INTERNATIONAL ENERGY AGENCY

Energy Policies of IEA Countries

IRELAND

2003 Review

OECD

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INTERNATIONAL ENERGY AGENCY
9, rue de la Fédération,
75739 Paris, cedex 15, France

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

** IEA member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- to achieve the highest sustainable economic growth and employment and a rising standard of living in member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- to contribute to sound economic expansion in member as well as non-member countries in the process of economic development; and
- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Since the last IEA in-depth review four years ago, a number of important developments have taken place in the Irish energy sector. Ireland has initiated reform of both the electricity and natural gas markets. While work remains to be done in this process, considerable progress has already been achieved. The basic regulatory framework for both markets has been established and an independent regulatory body has been put in place. In addition, in November 2000, Ireland published the National Climate Change Strategy, providing a blueprint for the country to meet its Kyoto greenhouse gas targets. The country has begun implementing the policies and measures contained therein although much work remains to meet the challenging emissions target.

Concurrent with these two commendable developments has been a rapid increase in energy demand resulting from an impressive level of economic growth. This high rate of energy demand growth has occasionally strained the country's energy infrastructure and, while these constraints are generally being addressed, they increase concerns about the country's overall energy security. These concerns are fuelled in part by the country's lack of substantial domestic energy resources and consequent high level of imports. In 2000, only 15% of the country's energy came from indigenous sources. The country's relative isolation and lack of extensive international energy connections also exacerbate Ireland's vulnerability to supply disruptions and/or price spikes.

Market reform of the electricity sector began with the Electricity Regulation Act 1999 and was further advanced by the European Communities (Internal Market in Electricity) Regulations 2000 (S.I. 445 of 2000). Much of the impetus for this reform came from the need to comply with the European Union directive on the internal market rather than from any parties within Ireland. Currently, all customers with annual capacity greater than 1 GWh per annum are free to choose their electricity supplier; this covers about 1 600 customers, or 40% of the market by volume. All customers, regardless of capacity, are free to source their power from a supplier who provides electricity from renewable sources or combined heat and power plants. Ireland envisions 100% market opening by 2005. The Commission for Energy Regulation (CER), a legally independent regulator, was established with a mandate to oversee important aspects of the market reform process. In addition, a transmission system operator has been established to operate and administer the country's high-voltage transmission lines. Any eligible party may gain non-discriminatory access to these lines at cost-based rates determined by the CER.

These developments are commendable and the reform process is certainly headed in the right direction. Nevertheless, a number of obstacles remain before Ireland can fully benefit from reform of the electricity sector. One major problem has been the lack of interest in the Irish market from viable, committed new entrants. While this absence can be ascribed in part to the poor global investment climate in the private power sector, much of it is related to the particular characteristics of the Irish market. For one thing, the Irish market is the smallest in the EU (excepting Luxembourg), making it less attractive for entry. While Ireland cannot, of course, arbitrarily increase the size of its market, it can effectively do so by augmenting connections with other markets, primarily Northern Ireland and, perhaps, Wales. Another perceived impediment to new entrants is the still dominant role played by the incumbent utility, the Electricity Supply Board. With regard to the company's vertical integration, ESB has assets and operations in the generation and distribution market segments, subsidiaries which sell to both regulated and unregulated end-users, and ownership of the country's national transmission grid. In addition, it appears that ESB still has some power to influence transmission system planning. The current arrangement for separation of grid operation and ownership should be carefully monitored. In terms of horizontal market concentration, ESB currently owns between 85 and 90% of the total national generating capacity. ESB has stated its commitment to reduce this percentage to 60% by 2005 but no obligation to do so exists and, in any event, such a large market share would still give the company market power to influence prices to its benefit. The government needs to review ESB's role in the liberalised electricity sector to address the impression that the company could unfairly influence the market to the disadvantage of new entrant competitors. In general, the government is encouraged to explicate more clearly its vision for the ultimate shape of the reformed electricity sector, as lingering uncertainty over the final shape of rules and regulations is also deterring new entrant competitors.

While continued improvement of the structure and regulations for a successful long-term market reform will continue to be important, the most pressing matter is the expected need for new electricity generating capacity in the short term. Since investment in a new generating plant by independent companies has been below expectations, the country could face a generation shortfall in 2005, or even possibly in 2004. Given the long lead times for developing and building large power stations, it is unlikely that a fully independent power plant will be on line in time to address this coming need. As a result, the government must take steps to encourage the required capacity to enter the market in time. It can do so by means of a capacity inducement such as a short-term or partial off-take contract. Such inducements would ideally bring a non-ESB plant to the market at a minimal cost to consumers without impeding the long-term development of a reformed, competitive electricity sector. As a concurrent development, demand-side management of electricity would reduce the need for new capacity.

Reform of the natural gas sector is also moving in the right direction. As of 1 January 2003, all customers with an annual demand greater than 500 000 standard cubic metres were free to choose their own gas supplier. This covers about 250 of the largest gas customers in Ireland, accounting for over 85% of the market by volume. The mandate of the legally independent electricity regulator has been expanded to include jurisdiction over gas market reform. In addition, regulated third-party access to the incumbent's transportation grid is guaranteed for all eligible customers.

These developments have been too recent to draw any meaningful conclusions regarding the success of the reform effort in the gas sector. While some of the largest customers are engaging in self-shipping, it remains to be seen whether the small or even mid-size customers will switch suppliers or negotiate lower rates with the incumbent. There have, however, been some positive signs that competition is developing. The production from a new domestic gas field has been sold to a new entrant who will use this gas to compete in the Irish market, and another domestic gas field is scheduled to come on line in 2005, creating further possibilities for competition. Despite these desirable developments, Ireland's finite supply sources (gas from the United Kingdom and a limited number of domestic sources) make it unlikely that upstream competition could really give a substantial choice to eligible customers. Nonetheless, this limited upstream and retail competition should be beneficial and Ireland is encouraged to proceed with its reform efforts.

Passage of the country's National Climate Change Strategy (NCCS) in November 2000 was an important step towards addressing the country's climate change challenges. Under the EU burden-sharing arrangement in the Kyoto Protocol (ratified by the Irish Parliament in May 2002), Ireland must limit the net increase of its greenhouse gas (GHG) emissions to 13% above 1990 levels by the target period 2008-2012. As of year-end 2000, GHG emissions had already grown to 24% above 1990 levels and are believed to have grown since that time. Government projections show a 37.3% rise from 1990 levels by 2010 under a business-as-usual scenario.

The NCCS was designed as part of a consultative process with government, the private sector and consumer groups, and covers a wide range of emissions-producing sectors. Despite these important consultations, the lack of a comparative analysis of the cost-effectiveness of the different measures in the various sectors has made it unclear what the total costs of these measures would be or even if the least-cost measures are being pursued. One related problem is that no full projection of the economy and expected emissions reductions has been made that takes into account all the measures proposed in the NCCS. This should be done as soon as possible. The challenge of meeting the emissions target with domestic means alone makes it likely that Kyoto flexible mechanisms [emissions trading, Joint Implementation (JI) and Clean Development Mechanism (CDM)] will be needed to reach the country's target. While such mechanisms are discussed in the NCCS as important tools in reducing emissions, their integration into the overall climate change strategy is unclear. The manner and extent to which such international approaches to climate change will be used should be made more explicit, particularly as experience is gained.

The largest single measure proposed in the NCCS is to either shut down or fuel-switch the coal-fired Moneypoint power generating station. This one measure would account for 22% of the total GHG emissions reductions expected from NCCS proposals. It is not yet clear whether this measure will in fact be enacted, but the government is encouraged to make a decision on this matter as soon as possible. Not only will closure of the plant require the construction of substantial electricity generating capacity to replace Moneypoint, but if this and other fuel-switching measures in the NCCS are enacted, Ireland could use natural gas to generate up to 80% of all its electricity by 2010. Such a potential heavy reliance on gas raises energy security concerns that will require time to address.

A number of recent developments are impacting on Ireland's energy security. Continued uncertainty surrounding the reform of the electricity sector has deterred investment in power generation, and, as mentioned above, a push to eliminate coal-fired generation out of concern for GHG emissions may produce a power sector fuelled 80% by natural gas. In addition, recent economic growth has produced a rapid rise in energy demand which, in turn, has placed strains on the existing infrastructure. These developments, coupled with the country's modest fossil fuel reserves and relative isolation, raise legitimate energy security concerns that the country should continue to address.

The construction and commissioning of a new subsea natural gas pipeline from the UK shows not only the ways in which energy security can be enhanced but also the costs involved with such measures. Faced with an expected increase in gas demand by winter 2002, the government conducted a vigorous examination of the various options and decided to approve construction of a second subsea pipeline linking Irish demand centres with gas supply from the UK. While the added capacity of this second pipeline does in fact guarantee that there will be sufficient gas import capacity from the UK, the timing of the project appears to be premature. Gas demand has not risen as expected and the new pipeline is not likely to be required until 2005. However, the cost of the as yet unneeded second subsea pipeline (approximately €300 million) must be recovered now and is currently being borne by Irish gas consumers. This example shows that while there are in fact a number of ways to address energy security concerns, all the available options and their related costs must be considered carefully before being enacted.

While renewable energy does not currently make a substantial contribution to the country's energy mix, there is large potential, particularly in the form of wind power. Wind power is attractive since it provides emissions-free, domestically-sourced power, thereby addressing the country's climate change and energy security concerns. Ireland has taken steps to encourage renewables use, primarily through an auction process which offers long-term power purchase agreements to buy electricity from renewable sources. The country should facilitate the increased penetration of wind into the electricity system by examining the issues of system frequency stabilisation and back-up power that arise with substantial wind power use. The country should also ensure that all support schemes for renewables are market-based and include proper incentives to reduce costs.

Coal and peat play an important role in the country's energy mix. Together, they account for over 18% of the country's total primary energy supply (TPES), and over 36% of the country's electricity generation. While all coal is imported, its supply is considered very secure and hence, along with domestically-sourced peat, it can contribute to the country's energy security. Both fuels, however, have the disadvantage of high carbon content with correspondingly high CO_2 emissions. The role of these fuels in Ireland's energy mix must strike a proper balance between energy security and GHG emissions mitigation. Although greatly reduced in recent years, peat production is still supported by a subsidy ultimately borne by the consumer. The government should strive to achieve the most efficient level of peat production possible in order to minimise the level of subsidy.

Ireland has improved it energy efficiency dramatically over the last ten years with energy intensity falling by one-third from 1989 to 2000. This improvement was achieved by both government action and a shift in economic activity away from energy-intensive sectors. Efficiency improvements appear poised to continue with a variety of government programmes and initiatives already in place. Historically, Ireland had very low levels of combined heat and power (CHP) usage, but the government is now trying to encourage its use to improve overall efficiency. Transport, however, may provide the best opportunity to improve energy intensity, since an increase in energy use in this sector coincides with the need for a new transportation infrastructure. Thus, the new infrastructure can and should be designed in a way to minimise energy use and resulting emissions.

Ireland is taking a more proactive role in energy research and development than in the past. It has allocated €60 million[1] to this area for the 2001-2006 period. Despite this commendable increase of resources, national expenditures remain modest by total EU standards. As a result, Ireland would be well served by an active participation in energy R&D activities at the international level, including participation in EU and IEA programmes.

1. On average in 2002, € 1 = US$ 0.943.

In addition, Ireland should try to involve the private sector in its R&D activities in order to leverage limited public sector funds and build capacity for R&D within private companies.

RECOMMENDATIONS

The government of Ireland should:

Energy Market and Energy Policy

- *Develop a long-term strategy for optimal energy supply mix striking an appropriate balance between energy security and climate change mitigation, noting a rapidly growing share of natural gas in the electricity sector.*
- *Promote international integration in the electricity and gas sectors to enhance energy security and competition, and facilitate integration with the single EU market.*
- *Continue to undertake energy supply-demand and CO_2 emissions projections, noting rapid growth in energy consumption and CO_2 emissions.*
- *Pursue social objectives by means other than energy policies, prices and taxation.*

Energy and the Environment

- *Undertake energy and emissions projection and analyses which include the National Climate Change Strategy (NCCS) policies and measures.*
- *Monitor and evaluate the cost-effectiveness of policies and measures in the NCCS and update it as required to achieve the Kyoto targets in the most cost-effective manner.*
- *Ensure that greenhouse gas mitigation measures cover all energy and non-energy sectors and reflect externalities for each source.*
- *Clarify the use and role of CO_2 taxation, emissions trading, Clean Development Mechanism (CDM) and Joint Implementation (JI) in the NCCS.*
- *Develop, with close co-operation among relevant departments, an effective framework for negotiated agreements and appropriate monitoring/reporting mechanisms based on experiences gained from pilot agreements.*
- *For the industrial and power generation sectors, clarify the interrelation among negotiated agreements, greenhouse gas taxation and emissions trading, especially in light of the proposed EC directive on emissions trading.*

Energy Efficiency

- *Evaluate existing energy efficiency programmes with the aim of strengthening efforts to improve energy efficiency in a cost-effective manner.*
- *Expand the cost-effective use of pricing and mandatory regulations to promote energy efficiency, for example in the transport sector.*
- *Continue to explore cost-effective mechanisms to promote combined heat and power (CHP).*
- *Enhance the public transport infrastructure in co-ordination with demand management measures to curb energy consumption and CO_2 emissions from the transport sector with close co-operation among the relevant departments.*
- *Explore measures to promote efficient low-CO_2 vehicles, particularly in the public transport sector.*

Natural Gas and Oil

- *Ensure that the regulatory framework facilitates continued monitoring of developments in the natural gas market and, where results do not lead to effective market opening and corresponding competition in the market, work out and adopt the necessary procedures to ameliorate the situation.*
- *Ensure continued adequate transmission capacity and non-discriminatory third-party access to the transmission grid.*
- *Develop a security of supply policy by defining minimum objectives and responsibilities of sector participants while allowing individual players the means to achieve these objectives. The costs of implementing all security of supply measures must be weighed against benefits.*
- *Continue to engage in international co-operation, including through the IEA, the Energy Charter, the EU, and the International Energy Forum (IEF), to support regional security of gas supply.*
- *Undertake efforts to streamline and shorten planning procedures for domestic exploration and production, including ensuring that the affected regions understand the value of production to the country and to their community.*
- *Review taxation of automotive fuels in light of fuel tourism and the consequent impact on GHG emissions.*

Electricity

- *Decide as a matter of urgency how best to ensure the construction of new generating capacity to meet the imminent supply shortfall. Ensure that this* *next increment of capacity is owned and operated by an independent power producer (IPP) to facilitate market competition.*

- *Continue process of strengthening the transmission grid, including around the north-south interconnection.*

- *Develop as a priority a clear vision for the overall market design and structure, with a firm implementation timetable to provide market certainty and encourage investment in new generating capacity.*

  - *Monitor and amend if necessary the current arrangements for separation of the operation and ownership of the grid to ensure that the objectives of an efficient and secure grid continue to be met.*

  - *Work towards a clear and coherent set of long-term market rules for trading, including providing for transparent, non-discriminatory market-clearing wholesale prices.*

  - *Consider a means of dispersing control of ESB generation among competing companies, particularly for mid-merit (*i.e. *price setting) plant. Alternatives for break-up include privatisation, setting up competing state-owned companies (with independent commercial boards), or leasing or auctioning off management rights to individual plants.*

- *Take an early decision on whether the East-West interconnector will be constructed, taking into account supply security and competition concerns, in order to facilitate decisions on market structure and to provide market certainty, especially for new investors.*

- *Continue efforts to develop an all-island electricity market, including by increasing the usable capacity of the North-South interconnector, in the interests of security of supply and competition.*

- *Develop a clear policy on security of fuel supplies for electricity generation, including through diversity of fuels, generation technologies and dual-fuelling, to avoid over-dependence on imported gas in the long term.*

Renewable Energy

- *Develop a strategy to facilitate the increased penetration of wind power and other renewables into the national electricity market, taking into account back-up requirements.*

- *Ensure that any support schemes for renewables are market-based and incorporate proper incentives for further cost reduction.*

- *Continue to explore the potential for development of offshore wind parks, while taking into account the additional cost factors involved with grid interconnection.*

Coal and Peat

- *Evaluate the role of coal in the energy mix, striking a balance between energy security and greenhouse gas mitigation.*

- *Identify the impact on greenhouse gas emissions of the full cycle of peat production and use.*

- *Ensure that Bord na Mona (BNM - the state-owned peat company) continues to improve peat production efficiency in order to reduce peat subsidies and the distortive effect this has on the market.*

- *Keep under review the role of peat in the energy supply mix taking into account its contribution to energy security, impacts on the electricity market and greenhouse gas emissions.*

Energy R&D

- *Prioritise activities on a limited number of projects and concentrate resources on them with a view to meeting national energy policy objectives.*

- *Engage in active participation in R&D activities at the international level, including participation in EU and IEA programmes.*

- *Stimulate co-operation between the public and private sectors in R&D areas such as demonstration projects in the transport sector.*

ORGANISATION OF THE REVIEW

REVIEW TEAM

The 2003 IEA in-depth review of the energy policies of Ireland was undertaken by a team of energy specialists drawn from the member countries of the IEA. The team visited Ireland from 17 to 22 November 2002 to meet with government officials, energy suppliers and energy consumers. This report was drafted on the basis of those meetings and information gathered, as well as the government's official response to the IEA's 2002 policy questionnaire. The team greatly appreciates the openness and co-operation shown by everyone it met.

The members of the team were:

Michael Lear
Ministry of Economic Development
New Zealand

Stephanie Bauer
Federal Ministry of Economics
and Technology
Germany

Pekka Tervo
Ministry of Trade and Industry
Finland

Johannes Maters
Directorate-General for Energy
and Transport
European Commission

Jun Arima
Head, Country Studies Division
International Energy Agency

Jonathan Coony
Country Studies Division
International Energy Agency

Jonathan Coony managed the review and drafted the report. Monica Petit and Bertrand Sadin prepared the figures.

ORGANISATIONS VISITED

The team held discussions with the following:

The Department of Communications, Marine and Natural Resources (DCMNR)

Bord na Mona (BNM)

Commission for Energy Regulation (CER)

Department of Environment

Sustainable Energy Ireland

ESB National Grid

The Irish Business and Employers' Confederation (IBEC)

Competition Authority

Department of Transport
Airtricity
Bord Gáis Éireann (BGÉ)
Electricity Supply Board (ESB)
Economic and Social Research Institute (ESRI)
The Viridian Group

REVIEW CRITERIA

The *Shared Goals* of the IEA, which were adopted by IEA Ministers at their 4 June 1993 meeting held in Paris, provide the evaluation criteria for the in-depth reviews conducted by the Agency. The *Shared Goals* are set out in Annex B.

ENERGY MARKET AND ENERGY POLICY

COUNTRY OVERVIEW

Ireland has a population of 3.8 million of which slightly more than 1 million reside in the capital of Dublin and adjacent areas. Outside of Dublin and the eastern region, the country is sparsely populated. The Irish constitute approximately 1% of total EU residents. This island is shared by the Republic of Ireland (which occupies five-sixths of the island) and Northern Ireland (the United Kingdom). Ireland is bounded on the west and south by the Atlantic Ocean, on the east by the Sea of Ireland and on the north by Northern Ireland.

Total land area for Ireland is slightly less than 70 000 km^2. Terrain throughout the country is mostly level with rolling interior plains surrounded by rugged hills and low mountains. The less-populated west coast is characterised by high cliffs. The climate is temperate maritime, strongly influenced by the North Atlantic Current. It consists of mild winters and cool summers with a relatively high degree of humidity throughout the year.

Ireland's economy has expanded rapidly over the last ten years. From 1994 through 2001, GDP growth averaged 8.9% per year. This performance is largely believed to result in part from government policies favouring business activity, including a decrease in both corporate income taxes and barriers to international trade. Ireland experienced a significant slow-down in economic growth in 2001, reaching its lowest point in the fourth quarter of 2001 when year-on-year growth fell to 0.1%. In the first quarter of 2002, however, the economy had already begun to rebound with growth of 2.9%; the final 2002 growth numbers are expected to show a continuation of this rebound. Much of the increased economic activity over the last decade has been in information technologies (IT), services and pharmaceuticals. Irish GDP per capita is now above average for EU countries. Total GDP represents slightly more than 1% of the EU total. The Irish unemployment rate in 2001 was 3.8%. On 1 January 2002, Ireland adopted the euro as its currency at a fixed rate to its previous currency of 1.0 euro = 0.78756 Irish pound.

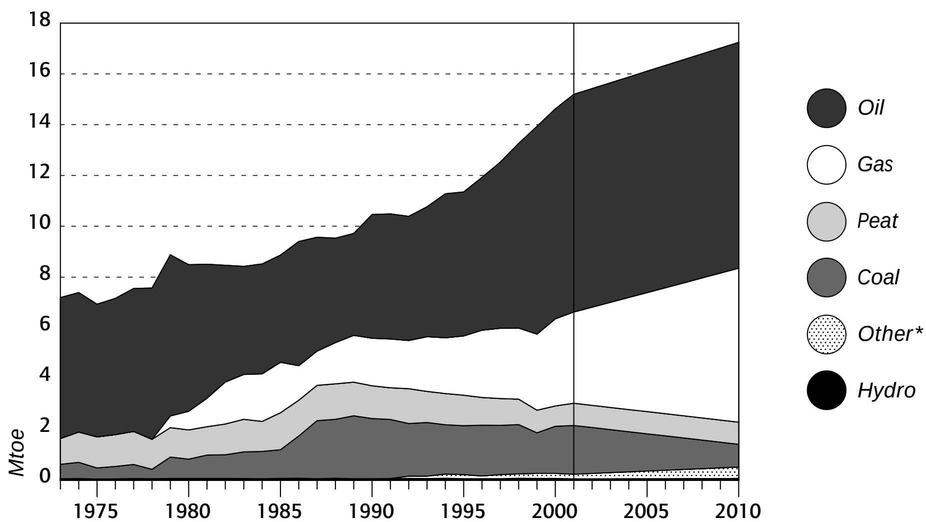
The governing coalition parties, Fianna Fail and the Progressive Democrats, both made gains in the general election on 17 May 2002. They have agreed to reconstitute their partnership without significant changes either in policies or personnel and will enjoy a solid majority in the Parliament. They are not expected to deviate significantly from their past policies. In October 2002, the Irish people voted in a referendum to support the Nice Treaty which allows expansion of the EU by ten new member countries.

PRIMARY ENERGY SUPPLY

In 2000, Ireland's total primary energy supply (TPES) was 14.62 million tonnes of oil equivalent (Mtoe). This represents a 23% rise from 1996, or an average annual rate of 5.2% per year. The long-term growth rate of TPES has been considerably below recent figures. From 1973 to 2000, TPES grew at an average rate of 2.8% per year. The accelerated growth of Irish TPES in recent years can be largely attributed to rapid economic growth which averaged 9.9% from 1996 to 2000.

Figure 1

Total Primary Energy Supply, 1973 to 2010



* includes solar, wind, combustible renewables and wastes and electricity trade.

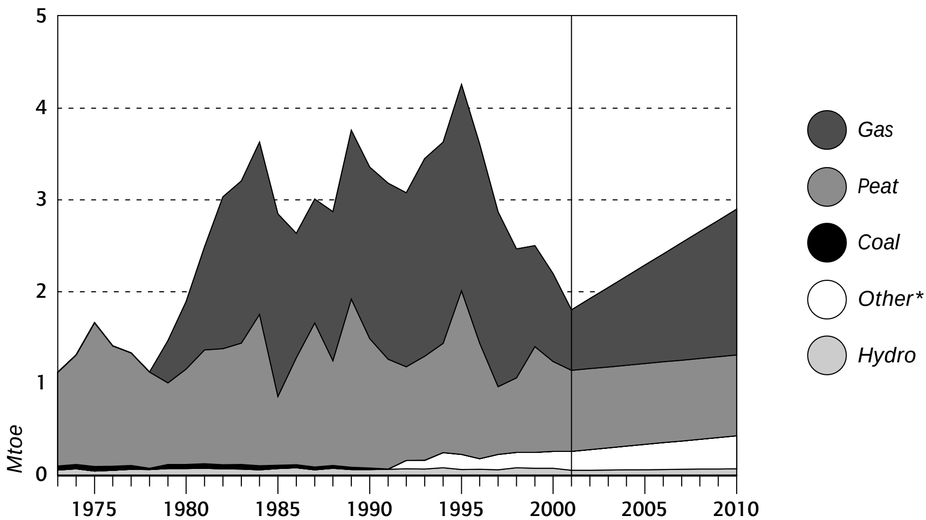
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

Oil is the largest contributor to the country's TPES with 56.5% of the total in 2000. In 1996, oil contributed 50.4% of Irish TPES, and the historic low came in 1989 when oil's share of TPES was just 41.3%. The subsequent rise in oil use as a percentage of total energy supply can be attributed to the country's economic success which allowed people to purchase more motor cars. Government forecasts predict that oil use will continue to increase in absolute terms, but decline as a percentage of total TPES until it reaches 51.6% in 2010. Natural gas is the second most important primary fuel in Ireland. In 2000, it accounted for 23.5% of the national TPES, rising slightly from 1996 when it was 22.2%. Gas use is expected to continue growing, driven by both economic and environmental factors, reaching 35.1% of TPES by 2010.

