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Report on CER Consultation Paper CER/03/016

Funding of Grid Upgrade Development Programme for Renewables

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1 Introduction

This report is submitted on behalf of Codling Bank Wind Park, who propose to develop an offshore windfarm on Codling Bank, approximately 10km off the East Coast, near Bray.

This offshore development offers the opportunity for a significant tranche of capacity, to contribute towards the successful achievement of the '500MW by 2005' target.

It has been recognised for some time that the successful extension of wind generation in Ireland, on the sort of scale required to achieve the Government target, of 500MW of new renewables by the year 2005, will require significant extensions of, and reinforcements to, the grid system, especially in the west of the country. Under present arrangements, the cost of these works would fall on the developers themselves. This has proved sufficient of a dis-incentive to development that it has been necessary to look into alternative methods of funding extensions, and of capacity surplus to the immediate requirements of developers.

The initial intention here was that the extensions should be funded by government subvention, being refunded as further developers came on line. However, budgetary constraints have meant that this route is not available, and that alternative methods have had to be investigated. The CER paper looks at the possibility that the work could be funded by ESB themselves, with the costs being recovered from Transmission Use of System (TUoS) charges.

2 The problem

In common with many developed countries, the system of charges for extensions and reinforcements to the electricity grid system are such that these costs (unless caused by general load growth) have to be met by developments. These developments have typically been new power stations, which have required substantial tranches of new transmission capacity, and have tended to be located comparatively near to existing grid systems, and/or centres of demand. It should be noted that there are some exceptions to this.

Grid capacity is not infinitely variable. The smallest 110kV lines tend to have a capacity of around 100MW per circuit, while 220kV lines will have at least four times this amount. The cost of new grid lines, transformers and switchgear at these voltages are high.

Land-based windfarms, however, have tended to be much smaller developments, of the order of 15 to 25MW. Under existing arrangements, if extension of the grid is needed, the lowest capacity increment for a 110kV extension has tended to be 100MW, with the entire cost being met by the windfarm. The cost of meeting the cost of an extension of four to six times the capacity needed has, not surprisingly, caused many prospective schemes to founder.

Historically, the existing grid systems in most developed countries have been planned and funded centrally, through government money, or government guarantees for funding by nationalised industry. The system thus produced was designed around medium and large sized thermal power stations fuelled by coal, oil and peat, with a modest addition from small hydro stations. Large gas-fired power stations have now been added to the system.

Increasing realisation of the environmental and social costs of the use of fossil fuels has led to increasing demand for electricity to be produced by environmentally-benign renewable energy, of which windfarms are at present the leading contender.

Ireland is well placed to generate from the wind, having one of the windiest coastlines in the whole of the European Union. The difficulty arises from the fact that the West Coast is comparatively undeveloped, and has a weak grid (with the exception of the 400kV lines linking Moneypoint power station to Dublin). Costs of connection for all but the smallest of windfarms have therefore required significant extensions to the grid system, with associated high costs.

This can be seen as a significant shift from the “traditional” structure of the generation business. As such, it requires an integrated approach to fund the changes to the main grid system that are needed in order that these new arrangements can be accommodated.

3 The proposal

It is now proposed that the necessary extensions to the grid system should be funded by ESB themselves, using funds raised from their customers through Transmission Use of System (TUoS) charges. This would enable extensions to be built which take into account the capacity of all the schemes being developed in a given area.

Each developer would be charged a sum equivalent to the proportion of the capacity of the grid extension that he was to use (for example, a 20MW scheme would pay one-fifth of the cost of a 100MW extension), plus the total cost of the lower-voltage scheme-specific work.

As further schemes are connected, they too would pay their proportions of the cost, with the aim that, eventually, the entire cost of the new grid extensions would be met by the generators connected to it.

This would appear to assume that the entire capacity of each extension is to be used up by generation developments. As has been noted, transmission system extensions come in quantifiable increments of size, and it is not made clear in the CER paper how any surplus capacity is to be funded should the windfarms in any given area not take up the whole capacity available.

