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# **Wind Farm Integration in British Columbia – Stages 3: Operational Impact**

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## Executive Summary:

The British Columbia Transmission Corporation (BCTC) commissioned this study to seek consultation on the subject of planning and interconnection criteria related to the incorporation of large amount of wind generation into the BCTC system. In addition, to review the potential operational impact of wind generation. This report constitutes stage 3 – namely, a review of the potential operational impact of wind generation.

Based on a review of potential operating concerns and the experience in Europe and elsewhere in North America, here are some key actions that BCTC can consider for minimizing operational impact of wind generation on the BC system:

1. **Controls/Monitoring:** Each wind farm will need to monitor its output and local wind speeds and supply this information to the system operator by telemetry. In addition, many control features are evolving as exemplified by recently commissioned wind farms in Europe. Such features can help to provide the system dispatcher with greater control and flexibility during system operation. These include:
  - i. *Power curtailment* – The ability to curtail power at a wind farm in blocks from a centralized control system at the wind farm.
  - ii. *Power limitation* – The ability to limit the maximum power being produced by a wind farm through a centralized control system at the wind farm.
  - iii. *Ramp rates* – Given the abundance of large hydro generation in BC, we presently do not see a need for imposing ramp rate requirements on wind generators. Provided turbines within each farm are staggered upon start-up and shut-down (which is the case with modern designs), it is quite unlikely that the system will ever see rates much greater than several tens of megawatts per minute. Given that many of the large hydro generators on the BC system are capable of ramp rates much faster than this, then if ancillary services are provided by the large hydro units this issue can be easily mitigated.
  - iv. *Frequency control* – Given the abundance of large hydro generation in BC, we presently do not see a need for frequency control by wind farms in BC. That is, provided the hydro units are available and providing frequency regulation. The one exception possibly, is for wind farms on Vancouver Island and other regions subject to being islanded. This, however, requires further study.
2. **Wind Forecasting:** BCTC should consider the possibility of investing in state-of-the-art wind generation forecasting tools. Such tools are available from European and North American vendors. Experience in the USA and Europe has shown that as the level of wind penetration in a system approaches 10% or higher (of peak load), such tools help to reduce the operating costs associated with wind generation variability by giving insight to the system operator in relation to expected wind generation in the hour and day ahead time frame. Such a wind forecasting tool may be implemented at each wind farm, or the wind farm owners may cooperate to share the cost of developing a single centralized tool that monitors and determines forecasts for all wind farms in the BC. The decisions of whether to invest in a centralized versus individual installations of such forecasting software presents commercial challenges, the consideration of which are outside the scope of this report. It should be noted that the benefit of a centralized scheme is that there is consistency and uniformity in the methodology and treatment of all wind facilities in the forecast, as

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opposed to having a variety of different forecasting tools at each wind farm in the system.

3. **Market Rules:** Even with wind generation prediction tools, there will still be some mismatch between actual and predicted wind generation. Market rules need to be put into place to deal with such intermittent resources. Two examples of present strategies used in North America are given in the report. These may be summarized as follows. Firstly, the wind power producer may either participate in the day-ahead market using the predicted generation from his/her facility based on the prediction tool and then compensate for the net mismatch between scheduled and delivered power over say a one month period. Alternatively, the producer may participate in the hourly market and compensate for the net mismatch between scheduled and delivered power by purchasing power on the real time market to make up for any deficit.
4. **Vancouver Island and North Coast:** In the case of Vancouver Island there are some particular challenges. Given the possibility, though remote, of losing all synchronous ties between Vancouver Island and the rest of the Province there needs to be particular attention paid to the integration of wind generation on Vancouver Island. There are essentially three options:
  - I. To limit the amount of wind generation on Vancouver Island.
  - II. To ensure that all wind generation on Vancouver Island have special frequency regulation controls that allow the units to respond immediately to a declining system frequency by increasing their output. This requires that the wind farms operate such as to always have a reserve margin between the actual amount of wind power available and what is being produced by the wind farm.
  - III. To build additional lines connecting the Vancouver Island system to the mainland in order to significantly reduce the probability of islanding.

More detailed analysis is required in order to identify exactly which of these three options is the most economically viable solution.

Similarly, there are regions of the BC transmission system near the North Coast that are equally susceptible to being islanded. As such, similar concerns may apply in these regions meaning the need for either significant additional transmission facilities to minimize the potential for islanding the region or the need to limit and control wind generation following an islanding event. These need to be studied in greater detail to identify the most cost effective solution.

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## Terminology

- ISO – Independent System Operator
- LVRT – Low voltage ride through
- OLTC – On-load tap changer (typically used on distribution substation transformers)
- STATCOM – Static var compensator based on voltage source converter technology (while an SVC is a constant impedance device, once it hits its limit, a STATCOM becomes essentially a constant current device at its reactive limit)
- SVC – Static var compensator based on thyristor switched/controlled devices (e.g. thyristor switched capacitors, or a combination of thyristor switched capacitors and a thyristor controller reactor)

# 1 Introduction

The British Columbia Transmission Company (BCTC) has received inquiries for wind farm interconnection in the province of several hundred megawatts. This study constitutes an initiative by BCTC to investigate the potential impact of wind generation on the British Columbia electric system. This report constitutes the third and final stage of this work. The documentation here is primarily qualitative and is an overview of potential operational impact due to significant penetration of wind generation into the BC electric grid. This document addresses the following topics:

- Section 2 presents an overview of the impact of wind energy on system operation, with examples from North American and European experiences and practice.
- Section 3 more specifically investigates the impact of the variability in wind generation. A discussion is given on wind forecasting techniques and how they can assist in overcoming some of the issues related to the variability of wind generation.
- Section 4 presents a discussion on the control characteristics of wind turbines as well as the potential for control modifications for enhanced performance for system support and operation.
- Section 5 presents a discussion of how operational issues related to wind generation in the context of the BC power systems and recommendations on further work and courses of action to be taken to address any concerns.
- Section 5 presents the overall conclusions and recommendations of this report.

## **2 An Overview of Operating Characteristics of Wind Generation**

The companion report [1] presented an overview of the experience with wind energy globally and in the North American continent. As presented in [1], on the global arena Europe (particularly Denmark, Germany, Spain and more recently Ireland and the UK) has had the greatest influx of wind generation. In the North American continent, the major developments of wind power have been in California and Texas, with the Midwestern region quickly catching up in installed capacity. In this section we will review some of the operating experiences and concerns, based on publicly available resources.

Wind generation is a naturally variable resource, due to diurnal and seasonal patterns of wind energy. The resource is intermittent and the energy must be used when available or it is lost. This simple fact results in a number of concerns associated with operations. Let us examine these concerns.

### **2.1 Generation Scheduling and Dispatch**

Most deregulated energy markets operate on the basis of day-ahead as well as real-time sale of energy. Power producers participating in the day-ahead markets are typically obligated to provide power in accordance with the amount and time they have scheduled with the system operator. If the actual delivery substantially differs from that schedule, then a considerable cost may be incurred by the power producer for correcting the imbalance (presumably through purchase of power on the real-time market) [2]. To a great extent these concerns can be addressed with proper forecasting tools which are discussed in the next section. It should be noted, however, that even with wind forecasting tools some deviations between actual and forecasted generation are unavoidable. This raises the question of how to provide and who pays for the generation needed to make up the difference (whether it is an excess or short fall in megawatts). As a separate matter, there is of course a cost associated with having available capacity to be able to serve load, even if it is not used.

The requirements for meeting scheduled power deliveries for a generator on the day-ahead market is based on [2]:

- i. The assumption that generation is predictable and controllable and therefore any variations may be an attempt on the part of a generator to exercise control over the market
- ii. The assumption that imposing penalties for non-compliance will encourage generators to becoming more predictable
- iii. That if allowed and excessive, imbalances can be detrimental to system performance and reliability

Item (iii) is clearly a system performance issue, and true for any system. Items (i) and (ii), however, may be true for conventional fossil fuel and other generators (e.g. nuclear, large-hydro) but these are not necessarily true for wind generation. Therefore, imposing too stringent a set of market rules with regard to adherence to a set schedule can be a significant barrier to wind generation and other forms of intermittent generation. As such, many markets in North America have adopted ways

of trying to accommodate intermittent resources while making every attempt to be fair to other market participants. The following are some examples:

- i. **PJM** – the PJM day-ahead market does not penalize power producers on scheduling deviations, instead they are settled in the real-time energy market [2]. If wind producers do not meet arranged schedules, they may buy power at market prices to meet their previously arranged schedules, and are paid at market-based rates if their resources deliver more than the previously submitted schedule.
- ii. **NYISO** – like PJM, NYISO allows real-time settlement of imbalances. Alternatively, the wind generator may bid into the hour-ahead market [2].
- iii. **California ISO** – The California ISO, based on FERC approval, has introduced an option where participants may settle imbalances due to variable resources over a monthly period rather than on the real-time market (to avoid high spot prices). To participate, the ISO requires that all wind generators install metering equipment that allow real-time telemetry of weather data and operating status of the farm to the ISO. The ISO uses this information together with sophisticated wind forecasting software [3, 4] to forecast the day-ahead schedules for each wind farm (this forecasting technique is discussed further in section 3.3). The wind power producer must pay the ISO a fee for the cost associated with this forecasting – the cost is typically up to US \$0.1/MWh [5].
- iv. **ERCOT** – ERCOT exempts wind generators (and other intermittent resources) from scheduling penalties if the actual generation is within 50 to 150 % of the arranged schedule in any given time period [2].