Coal is expected to lose the greatest share of TPES in the coming years. In 2000, coal contributed 12.7% of the country's TPES, down from 16.8% in 1996. It is expected to fall further until it holds just 5.2% of TPES in 2010. Peat has lost the largest percentage share of the country's TPES. From 1990 to 2000, its absolute contribution has fallen from 1.3 Mtoe to 0.8 Mtoe, decreasing its share of TPES over that time from 12.3% to 5.5%.

Figure 2

Energy Production by Source, 1973 to 2010



* includes solar, wind, combustible renewables and wastes.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

A large majority of Irish TPES is imported. In 2000, 84.1% of the country's TPES came from imports while 15.0% came from indigenous production[2]. Domestic energy came mostly in the form of 0.98 Mtoe of peat production (6.7% of TPES) and 0.96 Mtoe of natural gas production (6.6% of TPES). In recent years, primary energy production has fallen and imports have risen. In 1996, indigenous energy production accounted for more than 30% of TPES. Since 1986, when indigenous production as a share of TPES peaked at 42.6%, the longer-term historical trend also shows increasing reliance on energy imports. This greater reliance on imports seen in recent years results from a decrease in domestic natural gas production and, to a lesser extent, a decrease in domestic

2. The remaining TPES came from stock changes during 2000.

peat consumption. Projections forecast that while peat production will continue to decline, indigenous natural gas production will increase as new domestic gas fields are brought on line. As a result, Ireland is expected to maintain its current import percentage levels through 2010 at roughly the same current levels. Figure 2 shows historical and projected domestic energy production by source.

FINAL ENERGY CONSUMPTION

In 2000, Ireland's total final consumption (TFC) was 11.1 Mtoe. From 1996 to 2000, TFC rose at an average annual rate of 5.9%. Forecasts predict that TFC will grow at a lesser but still robust average rate of 2.4% per year through 2010. In 2000, the road transport sector consumed the greatest share of TFC, accounting for 29.0% of the country's TFC. The industrial sector was the second-largest energy consumer with 23.6% of TFC, and the residential sector was third with 22.6%.

- Energy consumption in the transport sector increased dramatically in recent years with TFC rising by 9.8% annually from 1996 to 2000. Government forecasts predict that road transport's share of TFC will continue to rise, reaching 33.6% of Ireland's total energy consumption by 2010. This trend is consistent with the increase in car use resulting from the country's economic growth.

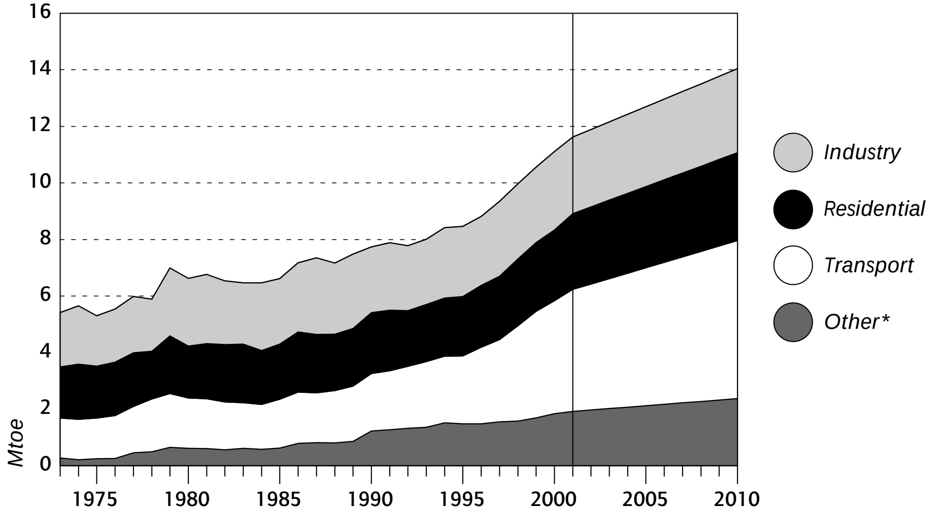
- While TFC in the industrial sector has grown in absolute terms in recent years, its share of the national total has fallen. From 1996 to 2000, industry's share of national TFC fell from 25.5% to 23.3%. The government expects this to fall further, reaching 21.1% by 2010. This decrease is a function of increased economic activity in the non energy-intensive fields of information technology, pharmaceuticals and services.

- In recent years, residential TFC has risen steadily in absolute terms but fallen slightly as a percentage of overall TFC. From 1996 to 2000, absolute residential TFC has grown by 3.4% annually. From 2000 to 2010, the government projects that TFC growth rates in the residential sector will roughly match overall TFC growth rates.

Final energy consumption is dominated by oil and oil products. In 2000, these fuels accounted for 64% of the country's TFC. Since 1990, this represents a rise in oil's share of TFC when oil accounted for only 54% of the nation's TFC. Over the next decade, oil as a percentage of TFC is expected to stay roughly the same, dropping slightly to 62% by 2010. This slow-down represents the conflicting effects of increased energy use in road transport and the phase-out of oil for use in home heating and industrial processes. End-user consumption of natural gas is expected to rise substantially over the next decade. In 2000, gas accounted for 14.3% of TFC, while in 2010, this figure is expected to rise to 17.0%. This rise only takes into account final consumption so would exclude gas use in power generation stations, which is also expected to rise over the next ten years.

Figure 3

Total Final Consumption by Sector, 1973 to 2010

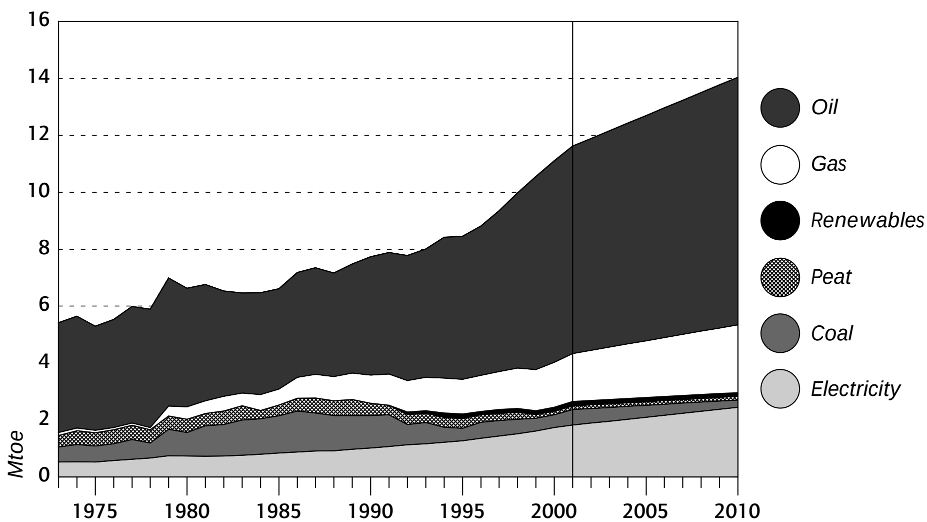


* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

Figure 4

Total Final Consumption by Source, 1973 to 2010



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

ENERGY FORECASTS

The government uses the energy and environment projections produced periodically by the Economic and Social Research Institute (ESRI), an independent research institute based in Dublin. A team at ESRI produces a medium-term review of the economy's prospects, covering the macroeconomy, industry, labour markets and overall demographic trends. This review also includes a chapter on energy and energy-related emissions. The most recent issue of the medium-term review appeared in September 2001 and covered the period up to 2015.

ESRI develops a number of scenarios for developments in the global and Irish economy, for example a high-growth scenario, a low-growth scenario and a central case. The ESRI draws a distinction between its shorter-term macroeconomic forecasts and the Medium-Term Review, which it sees as identifying possible alternative paths for the economy, rather than being a single firm forecast of the economy's future.

In preparing energy projections, ESRI consults with the main players in the energy sector, including the government, typically on the basis of a draft set of scenarios on which outside organisations are invited to comment. These scenarios may incorporate different assumptions about the policy context – for example, in the latest Medium-Term Review, there is a central case which is based on "business as usual" policy assumptions, while an alternative case assumes a more aggressive set of policies to reduce carbon emissions. Although the resulting projections are ESRI's alone and do not necessarily reflect the government's views, the government has found them a very valuable tool in energy and environment policy development.

GENERAL ENERGY POLICY

ENERGY POLICY OBJECTIVES

There are currently four main themes to Ireland's energy policy in order to achieve the government's "3 E's" of Energy Security, Environmental Protection, and Economic Growth.

- **Market reform and independent regulation:** The government is committed to the reform of its energy markets. Since the last in-depth review, progress has been made towards this goal, including a degree of market opening for gas and electricity consumers and the establishment of an independent regulator for the gas and electricity markets. The government has supported proposals at European Union level to create liberalised and integrated European energy markets.

- **Improving Ireland's energy infrastructure:** Rising energy demand and historically low levels of investment have created a need for increased investment in electricity generation, electricity transmission and natural gas networks. Investments are now under way in these areas.
- **Reform of the state-owned energy companies:** The Programme for Government agreed to in June 2002 states that the government will examine options for reforming the state-owned Electricity Supply Board (ESB), Bord Gáis Éireann (BGÉ) and Bord na Mona (BNM), which operate in the fields of electricity, natural gas and peat, respectively.
- **Sustainability:** High levels of economic growth, leading to strong growth in energy demand, have increased pressure on the environment. In particular, in 2000, GHG emissions were 24% above 1990 levels. As a result, significant emissions reductions will be required for Ireland to meet its Kyoto target of GHG emissions, that is 13% above the 1990 level by 2008-2012.

Energy security, which is another important theme in government energy policy debates, is receiving increased attention within the government. This issue, as well as the government position and activities in this area, are discussed further in the energy security section of this chapter.

Compliance with EU regulations and international agreements also plays an important role in Irish energy policy. For example, market reform in the electricity and natural gas sectors is being driven largely by the need to comply with the directive on internal markets. In addition, many Irish EU energy efficiency standards are taken from relevant EU regulations. Ireland also works with the IEA on oil stock arrangements and emergency preparedness.

Under the Electricity Regulation Act 1999, nuclear power cannot be used for the production of electricity in Ireland. There has never been any nuclear generation in Ireland.

ENERGY POLICY INSTITUTIONS

There are three main bodies responsible for the formulation and implementation of government energy policy: *i)* the Department of Communications, Marine and Natural Resources (DCMNR), *ii)* the independent Commission for Energy Regulation (CER), and *iii)* Sustainable Energy Ireland (SEI) which advises the government on energy and sustainability issues and delivers relevant RD&D programmes.

The Department of Communications, Marine and Natural Resources (DCMNR)

The Department of Communications, Marine and Natural Resources was formed in June 2002, as part of the reorganisation of government departments following the May 2002 general election. The former Department of Public Enterprise was split in two, with communications policy and energy policy forming part of the new DCMNR, and its transport responsibilities forming the core of the new Department of Transport. DCMNR has lead responsibility for all energy policy matters which previously belonged to the former Department of Public Enterprise. Five divisions report to the Director-General of Energy, covering the following areas:

- Electricity market policy, including legislation on electricity liberalisation and regulation.
- Gas market policy, including legislation on gas market liberalisation and regulation.
- The State's shareholder role in relation to the ESB, the state-owned electricity company.
- The State's shareholder role in relation to BGÉ, the state-owned natural gas company, and Bord na Mona, the state-owned peat company, together with oil security of supply policy.
- Energy policy co-ordination and sustainability, including renewables and the legislation and funding in relation to SEI.

DCMNR works closely with the Department of the Environment and Local Government (DoELG), which has lead responsibility for the government's environmental policy, including the Kyoto Protocol. All taxation matters including energy taxes are the responsibility of the Department of Finance, including representing the Irish government at Ecofin discussions on the development of the European energy tax directive.

Commission for Energy Regulation (CER)

The Commission for Electricity Regulation was established on 14 July 1999 under the provisions of the Electricity Regulation Act 1999. Following the passing of the Gas (Interim) (Regulation) Act 2002, the commission's jurisdiction has been expanded to that of energy regulator, incorporating both gas and electricity and has been renamed the Commission for Energy Regulation. The CER is legally independent in the performance of its functions. It is funded by means of a levy on energy undertakings and income from licensing fees and, as of Q1 2003, employed 38 staff. It engages in a wide-ranging consultation process on all aspects of the future direction of the electricity and gas industries. It is accountable for the performance of its functions to a Joint Committee of the Houses of Parliament and is subject to audit by the Comptroller and Auditor-General.

The CER authorises the construction of new plants and licenses companies to generate and supply electricity. It has a regulatory role in relation to the operation, maintenance and licensing of the transmission and distribution networks, as well as approving tariffs for third-party access to these systems. The CER also has the key responsibility for regulating prices charged to customers by ESB as Public Electricity Supplier (PES). However, the minister remains responsible for electricity market opening levels and the imposition of public service obligations.

The Gas (Interim) (Regulation) Act 2002 transferred the relevant gas regulatory powers from the Department of Public Enterprise to the CER. The act ensures a level playing field for public and private sector operators in the natural gas market and requires the CER to promote competition in the supply of natural gas.

Irish Energy Centre/Sustainable Energy Ireland

The Irish Energy Centre (IEC) was established in 1994 to promote the development of a sustainable energy economy. Under the Sustainable Energy Act 2002, it has now been renamed Sustainable Energy Ireland (SEI) and given an expanded role as the government's main agency for implementing its energy efficiency and renewable energy policies. The main functions of the SEI are:

- To promote environmentally and economically sustainable energy.
- To promote and assist energy efficiency and renewable sources of energy.
- To promote and assist the reduction of emissions associated with energy.
- To minimise the impact on the environment of the production, supply and use of energy.
- To promote and assist research, development and demonstration of technologies.

In September 2002, the Board of SEI approved and published a five-year strategy. Under the National Development Plan 2000-2006, a total funding allocation of €223 million, containing allowances for anticipated price inflation, has been made for SEI's programmes and operations. In turn, this funding has been allocated over the period of the National Development Plan to the following programmes: Research and Development (€72 million), Built Environment (€37 million), Renewable Energy/CHP (€67 million) and Other SEI Activities (€47 million).

ENERGY SECURITY

Ireland's modest domestic energy sources and its geographic distance from other countries make energy security an especially important issue. In February 2002, a statement was released by the Department of Public Enterprise in response to the European Commission's Green Paper: *Towards a European Strategy for the Security of Supply*, in which the government lays out its hopes and concerns for this issue from an Irish perspective.

The statement points out Ireland's "very limited indigenous energy resources" and its "relative geographical isolation with the [European] Community." It also points out the success its economy has had in recent years as the "most open" in the OECD and its belief that ensuring both secure and competitive energy supplies will be essential to maintaining such economic growth. The government advocates a three-pronged general approach to energy security. First, the EU internal market needs to be strengthened, including improved international links and more competitive energy markets. Second, links with exporting countries external to the EU need to be strengthened. And third, energy and environmental policy must be integrated so that attempts to achieve one or the other of these two related areas do not undermine the other. Ireland does not see nuclear energy contributing to long-term security of supply and is firmly opposed to nuclear energy.

NATURAL GAS

Import dependence on natural gas has risen substantially in recent years as increased domestic use has coincided with depletion of the country's largest domestic resource, the Kinsale field off the southern coast. Until 1993, gas demand was met entirely through domestic sources when small levels of imports were introduced. By 1996, imports had grown to 18% of the market and by 2000, imports supplied a full 72% of the market. Import dependency is now in the neighbourhood of 85%.

Future gas demand will, to a large extent, depend on its use in the power sector. In particular, Ireland's National Climate Change Strategy envisions the closure of the large coal-fired Moneypoint plant in 2008, replacing it with gas-fired generation. Under this scenario, natural gas could eventually provide 80% of the country's electricity needs. However, many energy industry participants in both the government and the private sector believe that such a level of dependence on gas could have serious implications for energy security, leaving the country vulnerable to supply disruption and/or rapid price increases.

Three new gas sources may help meet the country's near- and medium-term demand. The first source is the recently opened undersea gas interconnector between Ireland and the UK. This pipeline was brought on line in October 2002, being the second interconnector of this type running between the two countries. It was brought into commercial operation in January 2003 following the issuing of a consent to operate from CER. Irish gas demand is currently met by the combined supply of the first pipeline and domestic sources and, as a result, it is expected that the new pipeline will not be required until 2005. The other two promising sources of new gas supply are the Seven Heads and Corrib gas fields, which are being developed off the south and west coasts of the country, respectively.

ELECTRICITY

The electricity infrastructure has been strained in recent years by pronounced growth in demand. This strain has been seen in both the network (mostly transmission) and the generating plant. ESB, the national state-owned power company, is currently upgrading the transmission system, an extensive process expected to remove constraints and bottlenecks. The problem of adequate generating capacity is proving more difficult to solve. In both the winters of 2001 and 2002, ESB had to bring in temporary emergency power capacity to ensure that the country's electricity demand could be met. Two power plants, which came on line in 2002, have allowed ESB to forgo this practice for the time being, but they expect similar measures will be required in 2005, and possibly as soon as 2004, if no additional plant is brought on line by then. The ESB National Grid, operators of the country's transmission system, has projected[3] that without new additions, Ireland will likely face an estimated shortfall of 550 MW by 2007. This is equivalent to roughly 12% of the current installed capacity. The further implementation of demand-side management measures would reduce the need for new capacity.

This lag in generating plant investment, despite high demand, a shrinking reserve margin and projections of shortfalls, can be attributed to the transitionary period of market reform in which the country now finds itself. The mandate for providing sufficient generating capacity once lay firmly with ESB. However, ESB has agreed to lower its generation market share as a means of fostering competition in the industry and, as a result, it is not able to add new plant at this time. Independent power producers have been reluctant, as yet, to enter the market or in any way commit sufficient resources needed to add capacity. Such reluctance is fuelled by continuing uncertainties concerning the final shape of the liberalised market, the small size of the market, and the continued strength of the incumbent, among other factors. As a result, it is not yet clear who will build the capacity the country will soon need. (A more detailed analysis of this market reform process is included in Chapter 7.)

OIL AND OIL PRODUCTS

The Irish oil market is served by a number of multinational and domestic companies who source the majority of their products from abroad – mainly

3. *Generation Adequacy Report, 2003-2009*, ESB National Grid, November 2002.

from the UK – and from Whitegate, Ireland's only refinery. Rapid expansion of road transport in the past decade has dramatically increased the demand for oil products and the existing system has handled this increase without any difficulties. Since July 1995, responsibility for maintaining strategic stockholding has been vested in the National Oil Reserves Agency (NORA). Such stocks may be held directly by the agency or on its behalf by third parties. National stockholding policy is derived from both IEA obligations and EU requirements.

PEAT AND COAL

Peat and coal provide secure energy sources for Ireland. Peat is a domestically harvested product that, in 2000, provided the country with 5.5% of its TPES and 7.5% of its electricity. While Ireland has no domestic coal production, its continued import – mainly from the USA, Poland and the UK – is considered a secure supply source. In 2000, coal provided 12.7% of the country's TPES, and over 28% of its electricity generation.

ENERGY TAXATION

All energy taxation in Ireland takes place at the federal level and is the responsibility of the Department of Finance. Taxation levels are shown in Table 1 below.

Table 1

Irish Energy Taxation, Q2 2002

Fuel / User	*Excise Tax € / unit*	*VAT %*
Automotive Diesel	0.302 / litre	21
Automotive Diesel (haulers, taxis, etc.)	0.302 / litre	0
Premium Unleaded Gasoline	0.401 / litre	21
Light Fuel Oil / Industry	47.36 / 1000 litres	0
Light Fuel Oil / Households	47.36 / 1000 litres	12.5
High Sulphur Fuel Oil / Industry	13.64 / tonne	0
Electricity / Households	0	12.5
Electricity / Industry	0	0
Natural Gas / Households	0	12.5
Natural Gas / Industry	0	0
Steam Coal / Electricity Generation	0	0

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Ireland does not, at present, have any taxation policy explicitly intended to curb the emissions of GHG. Under the National Climate Change Strategy the government is committed to introducing an appropriate framework for greenhouse gas taxation from 2002 on a phased, incremental basis and in a manner that takes account of national objectives, particularly the maintenance of Ireland's international competitive position. In December 2002, the Department of Finance announced that, in order to cut GHG emissions, it would be imposing excise duties on fuel from the end of 2004. All such taxation measures are to be examined first under the aegis of the Green Tax Group and subsequently by the Tax Strategy Group (both chaired by the Department of Finance). The published programme of the new government specifically reiterates the commitment to implement greenhouse gas taxation policies on a phased and incremental basis. The programme further states that all such taxation must take account of national economic, social and environmental objectives.

At present, only mineral oils are covered by EU-wide minimum excise duties. The present Commission proposal for a Directive on Energy Taxation aims to increase these EU minimum rates and to introduce new rates of minimum taxation on previously untaxed energy products, including electricity, natural gas and coal. Discussion on the directive is ongoing but Ireland has already indicated its willingness to accept the broad thrust of the proposals which were established under the Spanish Presidency, although it recognises that a number of issues still remain to be settled.

Specific tax policies for automotive fuels and their implications are discussed in Chapter 6.

CRITIQUE

A number of commendable developments have taken place since the last IEA in-depth review. Ireland has initiated reform of both the electricity and natural gas markets. While work remains to be done in this process, considerable progress has already been achieved. The basic regulatory framework for both markets has been established and an independent regulatory body has been put in place. In addition, the country has expanded its international energy connections with the completion of a second undersea gas line with the United Kingdom. While the timing of the new line appears to be premature since it will not be required until at least 2005, it will eventually act to foster both energy security and greater competition. Both completed and planned expansion of energy interconnections with Northern Ireland will also improve the country's overall energy situation. In addition, in November 2000, Ireland published its National Climate Change Strategy (NCCS), providing a blueprint for the country to meet its challenging Kyoto GHG limits. The country has begun implementing the policies and measures contained therein, although much work remains to meet the emissions target.

The following four factors will be the primary forces shaping future Irish energy policy.

- **Energy security:** Energy security receives significant attention in Ireland. These concerns are fuelled in part by the country's lack of substantial domestic energy sources and consequent high level of imports. In 2000, only 15% of the country's energy came from indigenous sources. The country's relative isolation and lack of extensive international energy connections also raise energy security concerns.

- **Economic growth:** The country's economic development has increased energy demand, placing a strain on the existing infrastructure. While some of these concerns are being adequately addressed (*e.g.* electricity transmission and natural gas), others have yet to be satisfactorily resolved (*e.g.* the need for new power generating plant).

- **Greenhouse gas emissions reductions:** Ireland's commitment under the Kyoto Protocol creates real challenges. Without any climate change policies, Ireland would have GHG emissions that are more than 21% above its Kyoto target by 2010. The NCCS provides a framework for meeting the Kyoto goal; most actions prescribed therein will likely have important implications for the entire energy sector and the economy as a whole.

- **Market reform:** The reform of the electricity and natural gas markets prompted by the EU directives on the internal market is reshaping those markets. The country is now in a transitionary phase where players lack certainty over their roles and the rules that will ultimately govern the market.

Ireland is facing growing challenges trying to simultaneously accommodate these four factors which can often be contradictory and, at times, act to undermine one another. A typical example of such a conflict is the role that natural gas plays in terms of both climate change and energy security. While natural gas can reduce GHG emissions (especially when replacing coal- or peat-fired generation), very high levels of gas use raise energy security concerns. The NCCS projects that 80% of electricity will be generated by gas in 2010 if all policies and measures suggested in the strategy are implemented. Such a level of gas dependence could cause a security concern. While current and expected supply sources are sufficient to meet this demand, the lack of fuel diversity would place Ireland in a very precarious position should any gas supply problems emerge. It is important to note that Ireland's security regarding imported gas is only as good as that of the United Kingdom. UK fields are themselves depleting and the country is expected to become a net gas importer by 2005. High levels of gas (and oil) dependency can also imperil economic growth in times of rising oil prices, since gas prices are usually tied to oil prices. It is imperative to develop a long-term strategy for optimal energy supply mix by striking an appropriate balance between energy security and climate change mitigation.

Another example of competing forces is the relationship between economic growth, energy security in the electricity sector and market reform. Ireland's economic development has increased energy demand, placing a strain on the existing infrastructure. While some of these concerns are being adequately addressed (*e.g.* electricity transmission and natural gas transportation), others have yet to be satisfactorily resolved (*e.g.* the need for new power generating plant). This is closely tied to liberalisation. The transmission system remains under regulation and the necessary investments are being made to ensure its upkeep. By contrast, the transition to competition in the generation sector has created a gap between the regulated and the fully liberalised markets and, as a result, no companies have stepped forward to make the necessary investments in generating capacity. Potential private investors are deterred by the uncertainty of final market rules and the continuing dominance of the incumbent, ESB. No viable new power plant developments are under way and, given the long lead times for development and construction of such plants, it is becoming increasingly unlikely that such private generating stations can be in place by 2005 when the system is expected to require new capacity. Electricity market reform is discussed further in Chapter 7.

