IMPACTS OF WIND ON ELECTRICITY SYSTEMS WITH PARTICULAR REFERENCE TO ALBERTA

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Summary

Wind energy is becoming an established electricity generation technology, alongside the conventional sources, such as coal and gas. There are now 40,000 MW of capacity, worldwide. The fact that wind power generation is variable, and not wholly predictable, means that electricity system operators must provide additional reserves to cater for some additional uncertainty in balancing supply and demand. There is a reasonable consensus on the magnitude of these additional requirements for reserve and the associated costs since both electricity systems and wind have similar characteristics in widely-separated locations, particularly in Europe and America.

The advent of "market mechanisms", where electricity suppliers (or "electricity retailers" to use North American terminology) are required to "balance their own positions" complicates the issue, as the penalties for being "out of balance" can be severe. Prices in balancing markets are rarely cost-reflective and vary with time, and across electricity jurisdictions. It is therefore difficult to quantify typical monetary levels for wind penalties. However, there is a growing awareness, particularly in United States, that the penalties wind incurs are not cost-reflective and a growing trend towards exempting wind from balancing market penalties and providing System Operators with good forecasting tools. This puts System Operators once again in charge of integrated systems and able to deliver the improvements in efficiency that comes with aggregation of supply and demand.

The extra costs due to wind in Alberta will depend on how widely it is spread, as this affects the smoothing of the wind fluctuations. Quoting typical figures, the extra reserve capacity required is of the order 5% of the wind capacity, at modest wind penetrations, say 5% on an energy basis. Prices for reserve are broadly similar across many electricity jurisdictions and so the extra costs of this reserve are also similar, in the range $0.12-0.24/MWh of electricity consumption with 5% wind, rising to $0.4-0.6/MWh with 10% wind.

Prices for reserve in Alberta, however, appear to be higher than those in England and some American utilities and so the extra costs there, if this situation persists, may be at the upper end of these ranges.

Improvements in wind forecasting and increased uptake of demand-side management techniques are likely to reduce the extra costs.

Definitions, notes and Nomenclature

- *<u>Reserve</u>: plant held on part-load, or on "hot standby" so that its output can be increased or decreased, automatically, or at the request of the System Operator (SO). There are various types of reserve, and definitions vary, but important sub-sets follow; costs to the SO decrease from first to last:-*
    - *<u>Regulating reserve (US), or Frequency response plant (UK</u>) – responds automatically to frequency changes, increasing or decreasing output as appropriate*
    - *<u>Spinning reserve (US), or Regulating reserve (UK)</u>, is available to increase or decrease output, on instructions from the System Operator*
    - *<u>Contingency reserve, includes (standing reserve),</u> is the third tier*
- *<u>Operational penalty</u>: the extra cost of providing additional reserve (q.v.) on an electricity network to cope with the uncertainty of wind energy. When expressed in $/MWh the denominator is usually the total electricity generated. It should be noted that some studies assign the extra costs to the wind generation and so quote higher figures. These instances are noted.*
- *Canadian dollars have been used, except where stated*
- *<u>Wind energy penetration</u> levels are expressed on an energy basis wherever possible (wind energy generated/total electricity produced by the utility). Some reports, however, use the convention (wind power capacity/system peak demand) and it is not always possible to make the conversion to an energy basis, if insufficient information is provided.*
- *<u>Geographical diversity</u>: the greater the distance between two sites on which wind plant are installed, the lower the probability that the winds, at any given time, will be the same. s means that the wider the geographic distribution of sites, the lower the levels of wind power fluctuations.*

1. Introduction

The way in which the variability of wind energy impacts on the operation of electricity networks has been the focus of numerous studies over the last 30 years. There is now a considerable body of data on the topic, with a good consensus between most of the authoritative studies. The characteristics of wind are likely to be much the same in Alberta as they are in England, Denmark and Canada. Similarly, electricity networks also have similar characteristics and are managed in much the same way. The issues associated with efficient assimilation of wind are not in conflict with the delivery of least-cost electricity to the consumer. Both demand that the benefits of an integrated electricity system are exploited to the full (1).

