Renewable Energy Development in Northern Ireland

July 2001

1. BACKGROUND

This paper has been prepared as a contribution to the current reviews of energy policy taking place in Northern Ireland [*1*]. In addition, it is hoped that the paper will contribute to the formulation of the strategies on energy by the Departments of Regional Development and of Trade Enterprise and Investment as part of the Northern Ireland Executive.

This paper has been prepared by the British Wind Energy Association which is the largest renewable energy trade and professional association in the UK, with a membership of over 500, including more than 150 corporate members covering all aspects of wind energy development [See Appendix 1 for full list of membership]. The BWEA recognises that some of the measures proposed in this document differ from measures proposed in England Wales and Scotland. This is considered necessary given the particular circumstances existing in Northern Ireland.

2. CONTEXT

Renewable electricity is an important means of reducing the emission into the atmosphere of greenhouse gases. The increased use of renewables is supported by policy targets set by the European Union and by the UK Government. The European Commission, in announcing the draft directive on promoting electricity from renewable energy in the internal electricity market (May 2000) identified that the UK, more than any other member state, will need to make rapid progress if it is to achieve its targets. Broadly, the targets for the UK are as follows:

- Reducing greenhouse gas emissions to 12.5 per cent below 1990 levels by 2008-2012, and moving towards a domestic UK goal of a 20 per cent cut in CO_2 emissions below 1990 levels by 2010.
- 5 per cent of electricity in the UK to be generated from renewables by 2003, and 10 per cent by 2010 (of which the Government has indicated that 26% is likely to come from onshore wind energy).

These targets however have not been disaggregated to the Northern Ireland level. As policy stands at the moment, the only existing official Northern Ireland target is to secure 45MW (dnc) [*2*] by 2005. This would represent about 2.2% of Northern Ireland's generating capacity and about 3.3% of its electricity output.

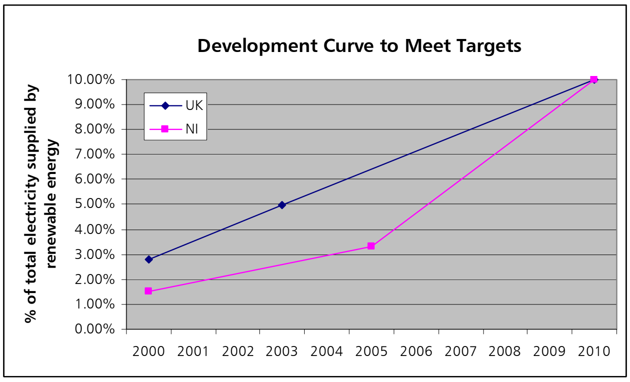

Figure 1: Development Curves for Meeting UK and NI Targets

At the beginning of year 2000, renewable energy sources represented for the UK as a whole 2.8% of total electricity generated in the UK [*3*] and, for Northern Ireland, 1.5% of total electricity generated in Northern Ireland [*4*]. It is therefore clear that Northern Ireland, on current policy and assuming it adopts a 10% target for 2010 itself, has adopted a very different development curve to that for the UK as a whole, requiring as it will a rapid and substantial increase in capacity after 2005 (see Figure 1).

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1. The current reviews include the Energy Inquiry by the Enterprise, Trade and Investment Committee, the upcoming consultation on renewable energy by the Department of Enterprise, Trade and Investment, the current review being conducted through the Trading Renewables Implementation Group established by OFREG, the consultation Paper "Greening Transmission and Distribution" by OFREG and the consultation Paper "Electricity Market Opening – The Time to Win" by OFREG.

2. "dnc" or "declared net capability" for intermittent renewables is the equivalent capacity of base-load plant that would produce the same average annual energy output.

3. *Digest of UK Energy Statistics, 2000*. The Stationery Office

4. Based upon total Northern Ireland electricity demand (7500 GWh) not upon units sent our from generators (8151 GWh).

2.1. CURRENT NORTHERN IRELAND POLICY ON CLIMATE CHANGE

In November 2000 Mr Sam Foster, Minister of the Environment presented the "*UK Climate Change Programme*" to the Northern Ireland Assembly. It outlines the measures that Northern Ireland has taken, and will continue to take, to ensure that it makes as significant a contribution as possible to cutting greenhouse gas emissions. One of the key aims of the Programme is to stimulate a national debate on how the country can respond to the challenges of climate change particularly in relation to the type of energy we will be using in future. Areas where Northern Ireland will be making a contribution to reduce emissions include among others: More efficient production and use of energy; switching to renewable sources of energy; and, planning.

