Strategy for Intensifying Wind Energy Deployment

Renewable Energy Strategy Group

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Foreword

In preparing this report the Renewable Energy Strategy Group owes a major debt to the Group's facilitator, Brian ó Gallachóir. He undertook the extensive research that provided an essential input to the Group's deliberations, as well as providing drafts of each Chapter to a very tight time-scale.

As Chairman of the Group I would like to record my thanks to all its members. They brought a wide range of essential expertise to its deliberations, together with a major commitment of their valuable time. This made it possible to reach final agreement on the different issues as the deliberations progressed. All the members of the Group brought an unusual degree of openness to the deliberations, making agreement on the final report a good-humoured experience, as well as making completion within a tight deadline possible.

Finally, the Group would like to thank the officials of the Department who provided an essential input into its deliberations and who provided the necessary back-up with their usual efficiency.

Prof. John FitzGerald

Renewable Energy Strategy Group Report

Glossary

AER	Alternative Energy Requirement – a scheme of competitions held for rights to generate electricity and sell the output to the ESB at agreed rates over 15 year period. To date there have been 4 competitions; wind energy technology was supported under two of these (AER I and AER III)
ALTENER Programme	ALTENER is an EU Programme which assists with the dissemination of information on renewables across Member States. The Programme offers financial support to projects approved under Calls for Proposals issued from time to time by the European Commission
BNE	Best new entrant
CCGT	Combined Cycle Gas Turbine
CER	Commission for Electricity Regulation established under the Electricity Regulation Act, 1999 to oversee the regulation of the liberalised electricity market in Ireland
CHP	Combined Heat and Power systems
CPI	Consumer Price Index
DoELG	Department of the Environment and Local Government
DUoS	Distribution Use of System
ERDF	European Regional Development Fund
GWh	1,000 megawatt hours
IWEA	Irish Wind Energy Association
kTOE	kilotonnes of oil equivalent
kWh	kilowatt hour; the standard measurement of electricity consumption
Kyoto Protocol	an agreement signed at Kyoto, Japan in 1997, which set legally binding targets for the reduction of greenhouse gases emissions by developed countries for the period 2008-2012
MW	Megawatt = 1,000 kilowatts

Net metering	Process which allows electricity customers with small renewable energy generators to use the electricity they generate to offset their usage over an entire billing period
PPA	Power Purchase Agreement – a contract between the ESB and an electricity generator guaranteeing purchase of the electricity produced
REIO	Renewable Energy Information Office is a service of the Irish Energy Centre established to promote the use of renewable energy sources
REFITs	Renewable Energy Feed in Tariff Schemes
“spill”	Electricity sold to ESB when there is an excess of supply not consumed by the supplier’s customer, in the liberalised market
THERMIE	Energy sub-programme of previous EU funded R&D Framework Programmes. Under the current 5th Framework Programme they are now amalgamated under the sub-Programme “ENERGIE”
“Top up”	Electricity bought from ESB to provide backup supply in the liberalised market
TPA	Third Party Access - to the electricity network by electricity suppliers
TUoS	Transmission Use of System
WTGs	Wind turbine generators

Executive Summary

The Renewable Energy Strategy Group was formed in November 1999 by Mr. Joe Jacob, T.D., Minister of State at the Department of Public Enterprise. The Group's terms of reference were set out in the September 1999 Green Paper on Sustainable Energy. This Green Paper reflected the Government's concerns about the need for domestic action to deal with the problem of climate change due to rising world emissions of greenhouse gases.

The principal focus of the Group's work in the initial 6 months, has been to develop a strategy for the increased contribution of onshore wind energy to electricity generation. In this period, the Group has examined many aspects of, and constraints to, the further deployment of wind energy. It is envisaged that the implementation of this strategy will assist the Department in delivering on the national targets up to 2005 for wind energy as set out in the *Green Paper on Sustainable Energy,* and inform future decisions regarding targets for the period 2005 – 2010.

The principal conclusion of the Group was that three key elements, *Electricity Market, Electricity Network* and *Spatial Planning,* need to be integrated into a plan led approach to wind energy deployment. Arising from the Group's deliberations, a number of recommendations are proposed under these headings. The recommended strategy, which hinges on this approach, is designed to meet the targets set for deployment of renewable energy at least cost.

The recommended plan-led approach sees spatial planning considerations as crucial in determining suitable areas where wind farms may be accommodated. These decisions should be informed by the availability of the resource (wind), the strength of the electricity networks, and landscape and other planning considerations. The locations thus identified should then determine the appropriate grid infrastructure required. Within the context of the agreed planning framework, the market mechanisms chosen should aim to minimise the cost of achieving the target deployment of wind energy.

Electricity Market

A major obstacle to the rapid deployment of wind energy is the uncertainty about the future of this market. The aim of the market mechanisms recommended in this report is to minimise unnecessary uncertainty and to provide a framework in which new operators will compete to provide the required generating capacity at minimum cost to future energy consumers.

For potential suppliers the stop-go nature of the tendering process, the administrative cost of tendering, and uncertainty about future policy all add to cost.

It is recommended that, in the short term, the market mechanism should concentrate on facilitating the development of capacity that has or can obtain the necessary authorisations, in particular planning permission, in years 1 or 2. Currently full planning permission has been awarded to wind farms with a combined installed electricity generating capacity of over 155 MW, not including AER III wind farms. An additional number with a combined installed capacity of over 160 MW are currently at various stages within the planning process. It is estimated that a further 215 MW are in the advanced stages of preparation for a planning application. To place this in context, the Green Paper target for all renewable energies is 500 MW by 2005.

Large Scale Developments

The market mechanism (AER V) recommended for the short term is to offer 15 year contracts for projects which have planning permission, the necessary licences and authorisations from CER and accredited certification. It is recommended that the price be based on projects delivered in the AER III competition corrected to allow for payment of the charges and levies introduced and approved by CER and the absence of AER III grants and linked to the Consumer Price Index. Essentially this will offer terms comparable to those arrived at through the competitive tendering process of AER III. It is recommended that this mechanism be available for 24 months to allow projects to enter and pass through the planning stages and to avail of the opportunity, in addition to the current projects with planning permission.

The Group feels that large scale wind farms should be encouraged to achieve efficient deployment of wind energy, and to avoid a proliferation of grid connections. In this regard, it is recommended that the project maximum size cap and ownership restrictions be removed.

The expected outcome from this scheme is an offer of power purchase agreements for large scale wind farms with a combined installed capacity of 160 MW within the 24 month period. This mechanism will be reviewed after 12 months to assess progress.

By offering a fixed price for a specified period the level of uncertainty, and related costs for promoters, will be reduced. By basing the price on that arrived at through a competitive tendering process the cost of provision will be minimised. Because of the speed of technical change in the industry it will only be appropriate that this price be held fixed for a limited period – 24 months – before a new price is determined through a competitive process.

Small Scale Developments

It is further recommended that a Small Scale Renewable Energy Scheme be maintained. The primary aim of this scheme is to encourage smaller scale projects in order to facilitate community based schemes. This provision is aimed at increasing public acceptance of wind energy and demonstrating the technology’s potential to contribute to social cohesion and regional development.

It is recommended that for small-scale wind farms, the project size allowable be capped at, say, 2.5 MW and the price related to the small scale wind farm section within AER III (again corrected and linked to the Consumer Price Index, as in the case of the AER III contracts). In addition, because this scheme will be more expensive than the mechanism for deploying larger scale wind farms, there will be an overall cap of 40 MW for this scheme over the 24 month period.

Liberalised Market

In addition to these specialised market mechanisms, wind farms will be able to avail of the opportunities offered by the liberalisation of the electricity market. However indications are that such projects may suffer from an initial lack of confidence among support players, in particular banks, in the early trading stages of the green electricity market. Accordingly, the Group recommends that the Department of Public Enterprise bring forward proposals for an interim period and for a limited amount of capacity to assist projects aimed at that market in securing loans to finance their developments. The purpose of such proposals is to reassure lenders of a continued revenue stream from the wind farm for a limited period of, say, 8 years.

Signals to the market

The Group identified the uncertainty about future offers to the market as a key contributor to bottlenecks. This uncertainty has resulted in projects being submitted prematurely swamping planning authorities and the ESB's departments responsible for grid connection. Recent experience has seen ten applications for every one authorised. It is therefore recommended that a clear signal be sent out to the market that the Government is seriously committed to the target on deploying wind energy and that, as a result, a further round of offers will be held in the future on a competitive tendering basis (AER VI). The Group further recommends that, based on currently available information, the model comprising AER V and AER VI continue as a rolling programme into the medium term.

Review

It is recognised however, that the above medium term recommendations may be overtaken by a number of related developments. EU driven liberalisation in other sectors suggests there will be rapid development of binding (EU) competition and regulatory rules as the electricity market develops into a liberalised single market. Measures to meet the challenge facing Ireland and the EU by emission targets agreed under the Kyoto Protocol are likely to have a significant impact on wind energy deployment. Experience with trading green electricity in the liberalised electricity market will also provide a valuable insight into what may be required. The proposed EU Directive on the Promotion of Electricity from Renewable Energy sources in the internal market may also bring specific conditions on which types of market mechanism are allowable. Similarly the Guidelines on the application of state aid rules for environmental protection are due to be revised.In light of this, it is recommended that the Department of Public Enterprise carry out a review mid way through the short term programme, i.e. during month 12, and at regular intervals thereafter, in order to determine the best possible route.

Electricity Network

The Group examined the electricity network from two perspectives, individual connections to the network (grid connections) and the ability of the network as a whole to accommodate increasing amounts of wind generated electricity. With regard *to grid connections*, in the context of delivering additional electricity generating capacity from wind energy, there is a serious shortage of capacity on the network. With regard to the *capacity acceptance*, the delivery of wind generated electricity poses challenges to the network which can limit the amount of such electricity acceptable while maintaining system security.

Grid Connection

The strategy recommended centres on facilitating grid upgrading in an efficient strategic manner. In the short term, it is recommended that funding available under the National Development Plan be invested in upgrading the distribution and transmission networks where a bottleneck exists. The priority locations for upgrading will depend on perceived demand (number of wind farms likely to be built) and planning considerations (projects with planning permission). As the projects come on stream, the cost of this infrastructural investment should be recovered through the pricing mechanism and should be recycled to support further infrastructural development.

In the medium to long term, it is recommended that greater integration with the spatial planning process should determine upgrading of the Distribution and Transmission networks, with information on resource availability and existing network strength as information inputs. It is recommended that the above mechanism for upgrading of the distribution and transmission networks be then carried out as in the short term (with the cost being recouped through appropriate user charges).

In addition, where strategic sites are identified for wind energy and where additional transmission infrastructure is required this grid upgrading should be funded under the National Development Plan. Once built however, this network extension will be available to all generators in a non-discriminatory fashion in line with national policy, and will not be reserved for wind farms.

Capacity Acceptance

The challenges to the network in accommodating wind generated electricity is a phenomenon which has yet to be fully researched. It is recommended that appropriate research studies be carried out in the short term to ensure that this does not become a constraint to reaching current and likely future targets for wind energy penetration. These studies are required in order to assess the likely impact of accelerated deployment and the resulting growing proportion of wind generated electricity on the system as a whole. The current targets to 2005 indicate this proportion will grow from 1% currently to 7% by the end of 2005. It is assumed that the necessary prediction tools, controls and information systems can and will be developed to accommodate this accelerated deployment. In the event of this not being the case, it is noted that the Commission for Electricity Regulation, in granting licences to generate electricity, must have regard for system security.

A necessary outcome of such research will be to provide clear signals for the impacts and cost implications of new deployment targets in the period 2005 – 2010.

Spatial Planning

In the area of spatial planning, experience to date shows that the planning process is supportive generally of wind energy but emphasises a need for greater cohesion between energy policy and environmental / planning policy.

The key recommendation of the Group is that a more plan led approach to wind farm development be adopted. This process involves identifying areas which are deemed suitable or unsuitable for wind energy development, under the following categories

- <u>Strategic areas</u> – these key areas are deemed to be eminently suitable for wind farm development and should be reserved for such purposes.
- <u>Preferred areas</u> – these areas are suitable for wind farm development and should normally be granted planning permission unless specific local planning circumstances would support a decision to refuse permission in the context of the development plan.
- <u>Areas open for consideration</u> – applications for planning permission will be treated on their merits with the developer having a clear responsibility to demonstrate why the development should be granted permission.
- <u>No-go areas</u> – these areas are identified as particularly unsuitable for wind farm development.

The above areas may be identified by Local Authorities or on a regional or national basis and should all be incorporated into Local Authority development plans. In this way, the plan led approach should identify where wind energy should be developed. From this, appropriate market mechanisms may be determined and appropriate locations for investment in the grid infrastructure. The approach needs to be informed by the existing grid infrastructure, cost effective upgrade options and wind speeds for the areas identified. Planning instruments, which are currently being developed through legislation, will be utilised to facilitate this approach.

The process recommended to achive this is as follows:

1. Issue a letter of invitation to Local Authorities from the Minister for Public Enterprise and the Minister for the Environment and Local Government, pointing to the benefits to Local Authorities of wind farms in their area such as the rates, possibility of investment in wind farms themselves and the possibility of cheaper electricity (through supplying their own electricity needs with wind energy)
2. Local Authorities identify areas which are deemed preferred and open for consideration in the Local Authority area in the context of wind farm development. Strategic areas and no-go areas may also be identified, if deemed appropriate by the Local Authority.
3. The appropriate Council is advised on the areas on a provisional basis
4. The Local Authorities then submit maps containing these areas to the Renewable Energy Information Office to advise on the wind energy resource and the network strength for accommodating wind energy in these areas, following consultation with ESB, IWEA, etc.
5. A revised map of areas deemed preferred, open for consideration, strategic and no-go, as appropriate, is then produced by each Local Authority which is sufficiently broad to allow for wind energy development without creating a situation where difficulties with land availability would create potential bottlenecks.
6. The Local Authority then proceeds to incorporate this into its development plan.

It is recommended that the above process begin immediately. This will assist in providing guidance on individual proposals for planning permission to developers, local communities, the Local Authorities themselves and, in the event of an appeal, An Bord Pleanála.

The Group welcomes the preparation of Guidelines for Local Authorities on Landscape and Landscape Assessment. In carrying out such assessments, it is recommended that Local Authorities take into account wind farm developments. As part of the characterisation of the landscape it is recommended that Local Authorities determine, in parallel, the sensitivity of different landscape character types to different kinds of wind energy development. This will involve assessing landscape quality, sensitivity, robustness and capacity.

It is recommended that the Renewable Energy Information Office develop an integrated resource map specific to the needs of Planning Authorities, the network operator and wind farm developers. Because of its importance to other recommendations, it is further recommended that its production be completed as soon as possible. This map should be updated regularly and made available, in particular, to all Local Authorities.

It is recommended that objective research be undertaken of public objections to previous planning consent applications and subsequent attitudes to successful projects to inform a comprehensive information campaign by the Renewable Energy Information Office for the purpose of informing and improving the public perception of wind farm developments.

It is further recommended that the Department of the Environment and Local Government revise and update their guidelines, *'Wind Farm Development – Guidelines for Planning Authorities'* to take account of recent developments, including the recommendations in this Strategy. In particular, it is important to incorporate the system and process, as recommended above.

In the medium term, it is recommended that the process outlined above should continue in an iterative manner and that as it develops, appropriate market mechanisms and grid upgrading plans for wind energy be informed by it.

Preface

The Green Paper for Sustainable Energy set an ambitious target for the increased penetration of renewable energy by 2005. In order for this target to be achieved, the need to tackle the deployment constraints is clearly recognised. In section 9.5 of the Green Paper, which deals with the proposals for the future of renewable energy policy in Ireland, the following task is identified :

> *identification of measures to redress constraints in the deployment of renewable energy, particularly in relation to economic costs, the planning process and grid connection.*

It is further stated that

> *the Minister will establish a Renewable Energy Strategy Group which will examine all aspects of, and obstacles to, the further deployment of renewable energy technologies.*

The Renewable Energy Strategy Group was formed in November 1999 by Mr. Joe Jacob, T.D., Minister of State at the Department of Public Enterprise. The principal focus of the work in the initial 6 months, has been to develop a strategy for wind energy deployment. In this period, the Group has examined many aspects of and constraints to the deployment of this resource.

Mandate

The mandate of the Renewable Energy Strategy Group is clearly specified in the Green Paper on Sustainable Energy as being, to examine and report on :

- the economic costs of promoting a green electricity market;
- the economic and technical barriers to green electricity production;
- international benchmarks for trade costs, delivery times and quality of service obligations in other green electricity markets;
- grid connection issues including capacity, price and delivery times;
- technical limits of the electricity grid including priority solutions to particular weaknesses and bottlenecks;
- electricity market factors likely to impede or obstruct the development of a green electricity market including top up and spill, transmission and metering;
- planning support issues including any emerging trends or weaknesses in planning consent applications; and
- factors impeding local and community based green electricity generating schemes.

Context

The context in which the Group was to prepare a strategy for wind energy comprised the following key elements :-

- the European Commission published a *White Paper on Renewable Energy* in November 1997 which set a target of doubling the contribution of renewable energy to total energy supply from 6% to 12% by 2010 (with a target of 40 GW installed capacity from wind energy) which was endorsed by the Council of Ministers and the European Parliament.
- the European Commission recently presented a proposal for a *Directive of the European Parliament and of the Council on the promotion of electricity from renewable energy sources in the internal electricity market.* The indicative target for Ireland is that 13.2% of total electricity produced will be derived from renewable energy sources. The target for the EU as a whole is 22.1% which translates the 12% White Paper target into a specific contribution in the electricity sector;
- under the *Kyoto Protocol,* the EU is committed to reducing greenhouse gas emissions to 8% below 1990 levels by the period 2008 - 2012. As part of a "burden sharing" agreement between EU Member States, Ireland has agreed a national target to limit the increase in greenhouse gas emissions to 13% above 1990 levels in the period 2008 – 2012. In a business as usual scenario, emissions are projected to grow in excess of 35% between 1990 and 2010. Most of this growth is attributable to fossil fuel based energy use;
- the *Electricity Regulation Act, 1999* had the effect of commencing the liberalisation of the electricity market in Ireland from February 2000. The key aspect of relevance is that the total electricity market is now open to wind electricity suppliers while only a portion of the market is open to those generating electricity from fossil fuels
- the *Planning and Development Bill, 1999* is currently in the process of enactment. This provides for regional planning guidelines and local area plans which allow for fresh thinking with regard to forward planning for wind energy.
- the European Commission is in the process of revising its *Guidelines on the application of state aid rules for environmental protection.*

In developing the strategy, the Group recognised that all of the above will impact on wind energy deployment in Ireland either directly or indirectly with regard to the competitive position of wind energy in relation to other energy sources, the supports available and allowable and the planning process.

The report is divided into 7 chapters. The *Introduction* sets the scene and introduces the context for the strategy and the constraints to wind energy deployment. *Market Mechanisms* examines support schemes to stimulate wind energy deployment. *Trading Issues* examines green electricity trading in the liberalised market. *Grid Connection* explores the issues associated with connecting individual wind farms to the network. *Capacity Acceptance* deals with the ability of the network as a whole to accommodate increasing amounts of wind generated electricity. *Spatial Planning* explores the planning system and draws on the new opportunities available from forthcoming legislation. Finally, *Strategy* focuses on the recommendations, drawing them together in an integrated manner.

A number of chapters in the report are grouped in specific sections for further clarity. *Electricity Market*, *Electricity Network*, *Spatial Planning* and *Conclusions*. The report also contains a number of appendices with additional relevant information.

Chapter 1 Introduction

Context – Current Deployment

Renewable energy is not new in Ireland. In the early 1930's the generation of electricity was almost 100% renewable, based on the hydro-power of the Shannon river, harnessed at the Ardnacrusha plant. Biomass has provided generations with warmth and cooking through the burning of wood in homes around Ireland. Of the renewable energy sources contributing to Ireland's energy supply, biomass remains the most significant, and continues to grow with the increase in wood processing activity in recent years.

Wind energy development, on the other hand, is relatively new in Ireland, particularly when compared to other E.U. Member States such as Denmark and Germany (see appendix J – *Global Wind Energy Development)*. The first commercial wind farm of 6.45 MW was commissioned and supplying electricity to the electricity grid in 1992. This project was supported by the E.U. under the VALOREN programme. It remained the only wind farm supplying the electricity network until 1997 when a further 6 were commissioned with a combined generating capacity of 44 MW. Of these, 4 wind farms were built under the AER I (Alternative Energy Requirement I) programme and 2 were built with E.U. support under the THERMIE programme. Since then a further 5 wind farms have been built including the first AER III wind farm and the first wind farm whose electricity is being sold directly to final customers, under third party access. Table 1.1 summarises wind farms currently operating in Ireland.

Year	Site	Location	Installed MW	Market Mechanism
1992	Bellacorrick	Co. Mayo	6.45	VALOREN
1997	Barnesmore	Co. Donegal	15	AER 1
1997	Altagowlan	Co. Leitrim	1.2	AER 1 + THERMIE
1997	Cark + Tullytresna	Co. Donegal	15	AER 1
1997	Tullymurray	Co. Leitrim	4.8	AER 1
1997	Kilronan	Co. Roscommon	5	THERMIE
1997	Cronalaght	Co. Donegal	3	THERMIE
1998	Drumlough Hill	Co. Donegal	4.8	AER 1
1998	Crockahenny	Co. Donegal	5	AER 1
1999	Inverin	Co. Galway	2.64	THERMIE
1999	Curabwee	Co. Cork	4.62	AER III
2000	Cronalaght II	Co. Donegal	1.98	TPA
2000	**Total**	**69.49**		

Table 1: Wind Farms Developed in Ireland (June 2000)

In total, there are 12 wind farms currently operational in Ireland. The combined installed capacity is 69.49 MW which represents 1.4% of Ireland's total installed electricity generating capacity. In terms of electricity produced, the contribution of wind energy currently represents 1%.

In 1996[1] a target was set for an additional 90 MW to be installed by the year 2000. The AER III competition was launched in March 1997 to secure contracts between ESB Power Procurement and Independent Wind Power Producers to reach this target[2]. Power purchase agreements were offered for 17 wind energy projects with a combined installed capacity of 137 MW[3].

Of these 17 projects, 9 (combined installed capacity 69 MW) have secured planning (one of which is commissioned). The remaining 8 are at various stages of the planning process. There are 8 wind farms (combined installed capacity 50 MW) currently under construction which are expected to be commissioned before the end of 2000. These comprise AER III, THERMIE and TPA projects and are listed in Appendix D.

Targets and Market Activity

Due to Ireland's geographical location, on the downwind side of the Atlantic Ocean, in the region of prevailing south-westerly winds, the Irish coastline is exposed to one of the most vigorous wind climates in the world. In a study on Ireland's renewable energy resources[4], the *feasible* wind energy resource, in areas at or above the 7ms-1 'cost effective' wind speed is estimated at 179 GW, or 40 times Ireland's current installed capacity. When areas which are more sensitive to the environmental impact of wind energy are excluded, what remains is the *accessible* resource estimated to be 2190 MW under certain assumptions, with a cost limit of 3p (0.0381euro)/kWh. Based on assumptions regarding the ability of the network to accommodate wind generated electricity, the *practicable* resource, according to the report is estimated to be 812 MW.

The recently published Green Paper on Sustainable Energy has resulted in a dramatic increase of renewable energy target between now and 2005, which is largely to be met by wind energy. The key driver behind this document is the challenge facing Ireland in delivering on its commitment to limit the growth of greenhouse gas emissions. In a business as usual scenario, emissions are projected to grow in excess of 35**%** between 1990 and 2010, compared to the 13% limit which Ireland is committed to. Most of this growth is attributable to the energy sector.

The target for renewable energy is 500 MWe of additional electricity generating capacity from renewable energy sources, in the period 2000 – 2005, with wind energy contributing the bulk. This replaces the previous target of 155 MWe for the same period. If these targets are met, wind energy will account for 10.7% of Ireland's projected total installed electricity generating capacity, 7.1% of electricity generated and 1.1% of total primary energy supply by 2005. Further details on these targets is provided in appendix E.

1 *Renewable Energy – A Strategy for the Future.* Department of Public Enterprise, April 1996.
2 *Energy Update* Issue 3 pg 1. Renewable Energy Information office.
3 *Jacob announces IR£160m Green Electricity Programme.* Department of Public Enterprise press release April 8, 1998
4 *Total Renewable Energy Resource in Ireland.* European Commission ALTENER Report XVII/4.1030/T4/95/IRL March 1997 pg 11

Against the backdrop of these targets, it is important to assess the level of activity in the market place. Examining the interest in the different stages of the AER III competition and comparing this to the AER I competition provides a useful starting point.

The first stage of AER III was to seek expressions of interest. **279**[5] expressions of interest were received for the competition for projects with a combined installed capacity of **1680 MW**. While some of these were for hydro power and biomass energy projects, the majority were for wind farms. Of these, 92 projects passed the technical and commercial evaluation stage and only 30 contracts were offered, of which 17 were for wind farms.

This interest compares with **168** registrations for the AER I competition - 3 years earlier - providing a combined installed capacity of **367 MW**. The target for that competition was 75 MW renewable energy based electricity generating plant of which 30 MW was to be reserved for wind energy.

A further measure of activity may be derived from the planning system. Wind farms with a combined installed capacity of over 155 MW which do not have AER III contracts have received full planning permission. An additional number (with a combined installed capacity of over 167 MW) are currently at various stages within the planning process. It is estimated that a further 217 MW are in the advanced stages of preparation for a planning application.

Deployment Constraints

The future seems bright for wind energy deployment in Ireland. The wind energy resource is the envy of Europe, the targets set in 1996 have been revised upwards and there is a lot of interest and activity amongst wind farm developers. There are however, a number of critical factors which need to be addressed in the form of a coherent strategy to deliver these targets. The development of a wind farm requires, inter alia :-

- market mechanisms which are appropriate to Ireland;
- planning permission for the turbines and, where necessary, for the connection to the network;
- securing wayleaves;
- availability of finance to fund the wind farm development; and
- use of the electricity network to deliver the electricity to the point of consumption.

These factors have the potential to facilitate or constrain wind energy deployment in Ireland. By drawing on the experiences of recent years and examining the successes and failures in other countries, it is possible to look to the future with a clearly focussed strategy in order to ensure that the role of each of these factors is facilitative.

5 *1997 Annual Report*. Energy Advisory Board.

Market Mechanisms

There are currently 3 mechanisms for bringing wind energy generated electricity to the market in Ireland.

The *Alternative Energy Requirement* (AER) is a public service obligation system in which prospective renewable energy producers are invited to submit competing tenders for the sale of a predefined quota of electricity to the national grid. Bidders who pass technical and commercial evaluation and who submit the lowest prices for the sale of electricity are guaranteed sale for their output to ESB Power Contracting for a fixed period. The competitive nature of these schemes ensures that the cost ultimately borne by consumers in respect of the higher direct costs of electricity generated from renewable sources is minimised.

Four AER competitions were held between 1995 and 1998. In AER I, the unit price was fixed and applicants were entitled to bid for capital grants. In the event, applicants chose not to bid for the grants and entered the competition on the basis of the fixed price alone. As a result, it was decided for subsequent competitions to have a price cap for each renewable technology rather than a fixed price. Winning bidders were offered power purchase agreements at their bid price and were entitled to an ERDF grant, subject to the approval of the European Commission.