When wind is introduced on a utility network measures must be taken to ensure that the additional uncertainties in meeting the supply/demand balance are mitigated by increasing the provision of additional reserve (possibly including existing pumped storage plant) or demand-side management. At low penetration levels the cost of these measures is small. However, as the amount of intermittent production increases, these additional costs will increase. These costs, the “operational penalties” depend on (roughly in decreasing order of importance):-

- The amount of wind
- The “demand prediction error” – the accuracy with which the System Operator can predict the supply/demand balance, since this affects -
- The amount of reserve normally scheduled by the utility, in the absence of wind
- The cost of the reserve
- The plant mix, as high amounts of inflexible [illegible]t (e.g. nuclear) make assimilation of wind more difficult, whilst flexible plant (e.g. hydro) makes it easier

The emerging consensus in [illegible]erica – from a review of several utility and other studies by the National renewable Energy Laboratory (2) - is that the variability of wind adds very little cost.

Two further important conclusions flow from this study:-

- The cost of reserves "is significantly less when the combined variations in load and wind plant output are considered, as opposed to considering the variations in wind plant output alone."
- “At high penetration levels the cost of required reserves is significantly less when the combined variations in load and wind plant output are considered, as opposed to considering the variations in wind plant output alone”.

The costs of the extra reserves are put at 10% or less than the value of wind on current wholesale markets at low wind penetrations (around [illegible] on a capacity basis). A later review of the same studies suggests the costs are around CA$0.67/MWh per unit of total generation with around 10% wind (3). These costs are discussed in more detail later.

Institutional changes, such as the introduction of trading arrangements based on bilateral contracts, do not alter the technical issues influencing efficient operation of the electricity network, and so technical conclusions drawn from earlier studie[illegible]main valid. However, - depending on the precise framework - technologies with variable and unpredictable output may be charged balancing costs which may or may not actually reflect the true costs they represent to the system. The renewables industry in the United States and Great Britain, in particular, have lobbied to eliminate this anomaly.

Many American utilities now recognise that the impacts of wind need to be evaluated in the context of their effect on the operation of an integrated electricity network. It is recognised that some market mechanisms have the potential to load wind with unrealistic penalties and so there are various exemptions from the full rigour of balancing markets. The most common approach is to allow imbalances incurred by wind to the averaged over, say, a month.

2 Technical background

As there is a broad measure of agreement on the technical impacts of variability between a number of utilities, this implies that both electricity systems and wind characteristics behave in a similar manner, worldwide. This section examines each of these assumptions.

2.1 The need for reserves on a network

No utility or System Operator can predict the match between supply and demand exactly. Backup generation, or reserve, (see definitions) is needed to deal with mismatches. In England, for example, the standard deviation of the average demand prediction error is about 1.3%, or 360 MW. Other criteria that determine reserve levels are the need to cover against a possible trip of the largest single unit on the network. In smaller networks (below about 10,000 MW capacity), the latter criteria may be more important.

The amounts of reserve that are needed depend on the time of day and the season; they usually take note of the "3-sigma" error in uncertainty, which broadly speaking, also enables the English SO to cope with loss of the largest unit. (1320 MW).

To illustrate the similarities between systems, key data for the Alberta and English systems are summarised in table 1. It may be noted that the system load factors are identical and that the average requirements for regulation are also very similar. The reserve requirements in Alberta are slightly higher, possibly because the largest unit may be a larger fraction of the average demand. However the comparison indicates that the two systems have very similar characteristics and visual inspection of the daily load profiles also supports this view.

Table 1 Operating data for electricity networks in Alberta and England

Parameter	Alberta	England, 2000/01
Average load, MW	5821	34,000
Peak load, MW	8800	52,000
Average/peak, %	66	66
Reserves (US definitions)		
Regulation, MW	110-225	889
Regulation/avg load, %	1.9-3.8	2.6
Spinning reserve	187-300	1000
Spin/avg load, %	3.2-5.2	2.9

2.2 Wind characteristics

There are two key issues related specifically to the wind itself that must be considered when assessing the impacts of wind into utility networks:-

- Quantifying exactly what is meant by “variability”. As the additional uncertainty that the system operator will encounter in balancing supply and demand needs to be quantified, this means that the uncertainty associated with wind variability must be quantified. However -
- As the wind capacity on a network increases, the increased geographical spread reduces the variability, and this also must be quantified.