2.2. CURRENT NORTHERN IRELAND POLICY ON RENEWABLE ENERGY

The NI Executive's "*Programme for Government*", which sets out plans and priorities for three years from April 2001, was submitted to the Assembly in February 2001. The Programme includes strategic energy objectives, which are in line with wider UK and EU policy. It also includes the diversification of supply and the encouragement of the clean production and use of power.

3. NORTHERN IRELAND RESOURCE POTENTIAL

Northern Ireland has a very impressive wind energy resource. To date, only the very best sites have been used where the energy production from a single turbine is about 60% more than the same machine installed in Denmark. On the assumption that further development takes places outside areas designated as Areas of Outstanding Natural Beauty, it is inevitable that sites with lower yield will be developed.

However, the resource is still substantial. It is estimated that the accessible resource is around 56,000 GWh [*5*]. Taking account of the resource potential, a grid penetration limit of 10% and demand projections, the BWEA has estimated that Northern Ireland is capable of contributing 9% of the UK's onshore wind energy target by 2010 [*6*]. This would require installing between 290MW and 340MW. In terms of the size of turbines currently commercially available, this would entail installing between 165 and 227 turbines in Northern Ireland.

4. GRID INTEGRATION

The ETSU study [*5*] imposed constraints on the maximum contribution that could come from wind energy which limited the developable resource to 160 GWh/y by 2025 (or 1.9% of *current* total electricity generation). This was based upon the level of grid penetration that was considered possible. These constraint assumptions were taken from a previous study in 1993 (also conducted by ETSU on behalf of NIE and DED) without any updating to take account of advances in wind turbine technology, further network integration between Northern Ireland and ROI and Scotland and advances in control management or without any consideration to possible future developments in these areas. The BWEA believes that by 2010 (and certainly by 2025) wind energy can achieve higher levels of penetration than the 1.9% suggested by ETSU.

We urge the Departments of Regional Development and of Enterprise, Trade and Investment working with OFREG and NIE to develop strategies for increasing the potential for wind energy to be integrated into the Northern Ireland network. In this regard we strongly support the OFREG proposal to incentivise, through the price control mechanism, the distribution network to carry more units than the transmission network. We consider this latter arrangement would be in line with EU measures to promote renewable energy development and utilisation. We consider that it is a failing of the current structures that NIE Transmission and Distribution does not consider further integration of renewable energy as a priority or concern of theirs.

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5. *Renewable Energy in the Millennium – the Northern Ireland Potential*, June 1999, ETSU for NIE and DED.

The "Accessible Potential" is the renewable energy resource that could be exploited, if the Technical Resource was limited only by practical constraints (such as roads, settlements, site suitability, etc) and institutional constraints (such as environmental and planning restrictions).

6. Planning for Wind Energy – A guide for regional targets, BWEA (available from www.bwea.com).

5. PLANNING

The DETR's regional frameworks guidance document recognises the need to establish the implications at a regional level of achieving the national renewable energy targets. Though not directly applicable in Northern Ireland, the recommendation to assess at a local level how the targets could be achieved is valid and welcome. We would therefore encourage the DoE Planning Service of Northern Ireland and the Departments of Regional Development and of Enterprise, Trade and Investment to review at a planning level how each County could contribute to the achievement of the renewable energy targets.

6. AUCTIONS OF NFFO CAPACITY

The auction of NFFO output for 2001/02 has provided a very useful springboard for those suppliers that are interested in supplying renewable energy in Northern Ireland. It has given them capacity under a short-term contract that enables them to test the market with potential customers. At the time of the auctions it was stated that the auctions would only be for one year to ensure that they would not themselves act as a barrier to renewable energy development by displacing the requirement to develop new sources of renewable energy capacity. The BWEA believes that it is difficult for wind energy generators to conclude any longer term contracts whilst the NFFO auctioned output has been available despite the existence of ready-to-build capacity in Northern Ireland . It is essential therefore in our view that the NFFO auctions are strictly limited to the one year 2001/02.

7. POLICY MECHANISMS

7.1. PREVIOUS SYSTEMS (NFFO 1 AND 2)

The NFFO process has enjoyed mixed success. For wind energy, all projects that received NI NFFO 1 or NI NFFO 2 contracts (8 projects totalling 36 MW or 15.48 MW dnc) received planning approval and have been successfully built. However, the process has been criticised for being inflexible, costly (both for developers and the electricity consumer) and incapable of delivering the capacity necessary to meet the targets within the context of a liberalised open market for electricity. To demonstrate the costly nature of the process for developers, for the NI NFFO 2 round 33 wind energy projects were submitted totalling well over 100 MW and only 2 projects totalling 6 MW (2.58 MW dnc) were finally awarded contracts – a very poor success to failure ratio.