Under the AER scheme, winning bidders are entitled to a 15 year power purchase agreement whereby the ESB buys the electricity output of the winning facility at the bid price. The additional cost to the ESB of buying the electricity is spread across all electricity consumers, as a public service obligation. The prices paid by the ESB are increased annually in line with the Consumer Price Index.

The effect of this was to exert downward pressure on price. In the period that the AER competitions have been held the bid prices have decreased significantly. In 1995, the AER I bid price per unit (kWh) for all technologies was 4 pence (€ 0.051). In 1998, the weighted average bid price for AER III was 2.748 pence (€ 0.035) per unit, a drop of 31%. AER I was completed at the end of 1997. Twenty projects have been fully commissioned with a total installed capacity of 69.4MW.

Projects which are successful in securing support under *EU Energy Demonstration Schemes* are guaranteed access to the electricity market in Ireland. Between 1990 and 1998, 10 wind farms were awarded funding under the *THERMIE* programme to demonstrate innovative wind energy applications. Four of these wind farms have been built, 2 failed and the remaining 4 are at various stages of the development process. One of those built was successful in the AER I competition and the remaining 3 (with a combined installed capacity of 10.6 MW) received THERMIE power purchase agreements. The wind farms received 15 year index linked power purchase agreements (PPA), the price being determined by the most recent AER competition prices.

The Green Paper on Sustainable Energy advises that this mechanism will continue to be available to projects which are successful under the Fifth Framework *ENERGIE* programme, which succeeds the THERMIE programme. The price offered in the PPA will be the average of the prices bid in the relevant category of the preceding AER competition. The duration of the PPA will be determined on the basis of each business case submitted to the European Commission.

The 3rd market mechanism, which entered into force in February 2000 is the *direct sale of electricity from wind farms* to customers. This mechanism is provided for by the Electricity Regulation Act, 1999 which commenced the inplementation of (EU) Directive 96/92/EC concerning common rules for the internal market in electricity.The Directive requires that approximately 28% of the Irish electricity market be opened up to competition at that time, increasing to 33% by 2003 with a review of further opening in 2006. In fact, Ireland has gone further than this with approximately 30% of the market opening now, 40% in 2002 and full liberalisation in about five years time. This will allow independent electricity generators and/or suppliers to contract directly with designated customers for the supply of electricity. To date one wind farm has been built in Donegal under this mechanism.

The main focus of the Act is to open up the electricity market for large electricity customers, thus removing ESB’s monopoly position. In addition to large consumers of electricity, however, those who wish to buy electricity generated from renewable energy may also choose their own supplier, thus opening the possibility of the direct sale of electricity from wind farms to customers.

The Commission of Electricity Regulation has been established under the Act with the power to

- grant licences to generate and supply electricity;
- grant authorisations to construct generating stations;
- provide for access to the transmission and distribution system by holders of licences, holders of authorisations or by eligible customers.

The responses by the wind energy industry to this new opportunity are mixed. The provision of direct sale is clearly seen as positive. The process is still evolving and issues should become clearer as time progresses. The half hourly trading system, which forms part of regulatory requirements, provides a significant challenge to wind energy given the intermittent nature of wind energy. Furthermore, the availability of finance to fund wind farms in the absence of a 15 year PPA is uncertain.

Financiers are now generally receptive to prospective wind farm developers, provided they have a PPA and planning permission. This positive response is a very recent development, reflecting a rapid change in approach resulting from increasing debate with developers.The introduction of tax relief under Section 62 of the Finance Act,1998 for corporate equity investment in certain renewable energy projects, including wind farms, has heightened the interest of the financial community in Ireland. A number of banks and other financiers are now in investment partnerships with developers.

The situation differs for projects seeking to avail of the opportunities offered by the liberalised market. The 15 year PPA will not be a feature for such projects. The most they are likely to achieve is a shorter term contract for the sale of electricity. As a result, it will be very difficult to bank a project at least in the initial stages. For larger players in the industry, who will be in a position to use balance sheet finance, the same difficulty will not occur. The large majority of Irish wind farm developers do not, however, fall into this category.

Access to the electricity network

Following the announcement of the results of AER I, the Department of Public Enterprise carried out a review of strategy, which led to the publication, in 1996, of *Renewable Energy – A Strategy for the Future.* One of the issues considered in the review was grid connection.

As part of the review, a workshop on grid connection issues took place in Dublin Castle (9th November, 1995). This workshop arose from the industry submissions received during the policy review process which conveyed some confusion, frustration and a seeming information gap on grid connection issues.

All of the issues raised could not be dealt with in a single workshop and at the close it was agreed that a *Working Group on Grid Connection Issues Related to Renewable Energies* be formed to address the issues raised and inform the Minister’s policy review. Initially the focus was on wind energy and hydro power projects. As activity increased in relation to biomass projects, the Irish Bioenergy Association was invited to appoint a representative to become a member of the Working Group also.

ESB have a number of concerns in relation to the increased penetration of renewable energy feeding into the Irish electricity network. One of these which is particularly significant with regard to intermittent sources, such as wind energy, is the provision of back-up capacity. Against that, where the point of generation is closer to the load and generation profile matches the load profile, then there are reduced electricity losses in transmission and distribution.

A further concern relates to the strength of the network and its ability to accommodate renewable energy. The best wind energy resource is, understandably, along the west coast of Ireland. This is where the electricity network is generally at its weakest however, due to the dispersed nature of electricity loads. This raises the issue of upgrading the electricity network strategically to accommodate renewables.

Planning Issues

In order to build a wind farm, as with other forms of development, planning permission is required. An application for planning permission is submitted to the relevant Local

Authority who will assess whether the proposed wind farm is in line with or contravenes the Development Plan and whether it is otherwise in keeping with the proper planning and development of the area. As wind farms are a recent form of development, few Local Authorities have clear criteria contained in their Development Plans. Most of the decisions made by Local Authorities are appealed to An Bord Pleanála, either by the wind farm developer or a 3rd party.

As a result, the planning process for the wind farm can typically take up to 14 months. Given that this has been coupled with a tight timeframe for project delivery under the AER competitions to date, time-scale has understandably become an issue. Of the 10 wind farms awarded PPAs under AER I, only 5 were commissioned by the deadline, 3 failed to pass through the planning stage, and 2 were commissioned after the deadline. AER III projects face an even more difficult task in attempting to be commissioned by the end of 2000. Part of the difficulty in relation to the timeframe is the requirement that the available grant funding through the Operational Programme for Economic Infrastructure must be committed by this deadline.

In addition, the connection from the wind farm to the electricity network will also require planning permission (for 38 kV and above). Obtaining wayleaves from landowners is becoming increasingly difficult and in some cases the associated discussions can seriously delay the provision of a grid connection. Most existing wind farm sites whose grid connections cross other private properties, have experienced delays due to objections. Whether the objectors oppose the line or the wind farm is unclear, although evidence suggests that there is some ill feeling related to the fact that individuals who gain no tangible benefit from the wind farm have to contend themselves with an overhead line across their land.

For local authority planners, wind turbines represent a strange new feature on the landscape. They are generally positioned in remote areas (where wind speeds are high), which are not accustomed to significant development of any description, let alone tall towers with moving parts. As a result, planners have had to develop the necessary tools for assessing landscape character in these areas, as a first step to determining whether the landscape can visually accommodate these developments. In addition, there is often conflict between the development of wind farms and other land use priorities for the area, in particular tourism and amenity, even though wind farms can themselves become a tourist attraction.

For local residents who oppose a particular wind farm development, the planning process is the principal means at their disposal to try halting the development. Generally amongst local residents, there is a mixed reaction. Some find wind turbines pleasing to the eye, while others find the turbines unsightly and a blot on the landscape. There are also fears about the threat to their livelihoods, noise levels, electromagnetic radiation levels, impact on birds and other wildlife and safety concerns. There is also some resistance to the fact that a local resource is being harnessed with very little or no direct local economic benefit, except to the landowners.

In 1996, the Department of the Environment and Local Government published planning guidelines for wind farm development to provide Local Authorities with some much needed guidance. The guidelines set out the considerations relating to the interface between wind energy and the land use planning system, including guidance on both the development plan process, and development control when dealing with a specific proposal. Overall national renewable energy policy is identified as a matter to which planning authorities must have regard in the discharge of their planning functions, and An Bord Pleanála must also have regard to the guidelines in considering appeals. However, the Department's guidelines lack the detail contained in the Irish Planning Institute's Guidelines which were published in 1995. Both documents have been overtaken over by more recent developments and are dated.

Conclusions

The constraints to the accelerated deployment of wind energy based electricity generating plant can be grouped under three broad headings, *electricity market, electricity network* and *spatial planning.* These categories of constraint are distinct and yet interrelated. As a result, the Group sought to examine the constraints initially under these individual headings and then take an integrated approach in developing a strategy.

Section A – Electricity Market

Chapter 2 - Market Mechanisms

This chapter examines the market mechanisms generally initiated by national governments in order to support the increased penetration of renewable energy in electricity production

Rationale

As a starting point, it is useful to ask why use special market support mechanisms to support renewable energy when the international trend, across all areas of economic activity, is moving towards liberalised, competitive, free markets unrestrained by controls which distort the market.

Renewable energy can:

- contribute to high priorities at the national and European Community levels;
- alleviate the environmental damage caused by the energy sector;
- contribute to the increased security of supply of energy sources;
- increase diversity in available fuel sources; and
- contribute to social and economic cohesion.

For a variety of reasons, discussed below, renewable energy cannot yet compete with conventional electricity generating means in an open market with competition.

The energy market which wind energy is attempting to penetrate is the electricity market dominated by fossil fuels. This market is currently distorted, where the market prices for these fuels and the electricity generated from them, do not reflect their full costs. These distortions arise from the fact that the external costs associated with fossil fuel use are not internalised into the fuel price. These external costs include the environmental and health costs attributable to the consumption of fossil fuels[6]. An example is the medical bill which arose from treating those with respiratory problems in Dublin prior to the ban on bituminous coal in 1990. This is an external cost arising as a result of the burning of bituminous coal but is not internalised into the purchase price of the fuel. In the fossil-fuel electricity sector, external costs include the damage done to health, ecosystems and buildings by combustion by-products (e.g. SO2 and NOx), and the costs of the impacts of climate change arising from CO2 emissions. If these costs were internalised, brown electricity (electricity from fossil fuels) would operate from a higher cost base, thus improving the competitiveness of renewable energies in general and wind energy projects in particular.

6 *European Commission 1995 ExterneE - externalities of energy.*

Historically, States have supported the deployment of electricity networks and the operation of electricity generating stations to ensure electricity is universally available at affordable prices. This has been achieved by state intervention in support of brown electricity production in the form of capital investments and on the operating side by guaranteed loans and subsidies, both direct and indirect, for sound historical reasons.

The role which renewable energy can play in allowing Europe to meet its international obligations under the Kyoto Protocol is a further reason for providing market support for renewable energy. Under that protocol, the EU is committed to reducing greenhouse gas emissions to 8% below 1990 levels by the period 2008 - 2012.

In addition, within Europe there has been a comparatively low level of investment in developing wind energy technology relative to that, for example, in fossil fuel or nuclear technologies. Although enormous advances in wind energy technology have been made in recent years for the present it can only be deployed commercially if support measures are applied. The disadvantage is further reinforced by the asymmetrical nature of competition until the green market achieves a critical mass.

Mechanisms Applied in EU Member States

Throughout the European Union, a variety of incentives for the production of electricity from wind energy are available or are being contemplated both at national level and under European Community law. These include price support mechanisms, financial incentives/subsidies, tax incentives, tax exemptions (where specific energy taxes apply), guaranteed sale of electricity to the national grid, third party access, green certificates and branding of green electricity, and are set out in Table 2.1.

Primary Supports – Premium Payment	**Secondary Supports**
Competitive bidding schemes	Capital grant support
Feed in tariffs	Financial and Tax incentives
Tradable green credits	Research and Development Programmes
Direct sale to customers at a premium	

Table 2.1 Summary of Market Mechanisms Employed Across the EU

Some countries have also sought to reduce administrative and technical barriers such as planning rules and arrangements for access to electricity grids and have introduced targeted information campaigns aimed at developers and the public.

This section provides an overview of the different market stimulation mechanisms which exist, essentially answering the question how can the wind energy market be stimulated.

The different mechanisms can be grouped under four headings as follows;

- premium payments for the electricity produced from wind,
- direct capital grant support, subsidising the investment in a wind farm,
- financial and tax incentives to lower the cost of finance,
- research, development and demonstration programmes.

The above support mechanisms can be partitioned into (a) primary support mechanisms and (b) secondary support mechanisms. Premium payments are a primary support mechanism whereas the latter three headings can be considered as secondary mechanisms. The distinction is based on the fact that secondary supports would not generally be enough to allow wind farms to be developed in the absence of an appropriate primary support. The experience generally is that one primary support is adopted by a member state and is supplemented by a number of secondary supports.

Primary Market Mechanisms

With the arrival of electricity market liberalisation, it is now possible for wind generated electricity suppliers to sell directly to customers. Currently in Ireland there are a number of operators responding to this opportunity. The market support mechanisms will complement the direct sale of wind generated electricity in increasing the deployment of wind energy.

Primary support mechanisms for electricity generated from the wind are those which most actively seek to reduce the market distortions discussed earlier. Internalising the external costs associated with fossil and nuclear fuel based electricity generation is the most direct, effective means by which this can be carried out but for a number of reasons this has not yet been achieved[7]. Supporting wind generated electricity through one of a number of primary market stimulation mechanisms has been the chosen route in many countries to increase the amount of wind generated electricity as a proportion of total electricity supply.

In each of the Member States, different primary support mechanisms exist but they can be grouped into the following categories;

- competitive bidding schemes,
- feed in tariff schemes,
- green credits trading,
- green pricing schemes.

7 *Environmental Tax Reform.* Commissioner Ritt Bjerregaard at IPPR conference Environmental Tax Reform in Europe, Brussels, October 27, 1997.

In the case of competitive bidding schemes, feed in tariff schemes and green credits trading the premium payment is passed on to the utility and to its customers. Green pricing schemes are schemes instigated by utilities which offer customers the option of purchasing renewable generated electricity at a higher price (generally) than conventional electricity.

Competitive Bidding Schemes

In a competitive bidding scheme, generally speaking, the Government sets a target for the amount of green electricity generating capacity to be commissioned within a certain timeframe. Developers then enter the competitive process, which comprises a technical appraisal followed by a commercial evaluation. Those who successfully complete both stages are ranked according to the price they seek for each unit of electricity (kWh kilowatt hour) and contracts are offered to the lowest priced offers according to the rank, until the target in generating capacity is reached. Those offered contracts then seek planning permission (if they have not already begun that process) and approach potential financiers in order to finance, build and commission the plant within the allowed timeframe.

Two examples of competitive bidding schemes are the AER (Alternative Energy Requirement) in Ireland and the NFFO (Non-Fossil Fuel Obligation) in the UK. The Department of Public Enterprise in Ireland has supported 4 AER competitions, with AER I and AER III including wind energy technologies.

In the UK, five NFFO competitions have been held in England and Wales, three SRO (Scottish Renewables Order) competitions have been held in Scotland and two NI NFFO competitions have been held in Northern Ireland. Power purchase agreements have been awarded for 3,500 MW DNC (Declared Net Capacity) of renewable energy plant and 650 MW DNC has been commissioned. One significant difference between the AER and NFFO scheme is the timescale for commissioning of plant. Under NFFO, developers have 5 years to commission, following the announcement of the competition, after which, the 15 year timeframe for the contract begins.

Some of the characteristics of this type of scheme to date are

- <u>low cost renewable energy plants</u> (in the AER III competition the weighted average bid price was 0.03489 € / kWh).
- <u>difficulties in achieving planning permission</u> as the successful projects need to be in areas of high wind speeds to be competitive; as a result they are confined to areas which are exposed leading to potential land use conflicts. However, it should be noted that moving projects to other sites would not, of itself, guarantee planning permission when account is taken of the objections e.g. an objection to the associated overhead power lines could be expected at any location.
- <u>intermittent</u> development of wind-energy marked by a lot of activity during the competitions and close to the deadline for commissioning of plant and reduced

activity at other times. This leads to bottlenecks at the planning, grid connection and commissioning stages due to the tight time-frame within which the projects must be completed coupled with the fact that they are generally being built concurrently.

- time is required (typically at least one year) to administer the tendering process.
- guaranteed market for the electricity produced by the wind farms. The successful developers receive a 15 year fixed price (index linked) power purchase agreement with the utility which removes market risks and facilitates the financing of these projects.

Renewable Energy Feed In Tariff Schemes (REFITs)

The longest standing form of primary market mechanism is the Renewable Energy Feed In Tariff (REFIT) Scheme. In this type of scheme, utilities are obliged to purchase electricity from renewable energy plants at a guaranteed price.

In Denmark[8] for example, the price paid for electricity from wind energy is 85% of the net price to a consumer of 20,000 kWh per year (minus costs for using the grid). As a result, the price paid by the utility depends on the area and averages 0.042 € / kWh. In addition, however, there is a government subsidy (incorporating the reimbursement of the energy/carbon tax) of 0.036 € / kWh giving an average unit price to developers in Denmark of 0.078 € / kWh. It should be pointed out, however, that that this scheme has tended to support small scale developments and Denmark is currently moving towards a mechanism based on tradable green credits.

In Germany grid operators are obliged to purchase electricity from renewable sources within their specific area at prices which are fixed at the national level and apply throughout the year. If the amount of electricity from renewables exceeds 5% of the total electricity produced in an area, the utilities are exempted from the obligation to purchase any excess above this threshold.

The price is fixed on the basis of average revenue during the second previous year, the rate for electricity from wind is 90% of the average revenue. The value for 1995 (starting point for 1997 prices) of the average revenue amounts to 0.098 ? / kWh, giving a price for wind produced electricity of 0.088 ? / kWh

Some of the characteristics of REFIT schemes are

- high growth rates in wind-energy. In Germany, installed capacity rose from 450 MW in 1990 to 2875 MW in 1998 and in Denmark the rise was from 343 MW to 1448 MW in the same period
- continuous development of wind farms in areas which are economically viable, for example Northern Germany.

8 E.V.A. (Energieverwertungsagentur) *Feed-in Tariffs and Regulations concerning renewable Energy Electricity Generation in European Countries,* August 1998

- prices paid for wind energy which do not reflect the market developments. With advances in turbine development and efficiencies, the cost of wind generated electricity has dropped in the last ten years but this is not reasonably reflected in the price paid under these schemes.

Green Credits Trading

This is the newest type of primary support mechanism, introduced for the first time in The Netherlands at the start of 1998. It essentially separates the price for the electricity produced from renewable energy and the *green* benefit associated with that electricity.

Each unit or kWh of electricity produced under this mechanism is sold at the market price for electricity. On its own this price would not be enough to make the development of a wind farm in the Netherlands a viable economic option. In addition, however, the generator receives from the utility a label or credit for every unit sold. These credits, representing the perceived added value to society of the green component of wind generated electricity are then sold in a secondary market.

The secondary market operates as a result of the Renewable Energy Resolution, passed in early 1997, in which the different utilities committed themselves to a specific targeted amount of units of renewable energy up to the year 2000. The targets may be met by the utility producing renewable generated electricity itself, or by purchasing the credits from a renewable energy generator who has fed electricity into its own, or one of the other utilities.

This mechanism is currently attracting significant attention in some member states. Denmark, Italy, Belgium and the UK are converting their renewable energy market mechanism to one based on tradable green credits. It draws positive elements from competitive tendering schemes, namely reducing the cost of renewable energy while also drawing from feed in tariff schemes through the focus on electricity produced rather than installed generating capacity. The mechanism will be applied differently in each Member State, the differences relating to among others, who must meet the obligation, the level of penalty, the possibility of banking credits (offsetting a shortfall one year with a 'borrowed' amount from the following year).

Direct Sale of Green Electricity at a Premium (Green Pricing Schemes)

This is based on the principal that consumers are voluntarily willing to pay more for electricity which is produced in an environmentally neutral manner. Consumers can usually choose to purchase all or a percentage of their electricity. The electricity supplier, in return, guarantees that each unit of electricity, usually[9] paid for at a premium price, corresponds to a unit entering the electricity supply network from a renewable energy

9 there is currently an operator in Ireland selling to certain customers below the incumbent operator's market price

power plant. One of the advantages of this scheme is that it can provide a market for electricity from renewable sources where none exists. Against that it operates in a manner counter to the polluter pays principal.

Green pricing as a mechanism for developing renewable energy is seen as having the following advantages:

- providing a market for renewables where no substantial market now exists;
- involving the consumer in questions of electricity supply;
- raising awareness about renewables thus giving a higher political profile;
- attractive option for utilities as it encourages consumer loyalty.

It is seen as having the following drawbacks :

- possibly delaying more fundamental energy policy changes, such as a carbon tax and pro-renewables market incentives;
- requesting that customers pay more for a product that is ultimately cheaper than its non-green competitors;
- erroneously making renewables appear expensive;
- open to abuse because of the difficulty of establishing the greenness of the resource mix;
- customers could change their minds so contracts tend to be short term and thus risky for the utility and/or developer.

The Netherlands was the first European country to take seriously the idea of marketing green electricity for its environmental benefit. All six utilities in the Netherlands now offer a green energy scheme. One of the first was EDON, which has 700,000 domestic customers. A mailing to most customers in October 1995 produced a positive response. 7,000 customers have signed up to the scheme choosing to buy either 25%, 50%, 75% or all their electricity from renewable sources. For this they pay an extra 4 cents/kWh on top of the regular 21 cents.

PNEM started marketing green power in June 1995 and by 1997 had 7,200 customers, about the same 1% of its total as in the EDON area. The charge was 6 cents/kWh above the normal. Only businesses with a large consumption can choose to have a proportion of their power from the scheme.

In **Sweden,** suppliers are applying to Naturskyddsfreningen (SNF) for green power certificates - for which the supplier must market electricity produced from renewable sources which SNF classify as existing (not new) hydro, biomass and wind power.

Demand for green electricity from industrial customers is outstripping supply with prices being forced up to SEK 0.01-0.02/kWh and likely to go up further. Several large companies are already specifying green power, including carton manufacturer Tetrapak, milk products company Arla and housing company Svenska Bostder.

Germany's largest utility, RWE Energie introduced the first German green pricing system in 1996. It offers green electricity at an *"environmental premium"* of DEM 0.2/kWh, plus sales tax, for at least 100 kWh a year. It invests the money raised, and matches the investment itself, into supporting the installation of wind and photovoltaic plant. By the end of 1996, 8100 of RWE's customers had signed up for the scheme including 12 industrial or large commercial entities.

The second scheme was introduced in February 1997 by two utilities : Badenwerk of Karlsruhe and Energie-Versorgung-Schwaben (EVS) of Stuttgart. Customers may order a minimum of 20 kWh a month at a premium of DEM 0.10/kWh. Additionally a minimum of 5 kWh per month may be bought specifically from photovoltaic plant for a further surcharge of DEM 1.60/kWh. Customers must pledge to pay the higher rates for at least ten years, although they can cancel the contract if they give three months notice before their next annual electricity bill is due.

In October 1998, **Northern Ireland Electricity** (NIE) introduced an Eco-Energy tariff. Eco Energy is electricity supplied at a slightly higher price up to a maximum of Stg£01.2p per unit. Customers may choose to have 10%, 50% or 100% of their electricity supplied from Eco Energy. The additional cost will contribute directly to electricity supplied from new renewable energy sources in Northern Ireland. A contract with a new renewable generator was signed to provide electricity from 3 wind turbines. It is hoped that demand will outstrip supply and any extra money will be paid into a fund managed by a Trust. The Trust will be independent of NIE and will include representatives interested in promoting Eco Energy, renewable power and the environment. The Trust will arrange to increase renewable generation through further new contracts.

In **Ireland**, ESB announced in September 1999, its intention to introduce a Green Tariff. This proposal has been supplemented by new entrants to the national green electricity market. Through these tariffs customers will be given the opportunity to elect for 'green' electricity. Customers who opt for the tariff are guaranteed that there will be a unit of electricity generated from new renewable energy plant for every unit of electricity purchased under the scheme. Independent confirmation of production of renewable energy will then be made available to participating customers. In the short term at least this emerging market will not create the critical demand necessary to achieve the policy objective of 500 MWe by 2005 with reasonable certainty.

The liberalisation of electricity markets across the EU allows for the direct sale of electricity to final customers. This brings new suppliers into competition with existing utilities seeking a share of the market. As a result, independent green electricity suppliers are finding new ways to compete with green pricing schemes operated by previous monopoly suppliers. However at this point in time there is little, if any, inter/intra–Community trade in green electricity due to restricted access to national support mechanisms.

All EU Member States deploy, to a greater or lesser extent, instruments for stimulating wind energy. Denmark, Germany and Spain, for example, have achieved considerable growth in the penetration of wind through fixed price schemes. Figures in table 2.2 illustrate the extent in terms of growth rates. Ireland and the UK, on the other hand, deploy schemes which focus on improving the price-performance ratio through a competitive process for the procurement of electricity generated from renewable sources. This is also illustrated in table 2.2 which shows that wind farm produced electricity from fixed price schemes is of the order of twice that in Ireland. Equally the penetration level achieved in 1998 may reflect the stop/go nature of the competitive offers or other factors.

Country	Installed in 1998 / MW	Total installed / MW	Average price (€/kWh)
Germany	794	2,875	0.086
Denmark	300	1,448	0.078
Spain	195	707	0.072
UK	14	325	0.070
Ireland	10	63	0.051

Table 2.2 Increases in wind energy penetration and average costs[10]

It should also be pointed out that with the development of a single market for electricity within the EU, there are proposals to harmonize renewable energy support mechanisms. The European Commission presented an initial proposed text (proposal for a *Directive of the European Parliament and of the Council on the promotion of electricity from renewable energy sources* in the EU's internal electricity market) to the Council of Ministers of the European Union in May 2000. In summary it proposes to:-

- monitor national schemes for a period up to five years;
- oblige Member States to implement programmes to increase the deployment of RES-E towards a non-binding target (13.2% in the case of Ireland);
- oblige Member States to implement certification schemes for RES-E.[11]

In reality the proposal recognises the absence of objective data to demonstrate that any one scheme is more beneficial than others in terms of delivering a uniform mechanism which can be applied across all Member States in a manner compatible with the (EU) Treaty.

A further mechanism exists in some countries for supporting self-sufficient wind energy projects at the micro scale level. It involves a form of net metering arrangement, which is in use in a small number of other Member States but more common in the United States. In a typical arrangement, customers who have small generating systems have their electric meter turn backwards as they feed extra electricity back to the network.

10 *Working Paper of the European Commission: Electricity from renewable sources and the internal electricity market; ILEX (1997) The UK Renewable Energy Support Mechanism; New Energy Magazine (BWE); EVA (1998) Feed-in Tariffs and Regulations Concerning Renewable Energy Electricity Generation in European countries, DPE, DTI (UK).*

11 Certification is for the purpose of assuring customers of the origin of the product.

In principal the way it works is simple. If at the end of a period of time, the customer uses more electricity than they generate they pay their supplier on the net kilowatt hours they use at a pre-determined rate. If the customer generates more electricity than they use, the supplier pays them for the net kilowatt hours produced. In principal no special equipment is required and a dual metering system would not be required.

