the strong and weak systems, respectively. A 6-cycle (0.1 sec), three-phase fault, was applied at 1.0 sec, through a fault impedance of $0.0 + j0.2$ pu, at the Point of Interconnection (bus 2). This approximately represents a line-to-line fault. For this simulation, the WindVar emulator was turned off.

The following variables are plotted for each of the cases. Variables are in pu, unless otherwise noted. Base for per unit P, Q variables is 33 MVA.

Table B-8: System Variables

Plot Label	Variable Description	Plot Color / Symbol
V_{inf}	Grid Voltage (Bus 1)	red x
V_{term}	Wind Turbine Terminal Voltage (Bus 5)	blue •
V_{POI}	Point of Interconnection Voltage (Bus 2)	green ■
Q_{term}	Generator Reactive Power [MVar]	blue •
Q_{POI}	POI Reactive Power [MVar]	red x
Q_{ord}	Q order from WindVAR	green ■
E''_{cmd}	E'' command to converter	blue •
I_q^*	Reactive component of I_{term}	red x
WndSpd	Wind Speed [m/sec]	blue •
Pitch	Blade Pitch [deg]	red x
P_{term}	Generator Active Power (MW)	blue •
P_{POI}	POI Active Power (MW)	red x
P_{mech}	Generator Mechanical Power (MW)	green ■
I_{pcmd}	I_p command to converter	blue •
I_p	Real component of I_{term}	red x
Gen. Speed.	Generator Speed	light green ▲
Turb. Speed	Turbine Speed	dark green ■

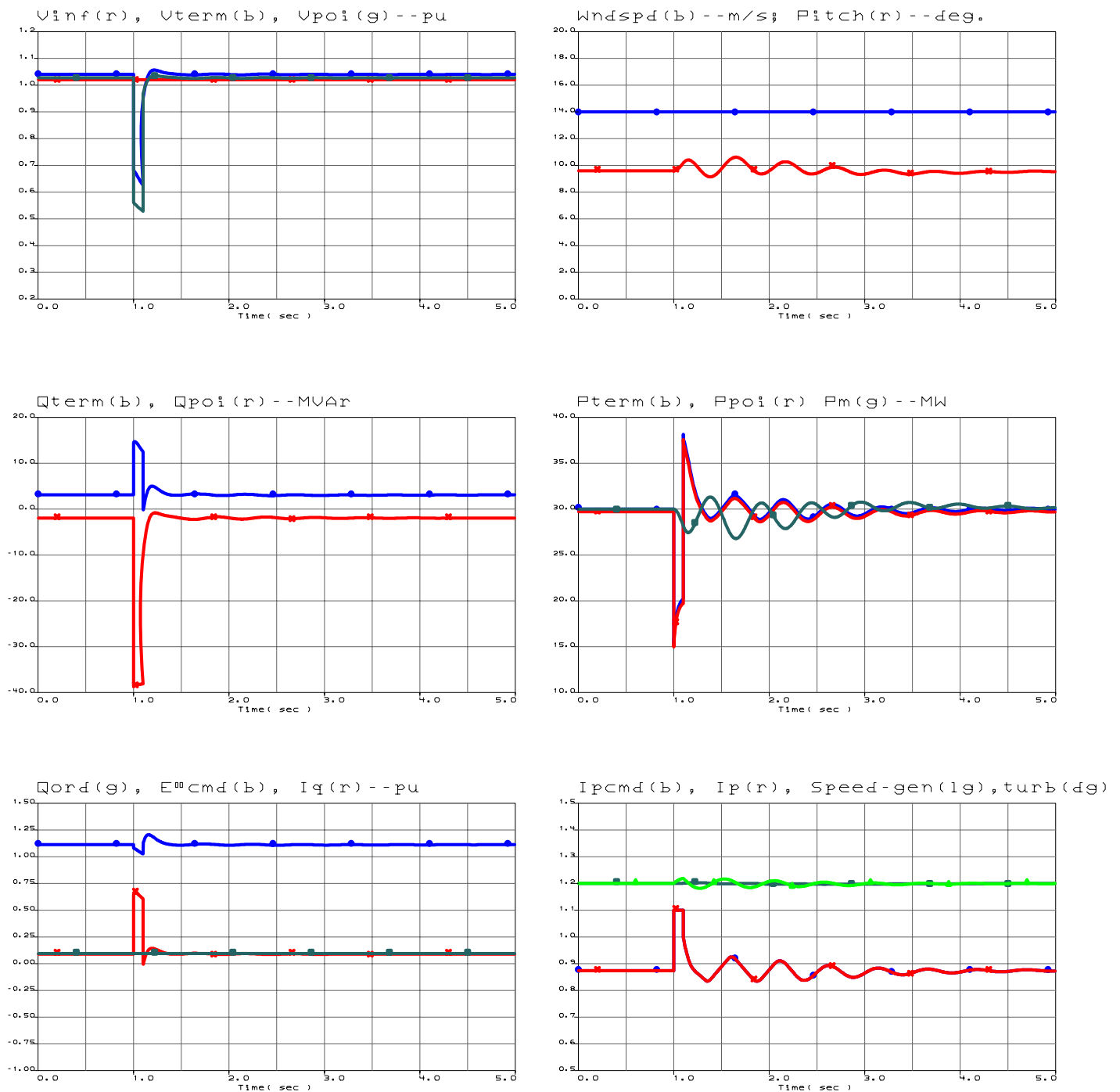


Figure B-9a: Fault at Point of Interconnection Bus - 1.5 MW Wind Turbine – Strong System.

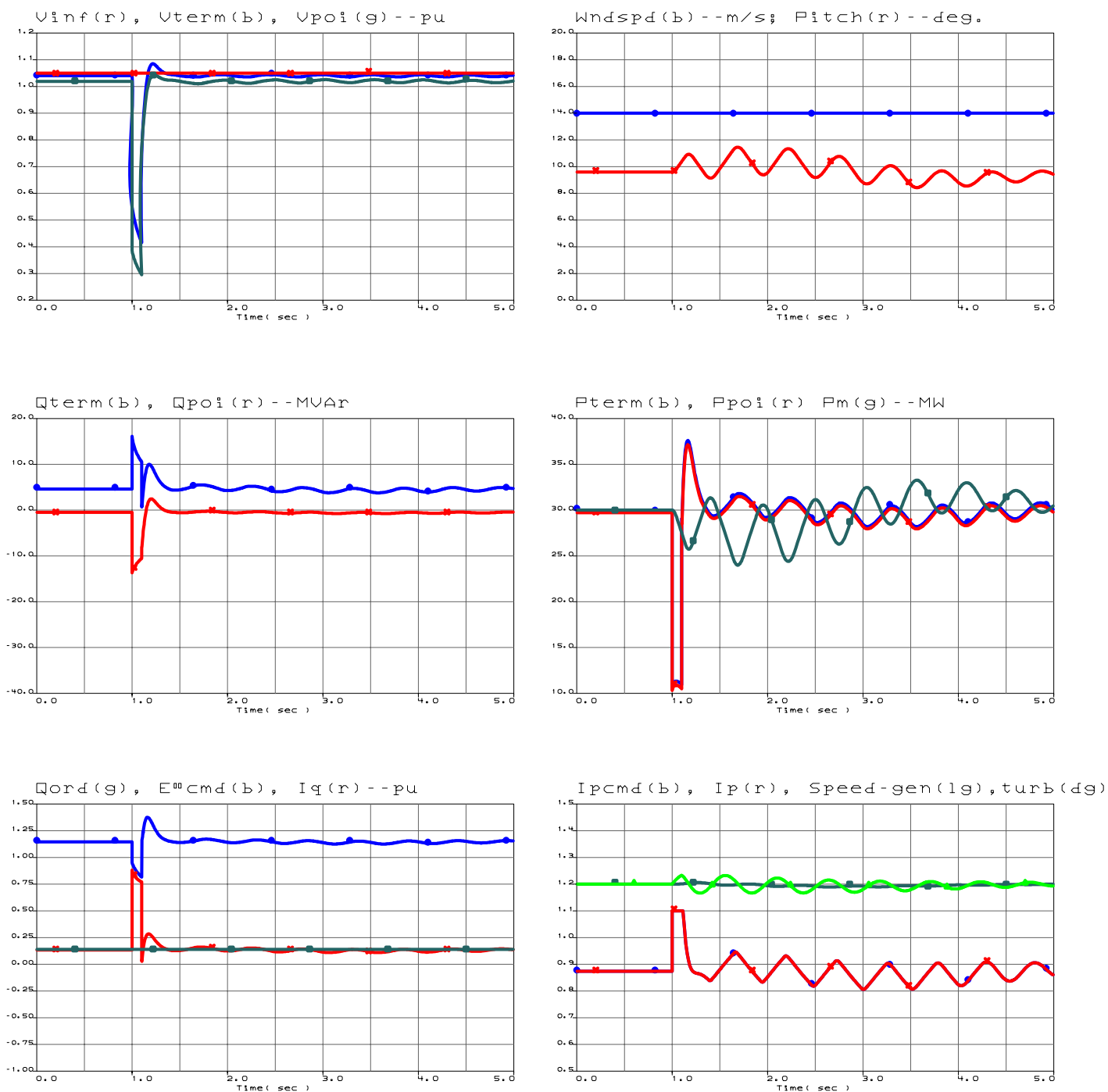


Figure B-9b: Fault at Point of Interconnection Bus - 1.5 MW Wind Turbine – Weak System.

B.6 Model Validation

Wind turbine model validation was performed by comparing the response of the model, as implemented in GE's PSLF® dynamic simulation software program, with simulations performed with the following detailed models:

1. WindTRAP software – detailed model of generator, converter, and converter controls for analysis of fast transient response to grid disturbances. WindTRAP is a proprietary program, owned by GE, which is similar to the EMTDC/PSCAD® software. This model has been validated against factory tests for a three-phase and line-to-ground fault at the generator terminals.
2. FLEX software – detailed model of the Wind Turbine structural and drive train dynamics and the turbine controls. This model is used by GE for design of the turbine controls. System disturbances can be analyzed with this model by their impact on generator torque and the resulting response of the mechanical systems and their controls

Validation comparisons with WindTRAP for grid faults and voltage disturbances are described in Sections B.6.1 and B.6.2. A validation comparison with FLEX for a generator terminal fault is described in Section B.6.3. The test system used for model validation is shown in Figure B-8. This system was modeled both in WindTRAP and PSLF.

B.6.1 Voltage Step Test

Two cases are included to illustrate the response of the wind turbine to grid voltage disturbances:

1. Small step changes in the grid voltage to test the linear response of the controls. The grid voltage was stepped down by 5%, then up by 10%, then back down to the initial value.
2. Large step changes in the grid voltage to test the impact of control limits on the response. The grid voltage was stepped down by 30%, then up by 60%, then back down to the initial value.

Since the WindTRAP model did not include the wind power plant supervisory voltage control (WindVAR) or the wind turbine controls, the inputs from these devices (voltage regulator setpoint and power order) were held constant in the PSLF simulation.

The results of the voltage step simulations are shown in Figures B-10 and B-11, respectively. The traces in the figures correspond to the PSLF model (red) and WindTRAP (blue). The following variables, all in per unit, are plotted:

Table B-9: System Variables

V_{WT}	Wind Turbine Terminal Voltage
Q_{WT}	Wind Turbine Reactive Power
P_{WT}	Wind Turbine Real Power
I_Q	Wind Turbine Reactive Current
$V_{bus\ POI}$	Point of Interconnection Voltage (Bus 2 in Figure 6-1)
$V_{bus\ Sub.\ St.}$	Substation 34.5 kV Bus Voltage (Bus 3 in Figure 6-1)

The simulation results obtained with PSLF closely match those computed with WindTRAP. The only differences observed are:

1. High frequency transients in WindTRAP responses due to cycle-by-cycle modeling employed in that program. These transients are not expected in PSLF simulations.
2. Small offset in the initial values of Q_{WT} and I_Q .

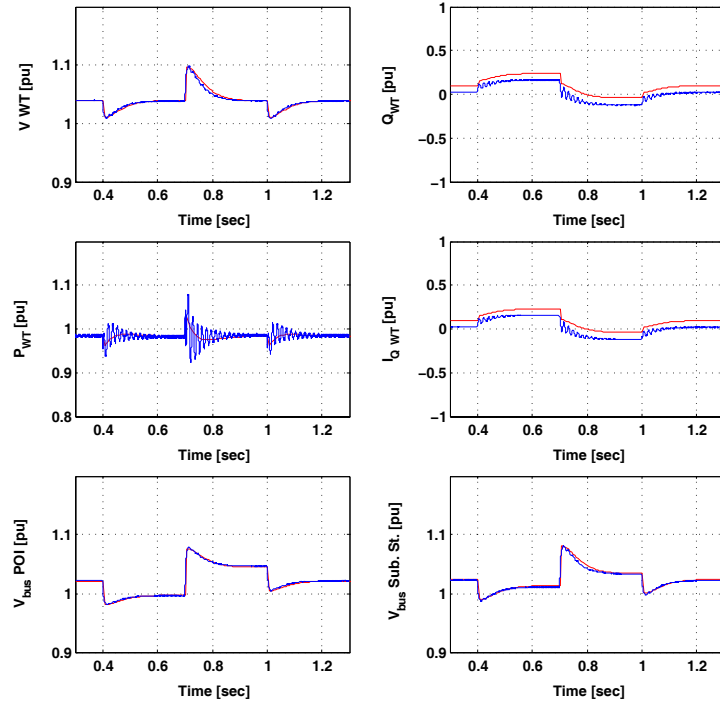


Figure B-10: Small Grid-Voltage Disturbance (PSLF - red; WindTRAP - blue)

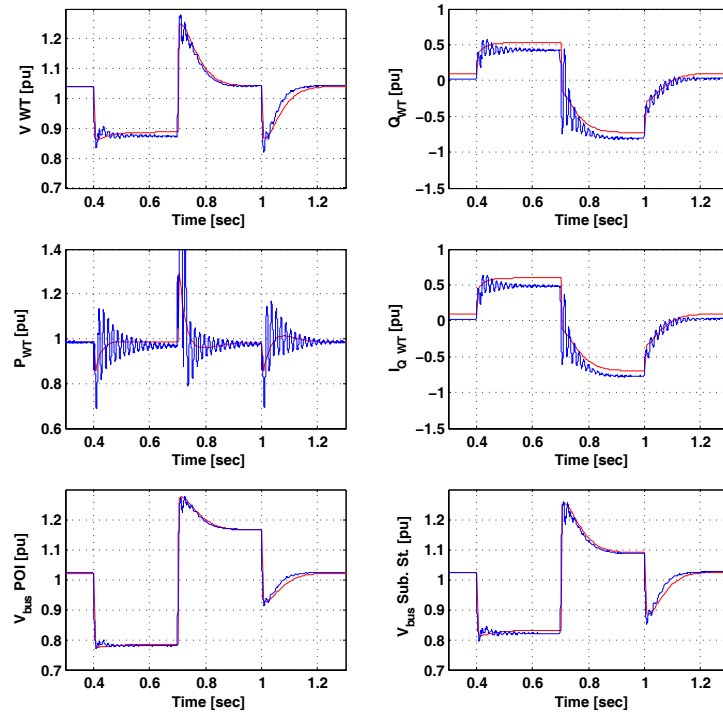


Figure B-11: Large Grid-Voltage Disturbance (PSLF - red; WindTRAP - blue)

B.6.2 Grid Fault Tests

One case is included to illustrate the response of the wind turbine model to three-phase and single-phase faults at the point of interconnection bus, bus 2 in Figure B-8. A five-cycle (0.0833 sec), three-phase fault was applied at 0.35 sec, and a five-cycle single-phase to ground fault at 0.55 sec.

Figure B-12 shows the simulation results for the fault.

The simulation results obtained with PSLF closely match those computed with WindTRAP. The only differences observed are:

1. High frequency transients in WindTRAP responses due to cycle-by-cycle modeling employed in that program. These transients are not expected in PSLF simulations.
2. Small offset in the initial values of Q_{WT} and I_Q .
3. Minor differences in voltage recovery following the faults.

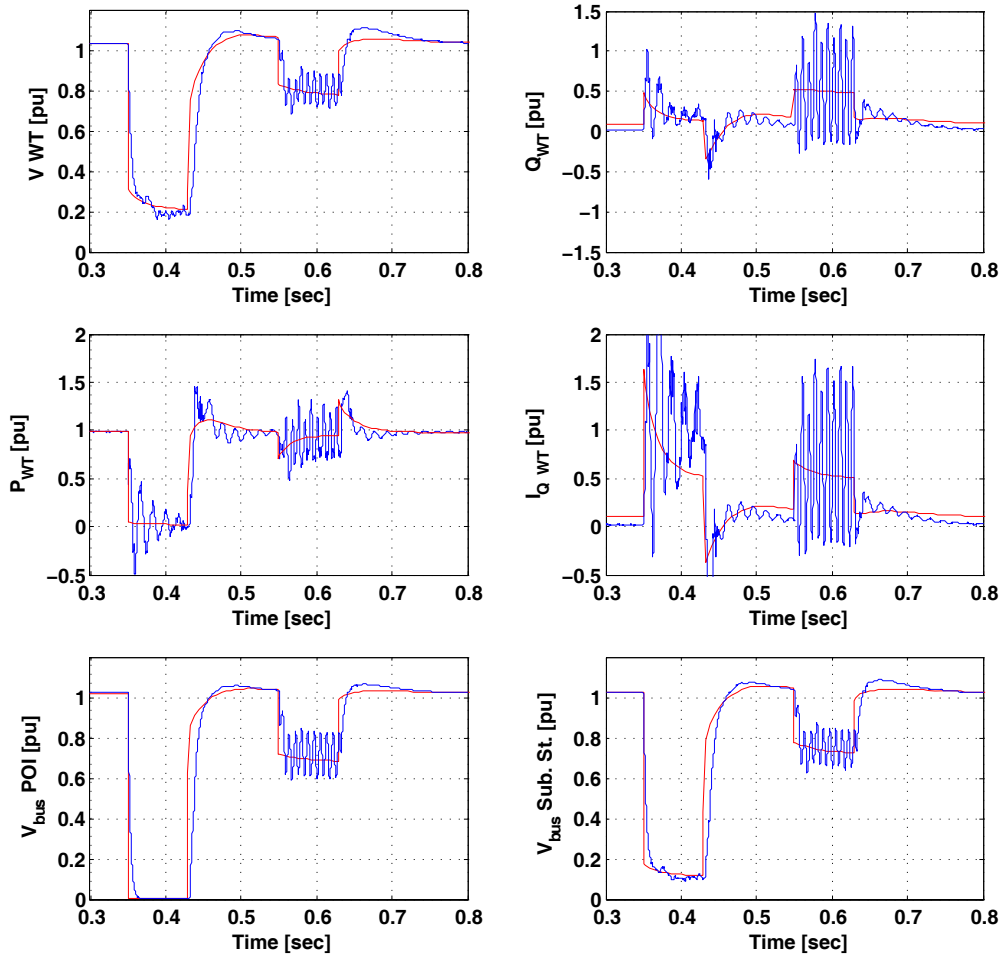


Figure B-12: Fault at Point of Interconnection Bus (PSLF – red; WindTRAP – blue)

B.6.3 Wind Turbine Control Model Validation

This section documents the results of comparisons between the PSLF model and FLEX model to validate the PSLF modeling of the wind turbine and turbine controls in response to a grid disturbance. The available FLEX simulation was for a six-cycle (0.1 sec.) three-phase fault at the terminals of the wind turbine. The FLEX simulation used a slightly different drive train configuration of GE's 1.5 MW wind turbine, resulting in different torsional model parameters (inertias and shaft stiffness) from those associated with the standard model of the 1.5 MW machine. These modified parameters were used to obtain agreement with the FLEX simulation.

Figure B-13 shows the response of the generator real power as computed by the PSLF model and the FLEX model. The well-damped response of the turbine-generator torsional mode of oscillation (1.36 Hz) is observed with both models, and is nearly the same for both.