Capacity adequacy concerns can be divided into the near term and the long term. Long-term generation security must be addressed as the government formulates rules for the liberalised market. Rules must be established which motivate private independent companies to construct sufficient generating plant. The nearer-term situation is more serious. As noted, it appears that an adequate regulatory environment will not be in place in time to attract new generating plant which could meet the coming capacity shortfall. In that case, the incumbent, ESB, may end up building new plant for reasons of energy security. This would further expand ESB's market share and undermine the country's reform efforts. To avoid this, Ireland could instead offer temporary inducements for independent companies to add new capacity to the system. The simplest way to do this would be to tender for capacity during the times of expected shortfalls. This could be for as short as several months and would involve temporary installation of moveable plant. Other options include a short- to medium-term power contract or a form of capacity payment, both of which would apply to new plants built in Ireland. (These types of measures are discussed further in Chapter 7.) Inducements of this sort need to be kept temporary and carefully structured to ensure consistency with the long-term vision of a competitive market place. If properly designed, however, such inducements would attract new players into the market, reduce ESB's market share, and address the pressing generation energy security concern that threatens the country in the coming two to four years.

Peat and coal contribute significantly to Ireland's energy security and fuel supply diversity. While they both have drawbacks vis-à-vis GHG, their energy security benefits should always be taken into account when considering their role in the country's energy mix.

Given its relative geographic isolation and the absence of extensive domestic fossil fuel deposits, Ireland is to be commended for the efforts it has made so far in building international energy interconnections. In general, these interconnections act to: *i)* enhance energy security, and *ii)* promote liberalisation. The benefits that such interconnections bring to energy security are self-evident in that they provide an additional energy source on which to draw. The benefits to liberalisation come from the effective enlargement of the market, allowing more companies to enter and thus creating a more competitive market. These benefits should be fully taken into account when deciding on all international interconnections. The North-South connection with Northern Ireland and the new gas pipeline with the UK are examples of such interconnections. While there are significant costs involved with interconnections of this type, the benefits they bring to both energy security and successful liberalisation should be taken into account when deciding on new or enhanced connections. Electricity interconnections with Northern Ireland offer the best short-term opportunities because they can build on existing infrastructure and will be much less expensive than comparably sized underwater transmission lines.

Taxation of energy products can be used to reduce overall energy use and to shape energy consumption patterns, both of which would curb GHG emissions. While taxation is cited by the NCCS as one tool that could be used in the climate change strategy, no taxation has yet been implemented with the explicit goal of reducing emissions, despite the recent announcement that such taxation would be levied on fuels in 2004. Advocating for such taxes can be difficult in a political context and such taxes may not, in fact, be the preferred method for reducing GHG emissions. Nevertheless, a thorough discussion on the advantages and disadvantages of such taxes needs to take place to determine what role, if any, they will play in the climate change strategy. Issues to be resolved include the proper tax rates for each fuel and energy, whether or not to make the tax revenue-neutral (and, if so, how the money would be recycled to tax-payers) and how to deal with the fuel poor (who tend to use coal for home heating in a disproportionate amount) and energy-intensive industries. In dealing with the issue of the fuel poor, care should be taken so that social objectives would be pursued by means other than energy pricing and taxation.

RECOMMENDATIONS

The government of Ireland should:

- *Develop a long-term strategy for optimal energy supply mix striking an appropriate balance between energy security and climate change mitigation, noting a rapidly growing share of natural gas in the electricity sector.*

- *Promote international integration in the electricity and gas sectors to enhance energy security and competition, and facilitate integration with the single EU market.*
- *Continue to undertake energy supply-demand and CO_2 emissions projections, noting rapid growth in energy consumption and CO_2 emissions.*
- *Pursue social objectives by means other than energy policies, prices and taxation.*

ENERGY AND THE ENVIRONMENT

CLIMATE CHANGE

GREENHOUSE GAS EMISSIONS

According to the "Burden Sharing Agreement" among EU countries, Ireland has agreed to limit the net increase of its greenhouse gas emissions to 13% above 1990 levels by the target period 2008-2012. This would correspond to an allowed rise in emissions of 7.0 million tonnes of CO_2 equivalent (Mt CO_2-Eq) from the 1990 baseline emissions of 53.8 Mt CO_2-Eq. Ireland officially ratified the Kyoto Protocol in May 2002.

Against the 1990 base, greenhouse gas emissions had risen by 24% (14.5 Mt CO_2-Eq) by 2000 (with emissions believed to have grown since that time) and the National Climate Change Strategy (NCCS) estimates that on a business-as-usual basis, emissions would climb to 37.3% (20.1 Mt CO_2-Eq) above 1990 levels by 2010. Within the EU burden-sharing agreement, Ireland's allotted limit is 60.7 Mt CO_2-Eq. Against the business-as-usual projections, Ireland would need to reduce GHG emissions by just over 13 Mt CO_2-Eq, or nearly 18% compared to the business-as-usual scenario.

CO_2 accounted for 66% of the country's GHG emissions. While this makes CO_2 the largest single component of Irish GHG emissions, this percentage is below that of most other EU countries. This is explained by the relatively high level of emissions from the agricultural sector which, in 1990, accounted for 35% of all GHG emissions. This sector tends to produce nitrous oxide and methane in greater proportion than other sectors of the economy. In 1990, methane and nitrous oxide accounted for 19.3% and 14.7% of total emissions, respectively[4]. CO_2 emissions increased their share of total GHG from 1990 to 2000, rising in volume by 33.3% over that time compared to a 24% rise for GHG in total. CO_2's share of total GHG emissions is expected to grow over the next decade as both methane and nitrous oxide emissions are to be reduced.

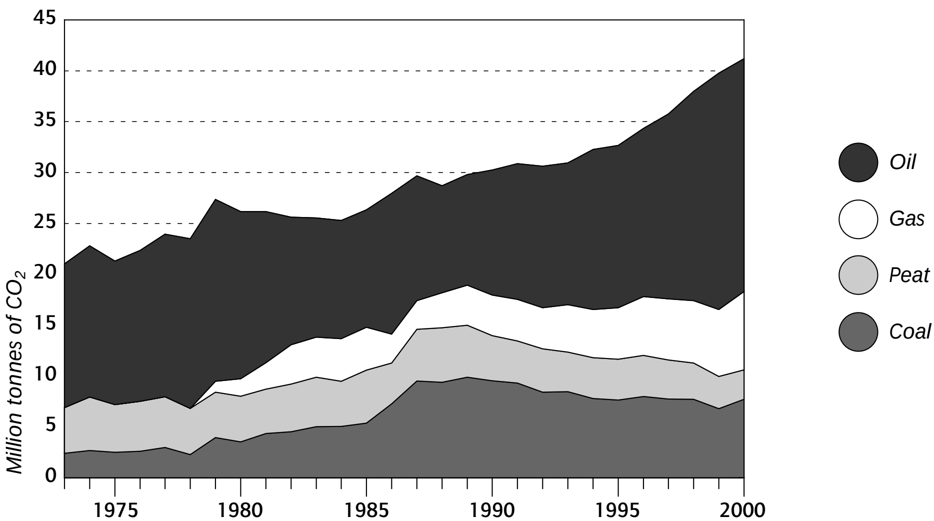
In 2000, oil accounted for 56% of total CO_2 emissions, followed by coal and peat with a combined 26% of emissions, and natural gas with 19%[5]. In recent years, coal and peat emissions have been declining steadily: in 1996

4. Data on GHG shares by gas are taken from the energy chapter of the Economic and Social Research Institute *Medium-Term Review*, published in September 2001.
5. Data on CO_2 emissions by sector and by fuel are taken from the IEA's *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2002.

emissions from these sources were 13% higher in absolute terms than they were in 2000. Emissions from natural gas and oil, on the other hand, have been steadily increasing. From 1996 to 2000, gas emissions have increased at an average annual rate of 7.4% and oil emissions have increased by 8.5% annually.

Figure 5

CO_2 Emissions by Fuel*, 1973 to 2000



* estimated using IPCC Sectoral Approach.
Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2002.

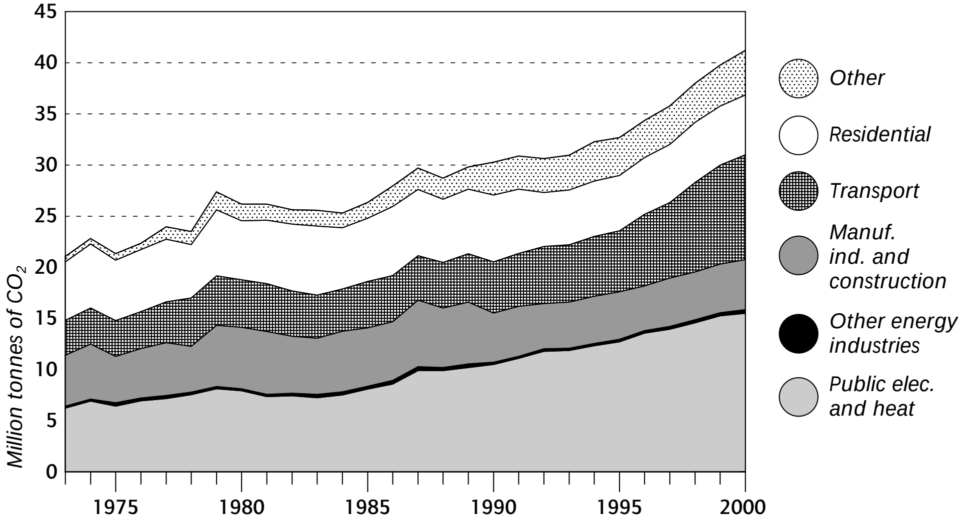
In 2000, the residential, transport and industrial sectors were the three largest emitters of CO_2, each one accounting for between 24% and 28% of total national emissions. By far the greatest growth in CO_2 emissions over the last decade has occurred in the transport sector. From 1990 to 2000, CO_2 emissions from transport grew by 103% with particularly pronounced growth coming between 1995 and 2000, when transport emissions grew at an average rate of 10.1% per year. By contrast, industrial sector emissions grew by just 28% from 1990 to 2000 and the emissions from homes and residences grew by just 8% over that time.

Projections of Irish GHG emissions have been carried out by two separate bodies: *i)* the Department of the Environment and Local Government (DoELG), and *ii)* the Economic and Social Research Institute (ESRI).

As part of Ireland's NCCS, the DoELG made two separate projections. First, it predicted that if no new policies were introduced in Ireland, GHG emissions

Figure 6

CO_2 Emissions by Sector*, 1973 to 2000



* estimated using IPCC Sectoral Approach.

Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2002.

would grow to 37.3% above the 1990 level by 2010. This was taken as a "business-as-usual" case. The DoELG also estimated the cumulative effects of the policy instruments proposed in the NCCS. This estimate did not come from a comprehensive computer modelling effort. It was projected that the combined effect of these measures would reduce GHG emissions by 15.4 Mt CO_2-Eq compared to the business-as-usual scenario, that is 2.4 Mt CO_2-Eq of emissions reduction more than would be required for Ireland to meet its Kyoto target.

The NCCS, published in 2000, sets out the government's plans for meeting its Kyoto commitments. The ESRI greenhouse gas projections are the basis of the NCCS, and despite the use of these projections, ESRI has not carried out a study which projects the actual amount of emissions reductions that would result from the NCCS policies and measures or the economic effect of such policies. ESRI has recently developed an energy model that has been integrated with its macroeconomic model. The resulting modelling framework now enables forecasts for energy and energy-related GHG emissions which are fully consistent with the underlying macroeconomic forecasts. This framework could be used to analyse the impact, on both the economy and on emissions, of a wide range of emissions reduction policies.

The ESRI GHG projections include two different scenarios. The first scenario is the Benchmark Forecast, which assumes a number of climate change policies intended to curb emissions. The Moneypoint plant (the nation's largest coal-fired power plant) is assumed to operate on half power from 2008, with the resulting electricity shortfall made up with gas-fired generation. From 2006, the existing peat stations are to be replaced with new, more efficient ones. Carbon sinks are assumed to contribute to GHG emissions mitigation and, by 2010, some 10% of electricity generated is assumed to come from renewable sources. With these assumptions, GHG emissions rise to 21.2% above 1990 levels by 2010. CO_2 still sees the largest growth of any GHG, with emissions growing by 52% from 1990 to 2010[6].

The second ESRI scenario is the Policy Action scenario, where existing gas-fired stations are expected to be phased out by 2015 and replaced with more efficient units. The two planned peat plants would not be built at all but replaced by new gas stations. These and other policy measures are assumed to increase electricity and other energy prices by 10%, which would lead to a corresponding 2% fall in energy use and related emissions. Under this scenario, in 2003, GHG emissions would peak at 20% above 1990 levels before declining thereafter. By 2008, emissions would be below the 13% growth threshold in the Kyoto Protocol. While actions taken under this scenario would allow Ireland to meet its Kyoto commitment, it would result in substantial costs to the economy. For example, it would require premature replacement of half of the country's generating capacity which ESRI estimates would cost between €1.2 billion and €2.6 billion. In addition, this scenario does not take into account the effects that the substantially higher energy prices would have on the economy in general (*e.g.* reduced disposable personal income and effects on international competitiveness), so the full effects of taking such actions are not completely measured.

CLIMATE CHANGE POLICIES

In November 2000, in order to ensure compliance with the Kyoto Protocol, the Minister for the Environment and Local Government published the government-approved National Climate Change Strategy (NCCS). The strategy sets out a ten-year framework to ensure Ireland meets its Kyoto target. The projected effect on all NCCS measures would be an emissions cut of 15.4 Mt CO_2-Eq against baseload scenarios by 2010.

The measures included in the NCCS would affect the entire energy sector and, to a lesser extent, the economy as a whole. Policy-makers are reluctant to jeopardise the country's economic success of the last ten years with unduly burdensome measures that focus solely on one or two sectors of the economy.

6. This includes CO_2 emitted because of energy consumption and CO_2 emitted as a result of industrial processes not directly related to energy production or consumption.

Nevertheless, both the electricity and natural gas sectors would be disproportionately influenced by these measures. In 2010, the NCCS estimates that 80% of all electricity would be gas-fired if all of the NCCS measures were to be implemented.

Cross-sectoral Measures

The NCCS includes both cross-sectoral measures and sector-specific measures. The two cross-sectoral measures, to be implemented as necessary in any or all of the emissions-producing sectors identified in the NCCS are: *i)* taxation and *ii)* international emissions trading. The NCCS advocates use of appropriate tax measures which target CO_2 emissions. It describes such taxes as a means of "ensuring equity between sectors in meeting Ireland's commitments" so that no one sector is unduly burdened. It further states that taxation will allow the government to best identify the least-cost approach to reducing emissions. These taxes were to have been introduced in 2002 on a phased, incremental basis and in a manner which takes account of national economic, social and environmental objectives.

As of Q4 2002, no such taxation had been implemented, although in December 2002 the Department of Finance announced that it would be imposing excise duties on fuel from the end of 2004. Issues relating to the implementation of carbon taxation include concern for the fuel poor, many of whom burn carbon-intensive coal for residential space heating. Other issues involve the wish not to unduly punish energy-intensive industries. Any type of carbon/climate change tax can be made revenue-neutral if recycled back to those companies paying it, but the means of recycling pose additional questions. Both the corporate income tax and the employer's liability tax are already low by OECD standards and may not offer sufficient revenue to cut as a means of offsetting any new climate taxes. The NCCS also expresses some concern that any new taxation would hurt the international competitiveness of Irish businesses. While tax harmonisation (which has been proposed in various ways on EU levels) provides one way to mitigate the international competitiveness aspects of such taxation, Ireland has traditionally been opposed to this.

Emissions trading, as envisioned by the NCCS, would occur both as part of the EU-wide emissions trading programme and with eligible countries not in the EU. Since the NCCS was drafted prior to formal agreement of emissions trading rules in the Kyoto Protocol, few details of any such programme appear in the original 2000 document. The Department of Environment currently envisions the entire power sector and the 65 to 70 industrial emitters (comprising around 70% of total industrial emissions) being involved in the emissions trading scheme. While both the NCCS and the Department of Environment strongly support a strategy that reduces emissions through domestic measures, both industry and ESB see trading as a way to meet the Kyoto commitments with minimal cost.

Sector-specific Measures

In the **energy sector**, the NCCS advocates measures which would support the discontinuation of coal use at Moneypoint by 2008 in a way that leads to fuel switching towards less carbon-intensive fuels. In addition, the NCCS seeks to expand the use of renewable energy, maximise CHP use and enhance the country's demand-side management programmes. These measures are expected to reduce emissions by 5.65 Mt CO_2-Eq by the first Kyoto target period when compared to the business-as-usual scenario.

In the **transport sector**, the NCCS suggests a number of fuel efficiency measures, including tax incentives favouring more efficient cars, fuel economy labelling for cars, and fuel switching and improved fuel efficiency for public transport and state-owned vehicles. It also encourages modal shift measures such as increased use of public transport through additional investment in the public transportation system. For transport-demand management, the NCCS advocates setting fuel taxes that would limit the rate of increase in overall fuel consumption, develop integrated traffic management and attempt to achieve higher residential densities. These measures are expected to reduce emissions by 2.67 Mt CO_2-Eq by the first Kyoto target period when compared to the business-as-usual scenario.

In the **industrial, commercial and services sector**, the NCCS relies extensively on market instruments such as targeted taxation and emissions trading. It also proposes the use of negotiated agreements. Under such agreements, emitters would reduce emissions by a certain amount although they would be free to do so in any manner they saw fit. This approach is much preferred by the companies themselves since taxation is viewed as prohibitively expensive and the costs of emissions trading (*i.e.* buying allowances on the international market) remain uncertain. In 2001, a sub-group of the Climate Change Team was established to co-ordinate work on developing and implementing these agreements. The team included representatives of DoELG, SEI and the Environmental Protection Agency (EPA), and three enterprise development agencies: Forfás, IDA Ireland and Enterprise Ireland. Its consideration of negotiated agreements has been undertaken with regard to interactions with other policy instruments such as taxation, emissions trading and JI/CDM. Following studies on these issues, SEI is leading a pilot project exploring the process of establishing three types of negotiated agreement, scheduled for completion in mid-2003.

Access to negotiated agreements is being targeted at those companies for which energy is recognised as a relatively significant factor in cost competitiveness, whether in terms of volume or intensity of consumption. The structure of Irish industry is such that less than 200 companies are estimated to account for over 50% of energy-related CO_2 emissions from industry as a whole. These companies are drawn from several sectors, including food & drink, pharmaceuticals & chemicals, electronics & engineering, and mineral resources processing. The three types of agreements being addressed in SEI's pilot project are: *i)* individual, for very large energy users; *ii)* group or sectoral, for clusters of companies; and *iii)* horizontal or technology-based agreements. The latter may have the potential to mobilise engagement of the smaller-scale or less-intensive energy users in an efficient and equitable manner.

Measures in this category are expected to reduce emissions by 2.175 Mt CO_2-Eq by the first Kyoto target period when compared to the business-as-usual scenario.

Measures in the **agriculture sector** concentrate on reduction of methane emissions from the national herd. The sector's major energy-related measure is the development of short-rotation biomass and anaerobic digestion of animal wastes for energy generation. The **forestry sector** measures largely involve sequestration through afforestation. Combined measures in these two sectors are expected to reduce emissions by 4.02 Mt CO_2-Eq by the first Kyoto target period when compared to the business-as-usual scenario.

In the **commercial and residential sector** (*i.e.* built environment), the NCCS proposes improved spatial and energy use planning and increased energy efficiency of buildings. Efficiency of new buildings will be encouraged by building regulations which seek to reduce energy use by 20% in 2002 with further reductions in 2005 and by the adjustment of the New House Grant that ensures that minimum levels of energy efficiency standards are met. Efficiency in existing buildings was encouraged through education and awareness programmes, changing the fuel mix in households, and the development of energy efficiency ratings for households. These measures are expected to reduce emissions by 0.9 Mt CO_2-Eq by the first Kyoto target period when compared to the business-as-usual scenario.

Table 2 provides a summary of measures by sector with the expected reduction in GHG emissions by 2010 when compared to the business-as-usual projection.

Implementation of the Strategy

A cross-departmental Climate Change Team, chaired by the DoELG, oversees the implementation of the NCCS. The team undertakes widespread consultation on actual implementation arrangements. It is developing indicators to measure implementation at sectoral and national levels. The team will also look at the costs and benefits of implementing specific measures. The NCCS is subject to a formal biennial review, and the team was to undertake the first such review late in 2002.

Local authorities have been identified in the NCCS as having an important role at the local level, including in partnership with local energy agencies. Local authorities are encouraged to adopt best international practice as developed through international networks, and to develop appropriate performance indicators in their progress in reducing emissions.

Table 2

Indicative CO_2 Reductions from NCCS Measures

Sector / Measure	*Reduction Potential (Mt CO_2-Eq / annum)*
Energy Sector	**5.65**
Fuel Switching	4.15
Of which: Moneypoint	*3.4*
Oil	*0.75*
CHP	0.25
Renewables	1.0
Efficiencies	0.1
Demand-side Management (DSM)	0.15
Transport Sector	**2.67**
Vehicle Efficiency	0.77
Fuel Measures	0.9
Vehicle Taxation	0.5
Labelling	0.1
Public Transportation	0.15
Traffic Management	0.2
Freight	0.05
Built Environment & Residential Sector	**0.9**
Building Regulation Standards	0.25
Existing Buildings	0.4
Fuel Mix	0.25
Industry, Commercial, Services Sector	**2.175**
"No Regrets" / Low-cost Energy Efficiency Gains	0.75
CO_2 Efficiency Measures	0.25
Process Substitution for Cement	0.5
Industrial Gases	0.5
Commercial and Services	0.175
Agriculture Sector	**2.41**
Reduction of CH_4 from National Herd	1.2
Fertiliser Use	0.9
On-Farm Forestry Sequestration	0.25
Manure Management	0.06
Sinks	**0.76**
Waste	**0.85**
Overall Total	**15.415**

Source: National Climate Change Strategy.

Progress to Date

A ***Progress Report on Implementation of the National Climate Change Strategy*** was published in May 2002, in conjunction with Ireland's ratification of the Kyoto Protocol. The report charts the first year of progress under the NCCS, and identifies major climate change policy developments. The report indicates that measures currently under way have the potential to reduce annual emissions by over 3 million tonnes of CO_2 equivalent (Mt CO_2-Eq), an amount equal to approximately 20% of the over 15 Mt CO_2-Eq identified in the NCCS. The report has found that the cross-sectoral measures identified in the NCSS (*i.e.* taxation and emissions trading) are taking longer to develop than certain sector-specific measures.

Policies are being implemented in all sectors. Examples of the major policies and their impact include:

- Ongoing support of renewable energy through the Alternative Energy Requirement (AER)[7]. The fifth AER auction resulted in long-term power purchase agreements at above-market rates being offered to 370 MW of renewable energy. This is expected to achieve a CO_2 emissions reduction of 760 000 tonnes per annum, if compared to coal-fired electricity generation.

- The granting of a foreshore lease for the first offshore windfarm on the Arklow Bank in the Irish Sea. This project is being developed in stages, with full capacity expected to reach 520 MW. Its full completion would result in an emissions reduction of 1.1 Mt CO_2-Eq per annum, if compared to coal-fired electricity generation.

- Full market access has been granted to all electricity produced from CHP plants or from renewable sources.

- Regulations, in place since August 2001, require all new passenger cars for sale to be individually labelled with fuel economy and CO_2 emissions information. This is expected to yield emissions reduction of 380 000 tonnes of CO_2 per annum by 2010.

- Regulations have been made revising Part L of the National Building Regulations, relating to the conservation of fuel and energy bringing forward the operative date for improved standards from 2005 to January 2003. A reduction of 300 000 tonnes of CO_2 per annum by 2012 is anticipated.

- The Dublin Transportation Office (DTO) was provided, in 2002, with approximately €40 million in respect of traffic management grants, an increase of almost 20% on the previous year's provision. Overall,

7. The AERs are competitions whereby selected renewable energy generators bid on long-term power purchase agreements. They are discussed in greater length in Chapter 8.

implementation of the DTO strategy for the greater Dublin area "A Platform for Change" will reduce emissions by over 1 Mt of CO_2 per annum by 2016, which is a 41% reduction from projected emissions.

OTHER ENVIRONMENTAL ISSUES

AIR QUALITY ISSUES – POLICY DEVELOPMENTS/ INVENTORIES

In 1999, the Environmental Protection Agency (EPA) was designated as the competent authority for implementation of Framework Directive 96/62/EC on ambient air quality assessment and management. The agency is also responsible for maintaining national emission inventories. In August 2000, the agency published a National Air Quality Monitoring Programme discussion document and in May 2001, completed a preliminary assessment of national air quality.