In practice, for transparency and for technical reasons, a dual metering system is more appropriate. In this way, rather than providing a full subsidy (essentially the users receive the market retail price for the electricity they send to the network when the meter "reverses"), this allows for a rate to be determined based on the extent of the policy decision to support micro-scale self generation. The electricity used by the customer may then be charged at standard rates, while the electricity exported by the customer can be sold for a pre-determined rate, for example spill price or spill price plus a subsidy, if deemed appropriate.

Secondary Support Mechanisms

Direct Capital Grant Support is a commonly used instrument to support new industries in the pre-competitive phase. Denmark[12] was the first to provide direct support for private investment in electricity generation from wind energy in 1979. The programme offered 30% direct support of total investment costs, lasted for 10 years declining to 10% in 1989 when the programme ended. Since then a similar model has been used in the Netherlands, Sweden, Ireland and Germany at the Länder level, with different rates in each Länder. The Dutch and Irish model is based on an amount per kW of installed capacity, as was the case in the mid-eighties in the USA.

Financial and tax incentives take a number of forms. In the Netherlands[13], for example, there are four different support mechanisms which fall into this category.

- *Green funds* is the term which describes money made available at lower interest rates (about 1.5%) for what are termed 'green projects' which include wind energy projects.
- The *VAMIL* scheme permits accelerated depreciation on equipment which appears on the VAMIL list, allowing companies to accelerate the write off of the investment.
- The *Energy Investment Relief Scheme* allows investments in certain environmentally sustainable technologies to be offset against taxable profit at a rate varying from 40% to 52% of the total investment (in Ireland Section 62 of the 1998 Finance Act allows corporate investment in renewable energy projects with a partial offset against taxable profits)

12 *Wind Energy - The Facts. Vol 5 Market Development.* European Commission Directorate General for Energy.
13 *Fiscal instruments for the financial support of renewable energy in The Netherlands.* Presented by Kees Kwant, NOVEM at EnR Renewable Energy Working Group meeting, July 1998, Portugal.

- Finally the *Regulatory Energy Tax* is a tax payable by households and SME's on electricity (3.5cents/kWh) and natural gas when consumption exceeds a threshold demand. This tax is paid to the utility companies who pass it on to the taxation authorities. In the case of electricity generated from wind energy however, the utility company must pay it to the generator instead of the taxation authority. This use of tax may also be seen as a primary support mechanism.

<u>Research, Development and Demonstration</u> programmes have been the most widespread means of stimulating wind energy development within the EU. These initiatives, instigated under various EU Programmes, have assisted with the development of the wind industry and related expertise. A typical example of the type of project supported is the development of the next generation of Megawatt turbines through the JOULE - THERMIE programme. This project commenced 7 years ago and has resulted in megawatt scale machines being brought to the market.

Future Market Mechanisms in Ireland

In order to decide which future mechanisms should be employed in Ireland, it is important to consider a number of key factors:

- what are the objectives of the mechanism? For example, is target delivery more important than delivering wind energy at least cost? (Table 2.2 illustrates this point to a certain extent). If the primary focus is target delivery, REFITs seem to provide the means to achieve this, on the assumption that a higher price will generate added interest or make uneconomic sites at the prevailing market bid price economic.
- how can lessons learnt from past experience here and internationally be incorporated into the development of future mechanisms? The AER system was established and run based on a clear set of objectives including an emphasis on competition. There are positive and negative aspects to the scheme and changes or amendments should be based on the experience gained. In addition, the other mechanisms described earlier, in particular REFITs and Tradable Green Credits, should be explored to draw any positive contribution they may make.
- in what way can mechanisms be developed in a manner which allows adaptation as market developments, in particular electricity market liberalisation and increasing internalisation of the external costs of energy, evolve? Developments taking place internationally need to be incorporated into the development of future mechanisms. This is particularly important in relation to the single market for electricity which is developing across the EU and arising from harmonization proposals for renewable energy support mechanisms. In addition, the forthcoming National Greenhouse Gas Abatement Strategy which will address the national response to the Kyoto Protocol may provide additional opportunities for renewable energy.

While the discussions of the Strategy Group were not limited by current Government energy policy, some elements of policy did provide a useful backdrop.

The Green Paper on Sustainable Energy has increased the national target for renewable energy penetration from 31 MWe per year to a single target of 500 MWe for the period 2000 - 2005. This target is in the form of additional electricity generating capacity from renewable sources, most of which will be derived from wind energy technologies.

As outlined in chapter 1, there are currently 3 mechanisms for bringing wind energy generated electricity to the market in Ireland. These are the *AER (Alternative Energy Requirement)* scheme, guaranteed market access for projects successful under the *EU 5th Framework ENERGIE programme* and the direct sale of green electricity by independent suppliers to customers.

The Green Paper states, *"it is envisaged that, in time, as renewable energy operators develop the market opportunities available to them under the Electricity Regulation Act, 1999 for direct sales to final customers, the need for AER support will diminish. In the meantime, the promotion of renewable energy technologies will continue under the AER programme…. The provisions of the next AER competition (AER V) will reflect the experience gained from previous competitions, particularly in relation to the ability of project developers to comply with statutory requirements and ensure timely completion of projects."*

In addition, in the short term, the *National Greenhouse Gas Abatement Strategy* will be published. One of its objectives may be to remove the current market distortions in relation to fossil fuels, dealing in particular with the financial cost associated with their damage to the environment. Any future market mechanism for renewable energy will need to accommodate short and medium term changes in the cost of fossil fuels, which clearly has a direct impact on the economic viability for wind energy projects and the amount of support required.

In brief, future market mechanisms for wind energy in Ireland will have the following requirements :

1. ensure target delivery at least cost, taking into account the benefits of wind energy, in particular, with regard to reducing greenhouse gas emissions;
2. overcome difficulties associated with previous AER rounds;
3. take account of liberalisation of the electricity market in Ireland and indeed EU wide;
4. accommodate reductions in market distortions addressed in the *National Greenhouse Gas Abatement Strategy;*
5. encourage increased local involvement in wind energy projects.

Regarding 1 and 2 above, the principal difficulties associated with previous AER rounds are:

(i) Market Access

In REFIT[14] schemes open access is guaranteed for compliant projects and development proceeds in an orderly manner. In AER, market access opportunities are restricted by the timing, categories and quantities announced from time to time. No one could reasonably predict when such competitions would be announced or the likely success of such competitions. This caused some project developers to withhold planning applications and development work with the ESB on connections until the results of competitions were announced. Any clear signal to the market of future proposals will reduce this uncertainty.

(ii) Paper projects.

The current AER procedure delivers an impressive portfolio of projects on paper. However, as a result of the uncertainty discussed at (i) above, the reality is that at least some projects can be predicted to fail in the planning process which adds significantly to the uncertainty regarding the commissioning of projects. If these elements are already secured, prior to the competition or the award of a contract, it increases hugely the chances of target delivery.

(iii) Cyclical demand.

A further reality of the current process is that after successful projects are announced there is a significant demand placed on planning authorities and the ESB for connections. This cyclical demand causes its own delays. Again, if these elements are already secured and processed, prior to the competition or the award of a contract, it increases hugely the chances of target delivery and in a shorter timeframe.

(iv) Administrative delays.

The administration of competitions heretofore involved a preliminary assessment of projects and financial ability of project proposers. In addition, considerable resources were required for the provision of grid connection estimates for projects which were then unsuccessful. The establishment of the Commission for Electricity Regulation provides an ongoing vetting mechanism which should facilitate a lighter approach in future AER competitions by eliminating a significant assessment period. Under the AER III competition, for example, the number of applicants at the technical stage exceeded the number of successful developers by a factor of 10 to 1.

(v) Internal capacity constraints.

Conditions of previous competitions imposed arbitrary ownership and project size limits to avoid ownership concentration. In the intervening period market interest and confidence have grown. A withdrawal of the ownership and

14 E.V.A. (Energieverwertungsagentur) *Feed-in Tariffs and Regulations concerning renewable Energy Electricity Generation in European Countries,* August 1998

project size caps would remove a barrier external to planning and technical constraints.

(vi) Variation in costs.
Connection costs can account for up to 15% of project capital costs which must be brought to account in calculating a bid price. However, the ESB can only provide an estimated connection cost on a stand alone basis. The actual cost can vary significantly where, for example, contiguous sites are successful. The current mechanism does not allow for variation of a bid price where verifiable costs above the estimated connection cost arises. This can be a deal breaker in certain circumstances.[15]

Regarding (3) and (4) above (future market mechanisms), in the liberalised market, green electricity generators will not receive a 15 year contract from downstream retailers or final consumers. The maximum contract timeframe that generators will receive is is likly to be for a shorter term. This may adversely affect access to funds.

The amount of support required for wind energy projects will decrease if the energy market becomes less distorted and the external costs of brown electricity are internalised. If, in the market mechanism, the electricity produced from a wind farm is separated from the renewable energy value associated with it, the price associated with the *'greenness'* can vary over time as other factors such as carbon taxes come into play to remove market distortions. However, AER contracts would not diminish in costs as other refined support mechanisms emerge. If the 500 MWe target is to be delivered, based on current experience in obtaining planning consent and physical connections target projects should be identified within 2-3- years.

One approach to dealing with point (v) is to establish a separate mechanism which is more appropriate to developers of small scale projects rather than commercial operators of large scale projects.

Recommendations

The Strategy Group recommends a short and medium term strategy for a market mechanism to increase the penetration of wind energy meeting the requirements outlined in the previous section. The strategy centres on the primary support mechanisms discussed earlier complemented by planned secondary supports referred to in the Green Paper which include

- continuation of existing tax relief measures and consideration of other fiscal measures for wind energy in the context of green tax measures in future budgets;
- a research, development and demonstration programme for renewable energy;
- an expanded and intensified work programme for the Renewable Energy Information Office of the Irish Energy Centre;
- the work of the Renewable Energy Strategy Group.

15 This is addressed in Chapter 4 "*short term strategy*"

Short Term Strategy

The Strategy Group recommends that, in the short term, the priority should be to deliver projects with planning permission at least additional cost to electricity users.

The market mechanism recommended for the short term is to offer 15 year contracts (AER V) for projects which have planning permission, the necessary licences and authorisations from CER and accredited certification. It is recommended that the price, linked to the Consumer Price Index, be based on projects delivered in the AER III competition corrected to allow for payment of the charges and levies introduced and approved by CER post AER III. Essentially this will offer terms comparable to those arrived at through the competitive tendering process of AER III. It is recommended that this mechanism be available for 24 months to allow projects which enter and pass through the planning stages to avail of the opportunity, in addition to the current projects with planning permission.

The Group feels that large scale wind farms should be encouraged to achieve efficient deployment of wind energy, and to avoid a proliferation of grid connections. In this regard, it is recommended that the project maximum size cap and ownership restrictions be removed.

The Group recommends that the total capacity on offer should be limited to 160 MW within the 24 month period.

It is further recommended that a clear signal be sent to the market that the Government is seriously committed to the target on deploying wind energy and that, as a result, a further round of offers will be held in the future on a competitive tendering basis (AER VI).

In addition, the Strategy Group recommends that a *Small Scale Renewable Energy Scheme* be maintained. This will have the benefit of increasing public awareness of the technology and allaying some concerns about the impact of wind turbines. This could decrease objections to future larger scale developments where the impact can reasonably be demonstrated as benign. The 5 MW cap for small scale projects applied heretofore supported commercial wind farms rather than bona fide community projects. As a result it is recommended that the threshold should be moved down to, say, 2.5 MWe. Any such scheme would have to set stringent rules to avoid project partitioning by commercial operators to benefit from any higher price for small scale projects.

Medium Term Strategy

The medium term strategy covers a 3 to 5 year timeframe. The Strategy Group feels that it is important that a clear message be conveyed to indicate what should follow the short term strategy in order that all involved are given the opportunity to be adequately prepared. After considerable deliberation, and in light of currently available information, the Group recommends that the model comprising AER V and AER VI continue as a rolling programme into the medium term.

One of the difficulties however, in recommending a medium term strategy, is the pace of change in the energy sector generally and the wind energy sector in particular. A number of the factors causing these rapid changes were touched on at the introduction to the section on future market mechanisms, namely

- the level of competition amongst electricity suppliers in the Irish electricity market;
- the impact of any (EU) Directive on the promotion of electricity from renewable energy sources in the internal electricity market;
- the possible development of an international market for CO2 emissions and / or tradable green credits.

A key factor in making these recommendations is that they are based on currently available information and must be subjected to review to take account of market developments and emerging or predictable European Community law. None of the other mechanisms discussed in earlier sections were ruled out by the Strategy Group. In particular, tradable green credits was discussed and seen to have particular merit. However, while a number of Member States are currently introducing it as a primary support mechanism to deliver national targets, its attraction as a mechanism is increased with the possibility of international trade. Currently, however, there are no mechanisms which allow this.

In light of the uncertainty, it is recommended that the Department of Public Enterprise carry out a review mid way through the short term programme, i.e. during month 12, and at regular intervals thereafter, in order to determine the best possible route.

Chapter 3 Trading Issues

This chapter examines the impact of trading issues on the liberalisation of the entire green electricity market by the Electricity Regulation Act, 1999 and commenced on 19 February 2000. The issues involved include access to the electricity network, use of system charges, trading and settlement, imbalances and the provision of top up and spill.

The Electricity Regulation Act, 1999 was signed into law on 14th July, 1999. It

- implements in national law binding provisions of a Council and Parliament Directive (96/92/EC) establishing common rules for a (partial) internal electricity market;
- provides for the establishment of an independent regulator styled the "Commission for Electricity Regulation" (CER);
- assigns certain functions to the regulator which he exercises independently as a matter of law;
- provides for the partial liberalisation of the brown electricity market and the liberalisation of the entire green electricity market.

Under the Act, the Commission for Electricity Regulation was established with power to

- grant licences to generate and supply electricity;
- grant authorisations to construct generating stations;
- provide for access to the transmission or distribution system by holders of licences, holders of authorisations or by eligible customers.

In relation to wind energy one of the CER's functions, under the Act, is *to promote the use of renewable, sustainable or alternative forms of energy*. The CER also has a duty to *encourage research and development into renewable, sustainable and alternative forms of energy* and *to require that the system operator gives priority to generating stations using renewable, sustainable or alternative energy sources when selecting generating stations.*

The CER has a large number of other functions and duties (e.g. protecting the interests of final customers, promoting competition, safety and efficiency). Given the tight time-scale within which the CER was required to establish a regulatory framework, these functions and duties have taken precedence over the aforementioned ones which relate to wind energy. In a recently published *Discussion Paper on Green Issues*[16] , the CER states that the duties relating to the promotion of green forms of energy are subsidiary to the duties of non-discriminatory regulation and protecting the interests of final customers. In relation to non-discriminatory regulation the CER concluded[15] that its duty to promote green forms of energy was subordinate to other duties including an obligation not to

15 This is addressed in Chapter 4 "*short term strategy*"
16 Commission for Electricity Regulation (2000) *Discussion Paper on Green Issues – CER/00/12*

discriminate between holders of licences. Further elaboration on this and the other provisions of the Act dealing with renewable energy e.g., priority dispatch, would increase certainty in the market place.

Provision for the Direct Sale of Green Electricity

Section 14 of the Act allows the CER to grant or refuse licences for the generation of electricity and for the supply of electricity to certain customer categories. One category is 'green customers', i.e. customers who wish to purchase electricity *which is produced using renewable, sustainable or alternative forms of energy.* Another category is *eligible customers* (defined as a customer whose annual consumption at a single premises is greater than 4 GWh). Essentially this means that the total electricity market is open to green electricity suppliers while only a portion of the market is open to those generating electricity from fossil fuels (unless they use co-generation, which is deemed a further separate category).

One of the principal challenges that arises for green electricity generators compared to those with an AER contract is the absence of a fixed price 15 year power purchase agreement which offers significant comfort to financiers in the "AER market". This will clearly have implications for the financial risks and the availability and cost of finance in the absence of a guaranteed sales mechanism. The supplier must seek customers who are willing to agree to purchase green electricity at predetermined rates for a certain time period. It seems likely that a 3 year contract would be the maximum that a green customer would sign up for.

The green electricity supplier will need to generate or source the green electricity to meet the demand of the customer base. Already new players are entering the market to act as brokers, with the aim of buying from a portfolio of green electricity generators and selling to a portfolio of customers. To date eirtricity Ltd. e Power Ltd., and E.Co – The Electricity Company Ltd. have applied for and secured licences to supply green electricity.

A further key challenge will be meeting the requirements of the trading system. The CER published a consultation document in September 1999, setting out draft proposals for a transitional electricity trading system in Ireland. It discusses the rules for scheduling and dispatch, the balancing market for reconciling scheduled and actual quantities, price setting in the balancing market (top up and spill) and the settlement period.

Following the publication of the consultation document, the CER held a public meeting at which industry participants and other interested parties were given the opportunity to seek clarification or express their views on the proposals. Participants subsequently received a summary of the written comments made on the proposals. In December 1999, the CER published a summary of the comments / responses to the proposed trading system. The CER also established a *Trading and Settlement Advisory Committee* to advise on the delivery of an interim trading and settlement system.

The CER published final proposals for a transitional electricity trading and settlement system in January, 2000. The Transmission System Operator has since developed details of the trading arrangements in a Trading and Settlement Code (Version 1.0), which has now been approved by the CER. The Code will be further developed by the CER as necessary, in accordance with the modification procedures as set out in the Code. Version 2 of the Code is expected shortly and version 3 in October.

A number of market roles have been identified within the code which are important to the green electricity market. ESB, through its National Grid Business Unit will act as the *TSO (Transmission System Operator)* and *SSA (Settlement System Administrator)* and through its Customer Services Business Unit will act as the *DSO (Distribution System Operator)* and *MRSO (Meter Registration System Operator)*.

The TSO is responsible for the dispatch of generating units on the basis of nominations adjusted for system security and stability reasons; energy transfers across the interconnector (with TSO in Northern Ireland); the recovery of transmission, connection, access and use of system charges and the recovery of costs of procuring Ancillary Services and System Constraint Costs.

The SSA is responsible for calculating constraint and energy market imbalances (total and by participant); identifying or calculating imbalance quantities and spill price (every trading period); issuing invoices and payments for imbalances and recovery of the costs of operating the Trading and Settlement System (as a separate element in the TUoS charge).

The DSO is responsible for the recovery of distribution connection, access and use of system charges.

The MRSO is responsible for the meter registration service, associating each metering point with a supplier so that the supplier can be billed for the energy consumed and the use of the transmission and distribution networks under those points the supplier is responsible for.

Entering the Market

In order to participate in the electricity market those who wish to become green electricity suppliers must:-

1. secure a licence from the Commission for Electricity Regulation to supply electricity under section 14(c) of the Electricity Regulation Act 1999 (or confirmation from the CER that a licence is not required). The application process seeks to ensure the availability of appropriate financial, managerial and technical resources to comply with the terms of the licence;

2. complete and submit the SSA Market Entry Application form to show that the admission requirements are fulfilled. These requirements include provision of contact and bank details, clarification of the role of the supplier (in this case green supplier), agreeing and putting in place the appropriate level of security cover with the SSA and having a half hourly export meter that is capable of being read remotely;
3. sign the *Accession Agreement (Annexed to the Trading and Settlement Code Framework Agreement*[17]) and thereby agree to be bound by the code. This is administered by the CER once the SSA is happy the requirements are met and following a successful testing of the applicant's ability to conduct electronic transfer of data.

There is a provision within the licence of green electricity suppliers not to sell more energy to their customers than is available to them from green sources. The responsibility for demonstrating that a supplier's energy sales to final customers have not exceeded their available generation rests with the supplier and is enforced through the Supply Licence. Condition 20 states *"the Licensee shall, on the date one year after this licence is granted and on the same date of each subsequent year, deliver to the Commission a certificate, duly audited, specifying the source of the electricity supplied and confirming that the Licensee has not, for the previous year, supplied more electricity in aggregate than the amount which is available to the Licensee and which is produced using renewable, sustainable or alternative forms of energy."*[18]

With regard to this issue, the CER defines for each green generator a nominal capacity, which defines the amount of energy that can be supplied to final customers in accordance with S14(1)(c) of the Electricity Regulation Act, 1999, such that the green generator's top-up requirement should not exceed its spill over a twelve-month period.[19] This nominal effective capacity will be based on the design capacity for the wind farm and the expected load factor[20]. Due largely to the availability of the wind, the load factor is of the order of 37% on average but this varies from site to site and from year to year. The nominal effective capacity is calculated as the installed capacity times the load factor.

Green electricity generators, as is the case for other generators, are required to apply to the CER for an authorisation to construct a generating station under section 16, and a licence to generate electricity under section 14(a), of the Electricity Regulation Act 1999. They are then required to follow stages 2 and 3 above in their role as an electricity generator entering the market. There has been concern expressed that the SSA market entry requirements currently place an obligation on green generators as well as green suppliers to pay a security deposit of €20k. This is despite the fact that green generators will typically be fully contracted to a supplier and hence not subject to the top up and spill regime.[21]

17 The Trading and Settlement code framework agreement is an agreement between the parties who give effect to and are bound by the code.
18 Commission for Electricity Regulation (2000) *Discussion Paper on Green Issues.*
19 Commission for Electricity Regulation (2000) *Final Proposals for a Transitional Electricity Trading and Settlement System.*
20 Load factor = (electricity produced per annum)/(maximum electricity that could have been produced)
21 Irish Wind Energy Association (2000) *Note to Renewable Energy Strategy Group*

The Trading System and Green Electricity

The first stage in the proposed trading system is scheduling. Essentially a green generator along with all other generators, if above a certain size, must notify the TSO (Transmission System Operator) of their contracted volumes of electricity, a day in advance of operation. The nominations are for each half hour period of the following day (6.00 a.m. to 6 p.m.) and generators will in general nominate amounts to meet their customer demands. All generators who wish to participate in the balancing market will need to have appropriate half-hourly meters installed on the generating units.

The main role for the TSO is the responsibility for the provisional running order on the nominations of generators. According to the Trading and Settlement Code, all generating units above 10 MW must be subject to central dispatch. Generators with units between 5 MW and 10 MW can choose to be exempt from central dispatch and all generators with units below 5 MW will be exempted from central dispatch and will self dispatch. Therefore, while most generators are subject to central dispatch, wind generators, due to the size of the turbines, are free to self-dispatch.

In its discussion paper on green issues[22], however, the CER suggests that wind farms above 30 MW be subject to a limited form of central dispatch. The rationale for this is to allow the TSO issue instructions in prescribed circumstances to de-energise such wind farms to ensure the security of the grid.

Some generators may not be dispatched according to their day-ahead nominations for a number of reasons including shortfall or excess in demand. The TSO will alter the nominations (of units subject to central dispatch) in order to maintain a balanced and secure system. To allow the TSO to re-schedule or re-dispatch generating units at least cost, generators will be required to submit, in addition to their nominated schedules, the availability of units and the start-up and idling prices and incremental and decremental prices of increasing (decreasing) output for both variations from nominated output levels.

The scheduling and trading and settlement mechanisms plan and balance electricity output with customer demand respectively based on half-hourly intervals. In effect this means 48 reconciliations at a cost in any twenty-four hour period. Imbalances, forecasts and actual dispatch will be dealt with through a “balancing market”. In the case of a wind farm not subject to central dispatch, the imbalance will be between what was generated (adjusted to take into account losses) and what was consumed by customers in each half hour. The electricity generated is metered at the wind farms on a half hourly basis. Green customers are not obliged to have time-of-use metering to measure their consumption[23]. For these customers, profiles are used to allocate consumption measured over a normal metering reading cycle of two months, to each half hour during that period.

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22 Commission for Electricity Regulation (2000) *Discussion Paper on Green Issues*

23 Eligible customers i.e., those large customers entitled to the benefits of competition under the Act will require meters. This would continue to be the case where they elect for green product.

Balancing is required for every half hour trading period where, for example, it might happen that more electricity was produced and dispatched than was actually consumed. The excess electricity in this half hour may then be sold to another green generator[24] who had a shortfall in the same period provided this is done within 7 days of the trading day. Otherwise ESB Generation will buy this amount of electricity at the 'spill' price (ESB's avoidable fuel price up to an initial tranche and thereafter the avoidable fuel cost of the best new entrant).

Equally, it might happen that less electricity was produced and dispatched, from the wind farm than was actually consumed by the customer(s). The shortfall in electricity in this half hour must then be purchased from another green generator who had an excess in the same period provided this is done within 7 days of the trading day. Otherwise ESB Generation will sell this amount of electricity at the 'top-up' price (which should average out over the year to the estimated full cost of a best new entrant).

Wind energy generated electricity will rely more on the balancing market due to the intermittent nature of the wind and the resulting lack of predictability for half hour periods, one day in advance. Most brown electricity technologies are reasonably predictable and output can be tailored to measured or predicted demand. This potential additional cost will clearly affect the economics of trading green electricity and will require suppliers to take a position on this.

Cost of Access to and Use of the Electricity Network

A key consideration in the direct sale of green electricity is the cost associated with using the electricity network to transport the electricity from the point of generation to the point of consumption. There are three essential elements in this cost, namely

- the cost of connecting to the network;
- the cost associated with the use of the transmission and distribution systems (use of system charges); and
- the cost incurred due to losses in the delivery of the electricity to the point of consumption.

Losses occur in the transmission system as electricity is transported from generators to the transmission / distribution interface. These losses are allocated to generators in the settlement process using transmission loss adjustment factors applied to the amount of electricity generated. These loss adjustment factors are site specific given that the amount of physical losses depends on the location of the generator relative to the network. A factor may be greater or less than one because output could have the effect of reducing,

24 *current arrangements do not allow green suppliers to trade with non-green generators/suppliers to resolve any volume imbalances prior to settling Top-Up and Spill with ESB. This is contrary to the Commission's original intention and its correction is being included in the current set of Trading and Settlement Code Modification Proposals.* – extract from Commission for Electricity Regulation (2000) *Discussion Paper on Green Issues*

rather than increasing, transmission losses at the margin. In other words, a wind generator, who contributes to reducing losses on the transmission system, will be rewarded by a loss adjustment factor of greater than one. While existing (prior to 19/02/00) embedded generators connected to the distribution network are not subject to transmission losses, all new wind farms connected to the distribution and transmission network will be.

Losses occur in the distribution system as electricity is transferred from the transmission / distribution interface to the end user. These losses are allocated to embedded generators and final consumers of electricity. The distribution loss factors applied to *customers* differ in respect of the voltage level at which the customers are connected but otherwise are not site specific. Suppliers take into account losses when purchasing from generators to meet their customers' needs. For example, a supplier with contracts to meet 50MW of demand will need to purchase in excess of 50MW depending on the Distribution loss factor. The distribution loss factors applied to embedded generators are determined by the DSO on a site specific basis. The generator's output is then scaled by the site specific distribution loss adjustment factor for the generator. The factor could be greater or less than one, depending on whether the embedded generator in question reduces or increases distribution system losses, as in the case of transmission loss factors.

The issues which arise in relation to connecting wind farms to the electricity network is dealt with in detail in Chapter 4.

Regarding use of system charges, different approaches are adopted by the TSO and DSO for TUoS (Transmission Use of System) and DUoS (Distribution Use of System). The TUoS is comprised of two parts: (a) *Network Charges:* for the use of national transmission system infrastructure for the transportation of electricity and (b) *System Services Charges:* the costs arising from the operation and security of the transmission system. ESBNG pays the costs of Ancillary Services to the providers of such services and users pay ESBNG a System Services charge in respect of these costs.

