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The Potential for Wind Energy Meeting Electricity Needs on Vancouver Island

Ryan Prescott, G. Cornelis van Kooten and Hui Zhu

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REPA Research Group
Department of Economics
University of Victoria PO Box 1700 STN CSC Victoria, BC V8W 2Y2 CANADA
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The Potential for Wind Energy Meeting Electricity Needs on Vancouver Island

by

Ryan Prescott

G. Cornelis van Kooten

and

Hui Zhu[1]

Department of Economics
University of Victoria
Victoria, BC V6W 2Y2

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ABSTRACT

In this paper, an in-depth analysis of power supply and demand on Vancouver Island is used to provide information about the optimal allocation of power across 'generating' sources and to investigate the economics of wind generation and penetrability into the Island grid. The methodology developed can be extended to a region much larger than Vancouver Island. Results from the model indicate that Vancouver Island could experience blackouts in the near future unless greater name-plate capacity is developed. While wind-generated energy has the ability to contribute to the Island's power needs, the problem with wind power is its intermittency. The results indicate that wind power may not be able to prevent shortfalls, regardless of the overall name-plate capacity of the wind turbines. Further, costs of reducing CO_2 emissions using wind power are unacceptably large, perhaps more than \$100 per t CO_2, although this might be attributable to the mix of power sources making up the Island's grid.

Keywords: Economics of wind power; grid system modeling; operations research

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1 INTRODUCTION

Under a business-as-usual scenario, global energy demand is forecast by the International Energy Agency (2004a) to increase by 1.9% annually between 2000 and 2030, with that of developing countries expected to rise from 40 to 55 percent of the total. Global emissions of carbon dioxide-equivalent (CO_2) are projected to rise by 2.1% annually over the same period because developing countries rely more on coal than rich countries. While the share of renewable forms of energy is anticipated to increase slightly (Figure 1), more vigorous public policy than Kyoto is needed to steer the world onto a sustainable energy path that relies on renewable resources to a much greater extent.

In this study, we explore the contribution that wind energy might play in a future energy scenario, a role that will differ from one region to another. Wind-generated power is frequently considered to be the 'best' renewable option because its costs are lower than those of other sources of renewable energy. Extant global wind power capacity is roughly 40 gigawatts (GW), but it is increasing at a rate of over 8 GW per year at a cost of some $9 billion per year, with the United States (2.4 GW added in 2005), Germany (1.8 GW) and Spain (1.6 GW) accounting for nearly one-third of the increase (International Energy Agency 2006). Many countries are in the process of developing large-scale wind farms; Canada, for example, is hoping to increase installed capacity from 683 megawatts (MW) in 2005 to 40 GW by 2040 and 50 GW by 2050 (National Round Table on the Environment and the Economy 2006). Even so, wind contributes an insignificant amount to global energy consumption, about one-half of one percent (Figure 1). While wind turbine technology continues to develop rapidly, the full costs of integrating wind power into electricity grids are only now becoming known.

The purpose of this study is to contribute to the growing literature on wind energy by examining its potential to contribute to energy needs on Vancouver Island, British Columbia. We choose Vancouver Island (VI) because there has been much debate about how future power demand will be met. A combined-cycle gas turbine (CCGT) thermal power plant had been proposed by the system operator, BC Hydro, but was subsequently cancelled as a result of environmental opposition. At the same time, BC Hydro identified several promising locations where wind farms could be located on VI and elsewhere in the Province (without imposing unduly on scenic amenities). Since wind power has good potential to contribute to future energy needs on VI, one objective of the research is to determine the potential 'nameplate' capacity of a wind farm that might obviate the need for the CCGT plant in the short and medium term (up to two decades). Further, we are interested in determining the potential environmental benefits of wind-generated power in terms of reduced CO_2 emissions and their cost.

The paper is organized as follows. An overview of wind power is provided in the next section, while the VI grid is described in section 3. In section 4, unlike previous studies that employ simulation models available only to the system operator, we develop a mathematical programming model of the Island's electricity grid to investigate the penetrability of wind energy. Data sources are discussed in section 5. Results are provided in section 6, followed by our conclusions and discussion in section 7.

2 PRODUCING ELECTRICITY FROM WIND

A primary motivation for the adoption of wind-generated power is its potential to mitigate CO_2 emissions by displacing emissions from thermally-generated power plants. There is an implicit expectation, most prevalent in policy thinking, that wind displaces CO_2 emissions from thermal generation in a linear fashion. Hence, for example, if wind replaces one kilowatt hour (KWh) of energy from coal, CO_2 emissions would be reduced by the full amount of the emissions that would otherwise have been emitted by burning coal. Evidence suggests that this assumption may be troubling.

Whimsicality and the Curse of Intermittency

Electricity is generally produced by first converting heat into mechanical energy and then into electricity; hydraulics and wind are two exceptions because mechanical energy is converted directly into electricity. Energy from hydraulics usually involves the construction of a dam, thereby enabling energy to be stored until it is needed. In the case of wind, however, storage is problematic and wind-generated energy must usually be used whenever the wind engages the turbine; as a result, wind power is considered non-dispatchable (it must be used when generated). Further, unlike hydropower, wind energy is intermittent or whimsical – available one moment and not the next.

Storing electrical energy is a particularly important factor in determining the physical and economic viability of renewable power generating facilities based on photovoltaic (PV) cells, micro- (run-of-stream) hydro, and wind turbines. Storage is needed because there is a difference between when power is generated and when it is needed. Upon re-analyzing Turner's (1999) data on the size of solar 'farm' required to generate all electricity required in the United States, Love et al. (2003) find that a solar 'farm' would need to occupy an area equivalent to about half the area of the State of Nevada if storage is taken into account. Given the high costs of PV energy (silicon panels are needed), wind farms are considered a better alternative, but the area required to service total U.S. electrical demand with wind turbines is estimated to range from 900,000 to well over 1 million square kilometers, mainly because of storage needs.

A storage system imposes an energy penalty in both the input and output conversion processes, with a typical battery system having a roundtrip efficiency of about 80% and a fuel cell system having an efficiency of 35-40%. As a substantial fraction of the energy is wasted in the storage system, the capacity of the wind power plant would need to be increased to overcome these losses. (To date, wind farms do not come with storage systems, and such a development is still some distance in the future.) In the absence of storage, the uncertainty of available wind power requires that a certain amount of backup generation be in place to provide electricity when wind speed is low. The operation and maintenance costs of this 'spinning reserve' can dramatically reduce the economic and environmental benefits of introducing wind energy into an electrical grid. Not surprisingly, study after study of wind systems has reached the same conclusion: Wind power can provide environmental and economic benefits when its proportion of demand is small, but financial costs rise rapidly and environmental benefits fall dramatically as its proportion of demand increases (Nordel's Grid Group 2000; Jensen 2002; Söder 2002; Sharman 2003; Liik, Oidram and Keel 2003; Hirst and Hild 2004a, 2004b; ESB National Grid 2004; Lund 2005).