## **2.2 Onshore versus Offshore Wind Farms**

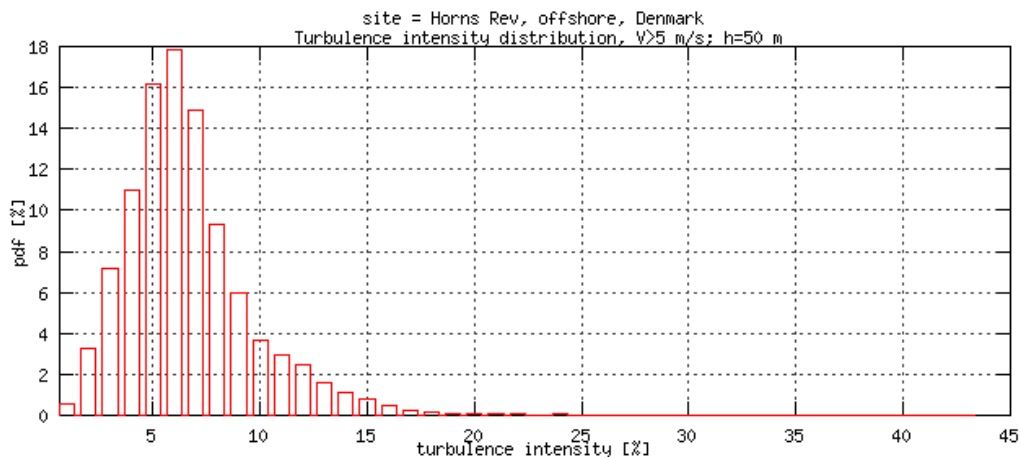
The main areas for wind generation potential in BC are:

1. The Peace region,
2. Vancouver Island, and
3. Prince Rupert and Hecate Strait

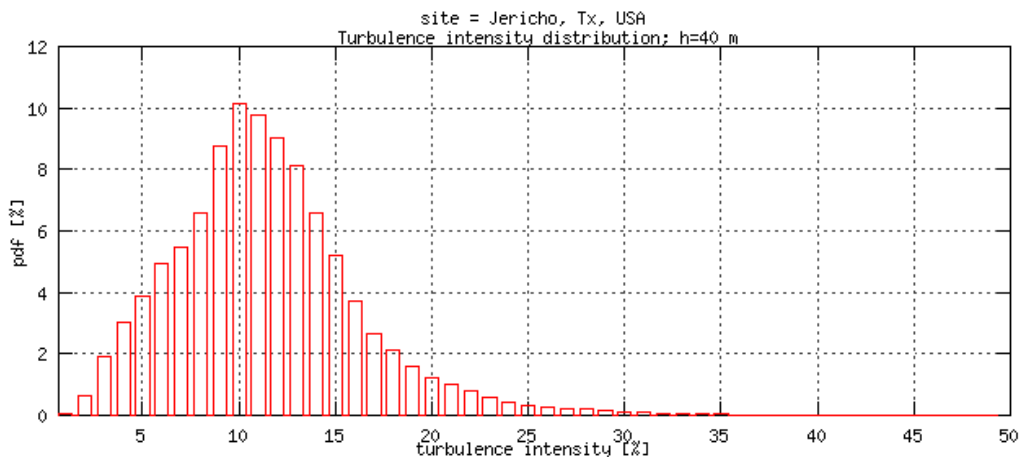
Thus, there is a significant amount of offshore wind farm potential in BC. Therefore, it is pertinent to review the main differences between onshore and offshore sites.

Typically, offshore wind sites tend to have higher and more stable (i.e. laminar) wind profiles. This is primarily because the oceans are flat with little to obstruct the movement of winds (no mountains, rough terrains, hill tops, etc.). Thus, the capacity factor of an offshore wind project is typically higher than onshore sites. These facts are illustrated in Figure 2-1 and 2-2. Figure 2-1 shows a comparison between the measured turbulence intensity at a large offshore wind farm in Denmark (Horns Rev.) as compared to an onshore wind farm in Texas (Jerico). One can clearly see that the turbulence intensity is higher for the onshore wind farm. Note: turbulence intensity is defined as the ratio of the standard deviation of the wind speed to the average wind speed over a specified time window (typically 10 minutes); it is thus a measure of the short term variations in wind speed or wind turbulence. The other interesting observation, from Figure 2-2, is that in general wind speeds are higher in offshore sites. This translates both to greater potential for energy capture, but also that there is

a greater portion of time during which wind speeds are high enough that the turbines will cut out (i.e. stop producing power) on high wind speed.

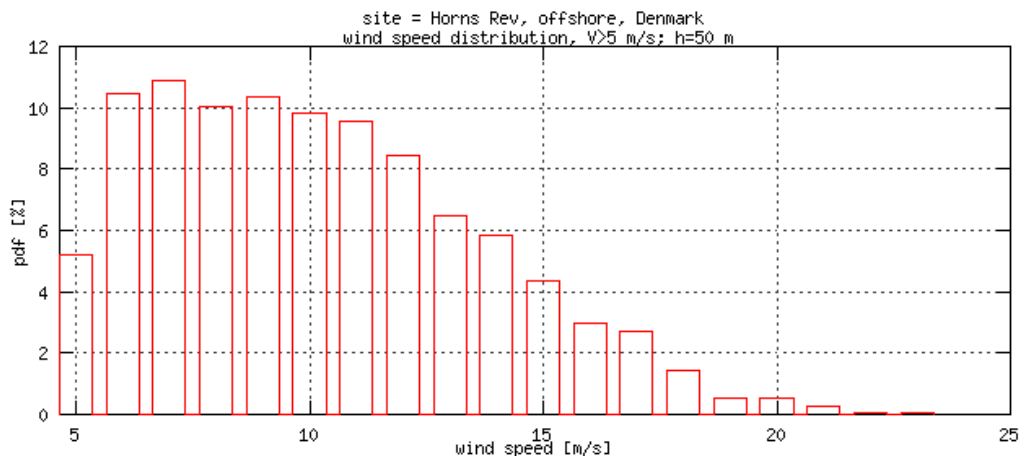


(a) Turbulence intensity at Horns Rev (from [www.winddatta.com](http://www.winddatta.com)). Plot shows turbulence intensity versus frequency (i.e. percentage of the time for which each level of turbulence intensity is observed).

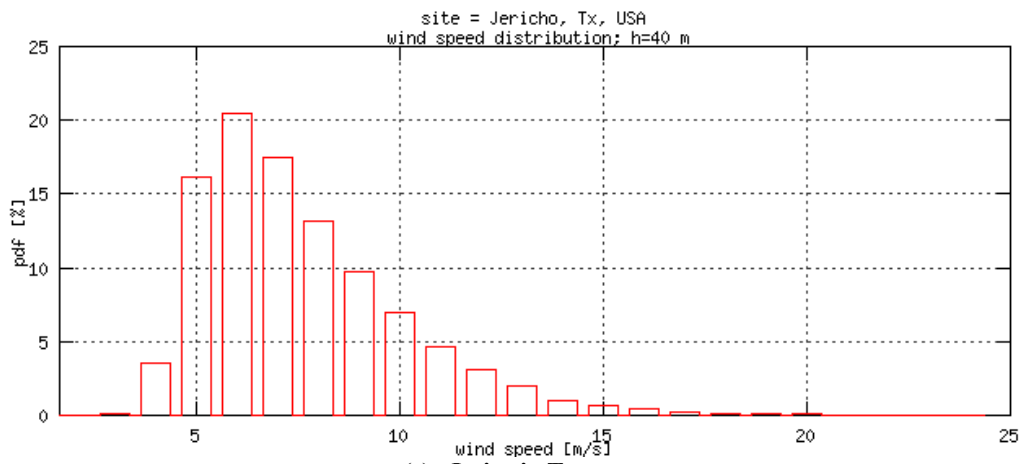


(b) Turbulence intensity at Jericho (from [www.winddatta.com](http://www.winddatta.com)). Plot shows turbulence intensity versus frequency (i.e. percentage of the time for which each level of turbulence intensity is observed).

