Financing the Renewables

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SummaryFew forms of renewable generation technologies can compete directly with fossil. As a consequence, they require additional revenues. The way in which this support is provided influences the sources of potential finance. In the UK, all forms of generation are exposed to price movements in the fossil market. For renewable generation, these risks are compounded by the uncertainties in the future value of Renewable Obligation Certificates. These factors are likely to constrain the available sources of finance and possibly impede the development of the renewable sector. On the positive side, customers are unlikely to be lumbered with the consequences of poor investment decisions.

IntroductionSupport for renewable generation in Britain has switched from the Non Fossil Fuel Obligation to the requirement for suppliers to obtain Renewable Obligation Certificates. This paper discusses how this change fundamentally alters forms of financing available for renewable generation projects and may act as a constraint on development.

The Introduction of Market RiskThe Non-Fossil Fuel Obligation was the initial support for renewable forms of generation in Britain. In essence, this provided a series of long term fixed priced contracts to prospective developers. The price for power was determined by auction where, for particular technologies, developers submitting the cheapest bids were rewarded with a contract. The premium of this “non-fossil” generation over the price in the ordinary wholesale electricity market was levied across all customers in proportion to the delivered price of electricity.

Once the developer had secured a contract, it was relatively easy to raise finance. Assuming that there was little technological risk, bankers would be happy to finance a project by debt, often up to 80-90% of the capital cost, since they could be confident that the project would receive regular, well-defined, income from the Agency. The revenues would be used to make interest payments and, eventually, pay down the debt. Loans from 7 to 15 year duration were not uncommon at costs of 200-400 points above LIBOR. The premium could be reduced if the project would provide a “parent guarantee” to the bank(s).

The remainder of the finance, 10-20% of the capital cost, would be provided by equity, which enjoyed the expectation of higher returns, of order 15-25%. Of course, if the project failed in some way, the equity holders could lose all their money.

If there were technological or construction risk, such as in the early stages of electricity generation from landfill sites, or early on-shore wind power, the projects were built using equity but, once a track record had been established, the revenue stream could be “sold off” or “securitised”. In these cases, the developer would be rewarded with a cash payment equal to the discounted value of the future income stream. Developers did not need extremely deep pockets.

Enter the MarketThe Utilities Act (2000) fundamentally changed the form of support available to renewable generation technologies. Suppliers are now obliged to purchase a proportion (currently 3%) of their requirements from renewable sources. Such purchases are confirmed through “Renewable Obligation Certificates. Failure will expose them to a penalty of £30/MWh for any shortfall.

The key effect of this change is that the price of electricity generated by a renewable source will be independent of the type of technology employed and will be the sum of:-

• The price of “non-renewable” electricity; and

• The price of the ROCs.

In the early to mid 1990s “ordinary” wholesale electricity prices were reasonably stable. Similarly, many thought that the value of ROCs would always be £30/MWh or even more – due to the mechanism whereby the penalty payments are recycled back to holders of ROCs. However, it would be a grave mistake to allow history and the last assumption imply that revenues for renewable generation in the 21st century will be predictable, like those under the NOFFO.

The non-renewable marketWholesale power prices in Britain have fallen dramatically over the past four years, so that they are now closer to those in the German and Nordic markets, as shown in Figure 1 below. The collapse was caused by the major generators losing control of the market, possibly helped by the introduction of NETA, coupled with a surplus of capacity. It seems that the market has moved from one where an oligopoly controlled prices to a fragmented market where there is no such control and prices are forced down to the marginal costs of production.

Figure 1International Wholesale Power Prices

The important question is when will prices rise? In fragmented markets, it could be a very long time – not until demand starts to exceed supply. Figure 2 indicates the type of price behaviour that might be expected. The actual shape is, of course unknown, as there is only little evidence so far. However, Figure 3 shows how the value of the cash-flows generated by a new gas fired power station depends critically on:-

• The time from commissioning to the next “peak”• The peak’s duration; and• The time between subsequent peaks.

In the British market, where demand growth is slow (so we may expect 6-10 years before the “peak”), it is clear that, unless the peak occurs within two years of commissioning, the investment would destroy value.

Figure 2Price Behaviour in Fragmented Markets

Figure 3:Values of Cash-flows from New Gas Stations in Fragmented Markets

The market for ROCsDevelopers of renewable generation have to face the uncertainties of the “ordinary market”, plus those of the ROCs. These ROCs were thought to have a floor value of £30/MWh, in line with the “buy out” option for suppliers; rather than pay the price for a ROC, they could just pay the penalty. Owing to the recycling of ROCs, the value of a ROC could be higher. Indeed, if one company owned all the ROCs, then it is easy to see that the value of each ROC would be supplemented by the penalties paid by all the other suppliers who would, by definition, be in shortfall. Indeed, the value of a ROC is sensitive to the ownership structure of the ROCs themselves. Figure 4 shows how the value of each ROC depends on the concentration of ROCs amongst the suppliers.

Figure 4Values of Renewable Obligation Certificates

Assumes a total market of 290 TWh, 3% renewable obligation, 2.45% generation available, £30/MWh buyout and 5 suppliers each with 20% market share.

However, more worrying, is the possibility that the Obligation is so successful in attracting renewable generation that, at some point in the not too distant future, the amount of renewable generation capacity available exceeds that required by the Obligation. Whilst the penalty, or “buy out” would remain at £30/MWh (indexed to inflation until 2027), an over-supply of ROCs would exert the same grief on ROC values as the over-supply in the non-renewable market has recently dealt to the owners of fossil and nuclear capacity. There is a real possibility that the value of ROCs could fall to zero.

