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**INTEGRATION OF WIND GENERATION
WITH POWER SYSTEMS IN CANADA:
Overview of Technical and
Economic Impacts**



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**INTEGRATION OF WIND GENERATION WITH
POWER SYSTEMS IN CANADA:
Overview of Technical and Economic Impacts**

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LIST OF ACRONYMS

ABB : Asea Brown Boveri Inc.

ACE: Area Control Error

AESO : Alberta Electric System Operator

AGC: Automatic Generation Control

BPA: Bonneville Power Administration

CANWEA: Canadian Wind Energy Association

CMSC: Congestion Management Settlement Credit

CPS1: Control Performance Standard No 1

CPS2: Control Performance Standard No 2

ELCC: Effective Load Carrying Capacity

GE: General Electric

HQ: Hydro-Quebec

HQD: Hydro-Quebec Distribution

HQP : Hydro-Quebec Production

HQT : Hydro-Quebec TransÉnergie

IESO Ontario Independent Electric System Operator

LOLP: Lost of load probability

MH: Manitoba Hydro

MRO: Midwest Reliability Organisation, Regional reliability Council

NERC: North American Electric Reliability Council

NPCC: Northeast Power Coordination Council, Regional reliability Council

NYISO: New York Independent System Operator

NYSERDA: New York State Energy Research and Development Authority

RPS: Renewable Portfolio Standard

WECC: Western Electricity Coordinating Council, Regional reliability Council

SUMMARY

Wind generation, as an intermittent source of energy, brings about a series of new challenges for the operation of electrical power systems. Wind depends on climatic conditions that fluctuate continuously and this gives it the status of a variable, non-dispatchable source of power that presents additional constraints on the operation of a power system. System operators have traditionally managed the variability of the system load through the use of different operating strategies that balance the load and the generating resources. In the process of balancing demand and production, they must follow strict standards to maintain the system frequency within a very narrow margin. With the advent of wind generation, additional reserve resources have to be deployed so as to keep the system performance within the accepted limits. This report discusses the issue of power system operation impacts due to wind farm and the resulting integration (balancing) costs. Also, it presents a few considerations related to capacity credit, long-term supply planning, transmission upgrades and environmental issues.

Recent studies have found that the additional reserve capacity needed to integrate wind generation is lower than initially expected being at most 10 % of the total wind plant nameplate capacity and in most cases, being only between 3 % and 5 %. This is an important fact, given that utilities design integration fees for wind projects based on the costs of providing the balancing operations. Based on studies developed in Europe and North America, the resulting costs are between 2\$ and 4\$ /MWh for low penetration levels, whereas they may be up to 6\$ /MWh for high penetration levels. The resulting fees should reflect these real costs. However, a generalization of results from one case to the other must be avoided. Each wind integration study requires detailed analysis that considers local wind data and the characterization of local operating practices in order to obtain accurate results. This is reflected in the variety of assumptions, hypotheses and methodologies adopted in the various wind integration studies developed so far. The complexity, uncertainty and variability of data and situations require some oversight from regulators or government agencies to insure that network operators charge wind developers fair and reasonable market prices for wind integration.

Studies have also shown that the coordination of the operation of hydro generating systems with the electricity produced from wind farms opens up new possibilities to the system operators and utilities. The wind plant's energy can be stored in the reservoirs and be delivered later at times most convenient for the company and/or customers. Wind and water inflows are weather related, stochastic phenomena that can complement each other satisfactorily.

The assessment of wind operational impacts is very important for Canada, given the perspectives and the goals for the wind industry growth across the country. Canada has many important advantages regarding wind power that may bring it to be a leader in wind production and network integration in the short run. Wind generation is now a competitive renewable source of

power and Canadian utilities are well suited to take advantage of this situation. The Canadian provinces of Alberta, British Columbia, Manitoba, Ontario and Quebec are leading the way in the analysis of the impacts of wind generation within their power systems and committing to new capacity in the near future of over 5000 MW.

The purpose of this report is to provide a thorough overview of the current status of the wind integration issues to all Canadians so that regional and provincial stakeholders can share ideas and knowledge on the subject.

SOMMAIRE

La production éolienne, comme source d'énergie intermittente, apporte une série de nouveaux défis pour l'exploitation d'un réseau électrique. Le vent dépend des conditions climatiques qui varient continuellement ce qui le caractérise comme une source de puissance variable difficilement programmable qui pose des contraintes additionnelles à l'exploitation d'un réseau électrique. Traditionnellement, les opérateurs des réseaux ont géré la variation de la demande du réseau en utilisant différentes stratégies d'exploitation pour équilibrer la charge avec la capacité de génération. Dans le processus d'équilibrage de la charge et de la production, ils doivent maintenir la fréquence du réseau à l'intérieur de normes strictes très étroites. Avec la venue de la production éolienne, des réserves de production supplémentaires sont requises pour garder la performance du réseau dans les limites recommandées. Ce rapport étudie la problématique de l'impact de la production éolienne sur l'exploitation d'un réseau électrique et analyse les coûts d'intégration et d'équilibrage qui en découlent. Ce rapport présente aussi quelques réflexions sur la planification long terme et la garanti en puissance, sur la capacité des réseaux de transport et sur l'environnement.

Les études les plus récentes ont montré que la réserve en puissance nécessaire pour intégrer la production éolienne est plus faible que prévue initialement. Elle peut, dans les pires cas, atteindre 10% de la capacité nominal des centrales éoliennes, cependant, la plupart du temps elle se situe entre 3% et 5% de cette puissance. Ceci est important parce que les compagnies d'électricité prévoient des charges supplémentaires d'intégration pour les projets éoliens basées sur les coûts de fourniture des opérations d'équilibrage. À partir d'études européennes et nord américaines, les coûts constatés se situent entre 2\$ et 4\$ /MWh pour de faibles niveaux de pénétration et approchent 6\$ /MWh pour des niveaux de pénétration élevés. Les charges correspondantes devraient refléter ces coûts réels. Cependant, une transposition des ces résultats d'un cas à un autre doit être évitée. Chaque étude d'intégration éolienne requière une analyse détaillée qui tient compte des données éoliennes locales et des paramètres des pratiques locales d'exploitation de façon à obtenir des résultats précis. À ce jour, les nombreuses études d'intégration éolienne effectuées reflètent une grande variété de suppositions, d'hypothèses et de méthodologies. La

complexité, l'incertitude et la variabilité des données et des situations requièrent la surveillance des Régulateurs ou des Agences Gouvernementales pour assurer que les exploitants des réseaux chargent aux promoteurs un prix juste et raisonnable pour l'intégration éolienne.

Les études ont aussi montré que la coordination de l'exploitation de la production hydraulique avec la production électrique des parcs éoliens ouvre de nouvelles possibilités aux opérateurs de réseaux et aux compagnies d'électricité. L'énergie éolienne peut être emmagasinée dans les réservoirs et livrée plus tard à un moment plus propice pour la compagnie et les clients. L'écoulement du vent et de l'eau sont des phénomènes climatologiques à caractère stochastique qui peuvent se compléter de façon très intéressante.

L'évaluation des impacts du vent sur l'exploitation est très importante pour le Canada compte tenu des perspectives et des objectifs de croissance de l'énergie éolienne à travers le pays. Le Canada a un avantage marqué en ce qui concerne l'énergie éolienne qui peut l'emmener rapidement à être un leader de la production éolienne et de l'intégration dans les réseaux. La production éolienne est maintenant source compétitive d'énergie renouvelable et les compagnies canadiennes sont bien placées pour prendre avantage de la situation. Les provinces canadiennes de l'Alberta, de la Colombie Britannique, du Manitoba, de l'Ontario et du Québec sont en tête de file dans l'analyse des impacts de la production éolienne dans leurs réseaux et la puissance totale qu'ils ont l'intention d'engager à court terme dépasse 5000 MW.

L'objectif de ce rapport est de fournir un bon survol de l'état actuel des questions d'intégration éolien à tous les Canadiens de façon à ce que les intervenants régionaux et provinciaux puissent partager leur connaissance et leurs idées sur ce sujet

1 INTRODUCTION

Wind generation as a power supply option has the important advantage of being a renewable energy technology that uses a zero cost fuel that cannot be depleted. The utilization of wind as an energy source has been increasing steadily during the last years due to several factors, such as technological developments in materials and power electronics, important cost reductions and reliability improvements. The unitary cost of producing electricity from utility scale wind plants is now reaching the costs of commercial conventional generating technologies. Wind generation technology displays also high availability levels (ability to produce electricity when the wind is blowing). Some of the effects of utility-scale wind power production can be summarized by the following five issues, which can have either a positive or a negative impact:

- *Power system operations impacts;*
- *Long-term supply planning;*
- *Transmission and distribution network upgrades;*
- *Regional development;*
- *Environment.*

This report will deal mostly with the first issue of power system operation impacts and balancing costs as well as a few considerations for capacity credit, long-term supply planning, transmission upgrades and environmental issues related to emission displacement.

Wind is a weather related energy source that displays an intermittent nature. The integration of fluctuating energy sources such as wind influences several facets of the electricity industry in different ways. One of the main issues to consider corresponds to the real-time operation of electrical power systems. Even if wind were predictable with satisfactory accuracy, its natural variability calls for the use of additional conventional generating units, besides the ones scheduled to produce electricity, in order to balance the short-run fluctuations of wind generation output. The main objective is to assure that the system reliability and the frequency standards are met.

Since the onset of the implementation of utility-scale wind plants in North America, system operators were concerned about potential elevated impacts of wind generation on the operation of their power systems [1] [2] [3] [4]. It was initially thought that these impacts would cost utilities about 15 – 20 \$/MWh of wind output. However, as more and more wind projects were implemented and more detailed impact studies were carried out, it soon became apparent that the total impact of wind on system operations was substantially lower than initially anticipated. [5]

In Canada, the issue of wind integration impacts and costs has received a great deal of interest. The province of Alberta is currently leading in total installed wind generation capacity. In the province of Quebec, Hydro-Québec has approved the integration of wind plants totalling 1,000

MW in the Gaspésie region to be installed by the year 2012 [6], and a second call for tender is presently under way for another 2000 MW. The Canadian Wind Energy Association (CANWEA) has set a roadmap that encourages the installation of 10,000 MW of wind plants by the year 2010 across Canada. Other provinces, such as Alberta, Manitoba and Ontario are moving forward to encourage the large-scale development of wind projects. Regarding the wind integration costs, experience seen in other cases in North America and Europe shows that these costs are low in general even for systems with large penetration levels. The most significant case is that of Denmark; where the wind penetration level reaches up to 40% of the total system demand, with some hours during the year where the country's total demand is supplied to a large extent by the wind plants. The reported balancing costs are in the order of 4 Euro/MWh [7].