Figure 2-1: Plots of turbulence intensity at two wind farms.



(a) Horns Rev in Denmark.



(c) Jericho in Texas.

Figure 2-2: Plots of average wind speed for tow wind farms.

Since offshore winds are more persistent (low turbulence intensity), it is expected that offshore wind farms are likely to experience lower mechanical fatigue loads and so their main mechanical part may last significantly longer [6] – this, however, has yet to be proven. In contrast, the saline environment is more corrosive than a typical onshore site and so requires more stringent designs and potentially higher maintenance costs.

Presently, due to the higher construction and maintenance costs associated with offshore wind farms [6] to be financially viable offshore projects need to be in the range of 100 MW or more. One way that this is achieved is by using the largest wind turbines available. At present the largest turbines offered by manufacturers, aimed particularly at the offshore market, are the REpower 5 M (5 MW), the Enercon E112 (4.5 MW), the Vestas V120 (4.5 MW)<sup>1</sup> and GE 3.6 MW unit.

Another aspect of offshore wind generation that differs from onshore sites is the nature of the interconnection to the bulk electricity grid. With most onshore wind farms, an attempt is made during the feasibility stages of development to identify a site that presents a good wind regime and is somewhat close to existing transmission lines. Thus, in most cases the farm is either tapped into an existing transmission line (by building a new substation to tap the line into say a three-ring bus) or a relatively short radial piece of transmission line needs to be built to carry the power to the closest transmission substation. Needless to say, a system impact study needs to be performed at an early stage to then determine the extent of any other required transmission facility upgrades to accommodate the wind farm interconnection – this of course is true of onshore and offshore wind farms, and for that matter of any generation facility. In some cases, if the wind profile is exceptional enough to justify the cost, an onshore site may be located in an area quite remote from available transmission and so a significant amount of new transmission may need to be built to (such as a long distance transmission line, i.e. 50 miles or more) to carry the power to the nearest substation able to take the level of power injection. For offshore wind farms, however, there is always a need to build an underwater transmission lines to connect the wind farm to an onshore substation. Though quite feasible technically, submarine transmission is slightly more challenging. Furthermore, though difficult to quote an exact number, at extra high voltage levels typically used for transmission of electricity submarine ac cables are feasible for distances of up to a few tens of miles – beyond such distances (and sometimes even for relatively small distances) high-voltage direct-current (HVDC) becomes necessary due to the difficulty in controlling the high levels of capacitive charging associated with the ac cables. This can be particularly true of wind farms where the relatively constant fluctuations in power means that the power being transmitted over the submarine cables are constantly cycling between high loading levels to relatively low loading levels. Thus, to control the net effect of significant reactive power fluctuations one would either need to have dynamic VAR support devices (e.g. SVC) on either end of the cable or to use a voltage-source HVDC transmission system that is capable of regulating the reactive

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<sup>1</sup> This product is to replace the NEG Micon NM 110 – 4.2 MW unit. It is being developed after the merger of Vestas and NEG Micon, and according to the Vestas website the aim is to have the product available in the market by the end of 2006.

power independently of the megawatt levels. Reference [7] presents a case study of such considerations for offshore wind farms.

### **2.3 Operational Experience in Europe**

One of the greatest operational burdens has been load following [8]. In addition, European grids have seen the loss of large portions of wind generation due to system disturbances [8, 9 & 10] and in some cases due to large blocks of wind turbines shutting down due to high wind speeds [11]. The potential for the loss of large portions of wind generation due to system faults was discussed in [1]. With the development of low-voltage ride-through (LVRT) capability by the major wind turbine manufacturers this concern can be mitigated [1], provided of course that wind turbines connected to the bulk transmission grid are fitted with LVRT. The following subsections provide some specific examples from the three major regions in Europe that have the largest installed base of wind generation.

#### **2.3.1 Denmark**

The Danish system has had significant operating experience with wind generation. Some of the key concerns that have been reported are summarized below.

Wind generation capacity in Denmark is 60% of peak load [12]. The Danish grid, however, has tie-lines to neighboring systems with a total capacity of nearly 70% of peak load, thus large swings in wind power can be sustained because of the relatively large and strong ties. This, however, comes at a price. For example, for the year 2000, an additional 460 MW of wind generation capacity was added to the Eltra system, increasing total wind generation capacity to 1860 MW. Using the then available wind forecasting tools, the average miscalculation in wind generation forecasts was 38% of the total wind energy production. This resulted in an additional cost of DKK 65 million in real-time megawatt imbalance payments [13] (at the time of first issuing this report DKK 65 million corresponded to CAD \$14.3 million).

Eltra (the transmission and overall system operator) covers 60% of Denmark [12]. Between Cogeneration (plants that produce combined heat and power and are often intermittent in nature due to the fact that the amount of megawatt generation is governed by the district heating demands) and wind power, 50% of the energy supply is intermittent in nature. Thus, in a matter of a few years Denmark has gone from one of the European countries with the lowest electricity costs to one of the most expensive [12]. The penetration of Cogeneration peaked in 2001 and is expected to stay flat, since it is controlled by the district heating needs in the country [12]. Wind generation penetration, however, has continued to grow. The primary operational concern in Denmark has been that of load following and real-time generation/load imbalance. Imbalances of the order of 800 to 1000 MW are common (with an installed base of 2.3 GW). Furthermore, these imbalances may be a deficit or surplus. As an example [12], on April 12, 2001 severe weather conditions lead to a sudden change in the forecasted level of wind generation. It had been forecasted that wind speeds would drop drastically and thus Cogeneration plants had been dispatched to replace the power. With a sudden change in the weather pattern the situation changed

into a scenario of 800 MW of excess power. Fortunately, since Denmark has strong ties to Norway, Sweden and Germany, the full capacity of the Swedish and Norwegian ties were utilized to stabilize the condition; it is interesting to note that at the same time Germany was unable to accept the surplus power due to their own large amounts of wind generation. Needless to say, such events though not in this case catastrophic to system security do impose a significant financial burden as scheduled tie-line interface flows must be compromised for the sake of system security.

To address the operating concerns, Eltra has implemented a number of strategies:

- A wind farm interconnection standard [11], which was described in the companion report [1]. This standard demands certain new capabilities from wind generators that are starting to evolve. These controls are further described in section 5.
- Sponsoring of research and development into better forecasting tools for predicting hourly and day-ahead wind generation.

### 2.3.2 Germany

Germany has the largest megawatt installed capacity of wind generation in the world. In Germany, as with Denmark, load following has been a concern. The approach thus far has been to implement wind power forecasting tools. Another major operating concern was the tripping of large blocks of wind generation for regional disturbances [10, 14]. This latter concern, as discussed extensively in [1], can be avoided with proper low-voltage ride-through capability, which is a featured now supplied by the leading wind turbine manufacturers.

The recent E.ON Netz Wind Report 2004 [14] highlights some of these concerns. The report makes the following statements:

- “The average fed-in capacity was less than one sixth of the wind power capacity installed in the yearly average.” In addition, the report states that “contributions made by wind power production to cover the respective peak load in the E.ON territory varied between zero [0.1 %] in real terms and just under one third of the grid load [32 %].” Although, the exact figures will vary from region to region depending on climatologically factors and nature of load (e.g. some regions such as BCTC are winter peaking a thus may see a greater correlation between peak wind months and peak load months) what these statements convey is the simple fact that the dependable capacity delivered by wind farms is a relatively small portion of the installed capacity. Put in simpler terms, a typical thermal power plant that has an installed name plate rating of 100 MW may have a dependable capacity of for example 80 MW – this is because due to forced outages it will not be available to serve load all of the time. On the other hand, a wind farm with an installed capacity of 100 MW may only have a dependable capacity of 20 MW due to the annual variations in the wind resource. This is explained a slightly greater detail in [1] section 4.1.4.8. The key observation here is that the dependable capacity of wind is significantly less (as a ratio to the installed capacity) as compared to conventional fossil fuel generation, however, it is not zero or negligible. Wind can contribute to capacity but only in modest amounts and so significant

portions of conventional generation is still required in the system to ensure that load can be served at an acceptable level of loss of load probability.