The timing of schemes coming forward is also problematic, in that in some areas there may be a rush of schemes connecting within a couple of years - in others, two years or more may elapse between each new connection.

A curious omission from the paper is that funding from within the industry is likely to avoid the scheme being classed as state aid under article 87(1) of the Treaty of Rome. There have been a number of rulings on this recently in the European Court, to do with schemes for the support of renewable energy.

Legal sources state that the law has not been applied consistently in all cases, and that, as a result, schemes (other than schemes which have already received approval, such as the French and German feed-in laws) have to be submitted to Brussels for approval by the directorate-general of competition. The cost per person is not great - it is assessed in the paper as the equivalent of 0.0035c/kWh, albeit that this charge will be levied over the next forty years.

4 Scope

The scheme proposed has been based on a study of schemes that already have planning permission, and schemes that have applied for planning permission.

However, the scheme as proposed seems to apply only to schemes that actually have planning permission. This seems to be a restrictive element to the scheme, as it presumably prevents grid extensions being designed with future growth in mind.

Even if the wording (which is not clear) actually means that system design takes account of all schemes that have planning permission and those that have applied, but that application for support can only be made in respect of those that already have planning permission, it means that no account can be taken of schemes in development, but which have yet to apply for permission to build.

It is almost inevitable that, in the absence to date of a firm scheme to assist in the extension of the grid system, developers will have picked sites that may be sub-optimal for windspeeds, on the grounds that connection is less expensive. By basing the proposed scheme solely on those schemes that have applied to date, there is a risk that some areas of high wind resource may be overlooked completely. This carries with it the risk that the larger schemes, which have the scope to contribute significantly to the renewable generation targets, will in fact not come forward.

Similarly, in the absence of grid infrastructure, developers may not have put forward schemes in areas of significant wind resource. There is therefore an opportunity here for CER to work with the planning authorities to develop a strategy for windfarm development that would guide developers towards particular areas. Planning authorities would be able to advise on the number of turbines / windfarms likely to be allowed in any given area, which could then be used as an input for the design of the required capacity of grid reinforcement.

5 Clusters

A policy of selecting those areas where there are already two or more schemes with planning permission may appear to offer the line of least risk so far as the grid system investment is concerned.

However, if the sites chosen are sub-optimal for the reasons given above, there may be a higher risk that the schemes will in fact not go forward. Furthermore, if the design of the grid extensions is restricted to consideration only of those schemes with planning permission, or for which planning permission has been sought, they cannot take account of further schemes in development.

Given that the cost of grid system enhancements is not linear with capacity, but offers a generally declining cost per MW as capacity rises, though with some large step increases where the next increment of new capacity is triggered, it seems unfortunate if scope is not available to optimise the size of capacity enhancement by taking account of all information available on the likely pace of development.

There is also the need to allow schemes to grow - there will be no scope for second and subsequent phases if there is no more grid capacity.

Emphasis on clusters appears to ignore the scope of a single, large development, such as the offshore windfarm, where the licensing arrangements in fact prevent the formation of clusters. These large developments provide the opportunity to ensure that the ‘500MW by 2005’ target is met (or, as announced in October 2002 by the Minister for Communications, Marine and Natural Resources, surpassed).

ESBNG have already stated that they envisage owning the transmission infrastructure out to the offshore substation. It would greatly support the economic development of these proposals if such connections were to be eligible for assistance under these funding proposals.

6 Steering Group Conclusions

The group reached five main conclusions, which are reported in the paper. These are as follows, with comments on each:

- *The grid upgrades should be planned by reference to perceived demand for shared infrastructure.*

Agree entirely, though there should be the widest possible scope to assess the likely demand. If the scheme is to be restricted to consideration of a limited number of schemes, it is likely that sub-optimal investment decisions will be made, leading to the need to come back again and undertake second reinforcements in the same area.

- *Perceived demand should be based on clusters with two or more projects with full planning permission intending to connect to the upgrade.*

This is a good point to start although, having established the area, a wider view on the likely overall demand, as above, will then need to be taken. In particular, schemes that have applied for permission, and/or schemes that have approached ESB or ESBNG to assess available grid capacity, should be considered once the initial areas have been chosen.