The TUoS charge for wind electricity generators connected to the transmission network directly or indirectly via the distribution network comprises a network location based capacity charge and system service charges for direct tripping and fast wind down tripping. The location based capacity charge varies depending on the location of the wind farm relative to the network.

The TUoS charge for wind electricity suppliers with customers connected to the transmission network directly, or indirectly via the distribution network (with maximum import capacity agreements) comprises a network capacity charge (a different charge depending on whether the customer is connected to the transmission or distribution network), a network unauthorised usage charge, a network transfer charge and system services charges.

The TUoS charge for wind electricity suppliers with customers connected to the transmission network indirectly via the distribution network (for all other demand) comprises a network capacity charge, a network transfer charge and system services charges.

There is no DUoS for wind electricity generators connected to the distribution system. The DUoS charge for wind electricity suppliers with domestic customers connected to the distribution system comprises a standing charge and a unit rate (per kWh), both of which depend on whether the customer is urban domestic or rural domestic. For street lighting there is a unit rate only. For low voltage industrial and commercial customers, medium voltage customers, looped customers and tailed customers there is an additional low power factor surcharge.

Recommendations

The absence of a PPA for green electricity generators who do not have access to balance sheet finance may impede the development of a competitive green electricity market. Indications are that such projects may suffer from an initial lack of confidence among support players, in particular banks, in the early trading stages of the green electricity market.

Accordingly the Strategy Group recommends that the Department of Public Enterprise bring forward proposals for an interim period to alleviate the predictable difficulty in securing loans for green electricity generators targeting the open market. The purpose of such a proposal is to reassure lenders that a continued revenue stream will be available to the generator from the windfarm project for a period of, say, eight years. The Group recommends that the proposal be along the following lines:

- the scheme will remain open for two years,
- will be limited to individual projects commissioned in those two years up to a total of 40MW in year one and 40 MW in year two,
- the PPA will be exercisable for eight years from the date of commissioning,
- the PPA price will be the difference between BNE and the AER price at commissioning (not indexed linked) or the unit price in the contract between the generator and the green supplier, whichever is the lesser,
- the PPA is exercisable in the event that the green supplier to which the generator is contracted ceases to trade.

The trading issues affect both wind energy generators and suppliers. The Strategy Group is cognisant of the fact that the CER is independent in the exercise of its functions, constrained by the Act in exercising discretion, is currently reviewing the issues relating to the green electricity market and welcomes this development.

In relation to the elements in the Electricity Regulation Act, 1999 making provisions for renewable energy it is recommended that early elaboration on the administrative application of these provisions be published in order to increase certainty in the market. The Strategy Group notes the particular impact of some provisions of the Act or consequential actions required of the CER which can have a disproportionate impact on wind energy operators. The Strategy Group recommends that any such anomalies should be brought to the attention of the Minister a soon as possible in order to ensure the CER has the necessary discretion in law to meet national policy objectives.

In relation to the security deposit of €20,000, and the exposure to financial risk in relation to failure of a market participant, the Group feels that wind generators should be treated in a manner which reflects both their scale and level of participation in the market. In this context, the Group welcomes the CER's consideration of scaling the security deposit to reflect the scale of the generator. Additionally, if bad debt was brought to account as another identified form of operating cost the proportionality of any contribution by an individual operator would also be scaled proportionately.

Separate to the issue of scale, the Group feels that wind energy generators with their output fully contracted to a supplier (e.g., the ESB in the case of an AER or THERMIE wind farm) have a limited involvement in the market and their exposure to risk should reflect this fact.

Section B – Electricity Network

Chapter 4 Grid Connection

This chapter examines the local impacts of connecting wind farms to the electricity network. It then draws together the impediments, actual or potential, arising and points towards a forward looking network upgrading strategy to address a number of these issues.

Context – Irish Electricity Network

Prior to the electricity market being liberalised, electricity was generated in Ireland for public supply almost exclusively by the Power Generation business unit of (ESB) Electricity Supply Board. More recently, a number of small independent power producers (including wind farm owners) signed power purchase agreements with ESB to sell the output of generating stations to the ESB. Emerging legislation requires that the electricity network be opened to new entrants to deliver their generated electricity to final customers in the liberalised market.

The Irish electricity network comprises the transmission and distribution systems. Transmission of electricity is the responsibility of ESB National Grid, who operate and maintain the 400 kV, 220 kV and most of the 110 kV circuits. Distribution of electricity to customers is the responsibility of ESB Customer Services, who operate some 110 kV circuits, all the 38 kV sub-transmission circuits, the medium voltage 20 kV and 10 kV networks, along with the low voltage networks.

These systems have evolved over the years to match the requirements of developing customer load and power station siting. For technical and economic reasons, the direction of power flow in the distribution networks was almost always from the higher to the lower voltage levels. The introduction of generation connected directly to the distribution networks changes this network from a passive system, merely supplying loads, to an active system with power flows and voltages being determined by the generation as well as the loads.

The supply of and demand for electricity is the backdrop against which the connection of new generating capacity must be considered. On the supply side, the total installed electricity generating capacity reached 4,544 MW by the end of 1999. Total electricity production in 1999 was 20,890 GWh while the maximum demand was 3,656 MW in the same year. The growth in both supply and demand has placed significant strains on both the transmission and distribution systems and plans are under way to address this.

Transmission Network

The purpose of a transmission grid is to transport electricity from all grid connected generation stations to the load centres where customers require the power. Power can flow in any direction on the grid. The amount of power required by industrial, commercial, farming and domestic customers varies depending on the time of day and year and other factors such as weather, holidays etc. The number of generators providing power and the amount of power each generator is providing may vary to match the changing customer requirements. The transmission system must be flexible and able to cope with credible combinations of generation and load.

Since the electricity supply to the entire country depends on the integrity of the transmission system, it must be designed to achieve and maintain a high level of reliability. The transmission system must be robust enough to withstand unforeseen events such as a transmission line being unavailable (due to fault, lightning or other outages) or a generator suddenly becoming unavailable so that another generator has to be used.

The Irish transmission network or national grid is a network of over 5,800 km of lines and cables throughout the country. It operates at voltages of 400 kV, 220 kV and 110 kV. Electricity generated in power stations is transformed to higher voltage and fed into the transmission network. This network incorporates over one hundred high voltage transformer stations where the voltage is reduced to distribution voltages of 38 kV, 20 kV and 10 kV. Some larger industrial premises are connected directly to the national grid.

Substantial investment in expansion and renewal of the transmission system is required to ensure continuing reliable electricity supplies and to cater for the growth of demand, the addition of new generating capacity and the requirements of the electricity market.

The transmission system is controlled and monitored continuously by the National Control Centre (NCC) in Dublin.

Distribution Network

The Distribution network takes power from the high-voltage transmission system and distributes it over an extensive network of some 160,000km of overhead and underground lines to end users. The Distribution network operates at 38kV, 20kV, 10kV and low voltage (400V three-phase).

Ireland’s rural distribution network is characterised by long lines feeding a dispersed load. ESB has more network per customer than most other European Utilities - twice as much as that of France and up to four times as much as similar UK Regional Electricity Companies.   In addition the rural networks are relatively ‘weak’ - that is short-circuit levels are low. These rather unique features of long line lengths, low short-circuit levels and low load density, limit the amount of generation that can be embedded onto the current distribution system.

ESB's medium voltage has traditionally been 10kV. Load on these networks has doubled over the last 15 years and as a result a large portion of the rural 10kV network is now loaded beyond its economic design limit, resulting in poor voltage performance and high levels of electrical losses.

In 1996 ESB embarked on a major network renewal programme which involves conversion of these networks to 20kV. Future development of the 38kV network will be limited and ultimately, the 20 kV system will be fed directly from 110 kV system.

ESB will soon embark on a major Asset Refurbishment Programme which will ensure that :

- 50% of the 10kV network is converted to 20kV by 2006,
- rural LV customer supplies are enhanced, and
- continuity performance matches that of comparable utilities within 10 years.

Connecting Wind Farms to the Electricity Network

The issues that arise for connection at 110 kV are very different from 38 kV and lower, primarily due to the fact that the 110 kV system is part of a means whereby bulk power is transmitted from centres of generation to bulk supply points.

Connections are offered on the basis of the lowest cost, technically acceptable. Wherever possible, local network connections (i.e. connection to the closest distribution line) are facilitated. In practice, there are site-specific parameters which may necessitate connections to 'stronger' points on the system.

As well as the physical connection of the wind farms to the electricity networks, account must be taken of the overall impact of the aggregate of wind farms in an area on the transmission and distribution systems. This is discussed further towards the end of this chapter.

The cost of connecting a wind farm to the network forms a significant proportion of the capital costs being of the order of 15% on average of a wind farm capital costs. The actual cost is very dependent on the location of the site, however, and is a determining factor in the viability of a wind farm project. The maps of the transmission and distribution networks in Appendices F and G respectively, illustrate how crucial location is, given that the most windy sites are generally along the western seaboard, coinciding with where the electricity network is relatively sparse, and consequently weakest.

Connection to the Distribution Network[25]

To date, most wind farms in Ireland have been connected to the Distribution network. On 38kV networks, a tee connection to the closest network section may not always be permissible. The 38kV network is a sub-transmission network feeding a large number of customers, and the integrity of the network from an operational and protection perspective must be maintained in order to maintain the quality of supply to final customers. Any connection to the network, be it an additional load or additional generation, must be tested against a set of specified criteria to ensure any negative impact on the system integrity is minimised or offset. To date, the largest wind-farm connected into a local 38kV sub-transmission system, i.e. downstream of the feeding 110/38kV substation, has been 5 MW.

Generally, embedded generators are connected to ESB's Distribution system via a single feeder. No alternative connection is made available, and the generator takes the risk that the single connection is available when required. In some cases, dual "looped" feeder may be required for operational or protection reasons.

In relation to connection charges applied to generators embedded in the distribution network, current practice is based on embedded generators paying 100% of the cost of connection and other work specifically to facilitate generation (e.g. export metering)[26]. They also pay an on-going charge to cover the cost of operating and maintaining the generator connection assets. As an alternative to the on-going charge, the operation and maintenance costs may be recovered as a capitalised amount charged at the time of the connection. Since embedded generators pay in full for their connection assets and pay their operating and maintenance costs through a annual charge, it is not proposed by ESB to apply a further distribution use of system tariff to electricity entering the system at embedded generator sites.

Assessment Criteria - Distribution Network

The following are some of the assessment criteria employed by ESB Customer Services when considering an application for grid connection of a wind farm to the distribution network.

<u>Voltage Rise</u> Based on a probabilistic approach, a theoretical voltage rise of 0.5% to 1.0% at times of minimum network load on medium voltage networks is acceptable. A theoretical voltage rise of up to 1.7% is accepted on suitable 38kV networks, again at minimum network loads.

<u>Voltage Dips and Flicker</u> The voltage performance and power quality of Distribution networks is governed by the EN50160 European standard.

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25 A detailed discussion on the specific impacts of wind farms on the network can be found in Grimes Simon (1998) *Connection of Embedded Generation to ESB Distribution Networks.* Paper presented to IWEA 1998 Annual Conference.

26 ESB (1999) *ESB Distribution Regulatory Submission to CER*

For wind farms, infrequent paralleling of any individual turbine must not produce a voltage dip of 3% or greater. For hydro turbines, this figure is 5%. In accordance with EN50160, the maximum acceptable voltage dip caused by any single event, such as the sudden disconnection of a wind farm, is 10%. More frequent voltage dips are limited by voltage flicker standards. IEC standard 1000-3-7 on power quality proposes a short-term flicker value (Pst) limit of 0.35.

Harmonics High frequency harmonic emissions caused by the modern Pulse-Width-Modulation frequency inverters on variable-speed turbines must be limited. Standards used are EN50160 and IEC 1000-3-6. In addition, the total harmonic voltage distortion at the connection point caused by the embedded generator must not exceed 1.5%.

Interface Protection Protection at the interface point with ESB Distribution networks is defined within ESB document G10/94. The specified protection is designed to safeguard the public, ESB staff and ESB networks, by disconnecting the generator from the ESB network for abnormalities on the Distribution system. The generator will require further protection installation for the safety of the generator installation and its personnel.

Connection to the Transmission Network

General: Wind farms are connected to the transmission network when the technical criteria for connection to the distribution network cannot be satisfied, or when, the transmission connection is a lower cost alternative. A connection from a wind farm to the transmission system is likely to have a substantially higher cost than an equivalent connection to the distribution system. This is due principally to two factors. Firstly, a connection to the transmission system must be designed so as to avoid any risk to the integrity and reliability of the transmission system. This is likely to require more sophisticated switching, control and protection equipment than would be required for an apparently similar distribution connection. Secondly, the high-voltage equipment required for transmission is inherently more costly than distribution equipment. In many cases, a longer distribution connection will have a lower overall cost than a shorter transmission connection.

In relation to connection charges, CER issued a direction[27] to ESB in relation to connections to the transmission network. The direction stated that offers by the Board for connection to the transmission system shall be on the basis of a shallow connection policy. In order to implement this direction ESB have prepared *A Supplemental Deed to the Generator Connection Agreement,* which is published on CER's website.

Power Quality: The power quality issues of starting voltage dip, voltage flicker and harmonics are relevant for transmission connections as well as for distribution connections. However, the greater inherent strength of the transmission system, as indicated by the short circuit level, will generally mean that the impact of the wind farm on these power quality parameters is less for a transmission connection than for a distribution connection.

27 Commission for Electricity Regulation (1999) *Direction from CER to ESB in relation to connections to the transmission network.*

Steady State Voltage Effects: When a generator connected to the transmission system exports power, the voltage at the point of connection will tend to rise. By specifying a lagging power factor, the voltage variation due to variation of power exported is counteracted by the voltage variation due to the varying absorption of reactive power. The power factor to achieve this balance will vary depending on network impedance, but is typically about 0.93, as measured at the point of connection to the transmission system.

Voltage step changes: The tripping or switching of a transmission line, especially in the weaker parts of the network, may lead to perceptible step changes in voltage. The simultaneous disconnection of a wind farm will tend to exacerbate this effect. This limits the amount of wind generation that may be connected on an unswitched connection from a transmission line (a T connection). In addition, T connections cause protection and reclosing problems as outlined below.

Voltage Stability: If a wind farm comprising induction generators becomes isolated from the main system with sufficient load to achieve a balance, and with sufficient capacitance to magnetise the generators, there is a risk of self-excitation leading to dangerous voltages and frequencies. To minimise this risk (and to improve steady-state voltage performance as mentioned above) wind farms are compensated to less than unity power factor, and protection systems are installed to minimise the risk of the wind farm continuing to operate in isolation from the network.

A second voltage stability issue that can arise is the risk of voltage collapse. The response of a wind farm with directly connected asynchronous generators to a voltage disturbance is inherently unstable. If the voltage falls, the reactive power output of the compensating capacitors falls in proportion to the square of the voltage, tending to cause a further voltage drop. At the same time, the reactive power drawn by the asynchronous generators will increase, causing the voltage to fall further. To minimise the risk of voltage collapse, wind farms should be connected to the network by means of a transformer with an automatically-controlled on-load tap changer, to ensure that the voltage applied to the generators and compensating capacitors is as close to normal as possible, despite changes in the system voltage. In addition, sufficient dynamic reactive power reserves must be available in the network to arrest any tendency towards voltage collapse. A high level of asynchronous generation will increase the reactive reserves required.

Protection: It is essential for the security and reliability of the national electricity system to ensure that faults are cleared from the system as quickly as possible. Furthermore, since many electrical faults on the transmission system are transient, being due to wind or lightning, high-speed automatic reclosing of transmission lines is used to enhance system reliability. Connections to wind farms from the transmission system must be designed to ensure that transmission system protection and automatic reclosing will continue to operate correctly. This means that transmission-grade switchgear and protection will be required as part of the connection. The precise configuration of equipment required will depend on the circumstances of each case.

Working Group on Grid Connection Issues Relating to Renewable Energies

The Working Group on Grid Connection Issues Related to Renewable Energies was established in 1995 in order to develop an agreed set of criteria governing the factors which influence the method of connecting renewable energy electricity generating units to the grid. This Group recently prepared a final report based on its findings.

The Network as a Deployment Constraint

The maps of the electricity transmission and distribution networks provided in appendices G and H respectively illustrate the geographical deployment of the electricity infrastructure in Ireland. Given that the windiest locations are generally situated along the western seaboard, where the networks are generally weakest, it is understandable that the grid itself has become a deployment constraint to wind farm development in Ireland.

The Strategy Group discussed a manifestation of this which is becoming increasingly prevalent as the number of wind farms connecting to the network grows. In a number of areas around the country, there is a limited amount of available capacity on the network for accommodating wind energy locally via a connection into the Distribution network, i.e. between its points of contact with the 110kV system. In Donegal, for example 10 – 12 MW can be accommodated currently and in Connemara, approximately 8 MW can be connected locally. The net point in the context of delivering 500 MWe of additional electricity generating capacity is that there is a serious shortage of capacity on the network.

Further investment in network upgrades is essential if 500 MWe of additional green electricity capacity is to be delivered. The normal charging mechanism for infrastructural investment for connections is bundled in its entirety on the first or next entrant and remitted if others connect to the additional capacity. There are cases where, say, 2 MWe capacity is required but, due to lack of available capacity on the network, the minimum infrastructure upgrade will accommodate, say, 10 MWe. This may constitute a deal breaker for new entrants, as the 2 MWe wind farm would be required to pay the full costs of the 10 MWe infrastructure. This is currently the case in the Arigna area for example. A number of wind farm projects have planning permission, some of which have AER III power purchase agreements. The electricity network infrastructure is currently constraining the development of these projects. Roughly £ 3 million pounds would be required to fund this infrastructure and given that this exceeds the envisaged total capital costs of the individual projects concerned, this required investment is unlikely to be forthcoming on an individual basis.

Recommendations

The Strategy Group recommends a short and medium term strategy to tackle a number of the issues associated with connecting wind farms to the network and upgrading the network to accommodate additional wind farms. The strategies are set in the context of the deployment constraints outlined in this chapter and the provision within the National Development Plan for infrastructural investment in the electricity grid to accommodate renewable energy projects. The key recommendation which underpins the strategy below is that grid upgrading for wind farms be planned in a strategic manner. This planning process should be informed by technical information on the current grid infrastructure. Strategic locations for wind farms should then be agreed and the infrastructure should be developed to accommodate the strategic plan.

Short Term Strategy

The Group feels that the short term strategy should address the twin short term impediments which are the absence of sufficient capacity and the financing arrangement for additional capacity. Specifically,

- some funds identified in the National Development Plan should be released to finance the additional costs of delivering additional capacity at designated locations, which the Department of Public Enterprise will supervise. The extent of upgrading will depend on perceived demand and subsequent connection charges will be proportional to the capacity connected. For example, if the perceived demand is 50 MW in a particular area, a 5 MW wind farm would be charged 10% of the infrastructural investment instead of the 100% charge[28] currently applied. As connections are made to the distribution and transmission networks the charge is remitted. These funds should be recycled on the same basis so long as additional demand can be predicted under reasonable assumptions,
- CER takes wind energy into account when deciding on plans to upgrade the network.

In addition, clear positive changes have been brought about as a result of the work carried out by the *Working Group on Grid Connection Issues Relating to Renewable Energies*. Further improvements can be made and in this regard the Strategy Group endorses the following recommendations from the final report of the Working Group:

- the four studies, detailed below, which were commenced should be completed as soon as is practicable. All test sites should be set up by mid 2000 and evaluation of the collected data should be completed by mid 2001.
  1. the use of MV (medium voltage) voltage regulators with line compensation to counteract excessive voltage rise;
  2. the use of high sensitivity over-voltage relays at embedded generator sites policing voltage levels during load/generation variations;

28 In such cases part of the charge would be remitted as others connect to the facility.

3. the testing of modern inverter technology in variable speed wind turbines to assess harmonic performance and power factor control;
4. the use of power supply monitors at generator sites recording voltage, power flows, harmonics, flicker, etc.

- for future competitions based on lowest bid price per kWh, applicants whose wind farm proposals potentially interact[29] from the point of view of grid access,
  1. each should be given a connection estimate on the basis of the project proceeding in isolation from all others;
  2. ESB (CS and NG) should advise the competition assessor of interacting proposals;
  3. It is recommended that a mechanism be applied to those interacting proposals which successfully complete the commercial phase of the competition, whereby any connection cost differential would be incorporated into the project's bid p / kWh price. If projects were still successful at the competition bid price with the p/kWh alteration, PPAs may be offered on this basis. The adjusted p/kWh prices would only be payable if interrelated interacting projects proceed.
- also in the case of future competitions, when there are mismatches between sought capacity and that deemed locally acceptable from a network perspective there should be a feedback mechanism between ESB and the competition assessor. This should be restricted to cases where deemed locally acceptable capacity on the network is less than sought capacity by at most 20%.

Medium Term Strategy

The Strategy Group recommends that in the medium term, upgrading of the electricity infrastructure should be carried out with funding from the National Development Plan. The funding will be allocated as in the case of the short term strategy. The initial infrastructure will be funded based on perceived demand and this payment will then be charged to wind farm projects as they come on stream on an average rather than marginal basis. The recovered funding will then be used to pay the upfront expenditure for an additional grid infrastructure development and the process will continue.

In addition, where strategic wind energy sites are identified which require additional transmission infrastructure then such grid upgrading should be fully funded from remaining funding available under the National Development Plan. Once built, however, this network extension will be available to all generators in a non-discriminatory fashion in line with national policy.

29 This addresses the impediment discussed under "*variable cost*" (Chapter 2)

Chapter 5 Capacity Acceptance

This chapter examines the capacity of the Irish electricity network to accommodate wind power, given the current and future planned levels of wind generated electricity, coupled with the intermittent nature of the resource.

Context

As discussed in Chapter 1, the targets for renewable energy deployment to 2005 in Ireland are set out in the Green Paper on Sustainable Energy. It is anticipated that most of the increase will be derived from wind energy. Projections for wind energy growth, as summarised in Appendix E indicate that by 2005 there will be 601 MW installed electricity generating capacity from wind farms. This amounts to approx 10% of the total forecast installed capacity (6,100 MW) and compares with a current installed capacity from wind energy of 69.49 MW.

Assuming that these wind farms will operate at their rated capacity on average for 37% of the year (taking into account wind availability, turbine efficiency, operation and maintenance, etc.), the annual production of wind generated electricity will be 1948 GWh by 2005. This amounts to 7.24% of the total forecast electricity demand (27,035 GWh) for that year and compares with just over 1% currently.

In a particular scenario, where this growth level of wind energy continues beyond 2005 (approx 95 MW per year), by 2010 there would be a 16% forecast share of installed capacity and an 11% share of electricity demand.[30]

A key question which arises is how these levels impact on the electricity network and arising from this, how much can the network as a whole accommodate? This is a hugely complex question, which is dependent on a number of interdependent factors. ESB National Grid who have overall responsibility for the network and IWEA who wish to see sustained growth in wind energy penetration levels have differing views on this.

Both organisations have been recently involved in studies to contribute to an increased understanding of the issues involved. This chapter draws on these studies – ESB's study is attached as appendix H and the IWEA studies are referenced in appendix A. IWEA maintain that a 20% penetration of wind energy is not problematic whereas for ESB the current target poses a significant challenge.

30 Based on a total installed capacity of 6,657 MW and a total electricity demand of 32,363 GWh

Impact of Wind Energy on the Network

Each additional electricity plant or load connected to the electricity network impacts on the network. One characteristic of the impacts which wind energy electricity plants have on the network arises as a result of the intermittent nature of the resource. A number of issues arise as a result of this in accommodating wind energy on the network which differ from the issues arising from gas or coal fired plants, or other renewable energy generating plants such as landfill gas. As the level of wind energy on the system as a whole increase, this affects the importance of these issues, as does the geographic distribution of the wind farms. These issues include :

- Operational factors
- Capacity credit
- Energy credit
- Effects of dispersed siting
- Long-term trends (including interconnection)

Operational Considerations

The operational considerations comprise power system characteristics, dispatch costs, measurement, forecasting, control, power quality, operating reserve and margin and maximum infeed.

Changing Structure of Electricity Industry

There are many changes taking place in power systems world-wide and these are driven politically, commercially, environmentally and technically. They include:

- privatisation of state owned assets;
- separation of businesses – particularly; generation, supply, network
- system operation;
- competition in supply and generation;
- replacing central planning with market signals;
- the change in generating plant mix, especially the growth of CHP and CCGTs;
- the trend towards distributed generation as opposed to large centralised plant;
- increasing growth levels in electricity demand.

The changes arising from the growth in wind energy should be considered alongside these other changes.

In 2005 it is forecast that the Irish power system will have approximately 6,100 MW of installed capacity. System loads will range from 1,550 MW to 4,725 MW. The Irish electricity market is in the process of change to a liberalised and independently regulated market. If one looks at experience elsewhere it is likely that some existing plant will be decommissioned and replaced by efficient gas-fired combined cycle gas turbine (CCGT) plant. Some of this plant is likely to be Combined Heat and Power (CHP) plant in the order of 50-100MW capacity, in addition to a single 250 MW plant. The remainder is likely to be 300-450 MW high efficiency CCGT plant. The CHP and large CCGT plant anticipate running near a base load operating regime rather than load following regime. It is likely the minimum loads that can be achieved by such plant is 50 -65% of rated capacity. This is due to plant type and EPA restrictions.

Note on data used in ESB study on operational issues

In attempting to understand the impacts of wind energy on the network in 2005, data from existing wind farms was used. The wind power series is based on the output of 8 wind farms recorded at half hourly intervals during the year 1999. The wind farms in question were Barnesmore, Crockahenny, Cark, Cronalaght and Drumlough Hill in county Donegal; and Spion Kop and Corrie Mountain in County Leitrim and Bellacorrick in County Mayo. A simple scaling technique was used to derive power series for different levels of WTG capacity. Total existing installed capacity in these five wind farms is 55.25 MW. Clearly there are limitations in using data from wind farms with a total installed capacity of 55.25 MW to model the impact of wind farms with a total installed capacity of 600 MW. This should be borne in mind when reading the next sections. In addition, these wind farms are all located in the North West of Ireland and thus do not take into account dispersion effects.

Dispatch

In order to maintain a stable system and system frequency, the generation on a system must always meet the instantaneous demand of the system as electricity cannot be stored readily (the only significant storage option currently available in Ireland is the pumped storage hydro power plant at Turlough Hill, although some of the other hydro plant can also meet instantaneous demand). Therefore, as the demand on the system changes, some generating plant will have to change power output (ramp) up or down to accommodate that change. With an increasing level of wind penetration on any system, the output of other generators will need to change not only as a result of load variations, but also as a result of wind power changes.

Based on current data from existing wind farms, ESB National Grid has estimated that typically wind generation operates in the range 0 - 80% of installed capacity i.e. wind generation rarely exceeds 80%. This applies for 90% of hours. See also Figure 5.4.

Applying this to a typical summer day in 2005, figure 5.1 shows the range in loads that the electricity system must be expected to cater for. Variations in generation can be seen as a greater uncertainty in load forecast and given the intermittent nature of the wind resource, its variation will be greater than centrally dispatched plant.

Errors in load forecasting carry a dispatch cost. It is difficult to estimate the additional dispatch costs that are due to uncertainty of wind generation. This can be reduced by better measurement and wind output forecasting. There is a normal uncertainty in load forecasting which the system operator must deal with. The calculation of additional dispatch costs could be the subject of a study when trends have been established in the new liberalised and regulated market.

