

## **RO Reform Consultation – BWEA response**

### **Annex B: Analysing the impact of the reforms on wind projects**

While Government is consulting on the principle of banding the RO and not on the exact multiples that should be applied to each technology, BWEA felt it appropriate to analyse hypothetical on- and offshore wind projects with a view to calculating appropriate multiples to a first order of accuracy. This has allowed us to make some judgements on the principles of banding that would otherwise have been difficult to make. Since the levels of multiples that will be required are highly dependent on the fine detail of any system that Government actually implements, the following should be taken as illustrative only.

BWEA is very grateful to our members Falck Renewables, Shell and Centrica for allowing use of their proprietary project models for this analysis. We are also grateful to Pöyry Energy Consulting (formerly Ilex) for allowing use of their forecasts of power and ROC prices: since this is commercial information, we cannot describe these forecasts in detail, though they are respected in the market. Clearly, ROC prices, and therefore required multiples, may well be very different under a banded Obligation, but use of the Pöyry figures at least allows consistency in the analysis.

For both onshore and offshore, hypothetical projects were looked at with commissioning dates of 1 January 2011 and 1 January 2017: the latter shows the effect of the RO's end in 2027.

#### Onshore wind

As described in Annex A, wind turbine prices have increased in the last few years, and are not expected to fall before 2011, and indeed may firm further before investment in the supply chain shows dividends. Our view of the capital cost of onshore wind is about £850,000/MW, on the basis of an engineer, procure & construct (EPC) contract for a project consisting of 10, 2.5MW turbines. In our analysis we assume that this cost will rise by 1%/yr in real terms up to 2011, and be flat thereafter. In addition, developers have to earn enough from successful projects to recover the costs of unsuccessful ones: we assume that it costs £500,000 to develop a project, and that only one in three projects are successful. There are also costs for connection (see below) plus legal, financing and other consulting costs to factor in (£60,000/MW). A contingency of 5% of the EPC contract cost is also required to cover the unexpected.

Operations and maintenance, rates, rent, community benefit, insurance, financing, legal and sundry other costs give a total for variable costs of £15.50/MWh. If TNUoS charges must be paid, which is the case for many projects in Scotland, then the figure of £15,000/MW/yr is used: the up-front cost of connection is £10,000/MW if TNUoS is to be paid, £60,000/MW

otherwise. Calculations were made for a required internal rate of return of 10%.

For the base case analysed, our project generates for 2,200 full load hours in a year (a load factor of 25%) and does not pay TNUoS charges, and thus may be regarded as typical of the kind of marginal project that will be required if we are to meet overall renewable targets of 15% and more. With the assumptions that there is no ROC income post-2027 and that the buy-out price is frozen in 2015, then this project requires a multiple of 1.2ROC/MWh to be economic if it is commissioned in 2011, and 1.5ROC/MWh for commissioning in 2017. If the project commissioned in 2011 has to pay TNUoS charges, then the required multiple rises from 1.2 to 1.35.

Case	Operation Date	ROCs Required
Base Case [2200hours]	1 January 2011	1.20x
TNUoS Case [2200hours]	1 January 2011	1.35x
Late Base Case [2200hours]	1 January 2017	1.50x

Looking at the problem another way, we can calculate how many hours in a year our 2011 project must run to be economic at 1ROC/MWh in our base case. Without the need to pay TNUoS, a project needs to run for 2,500 hours (a load factor of 28%) to be economic – this load factor is the current UK average, and if this were the bar, then developers would count out the large majority of England and Wales as viable for onshore wind development. If TNUoS is applied, then the required hours rise to 2,700 (a load factor of 30%). Sites are available in Scotland and Northern Ireland at that level, but there continue to be considerable problems in obtaining grid connections for many of these.

Case	Operation Date	Hours Required
Base Case [1.0x ROCs]	1 January 2011	2500 [28% capacity]
TNUoS Case [1.0x ROCs]	1 January 2011	2700 [30% capacity]

The prospects are much better, however, if the buy-out price is not frozen in 2015. If the buy-out were to continue rising with inflation, then our base case 25% load factor project, beginning operation in 2011, would be economic on 1ROC/MWh. For the same project commissioned in 2017, then the multiple stays low, at 1.1ROC/MWh.