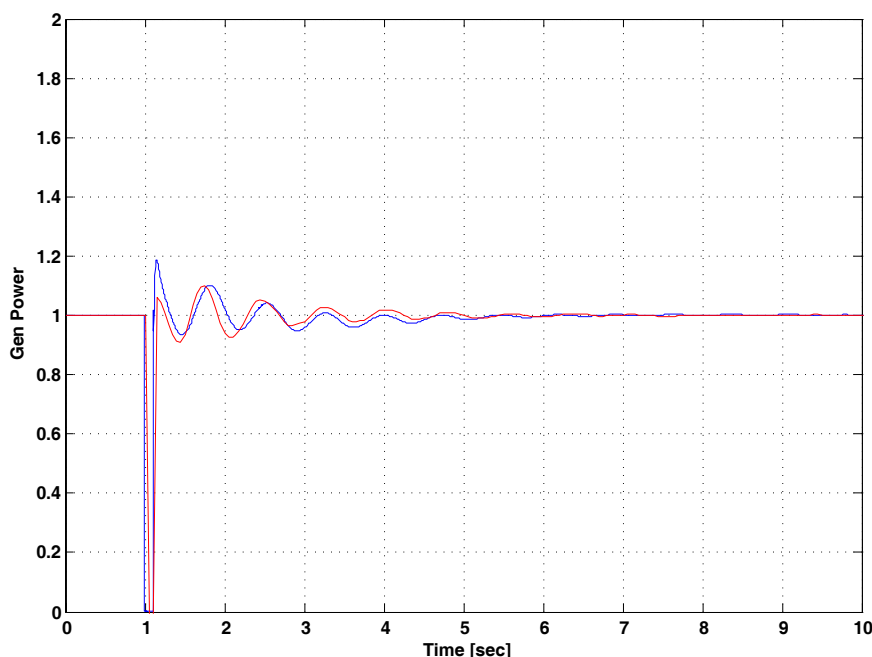


Figure B-13: WTG Terminal Fault (PSLF – red; FLEX – blue)

B.7 Conclusions

GE’s wind turbine model, as currently implemented in GE PSLF® and Siemens PTI PSS/E®, responds to grid disturbances with satisfactory fidelity compared with detailed, validated models for both the electrical and mechanical portions of the wind turbine system. The accuracy of this model for grid planning studies is comparable with models of other power system equipment used for such studies.

The wind turbine model presented in this appendix is based on design information, test data and extensive engineering judgment available at the time the model was developed. The modeling of wind turbine generators for bulk power system performance studies is still in a state of rapid evolution, and is the focus of intense activity in many parts of the industry. More important, the GE equipment is being continuously upgraded, to provide better dynamic performance. These ongoing developments necessitate continuing changes and improvements to these models. The model is expected to give realistic and correct results when used for bulk system performance studies. It is expected that as experience and additional test data are obtained, these models will continue to evolve, in terms of parameter values and structure, and so, it is *essential* that GE provide confirmation for the specific application for critical evaluations for wind power plant performance.

References

- [1] N. W. Miller, J. J. Sanchez-Gasca, W. W. Price and R. W. Delmerico, “Dynamic Modeling of GE 1.5 MW and 3.6 MW Wind Turbine-Generators for Stability Simulations”, *Proceedings of the IEEE PES General Meeting*, July 2003, Toronto, Canada.

APPENDIX C

HYDRODYNAMIC GEAR DRIVE TRAIN FOR VARIABLE SPEED WIND TURBINES TO REDUCE THE LOAD AND INCREASE RELIABILITY WITHOUT POWER ELECTRONICS

The new concept of a hydrodynamic gearbox is described here. This design, as shown in Figure C-1, provides an even lower mass and volume in the drive train than other more typical designs.

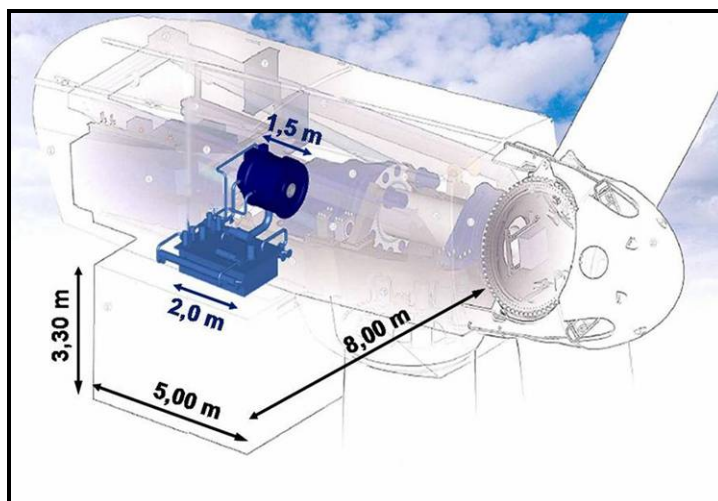


Figure C-1: Dimensional comparison of a 3.6 MW WPP [1] with double-fed asynchronous machine and variable frequency drive (box) and with hydrodynamic gearbox (blue).

The task of the hydrodynamic gearbox is to control the speed of the wind turbine rotor dependent on the prevailing wind velocities.

Thus the rotor rotates over a wide range of velocities, with an optimal aerodynamic efficiency, while at the same time the generator connected at the high-speed end of the gearbox rotates at constant speed.

The variable speed gearbox does not require any power electronics and thus allows the use of synchronous generators that can be connected synchronously to the power system network at medium voltage level. Thus, the 5 x 8 x 3.3 m box for the power electronics and transformer shown in Figure C-1 is not necessary.

Proven grid requirements can be achieved with the use of synchronous generators without power electronics, such as reactive power capability, fault ride-through and the lack of harmonic injection.

C.1 General Design

Figure C-2 shows the concept of the hydrodynamic gearbox. Dependent on the wind turbine, the general design of the drive train is characterized by a main gearbox with a fixed gear ratio of 20 – 30 and a hydrodynamic gearbox as the so-called "third stage" with a variable gear ratio. The output shaft of hydrodynamic gearbox is connected with the synchronous generator. The hydrodynamic gearbox consists of a planetary gear for power superimposition and a hydrodynamic torque converter for speed control. Following this principle, a rotor speed being variable over a wide range can be controlled to a constant output speed. In this way a synchronous generator that is connected directly to the grid can be operated without any power electronics.

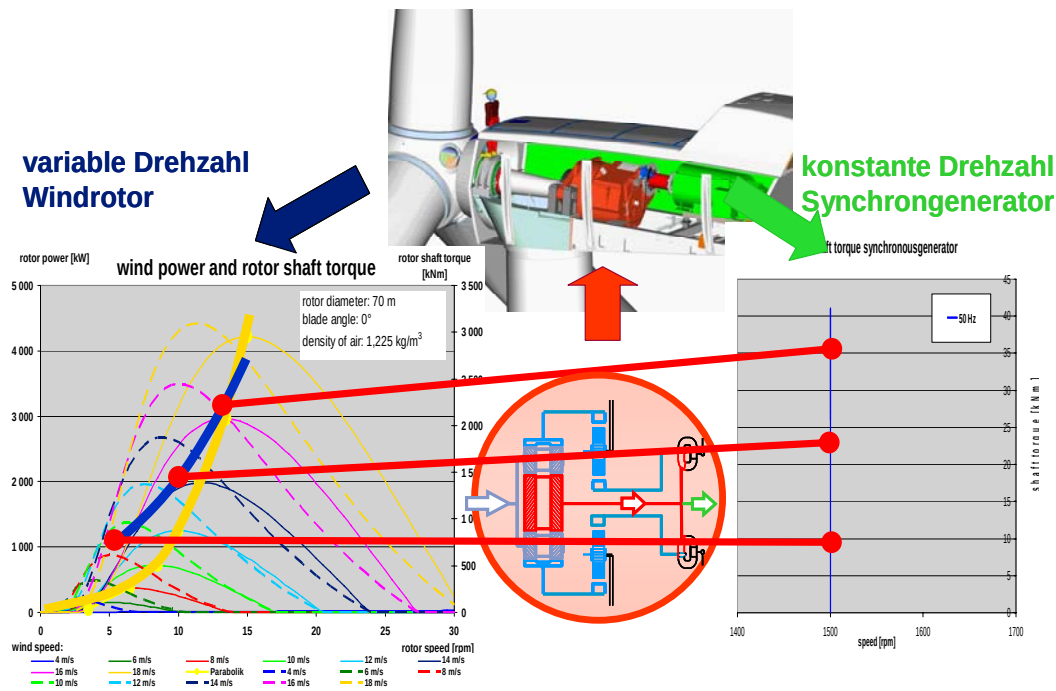


Figure C-2: Connection of variable input speed (wind rotor) with constant output speed (synchronous generator) by a hydrodynamic gearbox.

The principle of hydrodynamic torque conversion with superimposing gear is shown in Figure C-3. The input shaft drives the planet carrier that is supported by several planetary gears distributed over the circumference on the annulus gear and sun gear. The sun gear is permanently connected with the output via a central shaft. The annulus gear is connected with the fixed planetary gear via a coupling sleeve where reversal of rotation and speed step-up takes place. Finally the power at the annulus gear is taken from the turbine wheel. The torque converter controls the wind turbine behavior via its hydrodynamic characteristic and its guide vane positions.

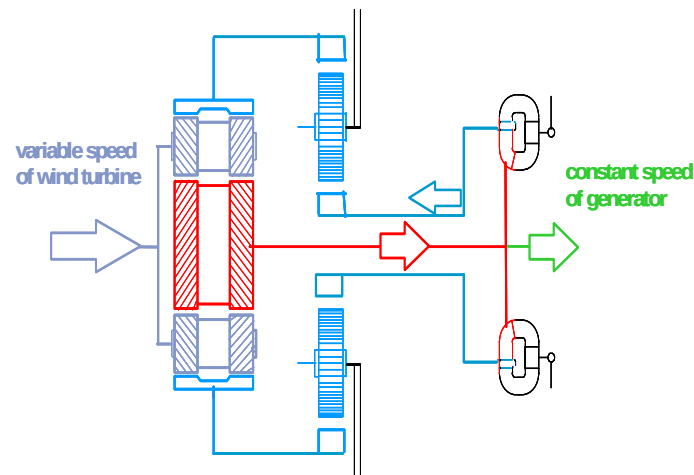


Figure C-3: Principle of a torque converter in connection with two planetary gears as revolving and fixed planetary gear.

C.2 Requirements for The Power Characteristic

The hydrodynamic gearbox has to control and regulate the various requirements of the power generation characteristic of a wind turbine, i.e. the turbine power generated as a function of turbine speed. The following four basic types of characteristics need to be considered:

- parabolic operation,

- operation at constant speed,
- at constant torque and
- operation with short-time energy storage and torque reduction.

Figure C-4 shows this diagrammatically. The last item can be realized ideally by using hydrodynamic gearboxes.

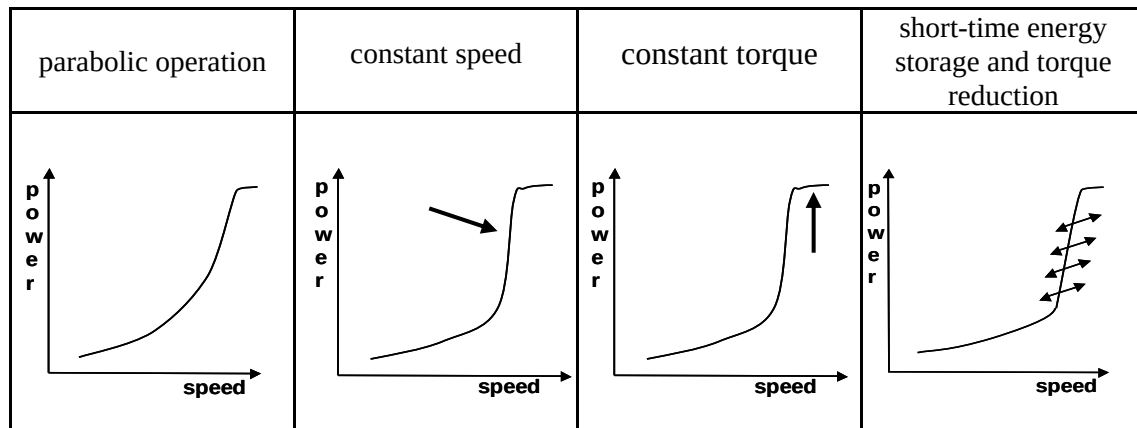


Figure C-4: Power flow characteristics of variable speed wind turbines.

The parabolic operation is based on the wind rotor's behavior. When the wind turbine rotor is operated at the best aerodynamic efficiency, at various wind velocities, this results in a parabolic power generation characteristic as a function of the rotor speed. When comparing now the characteristic of the hydrodynamic gearbox with the wind rotor, the hydrodynamic torque converter as a turbo machine shows the same behavior. This means that the wind turbine rotor and the hydrodynamic gearbox have the same parabolic power and torque characteristic. Both components behave identically with an optimal design and it is not necessary to control the drive train of the wind turbine. Figure C-5 shows the parabolic operation of a 2.5 MW wind turbine generator with the required guide vane position (blue line) of the hydrodynamic torque converter. This illustration also shows that the guide vane position in the hydrodynamic torque converter remains almost the same over the whole wind rotor speed range.

To limit the noise level of the wind rotor, the maximum wind rotor speed has to be limited calling for constant speed operation beyond a certain point. In this mode, the guide vane position is varied in the hydrodynamic gearbox and thus the transmission behavior of speed and torque in the hydrodynamic torque converter changes. This is shown in Figure C-6. To keep the generator speed constant, the speed/torque ratio varies as necessary.

On reaching rated power with another rise of the wind velocity and the resulting power, the maximum torque in the drive train (limitation of load) has to be limited for which operation at constant speed is necessary. New control conceptions were worked out for short-term energy storage and torque reduction enabling a variable speed range of the wind rotor including the drive train around an operating point according to the average value of the current wind profile. The parabolic characteristic of the wind rotor is also considered at every operating point (see Figure C-7).

The operation with short-time energy storage is new in the variable speed control of a wind turbine and is achieved by the inherent characteristic of the hydrodynamic gearbox. This inherent characteristic does not require additional controlled systems and is outstanding by its fast reaction times to gusts which in turn results in a torque reduction in the drive train.

C.3 Dynamic Simulation and Control Optimization

Extensive simulations and calculations regarding power optimization and load reduction need to be done to ensure operability of the drive train with hydrodynamic gearbox [2, 3]. Various operating modes (synchronization, operation, load shedding, voltage dip, etc.) at different load cases (wind profile between $v = 3 \text{ m/s} - 30 \text{ m/s}$, etc.) have to be simulated.

The simulation results of a 3 MW wind turbine generator are shown on Figure C-8.

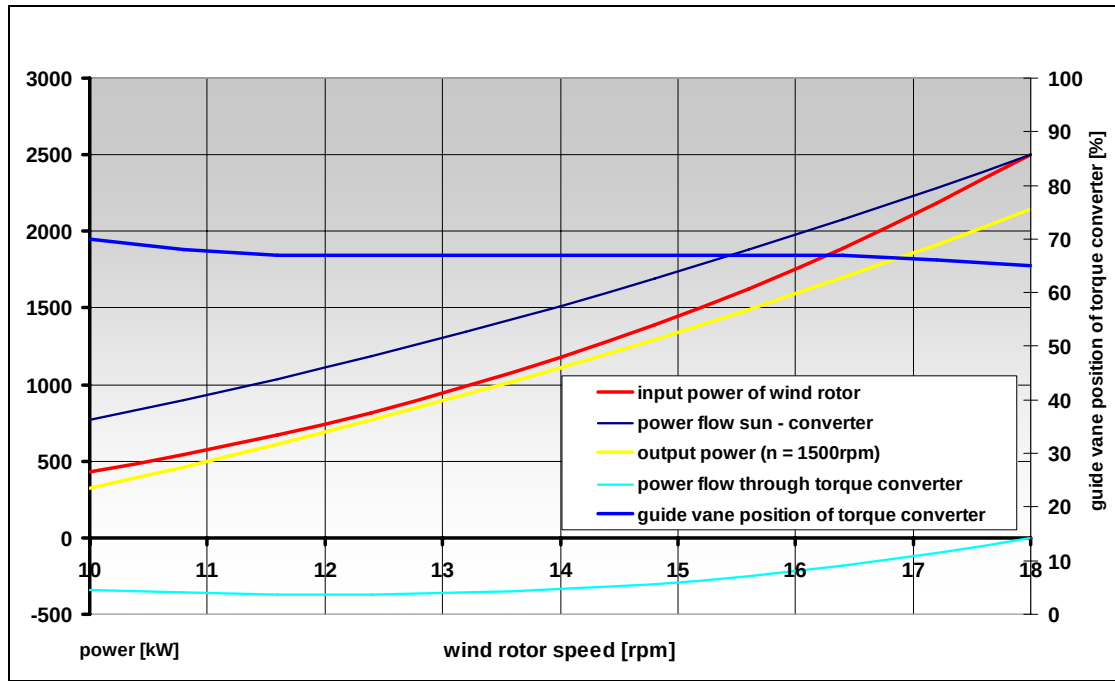


Figure C-5: Parabolic characteristic of hydrodynamic gearbox.

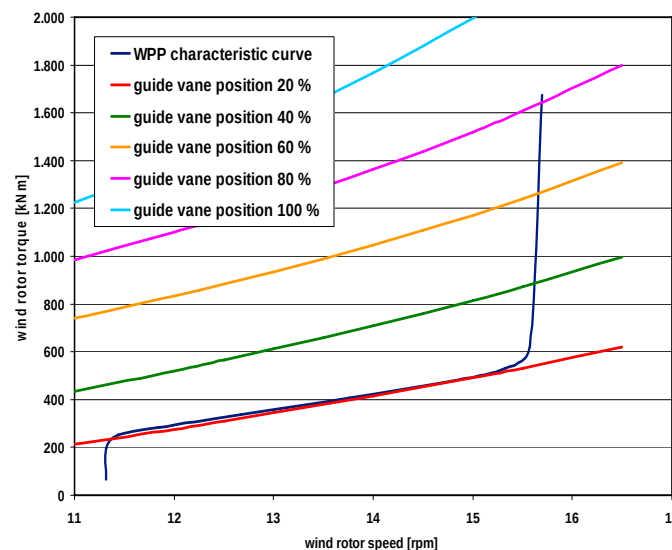


Figure C-6: Guide vane positioning in hydrodynamic gearbox for wind turbine operation at constant speed.

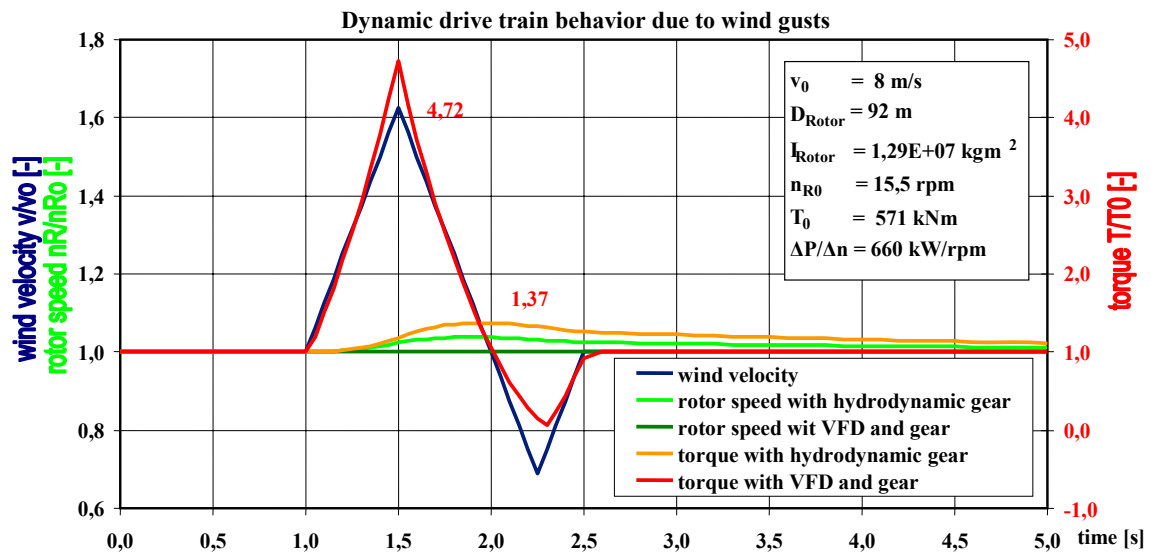


Figure C-7: Comparison of torque rise in case of a wind gust between constant speed and variable speed operation.