The cost of the short notice change in a generator's availability is recognised in the Trading and Settlement Code. Generators subjected to central dispatch must pay a penalty to the system operator for such short notice downward change in availability. The penalty is calculated to compensate the system operator for the additional dispatch costs that occur.

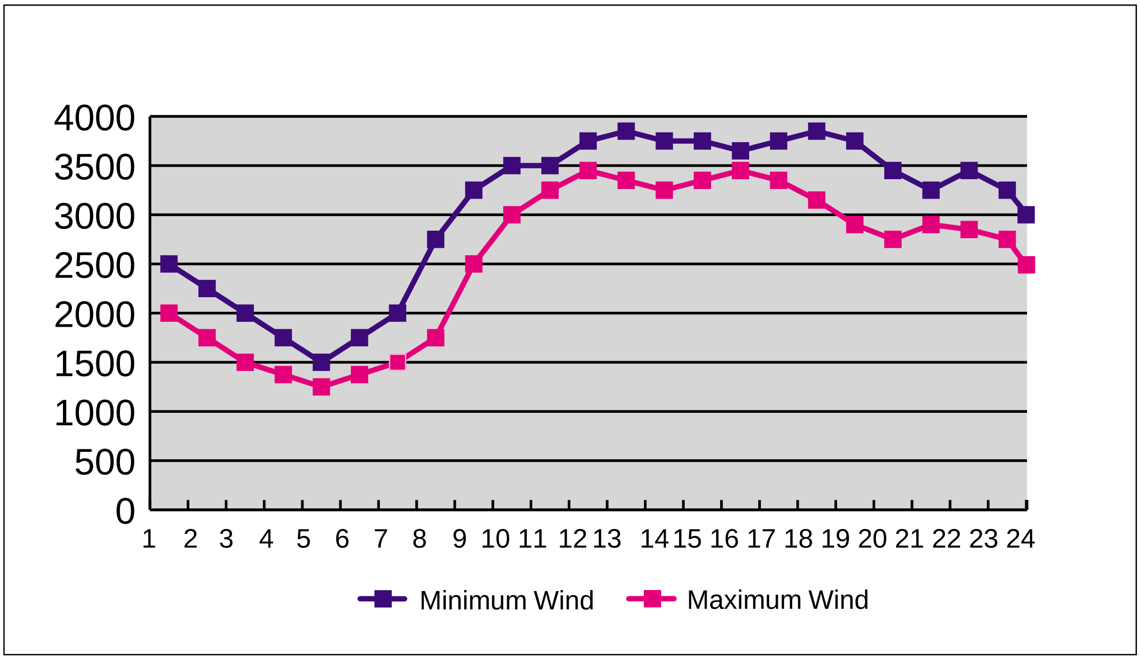

Figure 5.1: Possible Variation in Dispatched Generation for 0% and 80% wind generation – summer 2005

Forecasting

Accurate forecasting of wind power output in a 0-48 hour time window is necessary to facilitate increased wind generation penetration.

A Wind Power Prediction Tool was installed in the Danish utilities Elsam and Eltra in 1997 and has been used for forecasting since January 1998[31]. The forecast examples indicate that, even when the forecast is not perfect, the variations are small enough not to incur additional operating costs. Work in Northern Germany indicates that wind predictions are better for higher windspeeds. Therefore, with forecasting in place, the

31 "Penetration of Wind Energy in Ireland," Econnect (2000)

probability of a sudden unexpected loss of wind power at a critical time (i.e. during high wind output) is even less likely. Forecasting has real benefits in predicting wind energy outputs in the timescale 3 to 36 hours ahead. For the period between 3 and 6 hours ahead, persistence forecasts are the optimum. In order to make a persistence forecast it is important that the system operator has data from a representative sample of wind farms available. The forecasting error for a single wind farm is about 10-15% (Root Mean Square or RMS) at 6 to 24 hrs ahead. When this is taken for a number of wind farms over a region the RMS error drops to under 10%. One of the main benefits of forecasting and of understanding the certainty of forecasting will be in managing the spinning reserve.

ESB National Grid is a member of a consortium taking part in a project to develop a wind-forecasting tool. This project (3 year duration) is part-funded by the EU 5th Framework Programme and will build on developments already achieved elsewhere. It is planned to produce a wind forecasting tool for Irish conditions. However, there are likely to be additional costs to bring this system to production standard for use in the National Control Centre and for its on-going use.

Control

It will be necessary to limit wind generation at times if it is adversely affecting the system. This issue needs to be addressed over the next few years as wind penetration increases. Technical means of system control would need to be developed and put into effect in individual wind farms, if appropriate.

Power Quality

The addition of 600 MW of wind generation changes the dynamics of the power system. The worst situation occurs at low loads when there is high wind generation. At this time there are few generators contributing to system inertia, frequency regulation and voltage control. In such an instance, the loss of a large generator could have a significant impact on the stability of the power system.

Currently ESB have a number of customers with rapidly changing loads which place significant demands on frequency regulation. The impact is reduced by increased system inertia that slows the changes in frequency. The variability of 600 MW of wind generation will be additional to the normal variations in loads and generation that the power system is designed to manage. Wind generators contribute little to system inertia. In addition, they do not contribute to frequency regulation or to reactive power/voltage control.

This puts increased pressure on centrally dispatched generation and would increase the requirement for better regulation on existing and future generating units. A study is required to evaluate the short-term impact of wind power output variation on frequency and the requirements for stability and frequency regulation. This type of study requires the collection of high frequency data from generators.

David Milborrow, who studied such issues for the CEGB, has estimated the extra costs of keeping thermal plant on part load[32][33]. These are estimated at 0.1p (0.127€)/kWh for energy penetrations of 5% rising to around 0.3p (0.381€)/kWh for 15% wind energy penetration. It should be stated however, that these studies were carried out ten years ago and that the UK network has different characteristics than the Irish system, not least of which being overall size.

Operating Reserve and Margin

Operating reserve is related to frequency regulation in that the amount of generation for regulation is included in operating reserve. Operating reserve covers a longer time period – up to 4 hours - and operating reserve can be obtained from a number of sources including interruptible load. Increasing wind energy penetration could lead to a requirement to increase operating reserve due to the size of wind power output.

The number of times that operating reserve is called upon could also change. The cost of interruptible load is related to the number of interruptions and the length of time interruptions last. Wind generators do not contribute to operating reserve. Meeting reserve requirement could be a problem at times of low load and high wind generation. The worst contingency is the loss of a large generator in such circumstances. Wind generation may contribute to operating margin but only over a short time-scale and when there is very accurate forecasting of wind power output.

Maximum Infeed

To maintain system operational integrity, it is normal to limit the largest conventional generation infeed to 30% of instantaneous demand. This limit assumes infrequent loss of such generation. Operational considerations could dictate that the total input from wind generation be restricted to 20-25% (or even lower) of instantaneous demand, because of its intermittency[34]. For modelling purposes, however, this limit may be increased to a maximum credible value of 30%, to allow for possible smoothing effects resulting from widely dispersed siting. The actual limit needs to be established based on a study of what would be appropriate.

Capacity Credit

When new generation capacity is added to an electrical power system it increases its ability to serve system demand to a specified adequacy criterion. This adequacy criterion has been defined on the Irish electrical power system as a long-term loss of load expectation of 8 hours per year.

32 Milborrow D, (1998) Windpower Monthly, April 1998
33 Milborrow D, (1994) *Wind Energy Economics* BWEA annual conference 1994
34 “Penetration of Wind Energy in Ireland,” Econnect (2000)

To compare new generation additions, different options should be equivalent in the sense that each, when added in turn to the generation system, gives the same standard of adequacy.

The capacity credit of WTG is defined as the amount of conventional generation capacity which gives equivalent system generation adequacy. Various studies on capacity credit have come up with a range of different results in the order of 5% to15%. For purposes of analysis by ESB National Grid, this conventional capacity was taken to be CCGT plant, declared as Best New Entrant (BNE) generation by the Commission for Electricity Regulation (CER).

The analysis was carried out for year 2005, with a projected energy demand of 27 TWh and a peak load of 4,725 MW. The electricity demand growth rate is projected as 4.5% p.a. from 1999. Results, computed using computer program CREEP, are set out in Figures 5.2 and 5.3. They are based on a power output time series from 5 Irish wind farms existing in 1999. The capacity credit range is estimated as being 9 – 40 %, varying with penetration levels. Caution should be taken in interpreting the results given the aforementioned data limitations.

Figure 5.2 shows percentage capacity credit, calculated as the ratio of equivalent BNE capacity to WTG capacity. Figure 5.3 shows absolute capacity credit (MW of BNE). It can be seen, for example, that 2,000 MW of WTG capacity is equivalent to 300 MW of BNE capacity from a system adequacy viewpoint. These results are broadly in agreement with theoretical results that were obtained in *The Case for Wind Energy* study carried out in 1989/1990.[35] They are also in line with results obtained internationally.[36] [37]

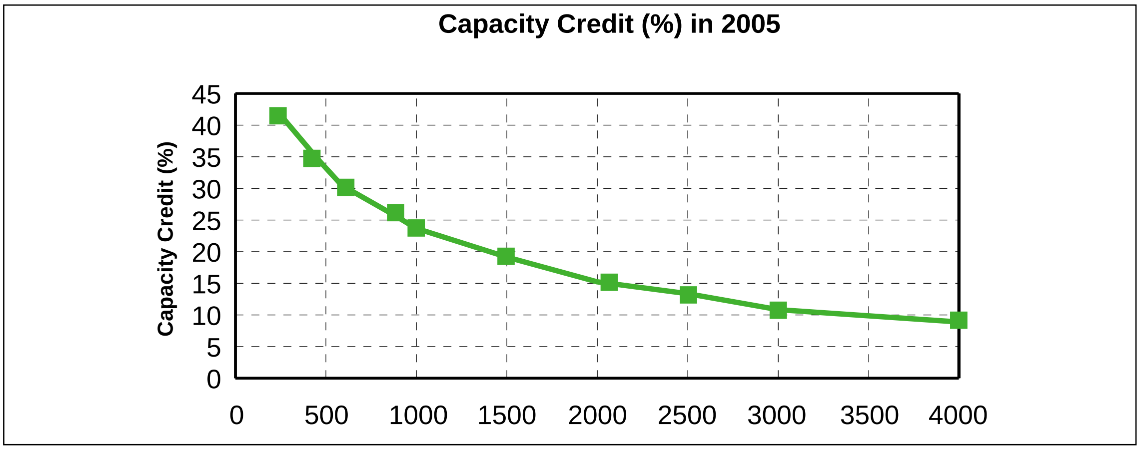

Figure 5.2 ESB National Grid Projected Capacity Credit (%) in 2005

The capacity credit return from additional WTG capacity gradually decreases in percentage terms as WTG capacity is increased. It can be seen to saturate at a BNE capacity in the order of 350 MW. This is true with wind power limited to 30% of instantaneous demand, but holds even if no such limit is imposed.

35 O'Dwyer E. et al (1990) *The Case for Wind Energy*, Cigre
36 Halberg N. SEP (1991) Wind Energy Research Activities of the Dutch Electricity Generating Board
37 Van Wijk et al. (1992) *Capacity Credit of Wind Power in the Netherlands*

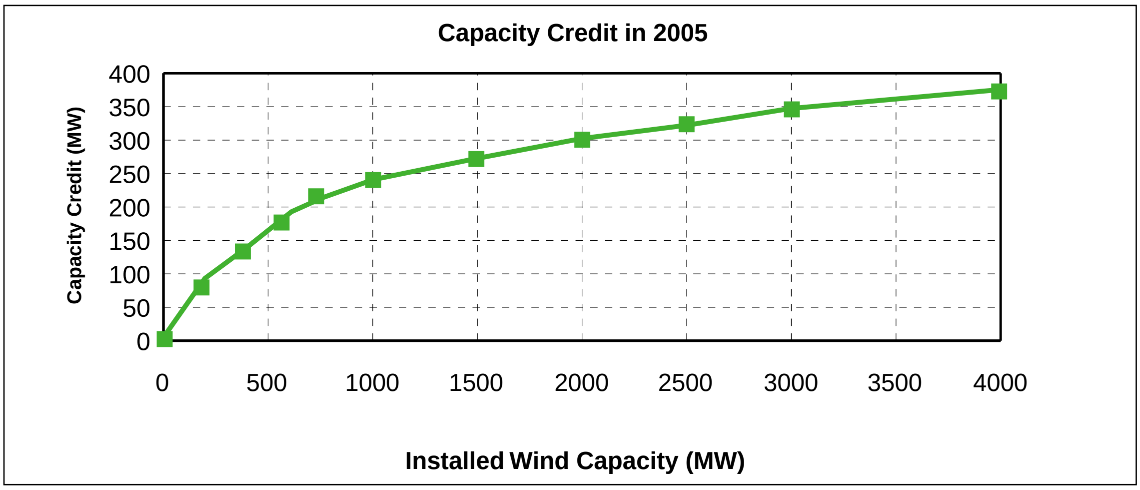

Figure 5.3 ESB National Grid Projected Capacity Credit (%) in 2005

The maximum hourly variation in power output is 60%. A load duration curve for the wind power series is shown in figure 5.4. Interpreting the graph by means of example, the point (0.1,0.8) shows that 80% of maximum generation is available for 10% of the time.

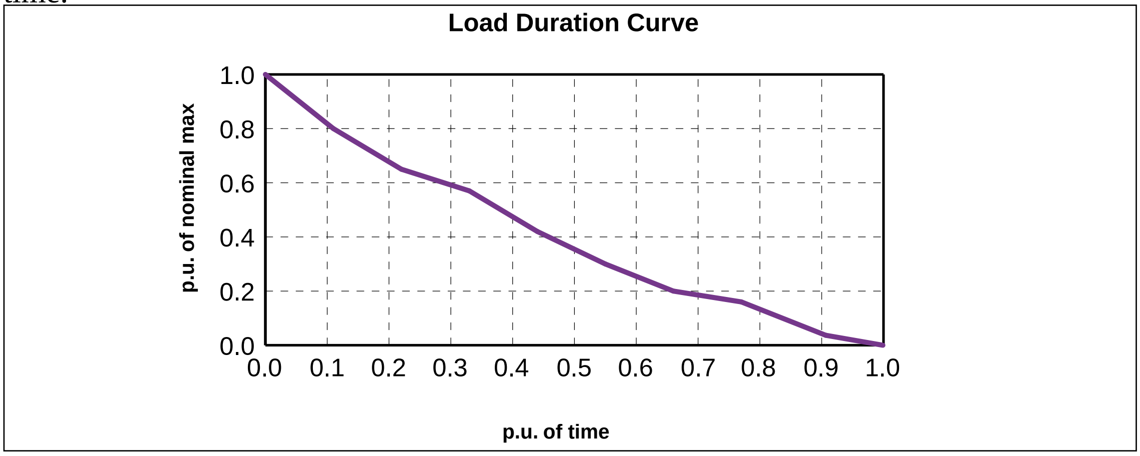

Figure 5.4 Load duration curve for wind power series

The wind power series used by ESB to carry out capacity credit evaluation is based on the output of five wind farms recorded at half hourly intervals during 1999. The wind farms in question were Barnesmore, Crockahenny and Drumlough Hill in County Donegal; Spion Kop and Corrie Mountain in County Leitrim. A simple scaling technique was used to derive power series for different levels of WTG capacity. Total existing installed capacity in these five wind farms is 30.8 MW.

It is recognised that the number of wind farm locations used to derive this time series is limited, and hence the full benefits of geographical dispersion may not be captured. However, some comfort is taken from the fact that the load duration curve as obtained from this wind power series is in very close agreement with the load duration curve from theoretical and geographically dispersed wind farms (as published in the IWEA commissioned Ecofys Report "Geographical dispersion of wind power output in Ireland").

The Danish Situation

The development of wind power in Denmark has aroused considerable interest. The national objective to achieve 50% wind energy penetration by 2030 in particular has been the focus of much comment.

ELTRA is the TSO for the western part of Denmark. The information in Table 5.1 was obtained from ELTRA.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore and nearshore turbines	1,500	1,700	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Offshore turbines			150	300	300	450	450	600	600	750	750
Total	1,500	1,700	2,050	2,200	2,200	2,350	2,350	2,500	2,500	2,650	2,650

Table 5.1 ELTRA forecast for installed wind power (MW)

Installed WTG capacity in ELTRA’s area at year-end 1999 was 1,312 MW. Wind energy production was 2.37 TWh, which was 11.5% of domestic consumption. Accommodation of this level of wind power, in conjunction with acceptance of electrical power associated with heat production, results in difficult operational problems, especially at low load periods. Power balancing and frequency regulation are only possible because of interconnections with Germany, Norway and Sweden. The strong interconnections with NordPool are also of particular importance.

Danish national plans for increased electrical production from wind are subject to regular review. In particular there will be a significant decision to be made at the end of 2004, when the demonstration phase for off-shore wind farms at Horns Rev will end. Wind energy expansion plans beyond that year are therefore uncertain, depending as they do on the competitiveness of off-shore WTGs. The rate of expansion in Denmark of wind energy depends also on the development of a trade in renewable energy certificates, together with strengthening of interconnections. The existing situation has been achieved through Government legislation and regulations.

Regional Dispersion

From the perspective of an individual wind farm owner, there is a strong incentive to site in an area where the wind yield is highest. In the evolving Irish context, this explains the location of existing wind farms near the west coast. However there are two system advantages which would accrue from more dispersed siting :

- The combined fluctuations due to the intermittency of wind power would become considerably smoother. This is very important from a system operational perspective,

- The capacity credit attributable to WTG capacity in total would increase.

These two advantages are demonstrated in studies carried out[38][39]. Dispersed siting means that some wind farms should be located near the south and south eastern coasts, where wind yields can be quite satisfactory. The difficulty in the new market situation is to devise correct price signals to gain the desired effects for the ultimate benefit of the electricity consumer.

Locational price signals are in place in England and Wales through the transmission use of system charges[40]. These are designed to encourage generation and penalise demand in the south and vice versa in the north. For embedded generation these use of system charges (known as "Triads") benefit generation in the south and confer little or no benefit in the north. For transmission connected generation the charges are high in the north,diminishing in the south and negative in some zones. The result is an encouragement for generation to locate close to demand and minimise both transmission network expenditure and losses.

In the evolving Irish market, there are also locational signals contained in the pricing structure for using the network[41]. All generators are required to pay a *Network Location-Based Capacity Charge* element of the Transmission use of system charge.

More recently, a study[42] was commissioned by the Irish Wind Energy Association to examine the impact of geographical dispersion of wind farms in the Irish context. The study was based on an assumed installed wind energy capacity of 1500 MW evenly spread around the country, half of which is installed offshore.

The effect of geographical dispersion on wind power output in Ireland was investigated by means of a simulation. A data set of 10 years was obtained from Met Éireann containing hourly observations of wind speed and wind direction of five meteorological stations dispersed across Ireland. The wind speeds were scaled up with a simple algorithm to heights of 40, 60 and 80 m, accounting for two different surface roughness lengths. Then the wind speed data were converted to power output data by using the Pv-curves of several wind turbines, ranging from 660 kW to 2 MW rated power. The resulting time series were summed with weight factors to arrive at a total of 1500 MW of installed wind power capacity.

Figure 5.5 shows the relative frequency with which the combined power output changes within one hour. The case of total power output from dispersed wind farms is compared to 5 other cases, each representing the total wind power output being placed at a single site.

38 ECOFYS (1999) "Geographical dispersion of wind power output in Ireland,"
39 O'Dwyer E. et al (1990) *The Case for Wind Energy* Cigre
40 "Penetration of Wind Energy in Ireland," Econnect (2000)
41 ESB National Grid Statement of Charges and Payments Transmission Connection & Use of System Ancillary Services
42 "Geographical dispersion of wind power output in Ireland," ECOFYS (1999)

The figure shows that in the case where the wind farms are dispersed around the country, the combined power output varies considerably less than when the wind farms are concentrated in one location. In addition, the study found that the variation in combined power output from the dispersed wind farms *never* exceeds 60% (increase or decrease) within a one hour time period.

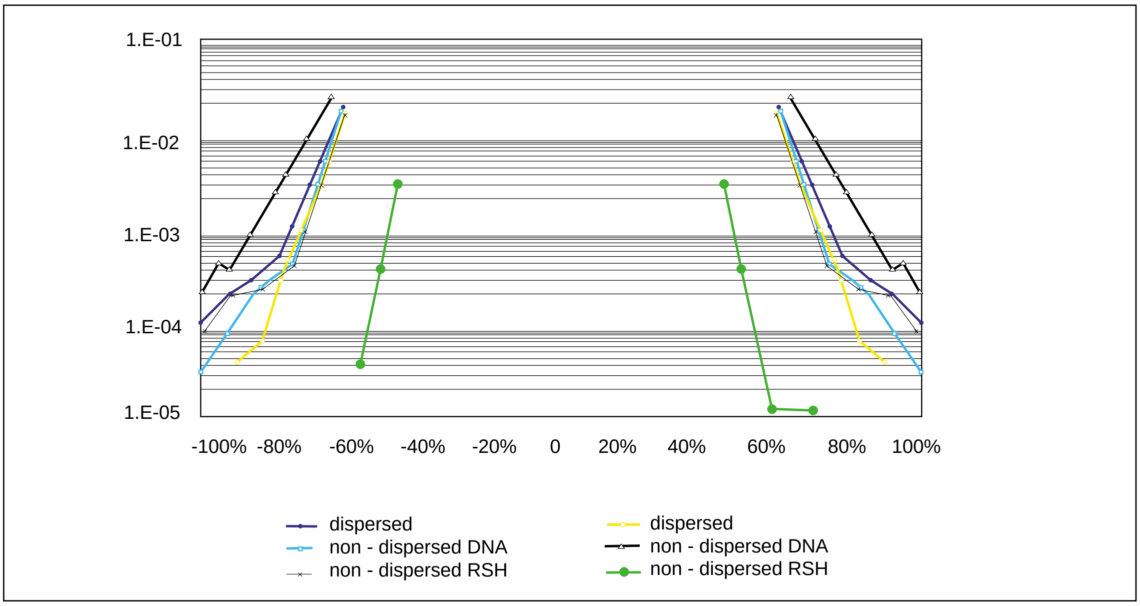

Figure 5.5 Relative frequency of occurrences of power output differences in 1, hour for dispersed and non-dispersed wind farms. .

Impact of Electricity Interconnector with Northern Ireland

The impact of electricity interconnection with Northern Ireland on the connection of renewable generation is limited. The enhancement of the existing 110 kV cross-border lines between Letterkenny and Strabane and between Enniskillen and Swanlinbar will increase the strength of the 110 kV networks around Letterkenny and Swanlinbar. This will lead to a slight increase in the ability of the networks in these areas to accept renewable generation. However, account must also be taken of the impact of existing or future renewable generation in Northern Ireland.

Recommendations

Into the medium term, the national electricity system has the capacity to absorb a wind energy penetration level of 5% - 7%, provided that the necessary prediction tools, controls and information systems will be developed to accommodate this accelerated deployment. This poses a significant challenge given that the contribution of wind generated electricity will be approximately 7% by 2005, if the Green Paper targets are realised.

It is recommended, therefore, that appropriate research studies be carried out in the short term to ensure that this does not become a constraint to reaching current and likely future targets for wind energy penetration, viz.

- A study should be undertaken on all existing wind farms in Ireland to evaluate the short-term impact of wind power output variation on frequency and the requirements for stability and frequency regulation. This type of study requires the collection of high frequency data from generators;

- System studies should be undertaken in consultation with the wind energy community to understand the potential impacts, if any, of likely wind development scenarios. These should be discussed in time for appropriate technical and / or commercial measures to be implemented;

- The calculation of additional dispatch costs associated with wind energy should be the subject of a study when trends have been established in the new liberalised market;

- It is recommended that ESB continue its studies on forecasting and compares the results to actual wind farm outputs to gain experience. If necessary, ESB should also work with the forecasting service supplier(s) to refine the service in the light of this experience and other developments in this field;

- Additional technical means of control should be developed for wind farms and integrated into the National Control Centre. A study of the costs and benefits of such a program should be commissioned in close co-operation between ESB and the wind energy community.

There is an ongoing process within the established regulatory framework to revise procedures to accommodate regulatory and competition based obligations. In addition, there are unique requirements for wind energy, which should be established.

The Group notes that the CER is considering whether it is appropriate to set a level on the maximum total capacity of green generation that should be connected to the transmission system in Ireland. As discussed earlier, a quantitative limited can be justified

(i) on an economic case where the dependence on wind is so high that identical back up or inter Community connections to provide the necessary back up are necessary to ensure security of supply when the wind abates or is excessive, or,

(ii) for technical reasons if the security of the system is threatened.

The group recommends that any study of the capacity limit of green generation connected to the transmission system in Ireland should segregate the limits dictated by

(i) economic factors i.e. the need to fund additional intercommunity connection or standby generating stations to cover periods of outages by wind farms, and

(ii) the technical limits dictated by system security issue

This will assist the Minister and Government in determining the true cost and alternatives when establishing future targets implementing (i) national policy or (ii) programmes implementing binding EU obligations.

Section C – Spatial Planning

Chapter 6 Spatial Planning

This chapter examines the experience of wind farm developers with the Irish planning system and explores options for a more forward looking approach, examining the merits of approaches in other EU Member States and drawing on some recent developments in Irish planning policy.

The planning system has approved the construction of a significant number of wind farm projects but greater cohesion between planning policy and energy policy is both necessary and attainable. It is recommended that a new process be initiated which will lead to a more plan led approach to wind farm development. This process involves identifying areas as *'preferred'* and *'open for consideration'* with regard to wind farm development, which is different from 'zoning' in the sense of current planning vocabulary. In addition areas could be identified as *'strategic'* for development and *'strategic no-go'* areas. The participation of Local Authorities in this process is essential.

Context –Wind Farms and Planning

Chapter 1 introduced a number of issues concerning the experience of wind farms with the planning system in Ireland which are summarised as follows :

- as with other forms of development, wind farms require planning permission. Planning permission is also required for the construction of some connections (>20kV) to the electricity network which is currently applied for separately by ESB.
- most of the decisions made by Local Authorities are appealed to An Bord Pleanála, either by the wind farm developer, or a 3rd party. The planning process for a wind farm can typically take up to 14 months. The subsequent planning process for any construction of the grid connection depends on whether the connection made is to the 38kV or 110kV networks. The time required to obtain planning permission for 38kV lines ranges, typically, from 5-8 months (with no appeals to An Bord Pleanála), depending on route lengths, complexity, etc. and an additional 7 months where there are appeals (ESB has recently obtained full planning permission for 2 wind farm connections (38kV) within a 5 month period). Securing planning permission for 110kV lines requires more time normally due to more precise information being sought by Local Authorities and can take 14 months. Way leaves then need to be secured before construction of the grid connection line and this too is proving increasingly difficult.
- few Local Authorities have clear criteria in relation to the assessment of applications for wind farm development in their Development Plans. Wind farms are generally positioned in remote areas (where wind speeds are high) which are not accustomed to development generally, let alone tall towers with moving parts. As a result, there is the possibility of conflict between the development of wind farms and other land use priorities for these areas, in particular tourism and amenity.