Even if wind turbines are located in the 'best' areas for capturing wind energy, the penetrability of wind into electricity grids is low. Weisser and Garcia (2005) found that the *instantaneous penetration* – the ratio of wind-power output to load (demand) at any given instance – of wind power in any grid has not yet exceeded 40% for any length of time. Therefore, the ratio of wind-power output to annual demand, or the *energy penetration*, would be very much lower than 40%, although this could be the result of too little installed capacity. A better measure of wind penetrability might be the ratio of actual wind power made available throughout the year to the capacity of the wind plant – the *capacity utilization factor*. Given that wind plants would initially be sited in the most advantageous and least expensive spots, one would expect the capacity utilization factor to be quite high. A summary of 2005 capacity factors for 25 countries that have developed significant wind plants is provided in Table 1. These indicate that the best capacity utilization amounts to only some 35%, while the average is only 21%; for countries that have significant wind capacity (exceeding 2 GW), capacity utilization is less than 25%. Even though wind farms might be optimally located, they tend to deliver power well below their nameplate capacity because wind is intermittent.

Wind power is often generated when it is not needed and unavailable when need is greatest. In the absence of storage devices, benefits of wind generation improve in direct proportion to the ability of the system operator to dispose of 'excess' non-dispatchable power. To illustrate this, we briefly examine Denmark, Ireland and Estonia.

Denmark's Wind Initiative

Denmark has installed some 3.1 GW of nameplate wind capacity, with wind accounting for some 18-21% of consumption in a given year, which we refer to as the *average penetration*. However, the true average penetration into the large NORDEL electricity grid, which includes Denmark, Norway, Sweden and other countries, is only 1-2% (Pitt et al. 2005). While electricity demand is forecast to rise from 35.3 terawatt hours (TWh) in 2001 to 41.1 TWh in 2020 (0.8% per annum), installed wind capacity is expected to increase to 5.7 GW over the same period (3.1% annually) (IEA 2006). This is a significant commitment to wind power. The Danes have also increased their reliance on combined heat and power (CHP) for electricity – energy used in factories to produce heat generates (non-dispatchable) power at the same time.

Upon closer examination, these well meaning initiatives have not resulted in savings equivalent to the power displaced, but they have created real problems for the system operator, Eltra. Both wind and CHP energy are both treated as ‘bound’ or ‘priority’ production meaning that Eltra has no control over when it is produced but is bound to absorb and distribute it. CHP is driven by thermal demand so that, when it is cold, thermal plants are at full output. If it is windy at the same time, wind output comes on top. For example, at 2:00 AM on a weekend when electricity demand is low, both CHP (for heating) and wind output could be very high, so the grid operator has a lot of non-dispatchable electricity to dispose of into other markets and/or route along transmission lines (perhaps in circles) to maximize transmission (power) losses.

CHP and wind capacities are quite high in Denmark and they dominate the Danish system. Several large coal-fired plants are also on the grid, but they are frequently used to satisfy follow-up demand and not base load (for which they are designed). Thus, coal plants may often be idling as spinning reserve (burning coal but not dispatching electricity into the grid). Yet, power from large coal-fired power stations is needed to balance supply and demand, and ensure grid stability (Lund 2005). Given the limited available capacity and flexibility of the dispatchable thermal plants, Eltra finds it challenging to balance supply and demand and often relies on its Nordic neighbors to balance its power needs, but at a cost.

Norway and Sweden rely on hydropower for about 85% and 33% of their respective power needs, absorbing wind-generated power from Denmark when available wind power exceeds Danish needs and selling hydropower to Denmark when supply cannot balance demand (when energy from wind is inadequate). The ability to sell electricity to Norway and Sweden during times of excess supply (usually meaning that too much wind energy is generated) and to purchase hydropower when there is excess demand is a bonus to Denmark's 'green' efforts. But it comes at a cost: Denmark tends to sell electricity to its Nordic neighbors at low prices and purchase it at much higher prices. Further, Sweden will sometimes sell nuclear power to the Danes despite their avowal not to use nuclear energy.

Despite this ability to 'store' wind-generated energy with its neighbors, the Danes have to maintain spinning reserves in coal-fired power plants to balance the system and ensure grid stability. Using an input-output simulation model, Lund (2005) finds that the future for large-scale integration of wind power into the Danish system is bleak: "The ability to utilize wind to reduce domestic CO_2 emissions is low. If Denmark were to increase the percent of wind power to 50% as planned, the problems [for maintaining supply-demand balance and system stability] would become severe".

Luck of the Irish

Unlike Denmark, Ireland's electricity grid currently has no ties to other grids that would enable it to 'dump' (store) electricity if there is too much wind, and purchase it when there is a shortfall. To meet EU targets, Ireland has agreed to generate 13.2% of its electricity from renewables by 2010. The major renewable under consideration is wind energy.

An ESB National Grid study used Monte Carlo simulation to determine the effects of introducing wind-power into the Irish grid (ESB 2004). It investigated a system with peak hourly demand of 5000 MW and annual demand of 29 TWh (representing the period to 2010), and another with 6500 MW peak demand and annual demand of 38.5 TWh (2010 to 2020). The latter adds more efficient CCGT plants (which provide base-load power) and open-cycle gas turbine (OCGT) plants (for peak load power) that release less CO_2 while somewhat reducing reliance on coal-fired generating capacity. A *wind penetration* (ratio of wind generating capacity to total capacity) of 15% results in the displacement of only some 5% in other generating capacity, while 25% penetration results in less than 8% displacement.

For the Irish grid, there is an estimated saving in CO_2 emissions of 0.470 tCO_2 per MWh for the 5000 MW peak-load system when the wind plant has a capacity of 1500 MW, but this falls to 0.313 tCO_2 per MWh in the 6500 MW scenario. The CO_2 saving is slightly lower for the (future) 6500 MW peak-load scenario because gas rather than coal is displaced by the wind. To meet its EU obligations, ESB (2004) considered only the future 6500 MW system. Information on added system costs, CO_2-emission reductions and costs per tCO_2 are provided in Table 2. If 11.7% of total energy demand is to be satisfied by wind power (still short of the 13.2% required by the EU), a 1500 MW wind plant would need to be constructed, resulting in CO_2 emission reductions of 1.42 Mt per year, but at a cost of €138/t CO_2.

Estonia and EU Accession

A similar result to that of Ireland was found for Estonia. As part of its accession agreement with the EU, Estonia is required to install renewable energy capacity for electricity generation that will account for 5.1% of energy use. While biomass burning and re-establishment of abandoned hydropower are two possibilities, wind seems to be favored. The Estonian grid relies on oil shale for nearly all of its power generation and it is only weakly linked to an electrical grid that serves Latvia and Russia. The oil shale power plants are unable to follow rapid fluctuations in wind power availability, so that a gas plant or an undersea cable link to Finland will need to be built, but these options are expensive.

Liik, Oidram and Keel (2003) use a constrained, mathematical programming model of the Estonian grid to investigate the costs of introducing wind. Upon minimizing fuel costs subject to various technical constraints, they find that fluctuations in wind power lead to costs that are 8-10% higher than they would be in the absence of such fluctuations, while savings of some 30% had been expected. Indeed, because of slow response by oil shale plants, in some scenarios the CO_2-emission reduction benefits from wind energy were entirely offset by the negative environmental costs of fuel expended on maintaining spinning reserves. Consequently, the costs of reducing CO_2 emissions are exorbitant.