C.4 Summary

Present results show that the hydrodynamic gearbox (WinDrive®) with a synchronous generator can be used in a multi-megawatt wind turbine generator. The drive train with a hydrodynamic gearbox and synchronous generator has the following advantages:

- Reduction of weight and volume for multi-megawatt units (5 MW unit reduced to the specific weight and volume of a 3 MW unit).
- Reduction of dynamic loads in the drive due to short-time energy storage in the rotating masses as well as load reduction.
- Technology for offshore applications.
- Good network compatibility by using synchronous generators.
- Support of weak supply systems in technological threshold countries.
- No network contamination by harmonics and flicker. Variable reactive power output over a wide range.
- Generation of energy already on medium-voltage level.
- High reliability and availability as there is no power electronics.
- Reduced expenses for maintenance and repair of generators (no slip rings as for doubly-fed asynchronous generators).

Figure C-9 shows a picture of the complete system with the hydrodynamic gear box. For more detail on modeling this type of wind-turbine generator, the reader should refer to [4].

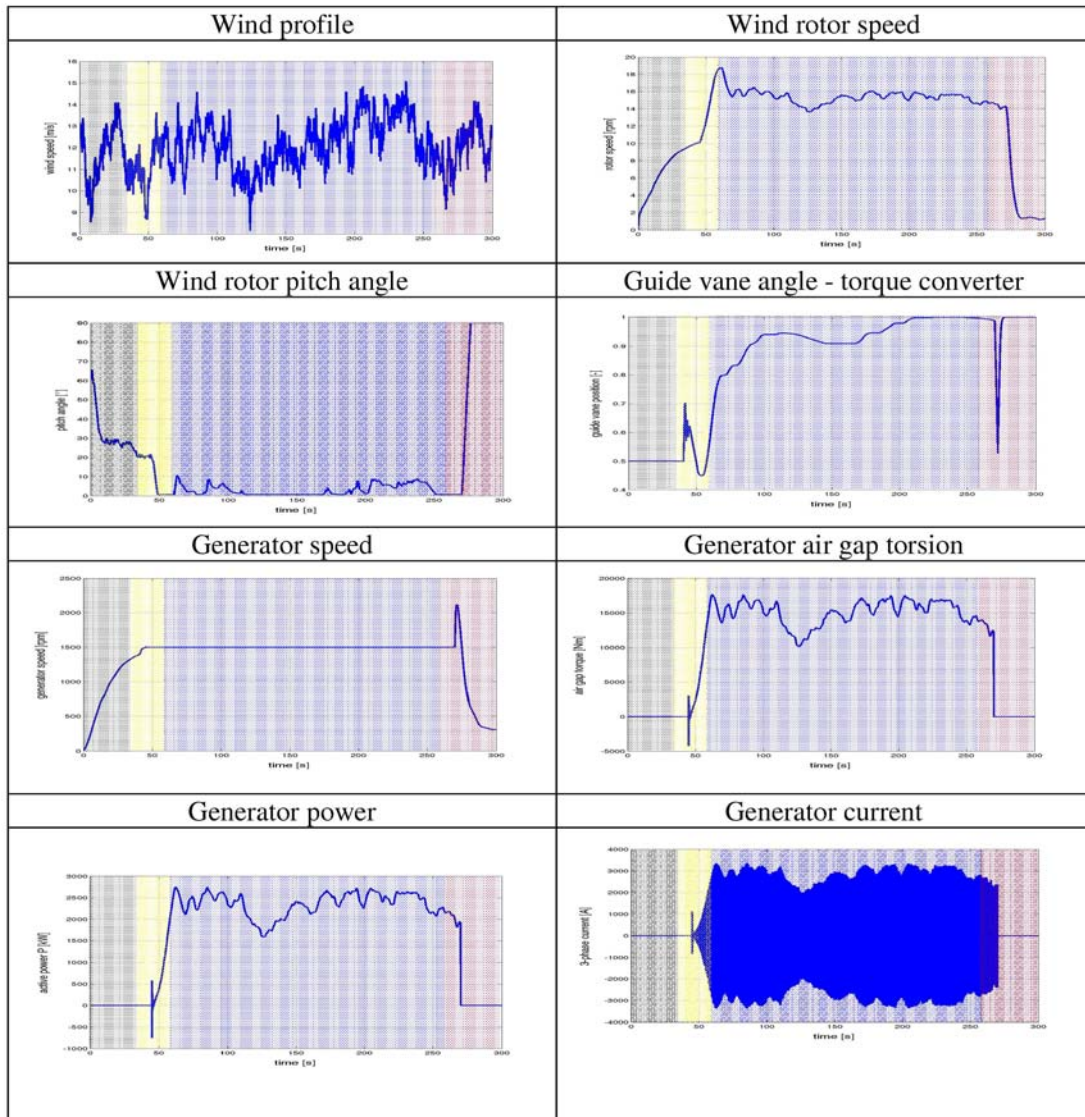


Figure C-8: Simulation of modes: run-up (GREY), synchronization (YELLOW), operation (BLUE) and shutdown (MAGENTA) at load case wind profile $v = 12$ m/s of a 3 MW wind turbine generator.

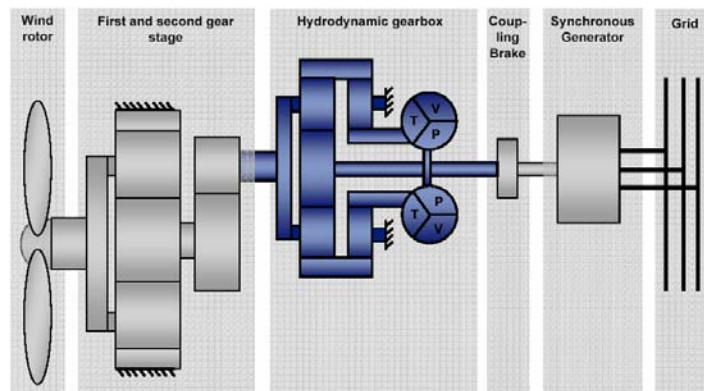


Figure C-9: Wind turbine drive train with variable input speed at the rotor and constant output speed at the synchronous generator.

References

- [1] General Electric, 3,6 MW Offshore WPP, Brochure, Germany 2003
- [2] B. Rabelo, W. Hofmann, M. Tilscher and A. Basteck, "Voltage Regulator for Reactive Power Control on Synchronous Generator in Wind Power Plants", *NORPIE 2004 Trondheim*, Norway, 2004.
- [3] A. Basteck, M. Tilscher, B. Schlecht, T. Schulze, T. Hähnel, W. Hofmann and B. Rabelo, "Hydrodynamically controlled Superimposing Gear Unit as new Drive Concept for Wind Power Units without Power Electronics", *VDI Conference Germany 2004*.
- [4] H. Müller, M. Pöller, A. Basteck, M. Tilscher and J. Pfister, "Grid Compatibility of Variable Speed Wind Turbines with Directly Coupled Synchronous Generator and Hydro-Dynamically Controlled Gearbox", *Sixth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms*, 26th-28th October 2006, Delft

APPENDIX D

MODELING WIND POWER IN PSS/E™

D.1 Introduction

The current design of the PSS/E™ software for wind farm/turbine analysis has been greatly influenced by the situation in the wind generation industry 5-6 years ago when the proprietary nature of the information was of great concern. There were no regulations established regarding the rights and responsibilities of various counter-parties: utilities and developers. There were no mechanisms providing for the procedures for information exchange. That is why one of the main objectives of the software design was to rid a PSS/E™ user from trying to obtain the information from wind turbine manufacturers. This approach required having the manufacturer's data mostly embedded in the code with a high level of automation in preparing the power flow case and dynamic setup.

D.2 Modeling Wind Farms in Power Flow

The power flow model of a wind farm serves two purposes: as the basis for power flow studies including thermal, voltage and other analyses, and as the initial condition for stability analysis. The level of modeling details can vary greatly from study to study, or even from wind farm to wind farm within the same study. One wind farm may include a separate model for every individual turbine within the wind farm, while another may be modeled as a single turbine equivalent.

For the lumped representation, the automation was accomplished through the development of a "model builder" program. It models the individual or equivalent units with the necessary steady-state parameters and facilitates the addition of individual or equivalent units, along with their step-up transformers, to the power flow case at "collector buses" specified by the user. The user must define the configuration between these collector buses and the system interconnection point.

The choice is provided between dispatching the unit directly with a given percentage of the nominal power or indirectly from the wind speed. The boundary conditions in terms of the reactive power output are calculated by the program based on the user's choice of control objectives typical for a specific technology.

Depending on a wind turbine type, the "model builder" program may include different features and provisions for automatic power flow solution. Since some parameters, like the machine reactive power consumption or the power factor correction system reactive power generation, are sensitive to the terminal voltage, the program includes iterative loops. For example, a very precise iteration process is needed to find the reactive power consumption for a wound rotor machine with a controllable external rotor resistor.

Because of this voltage dependency, the power flow case created by the "model builder" for the given dispatch sometimes cannot be accurately used for power flow studies, like contingency analysis, where change of the voltage profile may result from the contingency. The solution of this problem was found in developing a special "contingency processor" which is able to update the voltage sensitive parameters when "moving" from the base to contingency conditions in an iterative manner.

The same "model builder" is used for calculating and storing data needed for initialization of the dynamic simulation models without the user's involvement and writing out the dynamic data to a data file for input to the dynamic simulation program. The dynamic model initialization data flow is shown in Figure D-1.

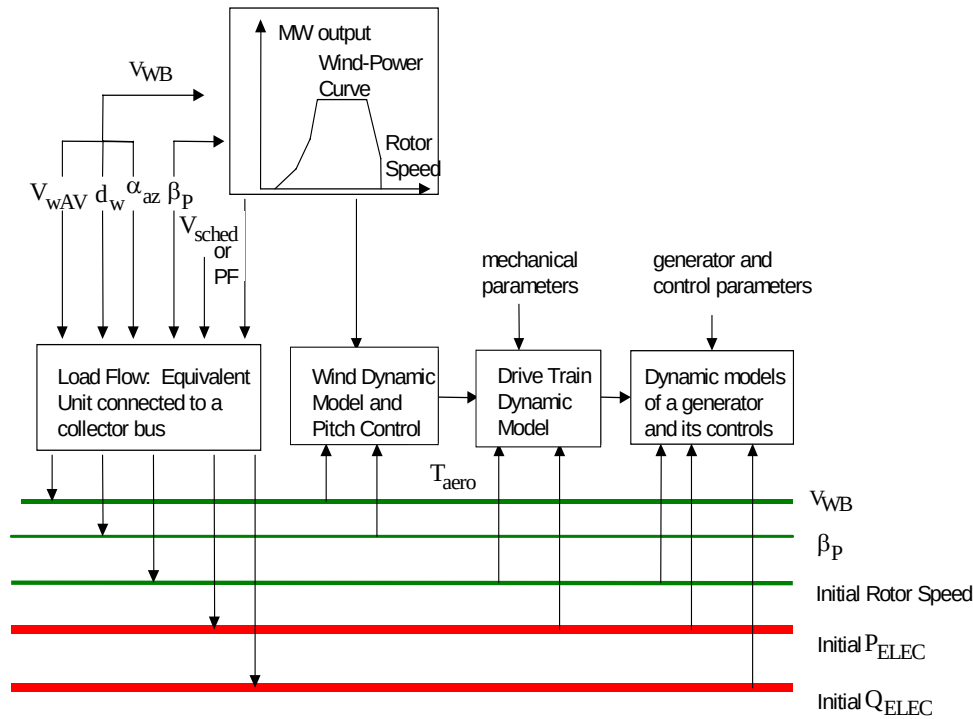


Figure D-1: Data flow for initialization of dynamic simulation models

V_{wAV} average wind speed
 d_w displacement factor
 α_w azimuth angle
 V_{WB} effective wind speed
 β_p pitch angle

D.3 Modeling wind farms for stability studies

The program designated for stability studies is usually split into two parts. The first part comprises all dynamic simulation models including models of the equipment physically connected to the grid. These models calculate and update at every integration step current injections from this equipment to respective network buses. The current injections are used by the second part of the program which is responsible for the algebraic network solution and for updating the bus voltage vector at each integration step. Actually, a question of accurate modeling of some equipment refers to accuracy of simulating the current injection. The fact that the programs designated for stability studies usually deal with fundamental frequency vectors of voltages and currents, not with their instantaneous values, makes this challenge somewhat less onerous.

The bandwidth typical for stability studies determines those features of the real equipment that must be taken into account or filter out. Let us illustrate this statement on the example of a doubly-fed asynchronous generator (DFAG).

The 3-phase rotor terminals of the DFAG are connected to the rotor side power converter. Terminal voltage of the DFAG is determined by controls. In the available implementations, the actual macro control objectives, e.g. real and reactive power, are met separately by controlling respective components of the rotor current as shown, generically, in Figure D-2.

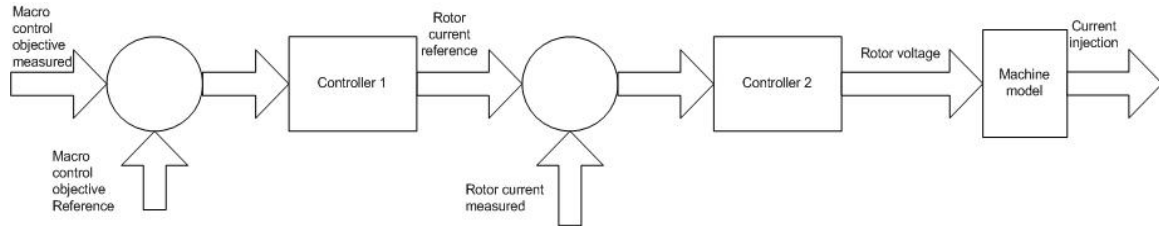


Figure D-2: The generic block diagram of the DFIG control.

The second controller shown in the diagram actually stands for all control systems of the power converter including PWM, firing system, etc. Naturally, for the stability models a lot of simplifications must be made, to filter out all systems whose response is beyond the respective bandwidth.

Similar simplifications can be considered with regard to the model of the machine itself. It is well known that, for the purpose of stability studies, the machine stator flux linkage dynamics can be ignored. For the conventional induction machine, without any controls, taking the rotor flux linkage dynamics into account is a must. Availability of fast acting controls may change this approach with respect to DFAG. The dynamics of controls determining the output of the power converter, along with the dynamics of the machine, are so fast with regard to the stability analysis bandwidth that only control dynamics may be taken into account. The only role of the machine model will be converting commands from controls into the current injected to the network bus in an algebraic way, along with simulating the mechanical rotor movement.

Mathematically, neglecting the rotor flux linkage dynamics is justified by the assumption that the rotor current components responsible for meeting the macro control objectives are given as outputs of the controls. In this regard, the generic block diagram of the DFIG with controls is simplified as shown in Figure D-3: rotor voltage is not needed anymore as an input for the machine model.

For the synchronous or induction generator decoupled from the grid by a full size power converter, the frequency of the line-side converter current will follow the utility voltage frequency, hence, the unit remains in synchronism with the grid. Both real and reactive power generation and their combination are subject to limits related to the power converter rating and/or limits imposed by the generator and the drive train. For studying the impact on the grid, a governor model is not needed as speed is controlled only by the power electronics.

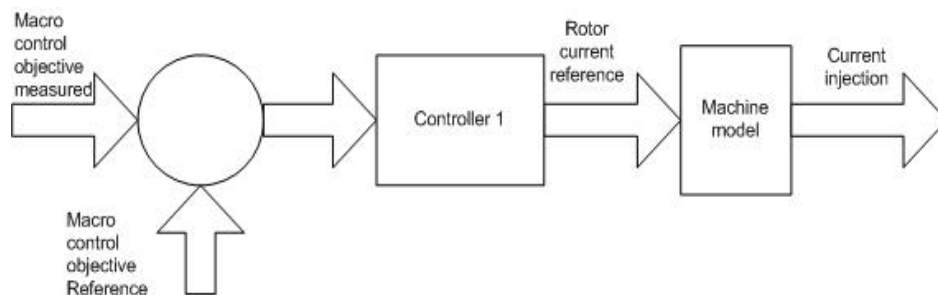


Figure D-3: The simplified block diagram of the DFIG control.

D.4 PSS/E™ wind software

Up to date, the following PSS/E™ software packages have been developed for wind power applications utilizing the various different types of turbine technology.

PSS/E™ Wind Model Packages developed by Siemens PTI					
Induction generator - directly connected	Induction generator - converter connected	Synchronous generator - converter connected	Doubly-fed induction generator with active control	Doubly-fed induction generator with passive control	
NEG MICON NM72 (now Vestas) 1.65MW 50Hz/60Hz	Kennetech 33-MVS 400kW 60Hz	Enercon E66 1.8MW 50Hz	Generic model	Vestas V80 1.8MW 60Hz	
NEG MICON NM82 (now Vestas V82) 1.65MW 50Hz/60Hz		Enercon E70 2.0MW 50Hz	GE 1.5MW 50Hz/60Hz	Vestas V47 660kW 50Hz/60Hz	
BONUS (now Siemens) 1.3MW 50Hz/60Hz			GE 3.6MW 50Hz/60Hz	Gamesa G80 1.8MW 60Hz	
BONUS (now Siemens) 2.3MW 50Hz			Gamesa G80 2MW 50Hz		
Mitsubishi MWT100a 1MW 60Hz			NORDEX N80 2.5MW 50Hz		
Suzlon S66 1.25MW 50Hz			REPower MD70 & MD77 1.5MW 50Hz		
Suzlon S88 2.1MW 50Hz			REPower MM70 & MM82 2.0MW 50Hz		

The majority of these software packages have a similar structure and include the following components:

The steady-state “model builder” to:

- Aggregate wind farm/equivalent wind turbines to collector buses
- Dispatch equivalent machines
- Setup reactive power control
- Implement control strategies
- Write out dynamic model data to the dynamic data input file

Dynamic simulation models:

- Wind gust and ramp
- Aerodynamic conversion
- Mechanical shaft system
- Pitch control
- Generator
- Generator controls (if applicable)
- Reactive compensation (if applicable)
- Voltage protection
- Frequency protection

Input data files

- Aerodynamic Cp matrix
- Machine parameters

- Dynamic models datasheets and block diagrams
- Instructions and other documentation
- Example data files

- Collector bus data
- Wind speed data
- Protection data
- Compilation and linking

The present wind models being supplied by Siemens PTI are in a user written form, meaning that the use of these models requires user compilation of the connection routines and linking to the Siemens PTI supplied library of the wind models.

D.5 Model validation

Unfortunately, a very limited number of wind turbine generator field or factory dynamic test results are available. The main way of validation is comparing results of the simulations using simplified stability models, as mentioned above, versus results of the simulations obtained by manufacturers using their so called design models. These mostly are PSCAD/EMTDCTM or MatLab/SimulinkTM or some other in-house models that comprise models of the machine, power converter, and controls (where applicable) with great number detail.

Fortunately, in the course of PSS/ETM modeling package development and validation, Siemens PTI entertained a close co-operation with several wind turbine manufacturers. Sometimes they provided results of their detailed modeling. Sometimes, as it was for GE 1.5 and 3.6 MW wind turbines, the PSS/ETM model development followed algorithms suggested by the manufacturer.

D.6 Future plans

Currently work is being done on making the commonly used wind models an integral part of the PSS/ETM supplied library of models. An essential aspect of integrating wind models into the PSS/ETM supplied library of models is that this would inevitably require creation of new dedicated arrays for exclusive use by the wind models, like array WAERO to contain output of aero-dynamic models, array WPITCH to contain the output of pitch control models etc. These new arrays will be made available for PSS/ETM plotting.

New model categories for wind related models will be created. This will allow wind models to be called in a manner similar to any user written plant related model.

D.7 Generic wind models

Based on research work, to be conducted in Netomac, EMTP-RV and PSS/ETM comparing simulation results from different simulation tools (for which there are benchmark data of actual turbine performance available), there is an effort at present to develop generic wind turbine generator models in PSS/ETM. This work will be coordinated with efforts to participate in analogous activities within the WECC Wind Generator Modeling Group. Naturally, model validation will be the most important issue for this development.

WIND GENERATOR MODELING WITH DIgSILENT POWERFACTORY

E.1 Introduction

DIgSILENT *PowerFactory* integrates a large variety of power system analysis functions for steady state, dynamic and transient network analysis (see [1] for a detailed description).

With the increased need for studying wind generation impact on transmission and distribution systems, a large variety of wind generator models for transient and dynamic analysis has been implemented during the past years.

