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Estimating the impact of wind generation and wind forecast errors on energy prices and costs in Ireland

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ABSTRACT

This paper studies the impact of wind generation on system costs and prices in Ireland. The importance of wind power and potential impacts on system costs is of interest to power system planners and policy makers globally. However, the impact of wind generation on system costs has been only studied with limited actual data from power systems with increased wind penetration. The paper uses a unique dataset of half-hourly system demand, generation, forecast and actual wind generation, along with Irish system marginal price (SMP) data from 2008 to autumn 2012. An econometric time-series model of SMP as a function of forecast and realized demand and wind generation yields results which suggest that each 1% increase in wind generation reduces SMP in Ireland by about 0.06%, while each 1% wind forecast error increases SMP about 0.02%. In absolute terms, though, at the mean the impact of wind forecast errors is small, or about 0.4€cent/MWh-wind generated.

1. Introduction

While climate change continues to be one of the most important policy issues facing the developed world, the continuing pressure on the national budgets and expenditures from the economic downturn means that the costs of meeting climate change targets are increasingly at the center of policy debates. This paper contributes estimates of the added system costs of wind penetration and thus might prove valuable in the context of such debates.

Wind power has been seen as perhaps the best way towards meeting climate change and emissions targets by many countries, both small[1] and large.[2] Wind power external costs exist in total transmission system losses, system balancing costs, the cost of required reserves (both spinning and non-spinning), other ancillary services and the total cost of power generation. The cost of using wind power to meet renewables targets is of course uncertain and must be estimated. The costs to the system may exhibit scale and scope economies. The impact of increasing levels of wind power on smaller systems may be different than for larger systems and thus it is important to estimate the impacts of wind generation on system costs for a variety of systems. Finally, the external costs of wind on power systems may interact with fuel prices, market design elements, levels of competition, and other factors. Thus it is important to estimate wind system costs for a variety of systems and at different points in time.

This study investigates the impact of wind power on electricity costs in Ireland. Ireland is a particularly interesting case in which to study wind power system costs for a variety of reasons. The Irish electricity market has a number of characteristics which makes it an ideal case study for electricity market research. It is somewhat unique in that it operates in two different jurisdictions and operates with dual currencies. It is a small island system, with an installed capacity of 9 GW of conventional capacity of which approximately 2 GW is excess capacity and planning reserve, and limited interconnection to the Great Britain (GB) system through two interconnectors. Because of the system's small capacity and low interconnection (the interconnectors with GB are capable of importing 500 MW[3] each and exporting slightly less), the percentage increase and expected overall proportion of wind power in Ireland will be large, with targets of 40% of electricity to be generated by wind in 2020 [15].

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[1] Ireland is planning about 5.5–6 GW wind capacity by 2020, or about 40% of generation. See Ref. [17].

[2] See the UK Renewables Energy Roadmap Update 2013 [16]. This indicates between 25 and 30 GW wind capacity potential development as policy target to meet 2020 climate change goals.

[3] The East–West interconnector was commissioned in Autumn 2013 and the interconnection will increase to 1000 MW by 2023.

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The All-Island system has a high proportion of installed wind capacity equivalent to roughly 18% of total installed capacity. This has been used to generate up to 49.9% of the island's electricity demand; wind (non-synchronous generation) is curtailed if it exceeds 50% of total system generation at any given time due to power system reliability issues [18].

A second element perhaps unique to Ireland relates to its market design. While the generation market is fully open to competition, due to regulators' concerns about market power the prices bid by generators into the power pool are for practical purposes regulated; generators must bid their marginal cost (or average variable cost) of generation, with fuel prices and thermal efficiency of generation units checked by the regulator. A straightforward merit order and the day-ahead forecasts of demand and wind generation forms a day-ahead dispatch schedule and a daily set of half-hourly system marginal prices (*ex ante* SMP). In addition, the cost of constraints and other factors, and balancing, are included in the *ex post* SMP paid to generators, which adjusts the day-ahead SMP. This means that the final price paid to generators for the power they generate is not finalized until four days *ex post*. A more detailed description of the Single Electricity Market (SEM) design in operation in Ireland can be found in Ref. [7]. The market data are also all available online from SEMO (the market operator). Further, wind forecast and actual generation outturn data are available from Eirgrid (the Republic of Ireland (ROI) TSO). Thus the possibility of studying the total cost of wind power on the system, and including the impacts of wind forecast errors is made possible by the Irish data and market design. This is different from a previous study of the GB wind system balancing costs [10], which a) focused only on balancing and b) did not include the difference between forecast and actual outturn wind generation.