AIR QUALITY STANDARDS REGULATIONS

On 5 June 2002, new regulations were made entitled *Air Quality Standards Regulations 2002* (S.I. No. 271 of 2002). The regulations transpose into Irish law the European Union Directive 1999/30/EC relating to limit values for the pollutants sulphur dioxide, nitrogen dioxide and oxides of nitrogen, particulate matter and lead in ambient air, and Directive 2000/69/EC relating to limit values for benzene and carbon monoxide in ambient air, and those parts of Directive 96/62/EC on ambient air quality assessment and management not transposed by the Environmental Protection Agency Act 1992 (Ambient Air Quality Assessment and Management) Regulations 1999 (S.I. No. 33 of 1999).

The regulations specify limit values in ambient air for 6 pollutants (SO_2, NO_2 and NO_x, PM_{10}, lead, benzene and CO) to come into effect from 1 January 2005 for all except NO_2, NO_x, benzene and PM_{10} (Stage II), for which the effective date is 1 January 2010. Alert thresholds for SO_2 and NO_2 are specified. In addition, the regulations provide for advice by the agency to local authorities about the need for air quality management plans where the limit values, plus margins of tolerance, will, or may be, exceeded and the preparation of such plans by local authorities. Provision is also made for air pollution action plans for short-term risks of excessive limit values and alert thresholds. The regulations also provide for public information procedures, including where specified public alert thresholds are exceeded, to deal with incidences where there is a risk to human health from brief exposure of SO_2 and NO_2.

In December 1999, Ireland signed the UNECE Protocol to the 1979 Convention on Long-Range Transboundary Air Pollution to Abate Acidification, Eutrophication and Ground Level Ozone. The objective of the protocol is to control and reduce emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs) and ammonia (NH_3). These pollutants cause adverse effects on human health, natural ecosystems, materials and crops by acidification, eutrophication and ground level ozone, and all are transported for long distances. EU Directive 2001/81/EC sets the same ceilings for Ireland as the UNECE Protocol. To achieve the protocol objective, Ireland will, by 2010, have to meet national emission ceilings of 42 000 tonnes (42 kT) for SO_2 (76% below 1990 levels), 65 kT for NO_x (43% reduction), 55 kT for VOCs (72% reduction) and 116 kT for NH_3. Meeting these requirements will be challenging, particularly in the light of Ireland's economic growth and increasing transport emissions.

CRITIQUE

Ireland's Kyoto commitments represent a serious challenge. The country has already increased emissions beyond their allowed growth in accordance with the EU burden-sharing agreement, and must now reduce its GHG emissions by 11% from the 2001 levels by the first Kyoto target period of 2008-2012. This would require reversing the trend from 1990 to 2000 when emissions grew at an average rate of 2.2% per annum, driven largely by the country's pronounced economic growth over that period. In addition, despite the implementation of some climate change measures, there is every indication that emissions have continued to grow in 2002. Consequently, Ireland has a shorter time period to reduce emissions even further.

In order to meet the Kyoto target, Ireland formulated the National Climate Change Strategy (NCCS) in November 2000 identifying a range of sectoral and cross-sectoral measures. While this is a commendable development, several issues should be taken into account in implementing the NCCS.

GHG emissions projections are the starting point in assessing the efficacy and implications of different climate change measures. However, projections made by the DoELG and those made by ESRI do not appear entirely consistent. While ESRI provides many of the energy and emissions projections used to inform government energy policy, it has not made a full forecast which includes the policies and measures proposed in the NCCS. Such a forecast could elucidate the effectiveness of the different climate change tools and, using the modelling framework recently developed at ESRI, could provide a better understanding of the costs that would be incurred by the economy as a whole and by individual sectors.

The division of emissions reduction by sector which is included in the NCCS was not informed by extensive comparative cost analysis of measures in the different sectors. Such initial cost analysis was performed, but the decision was largely informed by political considerations of the involved parties and a desire for equitable burden-sharing among sectors. Cost analysis of this sort can be very difficult to realise as the country had relatively little practical experience with these measures at the time the NCCS was developed. The NCCS recognises the benefits of such cost analysis and recommends that a full quantification of the costs and benefits at a sectoral level be undertaken. This has not yet occurred. A regular assessment of the costs incurred for each of the implemented measures will allow Ireland to reduce the overall economic burden of reducing its GHG emissions.

Measures taken to meet the country's Kyoto limits are heavily influenced by the country's geography and natural resource portfolio. Because of Ireland's relative isolation and the consequent lack of extensive energy interconnections, energy security concerns must be weighed in any climate change decision. In the NCCS, 22% of GHG emissions reduction is expected to come from the closure of the Moneypoint coal-fired generating station with capacity replacement in the form of gas-fired combined cycle gas turbine (CCGT) plants. This will raise the share of gas in the power sector to 80% by 2010, which raises very serious energy security concerns and leaves the country vulnerable to price shocks and/or supply disruptions.

The government considers that in an electricity market moving to full liberalisation in 2005, decisions regarding ESB power station closures and investment are a matter for the board of the ESB. The government is aware that the introduction of a carbon tax, or other measures like emissions trading as currently envisioned in the EC directive, could effectively make the continued operation of Moneypoint unprofitable. However, the closure of Moneypoint has serious implications for security of energy supply and fuel diversity in the power generation sector and therefore the government is likely to be closely involved in discussions regarding its future. While the NCCS does not propose Moneypoint closure until 2008, a quick resolution of this issue will be important for Ireland. Delaying the decision on Moneypoint will only make the situation more difficult. If the plant is to be closed, significant new electricity capacity will need to come on line to replace it. This will take significant time and involve substantial expenditures on capital equipment, costs that will eventually be borne by the consumer. If the plant is not to be closed, the country will have to either find other areas in which to reduce emissions or buy GHG allowances from other Kyoto Protocol Parties. In any event, all relevant government departments and agencies are encouraged to work closely together so that any energy security consequences from emissions reduction measures are fully addressed.

The difficult trade-offs faced in the Moneypoint decision may suggest that a disproportionate burden in achieving the Kyoto target is being placed on the power sector. A comprehensive approach covering both energy and non-energy sectors is essential to reducing emissions with minimal costs to the country as a whole. Energy security concerns resulting from the possible 80% dependence on natural gas in the power sector must be a factor in all such assessments. In order to achieve the Kyoto target without negative consequences for energy security, a full range of GHG mitigation measures should be explored both in energy and non-energy sectors.

The NCCS makes the cross-sectoral measures of taxation and Kyoto flexible mechanisms (emissions trading, JI and CDM) important parts of the overall climate strategy. However, it is not entirely clear how these measures will fit into the individually defined sectors. The cross-sectoral measures are mentioned in the context of individual sectors, but the exact manner in which they would be applied is not explored. Nor is it clear what percentage of emissions reductions can be expected from these two measures. Further clarification on the extent and manner in which these tools are to be applied across the various sectors will be the first step in applying them effectively. Defining the exact contribution from carbon taxation will be particularly important given the domestic challenges Ireland will face in implementing this policy. Contributions from emissions trading will be determined to a large extent by the final shape of the EC directive establishing an emissions trading regime for the EU member States.

Tax measures were to have been implemented by 2002, but nothing has, so far, been done on this front. While taxes as a tool to reduce emissions have both advantages and disadvantages, the fact that this issue has not been resolved by the time stated in the NCCS is not encouraging. The Department of Finance's intention to introduce a climate-driven excise tax on fuels by 2004 may be the beginning of more widespread taxation. However, there is very little indication as to what the parameters of such additional taxation would be. The many auxiliary issues such as the extent and means of revenue recycling and how to deal with international competitiveness are by no means resolved. Continued debate on the many issues bearing on such taxation should continue but only towards the goal of a timely decision.

Companies' use of voluntary agreements to reduce GHG emissions is practical, especially given the unwillingness, as yet, in enacting taxation as a means of curbing emissions. Lessons should be drawn from the ongoing pilot programmes so that the effectiveness of this instrument can be quickly assessed. It will also be important to determine how, if at all, such negotiated agreements would work in concert with taxation introduced to curb GHG emissions. For example, some tax exemption may be considered for those industries which work out negotiated agreements with the government. The use of voluntary agreements in the context of emissions trading in the EU will also need to be determined. According to existing plans for the EU emissions trading system, countries may choose to exempt certain industry segments from 2005-2007, but all eligible sources should be included by 2008. All voluntary agreements should take this into account so that companies participating in such contracts will also benefit from the emissions trading system.

RECOMMENDATIONS

The government of Ireland should:

- *Undertake energy and emissions projection and analyses which include the NCCS policies and measures.*
- *Monitor and evaluate the cost-effectiveness of policies and measures in the NCCS and update it as required to achieve the Kyoto targets in the most cost-effective manner.*
- *Ensure that greenhouse gas mitigation measures cover all energy and non-energy sectors and reflect externalities for each source.*
- *Clarify the use and role of CO_2 taxation, emissions trading, CDM and JI in the NCCS.*
- *Develop, with close co-operation among relevant departments, an effective framework for negotiated agreements and appropriate monitoring/reporting mechanisms based on experiences gained from pilot agreements.*
- *For the industrial and power generation sectors, clarify the interrelation among negotiated agreements, greenhouse gas taxation and emissions trading, especially in light of the proposed EC directive on emissions trading.*

END-USE EFFICIENCY TRENDS AND OBJECTIVES

In 2000, Irish energy intensity, as measured by a ratio of the country's TPES (in toe) over its national GDP (in thousands US$ PPP), was 0.14 toe/1 000 US$. This was more than 20% below the average of all IEA European countries who had an average energy intensity of 0.18 toe/ 1 000 US$. The relatively mild winters and summers in Ireland act to lower the country's overall energy intensity.

Irish energy intensity has improved dramatically over the last ten years. In 1989, the country's energy intensity was equal to that of IEA European countries as a whole (0.203 toe/US$), but since then, fell to less than two-thirds of that value, while the average IEA European country improved its efficiency by only 12%. This improvement is due to two factors. The first is a change in the Irish economy which has seen tremendous growth in non-energy intensive activity such as pharmaceuticals, services and information technology. The energy-intensive industrial companies have seen their relative contribution to the economy decline. The second factor is the more efficient use of energy. SEI estimates that one-third of the improvement in energy intensity over the last decade comes from structural changes in the economy and two-thirds come from more efficient energy use.

Figures 7 and 8 compare Irish energy intensity with that of other IEA countries over an historical and projected timeframe.

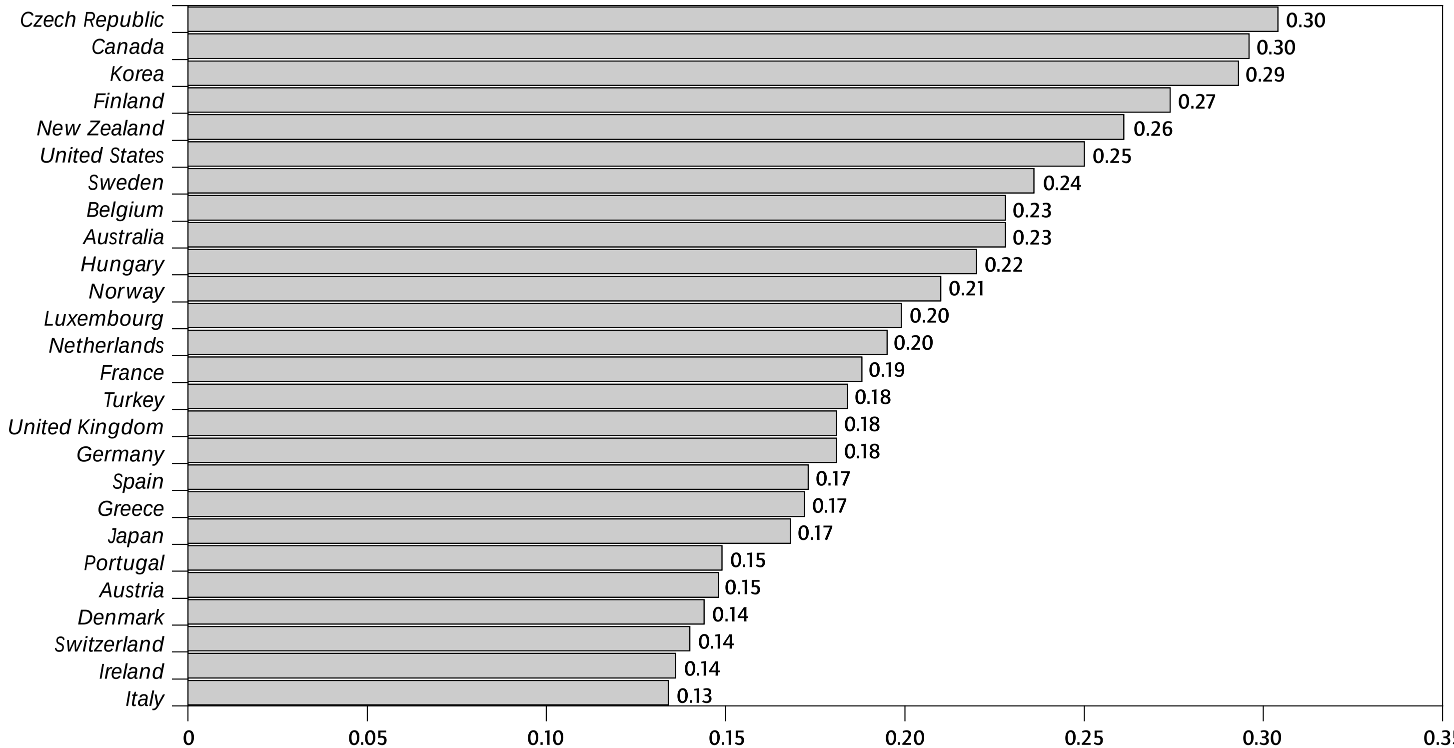
Analysis of the energy intensity by sector[8] shows a pronounced decrease in the industrial sector. In 1994, energy intensity in the industrial sector was 0.042, while in 2000, it had dropped by nearly 40% to 0.026. This large drop resulted from the relative growth of low energy-use industries, as noted above. Energy intensity in the residential sector fell by approximately 30% over the same period. Transport sector energy intensity has remained almost level from 1990 to 2000. The constancy of the transport energy intensity demonstrates that the growth in the number of vehicles and miles driven has kept pace with the growth in the national GDP. Figure 8 shows energy intensity by sector for Ireland, other relevant countries, and the IEA European average.

8. Energy intensity by sector is calculated as the end-use energy consumed by a given sector over the total national GDP.

Figure 7

Energy Intensity in IEA Countries, 2001*

(toe per thousand US$ at 1995 prices and purchasing power parities)



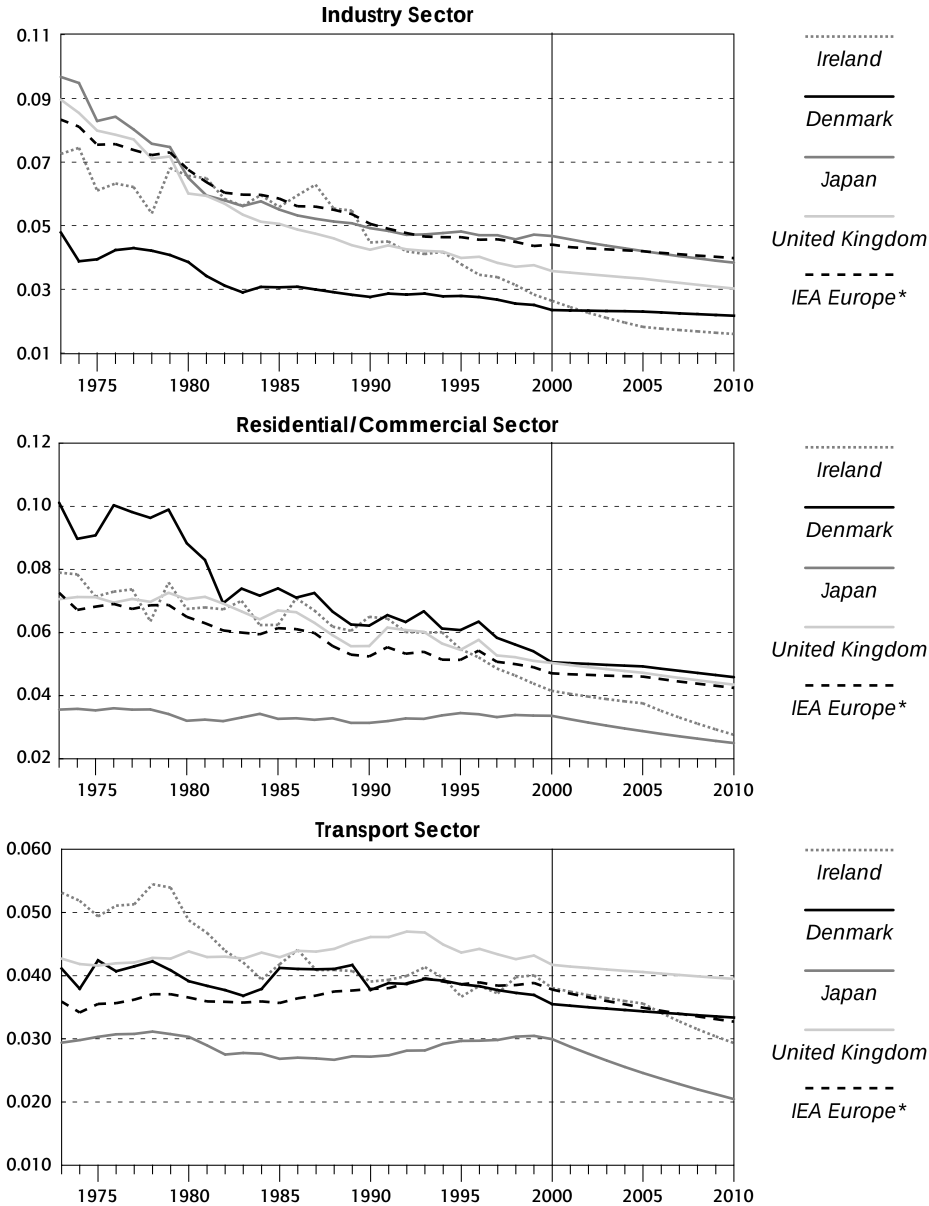
* preliminary data.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and *National Accounts of OECD Countries*, OECD Paris, 2002.

Figure 8

Energy Intensity by Sector in Ireland and in Other Selected IEA Countries, 1973 to 2010

(toe per thousand US$ at 1995 prices and purchasing power parities)



* excluding Norway from 2001 to 2010.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; *National Accounts of OECD Countries*, OECD Paris, 2002; and country submissions.

COMBINED HEAT AND POWER (CHP)

In 2000, Ireland generated 2.4% of its electricity from CHP facilities, the second lowest level of any EU country. According to the European Commission, in 2000, the EU average was 9.8% with some countries such as Denmark (61.6%) and the Netherlands (48.2%) generating considerably more power from CHP plants. The absence of local energy companies, the climate and historically low levels of natural gas use all combined to limit the use of CHP in Ireland.

Much of the current Irish CHP capacity was installed in the 1990s. Government policy to promote CHP at that time led to the doubling of installed capacity in the decade. This was stimulated primarily by the incentives under the AER scheme and the Irish Energy Centre's (now SEI) Energy Efficiency Investment Support Scheme. The increasing availability of natural gas, particularly in the south and east of the country, further assisted CHP growth with virtually all the capacity installed during this period being based on natural gas. At the end of 2000, installed CHP capacity was 122 MW.

CHP growth during the 1990s has come to a virtual halt. This is due, in part, to changing market conditions and increased risks to investment. Specifically, the price of gas has risen while at the same time the price of electricity from competing conventional electricity generating plants has been effectively capped. Recent increases in ESB Public Electricity Supplier tariffs should improve the economics of CHP in the short term.

Ongoing challenges to CHP in Ireland include:

- The absence of any heat distribution infrastructure (and the absence of a discrete commercial market for heat).
- The limitations of the existing gas grid.
- Difficulties in financing CHP/district heating (DH) developments.
- Low population density.
- The limited number of continuously operated heavy industries with power and heat loads suited to CHP.

The NCCS advocates increased use of CHP. By 2010, the strategy allocates a saving of 0.25 Mt CO_2 per year from the use of CHP. This equates approximately to the installation of an additional 250 MWe of CHP plant, a tripling of current capacity. It is the intention to maximise the generation of electricity from CHP where the environmental gains can be fully demonstrated.

In the Green Paper on Sustainable Energy, SEI was given the task of producing a report for both the Minister of DCMNR and the Commission for Energy

Regulation on the future potential of CHP in Ireland in the light of market liberalisation, technology advances, fuel sources, extension of gas grid and financial incentives. This report *CHP in Ireland – An Examination of the Future Potential of CHP in Ireland,* was presented to the Minister in December 2001. The report included an environmental assessment of CHP and an appraisal of the economic advantages and disadvantages of CHP in liberalised energy markets. It also highlighted constraints to further CHP deployment in Ireland, many of which stem from the fact that the legal, administrative, financing and planning infrastructure is designed for large, centralised energy supply rather than for distributed generation such as CHP.

In October 2002, SEI published a further report entitled *CHP and District Heating Research, Development & Demonstration – Programme Strategy*. This report lays out a number of ways in which the government will support CHP. Total planned expenditure for SEI's programme for CHP in the period 2001 to 2006 is €5.08 million. Planned activities include:

- Study on the potential of District Heating.
- Feasibility Studies / Pilot Programmes for Innovative CHP Projects.
- Consulting with the regulator and the government to ensure that legislation and regulation do not impede CHP deployment.
- In addition, SEI will dispense funds to research, development and demonstration projects.

Other developments in the field of CHP include:

- Section 9 of the Electricity (Supply) (Amendment) Act 2001 opened the CHP market to all customers irrespective of their level of annual consumption. This means that any electricity consumer may now purchase electricity from a licensed CHP supplier.
- Aughinish Alumina, an alumina manufacturing company, has announced plans to build a 140 MW power plant at its site in Co. Limerick. The CHP plant will cost €100 million and is due to be operational by 2005.

ENERGY EFFICIENCY INSTITUTIONS AND INSTRUMENTS

GENERAL ENERGY EFFICIENCY POLICY

The Green Paper on Sustainable Energy establishes a new framework for energy efficiency and sets out policies considered appropriate for Irish circumstances. It highlights the measures necessary to promote energy efficiency in all energy-consuming sectors. It applies a systematic and comprehensive approach, incorporating considerations of scope for improvements in energy efficiency, cost-effectiveness, technical feasibility and environmental impact. Energy efficiency policy in Ireland is also informed by EU policy, particularly the EU Action Plan on Energy Efficiency and the Green Paper on Security of Energy Supply. The SAVE (Specific Actions for Vigorous Energy Efficiency) programme of the European Union is a major component of the country's energy efficiency policy.

INDUSTRIAL ENERGY EFFICIENCY AND CONSERVATION POLICIES

The industrial sector's total annual energy (fuel and electricity) expenditure is estimated at €700 million, of which over €240 million (35%) is for 80 large industrial sites with a further 1 200 sites having an estimated €200 million energy expenditure. For the majority of industrial customers, energy costs as a percentage of total expenditures are relatively low. For example, 95% of medium-sized companies spend less than 2% of their total expenditures on energy. SEI has identified a range of measures for achieving energy efficiency gains within the industrial sector.

Industry Agreements

A key programme relates to Industry Agreements. With a budget of €6 million for 2001-2006, the Industry Agreement programme has two main objectives. The first is to develop support networks with self-audit schemes and the preparation of negotiated agreements. The second objective is to expand the existing benchmark system.

Large Industry Energy Network

The Large Industry Energy Network is a programme designed to help energy-intensive industrial companies achieve greater energy efficiency and reduce energy costs and associated emissions. Established in 1994 and run by SEI, the programme is a voluntary agreement system which provides a structured framework for energy auditing (performance reporting and target setting), technology evaluation, and a networking environment conducive to members learning from one another.

The network has a membership of 80 company sites, which together account for over one-third of energy use in the industrial sector. This equates to a total energy expenditure in 2000 of approximately €240 million. In 2001, the network resulted in a CO_2 reduction of more than 120 000 tonnes, representing a cumulative energy saving of €16 million.

Annual Boiler Awards

The Annual Boiler Awards competition, organised by SEI, was first launched in 1996. A precursor to the awards element of the scheme is the provision of site inspections and energy-saving advice. Since its inception, the competition has achieved savings of over €25 million in some 180 participating companies, primarily by recognising and rewarding innovation and best practice in the implementation of energy-efficient boiler technology. The competition is now also being run in the power sector. In 2001, the total energy bill targeted in this sector by the competition amounted to €411 million, with savings of over €7.36 million.