Harnessing the Wind: Additional Considerations

According to Betz' law, wind turbines have a maximum efficiency of 59%.[2] This implies that, even under ideal circumstances, a wind farm can convert less than 60% of the available wind energy into mechanical energy. The conversion factor falls as one turbine interferes with another. Upon modeling a proposed 9 GW, 9000 km^2 wind farm off the Dutch coast, Rooijmans (2004) found that turbines located in the interior of the wind farm experienced wake-effect losses that reduced average electricity production by up to 50%.

More people are also starting to recognize that the opportunity cost of land can play an important role in determining the true cost of electricity from wind energy. Still, it is rare to come across discussions of the land required for utility-scale wind farms and the associated costs of those lands. Conventional thermal power plants that utilize nuclear, coal or natural gas require much less land to generate the same amount of electricity. Land area required to produce electricity is much greater for wind farms and solar photovoltaics than thermal power plants (Love et al. 2003). To generate 1000 MWh (=1 GWh) of electricity, which can provide

[2] German Physicist Albert Betz formulated this 'law' in 1919; see http://www.windpower.org/en/tour/wres/betz.htm as viewed on 29 June 2006.

power for 1 million homes or a mid-size city in the United States, the land requirement for a thermal (coal or nuclear) power plant is around 50-100 ha compared to 30,000-100,000 ha to generate this electricity from a wind farm and 6250-10,000 ha using solar PV. According to the United States Department of Agriculture, farm real estate was valued at an average of $1,270 per acre as of 1 January 2003 (although this included buildings as well as land). Thus, in order to supply electricity for one million homes, the cost of land for a thermal power plant will be $63,500-$127,000 on average compared to $38.1-$127.0 million for a wind plant.[3] Therefore, although wind power plants are cost competitive based on daily production and maintenance, the cost of land could negatively affect the profitability of wind farms.

There are negative spillovers related to wind power that have not been quantified to date. The most obvious of these is the visual appearance of wind farms: many people have an aversion to a landscape dominated by wind turbines. Wind turbines disturb wildlife and cause harm to birds. Further, given that vast amounts of concrete are required to build turbines, a full cost accounting would need to take into account the CO_2 emissions that result from cement making and the construction of the wind towers.

3 THE VANCOUVER ISLAND POWER GRID

The Vancouver Island electricity grid has more in common with Denmark than with Ireland or Estonia because it is connected to the larger British Columbia grid. The BC system operator has a maximum sustained generating capacity of 10,800 MW, of which 94% is hydro and the remainder thermal, with a large 912.5 MW gas facility near Vancouver (Burrard

[3] Of course, land under the turbines can be used for other purposes, such as livestock grazing or even crop production. In the case of crop production, the costs of avoiding turbines during machinery operations would need to be taken into account as would the actual loss of area occupied by a turbine. Wind turbines may also disturb livestock.

Generating Station) capable of supplying about 7230 GWh per annum, and smaller facilities at Prince Rupert (90 MW); additional capacity is available from independent power producers, including forest companies that have an installed biomass capacity of 600 MW (BC Hydro 2002). Much of the biomass capacity relies on timber residue and is produced in co-generating plants. Sixty-five percent of BC Hydro's power generation is based on water flows in the Peace and Columbia River basins. Given this reliance on hydropower, BC appears to be ideal for wind power generation because it relies on hydropower to supply base- and peak-load. Thus, the Denmark-Norway analogy applies to VI and the rest of BC.

VI is connected to the rest of BC by high-voltage power lines running under Strait of Georgia, and these account for some 65% of VI's power (see below). Remaining electricity is provided by a natural gas power plant in Campbell River (20% of needs), a number of hydro-electric generators that account for 33% of installed capacity and 18% of demand, and a diesel backup unit at Keogh (see Table 3). The Campbell River/Elk Falls facility is operated by an independent power producer and is capable of using diesel fuel as well as natural gas. The Keogh diesel facility had two turbines with a capacity of 90 MW, but had operated on one turbine with BC Hydro having decided to close the facility and sell the turbines (Steve Miller & Associates 2003). The undersea cables are the primary source of electrical power to the Island.

Controversy Regarding the Undersea Cables and Growth in Energy Demand

Three sets of undersea cables bring power from the mainland. The largest of these is a pair of 500-KV, high-voltage alternating-current (HVAC) cables (referred to as Cheekye-

Dunsmuir) laid down in the early 1980s.[4] These are each capable of transmitting large amounts of power and together are rated at 1300 MW of capacity, although they are able to operate at 1450 MW with a further ability to operate up to the 1800 MW capacity for a maximum of two hours. However, at rates above 1300 MW, the contingency factor (that one of the cables goes out of service) is exceeded. That is, at this level of output, the loss of one cable cannot be covered by other sources. If output exceeds 1800 MW, there is a real danger that one of the lines will be damaged. Operating for too long a period above 1450 MW increases the chances that an overload will result in damage to one of the cables.

The remaining undersea cables consist of a HVAC 138-KV system that supplies power to Saltspring and Galiano Islands (but can supply VI if needed) and a HVDC (direct-current) system that was originally designed for a capacity of 800 MW.[5] The small HVAC system is considered unreliable, but can deliver up to 240 MW of power. BC Hydro determined that the HVDC system is aging, cables and converters are in constant need of repair, there is seismic risk to cables and one substation,[6] and the HVDC system is generally unreliable and expensive to operate; engineering studies indicate that it should be decommissioned (Gillespie and Mumick 2003). Yet, in winter 2001 when the Cheekye-Dunsmuir system failed, the HVDC system carried the load for most of VI. Some argue that the HVDC cable has another 25 years of use and can be rated for a maximum capacity of 600 MW, although its capacity is currently rated at 240 MW (Steve Miller & Associates 2003).

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[4] Underground and submarine transmission lines have a lifetime of less than 40 years according to BC Hydro (2000, p.4).

[5] HVDC is the preferred technology for transmitting electricity over long distances as transmission losses are significantly lower than with HVAC cables. AC transmission lines can lose up to 20% of their energy over long distances. DC also has no fluctuating electromagnetic field, which may be important in sensitive marine environments.

[6] Substation facilities have a lifetime of only 30 years (BC Hydro 2000, p.4).

BC Hydro planned to de-rate to standby use the HVDC line upon construction of a gas plant at Duke Point near Nanaimo (Table 3). Background preparation for the Duke Point CCGT facility had been completed and turbines purchased when BC Hydro cancelled the project on 17 June 2005, even though more than $125 million had been sunk in the project (Duffy 2005). BC Hydro subsequently re-assessed its ability to supply power via the undersea cables. With some upgrading work including construction of overhead transmission lines in Delta (on the mainland) and Galiano, Parker and Saltspring Islands, which are opposed by residents in these areas, the system operator feels it can alleviate potential supply shortfalls in the future. Even so, with expected growth in demand, the current on-Island generating facilities and undersea cables will be strained.