- wind turbines represent a new feature on the Irish landscape. Currently, planners do not have access to the appropriate training and necessary tools for assessing landscape character in these areas, which would be a first step to determining whether the landscape can visually accommodate these developments.
- in 1996, the Department of the Environment and Local Government published planning guidelines for wind farm development to provide Local Authorities with some much needed guidance. The Irish Planning Institute's Guidelines, which were published in 1995 contain more detail but both documents are now dated, particularly as a result of technological progress. The Department's guidelines do provide for Local Authorities to 'zone' land for wind energy development but this option has not been adopted by Local Authorities to date.
- a number of events in recent years organised by the Renewable Energy Information Office, Irish Planning Institute and the Irish Wind Energy Association have played a significant role in facilitating debate on these important issues. The proceedings from these events provide a good insight into the issues involved from the different perspectives.
- A Local Authority development plan is a key instrument in providing clarity regarding locations which are deemed suitable to wind farm development. A lot of recent development plans do contain a section on renewable energy generally and wind energy in particular. These sections typically do not go much further than general statements such as "*The Planning Authority will adopt a positive approach to renewable energy developments provided they are environmentally acceptable".* Some plans go further and state where wind farms are deemed unlikely to secure planning permission due to, for example, proximity to a scenic route.
- for those opposed to particular wind farm developments, the planning process is the principal means at their disposal to halt the development. Fears expressed relate to the visual impact, threat to livelihoods, noise levels, electromagnetic radiation levels, impact on birds and other wildlife and safety concerns. There is also some resistance to the fact that a local resource is being harnessed with little direct local economic benefit, except to the landowners, where the land is rented or purchased and the Local Authority, in the form of rates payable.
- of the 17 wind farm projects which were awarded power purchase agreements under the AER III scheme, 10 (combined installed capacity 69 MW) have secured planning permission and are at different stages of construction and commissioning. 3 have failed at the planning stage (45 MW). The remaining 4 are at various stages of the planning process. In addition, wind farms with a combined installed capacity of over 155 MW which do not have AER III contracts have received full planning permission and a further number (with a combined installed capacity of over 167 MW) are in the planning process. It is estimated that a further 217 MW are in the advanced stages of planning application preparation.

Experience to date, as evidenced above, shows that the planning process is supportive generally of wind energy but emphasises a need for greater cohesion between energy policy and environmental / planning policy. As a result of energy policy, a number of wind farms successfully secured a market to sell electricity but failed to secure planning permission to be built. Within the same time frame, a number of wind farms successfully secured planning permission but failed to secure access to the market, thus rendering them non-viable.

Impact on Policy

Under the AER process, the existence of, or even the likelihood of securing planning permission for wind farms was given no significant weighting in the competitive bidding phase of competitions to date. Most of the successful applicants under AER I were for wind farms located in Donegal. This placed pressure on Donegal County Council to develop an interim policy on wind farms essentially while responding to applications for planning permission. AER III provided a similar scenario in Cork. Cork County Council had commenced the process of carrying out resource and landscape assessment studies in order to develop a policy on wind farms when it was faced with a number of applications for planning permission[43], making it difficult for the Local Authority to finalise its policy.

Within the planning system, decisions on strategic policies are frequently made in the context of planning applications in the absence of a clear policy framework for those decisions[44]. The reason for this is that development plans rarely contain sufficient detail to enable an applicant to make a reasonable assumption on the likelihood of a planning application for any particular site or in any particular region. The Irish planning system is a discretionary rather than a ‘plan led’ system.

It is not surprising, therefore, that the initial consideration of applications for planning consent to construct wind energy infrastructure took place in the absence of a local expression of spatial planning policy for wind energy. More recently, national guidelines on wind farm development from the Department of the Environment and Local Government have offered a policy outline which has been incorporated into later development plans. Even with the benefit of policy statements such as the national guidelines and more recent development plans, these are generally insufficiently specific to give adequate guidance to planners on individual project developers.

An Bord Pleanála is obliged to have regard to public policy in determining appeals. Government policy on renewable energy, as enunciated by the Minister for Public Enterprise, is such a public policy and in this context, the Board is empowered to contravene the provisions of a development plan. Planning Authorities also have a duty under the Local Government Act, 1991, in the performance of their functions under any enactment, to have regard to policies and objectives of the Government or any Minister insofar as they may relate to their functions.

43 O Sullivan, Brendan (1998) *The Planning Authority Experience of Wind Energy.* Planning and Wind Energy: Creating a Secure Framework For Investment Workshop, Kilternan.

44 van der Kamp, Hendrik W (1999) *National Spatial Planning and Wind Energy Infrastructure;* presentation at Wind Energy Planning for 2000 Conference, Galway.

While there have been national targets for wind farm development since 1993, these have not yielded any reasonable indications of the likelihood of planning consent, or rejection, at any particular site or region.

Experience from EU Member States

In order to gain a deeper understanding of the situation here and to point towards possible recommendations, it is useful to set it against a context of developments in other EU Member States. A recent EU funded study *Municipal Action and Wind Power* provides a useful reference point. This study set out to examine the non-technical barriers that had been behind differences in the development of wind energy EU wide and to examine the ways in which Local Authorities could help to overcome them.

One focus area for the study was the impact on the pace of wind energy development of the different planning systems within the EU. Unlike Ireland, the planning system in most European mainland countries is regulatory. Regulations and a detailed zoning plan are prepared by municipalities defining in detail the conditions and locations where development is acceptable. If an application meets these regulations, then it is generally approved.

In the regulatory approach it is effectively the Local Authority that defines the sites for development. The local plans define in detail the site and in the Danish system actually define the location of turbines! (the Dutch system is very similar). In Germany wind energy development was considered a priority rural use (like agriculture and forestry). However, this right has been greatly circumscribed in those regions a regional framework for planning has been prepared. Here sites are defined in detail in local plans in the same way as in Denmark.

Many countries have regional plans for wind energy. In the case of Denmark the regional plan sets the regional targets for capacity, identifies key sites for large installations and prescribes key regulations (e.g. regarding tower height and noise). These form the framework within which the municipalities prepare their plans. In Germany the regional authority can assess their target capacity, identify search areas for 'spatially significant' development and can set out regional regulations, as Schleswig-Holstein and Neidersachsen have done. Other German regions have not prepared such detailed plans and regulations since they wish to promote wind energy. By contrast the regional authorities in Spain identify sites in detail and they are directly responsible for approving applications.

The planning system in Ireland and the UK, on the other hand may be described as discretionary.[45] In a discretionary system applications are considered against a series of

45 Cahn Martin (1999) *Municipal Action and Wind Power.* presentation at Wind Energy Planning for 2000 Conference, Galway.

policy criteria which rarely define matters in regulatory form (e.g. maximum mast height). Detailed considerations can be defined in “supplementary planning guidance” which does not form part of the approved plan and which could refer to matters such as decibel limits or height and colour. However, the Local Authority has the discretion to refuse applications subject to the right of appeal to An Bord Pleanála or, in the case of the UK, the Secretary of State.[46]

Framework guidelines in both systems are provided at national level. These can set targets as in Denmark and require regional authorities to provide for them. They can set the framework conditions for development in the form of national regulations (Germany) or they can simply be guidelines outlining considerations to be taken into account when considering applications and drafting plans such as the Planning Guidance for Renewable Energy prepared in the U.K. and Ireland. National planning is particularly important in Denmark and Germany where national policy promotes wind energy. It is evident that strong support and clear direction from above greatly helps the application of planning policies at local level.

There is a major difference in practice between the two approaches. In a discretionary system it is the developer who finds a site and then attempts to get permission from the Local Authority. Search areas are not usually defined - the only example that was noted was in the former County of Gwynedd. Even where there are broad search areas, the developer can apply for permission in any location and can be refused within these priority areas. A significant effort is required by developers, given the uncertainty of the outcome in preparing applications which usually have a very full presentation of the environmental impact in an attempt to smooth the passage in front of the planning committee of the Local Authority.

There are clear advantages in each system. The Dutch and Danish systems provide a real degree of certainty for the developer where the application conforms to the conditions in the plan. The work load on both the developer in preparing applications and the Local Authority in dealing with proposals is much greater under a discretionary system than under a regulatory system. In the regulatory system, once the plan has been approved, there is a large degree of certainty and this avoids much of the argument over project refusals found in the UK and Ireland.

Plans with definitive zoning allocations do not exist in the UK or Ireland. Even when a policy with search areas is devised like that adopted by the former County of Gwynedd, the search areas are very general. The British approach is the antithesis of a defined search area. Policies are general and intimately entwined with policies for other development. It is in practice a truly comprehensive approach but suffers from the inevitable bugbear of a general and integrated approach - there is the risk of achieving nothing since one can always find disadvantages with any proposal.

46 Trinick M & Holmes S (1997) *Wind Energy – Steps to Successful Development. Guidelines for Planning Practice and Environmental Assessment in the European Union.* Page 136. EU ALTENER project 95-001.

The role of clear national policies and targets was emphasised in the EU funded study. It was generally felt by all participants that this is a most important factor and that these national targets need to be applied at regional level by setting regional wind capacity targets. This greatly eased planning in those countries that had set them (e.g. Denmark and the Netherlands), by determining an agreed share-out of wind capacity. This enabled the discussion and battling between regions to be at least provisionally resolved, and took this matter out of public debate.

Public Perceptions

One of the objectives in the changing planning process in Ireland is to encourage more local community participation at the formative stage. The aim of this is to provide local communities with an increased sense of ownership of the development plan and to reduce controversy about development that conforms to plan objectives.

Public perceptions of wind energy development in recent years have been mixed. Wind energy is viewed generally as a good thing, making a positive contribution to reducing the impact we have on the environment. This positive impact is, however, global and the local impacts of wind energy development are, in a number of cases, perceived by individuals as negative. This is evidenced in objections to proposals for planning permission, statements made to the local and national media, 3rd party appeals to An Bord Pleanála and objections to wayleaves issued by ESB to connect wind farms to the electricity network.

The perceived negative impacts typically relate to the visual impact of the wind farm in the landscape, the local economic impacts, the noise levels from the machines and health issues, the latter of which generally focuses more on the grid connection than the wind farm itself.

Visual impact of a wind farm is a subjective response to its shape and form, in the context of the landscape where it is situated. To some people, wind turbines are attractive and elegant machines, presenting a positive forward looking statement on energy production. To others they are unsightly machines which do not fit into the context of the countryside. There are also those who feel they are appropriate additions to the landscape but it depends very much on where they are located, how many turbines there are and the design of the grouping.

The local economic impacts of a wind farm have also prompted objections to proposals for wind farms. This may stem from the view that the resource is local, so the community should benefit economically from its harnessing or that the local impact is negative and the community should be compensated[47]. There is also a perception that the wind farm

47 Collins, Martin Headd Adrian & Morgan Berna (1999) *Derrybrien & District Concerned Residents Group A Policy Statement* Planning and Wind Energy: Creating a Secure Framework For Investment Workshop, Kilternan.

may have a negative local economic impact through its impact on tourism and on property values. The views are a response to the fact that despite the large investment and potential economic gain, the only local economic gain is in land purchase or renting, rates to the Local Authority and possible local employment in the construction phase. These views can be part of a general sense of economic isolation being felt in many remote rural areas.

The issue of noise was seen by the wind turbine industry as an important one to resolve given the public response to early machines which caused mechanical as well as aerodynamic noise effects. Careful attention has been paid to the design of the blades and mechanical parts of the turbine which have reduced considerably these effects.

In addition, perceptions of health issues related to wind farm development have arisen more recently as an issue of some public concern. The focus is on the impact of electromagnetic radiation emitted from the grid connection lines with requests that they be placed underground.

Finally there is anecdotal evidence that the local acceptance of wind turbines increases dramatically after commissioning. This suggests that objections are more about the perceived impact than the reality. If this is true and the perception can be corrected this would be salutary in the context of minimizing planning objections.

Local Involvement & Benefits

As previously mentioned, the current local economy benefits from wind energy developments generally comprise the rates paid to the appropriate Local Authority, the purchase or renting of the land which the wind farm occupies and a possible element of local employment in the construction phase. Interest in additional local involvement and benefit in wind energy is growing as the number of developments increase. This is as a result of an increased awareness of the economic viability of wind farms prompting a broader base of interest and also an interest in developers showing clear local benefits in order to increase the chances of securing planning permission.

An example of the former is Kerry County Council carrying out a feasibility study to develop a wind farm on the site of a landfill dump. A further example is the formation of Meitheal na Gaoithe who seek to build co-operative based wind farm developments. A third example is the IFA and ICMSA recently joining the IWEA and being represented on the executive council.

Given the difficulties in competing with large companies with access to balance sheet finance and economies of scale, local involvement in wind energy development will require specific incentives. One such incentive is recommended in Chapter 2, a Small Scale Renewable Energy Scheme which specifically sets market conditions for small scale projects which would be of limited interest to large commercial operators. This scheme will allow local involvement but will not necessarily result in broad community involvement.

When discussing local involvement the Danish situation is invariably cited, where a significant proportion of wind energy development is controlled by locally based wind energy co-operatives. A number of factors explain this, not least being the pace of development, the price offered for wind generated electricity and the planning system. Apart from electricity utilities, Danish regulations dictated that privately owned wind farms must be financed by shares sold to people living in the same or neighbouring municipality.[48]

Part of the challenge in increasing local involvement in wind energy development is that it would mark a significant change in policy direction. Wind energy development has followed a focus of specific targets being met at minimum cost through competitive means. While this approach has not excluded local involvement it has not encouraged it either.

A number of possible options exist to encourage local involvement[49, 50]. Before deciding on them, it is useful to first decide whether the objective is to reduce the number of objections to large wind farms at the planning stage or to increase local participation in wind energy development.

- Fixed Prices appropriate to the economies of scale for small scale projects, in conjunction with continuous access to the electricity network.
- Net metering for wind energy projects up to 100 kW. This scale of wind energy is for homes, businesses and farms who wish to offset their electricity bill with on site wind energy. Electricity produced by the wind turbine which is not used on site is exported to the electricity grid at the retail rate for electricity. Net metering has resulted in relatively few additional renewable energy system sales in most parts of the USA where it was marketed. However, it has been successful in increasing awareness of renewables. Small renewable energy systems produce relatively expensive electricity, such that even though they are replacing electricity otherwise bought at the retail rate, the economics are often still marginal[51]. As a result, net metering projects would also require additional support such as exemption from rates, grant support, tax credit or reduced use of system charges.
- Regulations to favour locally owned projects. This could use the Danish example as a model, requiring local ownership to be a condition of planning permission, or a condition of the licence to construct issued by the Commission for Electricity Regulation.

48 Trinick M, & Holmes S. (1997) *Wind Energy – Steps to Development. Guidelines for Planning Practice &Environmental Assessment in the EU.* EU ALTENER Project 95-001

49 Teagasc, WORD, IFA & Wexford Wind Energy Co-op (2000) *Wind Energy – A source of additional income for farmers.*

50 Bere Islands Project Group (2000) *Small Scale Wind Energy Projects – Submission to the Renewable Energy Strategy Group*

51 Staudt L. (2000) *Net Metering.* Note prepared by IWEA for the Renewable Energy Strategy Group.

- Fiscal incentives. There are a large number of options here in including exempting the landowner from tax on income from land rental, extending Section 62 of the Finance Act, 1998 from corporate investors only to individual investors also, with conditions restricting participation to those living within a certain radius of the proposed win farm.
- Other Incentives The price paid for electricity by locals within a certain distance from a wind farm could be reduced, the difference becoming a public service obligation.

It is recognized however that some, at least, of these measures need to be considered further in the context of national law, European Community law having direct effect and for precedent. In addition, they relate more to rural development policy than energy policy and thus may more appropriately fall under the remit of the Department of Agriculture and Food.

Dispersed Siting

The accelerated deployment of wind energy, which is envisaged in the short term, raises a number of questions for planners regarding the siting of turbines. Is it better from a planning perspective to have a large number of wind farms, each with a limited number of turbines? Alternatively, should the focus be on a small number of wind farms each with a large number of turbines? Should wind farms be intervisible from each other?

The size of the individual turbines raises similar questions. If the turbines are small, they may be more easily accommodated spatially, depending on the landscape. To achieve the maximum from the wind energy resource, however, the deployment of larger machines will typically be necessary.

What must also be borne in mind is the infrastructure relating to connection of the wind farms to the electricity network. For smaller wind farms, say 3 MW, less infrastructure is required where grid connection to the local distribution network is possible than that for a large wind farm, say 20 MW, connecting to the transmission network. Against that, one might consider the advantages of avoiding a proliferation of grid connections to meet a specific target.

In Chapter 5, regional dispersion was discussed from a network perspective where it was shown to exhibit a number of positive characteristics. In discussing dispersed siting from a spatial planning perspective, the focus is clearly different, as it is accommodation of the turbines by the landscape and environment, rather than the electricity network, which is of importance. In an integrated approach, it would be necessary to consider wind farm design from both perspectives.

Planning Policy Developments

The passage of the Planning and Development Bill, 1999 through the Houses of the Oireachtas on the 22nd of June 2000 marks a significant development in planning policy in Ireland. The Act provides for the revision and consolidation in one Act all 9 Local Government (Planning and Development) Acts enacted since 1963 and introduces a sustainable development philosophy to the Irish planning system. The term sustainable development first appears in the title of the Act *'.. to provide, in the interests of the common good, for proper planning and sustainable development.'* It is also explicitly mentioned in Section 10 of the Act which deals with mandatory objectives for development plans - and requires the overall strategy for the authority to be drawn up *'for the proper planning and sustainable development of the area.'* This key emphasis on sustainable development provides a welcoming legal context in which a wind farm planning application will be examined.[52]

Development Plans

As previously mentioned, the development plan is a key instrument (although underused, according to some commentators) in providing clarity regarding locations which are deemed suitable for wind farm development. Currently, each planning authority must make a development plan, and review it every five years. In practice the development plan review timescale has varied from one Local Authority to another and has generally been well above 5 years. This has significant implications for more recent types of development in Ireland, such as wind farms. The Act will ensure that out of date plans will not be a feature in the future by obliging planning authorities to *"every 6 years make a development plan."*

The Act further proposes that in the context of a strategy of proper planning and sustainable development, development plans must contain a number of objectives. Section 10 states that

***10**.- (1) A development plan shall set out an overall strategy for the proper planning and sustainable development of the area of the development plan and shall consist of a written statement and a plan or plans indicating the development objectives for the area in question.*
(2) The objectives to be included in a development plan shall at least include the following matters:
(a) the zoning of land for the use solely or primarily of particular areas for particular purposes (whether residential, commercial, industrial, agricultural, recreational or otherwise, or a mixture of those uses), where and to such extent as the proper planning and sustainable development of the area, in the opinion of the planning authority,

52 Griffin, Luke (1999) *Implications of the Planning Bill for Wind Energy.* Wind Energy Planning for 2000 Conference, Galway.

requires the uses to be indicated; (which allows for zoning of areas for wind energy development although this is already provided for in the DoELG Wind farm Guidelines of 1996.
(b) the provision or facilitation of the provision of infrastructure including transport, energy and communication facilities, water supplies, waste and waste water services, and ancillary facilities; (this could relate to the wind farm itself and the grid connection infrastructure).Section 10 further states that

(3) Without prejudice to subsection (2), a development plan may indicate objectives for any of the purposes referred to in the First Schedule.

The first schedule referred to outlines the purposes for which objectives may be indicated in Development Plan. Part 1 of this schedule deals with location of and pattern of development.

Location and Pattern of Development
1. Reserving or allocating any particular land, or all land in any particular area, for development of a specified class or classes, or prohibiting or restricting, either permanently or temporarily, development on any specified land.

This in effect allows for fresh approaches to identifying areas different from 'zoning' in the sense of current planning vocabulary.

Other objectives which must be included relate to protection of designated areas which also has clear implications for wind farm development.

The Act also sets out clearly how a development plan should be formulated and the aim is to give local communities an opportunity to participate at the formative stage. This will provide more clarity and an increased sense of ownership regarding agreed development plans which should help reduce controversy about developments which conform to the plan's objectives.

In addition there is a clear opportunity for the providers of infrastructure for energy (which would include wind farm developers and ESB) to have a say in the policy of the Local Authority. Section 11, which deals with the preparation of the development plan, states that

'a planning authority shall take whatever measures it considers necessary to consult with the providers of energy … in order to ascertain any long term plans for the provision of the infrastructure and services in the area of the planning authority and the providers shall furnish the necessary information to the authority'.

Planning Hierarchy

The most significant impact the Act may have on wind energy development however, is in the integrated strategic approach to planning adopted therein. In order to place development plans into a more strategic context, the Act provides for planning guidelines at a regional level. Section 21 states that *'A regional authority may, after consultation with the planning authorities within its region, or shall at the direction of the Minister, make regional planning guidelines.'* The Act also gives specific statutory recognition to the Strategic Planning Guidelines for the greater Dublin area.The significance of this development is in bridging the current divide between national sectoral policies on the one hand and local planning policies on the other. It also brings the Irish discretionary planning system closer to the more widespread (in an EU context) regulatory, or plan led system.

Along with providing for a regional strategic context for development plans, the Act also gives statutory recognition to local area plans. This will allow development of areas zoned for large-scale new development to be subject to more detailed planning and further local consultation (ensuring proper provision for facilities, etc.). Local area plans will fill the planning void that is often felt between the broad objectives of the development plan and individual development proposals.[53]

A further concept introduced in the Act with possible implications for wind energy is the *'designation of one or more sites as a strategic development zone for specified development which, in the opinion of the Government, is of strategic importance for the national economy.'* The proposal provides a means of disposing of the major planning issues before an individual project is identified. The rationale behind Strategic Development Zones is to offer sites to internationally mobile companies with a much greater degree of certainty both in relation to securing planning permission and the time horizon for same. This provision may also assist wind farm development.

As part of the National Development Plan 2000-2006, the Government decided to prepare a National Spatial Strategy. The aim of this strategy is to achieve the Government's objective for regional policy of more balanced regional development in the long term. The strategy will be completed within two years and will translate the broad approach to balanced regional development into a more detailed blueprint for longer-term spatial development over a twenty-year horizon.

As part of a public consultation process, the Department of the Environment and Local Government published a consultation paper, "What are the Issues?"[54] and invited interested groups to comment on the issues identified and to identify any additional issues that should be addressed. There is currently no mention of wind energy specifically in the indicative list of issues to address the key challenges which the National Spatial Strategy will seek to address. Under the heading of *Communications Infrastructure and Balanced Regional Development*, however, one identified issue is *'Identifying parallel infrastructure needs in other related sectors such as the production and distribution of energy.* This would seem to place energy in the realm of infrastructure to development rather than a form of development in itself.

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53 *Planning and Development Bill, 1999 – Information note.* Department of Environment and Local Government.

54 *The National Spatial Strategy – Consultation Paper No. 1.* Department of Environment and Local Government, February 2000.

Wind farm developments are not decided on planning grounds alone. Other issues including the wind resource and the electricity network are also deciding factors. Relevant data is key to commercial decisions and essential to planning authorities in order to identify suitably resourced sites for consideration in any proactive regulatory planning approach. An integrated resource map illustrating the convergence, or not, of such resources is essential to planners, the electricity grid operators and potential project developers and investment planning to support the national target.

Landscape

The treatment of Landscape has changed in the proposed amendments to the Act since it was published, which has implications for wind energy.[55] In the amended version, the objective relating to landscape now reads as follows: *'the preservation of the character of the landscape where, and to the extent that, in the opinion of the planning authority, the proper planning and sustainable development of the area requires it, including the preservation of views and prospects and the amenities of places and features of natural beauty and interest'*.

When it becomes a legal requirement to have a mandatory objective dealing with landscape character, then it will be necessary to have a policy on the landscape or landscapes in the Plan area[56]. Assessments will have to be carried out according to accepted criteria and following assessments, policy responses will be spelled out by the Local Authority in its development plan.

Regarding its relevance for wind energy, firstly, all the relevant counties are likely to have similar landscape policies based on the same objective criteria. This will make for a level playing pitch. Secondly a policy based on landscape character is likely to give rise to policies which are on the whole more proactive, welcoming and more accommodating.

Draft Guidelines for Planning Authorities on Landscape and Landscape Assessment were published for a three-month public consultation period on 19 June 2000. The guidelines heighten awareness of the importance of landscape in all aspects of physical planning, provide guidance to planners and others as to how landscape considerations should be dealt with and indicate specific requirements for Development Plans and development control. They propose that all planning authorities should classify the landscapes in their areas, recommending the use of *Landscape Character Assessment*. This method of assessment enables a much more proactive approach to landscape and allows landscape to be viewed for its ability to accommodate developments. It gives indicators as to which developments might be most suited, under what conditions and using what design criteria. It will, therefore, be possible for planning authorities to indicate particular landscape areas which would be suitable for one kind of development while being

55 Griffin, Luke (1999) *Implications of the Planning Bill for Wind Energy.* Wind Energy Planning for 2000Conference, Galway.

56 Griffin, Luke (1999) *Implications of the Planning Bill for Wind Energy.* Wind Energy Planning for 2000Conference, Galway.

unsuitable for another. These policy responses will correspond to the degree of sensitivity of a particular landscape. By proposing the same approach for each planning authority, the guidelines will ensure compatibility of decision-making along boundaries between adjoining authorities.

Recommendations

The recommendations of the Strategy Group focus on an informed plan led approach to wind energy development, achieving a much higher degree of clarity which will be useful to all players.

System

The plan led approach will centre on the identification of 4 distinct categories of areas to be identified with regard to wind farm development. These should not be confused with zoning, in the sense of current planning vocabulary which is already provided for in the guidelines for wind farm development. The categories are :-

- Strategic areas – these key areas are deemed to be eminently suitable for wind farm development and should be reserved for such purposes.
- Preferred areas – these areas are suitable for wind farm development and should normally be granted planning permission unless specific local planning circumstances would support a decision to refuse permission in the context of the development plan.
- Areas open for consideration – applications for planning permission will be treated on their merits with the developer having a clear responsibility to demonstrate as to why the development should be granted permission.
- No-go areas – these areas are identified as particularly unsuitable for wind farm development.

The above areas may be identified by Local Authorities or on a regional or national basis and should all be incorporated into Local Authority development plans. In this way, the plan led approach should identify where wind energy should be developed. From this appropriate market mechanisms may be determined and appropriate locations for investment in the grid infrastructure. The approach needs to be informed by the existing grid infrastructure, cost effective upgrade options and wind speeds for the areas identified. As earlier mentioned, planning instruments which are currently being developed will be the instruments utilised to facilitate this approach prepare the plan.

Process

The process recommended to achieve this is as follows:

1. A letter of invitation should be sent to Local Authorities from the Minister for Public Enterprise and the Minister for the Environment and Local Government. The letter should point to the benefits to Local Authorities of wind farms in their area such as rates, the possibility of investment in wind farms themselves and the possibility of cheaper electricity (through supplying their own electricity needs with wind energy).
2. Local Authorities to identify areas which are deemed preferred and open for consideration in the Local Authority area in the context of wind farm development. Strategic areas and no-go areas may also be identified, if deemed appropriate by the Local Authority.
3. The Council is advised on these areas on a provisional basis
4. The Local Authority then submits a map containing these areas the Renewable Energy Information Office advise on the wind energy resource and the network strength for accommodating wind energy in these areas, through consulting with ESB, IWEA, etc.
5. A revised map of areas deemed preferred, open for consideration, strategic and no-go is then produced by the Local Authority which is sufficiently broad to allow for wind energy development without creating a situation where difficulties with land availability would create potential bottlenecks.
6. The Local Authority then proceeds to incorporate this into their development plan.