Although early studies of the impacts of intermittency were based on simulations, there is now a growing database on information from operational wind plant. The variability is normally quantified by the standard deviation of likely changes in power outputs over various on timescales. For example, the standard deviation of the output from all the wind power in western Denmark, one hour ahead, is a little over 3% of the rated output, and the maximum change in hourly average output – inspecting data over the last three years – has not exceeded about 18% (4). To illustrate this point, with 2000 MW of wind on the network, if it was generating 1000 MW at 12:00 hours, then the output at 13:00 hrs would be 1000 MW, plus or minus 60 MW (standard deviation); it is very unlikely that it would be less than 640 MW, or more than 1360 MW.

When wind power data from western Denmark is compared with data for the UK and Germany, there are strong indications that it fits a consistent pattern, as shown in Table 3. The table also shows the substantial reductions in fluctuations that are achieved due to geographical diversity. The standard deviation at one hour ahead, for example, comes down from 12% for a single wind farm to 3% for the country (west Denmark) as a whole. It should be noted that the "single wind farm" in the UK had an output of 5 MW whereas the corresponding American data is for a 100 MW wind farm and so it might be expected that the variability from the latter might be less - which is indeed the case.

Table 3 Standard deviations (1,2,4 hr) and extremes (1 hr) of wind power fluctuations (% of rated power of wind plant)

Lead time, hr	1	2	4	1h extremes
Nation-wide				
UK (NGC) (5)	3.1		6.0 (at 3.5 hr)	
Danish data (4)	3	5.6	10	18
German data (6)				20
Single wind farm				
UK data (4)	11.8	16.0	20.8	100
German data (6)				100
American data (7)	10			

The smoothing due to geographical diversity is illustrated graphically in Figure 1 (8). This shows the differences in extreme swings tabulated in Table 3, and the frequency of other swings – all substantially less over the whole country.

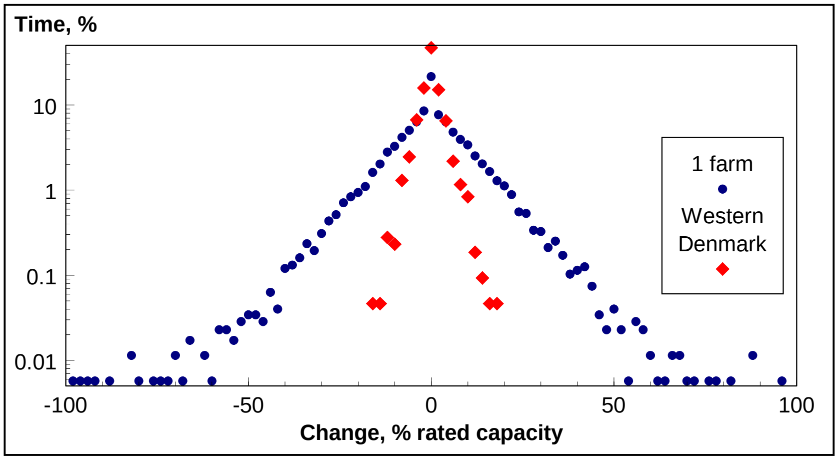

Figure 1: The smoothing effects of geographical dispersion: a single wind farm of 5 MW, and all the wind plant in Western Denmark.

Other relevant data from western Denmark and America includes:-

- The maximum measured change in output from 2400 MW of wind in western Denmark is about 6 MW per minute (9).
- For 52% of the time in western Denmark, wind output and demand rise together, or fall together (author’s analysis of Eltra data). Although this is not necessarily by the same amount, it illustrates the flaw in the argument that wind output should be “levelled”.
- An American study showed that ramping rates over 1 minute fall from 2 to 2.8% of average power to 1.7% when the combined outputs of two windfarms are measured together, rather than separately (10).

2.3 *Operation of electricity networks with wind*

The analysis of Farmer et al (11) laid the foundations for an analytical approach to the question of wind integration. It is widely quoted and respected. The authors simulated the operation of up to 10 000 MW of wind (17% of generation) on the CEGB (English) system, using hourly wind, demand and generation data. They formulated a number of key conclusions, most of which are still valid, and in particular, argued that the “sum of squares” approach to uncertainties in matching supply and demand can be extended to include wind generation[i], as follows:

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[i] In other words, the square of the standard error with wind is equal to the sum of the square of the demand prediction error, plus the square of the wind error

"There was a small positive correlation coefficient of 0.23 between the wind power output variations and the fluctuations in system demand. As a result there is negligible error in compounding the uncertainties in wind output and demand, as if they were statistically independent".