These models can be divided into generic wind generator models and manufacturer-specific models, which are built using manufacturer-specific documentation. Generic wind generator models allow simulating the typical behavior of wind generator types and control concepts and are well suited for general power system planning studies or feasibility studies, in which the actual turbine type might not yet be known at the time the study is carried out.

Actual wind farm connection studies, e.g. focusing on fault ride through capability or reactive power/voltage control capabilities, should generally be carried out using manufacturer-specific wind generator models. During the past years, turbines of all major wind turbine manufacturers have been modeled and implemented in *PowerFactory* and studies have been carried out using these manufacturer-specific models (e.g. planning studies for the Danish offshore wind-farm “Horns Rev” or the German wind-farm “Borkum-West”, system impact studies, such as summarized in [2])

This paper starts by introducing general modeling capabilities of DIgSILENT *PowerFactory*, followed by a description of generic wind generator models for the three most widely used wind generator types: doubly-fed asynchronous generator, fixed speed induction generator and synchronous generator with fully rated converter.

E.2 Time Domain Simulation in DIgSILENT *PowerFactory*

E.2.1 Network Models

Non steady-state phenomena in power systems cover a very wide time range, varying from a few micro-seconds (e.g. lightning surges), milliseconds (e.g. switching transients), a few seconds (transient stability, fast voltage collapse) or longer term phenomena in the range of minutes or even hours (e.g. long-term voltage stability).

For efficiently simulating transient and dynamic phenomena of different time ranges, different network models are commonly used in power system simulation software. These are:

1. Transient network model, using differential equations for network inductances and capacitances and/or traveling wave equations for transmission lines (instantaneous value simulation).
2. Steady state network model, using complex, algebraic equations for modeling network inductances and capacitances (fundamental frequency model, RMS simulation).

Transient network models have to be used for all applications that are directly related to network transients, such as lightning or switching overvoltage problems, harmonics resulting from power electronics circuits etc.

Steady state network models have become the standard approach for simulating stability phenomena in power systems, e.g. transient stability, oscillatory stability or long-term stability effects.

The time domain simulation of *PowerFactory* allows the user to select one of the network models described above. *PowerFactory* is therefore able to run stability studies of large power systems consisting of several hundreds of power plants or to carry out detailed transient studies considering transient effects of electrical networks including detailed analysis of power electronics circuits. Recently, wind integration studies have been carried out successfully, using a combined approach by simulating simultaneously one part of the network in the transient 3-phase model (wind farm) and another part of the system using a positive-sequence network model (national transmission system).

When simulating wind generation, the simplified, steady state network modeling approach can be used for carrying out stability impact studies. In case of detailed studies however, e.g. when investigating crow bar triggering of doubly-fed asynchronous machines or simulating the voltage in the intermediate dc-circuit of frequency converters, simulations have to be carried out using a transient network model. Because *PowerFactory* supports both network modeling approaches, it is particularly well suited for a wide range of wind generation studies.

E.2.2 Dynamic Modeling Environment

PowerFactory comes with built-in models for all primary power system components, such as lines, transformers, reactive power compensation units, electrical machines (synchronous, asynchronous, doubly-fed, etc.), power electronics converters (thyristor-bridge, PWM-converter), excitation systems with PSS, governors, SVC-controllers and also for various types of wind generators.

These models are implemented using the dynamic modeling environment DSL. This modeling environment is also available to every *PowerFactory* user so that new models can be implemented easily or existing models of the dynamic model library can be modified.

Especially in wind generation applications, a flexible modeling environment is essential because of the large variety of generator types and control concepts used by different turbine manufacturers that have to be reflected in the corresponding models.

The basic layer of the dynamic modeling environment is the DSL-language, which is a general-purpose dynamic modeling language allowing to describe any system of linear or non-linear differential equations. For simplifying the model definition, a graphical editor is integrated, with which any model can be defined by drawing a block diagram (see e.g. Figure E-9 and Figure E-10).

E.3 PowerFactory Standard Wind Generator Models

The standard model library of *PowerFactory* includes generic models for wind turbines for:

- Doubly-fed asynchronous generators
- Fixed speed induction generators
- Synchronous generators with fully rated converter (full-converter units)

These models can be used for general feasibility or planning studies. For more detailed studies, manufacturer-specific models are available, which are implemented using the modeling tools described in the previous section. A list of manufacturer-specific models that have been implemented for *PowerFactory* is shown in Table E-1.

Table E-1: Manufacturer Specific Models.

Manufacturer	Type	Technology
REpower	MD70/77	DFAG
REpower	MM70/82/92	DFAG
REpower	5M	DFAG
VESTAS	NM64	Induction Generator, directly connected
VESTAS	NM82	Induction Generator, directly connected
VESTAS	V66-AGO1	DFAG
VESTAS	V80-AGO2	DFAG
VESTAS	V90-AGO2	DFAG
Suzlon	S88-Flexislip	Induction Generator, variable rotor resistance
Siemens	SWT 1.3	Induction Generator, directly connected
ENERCON	E70	Synchronous Generator, converter fed
VOITH	WindDrive-Concept	Synchronous Generator, directly connected, hydrodynamic gearbox

The main application of the generic models described in the following sections is the simulation of network faults. However they can also be used for analyzing the impact of wind turbulence on power quality. For this purpose, wind-turbulence models according to the principles described in [3] are available, which are not described in this paper.

All standard wind generator models can be used for simulations with a transient network model or with a steady state network model (refer to section E.2.1).

E.3.1 Doubly-Fed Asynchronous Machine

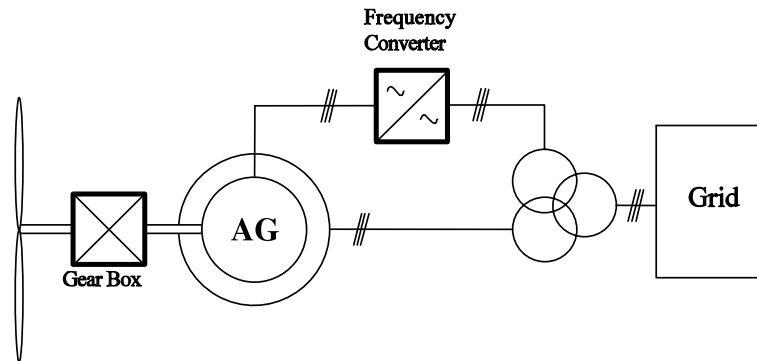


Figure E-1: Variable speed wind turbine with doubly-fed induction machine

A doubly-fed asynchronous generator (DFAG) is a wound-rotor induction machine with a frequency-converter connected to the slip-rings of the rotor. Typically, the frequency converter consists of two back-to-back voltage-source converters with an intermediate dc bus (see Chapter 3, section 3.2.6 and Figure 3-2).

In *PowerFactory* the user has the choice between an integrated DFAG-model, in which the components (the generator machine, rotor-side converter and grid-side converter) are integrated in one built-in model, or a component-wise modeling, where the machine, rotor-side converter, grid-side converter, capacitance of the intermediate dc circuit and additional protection systems such as “chopper” resistance in the dc-circuit or crow-bar on the ac-side of the rotor-side converter are modeled by individual components.

For general stability impact studies, the fully integrated model is usually the best choice. For carrying out highly accurate transient studies, analyzing different control concepts or converter protection concepts, the component-wise modeling approach is usually taken.

An example for a DFAG model built from individual components is shown in Figure E-3. The model shows the components:

- Asynchronous generator
- Machine-side converter (MSC)
- Line-side converter (LSC)
- Intermediate dc-circuit with dc-capacitance
- Grid-coupling reactor of the LSC
- Step-up transformer
- Crow bar circuit with control valves

An example for the application of the simplified, built-in DFAG model is shown in Figure E-4. Because the intermediate dc-circuit is not modeled explicitly in the simplified model, it is much easier to handle and requires less input data than the more detailed model.

For implementing a dynamic model of an entire variable speed wind turbine, the following additional components need to be modeled:

- Speed controller
- Mechanical drive train
- Aerodynamic turbine characteristic
- Pitch controller
- Converter protection
- Other protection (over-/undervoltage, overspeed, over-/under-frequency etc.)

Dynamic models of the generator and additional components are described in the following sections.

E.3.1.1 Induction machine model

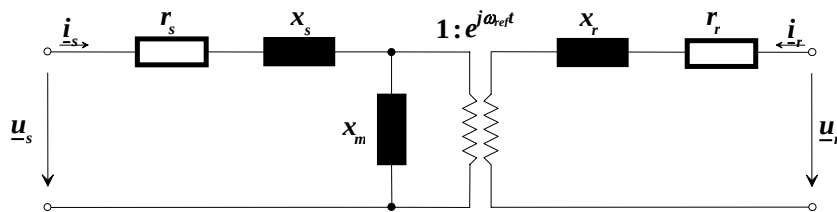


Figure E-2: Standard induction machine model with imposed rotor voltage.

Figure E-2 shows an equivalent circuit diagram of the standard induction machine model with open slip rings for allowing doubly-fed operation.

$$\begin{aligned}\underline{u}_s &= r_s \underline{i}_s + \frac{d\Psi_s}{\omega_n dt} + j \frac{\omega_{ref}}{\omega_n} \Psi_s \\ \underline{u}_r &= r_r \underline{i}_r + \frac{d\Psi_r}{\omega_n dt} + j \frac{\omega_{ref} - \omega_g}{\omega_n} \Psi_r\end{aligned}\quad (1)$$

In a reference system that rotates with frequency ω_{ref} , the stator and rotor voltage equations can be expressed according to (1). All voltages and currents are expressed by instantaneous phasors in a rotating reference system (d,q-components related to ω_{ref}). This model includes stator and rotor flux transients and is used for transient simulations with a transient network model (see section E.2.1).

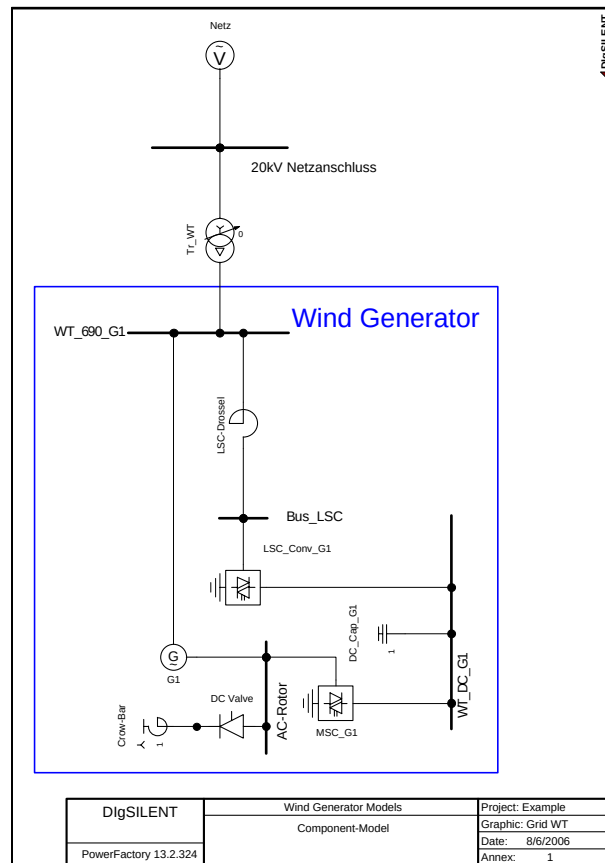


Figure E-3: DFAG built by individual components.

For stability simulations with a steady state network model, stator flux transients are commonly neglected and the induction machine equations can be described as follows (see also e.g. [4]):

$$\begin{aligned} \underline{u}_s &= r_s \underline{i}_s + j \frac{\omega_{ref}}{\omega_n} \underline{\Psi}_s \\ \underline{u}_r &= r_r \underline{i}_r + \frac{d\underline{\Psi}_r}{\omega_n dt} + j \frac{\omega_{ref} - \omega_g}{\omega_n} \underline{\Psi}_r \end{aligned} \quad (2)$$

Since stator flux transients are neglected, the model according to (2) is compatible to stability simulations with steady state network models (see section E.2.1).

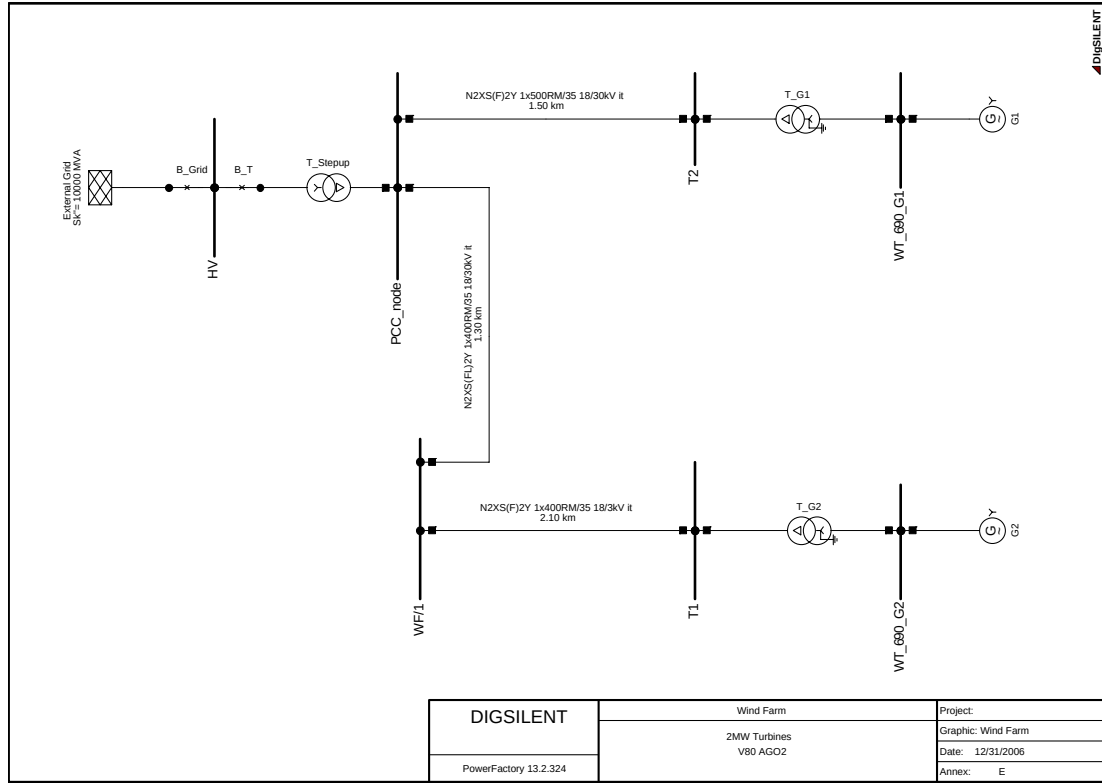


Figure E-4: Simple wind farm based on built-in DFAG-models.

E.3.1.2 PWM Converter Models

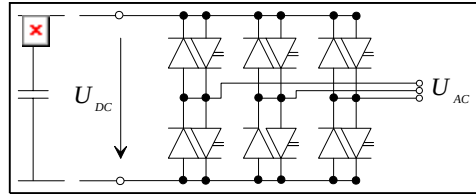


Figure E-5: Voltage sourced, self commutated AC/DC-converter.

Rotor-side and grid-side converters of modern DFAG units are usually built by voltage-source (self commutated) converters with an intermediate dc circuit, as shown in Figure E-5. The valves have turn-on and turn-off capability allowing any voltage waveform to be generated at the ac-side using PWM-modulation or other modulation methods.

The *PowerFactory* standard models are based on a fundamental frequency approach. The corresponding model can be described by three equations.

Two voltage equations:

$$\begin{aligned} U_{AC\alpha} &= K_0 m_\alpha U_{DC} \\ U_{AC\beta} &= K_0 m_\beta U_{DC} \end{aligned} \quad (3)$$

Power conservation:

$$P_{AC} = \text{Re}(\underline{U}_{AC} \underline{I}_{AC}^*) = U_{DC} I_{DC} = P_{DC} \quad (4)$$

The variables of these equations are defined as follows:

- $U_{AC\alpha}$, $U_{AC\beta}$: ac-voltage phasor in $\alpha\beta$ -components
- U_{DC} : dc-voltage

- m_α, m_β : Modulation indices in $\alpha\beta$ -components
- K_0 : constant factor, depending on modulation method
- P_{AC}, P_{DC} : ac- and dc-side active power

Switching losses, if necessary to be modeled, can be considered by a resistance in parallel to the dc-capacitance.

Converter blocking

When blocking a converter according to Figure E-5, the controller will stop sending ignition signals to the transistors, which means that the converter transforms itself into a diode-rectifier consisting of anti-parallel diodes (see Figure E-5).

The fundamental frequency converter model of *PowerFactory* supports this blocking functionality in the transient mode. When sending the blocking signal, the fundamental frequency converter model according to equations (3) and (4) is replaced by a diode-bridge model.

E.3.1.3 Frequency Converter and Electrical Control Concept

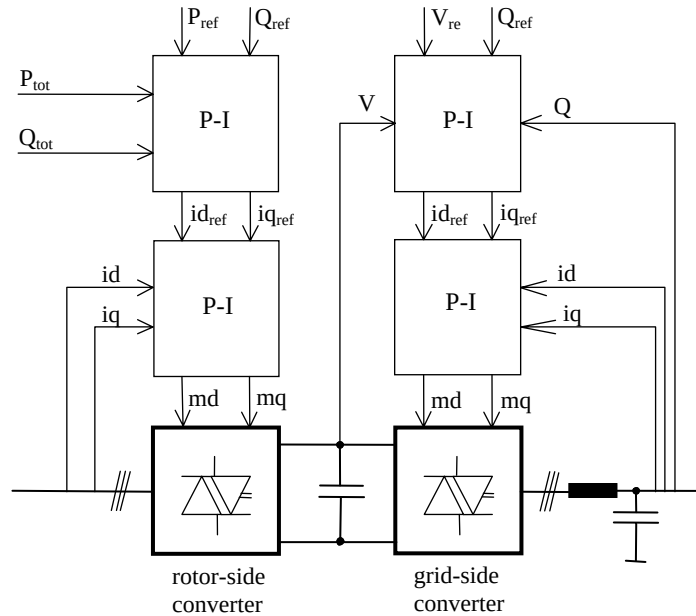


Figure E-6: Principal control structure of the *PowerFactory* standard DFAG-model.

The basic control structure, as used in the *PowerFactory* standard DFAG-models is shown in Figure E-6. The model is described in an ac-voltage reference frame, which means that d-components reflect active components and q-components reactive components.

In the control concept according to Figure E-6, the grid-side converter is equipped with a fast inner control loop regulating grid-side currents by adjusting the modulation indices in d- and q-axis. The outer control loop controls the voltage at the dc-capacitance by adjusting the active current reference (d-axis) accordingly. Reactive power is controlled through the reactive current reference.

Likewise the grid-side converter, the rotor-side converter is equipped with fast PI-controllers regulating rotor currents by adjusting the modulation indices in d- and q-axis. Slightly slower PI-controllers are used for active and reactive power control. It is the total active and reactive power (machine stator and grid-side controller), which is controlled by the rotor-side

converters. The Q-reference of the grid side controller can be used for defining the sharing of reactive power between the stator of the machine and the grid-side converter.

In the actual *PowerFactory* model, a rotor-flux compensation function is considered for transforming the output of the current controllers into actual modulation indices. The principle structure of the rotor-flux compensation term is depicted in Figure E-7.

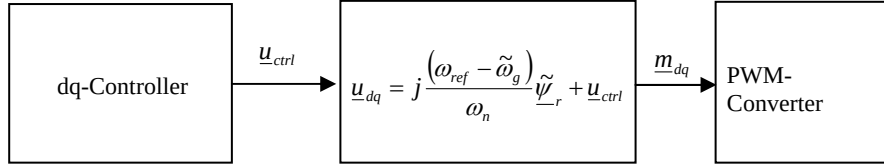


Figure E-7: Rotor-flux compensation.

With this rotor-flux compensation, the coupling of d-and q-axis through rotor flux, as shown by the rotor voltage equations (1) or (2) is compensated so that controller output directly influences either d- or q-axis currents leading to decoupled control paths in d- and q-axis.