Consider the data in Table 4. If planning capability is used as the basis for determining supply, there is sufficient flexibility in system capacity to prevent shortfalls at current (2005) levels of demand. If demand increases at BC Hydro's projected rate of 1.8% per annum, shortfalls at peak hours of nearly 100 MW can be expected by 2010. If operational capability is used to guide supply, there will be a cushion of some 123 MW. However, the reliability factor will be undermined at that point, although the system will still retain significant output capacity. Nonetheless, unless replaced, the HVDC cable is vital to maintaining adequate capacity to meet energy needs over the next several years.

In the absence of a new gas plant, there exists two means to increase generating capacity. The first is to contract with the large pulp mills to reduce power use during peak load (when the system is stressed to the limit) and/or encourage them to develop co-generation facilities using wood waste (bark, shavings and sawdust) and black liquor (a byproduct of kraft pulp mills) to generate power, some of which might be sold into the grid

(Stennes and McBeath 2005). The second is to encourage investments in wind turbines. Several locations for wind farms have been identified on the Island and excess power can be disposed of via the link to the rest of BC. We consider only the case of wind power.

Wind Power Generation on Vancouver Island

Sea Breeze Power Corporation proposed and received environmental assessment approval for a 66-turbine, 99 MW nameplate capacity wind farm at Knob Hill, near Holberg on the northern tip of Vancouver Island. This is just one of eight sites that BC Hydro has identified as having the potential to support wind plants.

Given this wind potential, we examine the costs and benefits of wind plants in terms of their contribution to VI's power grid. In particular, any excess wind energy generated can be delivered to the mainland via one of the undersea cables, thereby conserving water that might otherwise have been released to generate electricity, while any shortfall can be met by deliveries from the mainland. Hence, one would expect the benefits from deploying wind power to be large, especially since, unlike the Danish case, the amount of thermal power is small and can easily be ramped up or down since it is gas and not coal fired. A mathematical programming model is used to investigate this further.

4 A MODEL OF AN ELECTRICITY GRID: INTEGRATING WIND POWER

We develop a mathematical programming model to determine the hourly allocation of load among generators/power plants. While this qualifies our conclusions, it is important to recognize that the use of an hourly time step is arbitrary and any length of interval could be employed. A smaller time step may be more appropriate because, by reducing the time step to a real-time level (say, a 15-minute or even one-minute interval), the rates at which generators can ramp production up or down become more constraining.

We assume that wind can be perfectly forecasted so that we know how much power is available from wind turbines in the future. While forecasts of wind have greatly improved and may one day be extremely accurate, the current assumption is convenient from a modeling perspective, as it enables us to make the best possible case for wind.

We assume that the grid will take all the available electricity produced by the renewable energy source and that the total demand during any given period can be perfectly forecasted. We assume that the decision maker (system operator) minimizes the cost of supplying electricity over some period (one month, one year) subject to satisfying the demand for electricity in each hour, the capacity constraints of various generating sources, and the ramping up and down constraints on generators. Mathematically, the model can be written as:

(1) $$\underset{Q_{t,i},I_{t,i}}{Min} \sum_{t=1}^{24\times d} \left[\sum_{i=1}^{n} (F_i + b_i)\left(Q_{t,i} + I_{t,i}\right) + (F_w + b_w) Q_{w,t} \right]$$

Subject to:

(2) Demand met in every hour: $\sum_{i=1}^{n} Q_{t,i} + Q_{t,w} \geq D_t, \forall t = 1,\ldots,24\times d$

(3) Reliability satisfied every period: $\sum_{i=1}^{n} I_{t,i} \geq sD_t, \forall t = 1,\ldots,24\times d$

(4) Ramping-up constraint: $Q_{t,i} - Q_{(t-1),i} \leq \frac{C_i}{TU_i}, \forall i = 1,\ldots,n;\ t = 2,\ldots,24\times d$

(5) Ramping-down constraint: $Q_{t,i} - Q_{(t-1),i} \geq -\frac{C_i}{TD_i}, \forall i = 1,\ldots,n; t = 2,\ldots,24\times d$

(6) Capacity constraints: $(Q_{t,i} + I_{t,i}) \leq C_i, \forall i = 1,\ldots,n; t = 1,\ldots,24\times d$

(7) Non-negativity constraints: $Q_{t,i} \geq 0$, $I_{t,i} \geq 0$

Here *TC* refers to total cost ($); *i* refers to a conventional source of energy/power plant (*viz*., gas, coal, oil, existing hydro); *w* refers to wind energy; *d* is the number of days; *t* refers to the hour of day; *Q* is quantity of electricity (MW); *F* refers to the variable component of fixed cost ($/MWh); *b* refers to variable cost ($/MWh); *I* is idle capacity (MW); *D* is demand (MW); *s* is a reliability (safety allowance) factor; *C* refers to total capacity (MW); TU_i is the amount of time it takes to ramp up production from plant *i*; and TD_i is the amount of time it takes to ramp down production from plant *i*. Constraints (2) and (3) can be combined into a single constraint:

$$(8) \qquad \sum_{i=1}^{n}\left(Q_{t,i} + I_{t,i}\right) + Q_{t,w} \geq (1+s)\, D_t \ ,$$

which is the form used in the model for the thermal power plants.

In the past when the Island's load is especially high, exceeding the rated total capacity of all power sources, system requirements have been met by the Cheekye-Dunsmuir undersea cable. As noted earlier, this cable has some flexibility although it is limited. We model this flexibility indirectly by first determining potential times that the cable capacity might be exceeded given the load and in the absence of wind power availability. That is, we determine an optimal time path for exceeding rated capacities and permitting flexibility of the undersea cable. To do so, we create an interval ε>0 on either side of the rated total capacity as follows:

$$\sum_{i=1}^{n} C_i - \varepsilon \qquad\qquad \sum_{i=1}^{n} C_i \qquad\qquad \sum_{i=1}^{n} C_i + \varepsilon$$

Then, we solve the following programming problem:

(9) $$\underset{X_t}{Min}\sum_{t=1}^{24\times d}\left[X_t(\sum_{i=1}^{n}C_i+\varepsilon-(D_t(1+s)-Q_{t,w}))^2+(1-X_t)(\sum_{i=1}^{n}C_i-\varepsilon-(D_t(1+s)-Q_{t,w}))^2\right]$$

Subject to:

(10)	Cable cannot be on for more than two successive periods:	$X_t+X_{t-1}+X_{t-2}\le 2,\ t=3,...,24\times d$
(11)	Cable must be off for two hours to avoid burn out:	$X_t+(1-X_{t-1})+X_{t-2}\le 2,\ t=3,...,24\times d$

If total demand exceeds total capacity, the objective function is minimized when X=1;[7] if total demand is less than total capacity, the function is minimized when X=0. The values of X_t are then used to construct the time-dependent capacity constraints for the Cheekye-Dunsmuir cable in equation (6) of the main program.