More recently, The National Grid Company, the English system operator observed (12):-

"Sufficient fast response and reserve services will be available for a situation in which the entire 2010 renewables target [10%, energy basis, or about 40 TWh] is met by wind"

This message is reinforced in NGC's 2003/4 Seven-year Statement:-

"Current levels of frequency response are sufficient even if the goal of 10% of electricity …were all met by wind"
"…If more response and reserve services is required, our ancillary service markets should encourage their cost effective provision"

Similar principles to those used by Farmer were used in a recent American paper (13). The paper included two relevant observations:-

- The effects of geographical diversity were exemplified by noting that the additional requirements for extra regulation due to wind came down from around 11% of the rated wind capacity with 10 MW of wind, i.e about 1 MW, to around 6% with 100 MW, i.e. around 6 MW.
- A utility with a peak load of 2300 MW and 100 MW of wind (4.3% by capacity) would require 213 kW of extra regulation. (0.2% of wind capacity)

The author and Holttinen (14) have examined the fluctuations seen by the grid operator in western Denmark, with and without wind, over several months. Both analyses showed that the range of power excursions is very similar. The results of the author's analysis (15) are shown in figure 2.

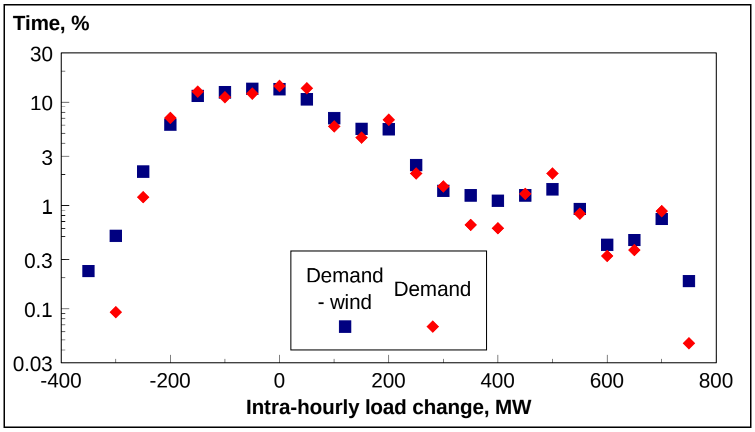

Figure 2 Intra-hourly load changes in western Denmark, with and without 20% wind

3 Results from integration studies

There are two key parameters that are of interest when examining the impacts of wind:-

- The extra back-up capacity that is needed, and
- The cost

3.1 Extra back-up capacity

Looking at likely changes in wind output on various timescales and evaluating the additional uncertainty that this imposes on System Operators enables the needs for extra reserve – usually from conventional thermal sources or storage - to be quantified. The exact procedures were first laid down by Farmer et al (11) and have recently been restated, in the context of an analysis of the Irish system, by Doherty and O'Malley (16). An American analysis uses similar, although not identical, reasoning (17).

Drawing on recent studies, which have used the parameter (wind capacity/peak demand) as a reference, Figure 4 shows that the back-up needs are modest: between 1-3% of wind capacity when wind capacity is 10% of peak demand (about 5% penetration on an energy basis), rising to 2-6% of wind capacity, when the capacity is 30% of peak demand (roughly 15% penetration).

