Potential risks associated with changes to renewables support levels

Note prepared for ScottishPower

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1 Introduction

DECC's Electricity Market Reform (EMR) consultation set out the prospect of introducing four new mechanisms into the GB wholesale electricity market, including a system of Feed in Tariffs (FITs) to provide financial support to renewable and other low-carbon technologies.[1]

Previous analysis undertaken by government for the 2008 Renewables Strategy concluded that replacing the existing renewables support mechanism (the Renewables Obligation, RO) with a system of FITs could have little effect on total support costs.[2]

In contrast, the analysis undertaken on behalf of DECC for the EMR consultation suggests that a key benefit of adopting DECC's preferred system of FITs with contracts for differences (CfDs) would be to reduce the risks faced by low-carbon generators, and in turn, lower their financing costs and the total costs to consumers.[3] However, as noted in the supporting analysis:

> The key risks with these approaches [fixed payment FITs with CfDs] are that they depend on Government being able to set prices and target volumes appropriately, and that they represent a significant departure from the current arrangements[4]

Thus, while DECC has outlined its preference for a system of FITs with CfDs, some important design issues remain to be addressed, including:

[1] DECC (2010), 'Electricity Market Reform. Consultation Document', December.

[2] BERR's renewable strategy concluded: 'In terms of efficiency, our analysis suggests that cost differences between the (banded) RO and feed-in tariffs are marginal'. See BERR (2008), 'UK renewable energy strategy', p. 95.

[3] Redpoint (2010), 'Electricity Market Reform. Analysis of policy options', December.

[4] Redpoint (2010), op. cit., p. 11.

– how the support levels will be set—ie, centrally determined by DECC, as in the current process for determining renewables support within the RO, or through an auction-based mechanism;
– how the volume, or capacity, of low-carbon technologies that will receive support will be determined.

This note provides an initial, indicative assessment of some of the potential risks to the level of renewables deployment, and potential distortions to the efficiency of the renewables mix, that could arise from the introduction of FITs with CfDs (or any other support system that provided low-carbon generators with a similar risk profile) if support levels are set at an inappropriate level. It considers the possible impact on the level of onshore and offshore wind deployment, which, combined, could represent around 65% of total practical renewables resource potential by 2020.[5]

The indicative analysis assesses the following scenario:

– as noted in the analysis undertaken for DECC, FITs with CfDs represent a significant departure from current arrangements and may therefore not reduce the risks and hurdle rates relative to the RO to the extent highlighted in the EMR analysis (the same considerations would apply to other FIT options, with similar economic effects);

– however, centrally determined levels of support may reflect policy-makers' expectations that FITs would result in a significant reduction in hurdle rates;

– this may lead to a reduction in onshore wind deployment if marginal projects become uneconomic under the revised levels of support, and if there is increased targeting of support to offshore wind projects due to their relatively higher resource potential.[6]

This note provides an estimate of the possible scale and impact of reduced onshore wind support levels, by estimating:

– the subsidy saving made from the reduction in support to the onshore wind that does get built;

– the reduction in onshore wind deployment due to the reduction in support, alongside the additional support costs of replacing the reduced onshore wind with offshore wind.

An additional sensitivity is also provided to assess the impact on onshore wind economics and support costs if financing costs were to fall in line with policy-makers' expectations but existing support levels were to be maintained.

2 Illustrative quantification of effects

The analysis that supports the EMR suggests that the impact of introducing FITs with CfDs for onshore wind could reduce hurdle rates by as much as 0.3 to 1.0 percentage points (post-tax, nominal) relative to the existing arrangements.[7] Using estimates of the costs of an

[5] See SKM (2008), 'Quantification of constraints on the growth of UK renewable generating capacity', June.
[6] An alternative policy response could be subsequently to increase support levels to onshore wind in response to reduced deployment rates, which would partially correct for any initial misalignment of subsidy levels, but would be likely to induce a delay in onshore wind deployment.
[7] Redpoint (2010), op. cit., p. 50.

average onshore wind plant prepared for DECC by Mott MacDonald,[8] this is equivalent to a reduction in levelised costs of around 7%.

2.1 Reduction of onshore wind deployment

The analysis in this section considers the impact of a 7% reduction in onshore wind revenues relative to Oxera's base-case electricity price and Renewable Obligation Certificates (ROC) price projections.