Short Term Strategy

In the short term it is recommended that the above process begin immediately. This will assist in providing guidance on approaching individual proposals for planning permission to developers, local communities, Local Authorities themselves and in the event of an appeal An Bord Pleanála.

In carrying out a landscape assessment, it is recommended that Local Authorities take into account wind farm developments. In parallel with this characterisation of the landscape it is recommended that Local Authorities should also determine the sensitivity of different landscape character types to different kinds of wind energy development. This will involve assessing landscape quality, sensitivity, robustness and capacity.

It is recommended that the Renewable Energy Information Office develop an integrated resource map specific to the needs of Planning Authorities, the network operator, wind farm developers etc. Because of its relevance to other recommendations in this report, it is further suggested that the compilation of the map should be undertaken as soon as possible. The map should be updated regularly and made available in particular to Local Authorities.

It is recommended that an objective research campaign be undertaken of public objections to previous planning consent applications and subsequent attitudes to successful projects to inform a comprehensive information campaign by the Renewable Energy Information Office for the purpose of informing and improving the public perception of wind farm developments.

It is further recommended that the guidelines for wind farm development be reviewed and updated to take account of recent developments, including the recommendations in this Strategy. In particular, it is important to incorporate the system and process, as recommended above.

Medium Term Strategy

In the medium term, it is recommended that the process above should feed into the process of developing regional guidelines and local area plans. In order to deal with the possible lack of sufficient preferred areas, the National Spatial Strategy could contain targets or alternatively the Minister can issue guidelines. This should continue in an iterative manner as illustrated in figure 6.1.

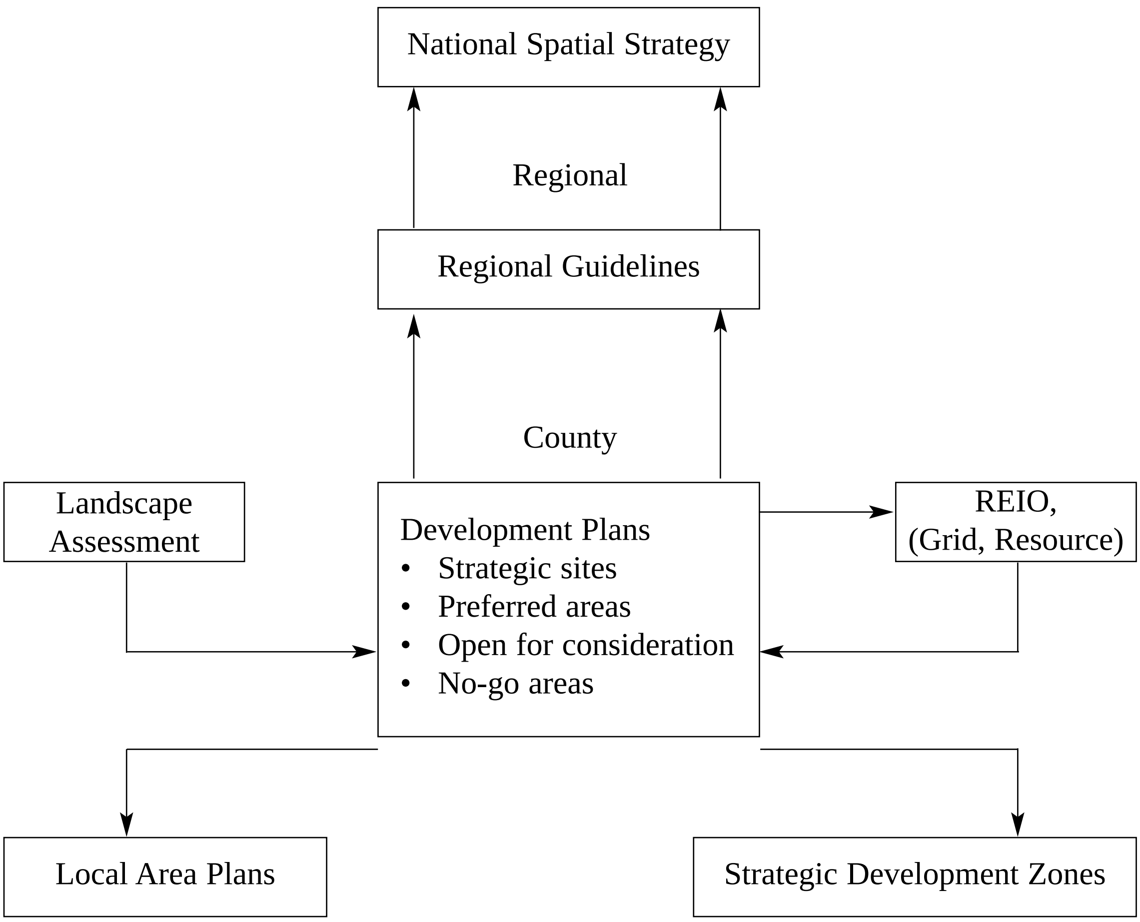

Figure 6.1 : Iterative process for identifying areas

Section D – Conclusions

Chapter 7 - Strategy

The main aim of the strategy is a support hierarchy to deliver the revised target of 500 MWe of renewable energy based electricity generating plant announced in the Green Paper on Sustainable Energy, the majority of which will be supplied by wind energy. The recommended strategy is an integrated one led by planning considerations incorporating resource studies and access to the national electricity grid.

The targets should be met at least cost, taking into account the benefits of wind energy, in particular with regard to reducing greenhouse gas emissions. In this regard, the Renewable Energy Strategy Group favours a withdrawal of the project size cap in favour of an open market approach constrained only by commercial considerations and technical limitations.

The three principal elements which require integration in a plan led approach are appropriate location, adequate availability of the wind resource and accommodating electricity network infrastructure.

The strategy centres on a cohesive plan led approach to market mechanisms, grid upgrading and spatial planning. Essentially it is recommended that spatial planning considerations should identify suitable wind farm locations, informed by the availability of the resource and the strength of the electricity networks. The strategic plan led approach determines the market mechanism and grid infrastructure required.

In the short term it is recommended:-

1. the strategy should promote those projects with, or well advanced in, the planning process in the form of an early AER V round in order to ensure the early delivery of additional capacity; and
2. this should be followed by at least one further round of AER in order to give added certainty to projects in pre-planning and to avoid bottlenecks caused by premature applications in the planning process and to the ESB for connections due only to a lack of certainty about future opportunities.

In the medium term it is recommended that the suitable locations for projects be identified in a strategic way and appropriate market mechanisms and grid upgrading be implemented in a timely and efficient manner to stimulate wind energy deployment to help meet Ireland’s renewable energy and greenhouse gas emission targets.

The action plan is presented under 3 headings – *Electricity Market*, *Electricity Network* and *Spatial Planning*. For clarity, the recommendations under each of the headings are summarised in tabular format.

Action Plan – *Electricity Market*

Short Term Strategy

Title	Recommendation	Delivery Agent	Time-scale
Promote large scale wind energy	Conduct a further AER competition (AER V), at prices linked to CPI based on AER III results, concentrating on projects with all necessary statutory permits up to a quantified limit. In AER V signal a further round (AER VI) based on open competition Remove the ownership and project size caps.	DPE or its agent.	Scheme open for 24 months.
Promote small scale wind energy schemes	Include a small scale category in AER V but project size reduced to, say, 2.5 MW installed.	DPE or its agent.	Scheme open for 24 months.
Support the liberalised green electricity market	Offer a fall back 8 year PPA at a fixed price without indexation for a limited amount of wind generated electricity plants entering the liberalised market.	DPE or its agent.	Scheme open for 24 months.
Review of market mechanisms	Light handed review of the proposed mechanisms in the context of capacity delivered, emerging requirements relating to Kyoto compliance & binding EU law and experience of wind energy developments within the liberalised electricity market.	DPE or its agent.	12 months from commencement of AER V
AER VI	Competition for wind farms based on price to follow AER V.	DPE	Commencing not later than month 12

Medium Term Strategy

Title	Recommendation	Delivery Agent	Timescale
Review of market mechanisms	Detailed review of the proposed mechanisms in the context of capacity delivered, emerging requirements relating to Kyoto compliance & binding EU law and experience of wind energy developments within the liberalised electricity market	DPE or its agent.	

Action Plan – *Electricity Network*

Short Term Strategy

Title	Recommendation	Delivery Agent	Time-scale
Network upgrading	Commit some funds for renewable energy developments in the National Development Funds to upgrade the distribution and transmission networks to accommodate wind farms where a bottleneck exists or can be reasonably predicted. As the funding is remitted it should be made available for further upgrades so long as additional capacity requirements can be identified under reasonable assumptions.	DPE, ESB National Grid and ESB Customer Services (Distribution)	24 months
Grid Connection Issues	Studies on the impacts of wind energy relating to connecting to the distribution network should be implemented.	ESB Customer Services (Distribution)	18 months
Impact of wind energy on the electricity network	Studies should be undertaken on the impact of wind generated electricity on the network with data collected from all existing wind farms. These studies should examine short term impacts, forecasting, requirements for stability and frequency regulation and additional dispatch costs. The effects of interconnection should also included.	ESB National Grid IWEA, DPE.	24 months

Medium Term Strategy

Title	Recommendation	Delivery Agent	Timescale
Network upgrading	Continuation of short term recommendation on network upgrades so long as additional capacity requirements can be identified under reasonable assumptions.	DPE, ESB DPE and ESB Customer Services (Distribution)	Month 24 - 60
Network upgrading	Strategic sites on the transmission network, where additional capacity requirements can be identified under reasonable assumptions, should be upgraded to allow increased wind penetration	DPE and ESB National Grid	Month 24 - 60
Impact of wind energy on the electricity network	The results of the studies carried out in the short term strategy should be incorporated into the medium term proposals.	ESB National Grid IWEA, DPE.	Month 24 - 60

Action Plan – *Spatial Planning*

Short Term Strategy

Title	Recommendation	Delivery Agent	Time-scale
Amend local authority development plans for wind energy proposals	DoELG and DPE invite local authorities to submit draft proposals identifying areas as 'preferred', 'open for consideration', 'strategic', and 'no-go' for wind energy development. The areas should then be modified based on information on the local electricity infrastructure and wind energy resource from REIO in consultation with others, and then incorporated into development plans.	Ministers for the Environment & local Government and Public Enterprise, Local Authorities & REIO	18 months for initial plans
Landscape assessment	In parallel with the characterisation of the landscape it is recommended that local authorities determine in parallel the sensitivity of different landscape character types to different kinds of wind energy development. This will involve assessing landscape quality, sensitivity, robustness and capacity.	DoELG, Local authorities	24 months
Information campaign	The Renewable Energy Information Office of the Irish Energy Centre should undertake research into attitudes to wind farm developments and develop and implement an information campaign addressing public concerns regarding wind energy development.	REIO	24 months
Wind energy map	A map should be prepared digitally which contains information regarding the wind energy resource, the transmission and distribution networks and sites which have received, failed or are passing through the planning system.	DPE	12 months
Wind Farm Guidelines	DoELG should revise and update the *'Wind Farm Development – Guidelines for Planning Authorities* based on the recommendations in this document to assist planner s in operating to a national standard and to increase certainty, to the extent possible, for project developers.	DoELG	24 months

Medium Term Strategy

Title	Recommendation	Delivery Agent	Timescale
Amend local authority development plans for wind energy proposals	Local authorities should further refine the areas identified for wind energy based on experience, additional network infrastructure requirements and the results of landscape assessment	Local Authorities	Month 24 - 60
Regional Planning Guidelines and National Spatial Strategy	Areas which are deemed to be of regional (national) importance for the development of wind farms or protection from wind farm development, should be identified and incorporated into the Regional Planning Guidelines (and possibly the National Spatial Strategy)	Local Authorities, Regional Authorities, DoELG	Month 24 - 60

Appendix A – Reference Materials

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UN Framework Convention on Climate Change (1997) *Report of the Conference of the Parties of its 3rd session, held at Kyoto from 1 - 11 Dec 1997.*

Appendix B - Renewable Energy Strategy Group Membership

Members

Name	Affiliation	Role
Prof. John Fitzgerald	Economic and Social Research Institute	Chair
Dr. Eamon McKeogh	Irish Energy Centre	Vice Chair
Mr. Tom Kennington	Department of Public Enterprise	Member
Dr. Tom McManus	Department of Public Enterprise	Member
Mr. Donal Enright	Department of the Environment and Local Government	Member
Mr. Peter Taggart	Dept. of Enterprise, Trade & Investment, NI	Member
Mr. Henk van der Kamp	Irish Planning Institute	Member
Mr. Niall Sweeney	City and County Managers Association	Member
Ms. Adele Sleator	Electricity Supply Board – National Grid	Member
Mr. Simon Grimes	Electricity Supply Board – Distribution	Member
Ms. Inge Buckley	Scan EES - Industry	Member
Mr. Brian ó Gallachóir	University College Cork	Facilitator

Other Contributors

Name	Affiliation
Mr. Eugene Dillon	Department of Public Enterprise
Mr. Lawrence Foye	Dept. of Enterprise, Trade & Investment, NI
Mr. Martin Hally	Irish Wind Energy Association
Mr. Liam O Donnell	Electricity Supply Board – Power Contracting
Mr. Phillip O Donnell	Electricity Supply Board – National Grid
Ms. Anne Scully	Electricity Supply Board – National Grid

Submissions Made

Bere Island Projects Group
Marine Institute
Údarás na Gaeltachta
Teagasc, WORD, IFA & Wexford Wind Energy Co-op

Appendix C – Thematic Meetings

The work programme of the Renewable Energy Strategy Group was based on thematic meetings, where specific deployment constraints were discussed. In addition there was an introductory and concluding meeting. The average attendance rate was 85%.

Meeting	Theme	Content
1	Introductory Overview	introduction, tour de table, timescale, work programme, introduction to deployment constraints, strategies employed to date.
2	Market Mechanisms	review of AER, strengths and weaknesses, explore green credits trading and other mechanisms.
3	Trading Issues	use of system charges, provision of top up and spill, accounting periods, maximum demand tariff structure and capacity charges.
4	Grid Upgrade	grid connection issues, Working Group final report, ESB plans for grid upgrading generally, scoping for a grid upgrade development plan.
5	Capacity Acceptance	how much green electricity can the network accommodate without the need for additional backup capacity ? costs of additional capacity, capacity credits, value of green electricity.
6	Planning Issues	strategic land use planning, landscape characterisation, accommodation of wind turbines by different landscapes, criteria for zoning areas as no-go or preferential, sub-optimal areas.
7	Integrated Resource Planning	planning ahead for wind energy taking into account all of the above, draft final report, consideration of proposed recommendations to appropriate bodies.
8	Strategy	finalisation on the agreed strategy for increased deployment of wind energy.
9	Report	finalisation of report by Renewable Energy Strategy Group on wind energy.

Appendix D – Wind Farms Currently Under Construction

Expected Completion Year	SITE	COUNTY	Installed MW	Market Mechanism
2000	Beenageeha	Kerry	4	AER III
2000	Milane Hill	Cork	6	AER III
2000	Tursillagh	Kerry	15	AER III
2000	Cuilleagh	Donegal	11	TPA
2000	Largan Hill	Roscommon	6	AER III/TPA
2000	Lenanavla	Mayo	2	THERMIE
2000	Beal Hill 1	Kerry	1.65	THERMIE
2000	Anarget Upper	Donegal	2	THERMIE
	Total		**47.65 MW**	

Appendix E - Renewable Energy Projections 1997-2005

Installed cap (MW)				
	1997	**1998**	**2000**	**2005**
Electricity				
Hydro	232	235	237	252
Wind	51	61	151	601
Landfill Gas	12	12	15	50
Waste to Energy	0	0	4	34
Total RE	295	308	407	937
Total Overall	4295	4305	4649	5640
% RE	**6.87**	**7.15**	**8.75**	**16.61**

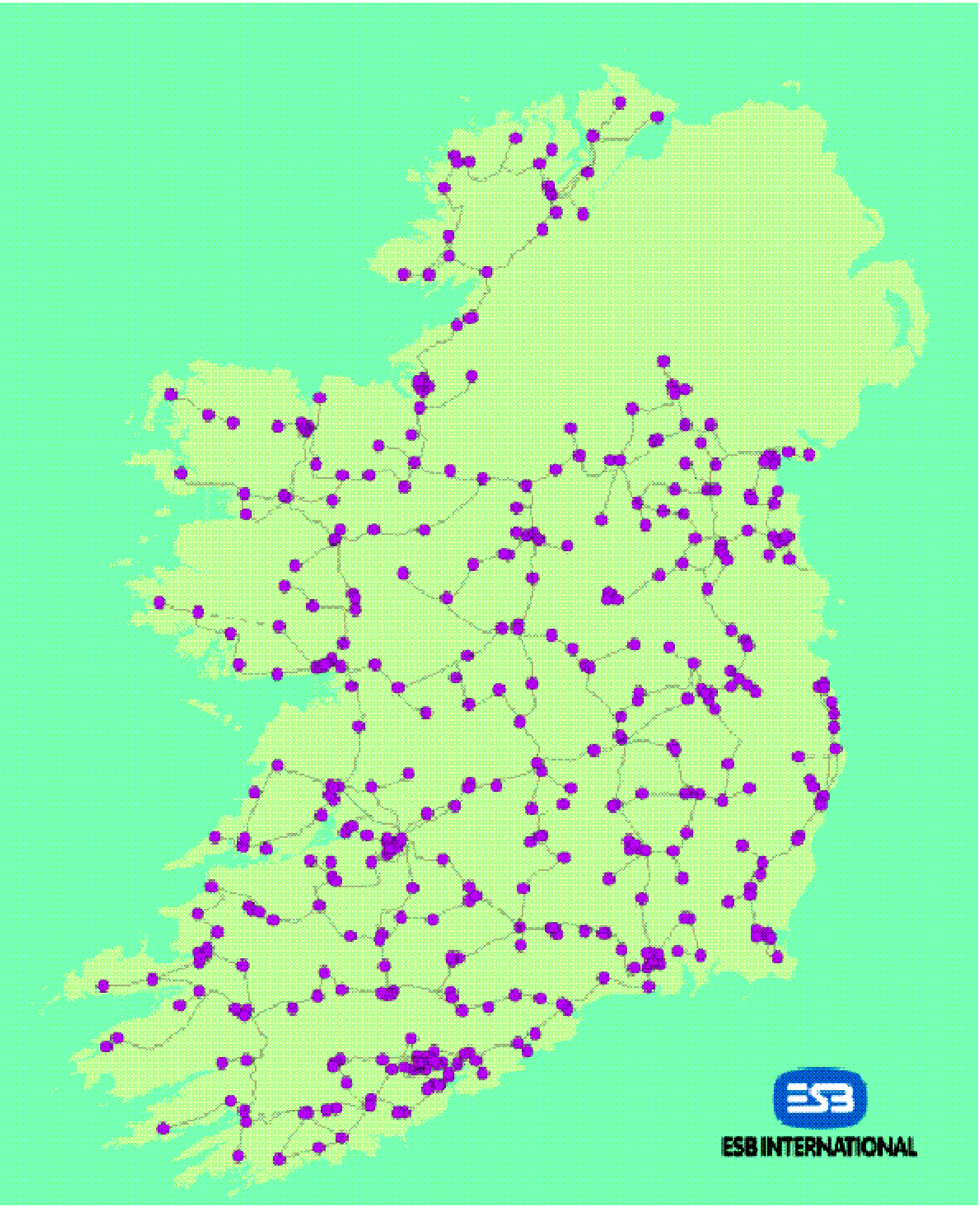
Electricity Produced (GWh)				
	1997	**1998**	**2000**	**2005**
Electricity				
Hydro	793	923	810	861
Wind	50	169	503	2001
Landfill Gas	89	85	112	372
Waste to Energy	0	0	30	253
Total RE	932	1177	1454	3487
Total Overall	19737	19317	23058	28146
% RE	**4.72**	**6.09**	**6.31**	**12.39**

Primary Energy Requirement (kTOE)				
	1997	**1998**	**2000**	**2005**
Electricity				
Hydro	68	79	70	74
Wind	4	15	43	172
Landfill Gas	8	7	27	91
Waste to Energy	0	0	13	109
Heat				
Biomass Dom	41	41	41	41
Biomass Ind	95	95	95	95
Biomass Agr	3	3	3	3
Total RE	219	241	292	586
Total Overall	11833	12682	13761	15613
% RE	**1.85**	**1.90**	**2.12**	**3.75**

Source: Green Paper on Sustainable Energy (1999).

Appendix F – ESB Transmission System

Appendix G – ESB Distribution System



Appendix H – ESB National Grid Report on Wind Capacity Acceptance

WIND CAPACITY ACCEPTANCE

To assist the Renewable Energy Strategy Group (RESG) in achieving its objectives, this input from National Grid attempts to clarify and update certain issues in relation to the acceptance of wind power on the Irish national electricity system.

These issues include :

- Operational factors
- Capacity credit
- Energy credit
- Economics
- Danish Situation
- Effects of dispersed siting
- Long-term trends (including interconnection)

1. Operational Considerations

This section addresses the impact that 600 MW of wind turbine generation (WTG) will have on the operation of the Irish electrical power system and the actions that should be taken to accommodate this level of wind generation.

Power System Characteristics

In 2005 it is forecast that the Irish power system will have approximately 6,100 MW of installed capacity. System loads will range from 1,550 MW to 4,725 MW.

The Irish electricity market is in the process of being de-regulated. If one looks at experience elsewhere it is likely that some existing plant will be decommissioned and replaced by efficient gas-fired combined cycle gas turbine (CCGT) plant. Some of this plant is likely to be Combined Heat and Power (CHP) plant in the order of 50-100MW capacity. The remainder is likely to be 300-450MW high efficiency CCGT plant.

It is possible that CHP plant will not be subject to central dispatch. The CHP and large CCGT plant anticipate a base load operating regime rather than load following regime. It is also likely that minimum loads that can be achieved by such plant is 50-65% of rated capacity. This is due to plant type and EPA restrictions.

Dispatch Costs

Based on current data from existing wind farms, we can estimate that typically wind generation operates in the range 0 - 80% of installed capacity i.e. wind generation rarely exceeds 80%. This applies for 90% of hours. See also Figure 4.

Applying this to a typical summer day in 2005, figure 1 shows the range in loads that non-wind generation must be expected to cater for.

The variations in wind generation can be seen as a greater uncertainty in load forecast i.e. the load that centrally dispatched plant must meet will be more varying. Errors in load forecasting carry a dispatch cost. This can be reduced by better measurement and wind output forecasting.

It is difficult to estimate the additional dispatch costs that are due to uncertainty of wind generation. There is a normal uncertainty in load forecasting which the system operator must deal with. However, load-forecasting error is likely to be small in comparison to wind generation uncertainty. The calculation of additional dispatch costs could be the subject of a study when trends have been established in the new de-regulated market.

The cost of the short notice change in a generator's availability is recognised in the Trading and Settlement Code. Generators must pay a penalty to the system operator for such a short notice downward change in availability. The penalty is calculated to compensate the system operator for the additional dispatch costs that occur.

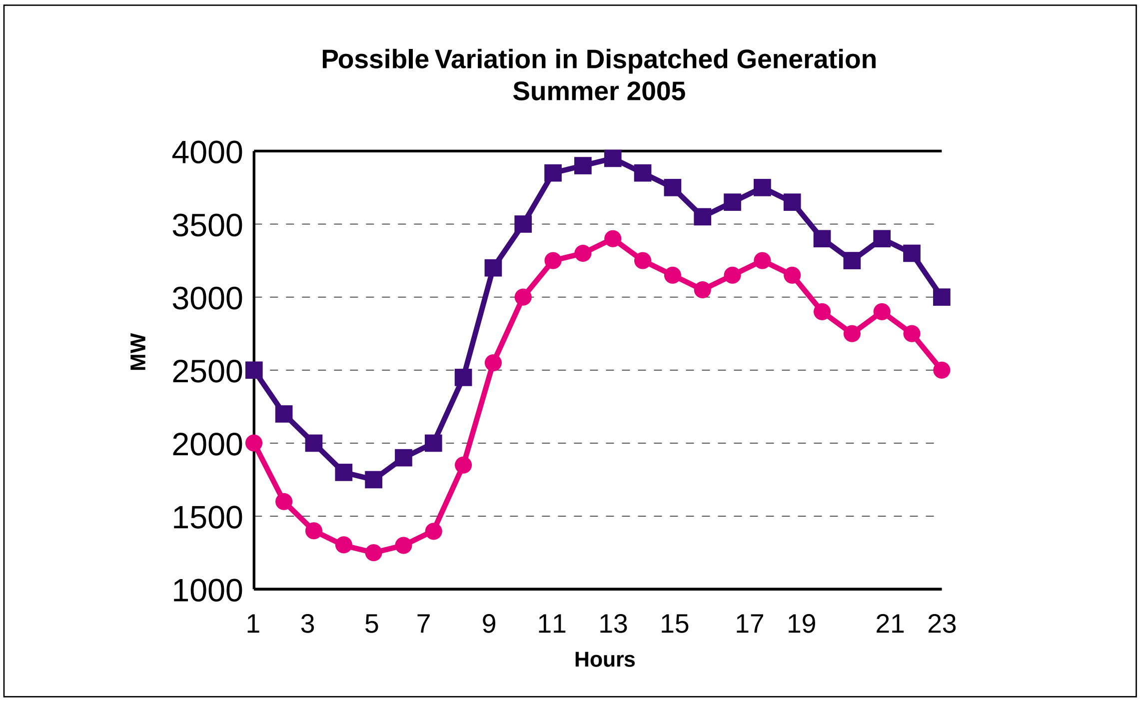


Figure 1: Variation in Dispatched Generation for 0% and 80% wind generation – summer 2005

Measurement

It is necessary for the system operator to have a real-time measurement of actual wind generation, subject to a minimum capacity size yet to be decided.

Forecasting

Accurate forecasting of wind power output in a 0-48 hour time window is necessary to facilitate increased wind generation penetration.

National Grid is a member of a consortium taking part in a project to develop a wind-forecasting tool. The partners in this program are National Technical University of Athens; Armines, Paris; Rutherford-Appleton Laboratories, UK; INESC, Portugal; PPC, Greece; and EEM, Portugal. This project is part-funded by the EU framework V program. This project will build on developments already achieved elsewhere. It is planned to produce a wind forecasting tool for Irish conditions. The project duration is three years.

However, there are likely to be additional costs to bring this system to production standard for use in the National Control Centre and for its on-going use.

Control

It will be necessary to limit wind generation at times if it is adversely affecting the system.

This issue needs to be addressed over the next few years as wind penetration increases. Technical means of control would need to be developed and put into effect in individual wind farms, if appropriate. The economic effects of the system operator constraining off generation also need to be considered.

Power Quality

The addition of 600 MW of wind generation changes the dynamics of the power system. The worst situation occurs at low loads when there is high wind generation. At this time there are few generators contributing to system inertia, frequency regulation and voltage control. In such an instance, the loss of a large generator could have a significant impact on the stability of the power system.

Currently the ESB system handles a 75 MW arc furnace at Haulbowline, Cork. This rapidly changing load is a major demand on frequency regulation from generators on the Irish power system. The impact is reduced by increased system inertia that slows the changes in frequency.