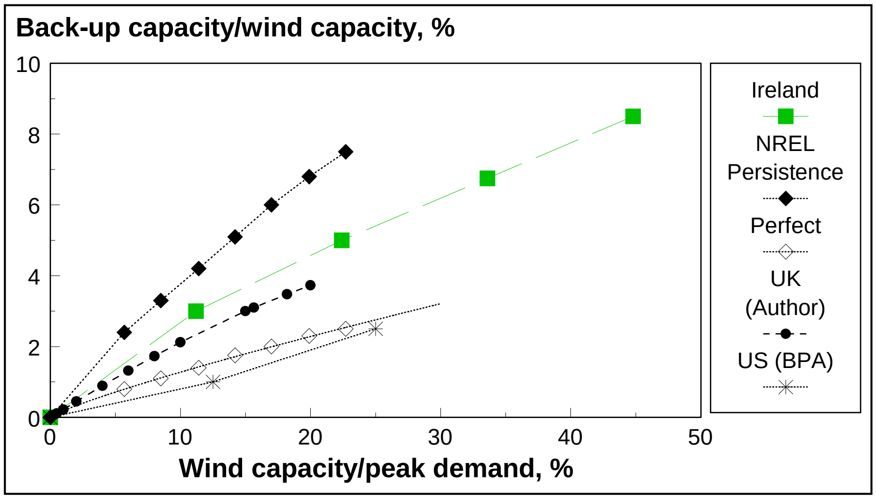

Figure 3 Estimates of extra back-up capacity needs

Data sources used in Figure 3:

"Ireland": Reference 16
"NREL": a study by the National Renewable Energy Laboratory in the US (18). "Persistence" assumes that the wind power at, say, 1 hour ahead, is equal to the

power generated at time zero. "Perfect" assumes that system operators have access to totally reliable wind power forecasts.

“US (BPA)”: a study for the Bonneville Power Authority, a system with a peak demand of 8054 MW (19)

"UK (Author)": Reference 4

3.2 Extra costs associated with wind variability

The extra costs associated with intermittency have two components: the capital cost of the plant and the additional running cost that is incurred when this plant provides operational reserve. As such plant operates at part load, it runs at reduced efficiency and hence incurs higher costs.

Few utilities derive their reserve costs in this way, relying, instead, on tenders. As the specifications for these varies, *data on reserve prices need to be compared with care*, but regulation in Alberta *may* be more expensive than in the UK (US$18/MW-h (20) in Alberta, compared with about half that in England (21)). Spinning reserve prices in Alberta are also more expensive (US$14.5/MW-h, compared with US$8-10/MW-h in the UK). In New York State, however, the price in 2001 was less than the UK figure, at $2.6/MW-h. However, prices vary with time.

Despite these differences, estimates of the extra costs due to wind variability show a reasonable measure of agreement.

One estimate of the cost of extra reserves that would be needed for wind comes from the System Operator in England and Wales, NGC (22); with 10% wind, they equate to around CA0.57/MWh. Beyond this, the extra costs rise to about CA1.2/MWh with 20% wind (23). It may be noted that a later analysis for England (labelled Ilex, ref 24) came up with lower values, probably due to the fact that reserve prices had fallen. There is a reasonable degree of consistency between results from similar studies elsewhere, as illustrated in figure 4 (25).

It may be noted that the data from Great River Energy with 2.4% wind energy penetration is significantly higher than most of the other estimates. The study suggested that the cost of extra balancing was about US$3.19/MWh of wind, whereas the other studies yielded values around US$2/MWh of wind. GRE suggested that this was due to its decision, for the purposes of the study, to provide ancillary services from its own generating resources. It also lacks resources that can follow wind economically, like marginal coal, hydro or combined cycle gas.

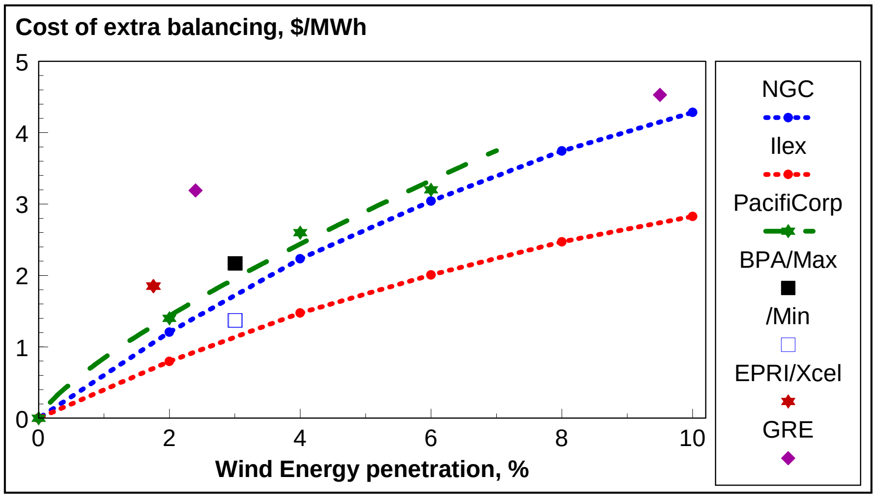

Figure 4 Costs of extra balancing (US$ per unit of wind energy generated) required for wind, from six studies.