Case	Operation Date	ROCs Required
Base Case (no freeze)	1 January 2011	1.0x
Late Base Case (no freeze)	1 January 2017	1.1x

We conclude that even if onshore wind remains at 1ROC/MWh, then the rest of Government's reform package combines to make large swathes of the UK impossible to develop, with projects crowded into the higher wind resource areas, where there is already difficulty in providing the required grid infrastructure. If development is to be spread over wider areas so that

onshore wind can make its full contribution to Government's aspirations for renewable energy, then not only must onshore wind remain at 1ROC/MWh, but the buy-out price freeze must be rescinded.

#### Offshore wind

For offshore wind, a relatively small project of 200MW is modelled, though at this stage in the sector's development, it is difficult to judge the size of possible scale effects. Common assumptions in the analysis include a development 'hit rate' of 100%, i.e. no projects fail, and therefore successful projects do not have to recoup the development costs of unsuccessful projects. Throughout, we also assume that the project has a load factor of 38% (3330 full-load hours): this is historically high, but should be available to suitably-sited and well-maintained offshore projects. All-in construction costs are £1.675m/MW, of which £325,000/MW is grid connection. We do not project any reduction in this cost, due to pressures similar to those for onshore wind. However, this cost is less than the most recently reported projects – for instance, contracts were recently signed for the Robin Rigg project at a cost of £1.8m/MW. We expect that increased experience in contracting and installation of offshore projects will provide an initial step reduction in capital cost, but savings beyond that are more likely in the operation side of the equation. Variable costs excluding TNUoS (O&M, rent/rates, legal, accounting, insurance, etc) are estimated to be £11.50/MWh.

TNUoS is made up of an onshore component (£1.2/MWh) plus an offshore component (£8.1-14.3/MWh). The onshore part will have to be paid in any case; the offshore part only if the offshore infrastructure is provided by a regulated transmission owner, in which case the upfront cost of the grid connection is removed. At the moment, it is unclear how much benefit regulation will bring, hence the range in offshore TNUoS charges used. The lower end of the range is roughly equivalent to the charges that would be paid under the capping arrangements for the western and northern isles of Scotland (charges are likely to be about £25/kW/yr under this scheme).

Calculations were made for internal rates of return of 10% and 12%. Certainly in the first instance, the higher rate will be demanded by investors to reflect the higher risk that these projects represent. The base case excludes grid connection capex, and includes offshore TNUoS at the higher rate. The results, in terms of ROC multiple required in each case, are shown in the table below for the project coming into service on 1 January 2011.

	10% IRR	12% IRR
<b>Base Case</b>	1.47 (£67.4/MWh)*	1.72 (£73.8/MWh)*
Low offshore TNUoS (£8.1/MWh)	1.26	1.52
Grid Capex included (no offshore TNUoS)	1.37	1.7
Include ROC inflation post 2015	1.3	1.62
Include carbon value post 2027 (£20/MWh RT inflated)	1.32	1.65

*\*Figures shown in brackets indicate the real terms flat revenue required to meet the IRR target.*

The case where the grid capex is included shows that, for 12% IRR, an offshore TNUoS level of £14.3/MWh is equivalent to the developer paying off the capital itself, i.e. there would be no benefit to regulation at this level of TNUoS. Having the lower TNUoS charge of £8.1/MWh is equivalent to 0.2ROC/MWh, which underlines the need for a beneficial outcome to the current discussions on the offshore transmission regulation regime. As for onshore, keeping the buy-out price inflator post 2015 is important, giving a benefit of 0.1ROC/MWh. If a hypothetical 'carbon benefit' of £20/MWh is given for the last few years of the project's 20-year life post 2027, then there is also some benefit, in this case less than 0.1ROC/MWh at 12% IRR. It is interesting to note that the benefits are all greater at the 10% IRR level – though it is hard to forecast when the risks of offshore wind will be well enough understood and managed for this hurdle rate to be used. It will not be before 2011, however.

Our analysis of the base case for a 2017 project (offshore TNUoS at £14.3/MWh, buy-out price freeze in 2015, no carbon value post 2027) shows how the end of the RO in 2027 would require the multiple to rise to compensate for the short ROC lifetime of projects. This highlights again that Government should be considering how to manage down the end of the RO rather than have it end suddenly in 2027.

	10% IRR	12% IRR
<b>Base Case</b>	1.93	2.14