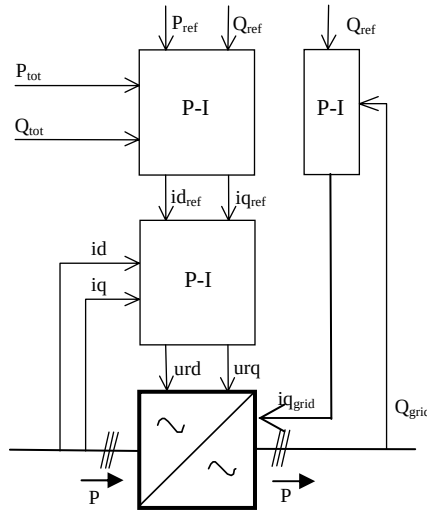


Figure E-8: Simplified DFAG-converter/control.

The electrical control structure of the simplified DFAG-model (see also Figure E-4) is depicted in Figure E-8. The rotor-side controller remains essentially unchanged, compared to the detailed model according to Figure E-6. The only difference is that the rotor voltage is directly used as control variable, instead of using modulation indices.

The grid-side converter and intermediate dc-circuit are entirely reduced; therefore no control of the dc-voltage is required. It is assumed that the converter is lossless, which means that the active power flowing into the converter from the rotor side will flow out of it at the grid-side. Reactive power can be controlled by an additional input “iqgrid” allowing to set the grid-side reactive current directly, which corresponds to a reduction of the grid-side current controller.

Benchmark simulations have shown that the simplified, fully integrated DFAG model provides sufficient accuracy for power system stability studies. For more detailed, transient studies however, the detailed model should be used.

E.3.1.4 Protection of the rotor-side converter

Wind generators with fault ride-through capability require special protection of the rotor-side converter against high currents and/or high dc-voltage (see Chapter 3, section 3.2.6).

Different manufacturers of DFAG-wind generators use different protection strategies. The most common strategies are the following:

- Blocking the rotor-side converter and inserting a crow-bar resistance at the ac-side of the rotor-side converter.
- Chopper resistance in parallel to the dc-capacitance
- Stator disconnection and fast reconnection.

In the component-based DFAG model according to Figure E-3, it is possible to implement all of the above protection strategies in the *PowerFactory* model.

The simplified model (see Figure E-4 and Figure E-8) considers crow-bar protection according to an overcurrent criterion or a voltage-step criterion. Using overcurrents as criterion for inserting the crow-bar is not appropriate when running stability simulations with steady state network models because the influence of decaying dc-components in the stator currents cannot be considered. Instead, it is recommended to measure the stator voltage variation over one period and trigger the crow bar based on a threshold of this “voltage step”. The appropriate “voltage step” setting can be identified by simulations using the detailed, transient model.

E.3.1.5 Speed Control

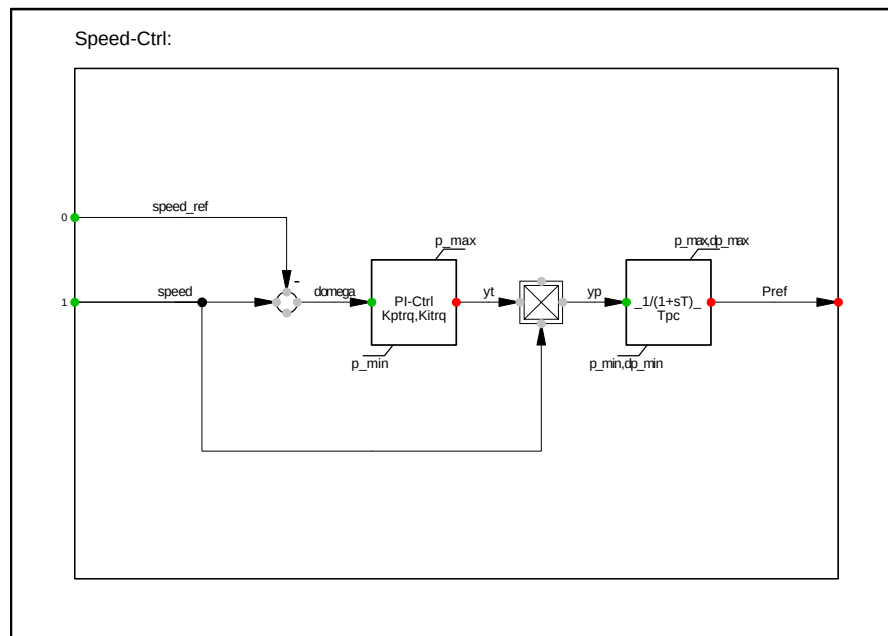


Figure E-9: Block diagram of a simple speed controller for wind generators.

The active power reference of the converter controller according to Figure E-6 or Figure E-8 is defined by the output of a speed controller as shown in Figure E-9.

E.3.1.6 Drive Train

Because of the weak coupling between generator and turbine inertia, a mechanical shaft model with at least two equivalent masses should be used for modeling the drive train of a wind turbine. An accurate modeling of the drive train is quite essential for simulating the turbine response to grid faults because even in a large wind farm, shaft-oscillations of all turbines are excited simultaneously by a grid fault, so that the corresponding interaction with the speed controller or the damping system are visible in the active power output of a wind farm.

In contrast to this, torsional oscillations excited by wind turbulences are usually not visible in the power output of a larger wind farm, because correlation of wind turbulences between

different wind turbines is usually very weak, especially in case of higher frequency components, which could possibly excite torsional oscillations.

E.3.1.7 Pitch-Control

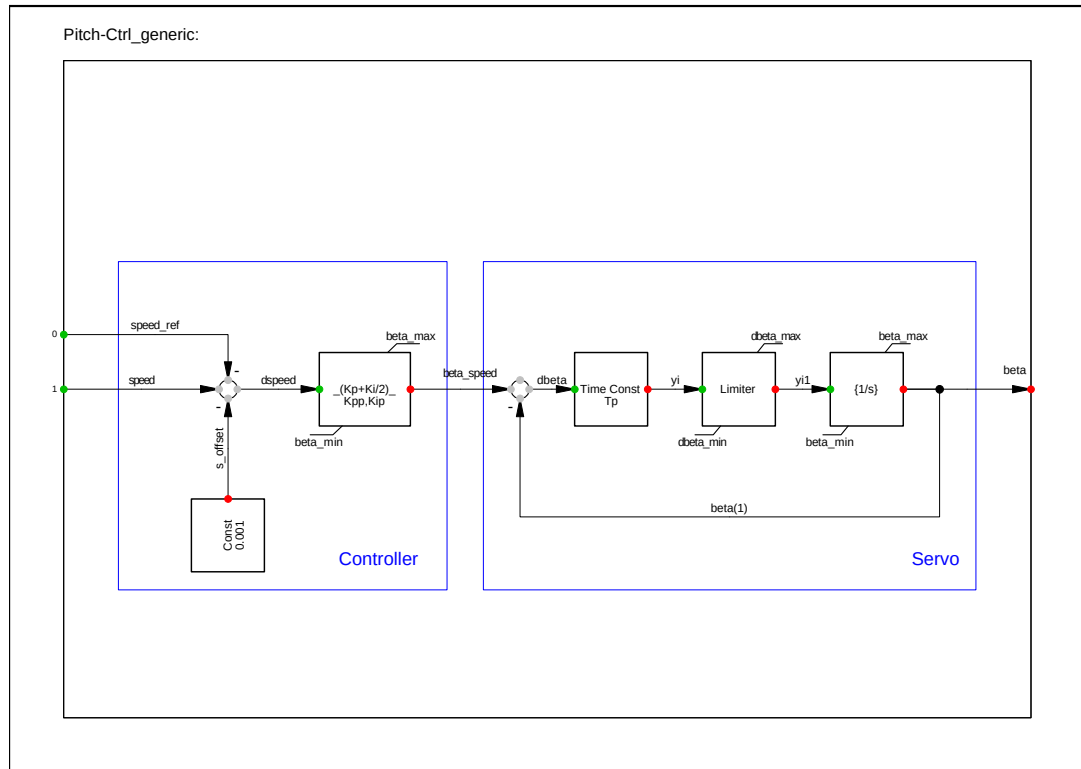


Figure E-10: Generic pitch controller for stability studies.

A generic pitch controller as it is used in the *PowerFactory* standard model is shown in Figure E-10. The model provides sufficient accuracy for power system stability studies. The servo is approximated by a model of first order. Of particular importance is an accurate representation of the rate of change limiter of the blade angle, because this will limit the pitch-control action in case of grid faults.

E.3.1.8 Turbine Aerodynamics

For modeling turbine aerodynamics, it is common practice to use a steady state model, which is based on the following, well known formula:

$$P_w = c_p(\lambda, \beta) \frac{1}{2} \rho A v^3 \quad (5)$$

The two-dimensional power coefficient characteristic is entered in *PowerFactory* using a two-dimensional table, e.g. in the form of an MS-EXCEL-spreadsheet, which can be directly copied into the *PowerFactory* model using standard Copy-Paste functionality.

For interpolating points between sampled values of the power coefficient curve, a special DSL-function is used, named *sapprox2*, which stands for “Spline Approximation, 2 dimensions”, which allows for a smooth approximation of the power coefficient characteristic.

The above formula is therefore realized by DSL-language in the form:

$$\begin{aligned} cp &= \text{sapprox2}(\lambda, \beta) \\ Pw &= cp * 0.5 * \rho * A * \text{pow}(v, 3) \end{aligned}$$

E.3.1.9 Power Flow Setup

In *PowerFactory* all time domain simulations (RMS-simulation and transient simulations) are initialized by a preceding power flow calculation.

In case of the detailed model, which is built by individual components, the generator speed is required for power flow analysis, so that the split of power flow between stator and rotor of the machine can be calculated.

The required input parameters for power flow initialization of the detailed model are as follows:

- Generator: *operating speed*
- Rotor-side converter:
 - control-mode: *PQ* or *PVac*
 - Point of reference: LV or HV-side of the step-up transformer (selectable)
 - Actual reference values of *P* and *Q* (or *Vac*)
- Grid-side converter:
 - control-mode: *Q-Vdc*
 - Actual reference values of *Q* and *Vdc*

Generator speed and active power should be set compatible to the speed-power characteristic of the turbine. Otherwise, the initial state of the dynamic model will be incompatible to the power flow setup, resulting in initial transients. This problem can be solved by using a so-called Parameter-Characteristic that allows inputting the entire speed-power characteristic leading to consistent initial values.

The power flow setup of the simplified, built-in DFAG-model is simpler because the split of active power flows between stator and rotor is not modeled in power flow analysis. This means that the power flow setup is fully compatible to the power flow setup of a conventional synchronous machine (PQ or PV). Generator speed is only required when initializing the dynamic model and can be provided by the power-speed characteristic of the dynamic model.

E.3.1.10 Initialization of Dynamic Models

The initialization of the standard dynamic variable speed wind turbine models is carried out based on the assumption that the turbine operates under “partial load” conditions, which means that the blade angle is set equal to its minimum value and wind speed is adjusted for establishing the required power flow. This means for a wind generator operating at “rated power” that the turbine is initialized with “rated wind speed” and operates right at the edge between partial-load and full-load.

In the case that simulations under full load conditions are carried out it is sufficient to replace the standard models of pitch controller and turbine aerodynamics by modified versions, which ask for initial wind speed and adjust pitch angle for establishing the required power flows.

The initialization of the nonlinear turbine aerodynamics model is facilitated by the “automatic initialization” functionality of *PowerFactory*, which solves corresponding initial conditions automatically by applying an iterative Newton method.

E.3.1.11 Simulation Results

The response of the generic DFAG model to a moderate grid fault leading to voltage sag down to 80% is shown in Figure E-11. In these simulations, a wind farm with 45MW rated output, consisting of 30 turbines with 1.5MW each has been modeled by one equivalent wind generator.

The curves in Figure E-11 show simulation results obtained with a detailed model according to Figure E-3 and a transient network model (red and blue) and results obtained with a simplified model according to Figure E-4 and Figure E-8 (brown/green) in combination with a steady state network model (RMS-simulation). In these simulations it is assumed that no crow-bar would be activated.

The response of the two models is in very good agreement. However, it also becomes obvious from the rotor currents that crow-bar activation based on too high rotor currents cannot be assessed using the simplified model because of the influence of decaying dc-components which appear in the rotor as higher frequency components.

The curves in Figure E-12 show the response of the same wind farm to a heavy grid fault. In these simulations, crow-bar activation is triggered in the detailed model but not in the simplified model. The difference between the two responses gives an idea of the importance of an accurate consideration of converter protection, such as crow bar activation.

The simulations according to Figure E-11 and Figure E-12 are based on a model considering voltage support during grid faults by increasing the reactive current reference. The model behaves according to fault-ride-through requirements and reactive support requirements as they are common in many international connection conditions for wind farms, e.g. [5].

The applicability of the models for unbalanced system conditions is shown in the charts of Figure E-13. The agreement of the results is again reasonably well. However, particularly in case of unbalanced system conditions, manufacturer-specific details with regard to the control of the dc-voltage and converter protection are quite essential, so that a generic modeling approach can always provide only limited accuracy.

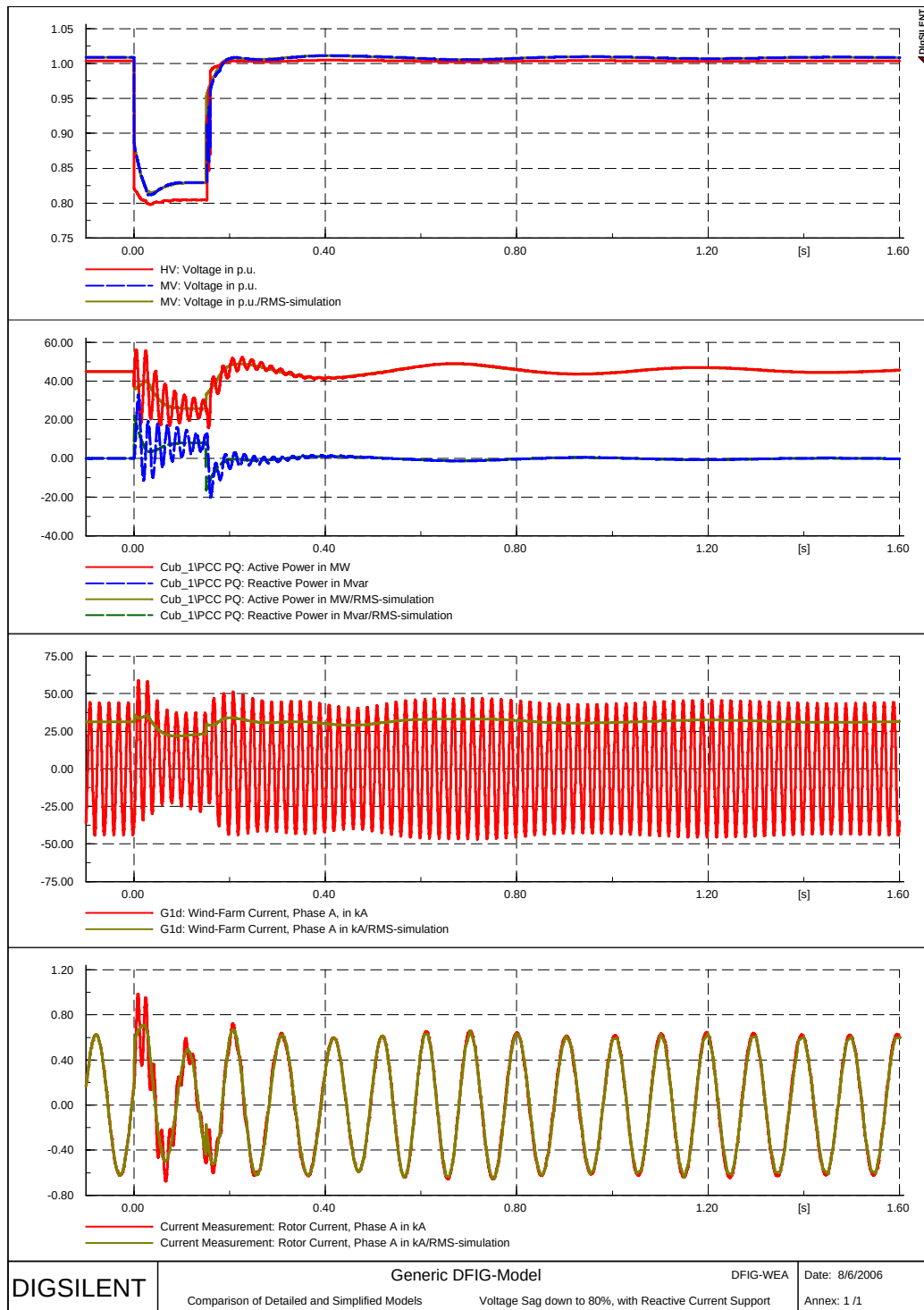


Figure E-11: Model response to a moderate grid fault - comparison of detailed and simplified models.

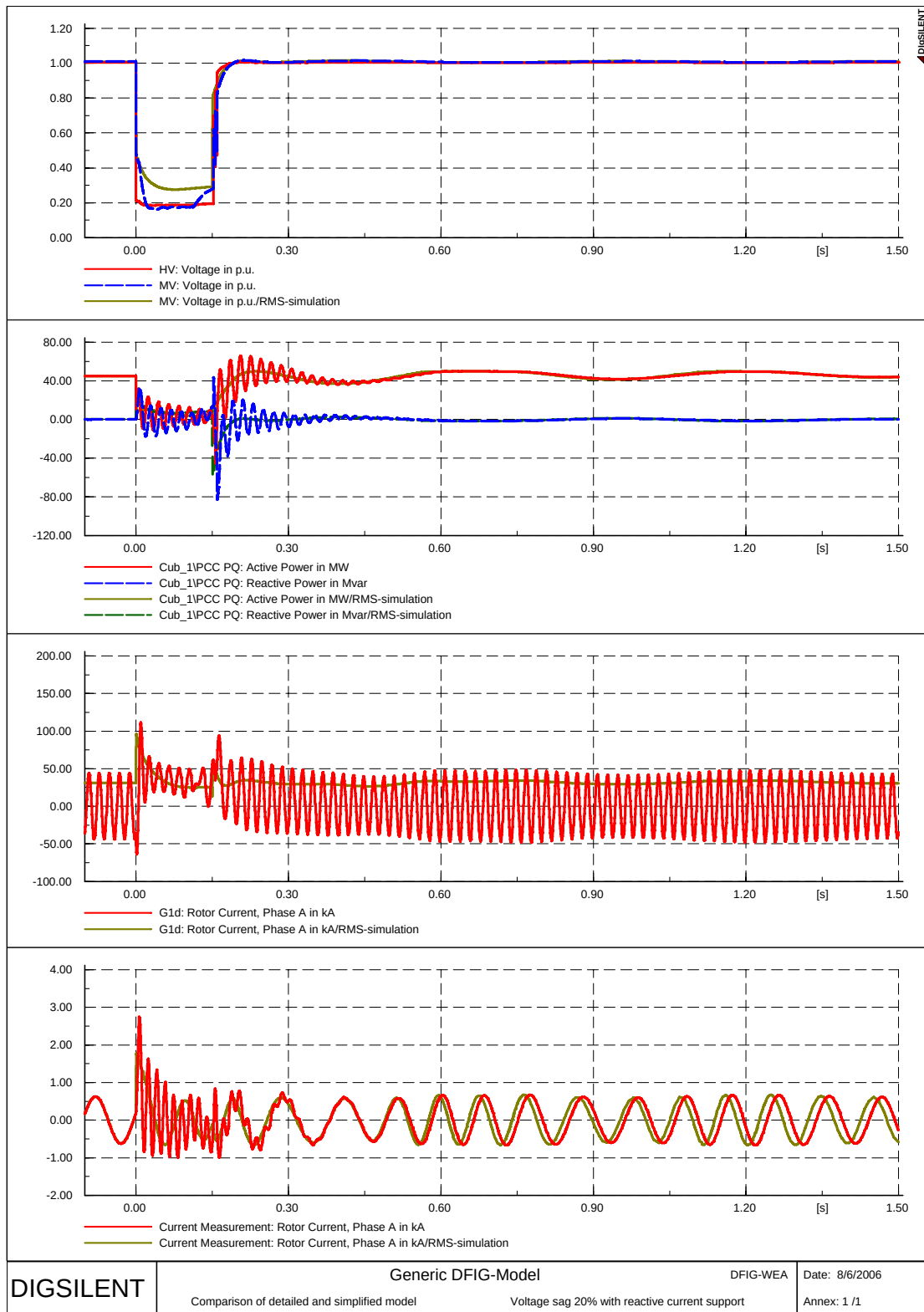


Figure E-12: Model response to a heavy grid fault - comparison of detailed and simplified models.