This overview report presents the most important technical and economic impacts of the integration of wind generation with power systems. It also provides an update on the work carried out so far in Canada. It discusses the fact that balancing charges set by the system operators, if any, should reflect the real costs incurred and that it is closely linked to the operative strategies of the power system combined with the quality of wind forecasting. Finally, regarding the impacts of wind generation, the report presents a survey of some work done in United States and includes a comparative analysis of wind integration costs in America and Europe. The purpose of this report is to provide a good overview of the current status of the wind integration issues to all Canadians so that regional and provincial stakeholders can share ideas and knowledge on the subject.

2 POWER SYSTEM OPERATIONS AND WIND POWER

Notwithstanding the advantages of wind generation for energy supply, when wind power production is integrated with the electricity grid, the way the conventional generating resources are operated may be influenced due to the intermittent nature of wind. Understanding how the operation of the system is affected and what are the extra costs incurred in integrating wind generation is of utmost importance in order to estimate its real economic impacts. The set of actions carried out to integrate the wind generation in real-time are commonly recalled to as balancing operations. The issue of generating capacity deployment for reserve adequacy and balancing operations in power systems is described in the following section.

2.1 Deployment of Generating Resources in Power Systems

The different generating resources have different operative characteristics (fuel cost, ramp-up and ramp-down times, availability, etc). In addition, the load is a random quantity that changes continuously with time. Therefore, the total output of the generators never perfectly matches the constantly fluctuating system load. According to the dynamics of the rotating masses of the generators, this imbalance induces system frequency deviations with respect to the desired nominal value (60 Hz in North America). In order to dispatch the different generating resources and keep the system frequency within desirable levels during real-time operation, System Operators normally use three planning processes in conjunction with adequate *Reserve* that depend on the timescale under which they are carried out. These actions are called the *Unit-Commitment*, *Load-following* and *Regulation*.

2.2 Classification of Operating Reserves in North America

All North American utilities (control areas) that are interconnected are subject to the criteria set by the North American Electric Reliability Council (NERC) regarding the operational reserve needed by the System Operators to comply with the operative performance standards and maintain system reliability in case of contingencies.

The different levels of reserve capacity established by NERC are summarized in Figure 1 [8].

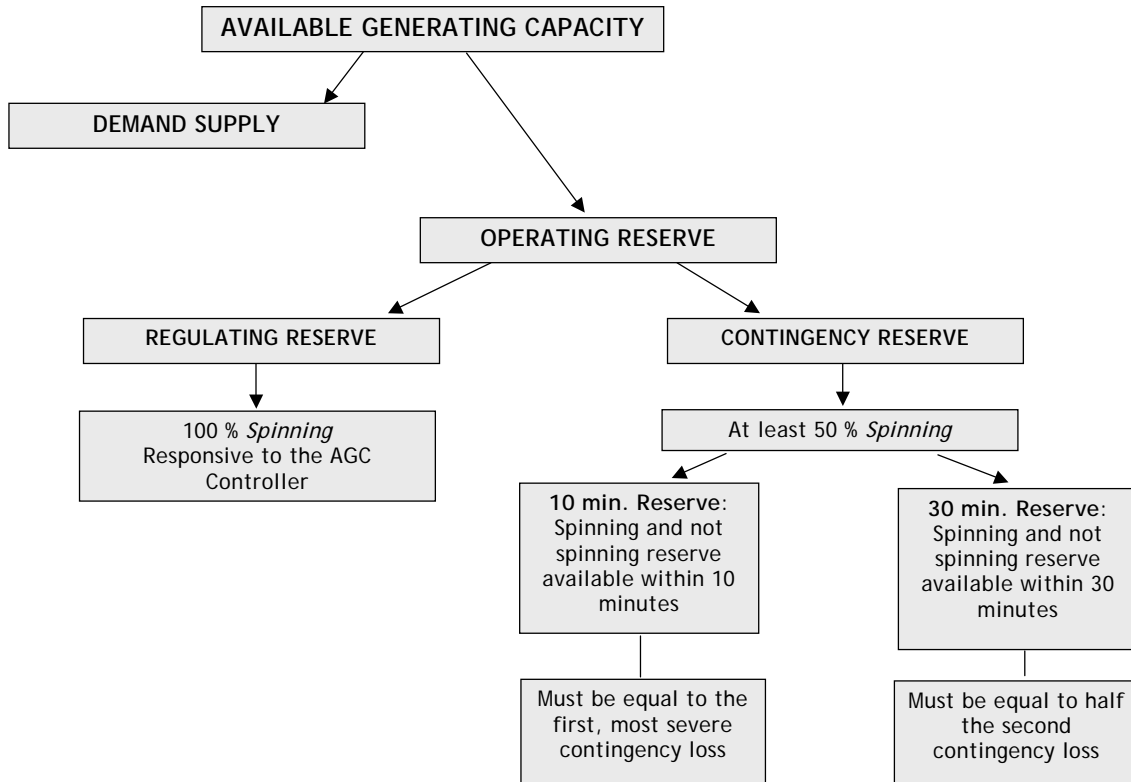


Figure 1. Different Levels of Reserve Capacity as Defined by NERC

The way the operating reserve is deployed by the system operator depends on the structure of the system itself. In electricity markets, the different levels of reserve are deployed based on the competitive bids from the generators whereas in non-deregulated systems, heuristic cost-based approaches are used.

2.2.1 Unit-Commitment

System Operators use complex computer models to perform the so-called “Unit-Commitment” process, whose objective is to determine the optimal mix of generating units to be scheduled the next day in order to supply the hour-by-hour forecasted load at minimum cost. Additional reserve units are also optimally scheduled to be ready to operate in case of generation or transmission contingencies.

In the case of electricity markets, the System Operator takes in all the necessary information from generators in the form of bids. These bids can be one-part or multi-part and may consist of start-up costs (\$/start-up), ramp-up and ramp-down times (MW/min), minimum operating capacity (MW), minimum up time (h) and variable operating costs (\$/MWh, represented as average or incremental costs). With one-part bids, generators internalize fixed and start-up costs

within a single incremental cost bid. With multi-part bids, generators explicitly bid each of these separate costs.

There are a number of time-coupled constraints and conditions that make the mathematical model related to the Unit Commitment problem a complex one. The solving process requires the use of sophisticated optimization tools and may lead to sub-optimal and sensitive solutions that can turn on or off particular generators due to slight changes in any of the various model inputs. There is continuous ongoing research on mathematical models and optimization theory with the goal of improving the solution process and reducing the computational times to find the optimal solution.

In addition to selecting the most economic mix of generating units needed to supply the loads, the Unit Commitment problem also considers the operating reserve capacity needed to keep the system secure and reliable. The model also takes into account the availability of the transmission network (considering maintenance schedules for power delivery equipment). This Unit Commitment model may also be run in real-time during the operation of the system when there are major changes from the conditions considered day-ahead.

In the presence of wind, the combined variability load-wind has to be factored in. Because the Unit Commitment process is carried out day-ahead, if the wind forecasts are inaccurate, the process will yield solutions that may deploy different reserve capacity levels than the ones actually needed. The wind forecasting error is one of the most important issues regarding the integration of wind power. Most of the system operators and electricity markets charge generating resources for real-time output deviations from the reported day-ahead schedules. In many cases, wind is considered an intermittent resource per-se, so no imbalance charges are imposed. The way wind generation is treated in electricity markets, especially regarding the real-time imbalances with respect to the forecasts has led to intense discussion between stakeholders.

2.2.2 Regulation and load following

In order to keep the system frequency and the tie line flows within desired levels a Regulation function is carried out in conjunction with a ramp up or ramp down load following process. Further these control actions are scheduled to ensure the NERC control performance standards named CPS1 and CPS2,[8], are met. The objective of these standards is to minimize the system's sustained frequency deviations. The basic concept to quantify such deviations makes use of the concept called *Area Control Error* (ACE) and is defined as follow:

$$ACE = (I_{actual} - I_{sched}) - 10\beta(f_{actual} - f_{sched})$$

Where:

I_{actual} , I_{sched} : Sum of actual and scheduled tie-line flows (MW)

f_{actual}, f_{sched} : Actual and scheduled interconnection frequency (Hz)

β : Control area's frequency bias (MW/0.1Hz)

The CPS1 standard measures the relationship between the ACE and interconnection frequency on a minute-by-minute basis, consolidated and analyzed yearly. The CPS2 standard requires that the 10-minute ACE average must be within specified limits, with each control area required to achieve CPS2 compliance of 90 % (or 14.4 violations on average during any day or 10% of 144 10-minute daily periods). This control performance standard is consolidated and analyzed monthly.

In order to carry out the regulation function and comply with the performance standards set forward by the regulatory agencies, the System Operator uses what is called the Automatic Generation Control (AGC) system, a centralized control scheme deployed to follow the second-to-second load fluctuations. The System Operator assumes control of the AGC generators by sending out operating signals to the participating regulation units every two seconds or so. In this scheme, the participating units are on-line, spinning and producing electricity at a certain set point that allows them to move up and down according to the requirements of the AGC. The system operator selects the needed set of AGC-controlled generator by either accepting bids for the regulation ancillary service (in case of an electricity market with a real-time balancing market) or empirically selecting fast responsive units according to typical operational procedures, preferably hydraulic units with reservoirs.

The total required regulating capacity depends directly on the second-to-second variability of the load and indirectly on its variability over longer periods of time. The average system load changes as time passes, therefore the AGC generators may be operating far off the required set-points after a few minutes of operation. Therefore, the load following ramp up schedule is needed to re-establish the AGC generators operation near a suitable set point.

The regulating capacity needed is generally defined empirically. Some system operators deploy a regulating capacity equal to three times the standard deviation of the expected load fluctuations within the next 5 to 10 minutes (a load-following period) [9] [10] [11]. Other operators take the value of a given percentile of the expected load fluctuations as the regulating capacity needed, while others consider a value proportional to the square root of the peak load.

In the presence of wind, detailed studies must examine the combined variability of load and wind generation to determine the required levels of regulating capacity and the load following capability. As wind and load are uncorrelated, the total standard deviation of the combined wind output-load can be assumed to be the sum of the isolated standard deviations of both load and wind. Adequate load-following schedules that consider last-minute wind forecasts can reduce the need for extra regulating capacity, which is generally more expensive, per MW power, than other types of reserve in electricity markets. This process is illustrated in Figure 2.