The BWEA recognises that the process involves an excess cost paid for by the electricity consumer [*7*]. However, these costs are committed and, based as they are on a support mechanism that is no longer considered appropriate for supporting renewable energy – the NFFO process, should not be used for comparison with alternative proposed options. We consider that it is more appropriate to compare genuine alternative policy options for determining the least cost option.

7.2. OPTIONS FOR THE FUTURE

7.2.1 Another NFFO?

The BWEA does not consider that the NFFO process is the most appropriate or cost-effective mechanism for bringing forward significant new renewable energy capacity in Northern Ireland. It may, however, be considered appropriate for fostering emerging technologies that are not yet near commercial competitiveness.

7.2.2 Measures to improve renewable energy trading?

The BWEA recognises the opportunity that Northern Ireland has to learn from the experience of NETA in Great Britain, which, in some respects, is seriously hampering renewable energy trade and development.

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7. Purely for presentational accuracy, we consider that the excess costs of NFFO (for year 2000 generation figures) equate to approximately £4,145,000 rather than the figure of £7,000,000 stated in various OFREG papers. This is based upon the following assumptions:
   - NFFO annual generation of 115720472 units at total annual cost of £7,794,511 (source: NIE PP);
   - Energy displacement value of NFFO generation of 2.205p/kWh (source: NIE PP);
   - Embedded generation rebate of 0.498p/kWh - though flat rate is only 0.249p (source: NIE T&D data);
   - Capacity charges averaging 0.2p/kWh (source: NIE T&D data); and,
   - Climate Change Levy of 0.43p/kWh.

Northern Ireland should benefit from this experience by introducing, at the outset, measures that can avoid such problems and that can successfully support the trade of renewable energy.

a) Metering, profiling and removing the need for half-hour measurement

The cost of installing dedicated code 5 half-hour on-line metering is prohibitive for entering the supply business for domestic and possibly even the SME market. It is recognised that, given the small size of the Northern Ireland system, the cost of implementing a profiling system is also excessive for Northern Ireland. In the BWEA's view, it is therefore quite appropriate that the need for half-hour on-line metering is removed for renewable energy trade through the imaginative solutions proposed by OFREG of levelising the cost of Top up (see further, Section 7.2.2b). This has the benefit for a renewable energy supplier (or a *de minimis* generator wheeling to a remote site) of removing the need for on-line half-hour metering. Top up would simply become the product of the time-weighted average of the prevailing BST table (divided into a Summer and a Winter rate) and a factor to represent the degree (if any) of support afforded to renewable energy to reduce the difference between Top up and Spill prices.

b) Top up and Spill

The current structure of the settlement system in Northern Ireland requires renewable energy to be traded in the same way as conventional sources of electricity. For intermittent sources, this provides a significant problem because of the inevitability of there being a significant mismatch between supply and demand. Analysis conducted by using half-hour wind energy generation data from Northern Ireland over a 5 year period and demand data from a range of sources [*8*], shows that the degree of matching supply with demand is likely to be, on an annual average energy basis, around 60% (see further Appendix 2). There is therefore a significant reliance on the Top up and Spill arrangements for wind energy generators.

The Top up and Spill arrangements pose a purely commercial penalty for a renewable energy supplier using wind energy as the source of its electricity. It is not the uncertainty over the level of demand / supply mismatch (since this is very consistent over the 5 years of the analysis [*9*]) but it is the financial implications of such a mismatch, where the half-hour spill price is 1.5p/kWh in summer and 2.0p/kWh in winter and the half-hour BST rate (2001/ 2002) ranges from 2.189p/kWh (summer weekdays early morning) to 7.09p/kWh (winter peak days mid afternoon). This commercial penalty from the settlement system for an intermittent source can be addressed through levelising the Top up rates to the annual time-weighted average and reducing the difference between the rates for Top up and Spill.

i) Levelising Top up rates

For 2001/02 rates, the time-weighted average of BST for the summer months is 3.157p/kWh and for winter months is 3.764 p/kWh. In itself, the benefits of fixing the rates for Top up at these figures are two-fold:

1. It removes the need for introducing either profiling for the Northern Ireland system or half hour on-line metering; and,
2. It simplifies the netting arrangements for small generators.

ii) Reducing the Difference of Top up and Spill

As an additional support for encouraging renewable energy in Northern Ireland, it is possible to reduce the differential between the levelised Top up rates and the Spill rates.