- Another observation is on the variability of the wind resource. The report states that “In 2003, the average negative forecasting error for the E.ON control area was -370 MW, and the average positive forecasting error was 477 MW.” These numbers translate, as a percentage of the total installed capacity of wind generation in E.ON, to -5.9% and +7.6%. The report indicates, however, that this error can be as much as 46.4% (i.e. +/- 2,900 MW) for some individual hours – this is quite a rare event. One example of a high period of fluctuation was given as occurring in the week of 17<sup>th</sup> to 23<sup>rd</sup> November, 2003. In a 6 hour period the wind generation fell by 3640 MW – that is, at just over 10 MW/minute. Put into context for BCTC, achieving these ramp rates to accommodate a sudden variation in wind power production using large hydro generators is typically not a problem from a technical stand point (according to BCTC select large hydro generators on the BC system can achieve ramp rates in excess of 100 MW/minute). Such variations will clearly incur a cost, which is paid based on the market structure. A key observation is that wind forecasting tools are necessary particularly for large wind farms to allow some amount of predictability in order to afford the operator some time to be prepared for such events. In this way the cost of carrying ready reserve can be minimized since one does not have to carry the maximum expected ready reserve requirements 24/7 but rather only during period when based on forecasting it is most likely to be needed.
- According to the report, the cost of wind-related reserve capacity in Germany has increased in recent years. “In 2003, costs amounting to around 100 million € for this were incurred in the case of E.ON Netz alone.” This comment should be understood in the context of the German transmission system. Firstly, that at the end of 2003 there was 14.3 GW on installed wind generation capacity in the system – this is more than 15% of the system peak load. Secondly, that up to now the generation in Germany was built as close as possible to the load centers to avoid transmitting electricity across long distances [14]. Thus, the system is starting to see significant congestion and the need for investing 70 million € for 110 km of new 110 kV lines. These comments emphasize the need for improved forecasting tools to minimize the operating expenses and the need for investment in the transmission system.
- Finally, an interesting observation is made in one of the Figures presented in the report (Figure 8 in [14], not reproduced here due to copyright). It is shown that although there is significant variation in the load in a typical daily load cycle, this variation is quite accurately predictable based on forecasting models developed by the utility over many years of load data. Thus, scheduling generation a day in advance for the expected load cycle for the next 24 hours can be achieved to a high level of accuracy. However, in the same graph an example of the comparison between wind generation forecast and actual wind generation for a 24 hour period is given, which shows that even though such forecasting provides significant improvement over a persistence model<sup>2</sup> or no forecast at all, there is still significant mismatch

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<sup>2</sup> A persistence model simply says that one predicts that the production by wind generators for the next time period (one hour or one day etc.) is equal to the previous time period.

between the forecast and actual production demanding that the difference be settled in the real time market.

### 2.3.3 Spain

In Spain the concerns have been similar, that is the loss of large blocks of wind generation thus requiring significant additional spinning reserves as well as real time load/generation balance [9]. The Spanish government is presently giving the Spanish grid operator (REE) the right to cap total wind generation between 2002-2011 to 13000 MW (the present peak load in Spain is roughly 41 GW). Furthermore, the government bill gives REE the right to curtail wind generation if the wind generation exceeds 3000 MW under light load conditions, in order to minimize power fluctuations [9]. These requirements are presently under review in Spain.

## **3 Wind Generation Variability and Wind Generation Forecasting**

### **3.1 Variability of Wind and Wind Power**

Wind energy is essentially derived from the sun. The radiated heat from the sun heats the land and ocean masses of the Earth, more so around the equatorial regions than the polar caps. As such the air mass over the equatorial regions become warmer and less dense and tend to rise in the atmosphere and move towards the north and south pole, where they cool down fall to the surface and move towards the equator again. This is of course an over simplifications, but it gives a simple understanding of the fundamental principle behind the movement of air masses around the atmosphere, which is basically driven by temperature gradients. The Earth rotation gives rise to an effect which is known as the Coriolis force. Due to the rotation of the Earth, in the Northern Hemisphere, an air mass moving from a high pressure region to a low region is deflected to the right. The opposite is true in the Southern Hemisphere. Thus, the prevailing wind directions on a global scale are NE and SW in the Northern Hemisphere and SE and NW in the Southern Hemisphere. Once we get down to the within 100 meters of the Earth surface, these prevailing winds are significantly influenced by the local geography. That is, whether we are in open plains or at sea or if the terrain is mountainous or full of hill tops, trees etc. The various natural and manmade land formations and roughness of the surface will slow down the wind as well as affect its direction and turbulence.

In general, when considering wind variability we may split the time frames of concern into several scales:

- Extremely short term (second to second variations)
- Short term (minutes to hour time frame)
- Day to Day variations
- Seasonal and year to year variations.

Let us look at a few case studies to get a sense of the level of variability in these various time frames.

#### **3.1.1 Seconds, Minutes and Hourly Variations**

A number of recent publications by NREL [15, 16 & 17] present results for wind power for two large (>100 MW) wind farms in the Midwest region of the USA. These farms are located in Pipestone County, Minnesota (Lake Benton II wind farm) and Buena Vista County, Iowa (Storm Lake wind farm). Reference [15] presents a detailed account of the observed variations in power due to wind variability over a 12-month period. The data was collected at a sampling rate of 1 second, thus allowing for quite detailed analysis. These publications are amongst the most informative and detailed documents readily and publicly available on the subject of recorded wind generation fluctuations over a twelve-month time period.

The Lake Benton study [15] looked at two types of variations: (i) step changes in power (from one time interval to the next), and (ii) ramp-rates in power. The step changes were determined in the 1-second data, 1-minute average and hourly average. Ramp rates were calculated from 1-second data and were calculated for 5-second, 10-second, 15-second, 5-minute and 10-minute intervals. In all this analysis, forced shut-down and start-up of the wind farms were ignored in order to faithfully capture variations in the wind farm output due only to wind variations rather than forced or controlled outages.

The following table summarizes the results. The maximum step-up and down in plant power (as a percentage of total MW capability, which for Lake Benton II is 103 MW) is shown.

**Table 3-1:** Maximum step changes in power at Lake Benton II [15].

Event	Maximum Up	Maximum Down
1-second step change	4.3%	7.3%
1-minute average	11%	14%
1-hour average	63%	50%

The values shown above are the maximums observed over the 12-month period. It was found, however, that the distribution of step changes was quite narrow. For example, 98% of the 1-second step changes were less than 0.5% of total capacity, 94.5% of 1-minute step changes were less than 1.4% and 93.6% of hourly step changes were less than or equal to 20%.

For the ramp rate calculations, the observation was that the ramp rate decreases as the time duration over which it is calculated increases. This is somewhat intuitive since as we look at longer time intervals the second to second variations tend to average out. For example, the largest ramp rate observed over a 5-second interval was -4.7 MW/s, while the largest ramp rate over a 10-minute interval was 6.9 MW/min (or 0.11 MW/s). Once again these were maximum rates observed. More than 90% of the ramp rates observed in each time frame were significantly slower.

Another interesting observation in the study [15, 17] was the probability associated with state transitions from 1 minute to the next. It was observed that if, for example, the wind farm output was at 10% then the likelihood that it would be a 20% in the next minute was roughly 1.8%. The likelihood that it would transition to 30% was 0.07%, with the likelihood of transitioning to 100% being less than one-hundredth of a percent. The likelihood of staying at 10% output was 99%. This trend continued up to peak load. In essence the likelihood of the wind farm changing by more than 10% was significantly less than 1%, while the likelihood of changing by 10% (up or down) was roughly 2 to 5%. And the likelihood of staying at the same power level was greater than 90%.

Similar results were also found for the Storm Lake wind farm. Also, it is interesting to note that if the power fluctuations of the two farms were combined, the absolute magnitude of the fluctuations is larger. However, expressed as a percentage of the combined total capacity of the two farms the combined fluctuation in power is less – this is due to the fact that the two farms are relatively remote from one another and thus

there is little correlation between wind fluctuations at the two sites. This illustrates the fact that where wind farms are spread over a relatively large area, geographic diversity tends to give an averaging out effect that reduces the relative amount of variability in wind generation.

### 3.1.2 Seasonal and Annual Power Variations

For the Lake Benton II farm (a 103 MW rated wind farm) in Pipestone County, Minnesota, the monthly production changes from a minimum of close to 14000 MWh in July to a maximum of nearly 35000 MWh in January. It is indicated that some monitoring equipment failures during July affected the results for the July measurements; nonetheless the trends indicated a clear picture that wind power production tends to be greater in the fall and winter months when winds are more favorable. Such seasonal variations are clearly a function of the climate of the geographic location. None-the-less, to some extent this does seem to be a general trend. For example, in Northern Europe similar trends are found where wind generation production tends to be greater in the colder months of the year. For power systems that are winter peaking this may be an advantage.