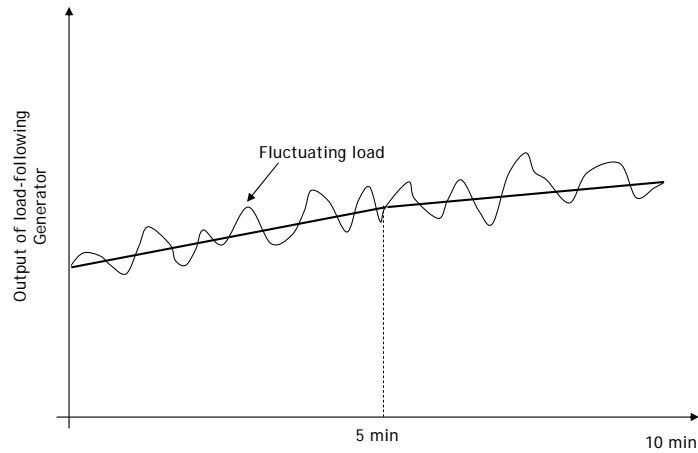


Figure 2. Ramp-up of generator performing the load-following function

In Figure 2 it can be seen that the load-following unit is scheduled to ramp-up uniformly during the load-following period. The second-to-second load fluctuations oscillate around this ramp and are handled with the units performing the regulation function.

In order to optimally deploy the load-following units, System Operators typically run an “Economic Dispatch” or a “Security Constraint Economic Dispatch”, typically every five to 10 minutes, minimizing total operating costs (considering only incremental costs and ramp rate constraints) [9] [10] [11]. This optimization problem is much simpler than the Unit Commitment problem.

3 ASSESSING THE IMPACTS AND BENEFITS OF WIND INTEGRATION

In the years before the advent of the restructuring of the power industry, system operators managed the operating capacity requirements (regulation and load-following reserves) taking the advantage of centralized, cost based schemes. In restructured electrical power industry, which in many cases include open, competitive electricity markets, the provision of the different levels of reserve capacity is considered now as an ‘ancillary service’ that has to be supplied and settled in an optimal way based on price bids from the participating generators.

The cost of deploying the capacity reserves therefore changes according to the scheme under which the power system is managed: the traditional centralized scheme or a market based scheme. In either case, utilities have gained important experience during the last decades on load forecasting methods and on how to manage the typical fluctuations of the system demand. The advent of wind generation as a fluctuating source brings about an additional source of variability to the operation of the system. At high wind penetration levels, such variability may impose important burden for the operation of the system. In order to assess the impacts of wind generation on power system operation, an integration study has to be carried out that considers the particular characteristics of the system under analysis.

The hypotheses and priorities considered when developing these wind integration studies depend widely from case to case. Utilities have different constraints and different strategies regarding the operation of the system and also have different perceptions of the advantages and impacts of wind generation. The presence of electricity and ancillary service markets requires a complete understanding of the market rules and typical real-time price data, which may turn out to be a cumbersome task. It is not possible to extrapolate conclusions from one case to another, each case requires its own series of common data that are necessary to perform a study.

3.1 Dataset for Wind Integration Studies

As a general rule, a comprehensive wind integration study requires minute-by-minute values for a period of at least 24 hours for a typical summer and winter day, covering the following topics:

- Control area generation mix (number of units/generators under different fuel/technologies), must-run, peaking and minimum load units.
- Typical area imports and exports at different times of the day and seasons.
- Seasonal peak and base system loads, daily and annual load duration curve.
- Capacity and location of existing wind plants and other intermittent generators.

- Typical electricity and reserve market prices for different hours of the day and different seasons (where applicable).
- Total system generation, differentiated between conventional and intermittent sources.
- Total system aggregated demand values.
- Timescale for real-time demand forecast.
- CPS performance and energy balance data:
 - Net area imports and exports
 - Net area scheduled imports and exports
 - ACE values
 - System frequency and frequency bias
- Market price clearing: day-ahead, hour-ahead and/or real-time
- Procurements and prices of regulation up and down (hour-ahead and real-time) for each settlement period (typically hour-by-hour).
- Criteria under which generators are called upon to ramp-up or down for expected demand increase or decrease, in the case that there is no real-time energy balancing market.
- Timescale for the real-time economic dispatch for load following (for instance, every 5 or 10 minutes).
- Criteria to determine the reserve capacity requirements, spinning and non-spinning (i.e., the loss of an interconnection, the size of the largest generating unit within the control area, the standard deviation criterion, etc).

As the amount of information collected can be considerably large, all the acquired data has to be classified filtered and checked for consistency. Most of the time, vertically integrated utilities have an easy access to the data, but the wind industry developers are at a disadvantage to gather the necessary information for their own project evolution and development. Public consultations managed by regulatory bodies are often critical for wind developer since utilities are often required to provide the rational and the supportive data to justify integration costs or technical constraints.

3.2 Wind Characterization

The complete understanding of the time-varying output of the wind plants to be integrated with the system is fundamental for the analysis of its operational impacts. The behaviour of wind has different ‘footprints’ according to the geographical layout of the region and the predominant climate conditions. For instance, it is known that wind speeds are more constant offshore than inland. Therefore, wind generation projects located offshore display better capacity factors over time. It is also known that the wind power production peaks during the night hours and also in the winter months, when the air density is higher.

Also, there are sites where wind speeds increase steadily during the first hours of the morning and follows perfectly the morning load ramp-up (in Scotland, for instance) while in other regions, wind speeds decrease gradually during the time where demand increases (as is the case documented for the province of Ontario) [12]. The capacity deployment operations are substantially different in those two cases. Therefore, the complete characterization of overall local wind speeds and real-time power production is crucial for the success of the analysis of the impacts of wind on power system operations.

In order to characterize properly wind conditions at the sites of the wind plants, actual minute-to-minute speed measurements are needed for those locations; however, such a detailed dataset is not always available. Several wind developers rely on data from meteorological stations located in nearby airports or measuring posts and uses extrapolation techniques to determine local wind conditions. Some specialists have used these local values to reflect the conditions of the whole wind plant, or even a whole region [13], [2]. Often wind data are incomplete and extrapolation techniques have to be used to fill in missing data sets.

Once the wind measurements are either collected from actual measurements at the project sites or modelled through statistic techniques, the next step is to calculate the potential power production resulting from those wind speeds. There are well known equations in the literature that translate wind speeds at hub height into power output [1]. This process will also allow the developers to estimate the capacity factor for their projects which is the most important parameter for the economic and financial assessment of their investments.

However, it is important when extrapolating wind measurements to simulate larger wind plants spread over a large area or a region, to consider the *geographic diversification* of wind be considered. The geographic diversification effect is important since the impacts of wind generation on power systems operations are all about output variability. If this variability is not carefully modeled, the negative impacts of wind generation may be overestimated.

In [14], it is shown in detail how the location of different wind generators across a large area results in a more stable total output from all the generators. Consider for instance Figure 3. In this hypothetical case, it can be seen how the combined output of two wind generators located

relatively distant from each other displays a lower volatility than that of each individual generator outputs.

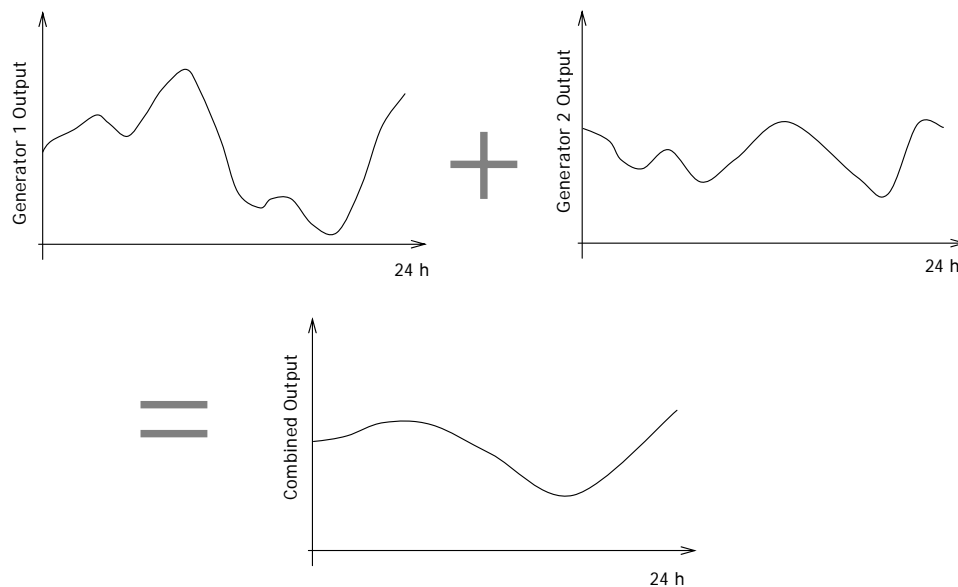


Figure 3. Combined Output of Two Distant Wind Generators

This issue of wind characterization over a larger geographic area is very important. In reference [15] it is shown that the variability of geographic dispersed wind plans located across the province of Ontario will be 60 % to 70 % lower than those calculated from a single site.

3.3 Wind Production Forecasting Error

The analysis of the impacts of wind on the system operations should simulate the real conditions of wind output during the wind-modeling phase, together with the reserve capacity dispatch strategies. This modeling entails the time simulation of the operation of the power system with forecasting. One of the factors that most affects the operation of the system under the presence of wind is the wind production forecasting error. Wind farms have good monitoring on site providing good short terms data. The wind forecast is thus much more accurate on shorter hour head time scale.

As any wind forecast model based on site monitoring data will still yield some errors that vary according to the timescale of the forecast, it is very important that any electricity market be adapted to take into account the uncertainty of predicting wind production accurately. For instance, such markets will be improved if hour-ahead bidding is permitted for wind generators instead of day-ahead. Electricity markets that are well adapted will be more efficient and will integrate wind power with the maximum benefits. Reference [16] for the Nordic European

Power System and reference [17] from David Milborrow gives some insight to the problem of the cost and penalties of wind forecasting error.

3.4 Generation Balancing Costs

Many studies have been carried out in an effort to estimate the extra reserve requirements and operating costs due to wind generation. It has been recognized that the extra levels of reserve capacity needed to accommodate the fluctuations of wind can be as high as 10 % of the total nameplate capacity of the wind plants, but it is generally between 3 % and 5 % of that capacity. In terms of costs, the deployment of these additional levels of reserve represent only a few dollars per MWh of wind output to the System Operators, as the results shown in section 5 will demonstrate.