Figure 2.1 highlights the potential impact of a 7% reduction in onshore wind revenues, which is based on Oxera modelling submitted in response Ofgem's Project TransmiT call for evidence.[9] The analysis suggests that a 7% reduction in revenues could result in a reduction in onshore wind volumes of up to 6.2TWh per annum by 2010.[10]

The figure compares the range of internal rates of return (IRR) of wind plant (relative to the central hurdle rate) across different regions of Great Britain, in order to capture different wind and cost conditions. It shows a scenario in which the IRRs of onshore wind plant decline due to the reduction in support following the introduction of FITs (the second bar in each region), with the result that an increased proportion of plant may be unable to meet its hurdle rate.

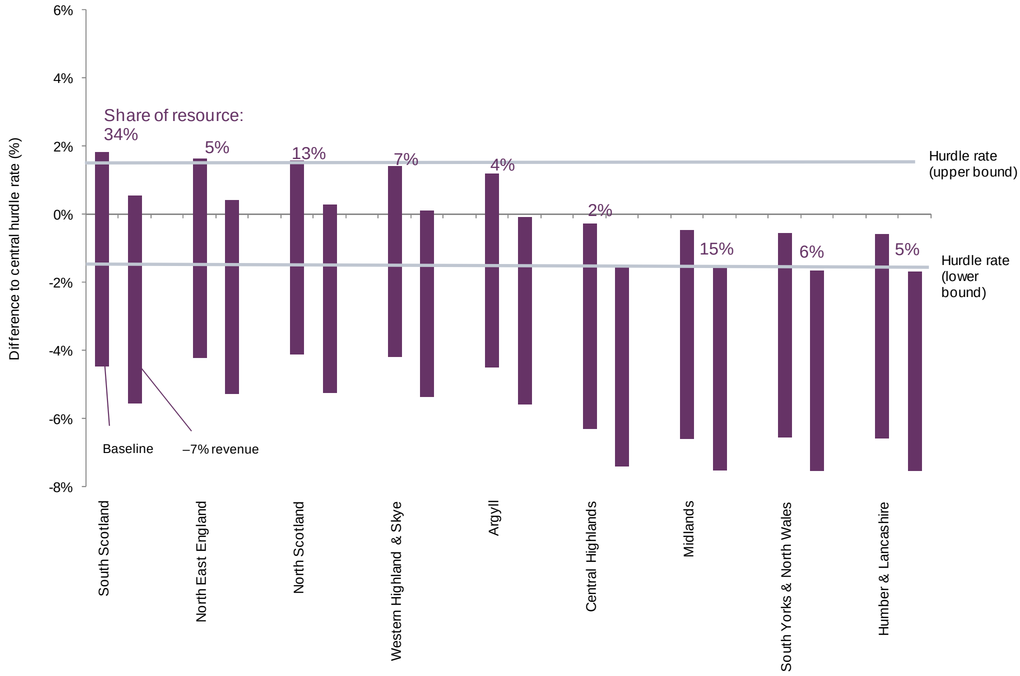
Potential onshore wind projects are assumed to be distributed uniformly between the upper and lower bound in each region, and the proportion of potential projects across regions is based on the distribution of potential wind projects within the BWEA database.

[8] Mott MacDonald (2020), 'UK Electricity Generation Costs Update', June.

[9] See Oxera (2010), 'Principles and priorities for transmission charging reform. Project TransmiT: call for evidence', November.

[10] Analysis carried out for DECC by SKM suggests that up to 35TWh of wind plant may potentially be built by 2020. In the absence of grandfathered support, the reduction in support relative to current RO levels could result in a reduction of 17.5% (or 6.2TWh) of onshore wind deployment. Oxera modelling indicates that around 25.2TWh of onshore wind may be deployed by 2020 under the RO. The reduction in support could therefore reduce total deployment by 2020 to 19.1TWh (the differences are due to rounding).

Figure 2.1 IRR versus hurdle rates



Note: The bars show the range in project IRRs within each region based on estimated variations in plant load factors and costs. The second bar in each region highlights the change in the range of IRRs from a 7% reduction in project revenues.
Source: Oxera analysis.