The variability of 600 MW of wind generation will be additional to the normal variations in loads and generation that the power system is designed to manage (including the Haulbowline arc furnace). Wind generators contribute little to system inertia. Wind generators do not contribute to frequency regulation or to reactive power/voltage control. This puts increased pressure on centrally dispatched generation and would increase the requirement for better regulation on existing and future generating units

A study is required to evaluate the short-term impact of wind power output variation on frequency and the requirements for stability and frequency regulation. This type of study requires the collection of high frequency data from generators.

Operating Reserve and Margin

Operating reserve is related to frequency regulation in that the amount of generation for regulation is included in operating reserve. Operating reserve covers a longer time period – up to 4 hours - and operating reserve can be obtained from a number of sources including interruptible load. Increasing wind energy penetration could lead to a requirement to increase operating reserve due to the size of wind power output. The number of times that operating reserve is called upon could also change. The cost of interruptible load is related to the number of interruptions and the length of time interruptions last.

Wind generators do not contribute to operating reserve. Meeting reserve requirement could be a problem at times of low load and high wind generation. The worst contingency is the loss of a large generator in such circumstances.

Wind generation may contribute to operating margin but only over a short time-scale and when there is very accurate forecasting of wind power output.

Maximum Infeed

To maintain system operational integrity, it is normal to limit the largest conventional generation infeed to 30% of instantaneous demand. This limit assumes infrequent loss of such generation. Operational considerations could dictate that the total input from wind generation be restricted to 20-25% (or even lower) of instantaneous demand, because of its intermittency. <u>For modelling purposes, however, this limit may be increased to a maximum credible value of 30%, to allow for possible smoothing effects resulting from widely dispersed siting.</u>

<u>Data used for study of operational issues:</u> The wind power series utilised for the analysis is based on the output of eight wind farms recorded at half hourly intervals during 1998. The wind farms in question were Barnesmore, Cark, Cronalaght, Crockahenny and Drumlough Hill in county Donegal; Spion Kop in county Leitrim; Corrie Mountain in county Roscommon, and Bellacorrick in county Mayo. A simple scaling technique was

used to derive power series for different levels of WTG capacity. Total existing installed capacity in these five wind farms is 55.25 MW.

2. Capacity Credit

When new generation capacity is added to an electrical power system it increases its ability to serve system demand to a specified adequacy criterion. This adequacy criterion has been defined on the Irish electrical power system as a long-term loss of load expectation of 8 hours per year.

To compare new generation additions, different options should be equivalent in the sense that each, when added in turn to the generation system, gives the same standard of adequacy.

The capacity credit of wind turbine generation (WTG) is defined as the amount of conventional generation capacity which gives equivalent system generation adequacy. For purposes of analysis, this conventional capacity was taken here to be CCGT plant, declared as Best New Entrant (BNE) generation by the Commission for Electricity Regulation (CER).

The analysis was carried out for year 2005, with a projected energy demand of 27 TWh and a peak load of 4,725 MW. The energy demand growth rate is 4.5% p.a. from 1999. Results, computed using computer program CREEP, are set out in Figures 2 and 3 overleaf. They are based on a power output time series from Irish wind farms existing in 1999. Figure 2 overleaf shows percentage capacity credit, calculated as the ratio of equivalent BNE capacity to WTG capacity. Figure 3 shows absolute capacity credit (MW of BNE). It can be seen, for example, that 2,000 MW of WTG capacity is equivalent to 300 MW of BNE capacity from a system adequacy viewpoint. These results are in good agreement with theoretical results that we obtained in a 1989/1990 study – see reference 1. They are also in line with results obtained internationally. See references 2 and 3.

The capacity credit return from additional WTG (wind turbine generation) capacity gradually decreases in percentage terms as WTG capacity is increased. It can be seen to saturate at a BNE capacity in the order of 350 MW. This is true with wind power limited to 30% of instantaneous demand, but holds even if no such limit is imposed. The consequence on the economics of wind energy is discussed further in section 4.

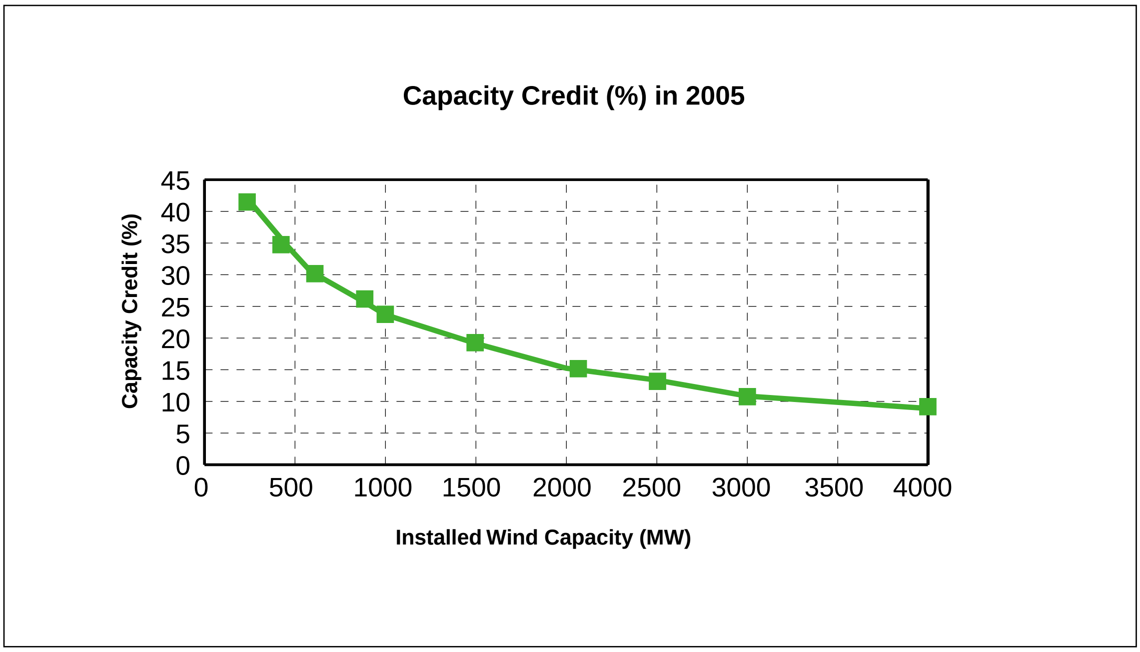


Figure 2

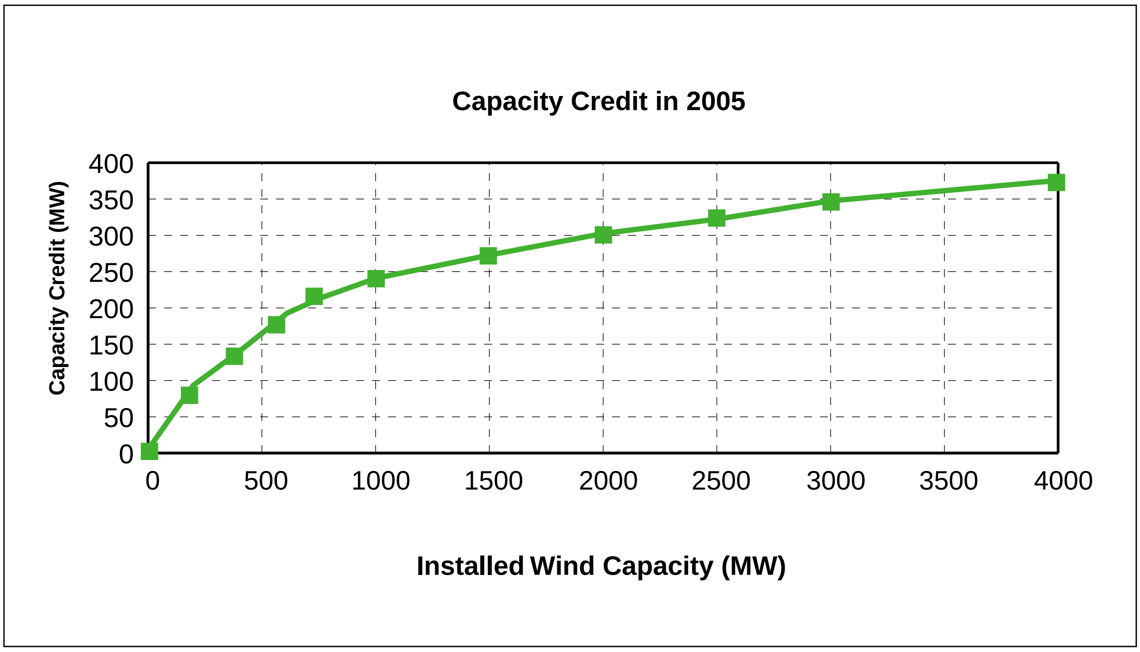


Figure 3

Data used for capacity credit studies: The wind power series is based on the output of five wind farms recorded at half hourly intervals during 1999. The wind farms in question were Barnesmore, Crockahenny and Drumlough Hill in county Donegal; Spion Kop in county Leitrim; and Corrie Mountain in county Roscommon. A simple scaling technique was used to derive power series for different levels of WTG capacity. Total existing installed capacity in these five wind farms is 30.8 MW.

The maximum hourly variation in power output is 60%. A load duration curve for the wind power series is shown in figure 4.

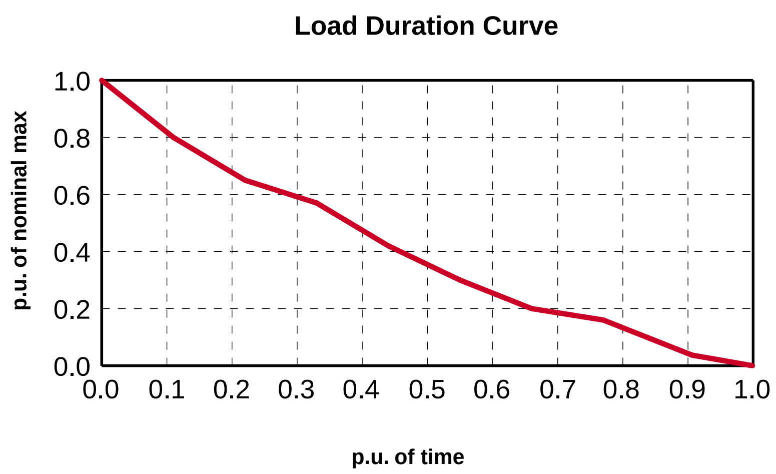


Figure 4

3. *Energy Credit*

The energy credit attributable to wind power generation derives principally from the reduction achieved in the consumption of fossil fuels and the consequent savings in total system fuel costs. There is an additional benefit from averted O&M costs. This is discussed further in section 4.

The required limitation of wind power input to 30% of instantaneous system demand obviously impacts the energy credit of wind generation.

Wind farm energy output will increase in a linear manner as installed capacity is increased. However what is at issue is how much of this energy can be accepted by the electrical system without causing unacceptable operational problems.

Figure 5 overleaf shows this linear increase in output with no restriction placed on wind energy acceptance. However this is not a feasible scenario. When wind energy input is limited to 30% of instantaneous demand, as is required to maintain system operational integrity, then the total energy which can absorbed by the system will saturate as WTG capacity is increased. This is shown in figure 5 for the Irish electrical system in 2005. It can be seen that beyond 2,000 MW of WTG capacity little additional energy credit would be obtained in that year.

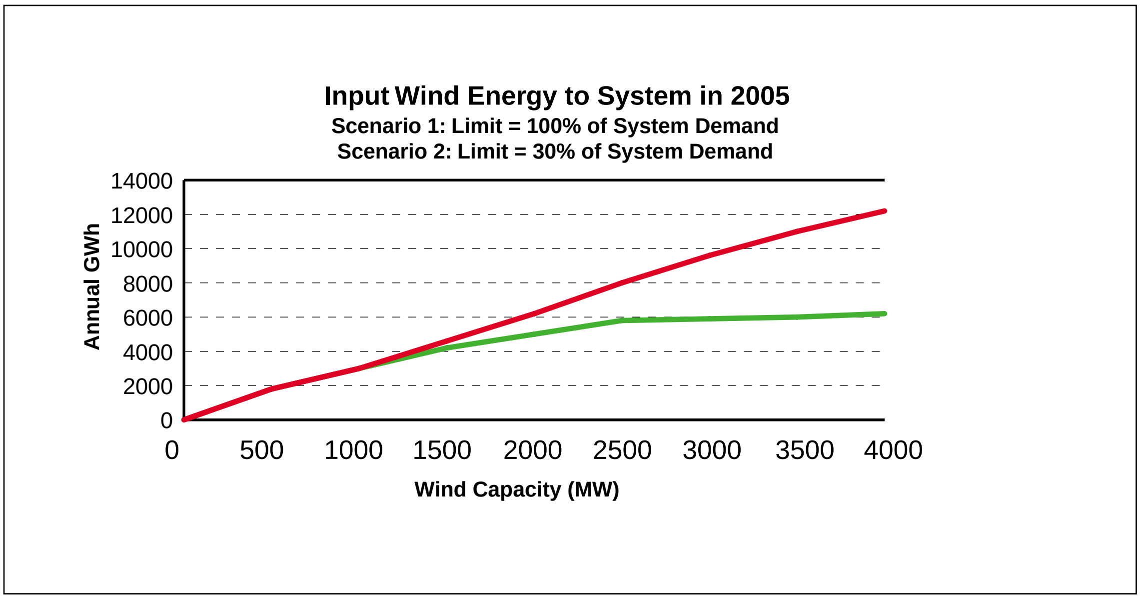


Figure 5

4. *Economic Considerations*

The analysis described in reference 1 was carried out in 1989. It examined the economics of wind energy for the monopolistic ESB electrical power system, and predicted that wind energy would not be fully competitive with conventional generation in year 2000.

This section describes how the economics of wind energy were reviewed in the context of a competitive market in electrical energy and supply for year 2005. The perspective was that of the consumer. The desired objective was to establish the price at which the consumer (and market) would be indifferent as between BNE generation and wind generation.

The analysis was based on comparing two scenarios for 2005. In the first scenario only BNE plant was added as required to satisfy system adequacy requirements. In the second scenario different amounts of WTG plant were added, together with reduced capacities of BNE plant, as necessary to meet the adequacy criterion, and leave the market indifferent to system adequacy effects. The reduction in BNE capacity corresponded to the capacity credit of each level of WTG capacity.

Production costing studies, comprising hourly Monte Carlo simulation, were carried out using PROMOD. The simulations corresponded to the two scenarios. In this way the fuel cost savings for different levels of WTG capacity were determined as the difference between the BNE-only scenario and those with different levels of WTG generation plus reduced levels of BNE generation. The costs of the extra operational reserve required with wind generation added were not included.

These production cost savings, plus the annualised capital and O&M value of the reduction in BNE capacity, comprise the economic value or worth of each level of wind generation.

As can be seen from figure 6, the incremental worth of wind generation reduces as WTG capacity is increased.

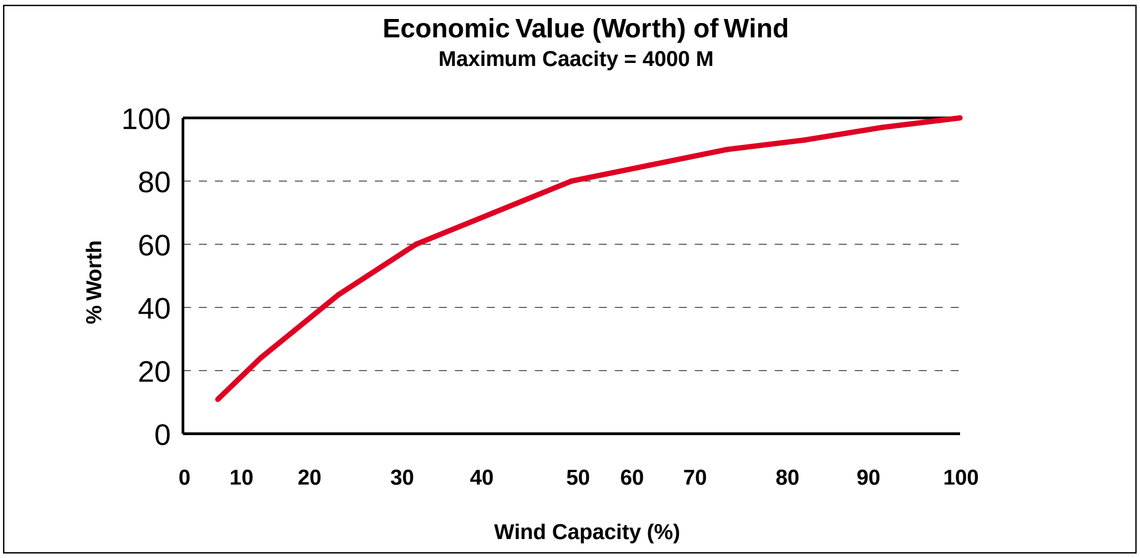


Figure 6

The valuations shown in figure 6 were used in conjunction with the energy output from wind generation to derive an indifference price per unit of output. This indifference price leaves the electricity customer economically neutral as between wind generation and BNE generation. Figure 7 identifies this indifference price normalised to the average price of unsuccessful AER III applicants with planning permission, which average was taken as a reasonable estimate of the required price for future WTG plant owners. It can be seen that as the penetration of wind energy increases greater support per unit of wind generation is required. This is an important result.

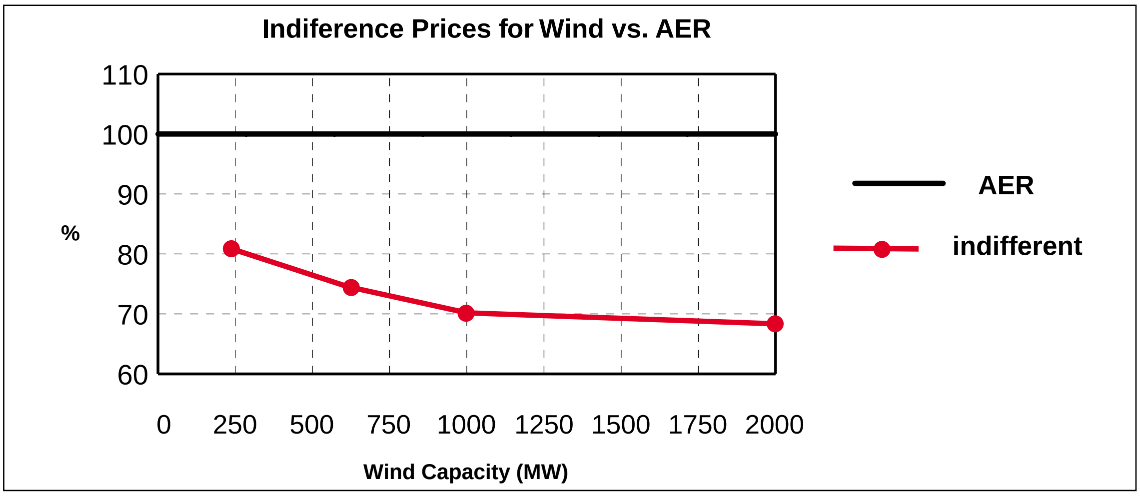


Figure 7

Economic Conclusions :

These findings confirm the results obtained in 1989, and set out in reference 1.

Wind energy is not yet economic in conventional terms, and requires subvention to be competitive when the costs of externalities are not included. It was not possible in this study to attribute a market value to the averted emissions.

Wind energy becomes less economic as its penetration increases for two underlying reasons. Both capacity credit and energy credit decline and eventually saturate with increasing penetration. This may pose a dilemma in devising an appropriate pricing mechanism to support wind generation.

The analysis in general illustrates trends and concepts, rather than determine exact numerical values.

5. The Danish Situation

The development of wind power in Denmark has aroused considerable interest. The national objective to achieve 50% wind energy penetration by 2030 has in particular been the focus of much comment.

ELTRA is the TSO for the western part of Denmark. There is no direct electrical interconnection with the eastern part of the country. The information tabulated below was obtained from ELTRA.

<u>ELTRA forecast for installed wind power (MW)</u>

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore and nearshore turbines	1,500	1,700	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Offshore turbines			150	300	300	450	450	600	600	750	750
Total	1,500	1,700	2,050	2,200	2,200	2,350	2,350	2,500	2,500	2,650	2,650

Installed WTG capacity in ELTRA's area at year-end 1999 was 1,312 MW. Wind energy production was 2.37 TWh, which was 11.5% of domestic consumption. Accommodation of this level of wind power, in conjunction with acceptance of electrical power associated with heat production, results in difficult operational problems, especially at low load periods. Power balancing and frequency regulation are only possible because of interconnections with Germany, Norway and Sweden. The strong interconnections with NordPool are of particular importance.

Danish national plans for increased electrical production from wind are subject to regular review. In particular there will be a significant decision to be made at the end of 2004, when the demonstration phase for off-shore wind farms at Horns Rev will end. Wind energy expansion plans beyond that year are therefore uncertain, depending as they do on the competitiveness of off-shore WTGs. The rate of expansion in Denmark of wind energy depends also on the development of a trade in renewable energy certificates, together with strengthening of interconnections. The existing situation has been achieved through Government legislation and regulations.

6. Dispersed Siting

From the perspective of an individual wind farm owner, there is a strong incentive to site in an area where the wind yield is highest. In the Irish context, this means that there is a strong incentive to locate wind farms near the west coast, and that is in general what has occurred to date.

However there are two system advantages which would accrue from more dispersed siting :

- The combined fluctuations due to the intermittency of wind power would become considerably smoother. This is very important from a system operational perspective.

- The capacity credit attributable to WTG capacity in total would increase.

These two advantages are demonstrated clearly in reference 1.

Dispersed siting means that some wind farms should be located near the south and south eastern coasts, where wind yields can be quite satisfactory.

The difficulty in the new market situation is to devise correct price signals to gain the desired effects for the ultimate benefit of the electricity consumer.

7. Long-term Trends

- A wind energy penetration level in the order of 5 % to 7% is achievable on the national electricity system by 2005. Just to maintain standstill at this percentage level, additional WTG capacity will have to be installed in later years if energy demand growth continues.

- A decision has been taken to strengthen the existing AC interconnection with Northern Ireland. That system in turn will be interconnected by DC submarine cable with Scotland. Furthermore there is a real possibility of DC submarine interconnection between this country and the England and Wales Pool in the time frame 2006 to 2010. These interconnections may facilitate the acceptance of higher levels of wind energy penetrations on the Irish system, judging by the Danish experience. However all solutions in electrical systems are system specific, and detailed technical and economic analyses are necessary to evaluate the capabilities and limitations of enhanced interconnection on the Irish electrical system in the new deregulated environment.

- If fossil fuel prices (gas, oil, coal) increase in real terms, and if the cost of WTG plant decreases in real terms, then naturally wind generation will become more competitive economically.

- The future is always uncertain. Economic, social and technological circumstances can alter very rapidly in an unpredictable way, and impact on wind energy generation targets. Thus planning is a continuing process, requiring regular updating. This is as true for wind generation as for any other future generation option.

References:

1. “The Case for Wind Energy” by E.O’Dwyer et al. (Cigre, 1990)

2. “Wind Energy Research Activities of the Dutch Electricity Generating Board” by N. Halberg, SEP. (1991)

3. “Capacity Credit of Wind Power in the Netherlands” by Van Wijk et al. (1992)

Appendix J Global Wind Energy Development

Martin Hally
Director of Technology, Bord na Móna

Wind Energy development is relatively new particularly when compared to the development of other conventional energy sources. Last year the Paris based International Energy Agencies (IEA) stated that the use of wind energy was set to reach an historic milestone crossing an installed capacity of 10,000 MW. Since then this figure has been well exceeded as can be seen in Table 1. Wind energy has been the fastest growing renewable energy source for four years running according to the IEA which monitors the world energy markets.

Year	World	Europe
1980	10	-
1985	1,020	80
1990	1,930	475
1995	4,820	2,531
2000	13,507	9,063

Table 1: How Wind Energy Installed Capacity in Megawatts has Grown

Wind energy growth continues to be driven by improved technology and supportive Government policies in their efforts to respond to environmental concerns about global warming and air quality.

Year	Europe	Rest of World	Total World
1997	37%	12%	27%
1998	32%	12%	24%
1999	44%	37%	41%

Table 2: Wind Energy % Growth Trends

Wind turbine prices have been reported to have fallen by a factor of at least five from 1981 to the present. The cost of energy generated by turbines has halved over the past decade as a combined result of the fall of turbine prices, higher efficiencies, lower operation and maintenance costs.

Totals	Capacity 2000 Jan	Installed 1999	% increase 1999
Europe	9,063	2,760	44%
Rest of World	4,444	1,197	37%
World Total	13,507	3,957	41%

Table 3: Growth in Wind Energy Capacity in 1999

Wind Energy has now reached a stage of technical and commercial maturity where significant wind energy developments have been made in E.U. Member States such as Germany, Denmark, Spain. Table 4 clearly shows the current global spread of wind energy development and provides a clear demonstration of how successful government policy directly encourages the growth of local Wind Energy development.

EUROPEAN WIND ENERGY CAPACITY REST OF THE WORLD WIND ENERGY CAPACITY

	Capacity Jan-00	Installed 1999	Increase 1999		Capacity Jan-00	Installed 1999	Increase 1999
Germany	4,443	1,568	55%	**USA**	2,706	886	49%
Denmark	1,761	320	22%	**India**	1,062	94	10%
Spain	1,225	518	73%	**China**	261	47	22%
Netherlands	411	71	21%	**Canada**	125	43	52%
UK	358.5	30.6	9%	**Japan**	68	28	70%
Italy	283	103	57%	**Costa Rica**	46	20	77%
Sweden	215	39	22%	**Egypt**	35	30	600%
Greece	82	43	110%	**New Zealand**	35	30	600%
Ireland	67.5	7.4	12%	**Brazil**	25	8	47%
Portugal	60	9	18%	**Australia**	17	0	0%
Austria	42	12	40%	**Argentina**	13	1	8%
Finland	38	21	124%	**Iran**	11	0	0%
France	22	3	16%	**Turkey**	9	0	0%
Norway	13	4	44%	**Israel**	8	2	33%
Czech Republic	12	5	71%	**South Korea**	7	5	250%
Luxembourg	10	1	11%	**Russia**	5	0	0%
Belgium	9	3	50%	**Ukraine**	5	0	0%
Poland	7	2	40%	**Mexico**	3	0	0%
Switzerland	3	0	0%	**Sri Lanka**	3	3	+
Romania	1	0	0%				
European Total	9,063	2,760	44%	**Rest of World Total**	4,444	1,197	37%
World Total	13,507	3,957	41%				

Table 4: Current World Wide Spread of Wind Energy Capacity (January 2000)

The growth trend in new capacity is expected to continue. It will be intensified as the 2010 deadline for the Kyoto Greenhouse Gas Abatement targets is approached and the same 2010 deadline for the EU energy target of 12 % of total primary energy from renewables. Failure to reach these targets is expected to carry punitive penalties with the ensuing serious economic consequences and potential damage to national competivity and growth.

Some Sources of Wind Turbine Commentary and Statistics:

Financial Times– Occasional features and articles on wind energy (UK)

Wind Power Monthly - Wind power monthly news magazine (Denmark)

Wind Stats Newsletter – Quarterly review of issues and wind energy production (Denmark)

Wind Directions – Magazine of the European Wind Energy Association (UK)

New Energy - Magazine for renewable energies (Germany) May 2000