Since power system management varies significantly, there is no universal acceptable methodology for estimating the balancing costs that covers all the needs. It is clear that some sort of simulation of the real-time operation of the combined load-wind fluctuating behaviour is required. As was discussed in section 3, this entails the use of commercial Unit Commitment and Economic Dispatch models and the understanding of the operative heuristic measures to be put in place to dispatch the required capacity. The simulation process can be carried out for a 24-hour period in order to include all typical realizations of wind and system demand. Also, typical days of different seasons can be simulated. The results should be computed in the form of an integration or balancing cost of wind generation in \$/MWh. In general, as shown in the following equation, the balancing cost over a given period of time is determined by the operating costs under the presence of wind (OC_W) minus the operating costs with no wind generation (OC_{NW}), with all other variables kept the same, divided by the total wind output of the scenario with wind, g_W .

$$BC(\$/MWh) = \frac{OC_W - OC_{NW}}{g_W}$$

This cost varies greatly according to the hour of the day, the day of the week and the season, but most importantly, according to the type of generating units that provide the balancing operations. Hydroelectric units are fast responsive and run on a free fuel. Fossil-fuel plants are expensive to run and their response to real-time fluctuations is slower. This situation may increase the costs of the balancing operations to integrate the wind power.

3.5 Network Integration Costs

The limits of the transmission network to integrate wind generation have received little attention in the wind industry. As the wind resources are often available in remote regions located far away from load centres, the network capacity and availability in times of high wind output must

be considered. The state of Texas (United States) is an example of how a transmission network can limit the deployment of large-scale wind plants [18].

The other important and no less controversial topic is the attribution of responsibility for the network upgrades. The industry has been inclined towards the idea of sharing the costs of these upgrades among all ratepayers as a way of encouraging the development of the wind plants as a renewable resource. A discussion of the issues involving transmission access charges to wind generation is reported in a study of the National Renewable Energy Laboratory (NREL) [19]. In the United States, the largest wind potential has been identified in the North and South Dakota, which are regions of very low population density. One important issue is to finance and share the costs of the high-voltage network that will have to be built in order to integrate the electricity produced from those isolated or remote wind farms.

3.6 Wind balancing with Hydro Storage

Besides the real-time interaction of wind generation output with the power system, system operators and utilities with hydroelectric generation predominance have also considered the analysis of the integration of wind over longer timescales. In this way, wind generation can be used in real-time or it can be stored in the hydro reservoirs of the system to be delivered back to the system as needed, following different strategies and operative interests. The issue of wind-hydro integration brings about opportunities for the system operators and also for the purchasers of wind power.

The real cost of balancing reserve depends on the opportunity cost of the generation capacity. In hydroelectric plants, this cost depends on the value of the stored water, which also depends on future inflow conditions that can only be estimated through stochastic analysis. Typical operating constraints, such as minimum downstream outflow requirements or maximum reservoir level requisites also play a key role in determining the economic value of the needed extra capacity. System operators can store the energy produced from the wind farms in their reservoirs to release it later under more favourable conditions, whether it be at times of higher electricity prices, higher system load, lower supply availability, etc. This possibility opens up new opportunities for the system operators to strategically coordinate the operation of the hydro system with the wind plants within their territory. For example, in the Province of Quebec, where there are large hydro basins, significant wind-hydro balancing can be a great advantage.

Although the production from wind plants is fluctuating, from a business point of view there is an equivalent capacity factor for the whole wind plant output that can play an important role in enhancing the firm value of the power produced by the hydro generating company. This increase in the system's firm capacity improves the ability to sign firm supply contracts with wholesale buyers in internal and external markets. These firm contracts are more profitable than non-firm commitments.

In order to quantify this benefit, one has to keep in mind that the additional firm capacity provided by the wind plants depends on *controllable* factors, such as the size of the wind plant, its geographic distribution, the capacity of the hydro reservoirs and the operating policies (downstream inflow and level constraints, etc). However, there are *non-controllable*, stochastic factors that influence the extent of the extra firm capacity provided by the wind. These factors can be explained by the natural cycles of wind and water as renewable sources.

In fact, the existing generating plants should be taken into account when considering the installation of new wind plants. It has been shown in [20], that properly sited wind plants may display lower long-term (seasonal to annual) resource variability than hydro resources. In colloquial words, if the locations of the new wind plants are carefully chosen, the wind as a generating resource will likely be available even during the worst droughts. This result shows the importance of how wind can complement the long-term natural cycles of hydro generation.

Given the natural variability of wind generation, those market agents engaged in contracts to purchase energy from wind developers are interested in acquiring the contracted energy in the form of fixed blocks [11]. Therefore, some system operators and the buyers of wind power have the opportunity to set up commercial arrangements whereby the former can integrate real-time the output of the wind farms and deliver it to the buyer instantaneously or at a later time under the form of fixed blocks of power defined for different time basis. The system operator (or generating company) will establish a basic fee to perform this activity. Again, this is nothing more than a commercial agreement as the wind output is integrated real-time, balanced and consumed instantaneously by the consumers. However, contractually acquiring the wind energy in the form of pre-determined blocks facilitate enormously the contractual and accounting process of wind energy trading.

One of the most well-know commercial arrangements to integrate and deliver wind energy by system operators for wind energy traders is that of Bonneville Power Authority (Washington State, US). The details of these services can be found in Appendix A-1 [36].

3.7 Benefits of Wind Integration

The integration of wind generation with power systems not only represents costs to the utility or the system operator. There are a series of system benefits that should be considered as part of a comprehensive analysis on the impacts of wind generation.

3.7.1 Capacity Credit

As wind penetration levels increase in a particular system, the contribution of wind generation to the capacity availability of the system starts to be realized. Although the annual capacity

factors of wind power are usually between 30 % and 40 %, this value changes with the season and with the hours of the day. Wind capacity factors are higher during the winter than in the summer. The availability of a wind generator is typically very high (the ability to produce power when the wind is blowing). Therefore, the total availability of a wind plant depends mostly on the availability of the resource (wind) and not on the generator. The forced outage rate of a wind plant (the probability that the plant will not produce electricity) is therefore not random since there is a seasonal and diurnal pattern of wind production and variability. In [9] it is argued that, if the capacity factor of a wind plant is 30 %, the forced outage rate cannot be assumed to be 70 %.

It is evident that there is a certain level of guaranteed wind capacity available during peak load hours. The determination of this guaranteed capacity depends on the specific conditions of the winds at the particular wind plant locations. A wind integration study should calculate in detail the effect of wind plant output on the system supply curve and how the capacity availability and/or the total system *Loss of Load Probability* (LOLP) are impacted. Another analysis focuses on the calculation of the *Effective Load Carrying Capability* of wind, by which the equivalent impact of the wind plants on the total supply availability of the system is compared to that of a generic conventional power plant [10].

The determination of the capacity contribution of wind is of utmost importance for the long-term resource and adequacy planning especially with high wind penetration. Overestimating the capacity value of wind will affect the reliability of the system while underestimating that capacity will be very costly because unnecessary investments will be made on additional generation or transmission capacity.

3.7.2 Avoided Fuel Costs and Emissions Displacement

When wind plants are integrated with power systems that use thermal generation such as coal, gas and oil-fired plants, the system supply curve is altered in a way that on-margin, more expensive plants are displaced. This modification represents savings to the utility and the society in general through lower wholesale spot electricity prices. The generation dispatch strategies vary widely among different system operators; therefore the analysis of the avoided generation costs depends on the particular operating strategies used to manage the different supply options within the system. In the presence of electricity markets, price bids from generators define the supply curve, which may facilitate the analysis, given that wind power is always considered as a low variable cost generating technology as operating and maintenance costs are generally small.

Following the last point, wind generation displaces the emissions from on-margin, fossil-fuelled power plants. If the system's supply curve is known in detail, the emission reduction potential of the wind output can be quantified economically if a market for emission reduction credits is

in place. However, the complete identification of the technologies that operate on-margin as well as its operating timescales is a rather complex task that requires the active participation of the system operator. For example the case study for New York State concludes that [9]:

“Energy produced by wind generators will displace energy that would have been provided by other generators. Considering wind and load profiles for years 2001 and 2002, 65% of the energy displaced by wind generation would come from natural gas, 15% from coal, 10% from oil, and 10% from imports. By displacing energy from fossil-fired generators, wind generation causes reductions in emissions from those generators. Based on wind and load profiles for years 2001 and 2002, annual NOx emissions would be reduced by 6,400 tons and SOx emissions would be reduced by 12,000 tons”.

In Canada, the rules of a nationwide renewable energy credits market are not yet established but the Federal government has already stated that Canadian enterprises will have unlimited access to international environmental markets in order to comply with their emission commitments at the lowest costs [22]. Wind generation and its potential environmental credits will certainly play a key role in achieving these goals. In [23], the results of a comprehensive study on the on-margin generation in all provinces in Canada are shown. This study can serve as a reference to estimate the impacts of wind generation in the provincial emission levels.

4 WIND INTEGRATION ANALYSIS AND REGULATORY ACTIVITY IN CANADA

To date, the provinces of Quebec, Ontario, Manitoba, Alberta and British Columbia in Canada have examined the impacts of the expected wind output on the operation of their electric power systems. Hydro-Quebec has officially submitted for approval, proposed wind integration fees through the incumbent generating company. The Ontario's government has decided not to charge wind plants within the province with balancing charges. Manitoba is currently executing a wind integration study for the province, while the development of wind integration standard for Alberta is underway.

Canada has many important advantages regarding wind power that may bring it to be a leader of wind production and network integration in the short run. In most provinces of Canada the peak load is in winter when the winds are the strongest and the most constant. Many studies have shown that in winter months of December and January the capacity factor at peak load could be as high as 45% as discussed in a Helimax study for Quebec [27], and a Truewind study for Ontario [33]. Many utilities in Canada have large hydro production and reservoirs so that the wind integration balancing cost should be minimal as discussed in section 3.6. Inventories of wind characteristics in many provinces have shown that wind power is very important with average annual power factor well in excess of 35%. The most favourable location are the eastern Maritime Provinces, British Columbia western shores and all location around James Bay and Hudson Bay in central northern Canada. A more detailed analysis of the activities carried out by these provinces is presented below.

4.1 Quebec

Hydro-Quebec has a total installed capacity of 40,000 MW taking into account Labrador's Churchill Falls 5500 MW plant. Hydroelectric plants account for 96 % of the electricity produced in the province. The remaining supply fleet is comprised of a 600 MW oil plant, three natural gas-fired plants (with a total of 870 MW), a 675 MW nuclear plant, and a total of 208 MW of wind production integrated to its power system.