Wind power production will also change from year to year because of changing global weather patterns; one example is the influence that phenomena such as El Niño can have on North and South American weather. An example of the magnitude of such variations is in Denmark where the standard deviation in the change in wind generation from year to year is typically 9 to 10 % ([www.newenergy.org.cn](http://www.newenergy.org.cn)).

Another general observation is that wind speeds (and thus wind generation) is significantly higher during the day time than during the night in coastal regions. This is primarily so since temperature gradients between the land and sea are greater during the day (in sunlight) than at night resulting in more persistent and stronger sea breezes during the day. Conversely, for flat inland regions (e.g. central states of the US) typically winds speeds at hub height will be higher during the night than during the day. This is because the ‘boundary layer’ (the part of the atmosphere in contact with the Earth’s surface) will collapse to within fifty or a hundred meters of the Earth’s surface (as opposed to being perhaps a kilometer or more thick during the day) due to the absence of the Sun’s heat. Thus, high wind speed laminar flow streams can come much closer to the Earth’s surface (near hub height) during the night.

## 3.2 *Forecasting of Wind Power Generation*

As briefly discussed in section 2, wind power forecasting is already a central part of operating centers in Europe, particularly in Denmark, Germany and Spain. In the North American continent, wind power forecasting has also been implemented, most notably in California by the California ISO [3].

The Informatics of Mathematical Modeling (IMM) in Denmark, together with the sponsorship of the local utility ELSAM (generation company) developed a tool for predicting wind generation for the ELSAM area from 0.5 hour to 36 hours ahead, in half-hour increments [3]. The Risø National Laboratory, in Denmark, expanded on

this work to develop the *Prediktor* program. This latter program is presently used by Danish, German and Spanish authorities for wind energy forecasting [3]. As indicated earlier, Eltra is working with the research authorities to continue to improve these tools for improved predictability of wind.

In North America, the three major suppliers of wind forecasting tools are AWS Truewind, 3Tier Environmental Forecast Group and WindLogics. AWS Truewind has developed the *eWind<sup>TM</sup>* wind power forecasting system. The 3Tier Environmental Forecast Group uses a tool some of which incorporate neural networks for prediction algorithms. The intent of this report is not to compare and contrast these tools, but rather to present some general information on wind forecasting tools and their benefits. As such, the discussion here is relatively generic with some specific examples extracted from public sources.

Figures 3-6 and 3-7 show some examples of the accuracy of the *eWind<sup>TM</sup>* program.

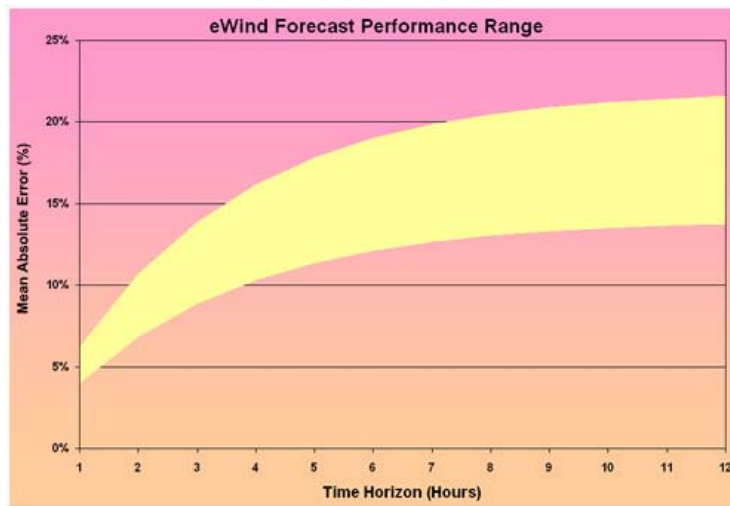
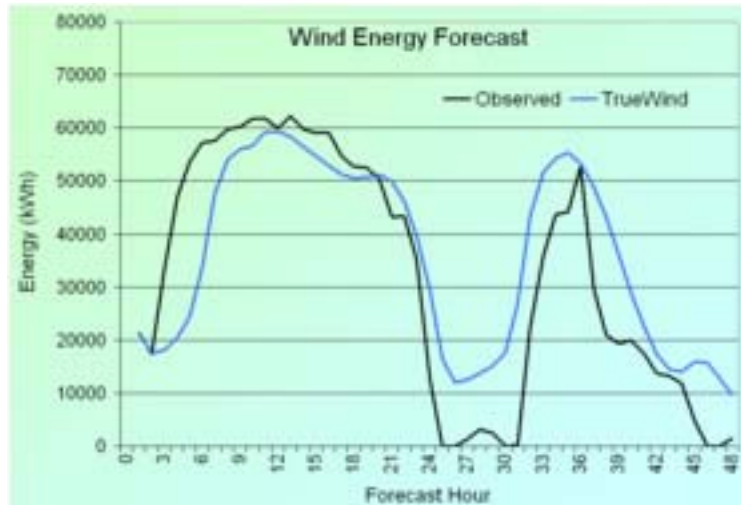


Figure 3-6: Performance of eWind<sup>TM</sup> software for wind generation forecast (source AWS Truewind website, [www.awstruewind.com](http://www.awstruewind.com))<sup>3</sup>

<sup>3</sup> TrueWind Solutions LLC has merged with AWS Scientific to form AWS Truewind. The depicted figure was downloaded from the TrueWind Solutions LLC website ([www.truewind.com](http://www.truewind.com)) prior to the merger.

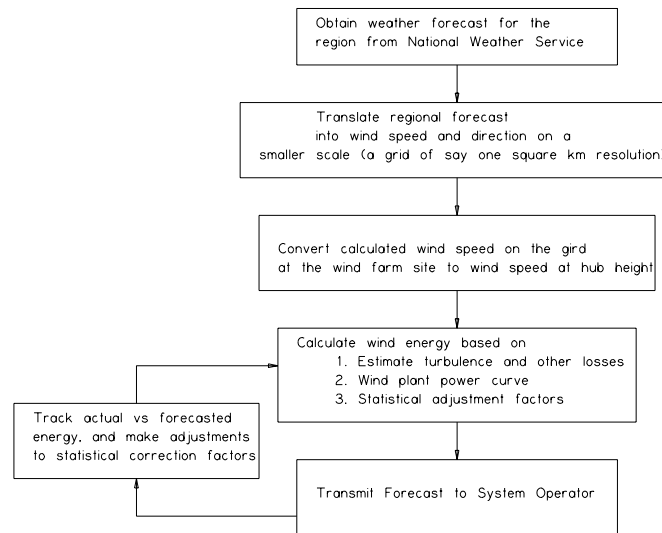


**Figure 3-7: Performance of eWind™ software for wind generation forecast (source AWS Truewind website, [www.awstruewind.com](http://www.awstruewind.com))**

Figure 3-8 shows a flow chart for a typical wind forecasting program and how it would be interfaced with the system operator. The forecasting process starts with data collection from the National Weather Service (in real-time) for the regional weather forecast. Based on mathematical models, specific to each region, the weather forecast is converted into predicted wind speeds and directions for the region of interest. Wind speed and direction is calculated, for example, for each square kilometer of the region. These wind speeds are then converted into estimated wind speeds at the hub height for each wind farm site. Finally the wind generation at each wind farm is calculated by estimating power production using the wind power curve for each plant. The wind power curve is essentially a look-up table, which correlates wind speed and direction with power output. This may be developed through actual measurements of 10-minute average or hourly plant output versus wind speed and direction, or constructed based on the power curve of each individual turbine as supplied by the manufacturer. In the next step of the forecasting algorithm, typically a statistical adjustment factor is used to adjust the predicted plant output. These adjustment factors are based on comparisons between previous predictions and actual measured plant output. An adaptive algorithm may be used to constantly refine these adjustment factors in an attempt to continuously improve the performance of the prediction software.

What is certain is that wind forecasting tools can help to reduce some of the costs associated with real-time load/generation imbalance, as illustrated in the previous section. In addition, it is clear, from the Danish and German examples described in section 2 [13], that even with wind forecasting tools some level of variability is unavoidable (since predictions cannot be perfect) and so once the level of wind penetration exceeds a certain level significant operation costs are incurred. Based on studies and experience, it is estimated that once wind generation exceeds between 10 to 20% of the total load demand in a system operation begins to incur additional cost and centralized wind forecasting of the type described here is prudent [18]. Wind generation in excess of 20% of the total load demand (such as is the case in Denmark, particularly during evening hours when load demand is low but wind generation is

high) the system operator begins to incur significant additional cost due to the increased volatility in the real-time energy market [8, 18].