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8. Demand data based upon Electricity Association published standard load profiles.

9. The analysis shows considerable consistency between the revenues (using 2001/02 BST and Top up and Spill prices) obtained for the five different years despite wholly varying half-hour profiles year-on-year. This observation is important because it indicates that the potential revenue results are largely independent of the half-hour generation profile - that is, the revenue figures (and hence any internal rate of return assessments) are valid for years with very different wind energy production data.

An analysis of the cost of equalising Top up and Spill for intermittent renewable energy sources has been conducted. This has used half-hour wind energy generation data over a 5 year period (scaled to 100GWh) and Electricity Association demand profiles for domestic and sub100kW non-domestic customers (scaled to 100GWh) - see Appendix 2. The results are summarised below in Figure 2, below.

	Year 1	***Year 2***	***Year 3***	***Year 4***	***Year 5***	***Average***
Domestic Unrestricted	£801,483	£853,004	£797,808	£814,575	£821,525	£817,679
Domestic Economy 7	£568,483	£667,275	£604,663	£630,803	£642,298	£622,704
Non-Domestic Unrestricted	£997,151	£609,956	£567,882	£583,402	£579,960	£667,670
Non-Domestic Economy 7	£709,341	£1,031,381	£988,288	£1,008,524	£1,008,401	£949,187
Non-Domestic Max. Dem. 0-20% LF	£1,039,134	£753,414	£707,570	£732,437	£734,259	£793,363
Non-Domestic Max. Dem. 20-30% LF	£966,971	£1,066,667	£1,032,926	£1,055,432	£1,050,241	£1,034,447
Non-Domestic Max. Dem. 30-40% LF	£816,555	£1,002,615	£961,175	£981,641	£980,979	£948,593
Non-Domestic Max. Dem. >40% LF	£699,346	£861,953	£808,488	£830,633	£836,664	£807,417
Combined [*10*]	£781,027	£748,028	£686,183	£710,461	£722,494	£729,639
Flat [*11*]	£620,101	£825,720	£772,451	£795,330	£803,642	£763,449

Figure 2: Cost of Equalising Top up and Spill using Half-Hour Wind Generation Data (*Highs and Lows indicated*)

The cost of equalising Top up and Spill for wind energy ranges from £0.567m to £1.066m per 100GWh of electricity supplied, or between 0.567p/kWh and 1.066p/kWh [12]. This would represent a subsidy equating to some 16-30% of the cost of wind energy generation. Such a subsidy would be a direct subsidy between 'the system' (though it would need to be paid for by a PSO on all customers) and the renewable energy supplier. It only acts as a support to the 'trade' in renewable energy - it does not help reduce the generation cost of wind energy itself.

Equalising the rates of Top up and Spill has a number of disadvantages;

1. It has the effect of treating intermittent sources the same as firm sources and thus distorts the competitive advantage of a firm source of renewable energy such as biomass over a non-firm source such as wind energy. It would be more sensible for a renewable energy supplier to choose a mix of renewable energy sources that could provide a greater degree of firmness rather than relying purely on wind energy.
2. In addition, such an arrangement would bizarrely create a more favourable situation for a supplier of renewable energy than would exist for a *de minimis* generator wheeling directly to a remote customer - since such a generator is obliged to install half-hour on-line metering and to pay Top up and Spill as incurred.
3. Last, we consider that such an arrangement would provide excessive support to a supplier that was seeking to use the 'system' as the provider of Top up compared to a supplier that was seeking to manage the risk of mismatch between supply and demand from within its own purchasing strategy. Typically, this would be a supplier aiming to supply only a proportion of the customer's total demand from renewable energy.

Though not as munificent as equalising Top up and Spill it is possible to reduce the difference of the Top up and Spill without the distortion to the markets involved in equalising the Top up and Spill costs and without the large subsidies required. The question then becomes, what percentage of the time-weighted annual average of the Top up rates should be used?

We would consider that it should 100% for >100kW customers (ie no reduction) and 70-80% for <100kW customers. For 2001/02 rates, the time-weighted average of BST for the summer months is 3.157p/kWh and for winter months is 3.764 p/kWh. The respective Spill rates are

10. This scenario has assumed a mix of customers with each customer type representing 1/8th of the energy demand (100GWh).

