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The cost of offshore wind: Understanding the past and projecting the future

Philip Heptonstall [a,*], Robert Gross [a], Philip Greenacre [b], Tim Cockerill [c]

[a] Centre for Energy Policy and Technology, Room 328 Mechanical Engineering Building, Imperial College, London SW7 2AZ, UK
[b] Centre for Energy Policy and Technology, Room 309 Mechanical Engineering Building, Imperial College, London SW7 2AZ, UK
[c] Centre for Energy Policy and Technology, Room 330 Mechanical Engineering Building, Imperial College, London SW7 2AZ, UK

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ABSTRACT

Offshore wind power is anticipated to make a major contribution to the UK's renewable energy targets but, contrary to expectations, costs have risen dramatically in recent years. This paper considers the context of these cost increases, and describes a disaggregated levelised cost model used by the authors to explore the effect of different assumptions about the direction and scale of the major cost drivers. The paper identifies the competing upward and downward pressures on costs in the medium term, and discusses the range of future costs that emerges from the analysis. The paper goes on to analyse the implications of these cost projections for the policy support levels that offshore wind may require. The paper suggests that there are good reasons why it is reasonable to expect a gradual fall in costs in the period to the mid-2020s, although it is unlikely that costs will fall as rapidly as they have risen, or that it will be a smooth downward trajectory. A key challenge is to reconcile the scale and pace of development desired for UK offshore wind with the potential growth rate that the supply chain can sustain without creating upward pressure on costs.

1. Introduction

The UK Government has set ambitious targets for electricity generation from renewables sources during the next decade, and the UK's national target under the EU 2008 Renewables Directive is for 15% of total energy consumption to come from renewable sources by 2020. The relative cost and difficulty of increasing the share of energy from renewables in other sectors such as transport means that it is expected that electricity generation will have to bear a greater proportion of this target than other sectors. It is anticipated that more than 30% of electricity will have to be generated from renewable sources by 2020 if the Renewables Directive target is to met (BERR, 2008), compared to a current figure of around 7% (DECC, 2010).

Whilst there is no specific target for the share of this generation that will come from offshore wind, it is expected that it will make a major contribution, partly because of the excellent offshore wind resources which the UK has (BCG, 2010), and partly because moving offshore avoids some (but not all) of the issues that have led to public opposition to onshore wind farms. Commentators suggest that if the renewables targets are to be met then the UK will require more than 15 Gigawatts (GW) of offshore wind generation installed by 2020 (HoL, 2008), with further substantial increases in installed capacity beyond this date. Current installed capacity for UK offshore wind is around 1.3 GW, compared to around 3.9 GW of onshore wind (RenewableUK, 2011), with the UK offshore wind market dominated by two turbine suppliers, Siemens and Vestas, who have supplied almost all the offshore turbines installed to date. However, manufacturers such as REpower, Multibrid (now Areva), GE, Clipper and Mitsubishi are entering, or are expected to enter, the UK market, some with larger machines (such as in the case of REpower) or innovative design aspects (such as in the case of Clipper).

Development rights for offshore wind in the UK are awarded by the Crown Estate (the owner of the seabed) and these rights have been awarded in 3 rounds to date. Rounds 1 and 2 granted rights for a total of around 8 GW of development, and Round 3 rights, awarded in early 2010, were for over 30 GW of potential development (The Crown Estate, 2010a, 2010b).

The scale of ambition is therefore clear but, contrary to expectations, the costs of offshore wind have increased significantly since the mid-2000s with capital costs (capex) currently around £3 m/Megawatt(MW) installed, compared to around half that five years ago (see Fig. 1). Whilst it is fair to say that costs for all types of generation have gone up in this period, offshore wind is particularly in the spotlight because it plays such a large part in the UK aspirations for renewable energy. In common with most other forms of renewable generation (and nuclear power and carbon capture and storage), offshore wind requires policy support to bridge the gap between its costs and the cost of conventional fossil-fired generation. For renewable generation, this support is currently provided by the Renewables Obligation (RO), although

* Corresponding author. Tel.: +44 20 7594 7309.
E-mail address: philip.heptonstall@imperial.ac.uk (P. Heptonstall).

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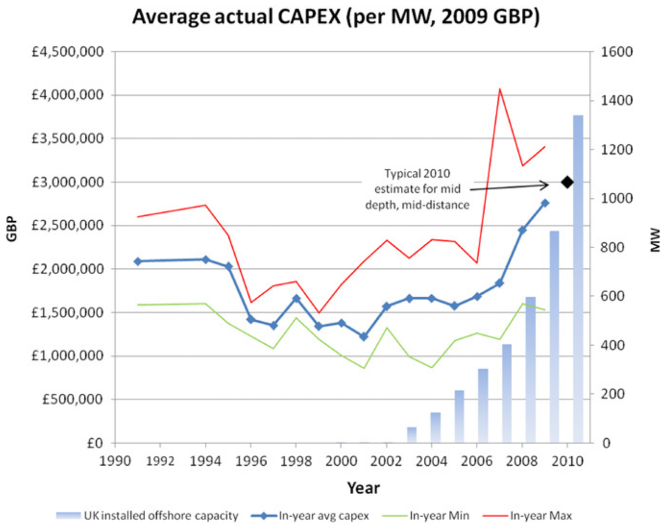

Fig. 1. In-year average, minimum and maximum actual capex, adapted from Greenacre et al. (2010).

the UK Government proposes to replace the RO later this decade with a Feed-in Tariff (FiT) (DECC, 2011b).