- *The prioritisation of clusters for investment support should operate on a first come first served principle subject to compliance with minimum requirements with a fall-back selection criteria in the event of simultaneous applications exceeding the available fund.*

This is sensible. However, as simultaneous applications can also be charged simultaneously, there is an argument that such instances actually place less demand on the available funds than longer drawn-out developments. Given the 2005 deadline for the first 500MW of capacity, it is logical to concentrate on approved schemes first, though the entire process should not be so constrained.

- *The first come first served principle should apply to any project compliant with the qualifying criteria, at that time.*

I take this to mean that only schemes that have full planning permission will be considered for funding, which is how it should be, provided that this does not inhibit grid capacity assessment taking a wider view at the design stage.

- *Project developers should be charged under reasonable assumptions for the capacity reserved as a proportion of the grid upgrade built.*

This is unclear. If we take as an example three, 20MW schemes, which trigger the need for a 100MW extension of the 110kV transmission system, does each scheme pay 20/100ths of the extension costs, or one-third (so that the total costs are met by the three schemes)?

If the former, then the fund needs to “carry” the cost of the additional capacity until such time as another scheme comes along to use it, while if the latter, schemes in clusters whose total capacity happens to equate more closely to the incremental capacity of the grid reinforcement will effectively pay less than those in the example given above.

Additionally, if the second option is chosen, this would totally remove any ability to plan capacity enhancements for a bigger picture, as the initial developers would be unwilling to fund the costs.

Meanwhile, a fourth developer coming along after the first three had commissioned would be able to get up to 40MW of capacity almost free. This does not seem equitable.

The five clusters identified by the steering group add up to 18 projects totalling 271.66MW with full planning permission. It would be a tremendous start to the 500MW target to get these up and running, though there is no guarantee that they would all come forward.

However, that is barely more than half way. We must assume that there are some more schemes in the same areas that do not yet have planning permission; if these come along fast enough, then perhaps 350MW could be achieved. That still leaves a shortfall of around 150MW, which presumably would have to be met by offshore wind.

7 Funding

It is noted that the proposed scheme has won funding under the EU Economic and Social Operational Programme (ESOP). The terms of ESOP are not stated. It would be helpful to know what restrictions exist under the ESOP programme, and whether any of these could act to delay or frustrate the completion of generation schemes.

Greater clarity is also needed on how repayments are to be made. The paper refers to investment being 'retrieved from customers', through TUoS (and, presumably, DUoS) funding. It is not clear how this will be apportioned. Will the costs go into the general TUoS/DUoS system, so that all customers pay a share, or will it be charged to specific Users (presumably, those for whom the connection was provided)?

There is clearly an all-Ireland benefit from the reduction in polluting emissions from fossil-fired power stations – it would therefore seem inequitable for the renewable generators, who facilitate this benefit, to have to face these additional charges alone.

Some charging structures are arranged such that both generators and suppliers pay TUoS/DUoS, irrespective of who actually 'owns' the electricity being conveyed. This can lead to double charging for new generating stations, while older stations with existing connections are generally exempt from such arrangement.

8 Cost of Connection

Generators will still have to pay the full cost of sole-user assets, and a share of shared-user assets.

Sole user assets will probably commence at the LV busbar of an 110/38kV substation. This means that the substation location will become the critical factor in assessing the cost of the connection, as full costs will be payable for works between the generator and this point.

The paper does not state how close together schemes have to be to form a cluster; however, we can reasonably assume that they could be a few kilometres apart. We could therefore have the situation arise that one farm will be close to the common substation - and thus comparatively cheap to connect.

Another farm perhaps 5km distant, could find itself funding that distance of 38kV line. Working on the basis of 38kV overhead with a capacity of 31MVA (winter), this would work out at around £110,000 (Euro 165,000) for the overhead line alone, excluding land and wayleave costs. If underground cable were necessary, the cost would multiply by a factor of 3.

This could have the result that marginal schemes furthest from the new 110/38kV substation became uneconomic (though I accept that the finances would have to be very close if this were the case) and therefore not proceed.