11. This scenario has assumed that the demand profile is entirely flat.

12. A combined demand profile (See Appendix 2) gives an average cost of £0.730m (0.730p/kWh).

1.5p/kWh and 2.0p/kWh. By reducing the difference by 20% and 30% and keeping the Spill prices the same, the resulting Top up prices would be as follows:

2001/2002	Reduction of 20%	Reduction of 30%
Summer	2.826 p/kWh	2.660 p/kWh
Winter	3.411 p/kWh	3.235 p/kWh

c) Embedded Generation

The proposal by OFREG to allow NIE T&D to support embedded CHP / renewable energy generation in appropriate circumstances as an alternative to local network reinforcement is both very sensible and very appropriate. The rate of return requirements of NIE T&D should be lower than a project developer's. In such circumstances, the final price of electricity would be lower than were the project financed with the rate of return requirements of an independent project developer.

d) Different Use of System Charges for Renewable Energy

The BWEA is aware of concern by some generators of the effect of the use of system charging arrangements in Northern Ireland on their business. It is without doubt true that reducing the UoS costs would aid the development of renewable energy / CHP generators, and it also quite true that this could lead to market distortions but which, in our view, would be negligible.

i) Levelising Use of System charges

Given that we have proposed (see Section 7.2.2b) that Top up rates should be levelised to remove the need for half hour-on-line metering, it would also be necessary to ensure that UoS charges were also levelised to the time-weighted annual average to be consistent – otherwise half hour on-line meters would still be required for metering electricity flows as part of the process of calculating half hour UoS charges. We therefore consider it is essential to establish UoS charges on the basis of a flat annualised figure rather than on the basis of different half hour rates for renewable energy.

ii) Reducing the Use of System charges

Whilst we recognise that a reduced percentage of the annualised UoS charges would be beneficial we are not able to state what would be required as this would vary from project to project. In addition, it should be recognised that there would be a significant benefit in moving to a flat annualised UoS charge (regardless of time of day) because of the effect of the low night-time UoS charges on the calculation of the flat annualised rate. This is because most renewable energy projects (other than wind energy) will tend to wheel during the day when they would normally incur higher UoS charges than were they to wheel during the night. By annualising the UoS charge to a flat charge regardless of time of day, the high proportion of low night UoS charges will significantly influence the calculation. For an under 1 MW customer connected at 6.6/11kV, the flat annualised time-weighted average UoS charge is 0.694p/kWh (excluding the effect of the embedded generation rebate) compared to a peak half hour charge of 13.271p/kWh.

The commercial advantage of fixing this charge in itself would also be of significant benefit as a aid to revenue forecasting.

On account of the above two observations, we do not consider that a reduction in the flat annualised UoS charge would be necessary or appropriate.

e) Balancing over one year

A supplier that was aiming to supply 100% of its customer's demand with renewable energy would require the ability to balance its Top up and Spill such that its customer would have confidence in the renewable energy product it was purchasing. To ensure a reasonable balance between the supplier's interests and the customer's confidence in the product, we consider that a one year balancing period is appropriate. Anything beyond this would jeopardise consumer confidence in the product.

f) ***De minimis* level for wheeling**

The wheeling limit of 1MW of generation for a renewable energy project is too small. We consider that increasing the limit to 2-3MW would be reasonable.

7.2.3 A Renewables Obligation for Northern Ireland?

In addition, to making it more possible to conduct trade in renewable energy, we consider that it is essential that measures are introduced that *encourage* the trade in renewable energy.

A customer will purchase renewable energy for a range of reasons. They might see a cost-benefit; they might see potential good public relations for doing so; they may have environmental motives; or, they (or their supplier) may have an obligation to do so.

The BWEA considers that a Renewables Obligation for Northern Ireland, coupled with the market enabling measures detailed above, has the possibility of introducing the right degree of market pull that would foster renewable energy. We consider it very important that the Department of Enterprise, Trade and Investment urgently introduces legislation to implement a Renewables Obligation in Northern Ireland.

If an appropriate buy-out level was set, then such a Renewables Obligation would both prevent any abuse of position being exercised by any one sector (eg suppliers or generators) and would ensure that the costs of compliance are as low as possible (both for individual companies and the Northern Ireland system as a whole). Since the Obligation would be on all suppliers, it would introduce a competitive solution to the encouragement of renewable energy and would therefore fit well with the ultra competitive proposals currently being proposed by OFREG.

There are legitimate concerns about how the GB system might work in the future. These concerns relate principally to the structure of NETA and not the Renewables Obligation itself. If the trading systems as described above are introduced it should be possible to construct a robust, flexible and appropriate system for Northern Ireland.