5 DATA SOURCES

Hourly load data for Vancouver Island for 2002 were obtained from the BC Transmission Corporation. We project demand over the next 15 years using BC Hydro's assumed 1.8% growth in annual demand.

Wind Data

BC Hydro measured wind speed at selected sites beginning in 2000; wind monitors were located at eight sites on Vancouver Island, but we focus only on Pulteney Point (elevation of 15 m), near Port McNeill, as wind speed data are available for the longest

[7] This is readily apparent: If total demand is greater than total capacity, the function is minimized when X=1 because $\left|\sum_{i=1}^{n}C_i+\varepsilon-(D_t(1+s)-Q_{t,w})\right|<\left|\sum_{i=1}^{n}C_i-\varepsilon-(D_t(1+s)-Q_{t,w})\right|$.

period.[8] Data are generally available from 1 July 2000 to 5 January 2003. Data gaps occur for the periods 17 April, 2001 to 30 April, 2001, 17 May, 2001 to 7 July, 2001, and 5 May, 2002 to 20 May, 2002, which are attributed to the manual data recovery method employed. Data for 2002 are employed, because these data are considered more realistic of winds during a given year and 2002 has the fewest missing data points (Figure 2). Where data are missing, corresponding data for 2001 are employed and, for 17 May through 20 May, data are generated randomly from a Weibull probability distribution (see Zhu 2005).

The power generated by the wind depends not only on wind speed but also on the height of the turbine hub. In order to determine the actual power available from a wind turbine, the wind velocity at the turbine hub height is given by (Patel 1999):

$$(12) \qquad Vhub = Vdata \times \left(\frac{Hhub}{Hdata} \right)^{\alpha},$$

where *Vhub* is the wind velocity at the turbine hub height (m/s), *Vdata* is the wind velocity at the height it was measured (m/s), *Hhub* is the height of the wind turbine hub (m), *Hdata* is the height at which the data was measured (m), and α is the site shear component that is dependent on the type of ground surface on which the wind turbine is built. For the Pulteney point site, *Vdata* is the wind data described above, *Hhub* is 113 m (the maximum height of an E-70 turbine), and *Hdata* equals 15 m (the height at which the data was measured). Empirical evidence indicates that $\alpha = 0.14$ is the most generic shear component value. The wind velocity at the turbine hub height is used to convert available mechanical energy to electricity.

Five wind turbine products are available from ENERCON GmbH; power density for

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[8] Information found at (viewed 29 June 2006): http://www.bchydro.com/environment/greenpower/greenpower1764.html.

each is calculated as: *Power Density* = *Rated Capacity* ÷ *Sweep Area* (Table 5).[9] The E-70 is chosen as it likely provides the highest yields in coastal areas. To get the wind power output for an individual turbine, we contrast the wind speed at the turbine hub height with the calculated power curve (Figure 3). Wind power is related to wind speed as follows: $p = \frac{1}{2} \rho v^3 \pi r^2$, where p is the power of the wind measured in watts, v is wind speed, r is the radius of the rotor measured in meters, and ρ is the density of dry air parameter (assumed equal to 1.225) measured in kg/m^3 at average atmospheric pressure at sea level at 15˚C.

Costs of electricity generation from all sources on Vancouver Island

Cost data are provided in Table 6. The estimated unit energy cost for the wind bundle is specific to VI, but information on small hydropower and diesel-fired IC engines is suitable for all regions. Information for small gas cogeneration projects is estimated for the Vancouver region, while that for a CCGT plant is for the interior of BC. The potential wind energy for the northern region of VI is estimated at 1100 MW.

6 MODEL RESULTS

We minimize the sum of the variable component of fixed costs plus variable costs multiplied by the electricity produced from all sources, subject to non-equivalent linear economic and technical constraints. Since all functions are linear, a linear program (LP) is used to solve the minimization problem and fixed costs can be ignored. The unit energy costs are the crucial parameters in the objective function. The model is solved in Matlab but calls GAMS to solve the integer programming and linear programming problems. Data import and export are interfaced with Microsoft Excel.

[9] Information found at http://www.enercon.de/en/_home.htm (viewed 29 June 2006).

Three questions are answered. (1) How is current VI energy demand met? (2) How do wind penetration rates affect the electricity production from existing sources in the VI grid (thermal plant, small Hydropower, HVAC cable and HVDC cable)? (3) What is the impact of differing cost scenarios on the costs of CO_2-emission reductions?

Current Energy Needs

Current VI energy needs are met by four major sources hydro, thermal, HVDC and HVAC. As demand increases (by 1.8% annually from 2002), there is increased stress on the four generation 'plants', with the HVAC cable handling most of the demand. In 2006, there are no blackouts and the HVAC is not forced to operate above rated capacity for any period of time, assuming that no other generators in the system fail. In most periods, the load is satisfied completely by the HVAC cable and on-Island hydropower. In winter months, when demand is higher, additional power is supplied primarily by the HVDC cable, with on-Island thermal power covering remaining demand. Blackouts begin to appear in winter months in 2010, where blackouts are defined as an inability of current generating sources to meet demand when they are at their rated capacity. By permitting the Cheekye-Dunsmuir HVAC cable to exceed operational capacity for short periods of time, blackouts can be avoided until 2012. The ability of the HVAC cable to exceed operational capacity provides needed flexibility to meet demand in the medium term and could be crucial to load satisfaction should any of the alternative sources become unavailable for a period. However, increased Island load or failure elsewhere in the system also puts pressure on the HVAC cable that increases the likelihood of its failure, with drastic effects for Vancouver Island.

Wind Penetration Rates

Set 2002 as the reference year and look at projected demand for 2006, and define:

$$\text{Ex-ante wind penetration} = \frac{\text{Wind Capacity Per Turbine (MW)} \times \text{Number of Turbines}}{\text{Total Capacity}}.$$

$$\text{Ex-post wind penetration} = \frac{\text{Realized Wind Capacity Supplied (MW)}}{\text{Realized Capacity(MW)}}.$$

For ex ante wind penetrations of 10%, 25% and 30%, the fluctuation in wind power increases with wind penetration. This in turn gives rise to increased fluctuations in the other generators, because of the increased wind power produced when the wind speed is between the cut-in and cut-out wind speeds. If the ex-ante wind penetration is set at 10%, the overall effect on the power supplied by other generators is minimal and ex-post wind penetration is approximately 5%, thereby having little effect on the overall supply of power. If ex-ante wind penetration is increased to 25% or 30%, however, there is a reduction in hydro or HVAC use in summer (low demand) months and a reduction in thermal production in winter (high demand) months.

Scenario Analysis

Now consider future demand scenarios where blackouts may arise. Projecting demand forward and allowing for flexibility in the HVAC cable, the model predicts blackouts will occur in 2012. We look at adding wind with the intention of eliminating blackouts. With even a small wind farm with an ex-ante wind penetration of 10%, there is a decrease in blackouts from three periods (March 20, 6 pm; December 27, 6 pm; December 29, 7 pm) to one (December 29, 7 pm). However, at that time (December 29, 7 pm) there is inadequate wind to produce power, so that, regardless of the extent of wind penetration, there will always be blackouts in that hour. This highlights a major problem associated with wind power – the wind does not necessarily blow with sufficient strength during high demand periods (winter months) when it is most needed.