Following the current provincial government's initiative on the development of wind energy, Hydro-Quebec Distribution (HQD) opened a Call for Tenders process in 2004 for the installation of 1,000 MW of wind generation in the Gaspesie region of the province on the Atlantic border. The bids of two wind developers, corresponding to nine wind plant projects totalling 990 MW were selected as winners. These projects will be installed and commissioned between 2006 and 2012. The province's regulatory body, *La Régie de l'Énergie du Québec*, has recently approved (July 22, 2005, [43]) the corresponding power purchase agreements between the wind developers and Hydro-Quebec Distribution (HQD). Also, at the provincial

government's request [24], on June 29, 2005, Hydro-Quebec announced the release of another Call for Tender process for an additional 2,000 MW of wind generation in all regions of the province.

The process of the 990 MW tender resulted in a very competitive price for wind power, a very high cost for transmission integration and a wind balancing integration fee of 9 \$/MWh of wind output [25] proposed in March 2004 by Hydro-Quebec Production (HQP) following the example of BPA Wind Integration Service of Washington State, USA [36]. The release of this proposal by HQP received considerable negative feedback from the industry concerning the high cost and a second very different proposal was released in July 2005.

Hydro Quebec Distribution (HQD) have submitted the new HQP proposal to the province's regulatory body, *La Régie de l'Énergie du Québec*, for approval [44]. The main attributes of this new proposal, based on a very different methodology to calculate the wind balancing, are:

- HQP accepts to integrate the total 990 MW outputs of the wind plants delivered by HQD in real-time.
- HQD must submit the schedule of the total wind generation output for every hour of the following day before 4:00 pm. This schedule can be revised four hours before the hour of delivery. The actual wind generation will be compared with the schedule submitted by HQD. The absolute value of the hourly differences between the scheduled and the actual output will be paid by HQD at a rate of 1 \$/MWh. This is the penalty for wind power forecasting error if any. Two additional charge settlements are also established, based on a total wind generation capacity factor of 35 %.

Power: HQD must pay HQP, at a rate of 80 \$/kW-year corrected annually, the difference between the '*guaranteed capacity*' (35 % of the total wind plant nameplate capacity) and the '*minimum hourly measured contributed capacity*' (which cannot be lower than 15% of the wind plant nameplate capacity contribution during the 300 hours of peak-load).

Energy: HQP receives the output of the wind plants and delivers the energy at the *guaranteed capacity* rate every hour of the year. The annual difference between the actual wind production and the *guaranteed capacity* multiplied by the number of hours of the year is to be settled at 7.5 cents/kWh, starting in 2005 and increased by 2.5 % every year from 2007.

The proposed agreement provides a quantification of the potential costs for HQD to integrate the output of the wind farms in the province; this cost was evaluated at approximately 5 \$/MWh by HQD in its presentation to *La Régie de l'Énergie du Québec* [26].

Two main conclusions can be extracted from that proposal. The first one is that HQP will charge HQD for the balancing operations to handle the variability of wind with a charge for its *forecasting error*, hours ahead. This scheme gives HQD the direct incentive to adopt reliable and precise day-ahead and hours-ahead wind forecasting techniques. This is one of the most important challenges of the wind industry nowadays. The second one is that HQP will charge to HQD approximately 5\$/ MWh to guarantee, at all times, the availability of 346.5 MW (=35% of the 990 MW installed capacity). This can be viewed as expensive considering that the few critical peaking months are in winter when the capacity factor of these farms is at its maximum value of around 47% [6].

4.2 Alberta

Alberta has a total installed generating capacity of about 12,000 MW. The supply mix is diversified among coal (47 % of the total capacity), gas (42 %), hydro (7 %) and others, including renewable sources (4 %). Since 1996, the power system in the province is run under an open and competitive wholesale electricity market. The province completed its restructuring process by introducing retail competition in January 2001.

In 2003, The Alberta Electric System Operator (AESO) [21] called for the development of a study on the impacts of wind generation in its interconnected electric system, following requests for the integration of 600 MW of new wind generation located mainly in the south-western corner of the province. The study done by the company ABB [13], begins by characterizing the wind variability. Two sets of data were used. The first set used hourly average wind generation over a four-year period. The second set used one-minute data for the month of November 2003. After characterizing maximum one, ten and 60 minute wind fluctuations for the existing wind plants, the study then extrapolates the results for a wind plant of the size expected by 2007 (1,202 MW). Considering the AESO operating policies in terms of ACE performance, interconnection schedules with neighbouring areas and typical 10-minute reserve requirements, the study concludes “regulating reserve margins would need to be increased by at least 120 MW and possibly 481 MW, which is the estimated maximum step change in power over a 10-minute time interval”. In terms of contingency reserve, the study suggests that additional 805 MW would be needed in order to account for maximum 10-minute fluctuations. Finally, daily extra regulation and contingency reserve are estimated according to typical market prices.

After the results of this study were released, AESO received considerable feedback from several specialists especially regarding the assumption that the wind characterization for the existing 160 MW of wind output can be extrapolated to the expected capacity of 1,202 MW in 2007 without taking into account the geographic diversity that should play an important role in reducing the aggregate wind variability. Therefore, this simplistic extrapolation was considered totally inaccurate.

The AESO has already recognized that “the ABB study did not adequately address the operational impact of wind power” [28]. Therefore the company requested a new more detailed study to examine the variability of the wind power generation and carried out an analysis of the operational impacts of wind. The first of these new studies, entitled “Alberta Wind Power Variability Study” [29] was released on July 8, 2005, and examined in detail the combined expected 1-minute and 10-minute variability of wind power output for four scenarios: 254 MW (existing installed capacity), 895 MW, 1,445 MW and 1,994 MW, located at different sites across the province. Real wind data was obtained from project developers and a detailed model that considered the relative location of the various wind generators within a wind plant was developed. A sensitivity analysis was also carried out, considering the type of wind generator power curve, the size of the wind plant, air density, among others.

The study showed how the combined variability of the output of different wind plants geographically dispersed is significantly lower than that of a single wind plant. Also, although the total variability increases with the wind penetration level, the *relative* variability decreases as the total installed nameplate capacity increases. For instance, 99.5 % of the time, the 10-minute fluctuations for 254 MW of wind plants is less than 29.69 MW (12 % of the nameplate capacity), as opposed to 105.58 MW for the 1994 MW scenario (5 % of the nameplate capacity).

A second study that considered the previous results was carried out by the AESO. The first draft of this study entitled “Incremental Impact on System Operations with Increased Wind Power Penetration” [30] has been released on September 22, 2005 for comments. The study modeled in detail the real-time operation of the Alberta Electricity Market, the ancillary services market and the operative practices in order to estimate the impacts of the different scenarios of wind penetrations on the operative performance standards (CPS2 and the so-called Operating Transfer Capability Violations and the Transmission Reliability Margin). The wind forecast errors for different timescales were also considered. The study concluded that there are no impacts on the system performance for the current levels of wind penetration (the 254 MW scenario), however, for the 895 MW scenario, “operational concerns are present”, that is, violations on the performance indexes are present. The results indicate that mitigating measures will have to be developed, however no details are given on what those measures or their costs should be. It is pointed out that increasing the regulating reserves will improve the CPS2 performance and that there is some evidence that the other performance standards under analysis would be improved.

4.3 Manitoba

Manitoba has nearly 5,000 MW of installed generating capacity. Approximately, 95 % of the province’s electricity is generated by hydroelectric plants. There is also a 95 MW coal plant located in the city of Brandon. In 2002, two gas-fired power plants with a total capacity of about

260 MW were added to its system. Most of the hydroelectric resources are located in the northern part of the province while the majority of the consumers are located in the south.

In the province of Manitoba, the generating company, Manitoba Hydro (MH), is currently developing a wind integration study, considering the strategic commercial and operational interests of the company.

The company has recognized that wind can be an alternative to enhance the portfolio of the supply offered to the customers. As the production of electricity in the province is dominated by large hydro reservoirs, wind generation offers a valuable resource to complement the natural cycles of the water inflows. Water and wind are essentially unrelated climatologic phenomena. In many cases, both resources can complement each other during times of scarcity.

MH has the mandate from the provincial government to incorporate the output of the existing and future wind plants to be installed within their territory. The company has, in turn, the discretion of setting the price at which the developers of wind generation will be paid for the output of their plants. This fact places MH in a strategic position, given the presence of the United States Midwest power market, to which the company sells part of its power after fulfilling its commitment to Manitobans.

Following the results of the study currently under development, MH will release a net price of electricity to be paid to wind developers inside the province rather than a balancing charge. This price will reflect the following main issues, according to [31].

- Value adding factors:
 - The added value of the wind capacity to firm peak-load capacity long-term firm contracts
 - The benefit of the wind accredited capacity.
- Value reducing factors:
 - Capacity opportunity cost
 - Energy shaping and firming costs (as in the BPA model)
 - Reserve deployment costs
 - Market risk perception, commercialization and management costs

The total price of electricity to be paid to the wind developers in the province will be defined according to difference between the valuation factors.

The calculation of each of the cost factors involves the use of different proprietary simulation models that consider in detail the characteristics of the transmission grid, rivers and reservoir

networks, together with the economic issues associated with the interactions between the operation of the systems in Manitoba and the electricity markets in Canada and Midwestern US.

Additional reserve requirements are also studied in detail according to the reserve deployment scheme adopted by MH. This scheme is statistically-based and considers the maximum positive deviations of load with respect to the average hourly load. Reserve capacity levels are defined based on the 85th percentile of those deviations, which leads typically to a 'load residual' of 50 MW beyond the reserve to be deployed.

The impacts of wind generation on the statistically based reserve deployment scheme are calculated by using wind time series. For the case examined (500 MW of wind), the balancing of the equivalent wind/load will require a reserve deployment given by the 97th percentile, which leads to the same load residual of 50 MW for the case with no wind.

This study corresponds to a phase I integration analysis and it is currently under review by the provincial government. This phase I integration analysis will be followed by a phase II that will include issues such as simulating the transmission grid, examining the geographic diversity effect of wind as well as the hydroelectric conditions in more detail, among other issues.

4.4 Ontario

Following the Ontario Electricity Act of 1998, the electricity industry in the province was re-organized. Publicly owned generation assets were congregated under a new company, Ontario Power Generation Inc, while the company Hydro One was created to manage the transmission network. The Independent Electricity System Operator (IESO) was established in order to ensure the safe and reliable operation of Ontario's electrical system and also to operate the wholesale electricity market.