**Figure 3-8: Flow chart for a typical wind forecasting program.**

The New York State Energy Research and Development Authority (NYSERDA) commissioned a detailed study of the impact of wind generation on the New York bulk transmission system. This work was commissioned in 2003 and has recently been completed. The draft final report was released on the NYSERDA website only recently (February 2005) [19]. The study was performed with the aid of a wind engineering firm (AWS Truewind) and took quite a comprehensive look at wind forecasting. The report recommended that state-of-the-art centralized wind forecasting should be pursued in New York.

## 4 Wind Generation Control Characteristics

In the companion report [1] a discussion was provided on the various wind turbine technologies and their controls. In this section, some of these concepts will be re-emphasized, with a particular focus on how they may impact system operations, and how controls may be improved in the future for better operational performance. It should be fully realized that wind turbine generation technologies are continuously evolving, and only in the last year or two have great strides been made in developments such as low-voltage ride-through system (now available from all the leading manufacturers). In this section, some of these aspects are discussed again briefly in the context of system operations.

### 4.1 Protection, Start-up and Shut-down

Wind turbines, much like conventional fossil fuel units, have automatic controls and protection. Protection functions such as over/under-frequency, over/under-voltage, asymmetrical voltage/current, etc. are provided. All these protective functions are automatic and do not require operator intervention. As with any generating facility, per interconnection and planning criteria, such protective functions should be properly coordinated upon commissioning with grid controls and protective relays.

Unlike most large fossil fuel plants, wind turbine start-up and shut-down is typically fully automated. This can present a challenge to the system dispatcher/operator. For example, if the average wind speed in an area with significant wind generation were to rise above the cut-out speed of wind turbines for a period of several minutes, all of the wind turbines in the farm may suddenly shut-down resulting in a sudden loss of power. Similarly, once the wind speeds are again favorable the wind farm can go to peak load quite quickly. This has been observed in Denmark [11]. These issues can now be addressed by recent and ever-evolving manufacturer improvements to the wind turbine designs. A specific example is given in section 4.3, of the Horns Rev wind farm in Denmark. Essentially, during start-up and shut-down, the individual turbines in the farm can be staggered such that they do not all simultaneously start or shut-down. Thus, the effective ramp rates seen in megawatts (up or down) can be controlled to say 10 MW/minute or less. For a system such as BCTC that has abundant hydro-generation, dealing with these rates of change does not pose a huge technical challenge. However, there is still a significant costs associated with the replacement of (or curtailing of) power due to changes in wind energy – these are commercial issues to be dealt with the market structure rather than technical concerns.

#### 4.1.1 Extreme Cold Temperature Operation

Since British Columbia tends to have significantly milder winters in terms of severe low temperatures as compared to the central and northern provinces in Canada, this may not be as significant a concern in BC as it is in say Alberta, Saskatchewan, Ontario and Quebec<sup>4</sup>. None-the-less, it is worth pointing out the operation of wind

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<sup>4</sup> Note: the Northeast portion of the BC province may be subject to extreme cold temperature similar to Alberta and the other central provinces.

farms under severe cold temperature conditions is limited. This is concern applies equally to most generation and transmission equipment. Consideration should be given to the range of temperatures within which wind turbines are expected to operate and the fact that under very extreme low temperature conditions (e.g.  $-40^{\circ}\text{C}$ ) wind generators may not be available, due to equipment operating limits.

## **4.2 Voltage regulation**

The subject of voltage regulation was discussed in the companion report [1]. Some further discussion, from an operational perspective is prudent.

Without low-voltage ride-through (LVRT) capability most wind turbine generators (irrespective of manufacturer or type) will trip during a system disturbance. This is a concern since as discussed in previous sections and in [1], there may be a potential for tripping large amounts of wind generation for regional faults thereby causing a sudden and large deficit in generation on the system. The solution is to simply require LVRT as a necessary feature on all wind turbine generators in future wind farms to be connected to the bulk transmission grid. Such LVRT packages are available from the leading wind turbine manufactures and are being continuously improved.

The other operating question/concern is one of real-time voltage regulation. This is somewhat more difficult to answer. Here there are really two time frames of concern:

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

Let us consider these items one at a time. 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 the secondly that they help in restoring system voltages. As discussed in [1], this can be achieved by all the various wind turbine technologies but exactly how it is achieved depends of 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). Thus, if the unit is able to ride through a disturbance, and if the necessary control and protection modifications have been made to ensure for 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 DFIG generators. As explained in [1], during a severe close in fault the protections on the DFIG converter controls will engage a crowbar circuit to short the rotor circuit. The crowbar is removed and the unit resumes DFIG 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.

With a conventional induction generator (which absorb reactive power from the system in order to maintain their 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 effect smooth and quick voltage recovery following a disturbance [20]. For conventional induction generators, another option may be that of a fast reduction in mechanical power following a disturbance, which could be effected through quickly changing the turbine pitch (for active-stall control designs). In this way the amount of over-speed on the wind turbine generators during the disturbance can be limited. Furthermore, once the disturbance has cleared the mechanical power is slowly increased back to the pre-disturbance value. In this way it may be possible to avoid a transient instability of the induction generator – an example of this type of control is demonstrated in [20, 21]. Such controls are evolving and standard models for simulating their performance are not yet available in the major simulation tools used in WECC (GE PSLF<sup>TM</sup> and PTI PSS/E<sup>TM</sup>). What is for certain is that dynamic var support (SVC or STATCOM, coordinated with additional switched shunt capacitor banks if necessary) can effectively stabilize the response of conventional induction generators to major grid disturbances, if properly sized and located [22, 20]. The example in [20, 21] shows the result of applying the mechanical power reduction to a single wind farm. The question is whether such a technique, if applied to a number of wind farms in the system would still ensure transient stability following a major grid disturbance, following which the grid is left in a weakened state. In addition, even if transient stability is maintained under such circumstances, the question becomes if the system voltage remains stable over a longer period (minutes time frame) under the weakened system condition. This requires further studies with improved models and using mid-term dynamic simulations. Finally, in [20] it was identified that although the fast ramp down in power during and after a fault helped to maintain transient stability, still a dynamic var compensation (in the form of an SVC) was required to prevent a system overvoltage; primarily used for its inductive capability. This is because during the ramp down in power there is excessive reactive power produced by the shunt capacitors connected at the wind turbine for on-load power factor correction. It may be argued that these (or some of them) should be disconnected during the disturbance or ramp down. However, then we would have the problem that we could not ramp the power of the wind turbine back up since the shunt capacitors would not be available to be reinserted for power factor correction and voltage support for perhaps several minutes until they have fully discharged<sup>5</sup>. This could be avoided if they were thyristor switched capacitors, in which case we are back to an SVC solution.

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

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<sup>5</sup> It is common knowledge that when energizing mechanically switched shunt capacitor banks they must be discharged in order to minimize the potential for severe switching transients that may damage the capacitor and/or other electrical equipment in the vicinity of the capacitor bank.

3. Automatic voltage regulators from synchronous generators
4. 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 induction 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 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 acts 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).

### **4.3 Case Study – Horns Rev Offshore Wind Farm in Denmark**

The Horns Rev wind farm, developed in the North Sea off the coast of Denmark, is the first example of a wind farm built in accordance with the Eltra interconnection standard [8]. The interconnection standard [11], discussed in the companion report [1] is an example of requirements set forth to address both system reliability and operational concerns with wind generation.

Horns Rev is a 160 MW off-shore wind farm consisting of 80, Vestas V80 wind turbines ([http://www.jxj.com/magsandj/rew/2002\\_03/horns.html](http://www.jxj.com/magsandj/rew/2002_03/horns.html)). The wind farm has been built with the following characteristics [8]:

- **Low-voltage Ride-through:** The plant disconnects in the case of a grid fault, however, the wind turbine generators all reconnect within seconds after the fault has cleared. This fast disconnection and reconnection was a compromise between the technical viability and cost of supplying low-voltage ride through and the requirement by Eltra that the turbines remain connected to the grid following a disturbance to minimize lost of generation.
- **Production Limit:** It is possible, by operator action, to limit the power output of the plant to a specified maximum.
- **Reserve Capability:** It is possible to operate the plant to maintain a reserve capability. That is, the wind farm can be asked to keep for example a 5% margin between the actual available wind energy at the present time and the amount being generated by the plant. In this way, the additional 5% reserve may be called upon at any time. The plant can be switched in and out of this mode of operation.

- **Ramp Rate and Production Control:** It is possible to limit the rate of increase and decrease in power output of the plant. In addition, under emergency conditions the operator may curtail blocks of generation at the plant.
- **Reactive/Voltage Control:** The reactive power consumption of the farm is controlled to keep total consumption/production at +/- 16 Mvar at the 34 kV side of the wind farm substation transformer.

