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Cost comparisons for wind and thermal power generation☆

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ABSTRACT

Comparisons of generation costs between renewable and conventional generation technologies are a key input to energy policy discussions. However there are many pitfalls around generation cost estimation: even apparently reliable sources can quote widely differing figures. This paper reviews methodologies and data sources to determine the main sources of uncertainty in the estimation of the costs of wind, coal and natural gas generation, based on illustrative cost calculations for the US, Denmark and India. It finds that the cost elements most likely to confound generation cost calculations are fuel costs and, particularly for renewable generation, the cost of capital. It explores the impact on calculated generation cost of alternative approaches to estimating these parameters. The results should be of particular value to users of generation cost estimates who are concerned about the reliability of the information they have to work with.

1. Why compare costs?

Passionate supporters of renewable energy believe that power generation using renewables is the key to a sustainable economy, is cheaper than fossil fuel alternatives and the sooner it provides 100% of the national energy supply, the better. Its equally passionate opponents see it as a deadweight on the economy and believe that its supporters dishonestly conceal its true costs. There is a clear need for accurate cost comparisons.

Unfortunately, generation cost estimates vary widely – particularly for renewables – and cost comparisons for different countries can throw up inexplicable differences. For example, estimates of wind generation costs in EU countries presented in the 2015 version of *Projected Costs of Generating Electricity* (IEA/NEA, 2015)[1] range between \$72 and \$123 per MWh (in 2013\$, using a 7% real discount rate, and controlling for differences in wind quality by adjusting all estimates to the same capacity factor).[2] This is an absurdly wide range - these are countries in a common economic zone with free markets for key components. Furthermore, the two most important variables in the cost calculation – the cost of capital and the capacity factor – are held constant.

Clearly, even for "official" data, we should question the validity of cost estimates. In this paper I set out to ask those questions. My aim is to examine the issues that can confound generation cost calculations rather than to produce definitive cost estimates (though I think that the estimates in Section 5 of the paper are as accurate as any others out there, and better than most). As concrete examples, I estimate generation costs in the US, Denmark and India – chosen because they are diverse in terms of market structures and, in each case, I was able to obtain believable data. For each country I assess the cost of wind generation and, because policy decisions imply comparisons, also coal and gas-fired plants (for India, I do not consider gas as it is little used for generation).

2. My approach to cost estimation

In this paper I consider only plant costs - a full analysis would

Abbreviations: AEO, Annual Energy Outlook - forecasts produced by the EIA; CERC, Central Electricity Regulatory Commission – the Indian regulator; DEA, The Danish Energy Agency; US DoE, (US) Department of Energy; EDPR, EDP Renewables – a Portugal-based firm with a global portfolio of wind power assets; EIA, Energy Information Administration; EU, European Union; fob, Free on board – i.e. the cost of a product loaded onto a ship for export, but not including the cost of freight to the destination; IEA, International Energy Agency; kW (MW), KiloWatt (MegaWatt); kWh (MWh), KiloWatt hour (MegaWatt hour); LNG, Liquefied Natural Gas; MACR, Modified Accelerated Cost Recovery – a system of depreciation used for tax accounts by companies in the US; MMBtu, Million British Thermal Units – US gas prices are expressed as \$/MMBtu; NEA, Nuclear Energy Agency; NGCC, Natural Gas Combined Cycle – a particularly efficient type of natural gas fired generation plant; NREL, National Renewable Energy Laboratory; TIPS, Treasury Inflation-Protected Securities - government bonds for which the principal amount to be repaid is adjusted for inflation over the life of the bond. The difference in yield between TIPS and conventional government bonds provides an indication of the expected level of inflation; WEO, World Energy Outlook – forecasts produced by the IEA; WTMR, Wind Technology Market Report. This report, produced annually by the US DoE, provides an overview of developments in the U.S. wind power market

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[1] This report is updated every five years – throughout the paper I refer to the 2015 version as EGC15.

[2] The capacity factor of a generation unit is the amount of electricity produced over a period expressed as a percentage of what would be produced if the unit operated at 100% of its design output throughout the period. I have adjusted the generation cost figures quoted above to the average capacity factor for wind power in European countries contributing to EGC15.

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Table 1
Cost categories by generation technology.

	Wind	Gas	Coal
Return on Capital	81%	20%	35%
O & M Costs	19%	10%	17%
Fuel Costs	0	70%	48%

Note: The percentages shown are averages of my estimates for the US, India and Denmark, using the current yield on long term government bonds as a proxy for the risk free rate.

include the impact on grid costs due to the intermittency of wind output, "costs" related to differences in the marginal value of power produced at different times of day and externalities such as the health impacts of emissions. I plan to examine these costs in a second paper. Plant costs can be categorised as operating and maintenance costs (referred to as O & M), capital costs and fuel costs. Table 1 shows the contribution of each of these categories to total costs for the technologies considered in this paper.