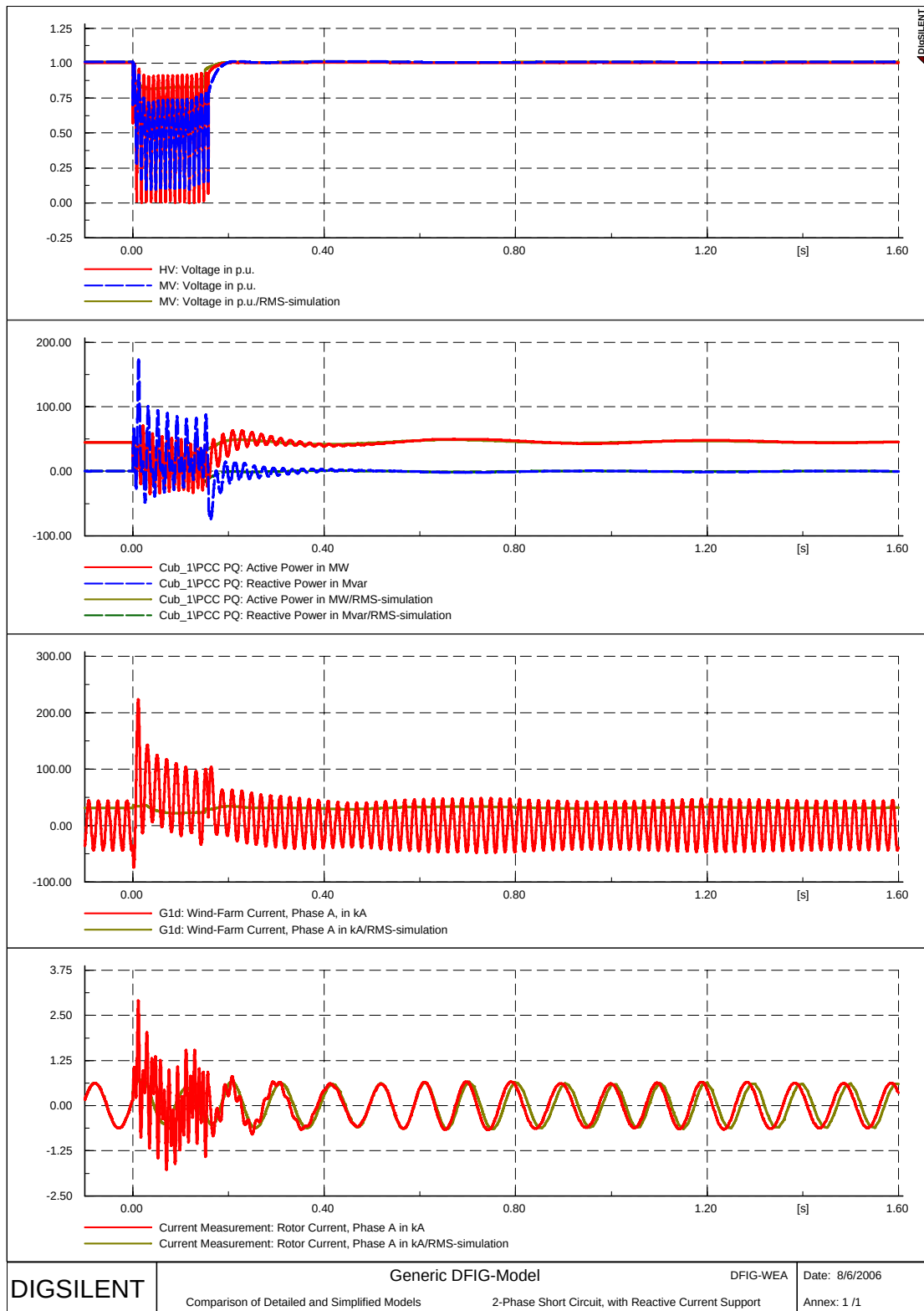
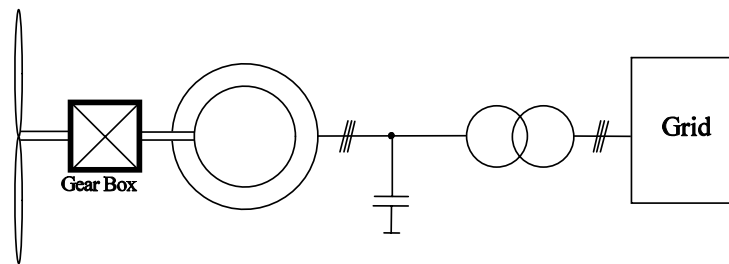


Figure E-13: Model Response to a 2-Phase Fault.

E.3.2 Fixed Speed Induction Machine



FigureE-14: Fixed speed wind turbine with induction generator.

The principal setup of a fixed speed wind turbine with induction generator is shown in Figure E-14. It consists of the turbine, gearbox, induction generator, reactive power compensation (fix or dynamic) and the step-up transformer.

The main components of such a wind generator type are:

- Induction generator
- Mechanical drive train
- Turbine Aerodynamics
- Blade control (Active stall/pitch)
- Reactive power compensation (discretely switched or smooth-dynamic, e.g. SVC, STATCOM etc.)
- Protection (especially undervoltage protection)

E.3.2.1 Induction Generator

The squirrel cage induction generator is modeled according to the diagrams and equations of section E.3.1.1, but assuming a rotor voltage of $\underline{u}_r=0$.

E.3.2.2 Mechanical Drive Train

Modeling of the mechanical drive train is quite important in the case of fixed speed induction machine wind generators, particularly for weak and distribution systems, because of the coupling between mechanical speed and reactive power and the corresponding impact on voltage recovery/dynamic voltage stability. A two-mass shaft model, as described in E.1.1.3 is used in the *PowerFactory* standard model.

E.3.2.3 Turbine Aerodynamics

Turbine aerodynamics is modeled according to section E.3.1.8.

E.3.2.4 Blade Control

In case of the fixed speed induction machine wind turbines, the blade angle controller is regulating power instead of speed. Therefore, a power feed-back instead of a speed feed-back is used in the corresponding standard model.

E.3.2.5 Reactive Power Compensation

Modern wind generators based on the fixed-speed induction generator concept that fulfill the requirements of modern interconnection conditions (e.g. [5], see also Chapter 3, 4 and 5) require fast, dynamic reactive power support for being able to ride-through faults. This can

be installed at the LV-side of each wind generator, or centrally, at the wind-farm connection point.

There are different concepts for dynamic reactive power compensation in use by different manufacturers. Dynamic reactive power compensation can be realized by:

- Thyristor switched capacitors
- STATCOM
- SVC

Also combinations of different approaches are applied, e.g. Thyristor switched capacitors at each generator and STATCOM at the wind-farm connection point (see Figure E-15).

E.3.2.6 Protection

The standard induction generator wind turbine model is equipped with a settable undervoltage protection device.

E.3.2.7 Power Flow Setup

PowerFactory considers in power flow analysis steady state induction machine equations derived from the dynamic equivalent according to Figure E-14. This means that for power flow initialization, a user just enters the active power setting of the machine. The power flow algorithm automatically calculates slip and reactive power of the induction machine.

Therefore, the dynamic model is fully compatible to the steady state power flow solution and a simulation can start without any initial transients or any “tricks” for matching up the dynamic and steady state models.

The STATCOM is initialized using the power flow initialization of the PWM-converter model. It is possible to initialize the STATCOM with the control-mode Vdc-Vac or with Vdc-Q. When initializing the model with ac-voltage control, reactive limits are automatically considered

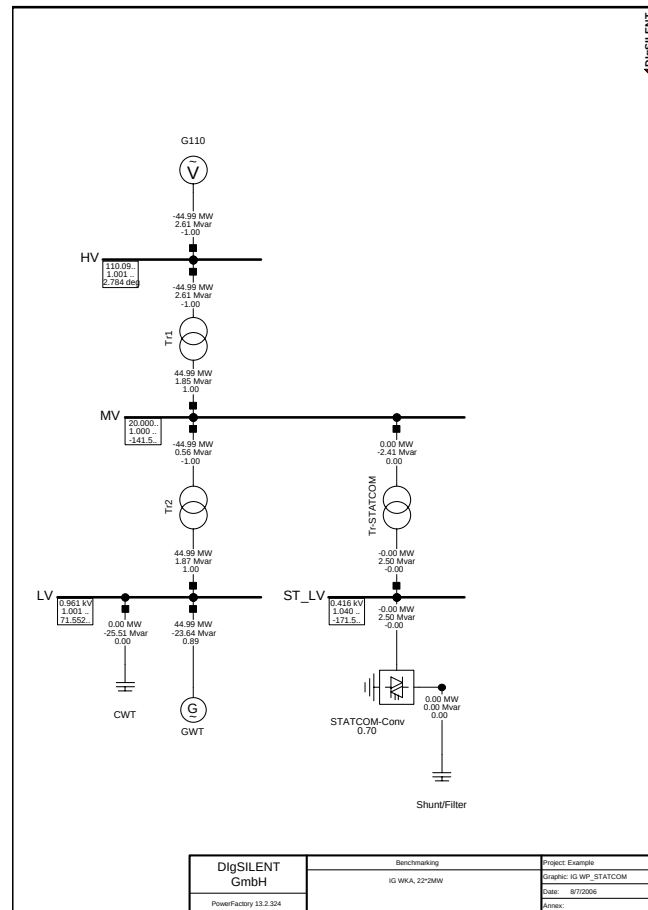


Figure E-15: Wind Farm with fixed speed induction generator wind turbines and STATCOM compensation at the PCC.

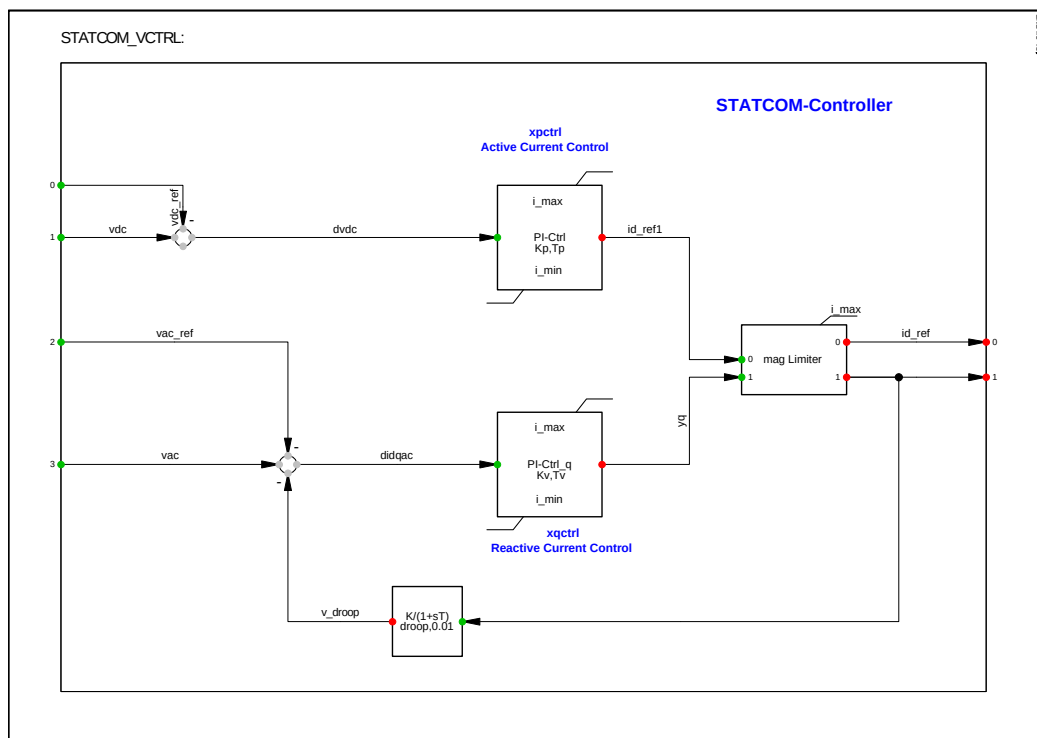


Figure E-16: Standard STATCOM-controller with AC-voltage control and settable droop.

E.3.2.8 Simulation Results

The performance of a 44MW wind farm model (22 x 2MW) with STATCOM compensation at the PCC is shown in Figure E-17. The simulation has been carried out with a third-order induction machine model and a steady state network model.

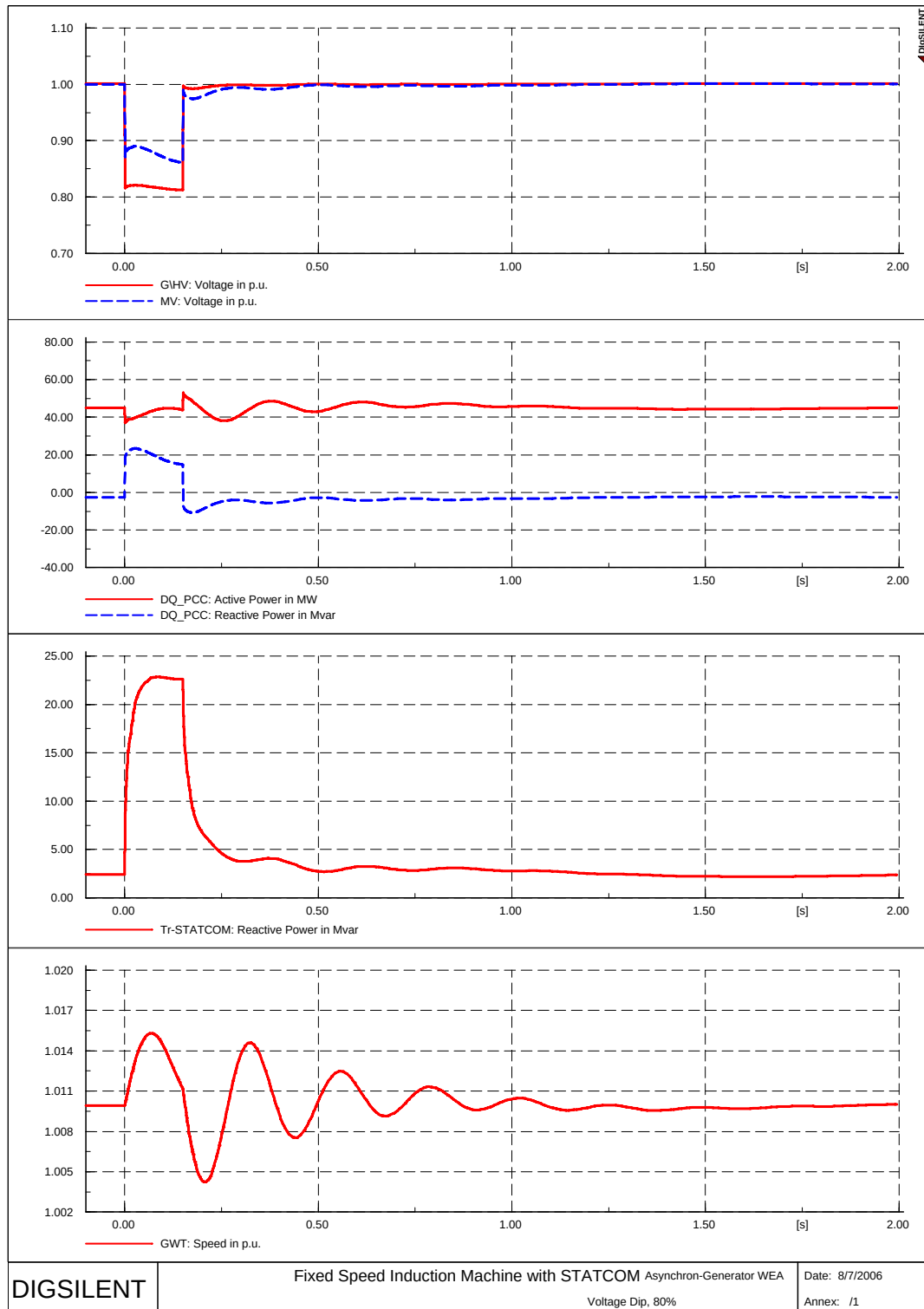


Figure E-17: Simulation of moderate network fault. Fixed speed induction generators with STATCOM.

E.3.3 Full-Converter Units – Synchronous Generator with Fully Rated Converter

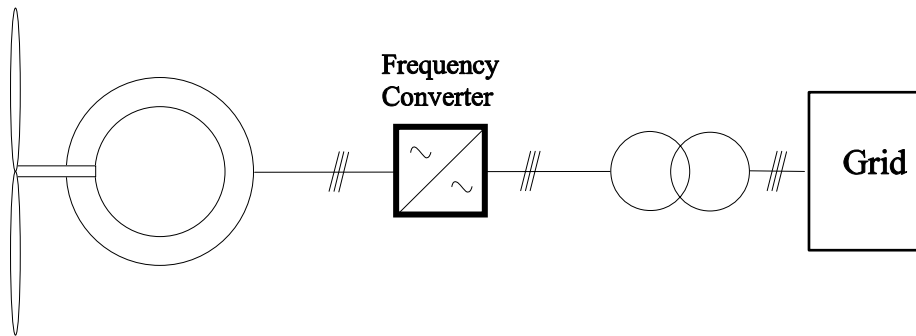


Figure E-18: Variable speed wind turbine (direct drive) with synchronous generator and fully rated converter.

The general concept of a wind generator with synchronous generator and fully rated frequency converter is depicted in Figure E-18.

With regard to the actual machines and converters, there are different concepts used by different manufacturers:

- Electrically excited synchronous generator, diode rectifier at the machine-side and PWM-converter at the grid-side.
- Induction generator with two PWM-converters.
- Permanent magnet synchronous generator and two PWM-converters.

All concepts have in common that there is a self commutated PWM converter, as described in E.3.1.2, at the grid side. The dynamics of the PWM-converter mainly define the grid impact of this type of wind turbine.

The main blocks to be modeled in this wind generator type are similar to a doubly-fed induction generator wind turbine:

- Generator with excitation
- Machine-side and grid-side converter with electrical controllers.
- Speed controller.
- Mechanical drive train
- Aerodynamic turbine characteristic
- Pitch controller
- Converter protection
- Other protection (over-/undervoltage, overspeed, over-/under-frequency etc.)

Because of the almost perfect decoupling of electrical machine dynamics from the grid by the fully rated converter, it is appropriate to highly reduce the model for grid impact studies and to use highly reduced machine models.

Hence, the proposed reduced model, which is appropriate for power system stability studies, just consists of the following functional blocks:

- Highly simplified generator model
- Grid-side converter with electrical controller

- Converter protection

This model is implemented in *PowerFactory* by a current source in parallel to the DC-capacitance (see Figure E-19). The current source represents the interface between the converter and electrical machine model.

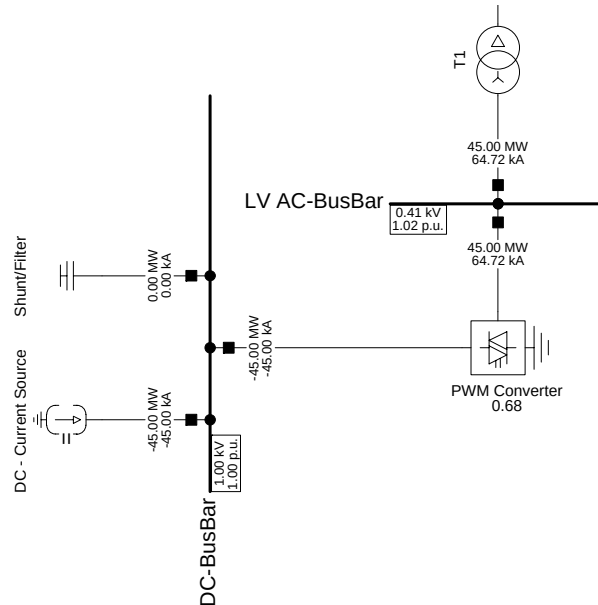


Figure E-19: Simplified model of a wind generator with fully rated converter.

E.3.3.1 Grid-side converter

The control concept of the grid-side converter of a wind generator with fully rated converter is analogous to the grid-side converter of a doubly-fed asynchronous machine, as shown in Figure E-6: An inner, fast control loop controls active- and reactive currents. The outer control loop controls dc-voltage (through active current) and reactive power (through reactive current).