Let us elaborate on some of these features.

By limiting the rate at which power is increased (ramp rate up), one is essentially dissipating (or deflecting) some of the available wind power by not changing the blade pitch on the turbines fast enough to quickly make use of the newly available power.

Putting in place proper low-voltage ride-through, active/automatic voltage regulation and a means of limiting or curtailing production during emergencies all seem prudent measures and are highly recommended. Since these features are presently available (and continuously being improved upon) by the leading wind turbine manufacturers, it seems only prudent to require them in interconnection standards [1].

The concept of frequency regulation is an evolving one, with Horns Rev being a showcase. To effect frequency control (through droop governing) when the system frequency is rising is technically achievable and can be guaranteed. That is, if the system frequency is on the rise then the turbine controls on the wind turbine generators can change blade pitch to remove some or all of the mechanical power and thus help to restore system frequency. On the other hand, in order to react to system under-frequency events the wind turbines must maintain some reserve. This is done by not taking all of the power available in the present wind conditions to reserve some margin to allow for a response to a system under-frequency condition. The potential problem is that wind energy is not a guaranteed source. That is, there is no guarantee that the available wind energy will not fall just when the farm is needed to respond to an event – granted, however, that the likelihood of this is relatively low. Also, the maintained reserve is a relative rather than absolute amount. That is, the amount of reserve maintained is a percentage of the available wind energy. Therefore, the actual amount of reserve varies with the wind energy. Finally, the amount of wind energy being held in reserve is essentially lost and unrecoverable as such this has an impact on the revenue from the wind farm and so in an energy market some form of financial compensation needs to be identified for carrying such reserve.

## 5 Impact on the BC System

In summary, the key operating concerns highlighted in the pervious sections are:

- The variability of wind energy and its impact on the energy market and system reliability.
- Ensuring that automatic controls and protection on wind farms are designed and coordinated in such as way as to help maintain, rather than deteriorate, system security during major disturbances (e.g. low-voltage ride-through capability, automatic voltage regulation capability etc.).

The items under the second bullet point above can be addressed with the latest wind turbine technologies and wind farm designs, regardless of the type of wind turbine generator (i.e. conventional induction generator, variable rotor resistance induction generator, doubly-fed induction generator or full-converter units with convention synchronous generators). If standards are put into place similar to those described in [1], then this will ensure that the wind farm is designed with adequate fault ride-through capability, adequate reactive power capability and automatic voltage regulation and control features in order to assist in maintaining system reliability.

As for the first item – the variability of the wind energy resource – let us consider its impact, qualitatively.

### 5.1.1 Load Following and Frequency Control

The peak load in BC in 2004 was 9616 MW with the off-peak load being 4133 MW. The system has an installed base of 14780 MW, which means it has surplus generation to export to the US. This is typically the case. British Columbia has ties both to the US through Washington State and also to the Province of Alberta. In total there is roughly 3000 MW of transfer capacity between BC and its neighboring systems. Of the 14780 MW installed base 13% is thermal (steam and gas) while 87% is hydro generation. Of this 87% hydro generation about 5% is small hydro (e.g. run of river). An interesting note is that hydro generation, similar to wind generation, does have a degree of variability due to seasonal changes in water levels. The contrast is that where the variability of wind generation from one season to the next is typically in the order of 15% for hydro it can be as much as 39%<sup>6</sup>. However, when looking at shorter time intervals such as variations from one day to the next wind generation variability can be as much as 50% while hydro is likely to be 5% or less.

From an operational perspective, in simple terms, there are two concerns:

1. To be able to constantly match generation with load in real time.
2. To have enough spinning reserve and adequate unit response (from units that are in droop frequency control mode) to control the system frequency in the event of the sudden loss of the largest generating unit or other events that result in load/generation imbalance on the system.

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<sup>6</sup> These numbers were presented in the context of British Columbia during the Wind Power Workshop sponsored by BCTC, BC Hydro and the wind industry on January 25<sup>th</sup>-26<sup>th</sup>, 2005 in Vancouver.

To constantly match generation and load, generation is dispatched in a scheduled way to come up as the load increases during the day time and to back down as the load decreases going into the night. In a typical power system, very large steam turbine generators (be they fossil fuel, nuclear or combined cycle) will typically be operated as ‘base load’ units. That is, they are dispatched at the full-load capacity 24 hours a day for several months at a time until they are up for their routine maintenance outage. This is because these large units are typically the most efficient. Also, large steam units tend not to be as maneuverable as gas turbines and hydro generation. A large (several hundred megawatt) steam turbine can take in excess of 12 hours to be cold started and brought up to its base load. In contrast a peaking gas turbine, operated in simple-cycle, can go from a cold start to full-load in perhaps as little as 30 minutes. A hydro turbine can achieve zero to peak load in perhaps only several minutes. The difference in time scales is driven by the chemical and mechanical processes involved starting and running each type of plant. In the case of a large steam turbine, there are many auxiliary systems (feed pump, draft fans, etc.) that need to be started first, followed by firing the boiler and allowing ample time for the boiler to thermally expand to avoid heat fractures in pipes and the boiler walls. For gas turbines, thermal stresses in the hot gas path (combustion chamber and turbine nozzles) also requires that the process be controlled and thus takes tens of minutes to reach base load. For a hydro turbine there are no thermal issues, therefore the gate may be opened and water released to run the turbine up to peak load more quickly than the other types of generation – there are of course mechanical stress issues. Based on our understanding, the BC power system does not presently have any pumped storage hydro generation projects, but this special type of hydro plant can provide additional benefits. Pumped storage hydro is a hydro generating facility that is also able to run as a pump. During light load conditions when electricity is cheap, water can be pumped back up to the reservoir by running the hydro turbines as pumps. Then during peak load hours the water is released again and power generated. While pumping, a hydro turbine is essentially a non-firm load and so in the event of a sudden severe loss of generation pumped hydro can be quickly tripped in an effort to balance load and generation.

To provide on-line spinning reserve, again hydro generation has an advantage over thermal units. The efficiency of steam and even more so gas turbines drops off significantly as the units output is reduced from its base load. Therefore, it is typically more efficient to carry spinning reserve on hydro units where available.

Given the abundance of hydro generation in BC and its flexibility in providing load following and spinning reserve, if state-of-the-art wind generation forecasting tools are implemented in BC we believe that the operating impact of wind generation variability can be effectively managed.

### 5.1.2 Vancouver Island and the North Coast Regions

Vancouver Island (VI) is connected to the BC mainland power system through four lines. Two parallel 500 kV circuits from Dunsmuir to Malaspina, a submarine HVDC cable from Vancouver to Vancouver Island Terminal, and a 138 kV ac circuit that is parallel to the HVDC. The Island had a peak load of 2186 MW in 2004 with a minimum load of 789 MW. There is a total of 790 MW of installed capacity on the

Island presently of which two thirds is hydro generation and one third thermal. The one third thermal is almost entirely steam – a single 290 MVA unit.

When the VI is synchronized to the mainland grid the issues are similar to the rest of BC and may be dealt with in a similar way. The unique issue with VI is the condition under which the VI system may become islanded. Although this is a relatively low probability event, based on operating experience it has occurred a few times in the past several years. The VI system must be designed to ride through such an event in a controlled fashion. Given the relatively low inertia of the VI system (as compared to the mainland) and the fact that the typical direction of power flow is toward VI, there are remedial action schemes such as underfrequency load shedding in place to quickly attempt to restore the generation/load balance within the island following such an event.

In the event of islanding VI, because of the sudden mismatch in generation and load (typically load exceeding generation) as stated above underfrequency load shedding is implemented. Such load shedding is typically based on both the rate at which the system frequency is dropping and the absolute value to which frequency falls. In the event that a substantial amount of the generation on VI is wind generation both the rate of decline and the minimum value of frequency after an islanding event can be significantly worse. This is due to two phenomena. First of all, wind generation typically does not maintain a megawatt reserve margin for governor response to frequency deviations. Secondly, wind turbine generators of the DFIG and full-converter design do not inherently have an inertial response. Let us explain these two issues in a little more detail.

*Governor Response:* To be able to contribute to system frequency regulation, a wind farm must have a closed loop governor control much like conventional thermal and hydro units. In addition, the farm must carry some reserve. That is, at any given point in time it must generate a fraction less (typically 5%) than the maximum amount of wind power available at that point in time. This is essentially the controls demonstrated on the Horns Rev project described in section 4.3. What this means is that we are constantly spilling away say 5% of the available wind energy. The wind farm owner will seek to be compensated for this, such as in an ancillary services market.