There are many instances during high demand periods (winter months) when there is little to no wind. For example, from December 26, 11 pm to December 29, 12 pm, there is little or no wind. Although this only produces one blackout due to the inability of the HVAC to exceed its operational capacity, if future demand were to continue to grow without more reliable sources of power coming on line, the model projects increased blackouts beyond 2012. If demand is projected to 2015, for example, there are 13 periods when load cannot be met, with these periods occurring predominantly in December, a month when load is high and, for this wind site and data, little wind power is available to the grid. These blackouts are the result of the intermittency of wind and could occur in any winter month depending on the configuration of the wind profile in any given year.[10]

Costs of Wind Penetrability and Costs of Reducing CO_2 Emissions

A principal reason for wanting to install wind farms is to reduce emissions of CO_2 – to reduce reliance on fossil fuels and de-carbonize the economy. In the LP model and given lack of information on prices/revenues (which will vary by commercial, residential and industrial consumers and perhaps time of day), the objective function is to minimize the overall costs of producing power on Vancouver Island. Only variable and not fixed costs are minimized.

Table 6 provides information on the direct capital (fixed) costs and fixed operating, maintenance and routine replacement (OM&R) costs associated with operating wind turbines on Vancouver Island. Fixed OM&R costs refer to costs associated with the overhaul of

[10] While we consider only one wind farm and while the addition of wind turbines at other locations might reduce the variability in wind-generated power, the overall wind profile might still not be sufficiently stable to prevent the occurrence of blackouts. Rather, more conventional power may be required or wind power must somehow be stored on a large scale.

thermal plant generators (turbines), which can be expected to increase if starts and stops are more frequent as a result of higher wind penetrations, or costs of cable inspections that also increase as traffic along them fluctuates more frequently. Currently the model does not take into account such changes, so the fixed OM&R costs are treated differently from variable costs, although future research will need to examine the effects on costs of more frequent fluctuations in the output of non-wind sources of power.

Fixed costs of wind turbines are estimated at $250 million, while the fixed component of O&M costs is estimated to be $7 million per annum (Table 6).[11] Assuming that the project life is 25 years, with a project lead time of three years, and a discount rate of 6%, the present value of total fixed capital costs can be calculated as:

$$\text{(13)} \qquad \mathrm{PV}_{\mathrm{CC}} = FC + \sum_{t=1}^{22} \frac{K_t}{(1+0.06)^t}(1+0.6)^{-3} \ ,$$

where FC is one-time fixed costs and K_t is annual fixed OM&R costs. Computing $\mathrm{PV}_{\mathrm{CC}}$ gives $320.772 million, which, if amortized over the 25 year life of the project, is $25.093 million per annum or approximately $167,286 per MW of rated capacity per year. With a computed capacity factor of 28%, the actual cost is $597,451 per MW per year, or $68.20 per MWh.

It is also possible to calculate the cost of CO_2 emission reductions as:

$$\text{(14)} \qquad \text{Cost of } CO_2 \text{ emission reductions} = \frac{Cost_{Wind} - Cost_{without\ wind}}{\sum_{i=1}^{N} GS_i \times EF_i - \sum_{i=1}^{N+wind} GS_i \times EF_i} ,$$

where GS refers to generation source, EF is the emission factor and N is the number of 'traditional' sources of power on Vancouver Island.

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[11] These costs are for a generic wind farm with installed capacity of 150MW. No details in how costs vary with capacity are available but are a subject of future research.

Only 13% of the generating capacity on VI is provided by thermal power plants. The remainder is provided by hydropower and undersea transmission cables. In the BC grid, 92% of all power supplied annually is from hydropower. Hence, we assume that all of the power provided by the undersea cables is from a hydro source. This is unlikely to be the case simply because, when electrical demand peaks on VI, it will also peak elsewhere in the Province. This implies that, at the margin, it is the Burrard gas plant that provides VI with power. Therefore, at peak capacity, the power provided along the HVAC and HVDC lines is likely from a natural gas source. This implies that, if VI were not a part of BC Hydro's grid, much less natural gas would be burned in the Burrard facility. Overall, therefore, we assume that the CO_2 savings that wind power provides come from the reduced use of the thermal power on VI (Elk River and Keogh) plus reduced use of the Burrard gas plant. To determine these savings, we multiply the reduction in electrical use from the on-Island power plants plus that of the HVAC and HVDC cables as follows:

$$(15) \qquad CO_2 \text{ reduction} = \sum_{i=1}^{N} GS_i \times EF_i - \sum_{i=1}^{N+wind} GS_i \times EF_i$$

where *i* refers to on-Island thermal plants and the HVAC cable, *EF* is 0.215 t CO_2 per MWh for thermal plants and 0.35 t CO_2/MWh for the HVAC and HVDC cable, GS_i is the hourly output (MWh) for thermal plant *i* or the HVAC cable.

Given that, in the summer, the thermal power plants are rarely used, any wind power mostly displaces the undersea cables (a hydro source at that time of year) and on-Island hydropower. In the winter, when demand is high, the power provided by the undersea cables is most likely covered by backup power from the Burrard facility. Thus, any wind power will result in some reduction in CO_2 emissions. For 2006 and with an ex-ante wind penetration of

10%, for the (winter) months November through February the expected cost of CO_2-emissions reductions is approximately \$103 per t CO_2. With increased wind penetration, the cost of the CO_2-emissions reductions increases slightly.

7 DISCUSSION

The model developed in this study is a simple representation of the allocation of power across generators in an electrical grid. While real-world electrical grids are much more complex and operate on a smaller time step, the current model provides an efficient method for allocating electrical power needs across generation sources in a way that minimizes system costs while explicitly taking into account real system constraints, especially those related to the flexibility of undersea cables to exceed rated capacities for short periods. The model can also be modified quite easily to operate at a shorter time step. Indeed, with a shorter time step the allocation of power over generation sources is constrained to a greater extent, thus reducing the ability of thermal generation to adjust to fluctuating wind power and increasing the costs of reducing CO_2 emissions. The reason is that ramping-up and ramping-down rates become more constraining as the time step is shortened, while costs of rapid adjustment are higher.

Perhaps the most constraining assumption in the current model is that of rational expectations – that the amount of electricity demanded and the wind power available are known a priori. Importantly, the wind turbines used in this study are located at the same place, but, even if they are scattered over a larger landscape, this does not ensure a wind profile that has no periods where wind-generated power is sufficient to cover any gap between demand and the capacity of conventional power sources. Although sophisticated forecasting tools can be used to forecast demand with a high degree of confidence, future projections of wind availability are always going to have some degree of uncertainty. Again, this only serves to increase the costs of adjustment and CO_2-emissions reductions. Therefore, the results of this study might be considered a best-case scenario.

