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Network constrained wind integration on Vancouver Island

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Abstract

The aim of this study is to determine the costs and carbon emissions associated with operating a hydro-dominated electricity generation system (Vancouver Island, Canada) with varying degrees of wind penetration. The focus is to match the wind resource, system demand and abilities of extant generating facilities on a temporal basis, resulting in an operating schedule that minimizes system cost over a given period. This is performed by taking the perspective of a social planner who desires to find the lowest-cost mix of new and existing generation facilities. Unlike other studies, this analysis considers variable efficiency for thermal and hydro-generators, resulting in a fuel cost that varies with respect to generator part load. Since this study and others have shown that wind power may induce a large variance on existing dispatchable generators, forcing more frequent operation at reduced part load, inclusion of increased fuel cost at part load is important when investigating wind integration as it can significantly reduce the economic benefits of utilizing low-cost wind. Results indicate that the introduction of wind power may reduce system operating costs, but this depends heavily on whether the capital cost of the wind farm is considered. For the Vancouver Island mix with its large hydro-component, operating cost was reduced by a maximum of 15% at a wind penetration of 50%, with a negligible reduction in operating cost when the wind farm capital cost was included.

Keywords: Electric networks; Optimal power flow; Wind power

1. Introduction

Global electricity demand is rapidly increasing as developed nations continue to expand and developing ones grow even faster, with future power demand still being met by carbon-based fossil fuels, mainly natural gas and coal (Energy Information Association, 2006; Asif and Muneer, 2007). Due to climate effects, air quality issues and questionable supply security of hydrocarbon sources, national decision makers increasingly emphasize deployment of less carbon-intensive and more sustainable electricity sources. As a result, wind power has gained considerable momentum, with the current global capacity at 74 GW and projections of 160 GW by 2010 (World Wind Energy Association, 2006).

Wind power is a non-dispatchable and highly intermittent electricity source, which raises problems when supplying a portion of utility scale demand. The analysis of wind power integration must examine the temporal match between the wind source, electricity demand and the operating abilities of the existing system. Wind power does not simply replace energy from existing facilities on a one-to-one basis; variable efficiency and cost, ramp rate limits and operating limits need to be recognized.

Modelling electricity generation and consumption commonly involves a simple load levelling technique that ensures generation satisfies demand during all periods—a simple energy balance (Kennedy, 2005). Load levelling neglects the actual transmission network that moves power from the generation sites to user locations. In practice, a utility must consider both the transmission network and load levelling, guaranteeing that demand is met and that the existing transmission system is capable of moving the power.

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Determining an optimal energy balance between demand and generation under various network constraints is known as an optimal power flow (OPF) solution. The OPF problem has been solved for AC networks using a variety of optimization algorithms (El Abiad and Jaimes, 1969; Dommel and Tinney, 1968; Sasson, 1969; Barcelo et al., 1977; Talukdar et al., 1983). While providing a description of the OPF problem and solution methods, such research fails to model the behaviour of dispatchable (traditional) and non-dispatchable (new) generation technologies. By optimizing a simplified OPF problem while considering non-traditional electricity generators, it is possible to shed light on the cost and emission trade-offs that occur when these new technologies are incorporated into an established and heavily constrained network. Thus, the objective of the current research is to create a network model that simulates the behaviour of both highly variable (wind) and traditional generation (thermal plants, large-scale hydro), while also solving the OPF problem under network constraints. We do this by taking the perspective of a social planner who desires to find the lowest-cost mix of new and existing generation facilities. The model detail is sufficient to resolve planning issues, but coarse enough to neglect detailed technical parameters of a specific grid. Thus, a purely resistance network is considered.

A disadvantage of low carbon energy alternatives such as wind is their high variability and limited predictability in terms of power output. When large amounts of wind power enter a transmission network, system operators must rely on wind forecasts to know when they must ramp existing generators up or down to balance the load unmet by wind. The speed at which intermittent wind generation ramps up and down forces the existing generators to ramp much faster than otherwise, which can significantly decrease their operating efficiency. A decrease in efficiency corresponds to an increase in per unit fuel consumption (on an energy output basis) and thereby higher carbon dioxide emissions intensity. Consequently, the introduction of intermittent and unpredictable sources into an existing mix dominated by thermal generators may not substantially reduce the net production of system CO_2 (DeCarolis and Keith, 2006). Ramp rate limits vary among existing facilities, so that it may be necessary to ramp some generators quicker than others when wind power spikes or falls. Regardless, ramping limits throughout the system may lead to excess generation in some periods, thus raising the cost of meeting system demand.

A number of studies have analysed the economic, environmental and operating issues surrounding large-scale wind integration. Giebel (2007) performed a variance analysis of wind power integration across Europe using a one-node model that ignored the transmission network and ramp limits for thermal generators (using minimum start-up times instead). He assumed a constant cost for generators, examined wind dispersion, considered energy storage (pumped hydro) and accounted for load uncertainties (by requiring a certain fraction of power to be held as spinning reserve). Giebel employed a scheduling model as opposed to an optimization model.

Kennedy (2005) minimized the long-run average costs of producing electricity, where costs included fuel, operating and maintenance (O&M) and capital costs, as well as costs related to CO_2 emissions and other pollutants. The average capacity cost of each generator was varied with respect to its average part load, but the efficiency of generation was held constant. In the model, wind capacity optimally replaced existing capacity, rather than being added to an existing mix. Load duration curves (LDCs) were used in conjunction with generator screening (cost) curves to determine the capacity of each technology in the mix, with and without various levels of wind penetration. Generator scheduling was determined by minimizing social cost subject to the load, variable wind resource, the demand and different levels of wind penetration.

DeCarolis and Keith (2006) studied the effects of wind dispersion by modelling up to five different wind sites across the United States. An optimal mix of wind, gas turbine, compressed-air storage and transmission capacities was found for varying levels of a carbon tax. With the exception of the tax component, fuel costs were assumed to be constant, utilizing a constant generator efficiency to produce them. Although transmission was considered, the connections only included links from the wind sites to a central wind merging site, with a single connection from the merged site to a single load centre. Capital costs of transmission were included, but network flows were purely unidirectional, as the main load centres were located some distance from the wind sites.

Belanger and Gagnon (2002) integrated wind power into a hydro-dominated mix over a period of several years. They discussed the requirement of additional back-up capacity to support development of a wind farm, and imposed stream flow effects that wind power might have on existing hydro-facilities. Their results showed that additional hydro-capacity must be installed to back up a wind farm that was intended to meet an unmet load, due to the low amount (or zero amount) of reliable capacity provided by the wind farm. Results also showed that wind power increases the short-term fluctuation of stream flows from a hydro-reservoir and heavily reduced the minimum flow from the reservoir during low demand periods. The authors touched on integration issues between wind and thermal generators, and noted that future studies must analyse the reduction in thermal efficiency of these generators caused by wind intermittency, as we do in this study.

In the current study, we employ various elements of the previous models but explicitly include transmission limits. We focus on the temporal interaction between wind power, network demand and the existing generators, modelling system costs and emissions as varying amounts of utility-scale wind power are integrated into the network. We include fuel costs, variable and fixed O&M costs, and capital costs of the wind farm and transmission upgrades. A novelty is the inclusion of variable generator efficiency,