TRANSPORT ENERGY EFFICIENCY AND OTHER TRANSPORT-RELATED POLICIES AND PROGRAMMES

There are a number of key sustainability issues in Irish transport, including increasing volumes of road traffic and congestion, harmful emissions, sustainable land use and the growth trend in energy consumption. Modal shift from private to public transport is an important facet of Ireland's approach to reducing greenhouse gas emissions. Measures taken to encourage this shift include increased investment in public transport and an increased focus on demand management.

The government's transport strategy for 2000–2016 for the Greater Dublin Area, *A Platform for Change*, published in November 2001, aims to reduce growth in the demand for transport, particularly for private transport, and to reduce the need for car commuting by improving the reliability, availability and quality of public transport. The strategy is based on the two interdependent elements of demand management and public transport infrastructure/service improvements. It will also be reinforced by complementary land use policies.

Demand management measures will be supported by substantial integration and expansion of the public transport network, including the improvement of the existing suburban rail network, the development of an on-street light rail network (LUAS), and the development of a higher capacity segregated light rail network (METRO). The bus network will also be greatly expanded.

A study is under way which will recommend key potential demand management measures under the following categories:

- Land Use Policies – advice on the location, scale and mix of development; parking standards; appropriate development layout and densities, sustainable travel catchment areas.

- Economic/Fiscal Instruments – including vehicle and fuel charges; public transport fares; road pricing/congestion charging; road tolling; parking charges, including workplace parking.

- Management and control of public parking.

- Mobility Management Plans: IT-related measures and reorganisation of work practices.

- Additional traffic management measures.

The transport strategy has been developed in conjunction with the Strategic Planning Guidelines for the Greater Dublin Area (1999). Further integration of strategic land use planning with transport planning and demand management will be achieved under the forthcoming National Spatial Strategy which will provide the framework for integrated regional and local planning.

Ongoing high levels of investment aim to bring the national road network to an acceptable standard by 2006. This will be accomplished as part of an integrated transport policy, facilitating continued economic growth and regional development while ensuring a high level of environmental protection. While continued work on eliminating bottlenecks can reduce energy consumption and improve air quality, such benefits are to be weighed against the induced travel demand that can result if the transportation system makes driving easier and/or more convenient.

The National Climate Change Strategy (2000) provides for a number of further economic instruments to promote improved efficiency in the transport sector. Proposed measures include: *i)* fuel efficiency measures, *ii)* modal shift measures, and *iii)* overall demand management.

Regulations operative from August 2001 require all new passenger cars offered for sale to be labelled with fuel economy and CO_2 emissions information. A free public information guide has been published by the Society of the Irish Motor Industry comparing the fuel efficiency and CO_2 emissions of all new car makes and models. The impact of this measure is estimated to produce a 4% to 5% reduction in fuel consumption over the next ten years or a reduction of 380 000 tonnes of CO_2 annually by 2010.

Three billion euros have been allocated under the National Development Plan to improve public transportation. As of Q2 2002, this money has been used to purchase additional buses for both the Dublin and the national systems, add track to the national rail system and develop plans to augment the commuter rail system in the Dublin area.

DEMAND-SIDE MANAGEMENT ACTIVITIES

ESB, the state-owned electricity company, commenced its Demand-Side Management (DSM) programme in 1991 both to delay future investment in power generation and to reduce environmentally harmful emissions by encouraging customers to use electricity more efficiently. ESB maintained the DSM programme in its original format until the end of 2000. The DSM programme produced total savings of 324 GWh over the period 1997-2000 inclusive. The corresponding savings in CO_2 emissions for each of the individual years 1997 through to 2000 were 100 000; 60 000; 50 000; and 40 000 tonnes respectively.

As the Irish electricity market moved towards a liberalised structure with increasing customer choice of supplier, the ESB DSM programme reduced in intensity as ESB prepared itself for the introduction of competition in the supply of electricity. ESB Customer Supply, fulfilling its role as the regulated public electricity supplier, continues to supply customers not served by independent suppliers in the competitive market. During 2001, ESB Customer Supply entered into discussions with the Commission for Electricity Regulation (CER) on its future role in delivering energy efficiency services. For the period 2002-2005, CER allowed ESB Customer Supply to recover the costs of its ongoing energy efficiency programmes from ESB's regulated revenue stream as the public electricity supplier. ESB Customer Supply agreed to change the basis of the reporting of energy savings starting in 2001. Energy savings would be reported on the basis of lifetime savings rather than for a single year as with the 1991-2000 programme. Also, ESB agreed to report only savings for projects significantly influenced by ESB. The total lifetime energy savings achieved in 2001 amounted to 126.5 GWh, equivalent to 100 000 tonnes of CO_2. DSM measures also reduce the country's need for new capacity investments.

THIRD-PARTY FINANCING OF PUBLIC BUILDINGS

Ireland has organised a series of promotional programmes and activities to promote third-party financing (TPF) to support energy efficiency in the public sector. The programme seeks to increase third-party energy efficiency investments by the private sector in publicly-owned and managed facilities. The private investor would then recover its investment (plus some rate of return) through the energy savings that public entities realise as a result of these new investments. This programme is being undertaken in co-operation with the Office of Public Works responsible for the provision and maintenance of energy services in government department buildings.

Despite these promotional and support activities, the concept of third-party financing for public buildings has made little progress in Ireland. The public sector has historically shown little enthusiasm for engaging in such private contractual services. However, the public sector has of late become more accustomed to outsourcing its services and it is therefore possible that the concept of TPF will be considered more favourably than it has been in the past. For example, the Department of Education and Science has recently issued contracts to facilities management companies for the operation, maintenance and provision of heating, hot water and electrical services in a number of schools. Also, a number of local authorities have recognised that there may be opportunities through the public-private partnership programme for the provision of energy services. They have recently been successful with applications for funding through a Department of Environment and Local Government scheme to make them operational.

Regarding activities in the built environmental sector, SEI will focus considerable resources on the public sector, including government department buildings and those occupied by local authorities. A total expenditure of €12 million is planned to 2006. This will include promotion of TPF through the provision of support to set up energy-related businesses in the monitoring and operation of heating, hot water and electrical systems in a number of public-sector buildings.

RESIDENTIAL ENERGY EFFICIENCY POLICIES AND PROGRAMMES

On 6 June 2002, the Minister for the Environment and Local Government signed a law amending Part L of the country's building regulations. These new regulations enhance insulation requirements for new dwellings and for work on existing dwellings starting on or after 1 July 2002, and are projected to reduce CO_2 emissions by 300 000 tonnes per annum by 2012.

Statutory instruments cover minimum efficiency requirements for new hot water boilers fired with liquid or gaseous fuels, household electric refrigerators and ballasts for fluorescent lighting. These instruments are in line with EU energy efficiency requirements. In addition, the EU Directive 92/75/EEC providing a framework for energy of household appliances has been transposed into Irish law.

CRITIQUE

The improvement of Ireland's energy efficiency over approximately the last ten years is impressive. The country went from having a national energy efficiency equal to the EU average to being 20% more efficient than the average. Moreover, this came over a period when other countries had also substantially improved their efficiencies. While some of Ireland's improvement was due to changes in the structure of the economy unrelated to specific efficiency policies, the Irish government should nonetheless be commended for its achievements in this field.

These efforts appear poised to continue with a variety of programmes and initiatives encouraged by both the Green Paper and the NCCS. Such a high level of effort is appropriate given the benefits that energy efficiency brings to both energy security and emissions reduction, two areas which will be crucial to the country's energy future. Despite these notable benefits, care should be taken at all times to ensure that:

- There is a consistency between the principles and plans outlined in the Green Paper and those outlined in the NCCS.
- These programmes are cost-effective.
- They encourage rather than crowd out energy efficiency efforts on the part of the private sector.

The cost-effectiveness of the energy efficiency programmes has not received extensive attention to date, but should be regularly reviewed as more experience is gained. The question of crowding out private-sector enterprise in this area should also be regularly reviewed. The government initiative to encourage third-party financing in public buildings is commendable and could act to catalyse further investments of this sort. Continued efforts should be made to overcome obstacles to this venture so that it can serve as a demonstration to private energy users.

Ireland's historically low levels of CHP indicate that opportunities for profitable energy-efficient investments in this area may exist. While SEI efforts in this area are commendable, care must be taken to ensure that CHP survive on its own merits. As a result, SEI's efforts (and funding) could be best spent on removing the institutional barriers to CHP rather than encouraging specific pilot programmes with investment reimbursement. Both the structure of top-up/spillage payments with ESB and the allocation of gas pipeline costs will affect the financial attractiveness of individual CHP plants. SEI's efforts in ensuring that these and other regulations work to support rather than hinder CHP plants would be the most effective use of its resources.

Transport is the one sector where Irish energy efficiency has not seen pronounced improvement and addressing this area will be particularly important in meeting the country's Kyoto commitments. Underdeveloped public transport infrastructure and a growing number of passenger vehicles provide an opportunity for improving energy efficiency and constraining overall consumption. The extensive efforts now under way to improve and extend the public transport system are commendable (even though the primary driver for these developments is to relieve congestion rather than to cut energy use). The rapid expansion of the transport network provides many opportunities to introduce energy efficiency technologies. Specific energy-related efforts could further improve efficiency in this sector. It is commendable that various demand management measures are currently under study or being implemented. The expected results of some of these measures, such as the claim that fuel economy labelling for cars could reduce vehicle fuel consumption by up to 5%, however, may be overly optimistic. The possible enhancement of economic/fiscal instruments and mandatory measures, which have not as yet been widely employed, should be further examined. Another area could be in the development of efficient low-CO_2 vehicles such as hybrid-electric buses. Such an effort would coincide well with the introduction of many new public transport vehicles at a time when significant funding has been mobilised to make investments for a new public transport infrastructure. Given transport's many dimensions, co-ordination among departments in charge of transport infrastructure, energy and environment is essential.

RECOMMENDATIONS

The government of Ireland should:

- *Evaluate existing energy efficiency programmes with the aim of strengthening efforts to improve energy efficiency in a cost-effective manner.*
- *Expand the cost-effective use of pricing and mandatory regulations to promote energy efficiency, for example in the transport sector.*
- *Continue to explore cost-effective mechanisms to promote CHP.*
- *Enhance the public transport infrastructure in co-ordination with demand management measures to curb energy consumption and CO_2 emissions from the transport sector with close co-operation among the relevant departments.*
- *Explore measures to promote efficient low-CO_2 vehicles, particularly in the public transport sector.*

NATURAL GAS AND OIL

GAS AND OIL EXPLORATION AND PRODUCTION

The major gas field in Ireland was the Kinsale Head field off the southern coast of Ireland operated by Marathon of the US. It has been producing gas for domestic consumption since 1979. The year of greatest production came in 1995 when it delivered 2.25 Mtoe, and from 1979 to 2000, it produced over 35 Mtoe. Production from Kinsale is declining, however, as it becomes depleted. In 2000, it produced 0.96 Mtoe. The decreased Kinsale production has been made up with imports from the UK.

A smaller field, Seven Heads, with reserves estimated at 8.5 bcm, is being developed by UK Ramco and is scheduled to begin production in 2003. Gas from this field will be carried to the main consumption centres on the east coast via the same pipelines carrying the Kinsale gas which now have extra available capacity because of Kinsale depletion. It is estimated that Seven Heads could eventually supply the country with up to 10% of its natural gas demand. Ramco's 86.5% share of Seven Heads gas is to be sold to Innogy, an integrated UK-based energy company acquired by RWE in 2002.

The Corrib gas field off the west coast of Ireland is the first commercial find in Ireland since Kinsale Head in 1973. The reserves are estimated at between 24 and 30 billion cubic metres (between 22.6 Mtoe and 28.3 Mtoe). Corrib is being developed by Shell's subsidiary Enterprise Energy Ireland, Norway's Statoil and Marathon of the United States. Planning permission for the construction of the Corrib onshore terminal was granted in August 2001. A request for planning approval, however, has been put to An Bord Pleanala (ABP) and a decision is expected in April 2003. If the ABP decision is positive, the developers predict that first gas will be brought ashore in early 2005. The government estimates that over the period 2005-2008, up to 70% of gas demand could be met from indigenous resources, with the majority from Corrib.

In order to boost domestic exploration, Ireland's natural resources ministry is opening the offshore Porcupine basin. Porcupine will be opened for bidding in four separate tranches, with bids accepted at six-month intervals, beginning in March 2003 and ending in October 2004.

There is no direct state involvement in oil and gas exploration. The pursuit of policy objectives requires that competent private-sector companies be encouraged to invest in the search for and production of oil and gas within Ireland's designated area. The policy objective is to maximise the benefits to the State from exploration for and production of indigenous oil and gas resources, while at the same time ensuring that activities are conducted safely with due regard to their impact on the environment and other land/sea users.

Since 1992, Ireland has had a comprehensive regime of fiscal and non-fiscal measures applicable to hydrocarbon exploration, development and production. Petroleum exploration and production policy is pursued under the Licensing Terms for Offshore Oil and Gas Exploration and Development (1992). These terms specify that private enterprise be licensed in order to conduct exploration and production under rules which balance the interests of the State with private enterprise. The terms ensure that there is effective and efficient exploration and production, that operations are carried out in accordance with best practices and that there is effective liaison between the State and the exploration and production industry.

The current fiscal terms are contained in the Finance Act 1992 as amended by the Finance Act 1999. A corporation tax of 25% applies where oil and gas production takes place under a lease issued before certain specified dates, depending on the location of the site in question. To qualify for the 25% rate, petroleum leases for fields in the more accessible waters must be granted by 1 June 2003. Leases in respect of "deep water" fields must be granted before 1 June 2007, and leases in respect of "frontier" waters must be granted before 1 June 2013.

One hundred per cent allowances are available for exploration, development and operating expenses with a provision for allowance of unsuccessful exploration expenditure for 25 years. A "ring fence" provision operates around oil and gas exploration and production to prevent companies from deducting the substantial development expenses from their taxable income in non-petroleum activities. There is also provision for an allowance in respect to expenditures on the abandonment of fields and the dismantling of pipelines onshore.

There is no provision for royalty payments or state participation in the licensing terms. These are negotiated on a case-by-case basis and Ireland has not had a long history of numerous producing fields to create a precedent. In the case of the Kinsale and Ballycotton gas fields, production is carried out under an earlier agreement with a royalty of 12.5%.

NATURAL GAS

INDUSTRY STRUCTURE

The natural gas industry in Ireland is dominated by Bord Gáis Éireann (BGÉ). BGÉ is a statutory body established under the 1976 Gas Act, 100% owned by the government of Ireland. The company is responsible for the supply, transmission and distribution of natural gas in Ireland. BGÉ owns and operates gas transmission lines bringing gas from the Kinsale Head, off the coast of Cork, and from the North Sea gas fields through its two undersea interconnector pipelines at Loughshinny in North County Dublin and Gormanston, County Meath. It also owns and operates all distribution lines running directly to end-use customers.

While BGÉ is an integrated company it has been restructured into four separate business units. This reorganisation has been prompted by the country's liberalisation efforts and is intended to ensure increased focus on customer needs and ensure that each business unit is accountable for its own performance. BGÉ also hopes that this new structure will ensure transparency between the operation of the pipeline business and the supply and new asset business, and will facilitate the development of new products and services. The business units are as follows:

- Transmission Operations: responsible for the major gas pipelines.
- Distribution Operation: manages the low-pressure networks within towns and cities.
- Business Development-Customer Products: responsible for buying and selling gas, customer service and new product development.
- BG CoGen: develops combined heat and power (CHP) systems.

No companies have yet emerged to compete for retail customers that have been declared eligible to source their gas from non-BGÉ suppliers (see Energy Policy and Market Reform below). Eligible customers that source their gas from companies other than BGÉ contract suppliers in the UK to purchase gas and arrange their own transmission needs on the BGÉ pipeline network. Innogy has recently contracted to purchase gas from the Seven Heads gas field and plans to use this gas to enter the market as a supplier. The first gas delivery is scheduled before the end of 2003.

GAS DEMAND AND SUPPLY

The Irish natural gas market is small by international standards. In 2000, total gas supply in Ireland was 3.4 Mtoe, an amount equal to 23.5% of the country's TPES. The demand for gas is growing rapidly, driven by the economic boom, the liberalisation of the electricity market, the expansion of the gas transport network, and environmental concerns. From 1996 to 2000, gas usage rose at an average annual rate of 6.8% and over the decade from 1990 to 2000, rose by nearly 80% in total. Gas's share of TPES has also grown, rising from 17.9% of TPS in 1990 and, more recently, from 22.2% in 1996. Overall gas use is expected to continue its expansion, with the Irish government forecasting that gas use will grow at an average annual rate of 5.6% until 2010 at which time it will account for 35.1% of the country's TPES. The majority of this increase in gas use will come from the power sector which will account for approximately 70% of absolute growth between 2000 and 2010.

The main drivers of historical demand growth were the power generation and feedstock sectors (primarily for fertiliser production). These two sectors provided the commercial basis for developing the Kinsale gas field. Natural gas initially displaced large quantities of oil for electricity generation in the power sector. Demand for gas in the power sector was temporarily reduced in the late-1980s following the commissioning of the coal-fired station at Moneypoint, which was operated as baseload capacity and displaced gas-fired generation. Demand in this sector recovered again in the early 1990s when the end-user demand for electricity began to increase at record levels. It received a further boost in 2000 following the commissioning of a new CCGT plant at Poolbeg, the first large-scale power plant to be constructed since Moneypoint in 1985.

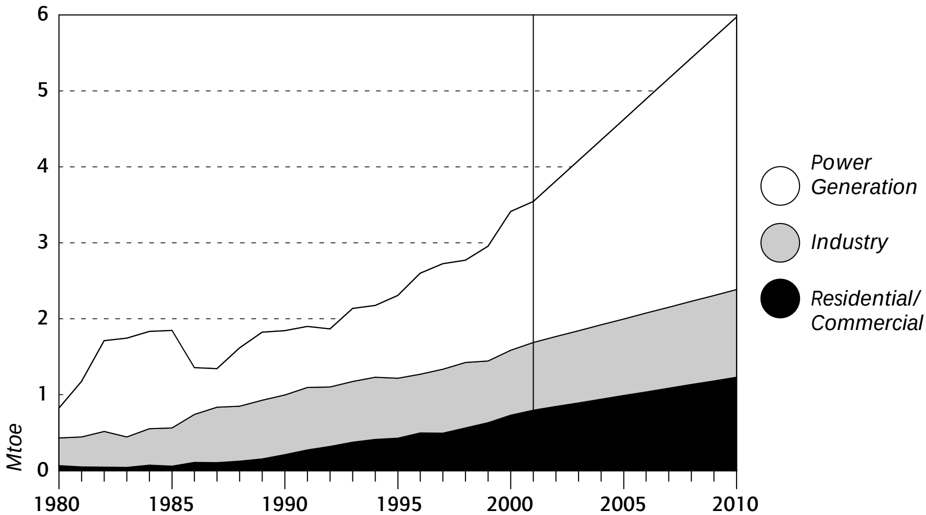
In 2000, electricity generation represented the largest share of gas use in Ireland, accounting for 53.8% of that year's total gas supply. Gas use for electricity generation has also increased substantially from 1996 to 2000, with average annual growth rates of 8.6% over that time. From 1990 to 2000, total gas use for power generation grew by almost 130%. In 2003, substantially more gas is currently being burned to produce electricity as two large gas-fired generating stations came on line in 2002. If the NCCS recommendation is followed and the Moneypoint coal-fired plant is fuel-switched to natural gas, 80% of the country's electricity could come from gas by 2010.

In 2000, the industrial sector represented the second largest consumer of gas with 24.9% of total consumption. Gas use in the industrial sector has stayed relatively level over the past decade, rising by only 4% from 1990 to 2000. In 2000, slightly less than half the industrial gas use was for petrochemical feedstocks, an industry segment whose gas use has decreased in the past decade, falling by 14% from 1990 to 2000. Gas use for petrochemical feedstocks has fallen much more since then owing to the October 2002 closure of the Irish Fertiliser Industries (IFI) plants in Cork and Arklow. This will significantly lower industry's share of Irish gas consumption.

The residential sector accounted for 12.8% of the 2000 gas supply. Gas use in this sector has risen the most, however, with consumption up by more than 10% annually from 1996 to 2000 and by more than 170% in total from 1990 to 2000. The government estimates that residences consumed 10% more gas in 2001 than in 2000. Figure 9 shows the country's historical and projected use of gas supply.

Figure 9

Natural Gas Supply Uses, 1973 to 2010



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

Gas is supplied to Ireland from both domestic sources and imports. In 2001, gas imported from the UK supplied 82% of Irish demand. This import percentage has risen dramatically in recent years. Indigenous sources supplied the country's entire gas demand until 1995 when an undersea gas pipeline was brought on line connecting Ireland with the UK. In 1996, the first full year the pipeline was used, imports constituted only 18% of total national demand. The depletion of the major domestic supply source, the Kinsale Head fields, coupled with the availability of relatively inexpensive gas from the UK, has led to a consistent replacement of domestic gas with imports over the last five years.

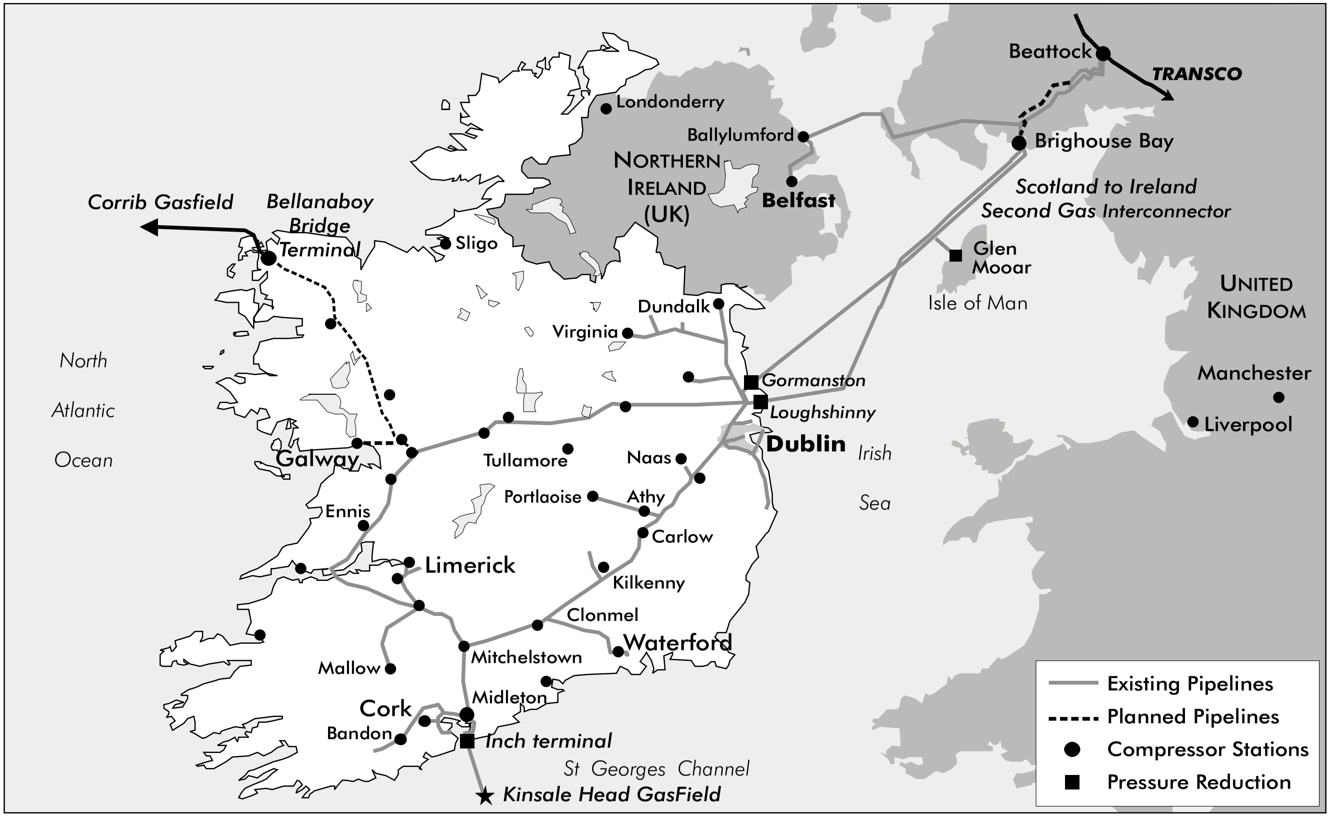
TRANSMISSION, DISTRIBUTION AND STORAGE

National Gas Transportation System

BGÉ has developed a transmission and distribution network providing gas to more than half a million homes in Ireland with access to gas. Currently, homes and commercial enterprises in Meath, Cavan, Louth, Dublin, Kildare, Wicklow, Laois, Carlow, Kilkenny, Tipperary, Waterford, Cork and Limerick are connected to the natural gas network. BGÉ continues to expand its network to all areas where they believe it is economically viable to do so. The gas network is currently being extended to Shannon, Baranakyle and Coonagh in County Limerick and plans are under way to bring gas to Ennis, Rathdrum and Glenealy in County Wicklow.