2. Review of literature

The overall system cost and price impacts as a result of wind are likely ambiguous, as different characteristics of wind affect cost both positively and negatively. For example, baseload units, such as coal, may be cycled more frequently with the introduction of variable generation sources such as wind [8]. This in turn could result in significant increases in a variety of costs, including impacting the merit order (flexible plant may run ahead of inflexible plant), and operation and maintenance (O&M) and start costs. Di Cosmo and Valeri [9] find that this may be dependent on market rules, however. Their results indicate that as wind increases, this may benefit baseload units such as coal relative to more flexible plants like gas and create an incentive to invest in less flexible units as their profit levels are less affected by variable wind generation given technical constraints. On the other hand, thermal units displaced by wind will lead to a fuel cost saving as wind has zero fuel costs.[4] The cost of providing reserve may also increase as wind penetration rises; as wind output is not as constant relative to traditional thermal units [3,4].

A number of previous studies have estimated the cost of wind generation on the system (Fig. 1). The results from the studies reviewed by Gross et al. [13] and Holttinnen et al. [14] are neatly summarized by a figure they present. They conclude that system balancing costs increase by about €1–4/MWh of wind power produced, for system wind penetration levels up to 20% of power generated. They also demonstrate that the methodologies used so far to examine the issue of balancing cost implications of wind power have mostly relied on simulation approaches. Historically in many countries, wind generation has contributed to a negligible degree to the overall generation mix, so that empirical studies have been of limited value. Moreover, the seasonal and annual variation

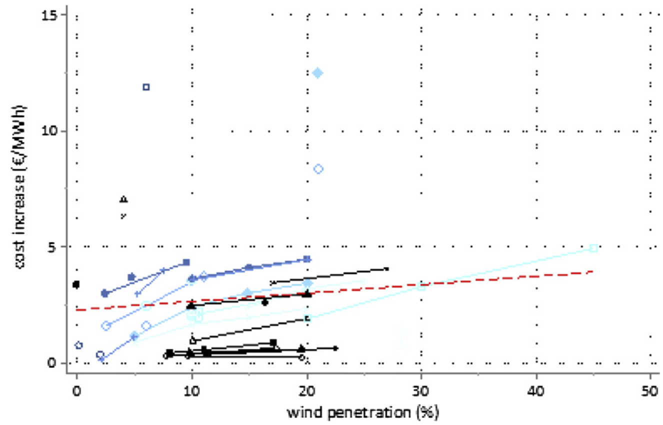

Fig. 1. The figure presents the range of cost estimates from previous studies on the increase in balancing costs due to intermittent generation (% wind penetration). (Note: the figure summarizes 36 estimates from 22 studies from Europe and the USA. It is based on Fig. 5 in Ref. [14] and Fig. 3.2 in Ref. [13]. £ values from Ref. [1] have been recalculated using exchange rates at the date of publication and adjusted by the Eurostat industry producer price index for "electricity, gas, steam and air conditioning supply". The dashed red line is a regression line through all observations.) (figure found in Ref. [10]). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

in energy consumption means that meaningful analysis likely requires time series of several years, which are only now becoming available. Ketterer [6] examines the impact of wind on electricity prices in Germany using a Garch model. This finds that prices decrease while overall price volatility increases. In one of the specifications considered, as wind increases by 1 percentage point the electricity price fell by 1.45 per cent. Wurzburg et al. [12] looked at the effect of wind and solar on electricity prices in Germany and Austria using an empirical approach. They found that prices in both countries fell by approximately €1/MWh for each additional GWh of renewables on the system expected in the day-ahead market.

Felder [4] notes that some of the savings associated with the fuel saving in the marginal price may simply be transferred to the uplift and capacity payment mechanisms. This would occur if units are switched on and off more frequently, or if generators require additional payments in order to recover their lost-energy operating margin. Brouwer [2] found that variable generation requires additional flexibility, while thermal generation is typically inflexible. This mismatch in needs may create operational issues with this combination. Tashpulatov [11] found that large fluctuations can introduce uncertainties about revenues for producers and costs for retail suppliers, which could result in higher costs paid by consumers.

3. Data

The dataset for the study comes from publically available data on the SEMO and Eirgrid websites [19,20]. SEMO is a joint venture between Eirgrid plc, the Transmission System Operator (TSO) in the Republic of Ireland, and System Operator of Northern Ireland (SONI) Limited, the TSO in Northern Ireland. All data are actual historic output from the system, recorded on a half-hourly[5] basis from January 2008 to December 2012. Demand and price data are from SEMO and thus are All-Island system outputs. Wind generation data is only available for ROI from public sources. ROI represents 72% of the total All-Island market, and 79% of installed wind capacity. We use ROI data due to a lack of available data for Northern Ireland over a similar time period, however as both

[4] For a more detailed investigation, see Denny & O'Malley, 2007.

[5] Wind and demand from EirGrid are actually available for each quarter hour, but we aggregate these data to half-hourly.