*Inertial Response:* In the case of rotating machine directly coupled to the power grid, following an imbalance between load and generation there will be what is referred to as an “inertial response” from each unit. This is true of all conventional synchronous generators and also of conventional induction generators. Consider the case of islanding Vancouver Island. If prior to islanding there was 400 MW being imported into VI on the synchronous ties to the mainland, then upon being islanded from the mainland there is essentially a sudden loss of 400 MW of generation. The load, however, does not change instantaneously. So the difference in power is essentially made up immediately by electrically drawing power from all the generators. Since the mechanical power on the generator shafts are constant, the power effectively comes out of stored energy in the rotating mass of the generator shafts resulting in the slowing down of the shafts and hence a drop in system frequency. How fast the system frequency drops and the minimum to which it drops before a new equilibrium is reached is a function of the total megawatt imbalance, the total system inertia and

governor response (and also the reduction in load as a function of frequency, which we have ignored here for the sake of simplifying the discussion). Consider the following simple example.

VI has a load of 1100 MW  
There is 874 MVA of generation on line on VI  
500 MW is being imported (100 MW on HVDC cable)

assume that the inertia of all generators on VI is 3 MWs/MVA (typical for hydro and steam units)

Now if we lose all synchronous ties to the main land

$$\Delta f/\Delta t = ((-400/874)/ 2 \times 3 ) \times 60 = -4.6 \text{ Hz/s}$$

That is, the frequency on VI will start to decline at a rate of 4.6 Hz/s. Clearly, to prevent a collapse of the system frequency it will be necessary to very quickly shed a substantial amount of load. In addition, a good portion of the generation on VI should be ready and able to provide governor response in order to provide a controlled recovery upon load shedding.

Now let us assume that half of the generation on VI at this time was being supplied by wind and that this was wind generators of a power electronic based technology (i.e. DFIG or full-converter units). Since for such units the electrical power out of the unit is actually controlled by an extremely fast (kilohertz) power electronic drive, upon a generation/load imbalance scenario, unless specifically designed to do so, the units will strictly maintain their megawatt output and thus will not provide any inertial response. So in the above example, we now have

$$\Delta f/\Delta t = ((-400/437)/ 2 \times 3 ) \times 60 = -9.2 \text{ Hz/s}$$

That is, the rate of decline in system frequency has doubled. This makes it significantly more challenging to control the decline in system frequency following such an event. It is possible, however, to implement frequency control as a function into the line side converter for both DFIG and full-converter units. Such control features are not necessarily standard and would require research and development effort.

The above example is quite simplified, but it illustrates the point. To make a fair assessment some detailed analysis of islanding operation and subsequent controls and protection on VI will be needed, as well as considering the response of load to declining frequency. Also, note that when VI is operating as an electrical island, the amount of regulating megawatts will likely increase as the penetration of wind generation increases. This is because the combined variation in wind generation and load as a function of time (as opposed to just load variation) will no doubt result in greater variability and thus an increase in the needed regulating reserve on the island to maintain system frequency at a constant 60 Hz. Not having any wind data for the island, it is difficult to quantify the impact of wind variability on additional reserve requirements on the island – this should be the subject of further study.

Vancouver Island is a convenient example of regions in the BC transmission system subject to islanding and as such the discussion above was focused on VI as a clear example. However, it should be pointed out that there are other regions of the BC transmission system near the North Coast that are equally susceptible to being islanded. Some of these islands have significantly less load than VI and thus are subject to even greater frequency excursions following an islanding event. As such, similar concerns may apply in these regions if a significant amount of wind generation is connected to this area. Further more detailed study would be necessary to properly quantify the concerns and the best approach for resolving them. In general, the solutions may be to either build additional lines to minimize the potential for islanding the region or to limit and control wind generation following an islanding event.

### 5.1.3 Recommendations

Given that the province of BC is rich in hydro generation, which is typically quite versatile in load flowing and providing reserve capacity, it is not anticipated that the addition of wind generation to BC will raise significant technical challenges with regard to maintaining system reliability due to wind generation variability. The largest unit in the BC system presently is a 500 MW hydro unit. Under current operating practice, through reserve sharing within WECC, there is adequate reserve to account for the sudden loss of this unit. Provided no single wind farm on the system exceeds 500 MW in installed capacity and provided LVRT is applied to all sizable wind farms as recommended in [1], there is not significant risk of an instantaneous loss of wind generation exceeding 500 MW. As for managing the hour to hour and day to day variations in wind generation, we recommend that through consultation with the wind developers BCTC investigate the possibility of establishing a state-of-the-art centralized wind generation forecasting tool. As experience has shown both in North America and Europe, such a tool will significantly help to reduce operating costs due to variations in wind power. Even with a wind generation prediction tool, there will still be some mismatch between actual and predicted wind generation. Market rules need to be put into place to deal with such intermittent resources. Two approaches were discussed in section 2.1 (e.g. in California and in the East by PJM and NYISO). That is, the wind power producer may either participate in the day-ahead market using the predicted generation from his/her facility based on the prediction tool and then compensate for the net mismatch between scheduled and delivered power over say a one month period. Alternatively, the producer may participate in the hourly market and compensate for the net mismatch between scheduled and delivered power by purchasing power on the real time market to make up for any deficit.

Given the flexibility of hydro generation for providing spinning reserve and governor response during system frequency excursions, and given the abundance of hydro generation in BC, we do not see at this stage a need for requiring wind generators to have frequency regulation capability (i.e. carry a reserve and to have an active governor control loop). However, if a wind farm developer wishes to have such a capability on his/her wind farm and to thus participate in an ancillary service market it should be allowed.

In the case of Vancouver Island and the North Coast regions, however, there are some particular challenges. Given the possibility, though remote, of losing all synchronous ties between Vancouver Island and the rest of the Province there needs to be particular attention paid to the integration of wind generation on Vancouver Island. There are essentially three options:

- I. To limit the amount of wind generation on Vancouver Island, since there is a limited amount of other generation that may be used as spinning and regulating reserve.
- II. To ensure that all wind generation on Vancouver Island have special frequency regulation controls that allow the units to respond immediately to a declining system frequency by increasing their output. This requires that the wind farms operate in such a way as to always have a reserve margin between the actual amount of wind power available and what is being produced by the wind farm.
- III. To build additional lines connecting the Vancouver Island system to the mainland in order to significantly reduce the probability of islanding.

As to exactly which of these options is likely to be most economical, that requires further more detailed analysis.

Similar concerns apply to parts of the transmission system near the North Coast that are also susceptible to islanding.

## 6 Conclusions and Recommendations

The province of BC is rich in hydro generation, which is typically quite versatile in load following and providing reserve capacity. Thus provided the hydro generation is available and engaged in providing such services (load following, spinning reserve and frequency control) through an ancillary services market, we do not expect there to be significant technical challenges in incorporating wind into the BC system due to variability in the wind generation resource. This variability in wind generation will result in some increase in operating costs. To minimize the operating cost impact it is recommended that state-of-the-art wind generation forecasting tools be considered. Even with wind generation prediction tools, there will still be some mismatch between actual and predicted wind generation. Market rules need to be put into place to deal with such intermittent resources. Two examples of present strategies used in North America are given in the report. These may be summarized as follows. Firstly, the wind power producer may either participate in the day-ahead market using the predicted generation from his/her facility based on the prediction tool and then compensate for the net mismatch between scheduled and delivered power over say a one month period. Alternatively, the producer may participate in the hourly market and compensate for the net mismatch between scheduled and delivered power by purchasing power on the real time market to make up for any deficit.

By providing the control and protection features discussed in the companion report, such as LVRT, adequate reactive capability and automatic voltage control at the point of interconnection it can be ensured that wind farms do not adversely impact system reliability. In addition, wind farms can participate in actively helping to regulate system voltage.

In the case of Vancouver Island there are some particular challenges. Given the possibility, though remote, of losing all synchronous ties between Vancouver Island and the rest of the Province there needs to be particular attention paid to the integration of wind generation on Vancouver Island. There are essentially three options:

1. To limit the amount of wind generation on Vancouver Island.
2. To ensure that all wind generation on Vancouver Island have special frequency regulation controls that allow the units to respond immediately to a declining system frequency by increasing their output. This requires that the wind farms operate such as to always have a reserve margin between the actual amount of wind power available and what is being produced by the wind farm.
3. To build additional lines connecting the Vancouver Island system to the mainland in order to significantly reduce the probability of islanding.

More detailed analysis is required in order to identify exactly which of these three options is the most economically viable solution. Similar concerns apply to parts of the transmission system near the North Coast that are also susceptible to islanding.

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