Figure 10

Map of Gas Pipeline Network in Ireland



Sources: BGÉ.

A major new pipeline development across the country, known as the Ringmain project, is under construction connecting Dublin to Galway and Galway to Goat Island, County Limerick. This will link in with the existing Limerick-Cork-Dublin pipeline to create a national transmission ring, reinforcing the network in the south and allowing imported gas to be used in the south, which is particularly important as the reserves in the Kinsale Head are almost depleted. The Dublin-Galway section of the pipeline was scheduled for completion by late 2002 but, because of minor delays, was brought on line in early 2003. This pipeline adds ten more towns to the natural gas grid *en route*. The Munster section of the pipeline is expected to be completed in the middle of 2003.

A pipeline from Galway to Mayo is also planned to connect gas supplies from the new Corrib gas field off the Mayo coast to the national grid. Figure 10 shows a map of all pipelines in use, under construction and planned.

International Gas Connections

Ireland has two undersea gas pipelines running from Ireland to the UK. The first Ireland-UK natural gas interconnector has been in commercial use since 1993. In 2001, 82% of Ireland's natural gas requirements were supplied to customers through this interconnector. The pipeline was built to ensure continuity of gas supplies in Ireland after the depletion of the indigenous Kinsale Head/Ballycotton reserves. It has served exactly that role, increasing in capacity utilisation as production from Kinsale decreased.

The first interconnector was expected to provide sufficient import capacity until 2015. However, the level of economic growth in Ireland has been such that, by late 2000, it was considered additional capacity was required to meet demand forecast for the winter of 2002. A number of possible options were considered, including the possibility of new indigenous reserves in the Corrib field. Following analysis of the problem, the government opted to proceed with BGÉ's proposal for a second interconnector from Scotland, not least because it was the only proposal that would have been completed within the required timescale.

This second Ireland-UK interconnector (IC2) was brought on line in the fourth quarter of 2002. It runs roughly parallel to the first interconnector, beginning in Ross Bay in Scotland, with a 30-inch 200 km pipeline under the sea before arriving at County Meath, Ireland. It includes a reception terminal in Gormanston which will pressurise the gas and allow for metering. The last stage of the new project is a 14 km onshore pipeline connecting Gormanston to the existing pipeline network in Dublin. The total cost of the pipeline was €301 million. The second interconnector has a larger potential capacity than the first one. However, actual gas usage has fallen far short of the projections in place when the government opted for the second interconnector and, as a result, it is not yet in operation and is not expected to be needed at least until 2005.

In September 2001, the Irish government decided to make a €12.7 million contribution to the Northern Ireland administration towards the costs of developing their gas network. This will involve a South-North interconnector and a pipeline between Belfast and Derry.

Storage

The Southwest Kinsale undersea gas field was converted over a 13-month period, concluding in October 2001, to allow reprofiling of gas. This development was carried out by Marathon International Petroleum Ireland Ltd. Gas is injected into the reservoir on a continuous basis during the summer and withdrawn intermittently at high rates to coincide with periods of high demand during the winter. The new facility will also result in increased recovery from the nearby Kinsale Head and Ballycotton gas fields and will increase peak deliverability of the Kinsale area reservoirs by a wintertime average of about 100 million standard cubic feet per day (60 days storage).

In addition to this development, there is sufficient capacity on the interconnectors with the UK to allow Ireland to use the flexibility mechanisms available on the UK gas market. Since baseload power generation accounts for 50% of total gas demand and the country has mild seasonal temperature differences, the seasonality of gas demand is less pronounced than in other European countries. This reduces the need for gas storage to accommodate fluctuations in demand.

NATURAL GAS PRICING

Industrial and household retail gas prices for Ireland and selected other IEA countries are shown in Figure 11.

The benchmark for retail gas prices as determined by the regulatory authority[9] is the price for gas in the UK plus additional transmission and distribution charges to bring gas from the UK to consumers in Ireland. Such a pricing scheme applies to all gas sold in Ireland, even that domestically sourced.

Gas transportation costs in Ireland are within the average range of those found in other EU countries as shown in Table 3.

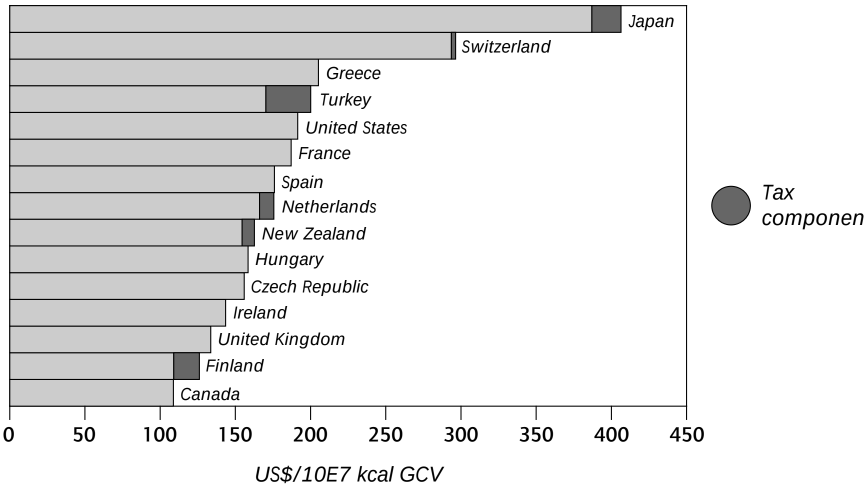
Irish gas transportation costs have risen recently[10] and are expected to rise above those shown in Table 3, in part to allow BGÉ sufficient revenue to recover the costs for the construction of the second undersea UK interconnector.

9. This had been the Department of Communications, Marine and Natural Resources, but in 2002 this function was transferred to the Commission for Energy Regulation, as explained in the Energy Policy and Market Reform section below.
10. This rise in transportation prices is already reflected in Table 3.

Figure 11

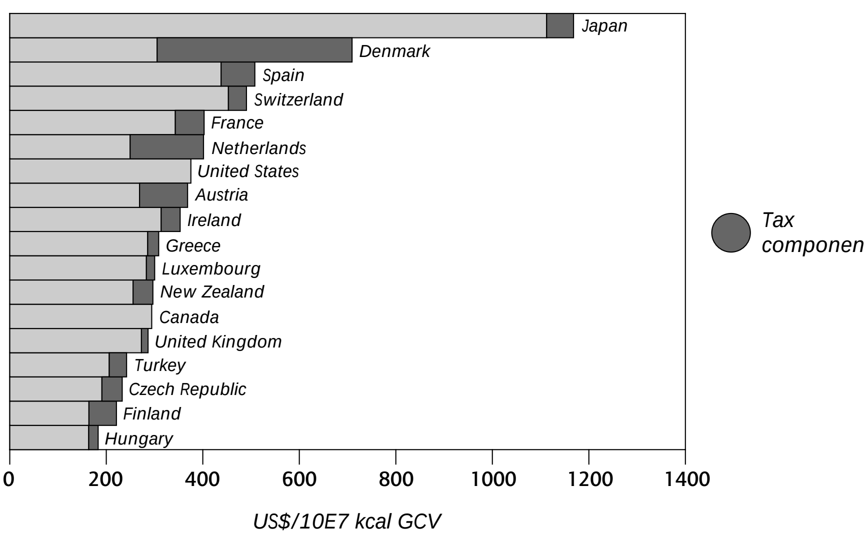
Gas Prices in IEA Countries, 2001

Industry Sector



Note: Tax information is not available for Canada and the United States. Data not available for Australia, Austria, Belgium, Denmark, Germany, Italy, Korea, Luxembourg, Norway, Portugal and Sweden.

Household Sector



Note: Tax information is not available for Canada and the United States. Data not available for Australia, Belgium, Germany, Italy, Korea, Norway, Portugal and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Table 3

Gas Transportation Tariffs for Ireland and Selected EU Countries

(€/MWh) [1]

	Min	*Max*
Belgium	1.0	2.0
Denmark	2.5	2.5
France	2.0	5.0
Germany	2.0	7.5
Ireland	1.5	2.5
Italy	2.0	4.0
Luxembourg	1.0	1.0
Netherlands	0.5	1.0
Spain	2.0	2.5
Sweden	3.5	3.5
United Kingdom	1.5	3.0
Average	**1.8**	**3.2**

(1) For large user with a minimum of 25 mcm of annual demand.

Source: "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

In the second half of 2002, following an application from BGÉ, the Commission for Energy Regulation (CER) sanctioned what was effectively an 18% increase in transportation charges to large industrial users. In accordance with the CER Direction of 27 September 2002, these transmission rate increases were put in place on 1 October 2002.

The effect of this increase on overall gas tariffs will be smaller however as transportation constitutes only a part of the total costs to end-users. The government projects a 1.7% rise in total final price for power stations and a 2% rise for large industrial customers.

In October 2002, BGÉ sought a further 17% increase in natural gas supply tariffs to its franchise customers. On 21 February 2003, the CER announced details of its approval of a 9.1% increase, and intends to issue its formal direction on 21 March 2003. In addition, the CER published a proposal from BGÉ for the supply of natural gas to all eligible gas customers consuming more than 181 000 therms of natural gas annually on the basis of a Regulated Tariff Formula (RTF). This RTF, which would be regulated by the CER, is designed to ensure that all such customers will be offered a single, transparent market price from BGÉ as a means of facilitating the procurement and comparison of competing quotes from new-entrant natural gas suppliers. The RTF will result in a range of increases/decreases depending on the particular contract, but overall there will be an average increase of about 2.5%. Individual increases will be capped at 15% above current demand and commodity tariff levels.

ENERGY POLICY AND MARKET REFORM

Ireland is in the process of reforming its natural gas market. Gas reform began in 1995 with the passage of the Energy (Miscellaneous Provisions) Act 1995. This act created the legal framework for third-party access to the BGÉ network by large customers wishing to source their gas from alternative (*i.e.* non-BGÉ) suppliers. At that time, only customers taking 25 million standard cubic metres of gas or more were eligible to choose their supplier, but given the large size of these customers, this equated to a 75% market opening by volume.

The Gas (Amendment) Act 2000 introduced a scheme to allocate spare capacity in the natural gas network for electricity generation. This allocation applied to large centralised power plants expected to come on line in the coming years. This act also extended the rights of access and compulsory acquisition of lands to companies other than BGÉ, effectively giving private pipeline developers the same rights as BGÉ to build and operate pipelines.

The Gas (Interim) (Regulation) Act 2002 (passed in April 2002) increased gas market opening from 75% (by volume) to almost 80% by reducing the eligibility threshold for third-party access (TPA) from 25 million standard cubic metres per annum to 2 million standard cubic metres. In effect, this increased from eight to somewhere around 100 the number of companies that are free to source their gas from the supplier of their choice and ship it through the BGÉ network. On 1 January 2003, further market opening was introduced with a reduction of the TPA eligibility threshold to 500 000 standard cubic metres per annum, thereby increasing the number of eligible customers to approximately 250 and increasing the level of market opening to over 85% (by volume). Full market opening is scheduled for 2005 at the latest.

The European Commission indicates that between 20% and 30% of eligible customers had switched to suppliers other than BGÉ as of the fourth quarter of 2002[11]. This does not include customers that have renegotiated their tariffs with BGÉ. BGÉ estimates that as of November 2002, approximately 50% of the eligible market (by volume) was sourcing its gas from suppliers other than BGÉ. These switching customers contract suppliers in the UK to purchase gas and arrange their own transmission needs on the BGÉ pipeline network.

Under the Gas Act of 2002, the Department of Communications, Marine and Natural Resources (DCMNR) maintains overall responsibility for the development

11. "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

of natural gas policy. The department also maintains its role as the sole shareholder of BGÉ. However, the Gas (Interim) (Regulation) Act 2002 transferred the department's gas regulatory powers and functions to the Commission for Energy Regulation (CER). This body was created by the expansion of the already existing Commission of Electricity Regulation.

Chief among the CER functions is the responsibility for the implementation of tariffs, including both the supply and transportation portions of the rates. BGÉ submits a request for a specific tariff to CER which either approves or denies that request. Tariffs are currently to be calculated according to the following criteria [12]:

- Use of an Irish Entry/Postalised Exit Model [13].
- Allowed rate of return for BGÉ investments equal to 6.5%.
- A ten-year levelised real tariff structure.
- Tariffs are adjusted to reflect variations in forecast demand, capital or operating costs or to reflect under- or over-recovery of capital expenditure in previous years of the tariff period.
- An annual adjustment based on the consumer price index.

Other CER responsibilities in the gas sector include:

- Granting of consents for the construction of distribution and transmission pipelines.
- Regulation of access to natural gas transmission and distribution pipelines.
- Regulation of unbundled accounts of natural gas undertakings.
- Preparation and publication of an annual Gas Capacity Statement.
- Imposing any public service obligations considered necessary by the minister.

While the basic legal framework for third-party use of the BGÉ gas pipeline network had been in place since the passage of the Energy (Miscellaneous Provisions) Act 1995, the Gas Act of 2002 further refined and expanded this system. Currently, access to the gas network must be granted by the pipeline operator (BGÉ) to any third party wanting to make use of this system to supply an eligible customer. BGÉ is entitled to refuse access to its pipelines on the basis of lack of capacity in its pipeline or lack of connection to the pipeline (save where the third party would be willing to pay for such a connection).

12. These criteria may change subject to a full review of network tariffs undertaken by CER in 2003.
13. The Irish entry/postalised exit system includes a tariff with two components. Pipeline users pay an entry charge that is distinct for each entry point and an exit charge that is common to all exit points.

BGÉ has developed a Code of Operations for Third-Party Access rules and principles. This document defines the relationship between the shippers and transporters and records the rights and responsibilities of each of the parties involved in the transportation of natural gas through the BGÉ transmission system. There have been no reports of alternative suppliers or eligible customers encountering problems accessing the pipelines system, either before or after the passage of the Gas Act 2002.

Market reform also includes the unbundling of all BGÉ accounts according to function. For the purposes of avoiding discrimination, cross-subsidisation and/or the distortion of competition, BGÉ must keep separate accounts for its transmission, distribution and supply activities. In preparing these accounts, BGÉ must include a balance sheet and a profit and loss account for each activity.

OIL

DEMAND AND SUPPLY

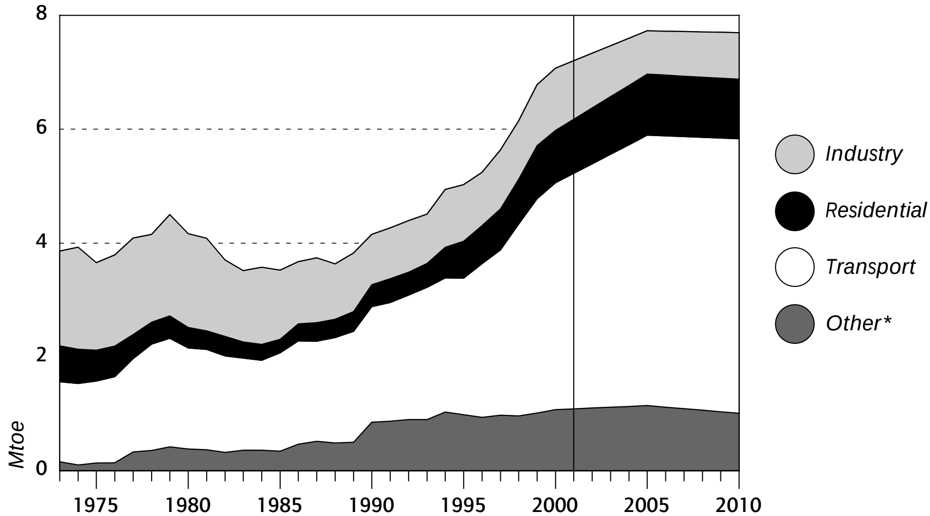
In 2000, oil and oil products accounted for 56.5% of Ireland's TPES. This figure represents an increase in oil's importance from 1996 when it accounted for just 50.4% of the country's TPES. From 1990 to 2000, Irish oil supply grew at an average annual rate of 5.4% per year. The reason is the growth in the road transport sector, spurred by Ireland's strong economic performance in the last decade.

Use of oil and oil products for electricity generation has risen substantially in the last decade. In 1990, oil accounted for 10% of electricity generation, while in 2000, that figure had nearly doubled to 19.6%. The Irish government predicts, however, that this trend will reverse itself with oil accounting for only 1.4% of electricity generation by 2010.

Transport accounts for the majority of oil total final consumption (TFC). In 2000, it was 56% of oil TFC and over 80% of this amount was for road transport. Since 1996, gas use for road transport has grown at an average annual rate of 9.9% and from 1990 to 2000 at an average annual rate of 7.8%. Oil use in the residential sector also grew rapidly, at an average annual rate of 8.5% from 1996 to 2000 and 9.3% from 1990 to 2000. In 2000, oil use in this sector accounted for 13% of oil TFC in Ireland. The industrial sector also accounted for 13% of oil TFC in 2000, although recent growth rates in this sector have been more modest. From 1990 to 2000, oil use in the industrial sector grew by 3.5% annually while from 1996 to 2000, it grew by 5.2% annually. Figure 12 shows the historical and projected TFC of oil divided by sector.

Figure 12

Total Final Consumption of Oil by Sector, 1973 to 2010



* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

Ireland has no domestic oil production. Until 2000, nearly all crude oil imported into Ireland came from Norway. In 2001, the large majority of Ireland's crude came from the United Kingdom. This change coincided with the sale of the Whitegate refinery by the government of Ireland to a private operator (described below). Nearly all imported petroleum products come from the UK.

Industry Structure

The Irish oil market is served by a number of multinational and domestic independent companies operating in accordance with their own commercial policies. Oil products are sourced from abroad and from Whitegate, Ireland's only refinery.

In July 2001, the State's direct involvement in operational aspects of the oil industry through the Irish National Petroleum Corporation (INPC) ended with the sale of the Whitegate refinery, the Whiddy Island oil terminal and the associated businesses to the Tosco Corporation of the USA. Under the terms of the sale agreement, Tosco is required to maintain operations at the refinery and terminal for at least 15 years on a fully commercial basis. Since the completion of the transaction, the facilities have been operated and developed by the new owners as an integral part of the Irish market's overall supply arrangements. Tosco Corporation was subsequently taken over by Phillips Petroleum and following the latter's merger with Conoco Inc, the Whitegate and Whiddy facilities are now operating as part of the ConocoPhillips group. With the sale, the mandatory offtake obligation on oil companies operating in the Irish market to take a proportion (most recently 20%) of their total light oil product requirements from the Whitegate refinery was abolished.

Emergency Preparedness

Legal Authority and Emergency Organisation

The Minister for Communications, Marine and Natural Resources is empowered under the Fuels Acts 1971 and 1982 to regulate the supply and distribution of petroleum products if the government decides that an emergency situation warrants action. Responsibility for the implementation of this legislation rests with the Department of Communications, Marine and National Resources. In the event of an oil supply shortfall, industry representatives would be consulted.

Emergency Reserves

Ireland's stock policy has evolved in response to its international commitments arising from its membership of the European Union and the International Energy Agency. The Fuel Acts and European Communities (Minimum Stocks of Petroleum Oils) Regulations 1995 were put in place to safeguard the supply and distribution of oil in an emergency, to meet EU and IEA stockholding obligations, and to gather adequate data regarding consumption, trade and stocks of oil products.

National Oil Reserves Agency (NORA)

Under the 1995 Regulations, responsibility for the maintenance of strategic stockholding was taken away from the industry and vested in a new state body, NORA, a subsidiary of the Irish National Petroleum Corporation (INPC). NORA has statutory responsibility for ensuring that sufficient strategic stocks are in place to meet Ireland's IEA and EU obligations. NORA's function is to arrange for the holding of strategic oil stocks at a level determined annually by the minister. Such stocks may be held directly by the agency itself or on its behalf by third parties at home or abroad. NORA is required to operate on a break-even basis and is funded by a levy of currently 0.476 cent per litre on oil sales. Oil importers and large oil consumers are not obliged to hold strategic stocks but are expected to hold a prudent level of operating stocks, which are included in Ireland's stockholding calculation.

Given the scarcity of commercial oil storage facilities in Ireland, the re-opening of the Whiddy Island oil terminal, Bantry, Co. Cork in 1998 under the INPC was of considerable practical benefit to NORA. Now that the refinery is owned by ConocoPhillips, NORA has entered into fully commercial, transparent contracts for the storage of oil products at both the Whiddy terminal and the Whitegate refinery (Cork). NORA also has storage contracts with other oil distributors and consumers in the Irish market and is open to further offers from third parties who are prepared to offer suitable tankage on competitive terms.

NORA is now the sole subsidiary of the INPC, which remains in being for the present, chiefly to discharge a number of residual functions following the sale of all of its commercial assets and businesses in July 2001. Future arrangements in respect of both NORA and the INPC, which are likely to involve proposals for new legislation, are currently being examined.

National Stockholding

A key element in relation to security of oil supplies is national stockholding policies whose guiding principles are derived from IEA obligations and EU mandatory requirements. The establishment of NORA has helped to give stronger focus on national stockholding arrangements during a period when Ireland experienced significant oil demand growth. Stockholding amounts (in number of days of net imports stored) are shown in Table 4.

Table 4

Oil Stockholding in Ireland

Year	*Days*
1998	104
1999	97
2000	89
2001	112
2002	119

Source: Irish government.

Fuel oil stocks have generally been in excess of requirements mainly because of high stocks held by the state electricity utility – the Electricity Supply Board – although this may change somewhat because of ESB's growing reliance on natural gas.

A strategic aim of the Irish authorities is the improvement of Ireland's ability to comply consistently with international stockholding requirements even in adverse oil market conditions, and to respond effectively to any local or temporary interruption in oil supply arrangements. In practical terms, this involves a review of the balance between the ticketed (rented) and wholly-owned elements of NORA's overall stocks, and an increase in the volume of NORA's stocks held in market-ready form.

Ireland would have no legal or other impediments to participating in joint stockdraw operations, including any below the ninety-day level. The regulations on minimum stocks allow the minister to authorise a drawdown of stocks in an emergency.

Demand Restraint

Ireland's emergency response programme centres initially on stockdraw, consistent with IEA and EU requirements, complemented by demand restraint measures. Ireland's demand restraint measures are multifaceted and correspond to different degrees of disruption. Compulsory Orders under the Fuels Acts may be made independently of the IEA emergency response measures and could be introduced in a sub-crisis situation. Formal rationing schemes are considered as a last resort. The administration has prepared necessary draft Government and Ministerial Orders for the implementation of demand restraint measures.

Policies

In November 1996, the government decided that the Mandatory Regime which required oil importers to purchase a proportion of their supplies from the Whitegate refinery at prices determined by the minister should be modified downward rather than be eliminated as previously intended. From 1 January 1997 this obligation was reduced from 35% to 20% and income support for the refinery under the regime was capped, rather than determined on a cost-recovery basis. With the sale of the refinery to Tosco Corporation in July 2001 for operation on a fully commercial basis, the Mandatory Regime was terminated.

Ireland has no policy influence in the retail sector. There is free access to the market and oil companies compete on the basis of such factors as brand image, location, convenience, service, loyalty schemes and price. As regards the latter, anecdotal evidence of wide-ranging disparities in the retail price of petrol at filling stations suggests that in the absence of large discounts (*e.g.* the operation of hypermarkets), the Irish consumer is not particularly price-sensitive.