This could lead to “common” capacity being provided, but not taken up. It is then not paid for, which therefore reduces the size of the “rotating fund” and thus reduces the scope for further works. This, coupled with the inevitability that not all the capacity of the various extensions will be used up, could result in the “rotating fund” lasting little more than two or three rotations.

9 Security of Connection

The paper makes no comment on the security of connection.

Normal practice is for small windfarms (which, in the Irish context, might mean less than 100MW), to have a single circuit connection, with the risk that a single system fault will cause the farm to be disconnected. Where a cluster of windfarms is to be connected, then the capacity concerned could be very much greater, and thus the risk to system stability and security from the loss of the entire cluster will be greater than for the loss of a single windfarm.

There is clearly a major cost implication in the provision of duplicate transmission circuits as far as the 110/38kV substations. Given that any single farm might expect to be connected at single circuit, the result of this is that twice the transmission capacity would be installed (say two parallel 100MW, 110kV circuits) to connect a cluster of windfarms whose total capacity is, perhaps, 90MW. If each windfarm pays capacity charges based on single circuit security, the effect is that 110MW of transmission capacity is not paid for by connectees.

It is true that the boundary where this will happen may not be 100MW, but it will be somewhere. This needs to be established, and decisions taken how it is to be dealt with.

10 Operation and Maintenance

Normal practice is to charge connectees with a sum to cover the future operation and maintenance of both sole-user and shared-user assets, based on the capacity installed and connected. In this case, there is every likelihood that some element of transmission capacity will be installed without a customer. This capacity will need to be maintained.

The paper is silent on how this is to be funded, but it would be helpful to know. If it is to be divided among the connecting parties, they could end up paying a higher than normal charge for this service, which would require CER approval for a change in the connection charge structure. If it is to come out of the revolving fund, that will be another cause of its' early exhaustion. Failing that, it is covered by ordinary TUoS, which would go up (though only by a very small fraction) to cover this.

11 Conclusion

There are a number of very positive features about the proposed funding process, not least of which is that there is agreement on the principle that funding is needed outside the generation business.

The principle of the rotating fund is sound; although the costs should be recalculated on the assumption that only 75% of the capacity thus paid for is actually taken up, which is probably not far from where the outcome may lie. Costs to the consumer have been calculated as a one-off sum (ie, the amount not reimbursed by connectees), amortised over 40 years, and it would help if this were calculated for the 75% take-up scenario. Commitment to further top-up funding as the original rotating fund depletes would also be welcome, along with a view on the costs of it.

The following points need clarifying:

1 That generators will only pay for grid capacity on the basis of the capacity of their scheme, rather than a larger share.

2 That ESB/ESBNG will be able to take into account in their capacity planning schemes that have not yet obtained planning permission. A decision will be needed on how far ahead they should look. It is perhaps reasonable that any extension constructed should not require to be further upgraded for at least five years, based on the information available at the time of design.

3 Consideration to be given to locating new substations as near as possible to the centre of any given cluster, in order to equalise connection charges for the members of that cluster. If that is not possible, or practical, consideration should be given to some form of equalisation of the costs charged within that cluster.

4 In view of the fact that this measure alone is unlikely to bring forward sufficient capacity to achieve 500MW of new renewables by 2005, a comment about the estimated amount of capacity that will have to be sourced elsewhere (ie, offshore wind, though CER are not the body to be so specific) would be helpful.

5 The scheme needs to be sufficiently flexible to incorporate more generators as they gain planning permission. At present it seems to refer only to those who have already obtained planning permission as participating.

6 The terms of the EU ESOP funding need to be made clear, so that compliance with any conditions can be ensured.

Finally, there are a few points that should be raised, but which have not been covered at all in the paper.

i Is it intended that offshore schemes will be eligible for support in this way?

ii Will there be a ceiling on the capacity of schemes that will be eligible for support, as large scheme will, in any case, be of a size where they will effectively use up an increment of grid capacity.

iii Security of connection, and how funding for duplicate circuits provide for system security will be provided.

iv Operation and Maintenance costs on transmission capacity for which there is no customer.

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