The results for Vancouver Island indicate that, for certain demand scenarios, extant power sources are unable to meet the load even when flexibility is built into the capacity constraints of undersea cables. While wind-generated power has been proposed as one means to alleviate future shortfalls, we find that this may not always be the case as wind power may not be available at the time it is needed. Further, the ability of wind power to reduce CO_2 emissions at reasonable costs is constrained in the case of VI by the makeup of the generation mix – a mix that has significant hydropower but is constrained by cables that connect it to the larger BC grid. As a result, costs of CO_2-emissions reductions are estimated to be more than \$100 per t CO_2, much higher than those of alternative means of reducing CO_2 emissions or otherwise removing CO_2 from the atmosphere. Nonetheless, the story of Vancouver Island is not much different from those of Denmark, Estonia and Ireland: There is room for wind-generated power, but its ability to replace conventional power is limited. Further, the effectiveness of wind systems will differ from one location and situation to another.

Future research related to the penetration of wind energy into electricity grids will need to focus on those components of the generation mix and grid that are somehow unique. The current model will need to be expanded to integrate storage options and transmission constraints, and to include a mix of multiple renewable sources of power, whether multiple wind farm locations or tidal plus wind generators.

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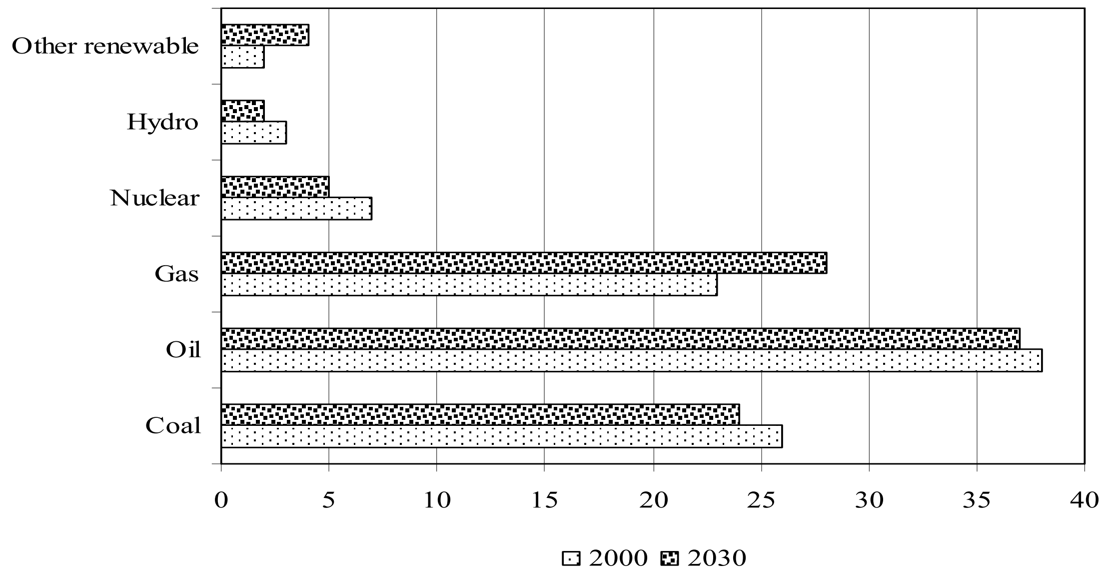

Figure 1: World Energy Consumption, 2000 (9.963 Mtoe) and 2030 (15.0 Mtoe), Percent
(Source: International Energy Agency 2004a)