Other sources of data for Figure 4, all by or for US utilities, are:-

Identity on graph	*Utility name*	*Peak demand, MW*	*Reference*
PacifiCorp	PacifiCorp	8550	(26)
BPA	Bonneville Power Authority	8054	(19)
EPRI/Excel	Xcel Energy, formerly Northern States Power Co	8000	(27)
GRE	Great River Energy	2361	(28)

3.3 Implications for Alberta

Although there is a good measure of agreement on the impacts of wind energy across a number of utilities, application of the "universal" results to Alberta needs to take into account a number of important factors, especially: -

- The degree of geographical diversity. Results from western Denmark, Germany and modelling in the UK all suggest that the standard deviation of the power fluctuations over one hour, for distributed wind, is about 3-4% of the rated capacity of the wind plant. The maximum power excursion within an hour is about 20% of the rated capacity.
- The wind capacity in Alberta, may continue to be concentrated in an area about one-third that of western Denmark. Current projects under development cover an area of around 65 km by 250 km. (West Denmark is about 160 km by 320 km). However, inspection of data from windfarms in the United States suggests that fluctuations decrease significantly with increasing size of farm (the standard deviation of hourly values from a 100 MW farm was 10%; from a 200 MW farm, 4.4% - (7))

- If 1200 MW of wind is installed in Alberta by 2007 and it is assumed that the standard deviation of 1 hour wind excursions is 7%[ii] of rated wind capacity, that equates to 84 MW. Using a “sum of squares” approach to add demand and wind prediction errors, in line with accepted practice, and then assuming that reserves are needed to cover the revised “3-sigma” case, suggests another 50 MW or so of spinning reserve may be needed (4% of the wind capacity). This is in line with the more pessimistic estimates from other studies, such as those shown in figure 3. Similarly modest amounts of regulating reserve may also be needed.

5 Recent developments in the United States

Despite the differences in the way that electricity systems are operated, and in the treatment of wind energy, many American utilities now recognise that the impacts of wind need to be evaluated in the context of their effect on the operation of an integrated electricity network. It is also recognised, however, that some market mechanisms have the potential to load wind with unrealistic penalties and so there are various exemptions from the full rigour of balancing markets. The most common approach is to allow imbalances incurred by wind to the averaged over, say, a month.

In recognition of these complications, the Federal Energy Regulatory Commission (FERC) has attempted to introduce a Standard Market Design (SMD) for the entire US power industry. It was halted in 2003 when strong utility opposition killed the FERC's proposal. Consequently, “A consistent policy across the US for how wind generation is integrated into utility systems, and how balancing markets treat wind resources, does not exist” (29). Policies for integration of wind, however, are being introduced, though in piecemeal fashion at regional levels.

The SMD would have removed the primary transmission obstacle for wind power by adopting a ruling it made in early 2002 when it approved a California Independent System Operator (CaISO) proposal to remove "imbalance penalties" from intermittent resources, such as wind generators, who fail to deliver power as scheduled. The ruling also proposed to schedule wind resources on the transmission system using a wind energy forecasting model and to average imbalances over a month.

Examples of the way wind is now treated illustrate the broad consensus that the impacts are modest:-

- The Electric Reliability Council of Texas (ERCOT), which oversees 85% of transmission in the state, simply excludes the existing 1305 MW of wind generators from its current balancing market. The biggest problem with integrating wind into its network is transmission bottlenecks, not wind's impact on reserve requirements.

[ii] In the absence of relevant data, half-way between the values for a single wind farm (10%), and distributed wind in west Denmark (4%)

- In the Pacific Northwest, BPA has removed generation imbalance penalties that amounted to as much as $100/MWh for wind (30) and now charges the same fees to all generators, regardless of fuel source. If a wind facility, or any other generator, delivers less than what it scheduled (within 2 MW or 10%), then it will pay 110% of the cost of market power to make up the difference. Conversely, if it delivers more power, it will receive 90% of market price for the extra electricity. Because BPA allows generators to set their schedules one day ahead, however, and to true up that schedule 20 minutes before the actual hour, it has a system that is near “real time." As all Northwest wind projects now use wind forecasting, scheduling accuracy is increasing (31). While that adds the cost of a forecasting service and the cost of an automated scheduling system to the final cost of wind generation, it saves more on imbalance charges and cuts the amount of reserves necessary.