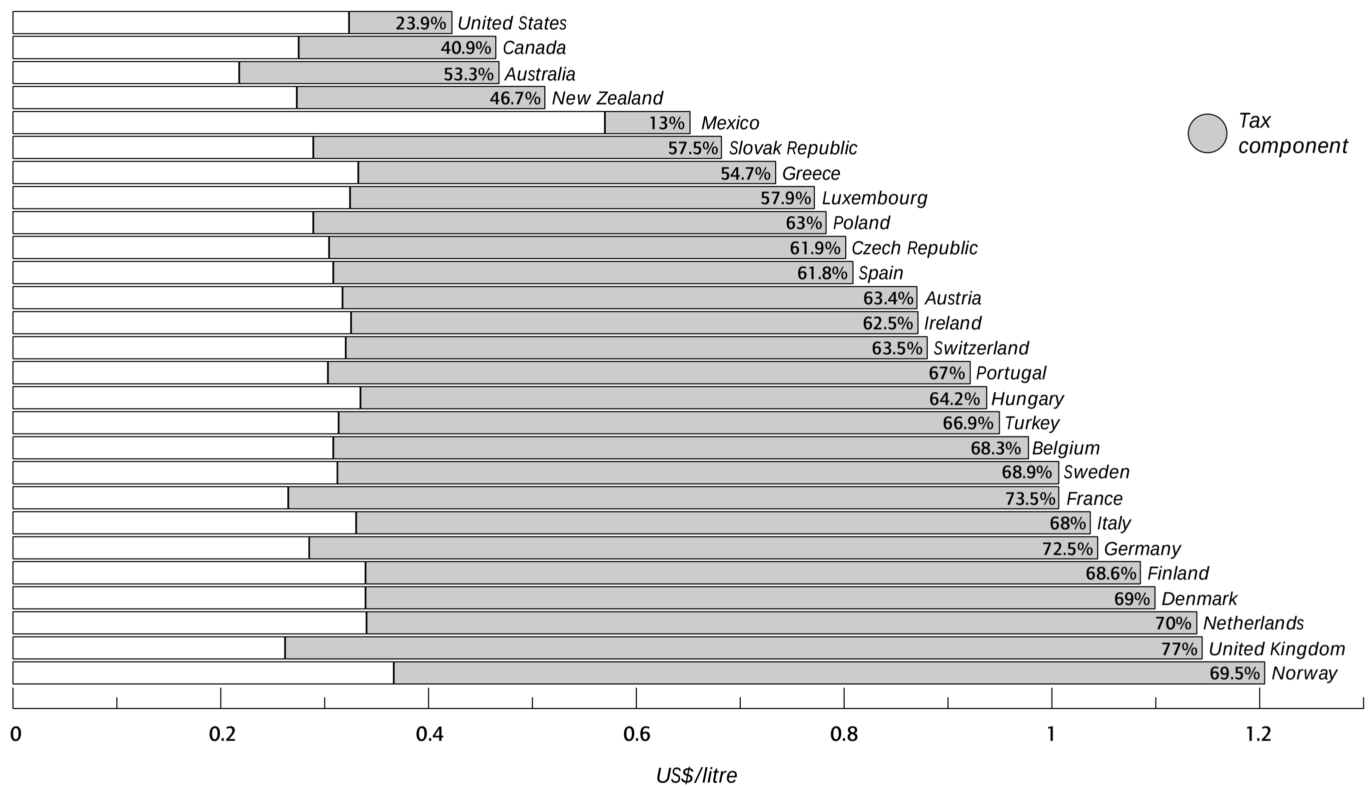
Under the Competition Acts, oil companies are precluded from requiring retail outlets to implement scheduled or recommended prices. Consequently, it is a matter for the management of individual service stations to decide their selling prices.

Prices and Taxes

With the exception of Greece, Luxembourg and Spain, Ireland had the lowest total price (*i.e.* including taxes) in the EU in the third quarter of 2002. The ex-tax price was in the medium range of EU prices. For diesel fuel, both Ireland's total price and ex-tax price are in the medium range of EU prices. Figures 13 and 14 show the range of prices for these two fuels in OECD countries.

Figure 13

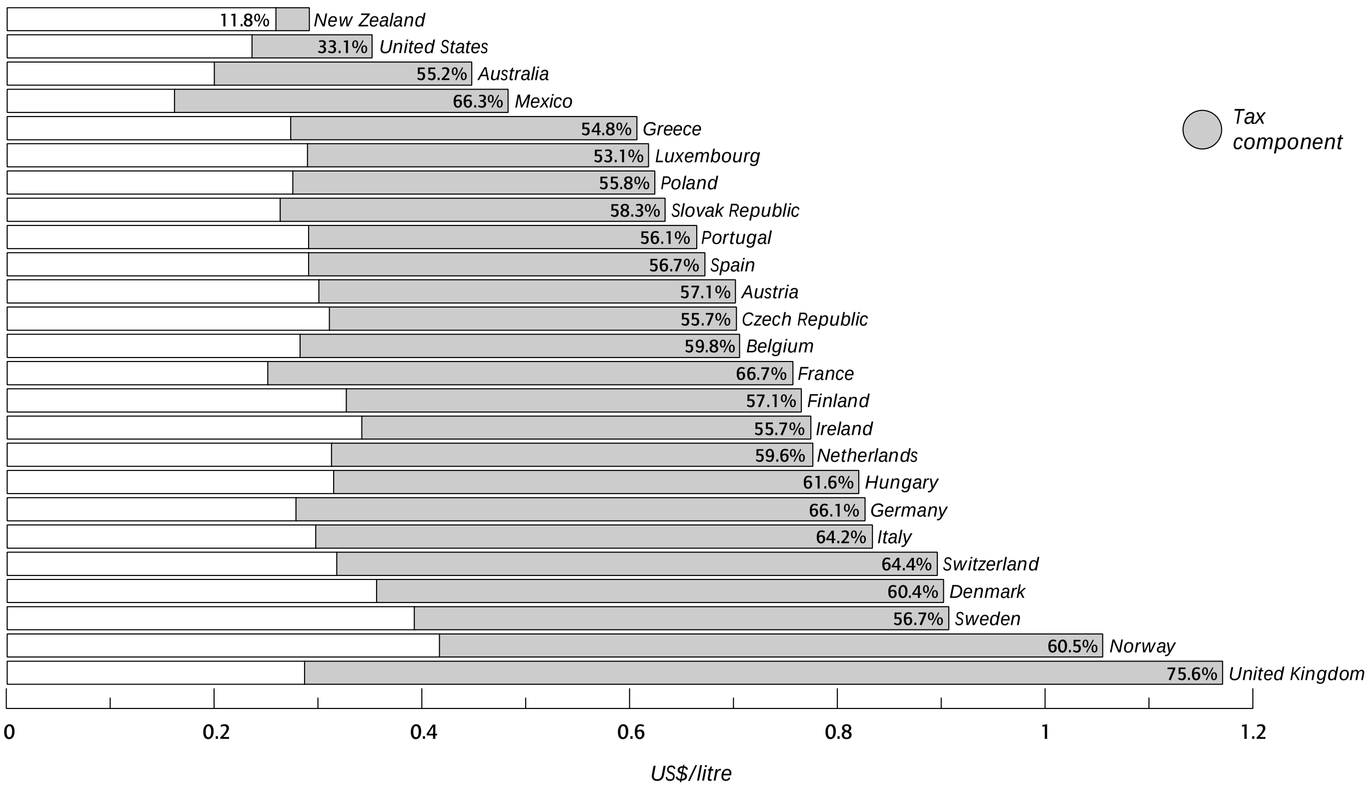
OECD Unleaded Gasoline Prices and Taxes, Third Quarter 2002



Note: Data not available for Japan and Korea.
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Figure 14

OECD Automotive Diesel Prices and Taxes, Third Quarter 2002



Note: Data not available for Canada, Japan, Korea and Turkey.
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Excise duty increases of 6.35 eurocents per litre for petrol and auto-diesel were implemented in the budget of 5 December 2001. In addition, value-added tax was increased from 20% to 21% with effect from 1 March 2002. There was no change in excise rates for other oil products.

Differences in automotive fuel prices between Ireland and Northern Ireland have given rise to "fuel tourism" whereby drivers from a high-tax country enter a low-tax country to purchase fuel at the lower rate. In 1990, vehicle fuel taxes were significantly higher in Ireland than in Northern Ireland and, as a result, Irish drivers purchased their fuel north of the border. Currently, the situation is reversed: Irish taxes are lower and drivers from Northern Ireland enter Ireland to purchase their fuel.

In addition to its effects on government revenues, such fuel tourism has significant GHG implications. If a resident of Northern Ireland buys fuel in Ireland, the emissions associated with that fuel are allocated to Ireland. The Department of the Environment estimates that, in 1990, Irish drivers purchased fuel in Northern Ireland which accounted for approximately 0.5 Mt of GHG emissions. In other words, those emissions were allocated to Northern Ireland even though Ireland consumed the fuel. Now, the situations are reversed and approximately 0.5 Mt of GHGs are allocated to Ireland when, in fact, they are consumed by drivers in Northern Ireland. This situation has created a net 1.0 Mt swing in the amount of emissions Ireland will have to cut to meet its Kyoto obligations.

CRITIQUE

The importance of natural gas to the Irish energy sector is poised to grow. From its introduction to Ireland in 1979, gas grew to account for over 20% of TPES in 1983 and has since provided approximately one-fifth of the country's TPES. Spurred on by its environmental benefits versus coal and oil, and the realised and expected construction of new gas-fired CCGTs, the government predicts gas use will account for more than 35% of the country's TPES by 2010.

The expansion of the gas network will continue to spread the use of gas to more medium and small commercial and residential users. This will allow them to enjoy an economic fuel choice and substitute for more environment-damaging coal and oil now often used for heating.

Ireland's efforts at market reform of the gas sector are certainly a step in the right direction. The expansion of the market opening, establishment of an independent gas regulator, third-party access, and unbundling of the integrated incumbent gas utility are all important ingredients in establishing a viable liberalised market place. Complete market opening by 2005, as envisioned, would be timely and make Ireland compliant with the relevant EU directive.

In one sense, the results of the reform so far are encouraging in that BGÉ estimates that 50% of the eligible market (by volume) has turned to alternative suppliers. However, the EU estimates that between 20% and 30% of eligible customers have switched and since only approximately 8 customers have been eligible, it means that only two or so have switched to suppliers other than BGÉ. Certain aspects of the Irish market have posed, and will continue to pose, challenges to the effective operation of a competitive gas market.

One such impediment to competition is the relatively small size of the Irish market. Potential new-entrant suppliers will tend to prefer larger markets, leaving Ireland with a dearth of viable competitors. The limited number of supply sources available to Ireland also acts to impede competition. Currently, gas can be sourced from the UK or through Kinsale. The Seven Heads fields (beginning production in 2003 and to be sold to Innogy) and the Corrib field (scheduled for a 2005 start date) will expand the supply possibilities. Nevertheless, this is unlikely to create enough supply sources to create upstream competition which, in turn, could offer final customers more choice. Regardless of the extent of market opening, prices will probably still be heavily influenced by the current benchmark of the UK gas price plus transportation costs. The CER should monitor developments in the natural gas market and, where results do not lead to effective competition in the market, work out the necessary procedures to improve the situation.

The expected rise in gas use raises energy security concerns. While the projected increase in gas to 35% of TPES makes Ireland vulnerable to interruptions or price shocks, the greatest exposure may be the 80% of electricity that would come from gas by 2010 if all proposals within the NCCS are implemented. This level of reliance on a single fuel will require measures to protect the economy from once-off shocks through sudden interruption in supply. As the market develops and grows, it will be necessary to ensure that an appropriate reserve of supply capacity is built up and maintained to enable the system to survive the loss of a source of supply. This could be achieved by a range of devices, such as ensuring diversity in sources, maintenance of excess capacity or gas storage. While it is not yet certain that all the NCCS proposals will be implemented (namely fuel-switching of Moneypoint), certain steps can be taken to improve the nation's security of gas supply.

The first such step involves enhanced domestic and international grid connections. This has largely been accomplished through the construction of the second undersea interconnector with the UK. While the timing of this pipeline appears to be premature given the expected capacity sufficiency of the first interconnector until at least 2005, the new pipeline ensures that Ireland will not encounter any import pipeline constraints in the foreseeable future. Expansion of the pipeline system with Northern Ireland will also help provide additional sources of gas supply that could mitigate any negative consequences from a supply disruption.

While sufficient pipeline capacity with the UK (and Northern Ireland) will help the gas security issue, this will only make Ireland's situation as secure as that of the UK which itself is expected to become a net gas importer by 2005. Development of Irish domestic gas resources will therefore also be a key to addressing this issue. This will be particularly important as Kinsale continues to deplete. The Seven Heads development and its promise to supply 10% of Ireland's natural gas will provide a significant boost to the country's security. The Corrib field and its approximately 25 Mtoe will significantly improve the country's gas security. While the delays in the Corrib development resulting from local planning issues are not unusual for such projects, the energy security benefits of such projects must be weighed along with the very legitimate concerns of local citizens and environmental groups. In this context, the general public, including local citizens, should be fully informed of the challenges in terms of energy security.

The development of gas storage also improves Irish gas supply security. The new gas reprofiling facility created in the depleted Southwest Kinsale undersea gas field provides one type of buffer against any supply interruption or a price spike.

The costs and benefits of all measures to enhance gas security of supply must be fully analysed before final implementation. The second UK interconnector, for example, has proven very costly now that gas demand has not materialised as projected and the pipeline sits unused while transportation rates have been increased to pay for it. In general, the government or regulator should set standards for security of supply rather than advocating specific measures. For example, the government can mandate that all suppliers must be able to continue supplying customers in the event of any of a number of supply interruptions. The companies themselves could then be free to choose the most appropriate means of meeting these standards. Such means might include gas storage, additional and/or redundant pipelines from supply sources to consumers, fuel-switching capabilities or interruptible contracts with customers.

While these activities can certainly help the country's gas security, they cannot completely solve this problem. The fact is that Ireland has limited domestic gas resources and is located at the "end of the pipeline" as far as imports from the major gas producers serving Europe are concerned. Actions at the national level can only mitigate these facts so much. Efforts by the Irish government could therefore be well spent in international activities that support sound gas markets on the European and global levels and stable relations with gas exporting countries such as Russia. Such engagement could include working with and supporting international organisations and forums such as the IEA, the EU, the Energy Charter and the International Energy Forum (IEF).

Mesures taken towards market reform and the expected rise in gas use are clearly positive steps for Ireland, allowing the country to utilise an economic fuel source with relatively benign environmental characteristics. Care must be taken, however, to ensure that market reform encourages rather than discourages the investment needed to develop the market further. Ireland's gas market is not yet mature; it has a limited number of supply sources and a substantial portion of the country has no access to natural gas. A stable regulatory regime that encourages investment and the entry of competitors will allow Ireland to develop the sector market to spread the contribution gas can make and to make the market suitable for effective competition.

For the oil and oil products sector, Ireland has a fully competitive open market that serves both consumers and the national interest. As a fuel supplying over 50% of the country's TPES, creating a viable competitive market for oil and oil products is crucial for the entire energy sector.

The government is to be commended for its sale in July 2001 of the Whitegate refinery, the Whiddy Island oil terminal and associated business. The related decision to abandon the mandatory offtake from this facility is certainly a positive step. The refinery continues to operate privately as a source of competition in the market for refined products into Ireland.

The taxation of automotive fuel deserves a re-examination, particularly the way that such taxes impact the climate change strategy as a result of "fuel tourism" seen between Ireland and Northern Ireland. The swing between 1990 and 2002 has added 1 Mt CO_2-Eq to Ireland's emissions, an amount equal to 14% of the emissions increase that Ireland is allowed under its Kyoto commitments. This issue needs to be kept under review in light of the proposed introduction of a carbon tax, exchange rate fluctuations between the euro and sterling, final customer pricing, government revenues and tax harmonisation efforts at EU level.

RECOMMENDATIONS

The government of Ireland should:

- *Ensure that the regulatory framework facilitates continued monitoring of developments in the natural gas market and, where results do not lead to effective market opening and corresponding competition in the market, work out and adopt the necessary procedures to ameliorate the situation.*

- *Ensure continued adequate transmission capacity and non-discriminatory third-party access to the transmission grid.*

- *Develop a security of supply policy by defining minimum objectives and responsibilities of sector participants while allowing individual players the* *means to achieve these objectives. The costs of implementing all security of supply measures must be weighed against benefits.*

- *Continue to engage in international co-operation, including through the IEA, the Energy Charter, the EU and the IEF, to support regional security of gas supply.*
- *Undertake efforts to streamline and shorten planning procedures for domestic exploration and production, including ensuring that the affected regions understand the value of production to the country and to their community.*
- *Review taxation of automotive fuels in light of fuel tourism and the consequent impact on GHG emissions.*

INDUSTRY STRUCTURE

In 1927, the Electricity Supply Board (ESB) was established as a statutory corporation in Ireland to co-ordinate and develop the country's electricity system. Until recently, it also acted as the regulatory body, with the power to grant permits for all electricity undertakings. Over the years, ESB grew into a fully integrated electricity monopoly, providing virtually all generation, transmission, distribution and supply services to Ireland. The company employs 8 000 people and, as part of a partnership process with management, trade unions represent their members on issues affecting the workers. ESB has approximately 1.6 million customers. With the enactment of the Electricity Regulation Act 1999, the function of regulation of the electricity industry was removed from ESB and transferred to the Commission for Electricity Regulation (CER).

While ESB has remained a vertically integrated company, it is in the process of separating its business units. The European Communities (Internal Market in Electricity) Regulations 2000 (S.I. 445 of 2000) provided for the establishment of an independent transmission system operator (TSO), known as EirGrid. While transmission system ownership remains with ESB, EirGrid is responsible for operating as an independent company, licensed by the CER. This relationship is discussed in greater detail below. ESB continues to own and maintain the Irish transmission system.

ESB engages in international consultancy work through its subsidiary, ESB International (ESBI). ESBI operates in over 77 countries providing a range of services in engineering, contracting, consulting, finance and software and is, together with the International Investments wing of ESB, the vehicle for pursuing ESB's international strategy. Another company within ESB is ESB Independent Energy Ltd. This company is ring-fenced from other parts of ESB and is free from any regulatory restriction to pursue generation and sales activities in Ireland and internationally.

ESB owns and operates 18 major power generating stations with a combined capacity of 4 508 MW. These are shown in Table 5.

ESB’s 4 508 MW of plant gives the company more generating capacity than the peak demand record of 4 400 MW set in January 2003. As part of the market reform process, ESB has committed itself to reducing its share of the market to 60% by 2005. Currently, ESB market share of all Irish generation assets is between 85% and 90%.

Table 5

ESB Generation Stations

Station	*Capacity (MW)*	*Fuel Type*
Shannonbridge	125	Peat
Lanesboro	85	Peat
Rhode	40	Peat
Bellacorick	40	Peat
Cahirciveen	5	Peat
Turlough Hill	292	Hydro (Pump Storage)
Liffey	38	Hydro
Ardnacrusha	86	Hydro
Erne	65	Hydro
Clady	4	Hydro
Lee	27	Hydro
Moneypoint	915	Coal
Tarbert	620	Oil
Great Island	240	Oil
Aghada	525	Gas
Poolbeg	1 020	Oil and Gas
North Wall	266	Oil and Gas
Marina	115	Gas
Total	**4 508**	

Source: ESB.

In 2001, two major generating plants were brought on line. In May 2002, Synergen, a special-purpose company owned 70% by ESB and 20% by Statoil of Norway, began commercial operation of a 400-MW gas-fired CCGT facility. This plant gained clearance only on the condition that it sell at least half its output to non-ESB independent suppliers. In November 2002, Huntstown Power, a subsidiary of the Viridian Group (Northern Ireland's incumbent utility), brought a 340-MW gas-fired CCGT on line. Power from the Huntstown plant will be sold and marketed by Viridian Energy Supply Ltd (also referred to as Energia), another subsidiary of the Viridian Group. Ireland's approximately 5 GW of installed capacity makes it by far the smallest electricity market in the EU (with the exception of Luxembourg).

On the retail side, the European Commission reports that there are 19 licensed suppliers in Ireland[14] that could compete with ESB for eligible retail customers.

14. Source: "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

However, the majority of these companies are not yet active in the Irish retail market. The three most active are, first, Energia, a subsidiary of the aforementioned Viridian Group, the incumbent utility in Northern Ireland. Energia sells to retail customers from its newly constructed Huntstown plant and from capacity acquired from ESB through the Virtual Independent Power Producer (VIPP) auctions which are described below. The second major supply company is ESB Independent Energy Ltd., the ring-fenced business unit of ESB mentioned above. ESB Independent Energy sources power from the newly constructed Synergen facility and from ESB capacity obtained through the VIPP auction. The third major supply company is Airtricity, whose generation activities are described in Chapter 8. The company is believed currently to serve approximately 15 000 customers with green electricity. Duke Energy International has also appeared in the Irish market, purchasing capacity from the VIPP auction of 2002.

ELECTRICITY DEMAND AND SUPPLY

In 2000, Ireland consumed 1.7 Mtoe (20.24 TWh) of electricity, an amount equal to 15.6% of the country's TFC. Industry consumes 38% of Irish electricity, followed by residences at 34% and commercial users at 27%.

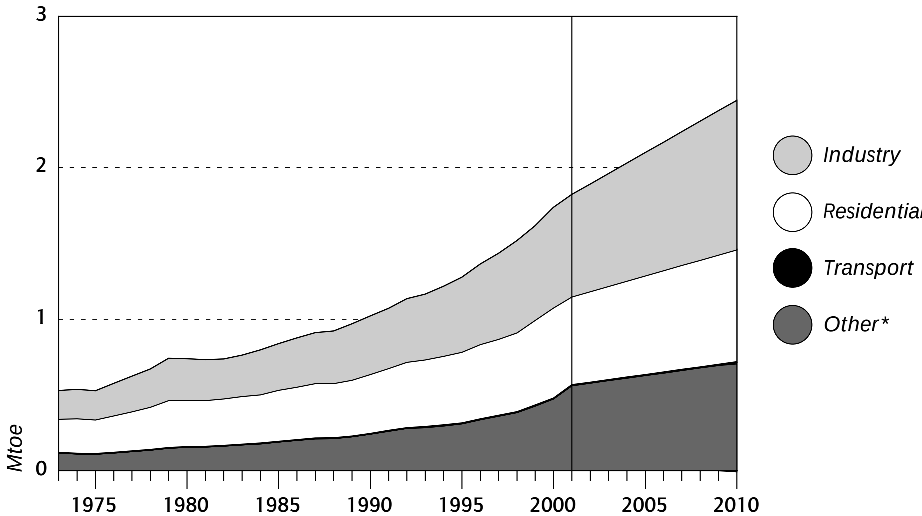
Electricity demand has grown steadily in the last decade. From 1990 to 2000, electricity consumption has grown at an average annual rate of 5.4% per annum. This is nearly double the IEA average of 2.8% annual electricity growth. Ireland's growth has accelerated in recent years with demand increasing by 6.9% per annum in 1999 and 2000. Much of this increase is due to the county's strong economic performance over the period and the consequent rise in energy demand. Figure 15 shows historical and projected final consumption of electricity by sector.

Peak electricity demand in Ireland is also growing at a rapid pace. From 1990 to 2000, this peak grew from 2.6 GW to 3.84 GW, an average annual rate of 4.0%. The peak demand growth has accelerated since then, growing at 4.6% per annum from 2000 to 2003. In early January 2003, it reached a new peak of 4.4 GW. Ireland is a winter-peaking electricity system owing to widespread use of electric heating. Electricity capacity has also grown over that time, but not as quickly. In 1990, the country had 3.4 GW of capacity, with a reserve margin of 31%. By 2000, capacity had grown to 4.29 GW but the reserve margin had fallen to 12%. The situation became worse in 2001 until new capacity in 2002 raised the reserve margin.

In 2000, natural gas was the largest generation source for electricity, accounting for over 39% of the power produced. Coal was second at 29% and oil products third with 20%. Generation from both natural gas and oil has increased rapidly in recent years. From 1995 to 2000, generation from

Figure 15

Final Consumption of Electricity by Sector, 1973 to 2010



* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

gas has grown at an annual average rate of 12.4% while generation from oil has grown at a rate of 11.6%. Generation from coal has remained stable in absolute terms although its percentage share of total generation has fallen from 40% in 1995 to 29% in 2000. Generation from wind turbines was introduced in Ireland in 1992 and has, since then, grown to account for 1.0% of total domestic generation in 2000.

Gas-fired generation is expected to dominate in the medium term. ESRI projects that natural gas could account for 80% of total generation in 2010 if the fuel-switching proposals in the NCCS are implemented. Coal's contribution to electricity generation would drop from 29% to 14% and oil from 20% to just 1.4%.

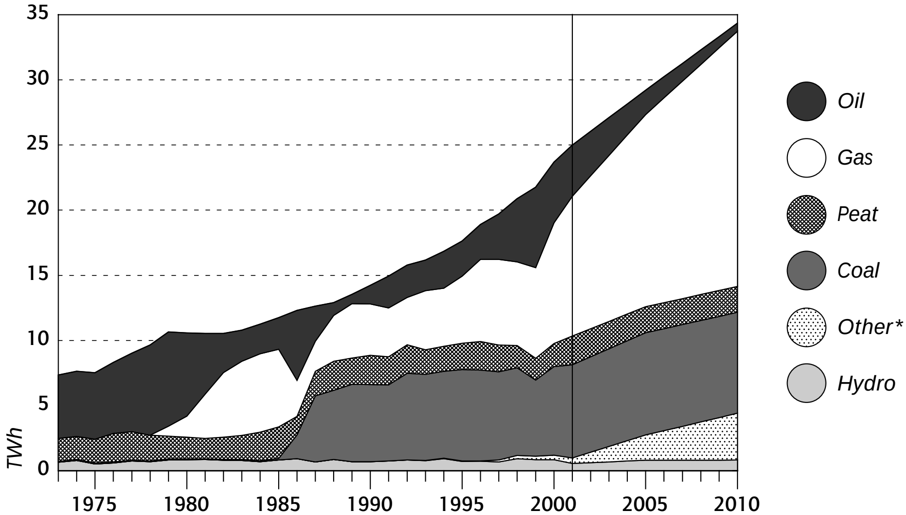
Figure 16 shows the breakdown of all historical and projected generation sources.