Today, the total installed generating capacity in the province is about 30,000 MW. In terms of electricity production, approximately 47 % of the electricity is produced from nuclear plants, 23 % from hydro plants, 17 % from coal, 7 % from oil gas and wood waste. The remaining 4 % corresponds to imports from Manitoba, Quebec and the United States. Coal plants operate mostly at the margin of the supply curve.

Regarding wind generation, the development of the wind industry in the province of Ontario will be closely linked to the initiative of the provincial government regarding renewable electricity sources. The government of Ontario has set a target by which five percent of the total generating capacity in the province will come from renewable sources by 2007 and 10 % by 2010. In June 2004, the province's Ministry of Energy issued a Request for Proposals (RFP) process for approximately 300 MW of renewable electricity sources for the province. Out of the ten winning projects of phase I announced on November 2004, five are wind plants, with a total

capacity of 354.6 MW. On April 2005, the government has released phase II and III of the renewable generation growth goals (for more details, refer to [32]).

The company *Superior Wind Energy* (now *Bras can Power Wind*) commissioned an analysis to study the potential impacts of wind energy production on the power system in Ontario [33]. The study examined the potential output of 17 probable wind energy project sites across the province combined with real load data provided by Ontario's Independent Electricity System Operator (IESO). The time-basis for the wind and load data was 10 minutes spanning a period of a full year, between May 2003 and April 2004. The study considered a total of 2,000 MW of wind generation from the 17 projects and examined the capacity value of wind, the combined variability load-wind and the geographic diversity effect as a result of the dispersed location of the wind farms across the province.

The main conclusion from the report is that the addition of 2,000 MW would increase the load-following requirement by 37 MW on an annual basis (57 MW in summer), considering one-hour time frame load-wind variations. This represents between two and three percent of the total wind nameplate capacity. On a three-hour time frame, the additional reserve requirement (tertiary or replacement reserve, in this case) would be 93 MW on an annual basis (146 in summer). Regarding the geographic diversification effect, the study shows that the combination of the output from all 17 sites is about 60 to 70 % less variable than the output from a single site. These results allow conclude that the impacts of the relatively high levels of wind generation considered for the province (2,000 MW) would have no major impacts on the operations of the system.

The IESO has not established balancing charges for wind plants in Ontario. According to the electricity market rules established in the province, wind plants are considered *intermittent generation* and as such, their output is priced real-time at the market's hourly electricity price. Moreover, according the market rules, generators considered as intermittent are not eligible for congestion management settlement credits (CMSC) (refer to [15] for more information). Wind operators must submit day-ahead output schedules to the IESO but they incur no penalties if the real-time output deviates from the day-ahead schedule.

4.5 British Columbia

A consultant report entitled "Wind Farm Integration in British Columbia – Stages 3: Operational Impact" [34] was presented to the British Columbia Transmission Corporation in May 2005. This study summarized the different aspects of power system operations influenced by the integration of wind power and gave an overview of the variability of wind as a natural resource considering real cases from United States and Europe.

With respect to the operative impacts of wind in the province, the study concludes that the system is ready to accommodate 500 MW of wind farms in the province with the current levels of reserve capacity (to cover the loss of the largest generating unit, that is, 500 MW). Also, general recommendations are given regarding the market rules and the necessary modifications in order to handle the hourly variations of wind output, following the examples of the PJM and NYISO systems in the US.

The study concludes that given the large availability of hydro resources in the province, the real-time wind fluctuations can be readily handled by the existing governor controls and the levels of spinning reserve that can be provided by the existing hydro plants.

According to the recommendations set out by this approximate analysis, it can be concluded that there would not be additional costs for the system operator for the integration of up to 500 MW of wind plants in the province of British Columbia

5 STATUS OF WIND INTEGRATION BALANCING COSTS WORLDWIDE

Several studies on the operational impacts of wind have been developed worldwide, [35]. Power system operators have also reported real incurred costs of integrating wind generation [7]. The main conclusion that can be drawn from the various studies and reports is that balancing operational costs imposed by the output of the wind plants on the power system are substantially lower than originally expected.

Table 3 summarizes the additional balancing costs due to wind generation as reported in different studies around the world. In North America, there are two cases of commercial agreements that stipulate an integration fee applied to the output of the wind plants. Table 1 presents the corresponding fees under commercial agreements in North America.

Table 1. Wind Integration Balancing Costs

Reference System	Pen. Level (%)	Cost in original currency	Equivalent CAD/MWh
USA - BPA (Washington) (Cost) [2]	1.5- 7	1.47-2.27 USD/MWh	1.79-2.74
USA- Xcel North (Minnesota) [41]	3.5	1.85 USD/MWh	2.24
USA - We Energies (Wisconsin) [42]	4	1.9 USD/MWh	2.30
	29	2.92 USD/MWh	5.53
USA - PacifiCorp (Oregon) [39]	20	5.50 USD/MWh	6.65
USA – Great River (Minnesota) [45]	4.3	3.19 USD/MWh	3.86
	16.6	4.53 USD/MWh	5.48
Denmark – Eltra [7]	33	27.02 DKK/MWh	5.72
England, ILEX [37]	20	3.30 – 6.55 GBP/MWh	7.49-14.88
	30	3.74- 7.32 GBP/MWh	8.89-16.6
England [17]	10	1.35 GBP/MWh	3.06

2005 Exchange rates: 1 CAD = 0.83 USD = 4.71 DKK = 0.44 GBP

Table 2. Wind integration fees under commercial agreements in North America

Reference System	Pen. Level (%)	Price in original currency	Equivalent CAD/MWh
Canada – Hydro-Quebec (First Proposal) [6]	3.3	9 CAD/MWh	9.00
Canada – Hydro-Quebec (Second Proposal) [26]*	3.3	5 CAD/MWh	5.00
USA - BPA (Washington) (Integration) [36]	N/A	4.5 USD/MWh	5.47
USA - BPA (Washington) (Shaping) [36]		6 USD/MWh	7.29

* Does not include the additional fee for wind forecasting error (1 cent CAD/kWh).

The case of Bonneville Power Authority [36] is already operating on commercial basis whereas the case of Hydro-Quebec has been recently proposed and is currently under review by the province’s regulatory body, as detailed in Section 4.1.

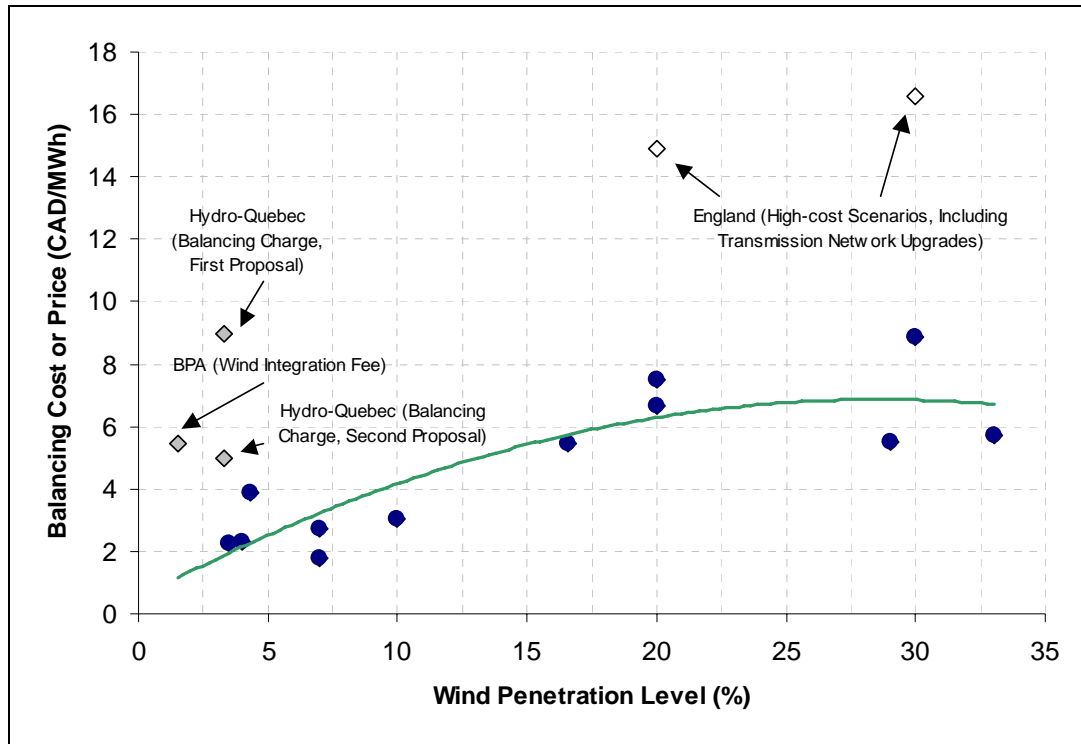


Figure 4. Plot of Wind Integration (Balancing) Costs

In Figure 4 it can be seen that the wind integration (balancing) costs reported in the various reports follow a common trend that flattens out as the penetration level increases. The cases of Hydro-Quebec and BPA correspond to integration fees and are therefore outside the cost trend.

The case of ILEX [37] high-cost scenario includes the addition of network upgrades and network integration costs.

It may be argued however that such comparative analysis can only be considered as informative and not as a way of estimating integration costs for other cases. The hypotheses, assumptions and methodology used vary substantially from one case to the other. Also there is a discrepancy on how the wind penetration level is defined. The most often used approach is to define the penetration level as the ratio of the total wind generation nameplate capacity to the system's peak demand.

The most important conclusions from this analysis are that the costs of integrating wind with power systems are only a fraction of typical wholesale electricity prices seen worldwide and that integration costs do not increase at the same pace then the levels of wind penetration. In fact, the data shows that the marginal increment on integration costs in \$/kWh decrease as the penetration levels increase.

6 CONCLUSIONS

This report has examined the factors that influence the costs of integrating wind generation with power systems and its implications on the real-time operations of power systems. Besides other positive and negative impacts of wind generation on power systems and society, the topic of balancing the fluctuating wind generation has received important attention from System Operators. This report has also examined the most important studies on wind integration carried out in Canada and the United States. It was seen how different hypotheses and methodologies were assumed in each case according to the particular needs of the corresponding utility or system operator.

In some studies, some very conservative assumptions were considered, proposing rare worst-case scenarios to establish wind integration policies. This approach can ultimately affect the development of the wind industry as utilities could set high integration charges based on the results of those studies. Wind characterization over a larger geographic area will reduce significantly the variability of aggregate wind plans up to 70% as was shown in Ontario study [15].