The rising costs of offshore wind led, in part, to the introduction in 2009 of 'RO banding' by technology so that higher-cost technologies earn more renewable obligation certificates (ROCs) per unit of electricity than lower-cost technologies. Offshore wind was originally awarded 1.5 ROCs per megawatt-hour (MWh). Later the same year, this was increased to 2 ROCs per MWh (on a temporary basis) in response to concerns that offshore wind projects would not proceed with the support level at 1.5 ROCs (RAB, 2009). The nature of the RO mechanism means that the precise value of this additional support varies, but it is suggested that the total value of the support premium (i.e. in addition to the revenue received from selling the electricity) is currently worth around £100/MWh (Greenacre et al., 2010), based on 2 ROCS/MWh.

This paper is based upon research undertaken at Imperial College for the UK Energy Research Centre (UKERC) which documented and explained the cost expectations for offshore wind in the early 1990s and 2000s, and the cost rises from the mid-2000s onwards (Greenacre et al., 2010).

This paper considers the context of cost increases for offshore wind (Section 2), explaining that costs for all major generation technologies have risen. Section 3 then goes on to explain the levelised cost calculations used by the authors to assess possible future costs for offshore wind, and explores the effect of adopting different assumptions about the major cost drivers. In Section 4 the paper recognises the generic limitations in the levelised cost approach and discusses those limitations which are particularly relevant to offshore wind, and Section 5 follows this with an explanation of the range of projected future costs that emerge from the analysis. Section 6 discusses the implications of the cost projections for the support levels required for offshore wind, and Section 7 concludes the paper.

2. The context—all costs have gone up

Electricity generation cost increases are not confined to offshore wind and since the mid-2000s costs for all the major electricity generating technologies have risen considerably. Table 1 compares the central estimates for levelised costs from the 2006 Energy Review (DTI, 2006) and the most recent cost estimates from work commissioned by the Department of Energy and Climate Change (Mott MacDonald, 2010). The 2006 Energy Review numbers have been adjusted for inflation to 2009 using the Office of National Statistics RNNK index. Note that the Mott Macdonald numbers cited here are 2009 estimates.

Table 1
Comparative cost rises (inflation adjusted).

Generating technology	Energy Review 2006	Mott Macdonald 2010	% rise
Combined cycle gas turbine (CCGT)	£42/MWh	£80/MWh	90
Coal	£32/MWh	£102/MWh	219
Nuclear	£46/MWh	£97/MWh	111
Onshore wind	£66/MWh	£88/MWh	33
Offshore wind	£99/MWh	£149/MWh	51

It is clear that all the generation technologies considered here have experienced dramatic cost increases, although it is interesting to note that *onshore* wind has been subject to the *lowest* percentage rise of the technologies shown in Table 1. Nevertheless, the costs of offshore wind have risen considerably, and as Fig. 1 shows, reported actual capex costs for offshore wind have increased dramatically since the mid-2000s, with current values centred around £3.0 m/MW.

This paper is primarily focussed on *future* costs rather than the reasons costs have increased in recent years. However it is important to be clear about the historic drivers of cost increases. The main drivers are well understood and include: rising materials, commodities and labour costs; adverse currency movements (particularly the fall in value of sterling compared to the euro); rising costs of offshore turbines due to supply chain constraints and additional engineering issues associated with operating in the marine environment; the increasing depth and distance from shore of some projects (which affects installation and operation and maintenance costs); constraints in the availability of installation vessels and suitable ports; and planning and consenting delays (Greenacre et al., 2010). We discuss the significance of, and sensitivity of future costs to, these factors in Section 3.

Note that when compiling the data for Fig. 1, non-UK sterling denominated values were converted to British Pounds at the rate prevailing for the year which the reported value refers to and then all values inflated to 2009 values using the Office of National Statistics RNNK index.

3. A levelised cost model for offshore wind and sensitivity analysis

3.1. Model description

So-called 'levelised' costs seek to capture the full lifetime costs of an electricity generating installation, and allocate these costs over the lifetime electrical output, with both future costs and outputs discounted to present values. One of the most succinct definitions of levelised unit cost is from IEA (2005), where it is defined as 'the ratio of total lifetime expenses versus total expected outputs, expressed in terms of the present value equivalent'. Such measures are not the only indicator of costs, and they do have limitations which we return to in Section 4, but they are a very widely used metric which allows a high level comparison between different technology options and can inform the policy debate and rationale for intervention in support of particular technologies (Gross et al., 2010).

One standard formulation of levelised cost is shown in Eq. (1). There are alternative approaches, principally the 'annuity' method which involves calculating the present value of the cost stream