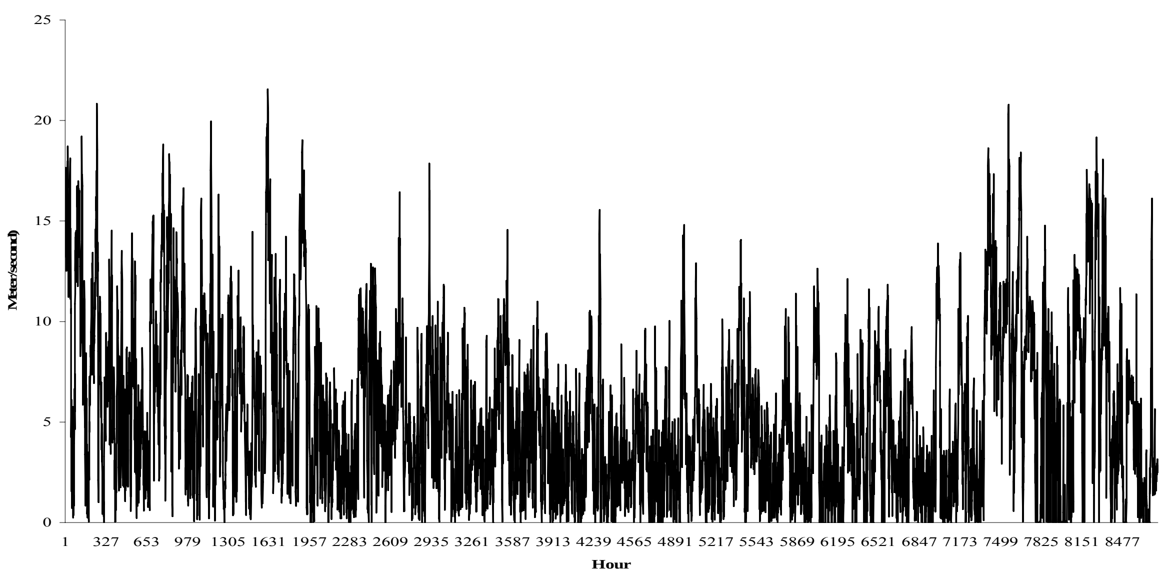

Figure 2: Hourly Wind Speed (m/s) at Pulteney Point on Vancouver Island, 2002

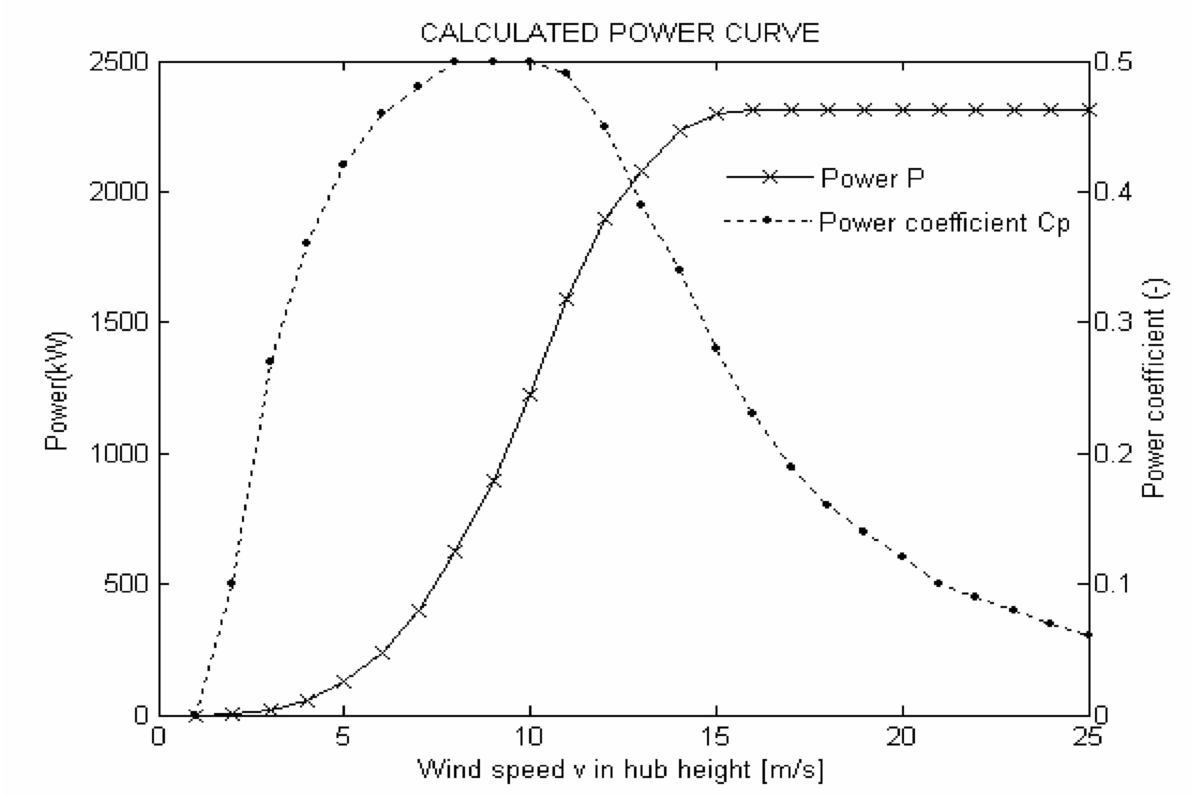

Figure 3: Power Curve for E-70 2 MW Wind Turbine

Table 1: Wind Production and Capacity Factors for IEA Countries, 2005
Values in [ ] are estimates. Values in bold italic are for 2004. NDA means no data available.

Country	Capacity (MW)	Production (GWh)	Capacity factor (%)
Australia	708	2171	0.35
Austria	819	NDA	NDA
Canada	683	[1800]	0.30
Denmark	3128	6614	0.24
Finland	82	170	0.24
Germany	18428	[26500]	0.16
Greece	605.4	1270	0.24
Ireland	492.7	**655**	0.15
Italy	1717	2140	0.14
Japan	1077.7	1438.7	0.15
Korea	100	[146]	0.17
Mexico	2.2	4.2	0.22
Netherlands	1213	[2000]	0.19
Norway	270	504	0.21
Portugal	1060	1773	0.19
Spain	10028	20236	0.23
Sweden	452	864	0.22
Switzerland	11.59	8.4	0.08
UK	1337.16	[2394]	0.20
US	9149	[28051]	0.35
Total (Average)	51363.75	96568.3	0.21

Source: International Energy Agency (2005)

Table 2: Estimated Costs of CO_2-emission Reductions, Irish Grid, 6500 MW System

Wind plant capacity	Increase in costs	Reduction in CO_2 emissions	Cost
1500 MW	€196 million	1.418 Mt	€138 per t CO_2
2500 MW	€309 million	2.403 Mt	€128 per t CO_2
3500 MW	€434 million	3.437 Mt	€126 per t CO_2

Source: ESB (2004) and calculations

Table 3: Vancouver Island Electricity Capacity and Energy Production, 2002

Supply facility	Rated generating capacity in MW	Average annual production GWh	Type of facility
Campbell River System	240	1,227	Hydro
Strathcona	(64)	(222)	
John Hart	(126)	(776)	
Ladore	(47)	(229)	
Ash River	27	193	Hydro
Puntledge	24	156	Hydro
Jordan River	170	242	Hydro
Subtotal Island Hydro	**458**	**1,818**	
HVAC undersea cable	1200	5449[c]	System supply
HVDC undersea cable	240	1000[c]	System supply
Subtotal cable	**1,440**	**6,549[c]**	
Keogh, diesel backup[a]	44	50[c]	Nonrenewable
ICP Elk Falls (Co-generation retrofitted for diesel)	240	1,935	Nonrenewable
Subtotal fossil thermal	**284**	**1,985**	
TOTAL ALL SUPPLY	**2,182**	**10,352[c]**	
Proposed			
CCGT for 2007[b]	260	2,100	Nonrenewable

[a] As of 2005, this facility was being decommissioned.
[b] Plans to build this plant were abandoned in mid-2005.
[c] Estimates using data from BC Hydro.

Table 4: Vancouver Island Electricity Capacity: Role of Undersea Cables

Supply source	Planning capability (MW)	Operational capability (MW)	Maximum output (MW)
On-Island Hydro	448	448	470
500 kV circuits	1,300	1,450	1,800
HVDC Pole 1	0	0	130
HVDC Pole 2	240	240	476
138 kV AC cables	0	0	55
On-Island Thermal	168	240	240
TOTAL	**2,156**	**2,378**	**3,171**

Source: Steve Miller and Associates (2003)

Table 5: Wind Turbines from ENERCON GmbH

Technical Data	E-33	E-48	E-70	E-82
Rated power (kW)	330.0	800.0	2300.0	2000.0
Rotor diameter (m)	33.4	48.0	71.0	82.0
Swept area (m^2)	876.0	1810.0	3959.0	5281.0
Cut-in wind speed (m/s)	2.5	3.0	2.5	2.5
Cut-out wind speed (m/s)	28-34	28-34	28-34	28-34
Power density	37.67%	44.20%	58.10%	37.87%

Source: http://www.enercon.de/en/_home.htm

Table 6: Unit Energy Cost of Electricity Generation from All Sources

	Small Hydro	Diesel Fired IC Engines	Small Gas Cogeneration Projects	Combined Cycle Gas Turbine	VI Wind Bundle[d]
Technical Information					
Installed Capacity (MW)	260	7	300	256	450
Average Annual Energy (GWh/year)	1000	12.2	2400	1947	1375
Dependable Capacity (MW)	65	7	285	243.3	0
Firm Energy (GWh/year)	0	12.2	2400	1947	–
Average Heat Rate (GJ/GWh)	–	8584	4800	7240	–
Financial Information					
Direct Capital Cost ($'000s)	0	3932	510000	304730	750000[c]
Fixed OMC ($'000s/year)	941[a]	153.5	0	11253	21000[c]
Variable OMC ($/MWh)	1086[b]	146.5	28	4.6	0
Unit Energy Cost ($/MWh)	**49**	**202**	**64**	**53**	**68**
Social and Environmental Information					
GHG emissions factor (tCO_{2e} per GWh)	0	705	215	350	0
Upstream GHG Emissions (tCO_{2e} per GWh)	–	–	130000	130000	–

[a] Water Rentals-capacity ($'000s)
[b] Water Rentals-Energy ($'000s)
[c] Capital costs are Based on three generic projects @ $250 million each. Fixed O&M costs are based on three generic projects @ $7 million each.
[d] Project life is 20 years and project lead time is 3 years. Discount rate is assumed at 6%.
Source: BC Hydro (2005)