The design of a generalized methodology for estimating the wind integration costs is an almost unfeasible and unpractical task. Regardless of the model adopted, it is clear that some sort of simulation of the real-time operation of the combined load-wind fluctuating behaviour is required. This entails the use of commercial Unit Commitment and Economic Dispatch models and the identification of the structure of the reserve markets or the complete understanding of the operative heuristic measures put in place to dispatch the reserve capacity. Electric market structures and rules are evolving to allow proper integration of wind energy and to give it a suitable place in the energy portfolio.

It was seen that the costs of integrating wind generation are between 2\$ and 4\$ /MWh for low wind penetration level, and that that for high wind penetration they seems to level off around 6\$/MWh. Furthermore, for power systems with predominance of hydroelectric generation like many systems in Canada, the integration (balancing) costs are expected to be even lower. Hydroelectric units respond nearly instantaneously to the small variations required by regulation reserves, needed on a time scale of a few seconds. Also, hydroelectric units respond faster and more efficiently than thermal units for the large variations needed for load following reserve, on a time scale of a few minutes. Finally, hydroelectric units run on a zero-cost fuel, unlike fossil-fuel units. Storage, shaping and balancing are key issues for proper integration of wind energy and can be best achieved using hydroelectric power.

The most important conclusion from the world wide cost comparison analysis is that the costs of integrating wind with power systems are only a fraction of typical wholesale electricity prices and that integration costs do not increase linearly with the level of wind penetration. In fact, the

data shows that the marginal increment on integration costs in \$/MWh decrease as the penetration levels increase.

The assessment of wind operational impacts is very important for Canada, given the perspectives and the goals for the wind industry growth across the country. Canada has many important advantages regarding wind power that may bring it to be a leader of wind production and network integration in the short run. Wind generation is now a competitive renewable source of power. This, together with the large wind potential already recognized for Canada, will play a key role in achieving the emission reduction goals for the power sector within the Canadian plan for honouring its Kyoto commitment. This is one of the reasons why it is important that utilities design fair integration charges to wind generation developers that reflect the real costs incurred by the System Operators to integrate their production.

One last conclusion is that Regulatory bodies that manage public consultations and interests are critical in insuring that the rational and the technical data supporting integration cost evaluation are readily available to all stakeholders. This will help insure that fair and reasonable market prices for wind integration are charged by network operators.

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**APPENDIX:
SUMMARY OF SELECTED WIND INTEGRATION
STUDIES IN UNITED STATES**

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A 1. The BPA Wind Integration and Shaping Services

Bonneville Power Administration, the largest generating company in the state of Washington in the United States, has announced two services whereby their hydroelectric system is used to integrate the output of the wind farms located in the region. The two services are described as follows (for detailed information on these services, refer to [38],[36]).

Through this service, BPA integrates in real time the *scheduled* output of the wind plants by using the balancing capabilities of the existing hydro units. Those involved in the commercial transaction of the energy produced by the wind plants will be charged a fee of 4.5 USD/MWh of wind generation. The wind project operator will pay BPA a certain imbalance fee for the difference between the scheduled output and the actual measured output. The wind delivery contracting parties are responsible for acquiring the corresponding wheeling service from the transmission company.

This service has been designed for users that do not want to manage the variability of wind. In this case, BPA will store the energy produced by the wind farms and deliver it back to the users a week later in the form of fixed blocks of power during on-peak and off-peak times. The contractual power delivery output from BPA will be limited to 50 % of the total nameplate capacity of the wind farm. The charge established by BPA to provide this service is 6 USD/MWh. As it is the case of the network integration service, the wind project operator responsible for the imbalance fees and transmission wheeling procurement.

A 2. New York

The New York Independent System Operator (NYISO) and the New York State Energy Research and Development Authority (NYSERDA) commissioned a study [9] to evaluate the impacts of 3,300 MW of wind plants dispersed across the state (10 % of the total state's generating capacity).

The study, released in March, 2005, focused on the analysis of wind-load variability, the simulation of the real-time operations and the evaluation of the impact of the projected wind generation on the reserve requirements. Frequency distribution of hourly and five-minute wind and load variations were obtained. Worst-case scenarios of load and wind variability were examined, especially during times of high-load conditions and lower wind availabilities (during the month of August). After extensive analyses, the study concluded that the 3,300 MW of wind generation could be accommodated “with only minor adjustments to its existing planning, operation, and reliability practices”.

A 3. PacifiCorp

The report corresponding to this study is found in [39]. PacifiCorp is an electric power utility covering six states in North-western United States, with a total generation capacity of 8,300 MW. The company's least-cost-mix of resources includes some 1,400 MW of additional wind capacity. Existing wind generation include the current 83 MW purchased from Wyoming. The company also provides integration services to 200 MW of wind power from Wyoming and along the eastern Oregon/Washington border.

The company's approach was to divide costs associated with wind integration into:

- Incremental reserve Requirements (increased need for operating, load following and regulating reserves to maintain system reliability within required limits). To calculate this requirement, wind generation was treated as negative load. The increase in reserve was then assumed to be proportional to the fractional increase in standard deviation of the loads over a year, with and without the wind generation. This fractional increase was applied to the empirical value currently used by the company for load following reserves. The company decided that wind output behaves like a load and not like the sudden loss of a generating unit.
- Imbalance Costs, which capture “the difference in system operating costs experienced by a system that meets load with an incremental amount of wind resources versus the same system meeting an identical load with an incremental amount of energy equivalent to the wind project, but delivered at constant rate”. The study also assumes 100 % accuracy on wind forecasting.

The study does not examine important intra-hour detail for load following and assumes a perfect wind forecast in the unit-commitment model. The report does not present any results in terms of costs of integration of the planned wind generation.

A 4. California

The report corresponding to this study is found in [10]. The California's Renewables Portfolio Standard (RPS) requires the state's investor-owned utilities to increase the renewable portion of their energy mix with a goal of 20% renewable energy generation by 2017. This report presents the results of Phase I of the RPS Renewable Generation Integration Costs Study. Consequent Phases II and III of the project will cover the analysis of key attributes affecting integration analysis and the finalization of a methodology for integration costs for application to RPS bid selection respectively.

This study was motivated by the requirement that indirect costs be considered in addition to the energy bid price of eligible renewable projects. According to the study, one portion of the indirect costs associated with a renewable generation project corresponds to transmission upgrades and remarketing costs. The other portion corresponds to the integration costs, which are the costs incurred to incorporate the electricity from a generation source into a real-time

electricity supply. These costs are implicitly borne by the system and are not allocated to a specific generator or load and are classified into Capacity Credit, Regulation Cost and Load Following Cost.

In this study, several existing renewable generation projects located across the state of California were considered. These projects comprise different technologies:

- Solar: the aggregate maximum yearly measured output is about 1 MW, which corresponds to 75 % of the installed solar nameplate capacity in the state.
- Geothermal: four plants, totalling about 800 kW of aggregate maximum yearly output (5% of the installed geothermal nameplate capacity in the state).
- Biomass: partial aggregate of a number of plants, with an aggregate maximum yearly output of 1 MW (38 % of the installed biomass nameplate capacity in the state)
- Wind: regional (at locations called Altamont, San Geronio, and Tehachapi) and state-wide aggregates (composed of all the wind specific generation data collected by the state's system operator) are considered. The total maximum yearly aggregate output accounts for 70 % of the total installed biomass nameplate capacity in the state.

Actual minute-to-minute system data (total load, total generation, frequency, etc) and generation output for conventional and renewable generators was retrieved for the year of 2002. Also, hour-to-hour regulation market data and outages were examined.

Capacity Credit Analysis:

The capacity credit of a generator, rather than a cost, is value of the generator's contribution to the reliability of the overall electrical supply system.

The capacity credit associated to a renewable generator is based on the concept of Effective Load Carrying Capability (ELCC), which is the amount of additional system load that can be supplied including the renewable generator and under the same system reliability performance (the same Loss of Load Probability obtained before the inclusion of the renewable resource).

A baseline model run was made with all renewable resources in the generating mix. To calculate a given renewable technology's ELCC, its capacity was removed from the system and the annual reliability was calculated. The model was then rerun for increasing increments of a natural gas benchmark generic unit until the standard system LOLP was achieved. The gas capacity that is required to achieve this level of reliability was the ELCC capacity of the technology, expressed as the gas equivalent.

This analysis was carried out for each technology. A relative capacity credit, equal to the ELCC is then proposed, with the capacity credit of a generic medium gas plant as the 100 % reference.

The results obtained show values of relative capacity credits of 97.8 % for biomass, 73.6 % and 102.3 % for constrained and unconstrained geothermal (constraints are given by the operation of geysers), 56.6 % for solar and values from 22.0 % to 26.0 % for three different wind locations.

Capacity credits were also calculated for increasing renewable penetration levels. In this case, total renewable generation capacities were doubled and the corresponding ELCC's were determined. The results obtained show slight declines of capacity credits for wind and solar generation. The values for biomass and geothermal remained unchanged. These results are, in any case, conservative as the generation technologies, especially wind, are continuously improving. Newer wind turbines can generate power at lower speeds and lower wind densities, outperforming the existing wind generation technologies considered in this study.

Regulation:

Regulation is used to compensate for minute-to-minute differences in the control area's aggregated generation and load. The costs of power regulation associated with each renewable technology were calculated by modeling the variability of minute-to-minute fluctuations of total power output considering all the renewable resources in the generation mix. Each technology was then removed from the mix and the operation was simulated again. Considering that the separate effects of each renewable output are uncorrelated with each other and with the demand, a share of the total fluctuations for each technology was calculated by using the standard deviations of each technology's output, total fluctuations and fluctuations without the presence of the corresponding technology.

Total costs were calculated simulating the California's regulation market. The results show that for the particular penetration levels considered, the impacts on regulation costs are very small. Values obtained are zero for biomass, 0.08 \$/MWh for medium gas, -0.10 \$/MWh for geothermal and 0.04 \$/MWh for wind. For the various wind locations, values vary from zero to -0.46 \$/MWh. It is expected that increasing renewable penetration levels will not greatly affect the values found in this study.

Load Following:

Similarly to the analysis of the impacts on regulation costs, this study concludes that there is no significant impact of existing renewable generators in the load following time scale, even if reasonable amounts of additional renewable resources are added to the system. As much of the regulation requirements are purchased in the balancing market by the Scheduling Coordinator, the impacts of renewable generators are much less than the bias effects created by the scheduling entity.

Future phases of the project will cover the effects of increased renewable penetration and the impacts on contingency reserves.

A 5. Minnesota, Xcel Energy

The report corresponding to this study is found in [40]. This study analyzes the economic impacts of very low penetrations of wind generation in the Northern Xcel Energy system (280 MW in an 8,000 MW peak load utility).