Critically for Northern Ireland, a Renewables Obligation would enable Northern Ireland renewable energy generators to trade the certificates within a UK wide Renewables Obligation market and thereby allow Northern Ireland consumers to benefit from exports of renewable energy certificates. This is crucial since no other system of support (whether by way of capital grants to generators or a more flexible trading environment involving subsidised Top up and Spill arrangements) would provide any opportunity to generate export income which can thereby, in theory, subsidise the domestic cost of electricity.

8. SUMMARY OF RECOMMENDATIONS

1. Northern Ireland formally adopts the wider UK target of 5% of electricity in Northern Ireland to be generated from renewables by 2003, and 10 per cent by 2010.

2. We urge the DRD and DETI-NI working with OFREG and NIE to develop strategies for increasing the potential for wind energy to be integrated into the Northern Ireland network.

3. We encourage the DoE Planning Service of Northern Ireland and the DRD and DETI-NI to review at a planning level how each County could contribute to the achievement of the renewable energy targets.

4. The BWEA believes it is essential that the NFFO auctions are strictly limited to the one year 2001/02.

5. The BWEA does not consider that the NFFO process is the most appropriate or cost-effective mechanism for bringing forward significant new renewable energy capacity in Northern Ireland.

6. We urge the DETI-NI and OFREG to learn from the experiences of NETA in GB by implementing the following measures:

a. levelising the Top up rates for renewable energy to the time-weighted annual average for >100kW customers;

b. levelising the Top up rates for renewable energy to 70-80% of the time-weighted annual average for <100kW customers;

c. allowing NIE T&D to support embedded CHP / renewable energy generation in appropriate circumstances as an alternative to local network reinforcement;

d. levelising UoS charges for renewable energy to the time-weighted annual average;

e. allowing suppliers supplying renewable energy to balance Top up and Spill over one year whilst still being regarded as a renewable energy supplier;

f. increasing the threshold for wheeling for *de minimis* generators to 2-3MW.

7. We consider it very important that the DETI-NI urgently introduces legislation to implement a Renewables Obligation in Northern Ireland.

Appendix 1: BWEA Corporate Membership

ABB Zantingh Ltd	Energy Unlimited	PMSS Ltd
ABP Research & Consultancy	ENERTRAG UK Ltd	PowerGen Renewables Ltd
AEA Technology Environment	Enron Europe Ltd	Proven Engineering Products Ltd
Aegis Rubber Engineering	Enron Wind	R.D.C. Ltd
Aerpac UK Limited	Enviros Aspinwall	Renew North
Aileron Associates Limited	Ernst & Young	Renewable Energy Systems Ltd
Airtricity Development Ltd	ESB Power Generation, Renewables	ReSoft Ltd
Ambient Energy Ltd	Fairfield Mabey Ltd	Riomay Ltd
Amec Border Wind	Farm Energy Ltd	RMB Engineering Services
Andaray Engineering Ltd	Fugro Limited	Royal and Sunalliance
Anderson Strathern WS	Furness Energy Partnership	Scottish & Southern Energy plc
Anglesey Wind & Energy Ltd	Galeforce Wind Turbines (N.I.) Ltd	Scottish Power
B9 Energy (O&M) Ltd	Garrad Hassan & Partners Ltd	Seabed Scour Control Systems Ltd
Baywind Energy Co-operative	GPA Partnership	Seacore Ltd
Bendalls Engineering	Halcrow Group Ltd	Shell International Renewables Ltd
Bomel Limited	Hammond Suddards Edge	SLP Engineering Ltd
Bond Pearce Solicitors	Harlequin Metal Supplies	Stephenson Halliday
Bonus Energy A/S	Hedley Purvis	Sustainable Energy Limited
British Energy plc	HR Wallingford	Thales Geosolutions
Brodies W.S., Solicitors	Hydro Soil Services	Theodore Goddard
Brown & Root Ltd	Impax Capital Corporation	Titan Environmental Surveys Ltd
Cambrian Engineering (Cymru) Ltd	Ingenco Ltd	Titan Maritime (UK) Ltd
CERPD	IT Power Ltd	TLT Solicitors
Centre for Sustainable Energy	Jennings O'Donovan & Partners	TMEnvironmental Power
Charles W. Taylor & Sons Ltd	John Mowlem & Company plc	Tomen Power Corporation UK Ltd
Chris Blandford Associates	Landscape Design Associates	Triodos Bank
Clarke Energy Ltd	Lilley Grant Rush Ltd	TXU Europe Power Ltd
CLRC, Rutherford Appleton Laboratory	London Power Company	UMIST
Collett Transport Ltd	M & N Wind Power Ltd	Umweltkontor Ireland Ltd
Conoco Global Power U.K. Ltd	Mannesmann Rexroth Ltd	unit[e]
Cornwall Light and Power Co Ltd	Marlec Engineering Co Ltd	United Utilities Green Energy
Corus Bi-Steel Solutions	Mayflower Corporation plc	University of Durham
Corus Northern Engineering Services	Mersey Docks & Harbour Company	University of the West of England
Coupe Foundry Ltd	Met Office	Vector Instruments
CREST	Metoc plc	Vestas - Danish Wind Technology A/S
Cumbria Windfarms Ltd	Mitsui Babcock Energy Ltd	Vortec Energy Ltd
Cwmni Gwynt Teg Cyf	Mobil Oil Company Ltd	Warwick Energy Limited
D.N.V. Ltd	National Energy Foundation	Wavegen
Dansteel Ltd	National Engineering Laboratory	West Coast Energy Ltd
Defence Evaluation Research Agency	National Wind Power Ltd	Western Windpower
DM Energy	Natural Power Consultants Ltd	Wichita Co. Ltd
DP Energy Ltd	NEG Micon UK Ltd	Wind Prospect Ltd
Dresdner Kleinwort Wasserstein	Nicholas Grimshaw & Partners	Windelectric Ltd
DSB Offshore Limited	Nordex UK Ltd	WCM Ltd
Dulas Ltd	North Energy Associates Ltd	Windforce Energy Development Ltd
E4environment Limited	Northern Electric Generation Ltd	WindGeneration Ltd
EcoGen Ltd	Norton Rose	Windjen Power Limited
Econnect Ltd	Oceans Engineering Ltd	Wind-Ways Ltd
Edison Mission Energy Limited	ODE, Offshore Design Engineering Ltd	Wragge & Co
eeegr, East of England Energy Group	Offshore Energy Resources Limited	Wrigleys Solicitors
EMU Environmental Ltd	Open University	Yorkshire Windpower Ltd
Energiekontor (UK) Ltd	Orga Suisse S.a.r.l	
Energy for Sustainable Development	Pirelli Cables Ltd	