My estimates are expressed in terms of the levelised cost of electricity (LCOE). This is the weighted average cost of electricity produced over the lifetime of a plant, the weights being discount factors calculated using the plant's weighted average cost of capital as a discount rate. It is widely used for generation cost comparisons but it is not the gold standard it is sometimes imagined to be – it has been described as "a flawed metric for comparing the economic attractiveness of technologies such as wind and solar with conventional dispatchable generating technologies such as nuclear, coal, and gas-combined-cycle" (Joskow, 2011). Joskow's concern was that LCOE effectively ascribes the same value to every unit of power generated although the market value of a unit varies according to the time of day and the pattern of demand. In more general terms, LCOE was developed to compare baseload generation technologies in a relatively stable world - it does not cope well with a world of intermittent generation and unpredictable change. It accounts for risk by applying one discount rate over a forty year project lifetime, when the risks that matter to a project developer today are one-off events such as disruptive new technologies or changes in government attitudes to the environment. Even without such events, discounting over forty years is a clumsy way to deal with uncertainty in fuel prices when forecasts can change radically from one year to the next. LCOE "essentially assumes a static world in which…costs occur in the ways they are "predicted" by a fixed annual cash flow schedule" - to quote the 2010 edition of *Projected Costs of Generating Electricity (*IEA/NEA, 2010*)*. I estimate LCOEs because they allow for useful comparisons of generation costs but they do not provide a firm foundation for complex decisions on energy policy.

My estimates exclude the effect of subsidies and incentives for renewable generation – in my view, these have little effect on the cost of power *to the country as a whole* - they simply redistribute the cost between consumers and tax payers. For the same reason I ignore taxes on inputs such as value added tax, though I take account of royalties on coal or gas production as these are – in theory – payments for the use of a resource. Some analyses – for example (Schmidt et al., 2012) – treat the low cost of domestic coal in India as a subsidy, on the grounds that the economic cost is the international price adjusted for freight costs. I do not follow this treatment, but I estimate two LCOEs for coal in India to illustrate the impact of the country's pricing policy.

Estimating costs in the absence of incentives raises complex issues – more is involved than leaving the subsidy out of the calculation. In effect, one is analysing a hypothetical situation in which unprofitable projects are financeable, using data that – to the extent they are based on observation - are misleading because what is being observed is a world in which subsidies exist. Worse - a recent study suggests that the need for incentives and the nature of the incentives provided may change the risk profile of an investment and therefore its cost of capital (Noothout et al., 2016).

The rest of this paper examines the most important sources of uncertainty in estimates of LCOE: Section 3 covers the basic cost and performance parameters such as the construction cost of a plant and its non-fuel operating costs while in Section 4 I review certain theoretical issues around the cost of capital. Section 5 examines the main source of uncertainty in estimating fuel costs – forecasts of coal and gas prices – by estimating LCOE in different price scenarios. This section, therefore, includes my own estimates of LCOE. Section 6 concludes.

3. The basic cost and performance parameters

Cost elements can be variable (the cost in any period is proportional to the amount of electricity generated) or fixed (the same in each period, regardless of output). To estimate the cost per unit generated we divide fixed costs by the plant's total output during a period - this can be calculated from its capacity factor (actual electricity output as a percentage of maximum theoretical output).

The capacity factor of a wind plant depends primarily on wind quality. This varies by location – hence the significant differences between capacity factors for different countries in EGC15 (nevertheless, some of the EGC15 capacity factors are surprising – possibly due to inconsistent definitions). Recent advances in technology potentially allow new plants to achieve higher capacity factors, but actual performance has not improved in line with potential due to site quality considerations – the best sites have been taken. Rather than trying to estimate what is theoretically achievable, I prefer, where possible, to use actual performance data for recent projects. This is feasible for Denmark and the US as comprehensive project-level output data are available; for India, my estimates of LCOE are based on the benchmark capacity factor allowed by CERC (the Indian regulator) in its tariff calculations for the best quality wind regions.

Coal and gas fired plants are capable (in theory) of running almost full time - for both technologies, my cost estimates are based on a (somewhat arbitrary) capacity factor of 85%.[3] For all technologies, I assume that capacity factor remains constant for the life of the plant. In reality, it falls slowly as the plant ages, however the errors introduced by making this simplifying assumption are small and the LCOE calculation is much less complex.

3.1. O & M costs – wind

O & M costs are something of a mixed bag – project developers and their accountants have plenty of scope for creating confusion. In some cases they have incentives to do so – for example, in a regulated market higher costs can justify higher prices. Even where this is not an issue, two projects may have different costs due to nothing more than accounting differences - for example, a share of the head office costs of the corporation that owns a plant might be allocated to the project. Another issue is that O & M costs include both fixed and variable elements but are normally reported as cost per MWh, as if they were 100% variable. The reported figure is arrived at by assuming a capacity factor, but often one has no way of knowing what was assumed. This is a global issue: wind O & M cost estimates for different countries in EGC15 show huge disparities - considering only advanced countries in the EU, estimates range from $14/MWh in Denmark to $36 in the UK.

It is essentially impossible to correct for such issues, but it is important to realise that uncertainty over definitions can reduce the validity of publicly available data on O & M costs. Taking the US as an example, the NREL's annual *Wind Technology Market Report* (WTMR), which provides detailed analyses of US wind generation costs, acknowledges that its data for O & M costs are unreliable due to

[3] In most countries, gas-fired plants do not run as baseload – they typically operate in peak-shaving mode with a capacity factor of 50–60%.