Improvements in forecast accuracy yielded savings as shown in table 2.

Table 2. Cost savings resulting from better forecasting (27)

Forecast error, %	50	40	30	20	10
Saving, US$/MWh of wind	Base	0.205	0.441	0.720	1.045

6 Impacts of forecasting

The discussion in the previous paragraph highlights the importance that is now attached to better techniques for wind forecasting. This is the focus of a considerable amount of research activity, worldwide. Although there are differences in the way that electricity jurisdictions operate, there is a reasonable consensus on the savings that can be realised through good forecasting. These savings accrue since the uncertainties that System Operators face when handling wind energy are significantly reduced and this enables them to reduce the amount of extra reserve plant that is scheduled.

Figure 3 suggests that the amount of reserve capacity can be reduced by a factor of over three, should "perfect forecasting" be realised. In practice, a halving of intermittency costs may be realistic. Although the monetary savings depend on the costs of reserve, they are of the order US$1-2/MWh of wind at low wind energy penetrations (2-4%), rising to around US$2.5-3.5/MWh with 10% wind energy.

The impacts of forecasting also depend on the precise market structure. The closer to real time that balancing markets operate, the more likely that wind generators will supply the system with what it has been told to expect. Conversely, in electricity jurisdictions where schedules are effectively frozen several hours ahead stand to benefit more from good forecasting.

6.1 A note on Denmark

The difficulties experienced operating the electricity network in western Denmark are often cited as illustrating the need for better forecasting. However, it should be noted that although the electricity system in western Denmark includes many elements of a market-based system, it does not appear to include all components of a dynamic market that operates near to real-time, as in England and Wales. "Gate closure" is effectively between 12 and 36 hours ahead, since binding forecasts for generation have to be made by noon for the whole of the following day. Any imbalances between the forecast and actual generation must be made good from the "upward regulation" and "downward regulation" markets. As forecasts of wind production between 12 and 36 hours ahead can be subject to significant errors (38% in the year 2000 (32)), substantial purchases and sales in these markets tend to take place. This means that there are opportunities for realising substantial savings through better forecasting.

7. Conclusions

A review of world-wide experience of the impacts of wind variability enables a number of key conclusions to be drawn: -

- Most utility studies have concluded that up to around 10% of wind energy can be absorbed without major technical changes and modest extra operational costs.
- Useful information can be derived from western Denmark, where the network has a similar capacity. The data suggests, for example, that the distribution of power fluctuations, net of wind, are very similar to those due to consumer demands alone. This suggests that the extra demands on load-following plant may not be too onerous.
- The amounts of extra reserve capacity required are in the range 1-3% of the wind capacity when the wind accounts for 10% of the peak demand, rising to 2-7% of the wind capacity when the wind accounts for 20% of peak demand.
- The costs associated with the provision of extra reserve are around CA0.12-0.24/MWh of generation with 5% wind, rising CA0.4-0.6/MWh with 10% wind.
- Market mechanisms that require individual suppliers to "balance their own positions" can introduce cost penalties for wind energy that are not cost reflective. It is difficult to quantify typical monetary levels, as the relevant prices in the market are rarely cost-reflective and vary with time, and across electricity jurisdictions. However, there is a growing trend, particularly in United States, towards exempting wind from balancing market penalties, often by averaging imbalances over a month, and concentrating on providing System Operators with good forecasting tools – for which the wind plant operators pay a levy. The magnitude of the levy roughly corresponds to the costs of the extra balancing that is required -- from the standpoint of the system as a whole.

- Improvements in wind forecasting methods may enable the estimates of extra balancing costs to be reduced, and increased take-up of demand-side management may also reduce these costs.
- Although wind in Alberta may continue to be concentrated in a relatively small area, the standard methods of estimating the need for extra reserves suggest that these needs will still be modest.
- Recent (spring 2004) prices for reserve in Alberta appear high, in comparison with England and some American utilities. This may mean that the extra costs for wind are at the high end of the estimates of Figure 4. 1200 MW of wind corresponds to around 6% of consumption, and the data in Figure 4 suggests that the associated costs for extra balancing may be in the region of CA$0.3/MWh of electricity generated.

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