Appendix 2: Demand and Supply Analysis

Common Assumptions: Demand scaled to 100GWh
Generation scaled to 100GWh

Summary Data for 1996

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	6.8	59%	£715,625	£1,517,108	£801,483
Domestic Economy 7	7847	6.8	58%	£720,534	£1,289,017	£568,483
Non-Domestic Unrestricted	2892	6.8	56%	£771,512	£1,768,664	£997,151
Non-Domestic Economy 7	1524	6.8	61%	£673,853	£1,383,194	£709,341
Non-Domestic Maximum Demand 0-20% Load Factor	605	6.8	55%	£793,446	£1,832,579	£1,039,134
Non-Domestic Maximum Demand 20-30% Load Factor	430	6.8	57%	£753,999	£1,720,969	£966,971
Non-Domestic Maximum Demand 30-40% Load Factor	326	6.8	60%	£700,677	£1,517,233	£816,555
Non-Domestic Maximum Demand >40% Load Factor	238	6.8	61%	£687,058	£1,386,404	£699,346
Combined	519	6.8	60%	£691,954	£1,472,981	£781,027
Flat	238	6.8	61%	£684,436	£1,304,537	£620,101

Summary Data for 1997

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	7.1	57%	£756,154	£1,609,159	£853,004
Domestic Economy 7	7847	7.1	59%	£729,229	£1,396,503	£667,275
Non-Domestic Unrestricted	2892	7.1	56%	£762,361	£1,372,317	£609,956
Non-Domestic Economy 7	1524	7.1	55%	£789,503	£1,820,884	£1,031,381
Non-Domestic Maximum Demand 0-20% Load Factor	605	7.1	59%	£714,901	£1,468,315	£753,414
Non-Domestic Maximum Demand 20-30% Load Factor	430	7.1	54%	£806,491	£1,873,159	£1,066,667
Non-Domestic Maximum Demand 30-40% Load Factor	326	7.1	56%	£773,609	£1,776,224	£1,002,615
Non-Domestic Maximum Demand >40% Load Factor	238	7.1	58%	£734,633	£1,596,586	£861,953
Combined	519	7.1	59%	£729,410	£1,477,438	£748,028
Flat	238	7.1	59%	£728,131	£1,553,851	£825,720