Unlike other deterministic studies where real wind output data was used, a probabilistic Monte-Carlo method is employed to generate synthetic wind series using the theory of Markov chains and the effects of each of these series are assessed on a deterministic manner. The statistics of the evaluation indices are compiled over all the sampling time series.

The specific cost impacts assessed in this study are:

- Cost of wind generation forecast inaccuracy for day-ahead scheduling: Using a commercial Unit-Commitment model, it was found that the additional costs for a forecast inaccuracy can be up to 1.44 USD/MWh for a distribution range of forecast error of 50 %.
- Cost of additional load following reserves: In this particular case, the requirement of load following reserve is not increased due to the presence of wind generation at the levels studied.
- Cost of intra-hour load following “energy component”: This component is referred to as the cost of deploying the available load following reserve to meet the intra-hour slow variations of load changes. After a series of assumptions, the “energy component” of the intra-hour load following cost was determined to be about 0.41 USD/MWh.
- Cost of additional regulation reserves: At the current wind penetration levels of 280 MW on a 8,000 MW peak system, the cost impact of additional regulating reserves to accommodate wind is assumed negligible.

Summing all cost components assessed, the impact of integrating the Xcel Energy’s existing wind capacity is approximately 1.85 USD/MWh of wind generation.

This study was carried out in a vertically-integrated utility, where there are no markets for ancillary services. The impact of increasing wind capacity was not examined and, also, the effect of the inaccuracy of load forecast was not taken into account. However, the study presents the originality of modeling synthetic wind output series with which the different probabilistic simulations can be carried out.

The report corresponding to this study is found in [41]. In this project, payments and charges to a wind farm based on the conditions established by the rules of the electricity market are calculated. Real data from an undisclosed utility are used. This utility has a peak demand of 5,000 MW and has an existing 100 MW wind park. In order to study the penetration of larger capacities of wind generation, real hour-to-hour wind speed data, taken by the utility at five

different locations across a 200-mile radius geographic area are used to simulate wind generation capacity up to 2,000 MW.

This report analyzes the revenues that a wind farm with capacities ranging between 200 MW to 2,000 MW might receive from selling its energy output according to the rules of the electricity market (day-ahead unit commitment, real time hourly dispatch and intra-hour load balancing and regulation). As it is well known through the various studies on the economic impacts of wind penetration, the limited control, the relative unpredictability and intermittency of wind affects primarily the regulation and load following operations in an electric power system. Unlike other reports, this work not only considered the inter-hour effects of wind, but also the intra-hour variations of wind output and demand. Minute-to-minute balancing payments and charges are calculated and a total payment was determined for the wind generator.

Regulation and balancing costs are incurred because conventional generators have to compensate for the unexpected variations of wind production. This may require the repetitive start and shut down of conventional generators, some of which have to be kept on-line at high operation costs.

The study also considered the proposal by Kirby and Hirst in which the total regulation requirement is calculated, according to the uncorrelated fluctuations of wind output and demand. The wind share of the requirement is used to determine total payments to the wind generator.

The main conclusion of this study is that under low penetrations of wind power, small wind farms would receive almost the zero-wind utility marginal price (30 USD/MWh). As the wind penetration levels increase, so do the impacts on regulation and load following. The payment to a 400 MW wind farm would drop to about 23 USD/MWh and to 16 \$/MWh for 1,000 MW of wind generation. There are two main factors for this: first, as the wind penetration increases, conventional generation is pushed down in the supply curve with lower marginal costs; second, the more wind that is added to the system, the more conventional generation has to move up and down to adjust for the lack of control, unpredictability and variability of wind output.

Another result is that the typical accuracy of wind speed forecasts is 35 %, when compared with actual data. This value is close to the wind output capacity factor for this specific study. In addition, the diversity of the location of wind farms affects their total payments. The concentration in fewer sites reduces diversity and therefore the revenues.

This is one of the most relevant reports developed so far in terms of the scope and applicability, foreseeing what would be the effects of larger and larger penetrations of wind power into relatively small utilities.

A 6. Washington State, Bonneville Power Authority

The report corresponding to this study is found in [2]. The Bonneville Power Administration (BPA) is a federal agency headquartered in Portland, OR, USA, that provides about half the electricity used in North-western United States and operates over three-fourths of the region's high-voltage transmission.

This study first analyzes the diversity of wind output for five different wind plants located in different areas, totalling an overall name-plate capacity of 164 MW now in operation. Real-time measurements of wind speed and output were considered for the time frame from January to April 2002. Four of those locations are geographically close to each other (along the Washington-Oregon border), whereas the fifth location corresponds to a wind plant in South-eastern Wyoming.

The results show high correlation of wind output variability (standard deviation) for the closely located plants, with an overall capacity factor (average output over installed capacity) of 32 %. The presence of the remote fifth wind plant lowers substantially the overall correlation of variability of total wind output.

The study also examines the potential impact of 1,000 MW of wind output. The existing wind plants capacity is scaled and the effects are assessed.

The BPA Hydro dispatch is cost-based (not price-based), follows empirical rules and numerous external constraints (recreation, navigation, etc). This makes more difficult the quantification of wind impact costs, in comparison with other studies where wind is integrated into power systems governed by real markets for electricity and ancillary services. Therefore, several assumptions unfavourable to wind were made, which include rough day-ahead wind forecasts, scaling to larger wind farms that ignores the diversity benefits of geographical dispersion; and the use of a high price (\$5/MW-hr) for capacity required in real time that was not scheduled day ahead.

Although the report is not conclusive on an overall integration cost per MWh of wind output, the main conclusion states that the cost to integrate wind with the BPA power system is likely to be well under \$5/MWh of wind output for 1000 MW of wind capacity, under the conservative assumptions initially established. The BPA power system counts on considerable hydroelectric resources that can rapidly respond to changes in load and wind conditions, which renders the economic impact of wind integration small.

The study calls for the development of improved wind forecasting techniques in order to reduce the capacity adjustments between day-ahead estimates and real-time operation.

A 6-1 Generic Study (2)

The report corresponding to this study is found in [4]. In this project, a method is developed that permits wind plants to bid its output into a short-term forward market (specifically, an hour-ahead energy market) or to appear in real time and accept only minute-to-minute and hourly imbalance payments for the unscheduled energy it delivers to the system. Also, the method analyzes the short-term (minute-to-minute) variation in wind output to determine the regulation requirement the wind resource imposes on the electrical system.

The project considered wind data from the Lake Benton II wind facility located in south-western Minnesota (138 turbines, each with a rating of 0.750 MW, with a rated (maximum) capability of the facility equal to 103.5 MW). The control-area data (electricity and ancillary service prices, etc) were obtained from the PJM ISO.

After compiling a vast amount of minute-to-minute information (load levels, electricity and ancillary service prices, etc), the study compared the revenues that the wind farm would receive if its output were scheduled hour-ahead or in real-time. Scheduling wind output ahead of time (e.g., in the hour-ahead energy market) yields greater revenues than having the wind appear entirely as intra-hour imbalance energy. Also, the benefits of improving the accuracy of the wind output forecasts can be substantial.

According to the case analyzed, the regulation charge to wind output would be lower (less than half) than the regulation charge borne by PJM costumers.

The results also conclude how the revenues to the wind facility decrease as the total wind plant capacity increases, if the wind output is scheduled only in real-time. When the wind output is scheduled hour-ahead, revenues do not display an important decline as a function of total wind plant capacity.

This study is the first to introduce wind data from a plant that is not physically connected to the electricity market under analysis.

A 7. Wisconsin, We Energies

The report corresponding to this study is found in [42]. The objective of this project was to study the impacts of integrating wind generation into the We Energies (power utility covering parts of Wisconsin and Michigan) power system for the year 2012. The study is based on proposed wind plants with capacities of 250 MW, 500 MW, 1,000 MW and 2,000 MW with a system peak demand of 6,000 MW and a projected peak for 2012 of 7,045 MW.

The state of Wisconsin has mandated utilities to incorporate renewable generation into their resource portfolio with total renewable capacity equal to 2.2 % of the total utility's generating capacity by 2011. The goal set by We Energies is to achieve 5 % by 2005.

Four types of impact costs were evaluated for the year 2012 scenario:

- Inter-hour variability: additional costs associated with dispatchable resources accommodating the fluctuations of wind generation even if those fluctuations are perfectly forecast. To calculate these costs, a fictitious unit of constant generation producing the same amount of annual energy as the aggregated wind generators was added to the system. The associated costs of inter-hour variability are the differences between the marginal costs of generation given by the unit-commitment model multiplied by hourly wind productions and compared with the constant unit's production. Unit start-up costs were not considered.
- Regulation: cost of tracking minute-by-minute high frequency random small fluctuations of wind generation. As no detailed data was available for the utility under study, statistical results of high-frequency fluctuation of system load and wind generation of other utilities were used to calculate the additional regulation requirements. Only the cost of regulation reserve (and not energy) cost was considered.
- Intra-hour load following: Only the cost of the required spinning reserve was considered. The energy cost resulting from the deployment of this reserve, every 15 minutes through an economic dispatch, was not considered. It is claimed that this energy cost is low compared with the reserve cost.
- Hour-ahead forecast uncertainty: cost of additional operating reserve to account for forecast uncertainty for both, hour-ahead wind and load pre-schedules (day-ahead schedules are not considered).

Since the majority of We Energies' proposed wind generation does not yet exist, projections of wind generation on an hourly resolution at identified sites were made by adjusting wind speed measurements, calculating turbine output based on turbine power curve and finally calculating total wind plant output based on assumed number of turbines, for the various penetration levels considered.

The simulations performed included a base case of wind generation for each of the four scenarios, considering a net load made of the system load minus the varying wind generation and the utility's required spinning reserves (regulation and contingency) and non-spinning (contingency). After the annual simulations were carried out, this process was repeated with wind generation replaced by fixed generation having the same annual production.

Results show that the cost of regulation reserve for wind integration range between 1.12 USD/MWh to 1.02 USD/MWh for the total wind capacities considered. As for load-following spinning reserve, costs vary from 0.09 USD/MWh (for 250 MW of wind plant) to 0.15 \$/MWh (for 2,000 MW of wind plant). Considering this, and the costs of reserve requirements due to

forecast uncertainty (for both load and wind output), total costs for wind integration range between 1.90 USD/MWh for 200 MW of wind plant (penetration level of 4 %) to 2.92 USD/MWh for 2,000 MW of wind plant (penetration level of 29 %). Also, it is shown that the increase of regulation reserve needed to accommodate the wind output with respect to the current regulation levels is minimal. These results are on the same order of magnitude as those calculated in other large-scale wind generation impact studies.