Who will finance renewable capacity?The above analysis has indicated that the revenues from renewable sources of generation are likely to be volatile; the uncertainty in the “non-renewable” market is compounded by that in the ROC valuations. Were a developer to build such a station “on-spec”; i.e. without securing any off-take contracts, a banker would look very hard at the expected revenues before lending any money. He might draw up a diagram like Figure 5.

Figure 5Average Revenues from Renewable Generation

This figure indicates that average prices for renewable electricity could exceed £50/MWh, but, as we have discussed, there is also the chance that for long periods, prices could be considerably lower. Bankers need confidence that the loan, and interest, will be paid on time and all the time. They will, therefore, only make loans to generating projects when they have reasons to believe that, whatever happens, the project will be able to service the debt. Since it is unlikely that the non-renewable price will fall much below the marginal costs of fossil generation, it is possible that a banker would be willing to assume that the non-renewable market price would not fall below, say £16/MW, representing the marginal cost of production and the annualised fixed costs of fossil generation. Add to that the benefits of avoiding the Climate Change Levy (CCL), and one could argue that £20/MWh would be a reasonable floor to the non-renewable market.

However, a more cautious banker would worry that coal and gas costs could easily fall, so there could be long periods where the non-renewable market traded as low as £10/MWh. Moreover, who is to say that the Government may not repeal the Climate Change Levy and combine it with the ROCs in some unknown way. Accordingly, the a cautious banker would only be willing to loan for an extended period, say 15 years, if revenues of £10/MWh alone were sufficient to pay the interest and repay the capital. On the basis of a plant having no fuel costs, or fixed costs, and a 90% load factor, such as hydro, this implies the lender may be willing to lend £675/kW at an 8% interest rate.

The remainder of the capital cost, some £325/kW for hydro, would have to be financed by less risk adverse forms of finance. For example, an investor may be willing to assume that, over the next 4 years, there was little chance that the CCL would be abolished. The investor could then lend money, at a higher rate of interest, say 12%, over a 4 year period. The associated £4.3/MWh income stream could then finance a further £100/kW. Finally, equity investors could provide the final £225/kW. This is a very simplified explanation, but in simple terms, finance can be provided by debt or equity, with “mezzanine” finance in between. Figure 6 indicates how the anticipated revenue stream may be allocated to the different types of financier. After meeting staff and operating costs (and tax!), the residual revenues are usually offered to the different lenders according to the level of risk, and return, they have accepted. Thus, the equity holders would enjoy the benefits of prices rising to £50/MWh, but also the pain if they fell below £14/MWh for long periods.

Figure 6Allocation of Revenue Streams

Providers of StabilitySo far the discussion has been in terms of short term market prices for power. The whole situation changes if the generator is able to sell the output from the generator over a long period at an agreed price. The problem is, who would agree to take on such a risk? Indeed, the history of competitive power markets is littered with suppliers who unwisely entered into long-term contracts for power. Nevertheless, if the generator were able to find a willing buyer (for the ROCs as well as the power) a banker would be willing to lend money against the contract revenues, having first, of course, checked the long-term credit worthiness of the buyer.

For example, a supplier may forecast that non-renewable power prices were likely to exceed £16/MWh for the next 15 years and, at the same time, the ROC and the Climate Change Levy, or their replacements, would entitle it to at least another £29/MWh, and so it may be willing to offer a wind generator £45/MWh for 15 years. On this basis, the income stream could be sold off (securitised) and raise over £1,100/kW, sufficient to pay the capital cost of the wind-turbine. The lenders, on the other hand, would want some comfort that the supplier would be able to recover this £45/MWh, from its customers. This clearly depends on the answer to three questions:-

• What is the possibility that the contact will move out of the money (i.e. become expensive) over the contract period; and

• If this does occur, will the supplier still be able to pass these higher costs onto its customers. Or

• Is the supplier likely to have sufficient cash reserves to allow it to weather the storm?

The experience, to date, in the British market suggests that it is extremely unwise for suppliers to enter into long-term contracts. Suppliers have not always been able to pass on the costs of out of the money contracts to their customers. This is because the industrial and commercial sectors have shown themselves to be very price sensitive. On the other hand, domestic customers have been rather sticky, tending to change suppliers only when moving house or when an energy salesman knocks on their door. As a consequence the incumbent suppliers, the successors to the 14 original Public Electricity Suppliers and Centrica are the only suppliers with the ability to sign long-term contracts.

So who provides the finance?The discussion suggests that the returns available from investing in any form of generation in Britain are likely to be volatile, and renewable generation only more so. Renewable generators are likely to be financed by equity, rather than debt, unless the risks are reduced by signing a long term off-take contract. However, stand-alone generator would be in a very weak bargaining position when trying to negotiate suitable contract terms.Potential renewable generation developers will therefore need to use equity finance to develop projects. However, this is where the capital markets have a problem. Most renewable schemes are, by utility standards, quite small. Scheme costs of £5 million or less are not uncommon, if not the norm. Many City institutions are not geared up to deal with such small sums. Indeed, the costs of preparing the financing “term sheets” for a £5m project would not be very different for schemes requiring £200m. Whilst it is the case that there is interest amongst within the “private equity” market for renewable projects, the market is immature, and balks at raising sums below £20m.

It therefore seems that most financing for renewable schemes will come from the balance sheets of large companies, either in the form of direct investment, or by their appetite to sign long term power purchase contracts. This could act as a deterrent to the development of renewable schemes because, as noted above, renewable schemes tend to be small and the large incumbent players may not have the skills necessary to develop small-scale technologies.IJ

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