Summary Data for 1998

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	6.7	61%	£674,793	£1,472,602	£797,808
Domestic Economy 7	7847	6.7	63%	£643,632	£1,248,295	£604,663
Non-Domestic Unrestricted	2892	6.7	58%	£708,537	£1,276,420	£567,882
Non-Domestic Economy 7	1524	6.7	58%	£725,974	£1,714,263	£988,288
Non-Domestic Maximum Demand 0-20% Load Factor	605	6.7	62%	£653,061	£1,360,630	£707,570
Non-Domestic Maximum Demand 20-30% Load Factor	430	6.7	57%	£750,832	£1,783,757	£1,032,926
Non-Domestic Maximum Demand 30-40% Load Factor	326	6.7	59%	£710,205	£1,671,380	£961,175
Non-Domestic Maximum Demand >40% Load Factor	238	6.7	62%	£657,868	£1,466,356	£808,488
Combined	519	6.7	63%	£643,866	£1,330,049	£686,183
Flat	238	6.7	63%	£651,410	£1,423,860	£772,451

Summary Data for 1999

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	6.8	60%	£693,720	£1,508,296	£814,575
Domestic Economy 7	7847	6.8	62%	£668,459	£1,299,262	£630,803
Non-Domestic Unrestricted	2892	6.8	57%	£725,021	£1,308,423	£583,402
Non-Domestic Economy 7	1524	6.8	57%	£747,165	£1,755,689	£1,008,524
Non-Domestic Maximum Demand 0-20% Load Factor	605	6.8	60%	£677,118	£1,409,555	£732,437
Non-Domestic Maximum Demand 20-30% Load Factor	430	6.8	55%	£774,144	£1,829,576	£1,055,432
Non-Domestic Maximum Demand 30-40% Load Factor	326	6.8	58%	£732,011	£1,713,651	£981,641
Non-Domestic Maximum Demand >40% Load Factor	238	6.8	61%	£680,267	£1,510,900	£830,633
Combined	519	6.8	62%	£667,744	£1,378,206	£710,461
Flat	238	6.8	61%	£674,862	£1,470,192	£795,330

Summary Data for 2000

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	7.3	58%	£737,449	£1,558,974	£821,525
Domestic Economy 7	7847	7.3	60%	£711,378	£1,353,677	£642,298
Non-Domestic Unrestricted	2892	7.3	56%	£745,647	£1,325,607	£579,960
Non-Domestic Economy 7	1524	7.3	55%	£787,504	£1,795,906	£1,008,401
Non-Domestic Maximum Demand 0-20% Load Factor	605	7.3	59%	£702,762	£1,437,021	£734,259
Non-Domestic Maximum Demand 20-30% Load Factor	430	7.3	54%	£809,452	£1,859,693	£1,050,241
Non-Domestic Maximum Demand 30-40% Load Factor	326	7.3	56%	£771,329	£1,752,308	£980,979
Non-Domestic Maximum Demand >40% Load Factor	238	7.3	59%	£722,558	£1,559,223	£836,664
Combined	519	7.3	60%	£713,166	£1,435,660	£722,494
Flat	238	7.3	59%	£716,770	£1,520,412	£803,642

Average Summary Data for 1996 - 2000

Scenario	Demand scaling:	Generation scaling (5MW original):	% of generation that matches demand	Revenue from Spill	Cost of Top-up	Required subsidy (top-up less spill)
Domestic Unrestricted	14258	6.9	59%	£715,548	£1,533,227	£817,679
Domestic Economy 7	7847	6.9	60%	£694,646	£1,317,351	£622,704
Non-Domestic Unrestricted	2892	6.9	57%	£742,616	£1,410,286	£667,670
Non-Domestic Economy 7	1524	6.9	57%	£744,800	£1,693,987	£949,187
Non-Domestic Maximum Demand 0-20% Load Factor	605	6.9	59%	£708,258	£1,501,620	£793,363
Non-Domestic Maximum Demand 20-30% Load Factor	430	6.9	55%	£778,984	£1,813,431	£1,034,447
Non-Domestic Maximum Demand 30-40% Load Factor	326	6.9	58%	£737,566	£1,686,159	£948,593
Non-Domestic Maximum Demand >40% Load Factor	238	6.9	60%	£696,477	£1,503,894	£807,417
Combined	519	6.9	61%	£689,228	£1,418,867	£729,639
Flat	238	6.9	60%	£691,122	£1,454,570	£763,449

Electricity Association Profiles

NB: The "Combined" profile is derived from the 8 EA profiles giving equal energy weighting to each customer type