E.3.3.2 Converter protection

During grid faults, when the grid-side converter cannot export all the active power that is “pumped” into the dc-capacitance by the generator, the DC-voltage increases rapidly. For protecting the dc-circuit against overvoltages, a resistance is inserted in parallel to the dc-capacitance (“chopper-resistance”). The chopper-resistance dissipates the active power that cannot be exported through the grid-side converter and keeps the dc-voltage within permitted ranges.

The chopper resistance can either be modeled by a resistance, which is recommended for transient studies, or by an equivalent voltage source, whose voltage is equal to the maximum permitted dc-voltage. When modeling the chopper by an equivalent dc-voltage source, disconnection of the chopper must be initiated when the equivalent voltage source starts generating power. The equivalent voltage source is the preferred approach in case of RMS-simulations with steady state network model, because it allows for larger step sizes (see also Figure E-20).

E.3.3.3 Machine-side converter and simplified generator model

In the case that there is a PWM-converter also at the machine side, a constant power control of the dc-current source can be assumed. In such a system, network disturbances have only minor impact on machine dynamics and can usually be neglected for grid impact studies.

In case of uncontrolled rectifiers at the machine side, a second order synchronous generator model with simplified excitation system can be used for considering machine dynamics. The output of the reduced order synchronous generator model (with rectifier) is the dc-current shown in Figure E-19. However, just using constant power leads to reasonable results, also in case of an uncontrolled machine-side converter.

E.3.3.4 Power flow Setup

The active power reference of the model is defined in the Current Source. The PWM-Converter model has to be set analogously to the STATCOM converter, either in control-model $V_{dc}-V_{ac}$ or in control-model $V_{dc}-Q$.

This will automatically establish the required active and reactive power flows and consider reactive limits of the wind generator.

E.3.3.5 Simulation Results

The performance of the described model is depicted in Figure E-20. Again, the charts compare results obtained by a more detailed model with a transient network model and considering the actual switching logic of the chopper resistance with a simplified model, based on a steady state network model and an “average” model of the chopper resistance, represented by a dc-voltage source.

The agreement between both models is very good, especially in the time frame that is relevant for power system stability studies.

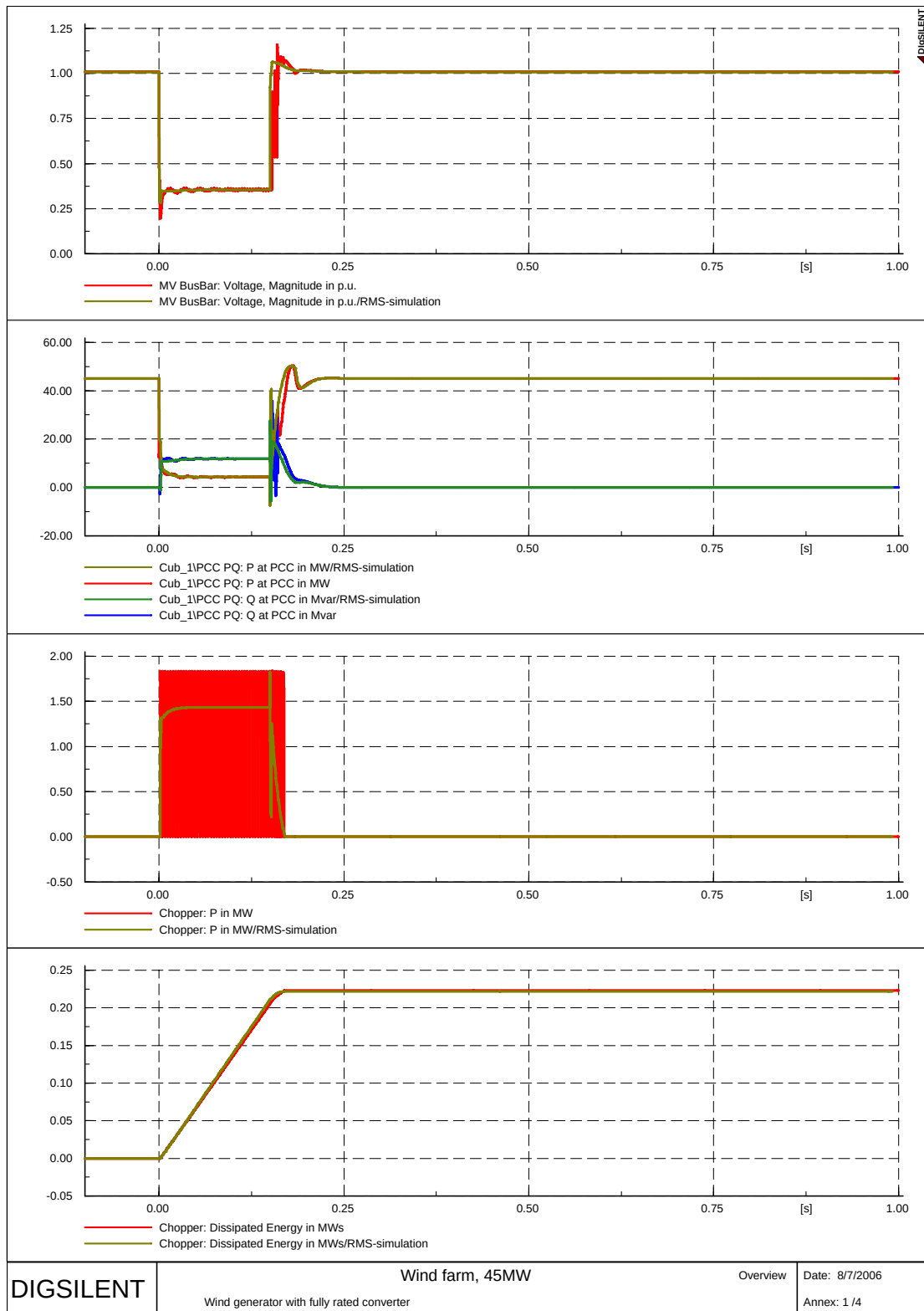


Figure E-20: Simulation Results of wind generator model with fully rated converter.

E.4 Wind Farm Models

The preceding sections described the modeling of individual wind generators. Wind farms with fifty or hundreds of individual turbines can be modeled in *PowerFactory* easily by Copying/Pasting models or using special scripts allowing for automatic wind-farm model generation.

In case of system impact studies, when a large amount of wind farms needs to be modeled, it is impossible to consider each wind turbine in detail. For these applications, aggregated wind farm models are usually taken, which are mainly based on the concept of representing a wind farm by one equivalent wind generator that is scaled to the rated wind farm output (see discussions in Chapter 6 and reference [6]).

E.5 Summary

Wind generator models for the main wind generator types, as available in the standard power system analysis software package DIgSILENT *PowerFactory* have been described in this appendix. The performance of all models has been demonstrated by simulations of typical grid-disturbances. Special attention has been paid on differences between detailed transient simulations and reduced order models, which are commonly used for power system stability studies.

This appendix has mainly focused on generic models. However, other turbine concepts e.g. based on variable rotor resistance (“Opti-slip” or “Flexi-slip”) or wind generators based on synchronous generators with hydrodynamic gearbox (see Appendix C) have been successfully modeled for carrying out wind generation impact studies or investigating the behavior of new generator or controller concepts in case of grid faults or under heavy wind turbulence.

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APPENDIX F

EXPERIENCE WITH WIND TURBINE MODELING AND MODEL VALIDATION BY VESTAS

F.1 Disclaimer

Information contained in this appendix expresses general views and shall not be construed as an expression of the policies or views of Vestas.

Information contained in this appendix shall not be construed as detailed description of the properties or functioning of wind turbines manufactured by Vestas.

Information contained in this appendix should merely be viewed as a contribution to the debate on the development of wind turbine modeling, wind turbine performance and the utilization of the potential of wind turbines in securing grid stability.

F.2 Introduction

Vestas started to manufacture wind turbines generators (WTG) in 1979 and has supplied and installed more than 30,000 WTG in more than 50 countries all over the world.

The grid requirements for interconnection for WTGs have changed in the last few years. Originally, the WTG was assumed to be “passive negative load”, which should disconnect immediately after a grid disturbance. Only recently in the past few year grid requirements demand that the WTG should help to support the grid following a grid disturbance. To investigate and document the performance of WTGs during grid disturbances, dynamic models of the WTGs are needed.

As Vestas delivers WTGs world wide, Vestas is subject to a wide variety of very different interconnections and grid requirements of WTGs. Vestas has supplied WTG for many different grids of greatly varying short circuit and X/R ratios at the connection point. This has resulted in many different expectations of the WTG models from different utilities around the world.

In this appendix is described:

- Briefly the different Vestas WTG types
- Modeling of Vestas WTGs
- Validation of Vestas WTG models

F.3 Vestas Wind Turbine Generator Types

Vestas supplies the major types of WTG described in chapter 3. The Vestas product line is a result of the merge between Vestas and NEG Micon. Vestas refers to its turbine types as follows:

- Active stall (AS) (conventional induction generator)
- Vestas Rotor Current Control (VRCC) (variable rotor resistance generator)
- Vestas Converter System (VCS) (doubly-fed asynchronous generator)
- Vestas Converter Resistor System (VCRS) (doubly-fed asynchronous generator)

All the Vestas turbines are equipped with three blades, pitch system, gear box and a transformer. For fulfillment of Low Voltage Ride Through (LVRT) requirements the turbines are equipped the Vestas Advanced Grid Options (AGO).

F.3.1 Active Stall Turbine

The active stall turbine is from the old NEG Micon product line. The generator used in this turbine is an induction generator with the rotor short circuited. The speed of this generator varies with the slip and the slip variation is normally from zero to roughly 1.2%, thus this is a constant speed unit.

To compensated for the reactive power consumption of the generator, various options are available:

- No load – compensation for the generators no-load reactive power consumption
- Full load – compensation for the generators reactive power consumption between no-load and full load
- Dynamic compensation – to support the grid under LVRT

The active power is controlled by the pitch system and the turbine can be delivered with LVRT options. Figure F-1 shows this system.

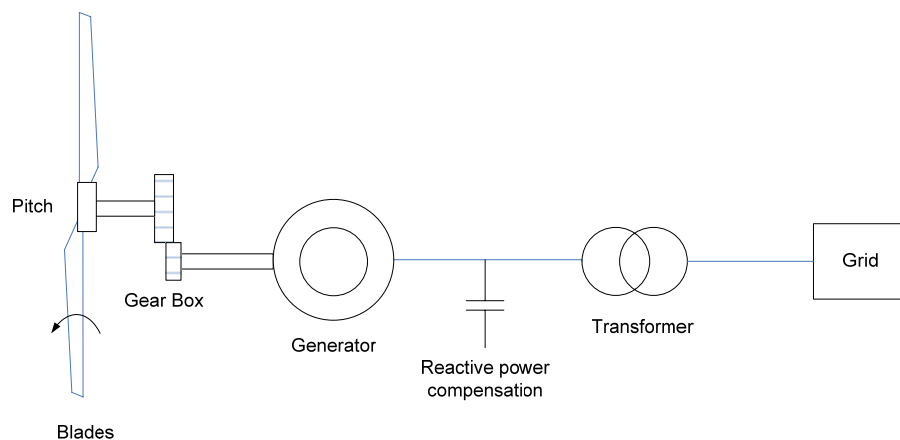


Figure F-1: Principal diagram for the active stall WTG.

F.4 Vestas Rotor Current Control

The Vestas rotor current control WTG is equipped with an induction generator, where the rotor current can be controlled by the Optislip® technology. This technology enables fast control of the generator torque and thereby the speed of the WTG. The speed range for this turbine is from zero to roughly 10% slip.

The reactive power is controlled by capacitor banks and the active power is controlled by the pitch control system. In partial load the Optitip® technology is used to optimize the energy yield.

For LVRT operation the turbine is equipped with the LVRT option AGO4. Figure F-2 shows this design.

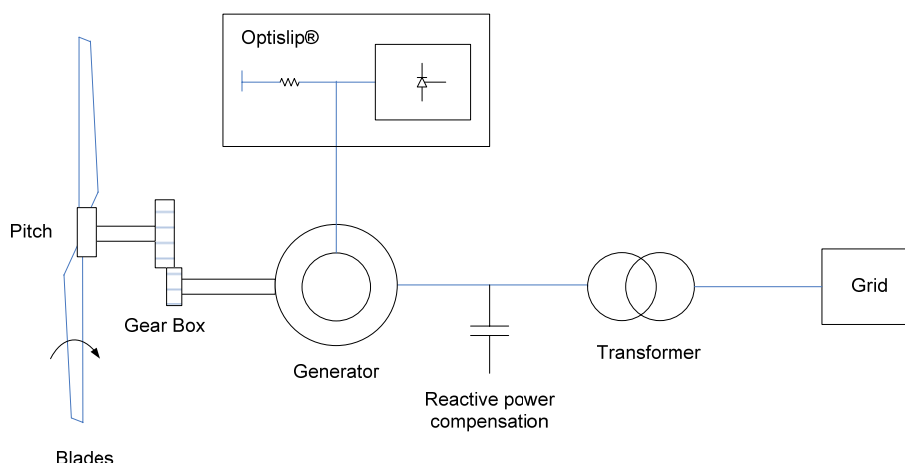


Figure F-2: Principal diagram for the VRCC WTG.

F.5 Vestas converter system

The Vestas converter system WTG is a pitch regulated variable speed WTG. The electrical drive system is a double fed generator and a four quadrant converter. One inverter of the four quadrant converter is connected to the rotor of the generator and the other is connected to the grid.

The reactive power is controlled by the rotor inverter and the active power is controlled by the pitch control system. In partial load the Optitip® technology is used to optimize the energy yield.

For LVRT operation the turbine is equipped with the LVRT option AGO2. Figure F-3 shows this design.

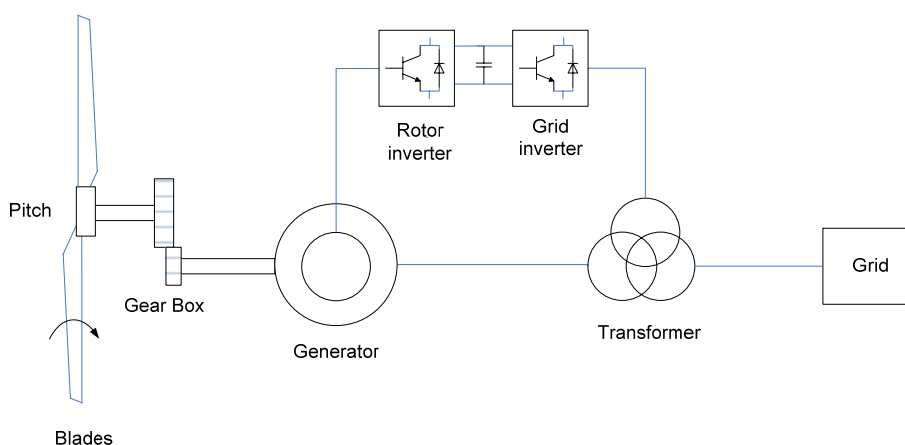


Figure F-3: Principal diagram for the VCS WTG.

F.6 Vestas Converter Resistor System

The Vestas converter resistor system (VCRS) is a pitch regulated variable speed WTG. The electrical drive system is a double fed generator, a two quadrant inverter and passive grid rectifier. The two quadrant inverter is connected to the rotor of the generator and the passive rectifier is connected to the grid. The normal speed operation area for this turbine is below

synchronous speed. A chopper circuit is placed in the dc link to enable the WTG to operate momentarily above synchronous speed for example during wind gusts or grid disturbances.

The reactive power is controlled by rotor inverter and the active power is controlled by the pitch control system. In partial load the Optitip® technology is used to optimize the energy yield.

For LVRT operation the turbine is equipped with the LVRT option AGO2. Figure F-4 shows this design.

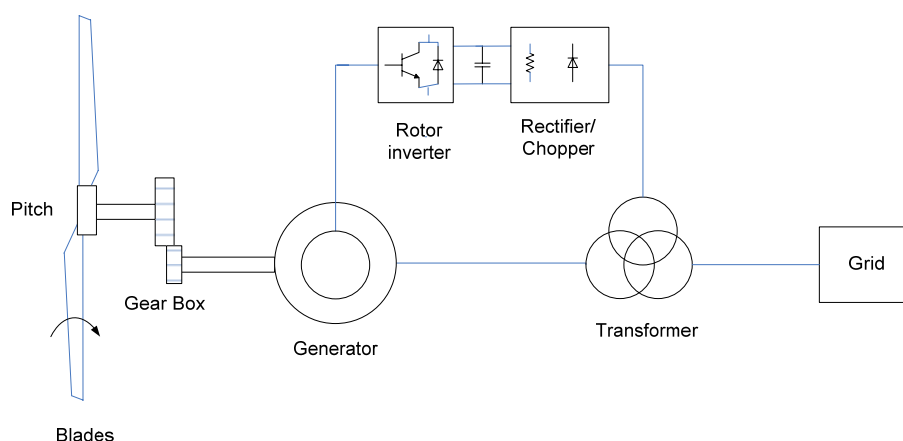


Figure F-4: Principal diagram for the VCRS WTG.

F.7 Modeling

F.7.1 Modeling requirements

Vestas has been working with a wide variety of different modeling requirements. Examples of modeling requirements can be found at the homepages of Eirgrid from Ireland and NEMMCO from Australia. Vestas has worked together with many different utilities to define the scope and content of models for their system studies. A successful way to capture all these requirements has been to make a common requirement specification, which includes requirements for:

- What performance is expected of the models?
- What frequency bandwidth is expected of the models?
- What components should be modeled?
- What control features should be modeled?
- What assumptions are needed and relevant?
- What are the requirements to test the model?
- What are the requirements to validate the model?
- What are the requirements for model documentation?

F.8 Model Types

The choice of model type depends of the purpose the model shall be used for. A way to distinguish between different types of models is to define them either as component models or performance/functional models.

The modeling approach for the component modeling is that every component in the WTG is modeled separately and thereafter the separate component models are linked together. The inputs to a component model are normally datasheets, block diagrams and source code.

The modeling approach for the performance/functional model is to use engineering assumptions on the components that have influence on the performance under study. Normally a performance/functional model is more simplified than a component model. For example the purpose of a performance/functional model can be to show the active and reactive power response of the WTG as function of grid disturbances and not show detailed information about the pitch performance inside the turbine.

Figure F-5 shows a Vestas working tool for discussion and classification of WTG models. The working tool works in this way, first the complexity (y-axis) is chosen and then a horizontal line is drawn to see how detailed each sub-model needs to be to contribute to the total WTG model.

In Figure F-5 are drawn three horizontal dashed lines for three different models:

- Detailed model - this is typical the Vestas EMTDC/PSCAD® model
- Stability model - could be a model for stability study
- Simple model – the model could be a constant P and Q source

The placement and size of the different sub-model blocks is not fixed and can be changed depending on the purpose, discussion and classification.

For a performance model one must distinguish between controlled and non-controlled responses. The controlled response is from the control systems in the WTG as for example the converter control and pitch control. Non controlled response comes for example from the generator dynamics itself or the drive train.

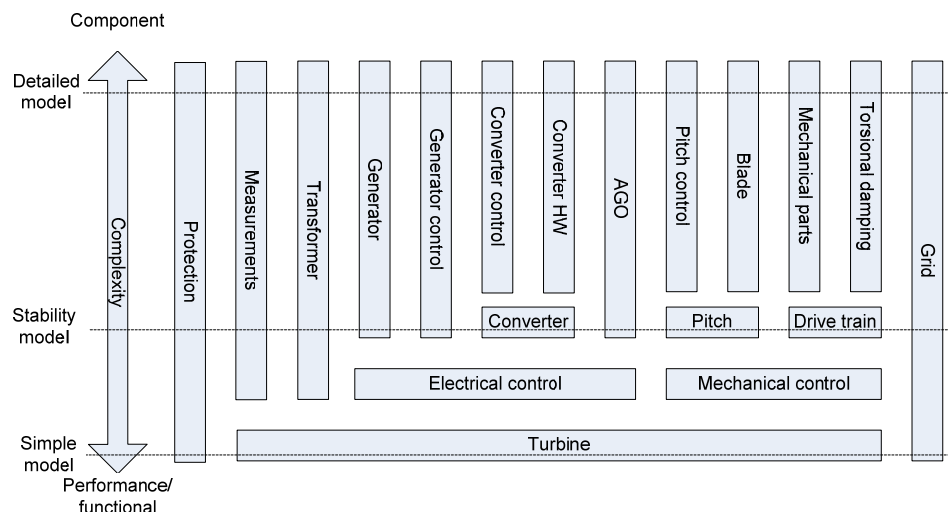


Figure F-5: Working tool for discussion of how each WTG sub-model shall contribute to a total WTG model.