In contrast, if support levels were to remain unchanged but hurdle rates were to fall in line with policy-makers' expectations (equivalent to a 7% net increase in revenues), onshore wind deployment could increase by around 5.8TWh.[11]

2.2 Change in subsidy costs

Figure 2.2 provides an assessment of the change in subsidy costs that could result from the reduction in onshore wind deployment estimated above. The figure highlights that:

– the reduction in support to onshore wind implies that the costs of the subsidy to onshore wind that does get built could fall by around £500m per annum, taking account of both the reduced unit subsidy and the reduced deployment;

– if these reduced onshore wind volumes were to be replaced by additional offshore wind, the costs of the subsidy would increase by around £890m per annum as a result of higher support being provided to offshore wind; and

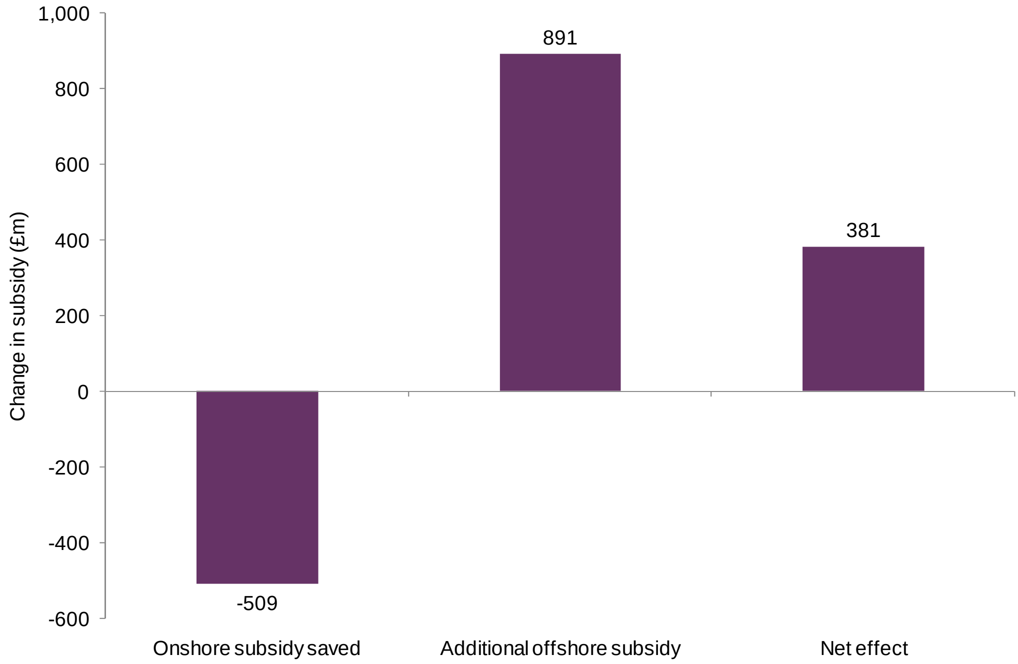
– the net effect could be to increase renewables subsidy costs by around £380m per annum.

The reduction in total support to onshore wind from reduced subsidy levels has been estimated on the basis that it would affect projects accredited from 2017 only,[12] with plant that is built and accredited before then receiving grandfathered support levels.

[11] Estimate based on the same method as illustrated in Figure 2.1.

[12] The EMR consultation suggests that FITs could be introduced from 2013, but that accreditation under the RO could also continue until 2017.

Figure 2.2 Change in annual subsidy in 2020 (£m per annum)



Source: Oxera.

If support levels were to remain unchanged but hurdle rates were to fall in line with policy-makers' expectations, the analysis presented here suggests that the result would be a significant increase in the deployment of onshore wind. The potential increase in onshore wind deployment would be around 5.8TWh, which, if substituted for offshore wind, could reduce net subsidy costs by around £288m per annum.

2.3 Summary

The analysis above highlights that a key risk associated with replacing the existing renewables support mechanism with a system of FITs with CfDs (or any other system intended to give projects a similar risk profile) relates to setting the level of support, and targeting renewable technologies appropriately.

If support levels are to be centrally determined, as in the current RO, an important consideration would be the extent to which risks and financing costs are assessed within the support-setting process, and how this is done.

If the risks faced by developers are not reduced to the extent assessed in the analysis undertaken for DECC, but support levels are nonetheless revised downwards, there could be a risk of potential distortions to the renewables mix that could have an adverse impact on the total costs to consumers.

In contrast, if support levels were to be maintained to onshore wind despite a reduction in hurdle rates, the increased deployment of onshore wind that could potentially substitute for relatively higher-cost offshore wind could lead to a net reduction in total subsidy costs.

These implementation issues are likely to have an important bearing on the success or otherwise of any proposed change in the renewables support mechanism.