F.9 Model example

As an example, here a user written PSS/E® model of a Vestas V80 VCS AGO2 is described. The model is neither a complete component level model nor a purely performance/functional model, but rather in between. Figure F-6 shows a block diagram of the model.

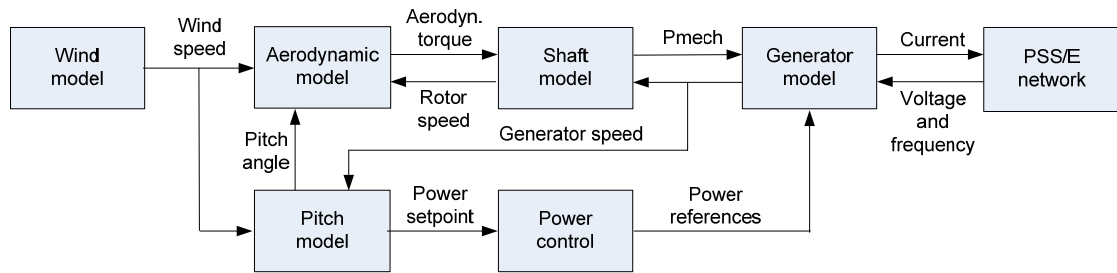


Figure F-6: Block diagram Vestas V80 VCS AGO2 PSS/E model.

The sub-models consist of the following:

- Generator model:
 - o Three winding transformer model (RMS)
 - o Double fed generator (RMS)
 - o Mechanical inertia representing the gearbox, brake and generator
 - o Generator control (rotor inverter control) including:
 - Power control
 - Current control
 - AGO2 control
 - Torsional damping control
 - o Grid inverter as a current source
 - o Measurements filters
 - o PLL for measurement
 - o Protection
- Power control:
 - o Active and reactive power reference to the generator model
 - o Choice between reactive and power factor control
 - o PQ chart limitations are taken into account
- Shaft model:
 - o The mechanical transmission system associated with the turbine-generator shaft is represented by a 2-mass model. One mass represents the blades and the other represents the generator. The masses are coupled by a spring constant (stiffness) and a mechanical damping constant.
- Pitch model:
 - o Pitch servo controller
 - o Pitch hardware
 - o Additionally the pitch model sets the power set-point to the power control model
- Aerodynamic model:
 - o In the aerodynamic model, the aerodynamic torque on the blades is calculated on basis of the wind speed, blade characteristic and turbine

rotor speed. The blade characteristic is described by the efficiency of the blades, also called C_p value.

- Wind model:
 - Allowing wind gusts and ramps to be applied.

The model is connected to the network in PSS/E®, which is a positive sequence network model. The frequency bandwidth in the PSS/E® network is from zero to approximately 2 Hz (see discussion in section 7.3).

The dc bus voltage is assumed constant in the model, since the grid inverter controls are very fast compared to the normal simulation steps in PSS/E®.

F.10 Vestas Model Portfolio

Vestas has made a wide variety of different models for different WTGs and applications. The models are used externally for demonstration and documentation of WTG performance and internally for design purposes. The WTG types AS, VRCC, VCS and VCRS have been modeled and the models are with and without LVRT options.

The models have been implemented in different tools such as: PSCAD®, PSS/E®, PSLF®, SIMPOW®, PowerFactory®, Eurostag® and MATLAB®. More tools will come in the future.

Models have been made for both positive sequence stability and electromagnetic transient (EMTP) type studies. Due to the intellectual properties of Vestas some of the models are confidential, but also non-confidential models are supplied as for example simple block diagram representations.

F.11 Validation

Vestas validates the models implemented in the different simulation tools. The preferred way to validate models is to compare simulation results against measurements on full scale turbines. Test bench tests have also been used, but these tests do not show everything which is relevant for dynamic models. For example the pitch control and the whole dynamics of the WTG are not taken into account in a test bench case.

At the WTG sub-model level it has been beneficial to compare simulation results between PSCAD® and PSS/E® – keeping in mind that PSCAD® is an EMTP program and PSS/E® is a positive-sequence stability program.

F.12 Full Scale Tests

Full scale tests have been performed by WTGs connected to a HVDC-Light® or a LVRT test container, where the voltages at the turbines can be controlled. Figure F-7 shows a simple sketch of the full scale test equipment and curves showing the input to the validation process.

Since HVDC-Light® is a voltage-source converter based technology, it is possible to control the voltage at the WTG. Voltage drops can be controlled in amplitude and duration. The LVRT test container works basically with a fault impedance that is switched on and off. A limiting impedance is placed between the fault impedance and the network to limit impact on the network when the fault impedance is switched on.

Another input to the WTG model validation process is the wind speed – which is off-course non-controllable.

Validation of V80 VCS AGO2 models implemented in the simulation tools PSCAD®, PSS/E®, MATLAB® and PowerFactory® have been performed up against test at the HVDC-Light® station in Tjaereborg in Denmark. The PowerFactory® model was developed and

validated in cooperation with Energinet.dk and Elsam Engineering. After the V80 VCS was validated the other VCS turbines were modeled by changing parameters in the V80 model.

Validation of the V82 active stall turbine models implemented in the simulation tools PSCAD® and PSS/E® have been performed with the use of the LVRT container¹. In the future, more measurement and validation will be performed on other Vestas WTGs and wind parks.

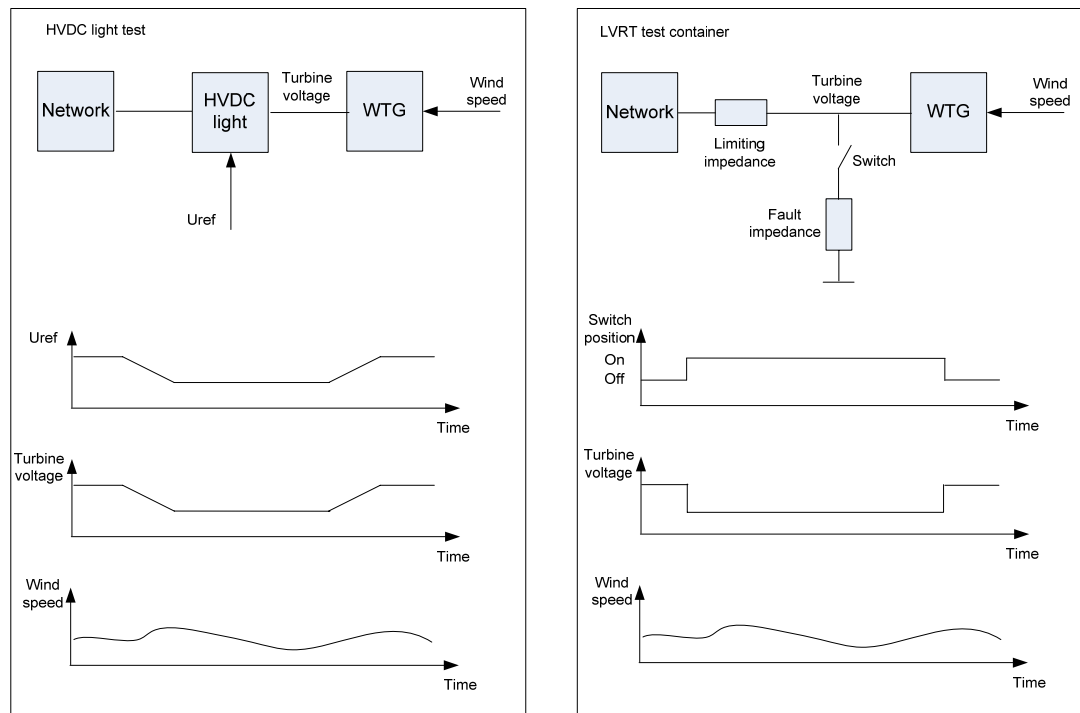


Figure F-7: A simple sketch of the full scale test equipment and curves showing the input to the validation.

F.13 Validation Example Showing the Dynamic Performance of a WTG

In this section a detailed validation of the V80 VCS AGO2 PSS/E® model is shown. The simulation results are compared against measurements performed at Tjaereborg in Denmark, where a V80 VCS AGO2 WTG is connected to a HVDC-Light® station.

Two examples are shown below. One showing a short fault where the voltage drops to 30% voltage for 150ms and a long fault where the voltage drops to 60% voltage for 2100 ms.

Inputs to the model are:

- initial reactive power set-point
- wind speed – assumed as a constant value
- voltage

The outputs showing the electrical performance are:

- stator voltage
- stator current

The outputs showing the mechanical performance are:

¹ The LVRT container is a portable test bed.

- generator speed
- rotor speed
- pitch angle

Measured results shown on Figure F-8 and Figure F-9 are not filtered and no fitting or adjustments has been made to the model. The solid lines are simulated values and the dashed are measured. The x-axis is time in seconds.

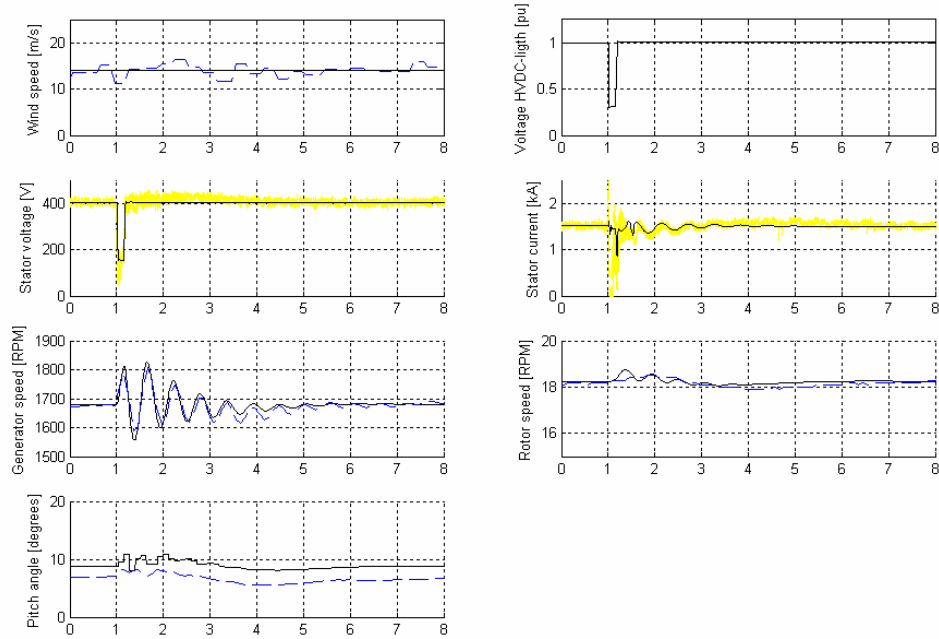


Figure F-8: Validation of PSS/E model with HVDC-light measurements for a short fault.

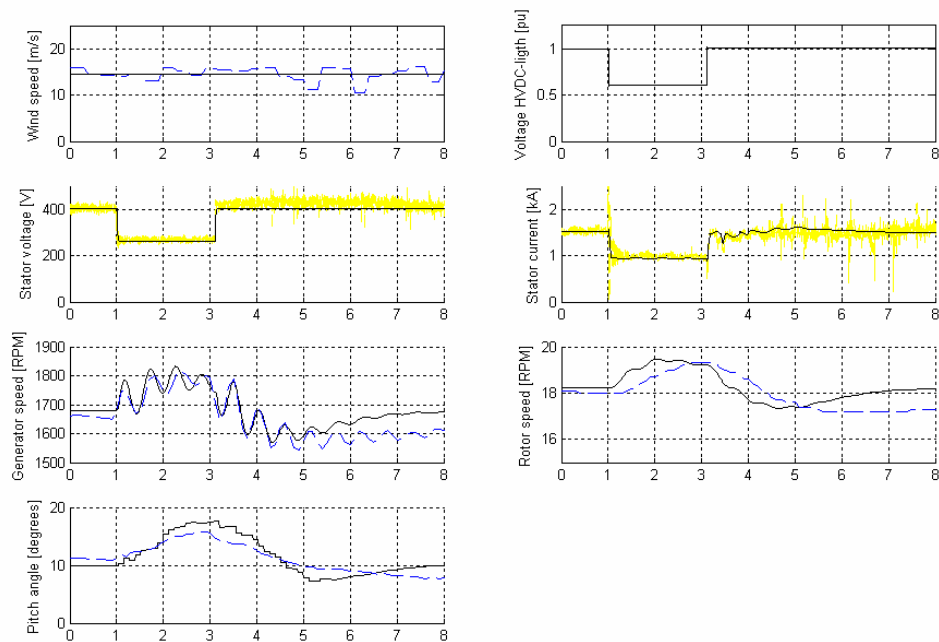


Figure F-9: Validation of PSS/E model with HVDC-light measurements for a long fault.

Figure F-8 and F-9 show good agreement between the simulated and measured results. This experience has shown that a full scale test such as this is the best way to validate models. Full scale validation also gives experience about what parameters are of importance for the performance under study, for the different WTG concepts.

F.14 Conclusion

The Vestas experience with modeling and performance of wind generation as it relates to bulk power system control and dynamic performance is that there are many different expectations of the WTG models from different utilities around the world.

Vestas has been working with a wide variety of different modeling requirements coming from many different utilities. To define the scope and content of models for their system studies, a successful way has been to define the requirements in a common requirement specification.

A method to classify the level of detail for the models has been presented in this appendix. The method is to distinguish between different types of models is to define them either as component level models or performance/functional models.

A detailed PSS/E® model is presented and the validation with full scale measurements is shown. The validation shows a satisfactory performance of the model.

The experience from full scale validation is that it is necessary to do full scale validation on WTG models to be able to conclude if the performance of a model is adequate. Full scale validation also gives experience about what parameters of the model are of most importance for the performance under study.

APPENDIX G

IEEE 1547 – IEEE STANDARD FOR INTERCONNECTING DISTRIBUTED RESOURCES WITH ELECTRIC POWER SYSTEMS

G.1 Introduction

The IEEE Standard 1547 is the parent document for a series of standards that establishes technical specifications and requirements, as well as test criteria for Distributed Resources (DR) – generators and energy storage technologies – that interconnect to distribution voltage level utility Electrical Power Systems (EPS). The standard does not set requirements for protection and operation internal to the resource itself. Other standards in this series [IEEE 1547.1 through .7] provide further detailed guidance on the issues discussed in the parent standard such as testing procedures, monitoring and information exchange, control, islanding, etc. The IEEE Standard 1547 has been included into the US Energy Policy Act of 2005 with all of its associated standards in the series.

Outside of the IEEE, other international activities to provide similar standards fall under the purview of IEC Technical Committee TC8. In Canada, the Canadian Sub Committee to TC8 has recognized that 1547 does not fully address differences between the US and Canadian systems; therefore, new standards are currently being written. CSA C22.3 No.9: Interconnection of Distributed Generation, and C61400-1: Wind Turbine Generator System-Part1: Safety Requirements are under development.

G.2 Summary of 1547 Interconnection Technical Specifications and Requirements

The standard identifies requirements that must be met at the Point of Common Coupling (PCC) with the commercial power distribution entity, identified as the Area EPS.

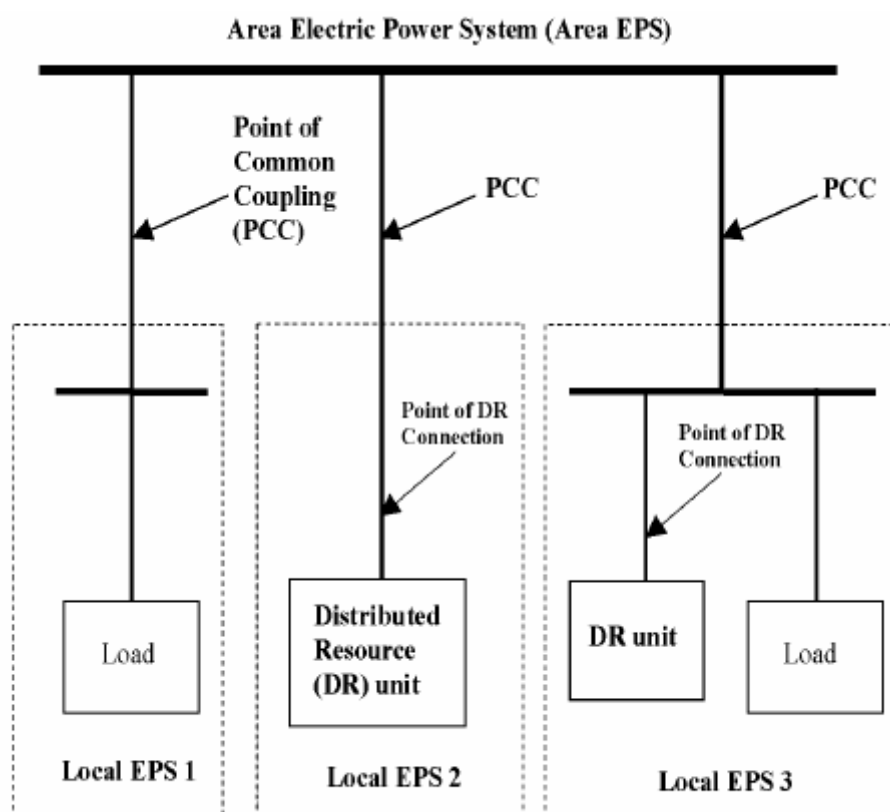
The requirements are described as functional in nature and do not specify how they are to be met, or by any particular type of equipment. General requirements are given that address voltage regulation, grounding, voltage fluctuation from DR synchronization to the grid, inadvertent energizing of the EPS, monitoring (interconnection status, real and reactive power and voltage), need for isolation devices between the DR and the EPS, and integrity of the interconnection to ensure it can withstand standard system transients and not cause system malfunction.

Response to abnormal system conditions are discussed to include system faults, reclosing operation and coordination, high and low voltage and frequency limits and clearing times, loss of synchronization, reconnections, power quality to include DC injection to the system, harmonics, flicker, as well as islanding concerns.

Testing specifications and requirements are given to ensure that the interconnection meets the technical requirements and are formally documented as such. Testing requirements for design, production, installation, and commissioning are specifically identified. Design tests are to be performed on a representative sample, sequenced as shown below, and can be performed at the manufacturing facility, a test laboratory, or in the field.

Table G-1: Test requirements.

Required order	Design test clause and title
1	5.1.1 Response to abnormal voltage and frequency
2	5.1.2 Synchronization
3	5.1.3 Interconnect integrity test
Suggested order	
4	5.1.1 Response to abnormal voltage and frequency
5	5.1.2 Synchronization
6	5.1.4 Unintentional islanding
7	5.1.5 Limitation of dc injection
8	5.1.6 Harmonics



Note: Dashed lines are EPS boundaries. There can be any number of Local EPSs.

Figure G-1: Point of common coupling for a DR.

G.3 Significance of 1547 to the wind power industry

Because IEEE Standard 1547 covers generating resources, up to 10 MVA, that connect to electrical distribution systems, single wind turbine generators (WTG) and small project installations are enveloped by its requirements.

One area of current wind turbine generator design needing to be reviewed in the context of this standard is in regards to Interconnection Integrity requirements of Electromagnetic

Interference (EMI) and Surge Withstand protection and testing within Sections 4.1.8 and 5.1.3. IEEE Standards C62.45 and C37.90 are identified to be used for conformance with the EMI and Surge Withstand requirements. However, since many WTGs are designed and manufactured outside of North America they conform to IEC (or other) standards, such as EN 61000-4, that can have differing test conditions and acceptability criteria.

Additionally, protective devices to meet the requirements of Section 4 for WTG response to EPS abnormal conditions such as faults, voltage, frequency, power quality, islanding, etc. are usually designed into the integrated multi-function computerized WTG processor. As such the processor is pre-programmed and tested in the factory prior to shipment. It often does not have test ports for injecting specific testing signals in the field; rather, manufacturer commissioning test procedures are relied upon to demonstrate proper operation of protection functionality to inspection authorities and utility acceptance personnel.