TRANSMISSION AND DISTRIBUTION

Ireland's transmission system comprises over 5 800 km of high-voltage lines operating at 110 kV, 220 kV and 400 kV. The Irish national grid was originally established as a 110 kV network but, as the demand for electricity grew, 220 kV and 400 kV lines were added. The 400 kV lines are used to

Figure 16

Electricity Generation by Source, 1973 to 2010



* includes solar, wind, combustible renewables and wastes.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002; and country submission.

carry power to Dublin from the large Moneypoint coal-fired generating station in the Shannon Estuary. The transmission system also includes over 100 high-voltage transformer stations where voltage is reduced for use in the local distribution lines at voltages of 38 kV, 20 kV and 10 kV. The distribution network includes about 80 000 km of overhead wires and underground cables. The total number of ESB customers at the end of 2000 was slightly more than 1 630 000.

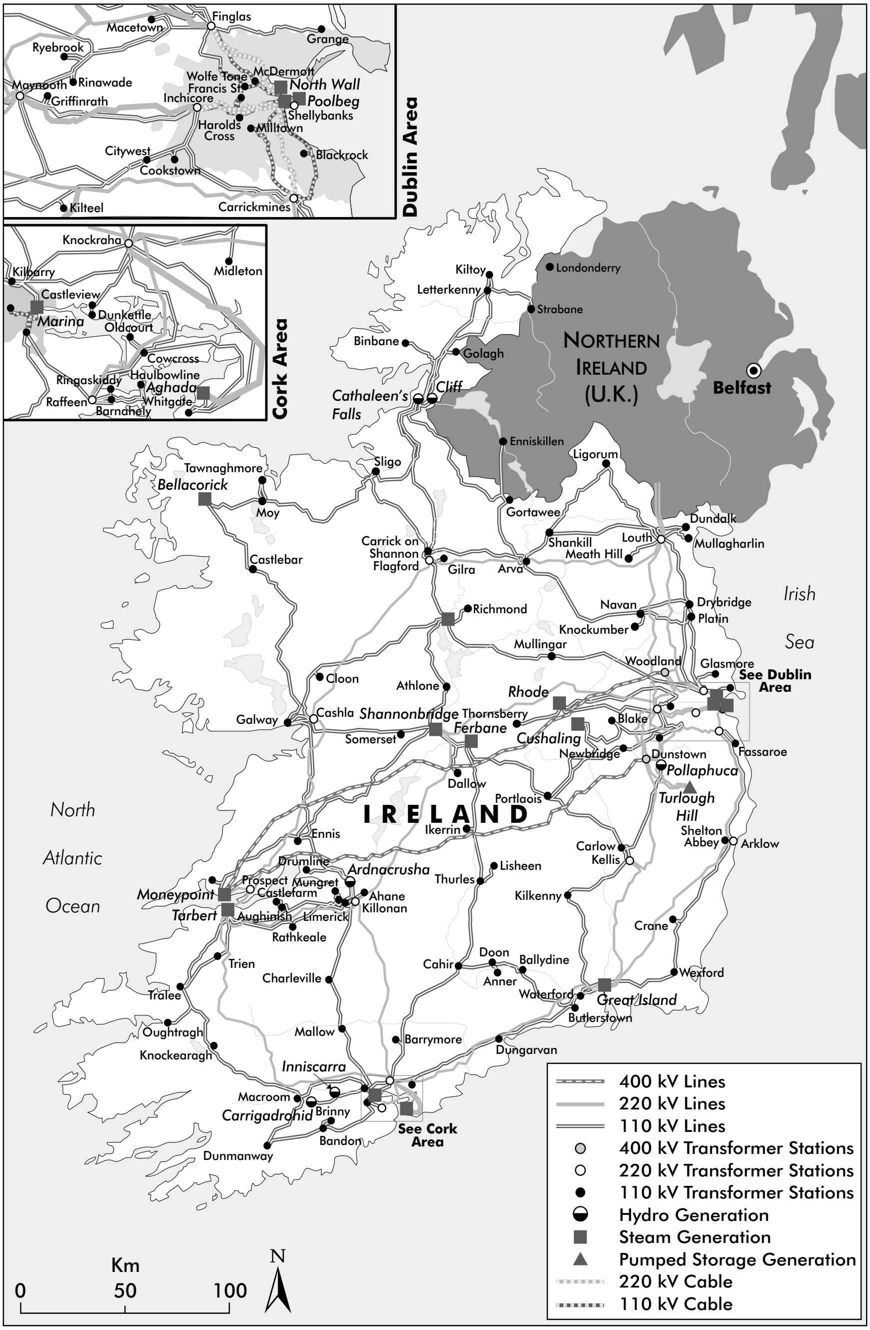
Figure 17 shows the map of the Irish transmission system.

As electricity demand has grown in the past decade, transmission system capabilities have become strained, creating a need for a system upgrade. A major refurbishment and expansion programme running from 2001 to 2005 is now in place. This programme increases annual capital expenditures on the transmission and distribution system by a factor of three. Over €2.6 billion is being invested in the high-voltage and low-voltage networks, particularly in the counties along the southern and western coasts. Over €820 million will be spent on transmission, over €1 billion on distribution renewal, and over €665 million on distribution reinforcement.

Ireland's only international electricity connection is with Northern Ireland. The original interconnector between Ireland and Northern Ireland was the Tandrage-Louth interconnector. Built in 1970, this interconnector was reopened

Figure 17

Map of the Irish Transmission System



Source: EirGrid.

in 1995 after a twenty-year interruption. In 2001 the interconnector was nominally upgraded from 2x300 MW to 2x600 MW. The €19.5 million financing for this upgrade was split equally between Viridian, ESB, and the European Regional Development Fund (ERDF). In addition, two smaller standby links have been commissioned as full system interconnectors with a capacity of 120 MW. This brings the total nominal north-south interconnection to 720 MW in both directions. However, constraints on both sides of the interconnection limit actual transmission capabilities to 195 MW of imports and 60 MW of exports.

An east-west electricity interconnector between Ireland and Wales was examined by ESB National Grid in conjunction with the UK National Grid as part of a Trans-European Networks (TENs)-funded project. This analysis resulted in the "Wales-Ireland Feasibility Study" issued in April 2002. The report has been made available to the CER on a confidential basis. The CER is now expecting a report from an external consultant in the first half of 2003. Technological advancements in the last ten years have lowered prices of such undersea transmission lines although no cost figures have been publicly made available. Estimates for possible project completion range from 2007 to 2009 and indications from representatives of the Department of Communications, Marine and Natural Resources are that the interconnector would have a capacity in the neighbourhood of 500 MW.

RETAIL PRICES

Up to 2000, electricity retail prices in Ireland were very close to the average for prices in all EU countries. In 2000, the Irish ex-tax retail price for industrial customers was 5.3 eurocents/kWh, while the average for the EU[15] was 5.1 eurocents/kWh. For residential rates, Irish end-users paid an ex-tax price of 9.8 eurocents/kWh, while the average for the EU[16] was 9.5 eurocents/kWh.

Historically, Irish retail prices in all customer classes have been very close to UK prices. An historical comparison between Ireland, the UK and other selected countries is shown in Figure 19.

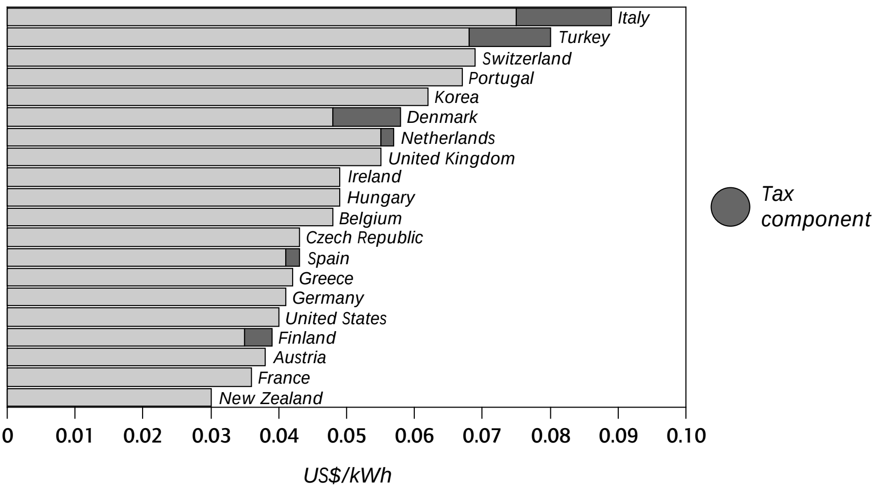
Since 2000, commercial and industrial prices have risen substantially in Ireland, taking them above the average prices found in other EU countries. In November 2001, industrial prices rose by 14%. The average unit price for industrial users from November 2001 to December 2002 was 6.04 eurocents/kWh.

15. Price data from Luxembourg and Sweden missing.
16. Price data from Sweden missing.

Figure 18

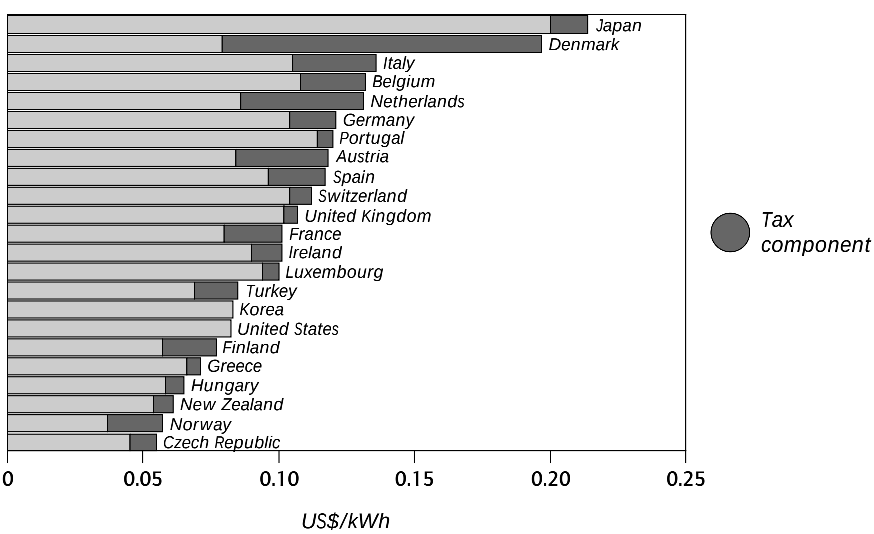
Electricity Prices in IEA Countries, 2000

Industry Sector



Note: Price excluding tax for the United States. Tax information not available for Korea. Data not available for Australia, Canada, Japan, Luxembourg, Norway and Sweden.

Household Sector

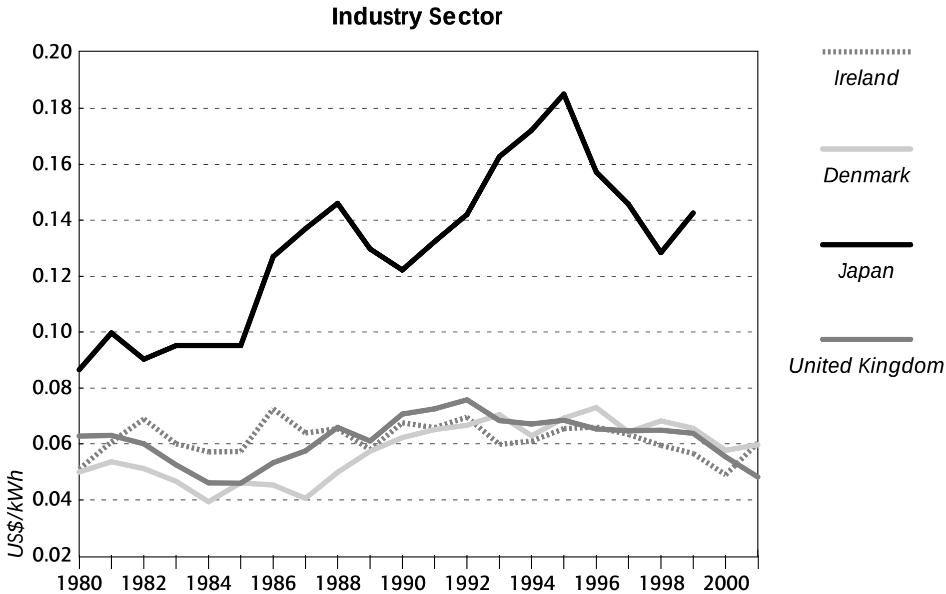


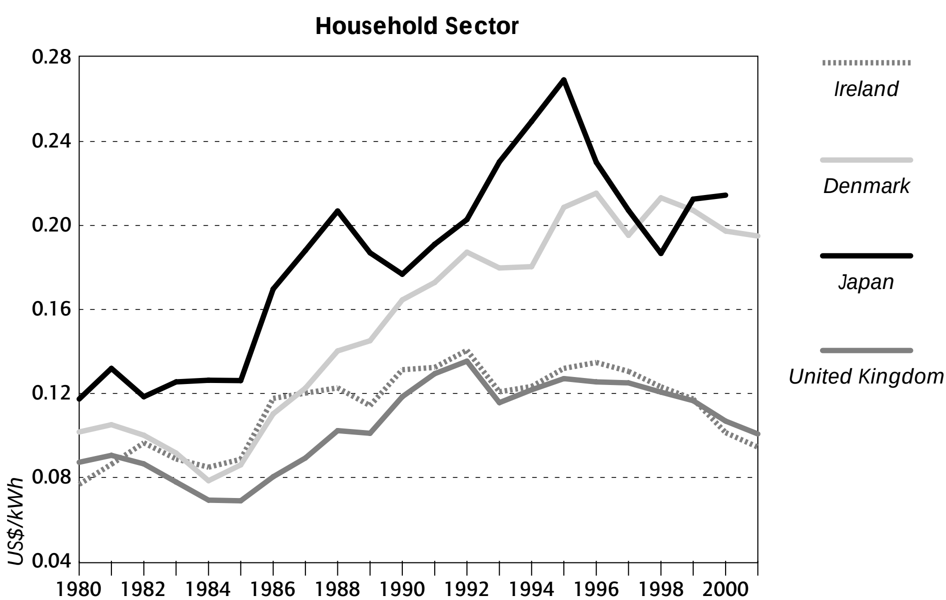
Note: Price excluding tax for the United States. Tax information not available for Korea. Data not available for Australia, Canada and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Figure 19

Electricity Prices in Ireland and in Other Selected IEA Countries, 1980 to 2001





Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

This price increase follows a September 2001 review of electricity prices by the CER. During the course of its examination, the CER found that ESB was significantly under-recovering its generation costs among the majority of customer classes, primarily because of increases in fuel costs that were not being effectively passed through to end-users. The commission found that such under-recovery threatened security of supply, since new generators would not enter the market while ESB had artificially low and/or non cost-reflective tariffs. As a result, the CER directed ESB to increase its charges by an average of 8.6%, with effect from 1 October 2001. This was the first step in a process to deliver fully cost-reflective tariffs.

On 6 September 2002, following cost submissions by ESB, the CER issued a proposed direction to ESB in relation to electricity tariffs. After considering representations from interested parties, the commission issued its final Tariff Direction to ESB approving a 9.85% increase in the average price of electricity. ESB had been seeking an average increase of 14.7%. The main drivers behind the tariff increases were the need to recover investment in the electricity network, increases in the unit costs incurred by ESB in delivering electricity to its customer base and the need to recover some costs deferred in the increases allowed to ESB last year. This latest tariff review sought to advance the process of rebalancing the tariffs to ensure that all tariffs fully reflect the cost of supplying the different categories of customers. The tariffs for providing electricity to the residential customer class have historically under-recovered the costs incurred. The CER states that such under-recovery is considerably reduced at this point and will be eliminated altogether by 2005.

The distribution component of the tariff has tended to be below tariffs in other EU countries. According to a study[17] published by the European Commission in November 2002, Irish system access charges for high-, medium- and low-voltage tariffs are below the average of all EU countries. This is due to the mild topography and relatively short distances in Ireland as well as the system capacity not exceeding requirements as has been found in other EU countries. Table 6 shows the low- and medium-voltage networking charges for EU countries.

GENERATION ADEQUACY

In recent years, emergency measures have been necessary to ensure the adequacy of Ireland's generating capability. In the winters of 2001 and 2002, ESB leased barge-mounted capacity to ensure that Irish electricity demand was met. In 2001, they procured 120 MW of distillate-fired

17. Source: "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

Table 6

Electricity Distribution Tariffs, 2001

Country	*Medium Voltage*		*Low Voltage*	
	Average Charge (€/MWh)	*Approx. Range (€/MWh)*	*Average Charge (€/MWh)*	*Approx. Range (€/MWh)*
Austria	20	15-25	65	50-80
Belgium	15	..	..	..
Denmark	15	..	25	..
Finland	15	..	35	..
France	15	..	50	..
Germany	25	15-45	55	40-75
Greece	15	..	..	..
Ireland	*10*	..	*40*	..
Italy	10	..	..	..
Netherlands	10	..	35	..
Portugal	15	..	..	..
Spain	15	..	45	..
Sweden	10	5-15	40	20-60
United Kingdom	..	10-15	40	30-50
Average	**14.5**		**42.6**	

Source: "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

combustion turbine capacity and in 2002, they procured 170 MW of capacity. With the completion of new plants in 2002, no such supplemental capacity was required for the winter of 2003.

The second EU benchmarking report clearly shows how tight the Irish electricity market is in comparison with other EU countries. It also shows how little import transmission capacity Ireland has to offset any losses in domestic generation sources. Table 7 summarises these data prior to the introduction of Ireland's new generating plants in 2002.

As noted above, Ireland has minimal international transmission connections. This is confirmed by Table 7 which shows that such interconnections make up only 6% of total peak needs, the second-lowest for any country in the EU. The relative lack of such interconnections makes domestic generation adequacy more important.

Table 7

Electricity Security of Supply

Country	*Reserve Capacity[1], %*	*Import Capacity (% of peak)*	*% Annual Increase in Peak Load*
Austria	34	44	2.1
Belgium	2	31	2.1
France	16	23	1.9
Germany	5	18	0.5
Luxembourg	–	100	2.8
Netherlands	7	25	3.0
Portugal	13	48	4.0
Spain	16	7	3.1
Greece	7	15	3.2
Italy	9	22	3.7
Ireland	*–2*	*6*	*3.0*
United Kingdom	12	3	1.0
Nordel	1	5	0.8

(1) Reserve capacity is defined as the guaranteed capacity minus load at 11 a.m. minus margin against peak load, all as a percentage of load at 11 a.m. plus margin against peak load.

Source: "Second benchmarking report on the implementation of the internal electricity and gas market", Commission of the European Communities, October 2002.

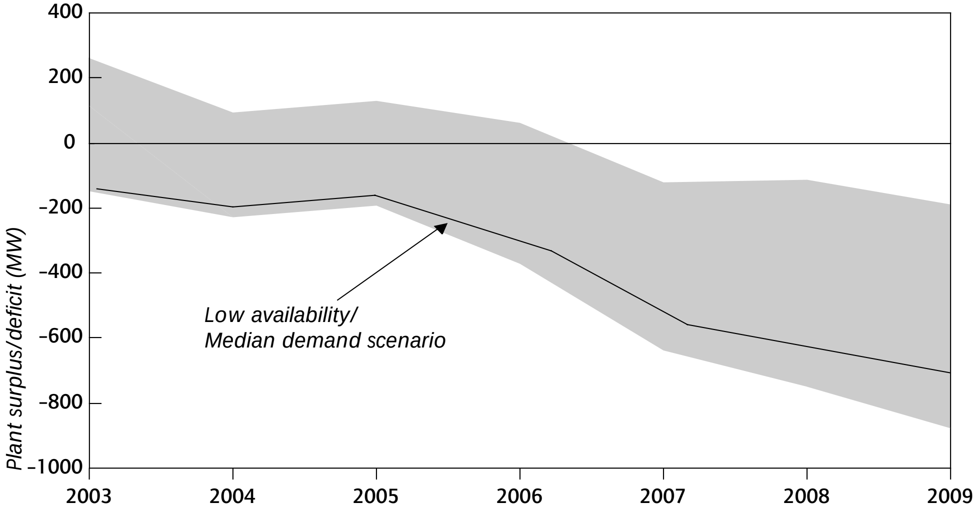
The National Grid has been given the mandate to periodically assess the adequacy of the generating plant infrastructure serving Ireland. In November 2002, it released the *Generation Adequacy Report, 2003-2009*. This report projects electricity demand over the coming seven years using high (4.01%), median (3.49%) and low (2.88%) annual growth rates. While such growth rates are significantly below what Ireland has seen in the last five years, they are still well above the electricity growth rates seen in most other EU countries. The report then projects capacity levels, taking into account announced new plants and closures. It then applies a range of availability figures (low, median and high) to the generating capacity based largely on historical performance which has been in the neighbourhood of 85%. Figure 20 shows the range of expected capacity shortfalls.

The report concludes that in 2004, but possibly as soon as 2003, Ireland will see a generation shortfall. In the final analysis the report recommends that by 2005 the system acquire 300 MW of centrally dispatched large-scale plant, 250 MW more by 2007 and 150 MW more by 2009.

The CER has also commented on the generation adequacy issue in its consultation paper, *Investment in New Electricity Generation Capacity*, issued

Figure 20

Projected Generating Plant Requirements for Ireland, 2003 to 2009



Source: *Generation Adequacy Report, 2003-2009*, ESB National Grid, November 2002.

on 24 October 2002. This paper concludes that unless some new action is taken (*i.e.* the construction of new generating plant) the system is unlikely to meet the future demand in 2005, taking into account expected reliability of the system and a safe reserve margin. The paper goes on to say that generation adequacy in 2004 is also in question but that it will have to be treated in a different manner since no large plant could be constructed in time to fill the shortfall.

ELECTRICITY MARKET REFORM

The government of Ireland has initiated market reform in the electricity industry. Reform began with the Electricity Regulation Act 1999 and was further advanced by the European Communities (Internal Market in Electricity) Regulations 2000 (S.I. 445 of 2000). The government intends the reform to facilitate and stimulate properly regulated and fair competition. These two pieces of legislation combined provide the overall framework for the development of the reformed electricity sector. A new Electricity Bill is being drafted which will consolidate all existing electricity legislation, while eliminating unnecessary legislation currently in force. The bill will also deal with all remaining regulatory and restructuring issues.

The Policy Direction issued by the Minister for Public Enterprise in 1999 required that a review of the overall trading arrangements for the Irish market take place in 2004. Currently the market is structured as a bilateral contracts market where specific generators contract directly with supply companies or end-users themselves. The CER decided to accelerate this review to provide existing and potential market participants with an increased level of certainty, and is due to be completed in 2003. This review will cover many aspects of the trading regime including: the nature of the trading system, obligation of supply, "green" participants, methods for calculating market price, demand-side participation in market and network access rights

THE COMMISSION FOR ENERGY REGULATION

On 14 July 1999, the Electricity Regulation Act 1999 established the Commission for Electricity Regulation (CER). Following the passing of the Gas (Interim) (Regulation) Act 2002, enacted on 3 April 2002, the Commission's jurisdiction was expanded to that of energy regulator, incorporating both gas and electricity. Since 30 April 2002, the commission has been renamed as the Commission for Energy Regulation to reflect its increased role.

The CER is legally independent in the performance of its functions. It is funded by means of a levy on energy undertakings and income from licensing fees. As of Q4 2002, it employed 33 staff. It engages in a consultation process on all aspects of the future direction of the electricity industry. It is accountable for the performance of its functions to a Joint Committee of the Houses of Parliament and is subject to audit by the Comptroller and Auditor-General.

The CER performs the following duties in the electricity sector:

- Authorising the construction of new generating plant.
- Authorising licences to companies wishing to generate and supply electricity to customers.
- Regulatory responsibility in relation to the transmission and distribution networks.
- Approving tariffs for third-party access to networks.
- Regulating prices charged to customers by ESB as Public Electricity Supplier.

MARKET OPENING AND SUPPLIER SWITCHING

Market reform has included the gradual opening of the market to customer choice of supplier. In January 2002, the Minister for Communications, Marine and Natural Resources signed the Electricity Regulation Act 1999 Eligible Customer Order 2002. This order gave customers with annual demand greater than 1 GWh the right to choose their electricity supplier. This order expanded supplier choice from 400 to 1 600 customers and covers about 40% of the market by volume. The markets for electricity coming from renewable energy technologies and from CHP plants had already been liberalised. Since February 2000, all customers have been free to source their power from any supplier offering "green" power and from April 2001, they have been free to source from any supplier offering power from a CHP plant. The government expects full market opening for all customers by 2005 at the latest. By mid-2002, 400 eligible customers had switched to suppliers other than ESB (primarily Energia and ESBI) accounting for 25% of the eligible market. In addition, approximately 16 000 customers have switched to green suppliers, out of the 1.6 million total customers who are now eligible to source from alternative suppliers offering green power. The large majority of green power is being provided by Airtricity.

The effect of market reform on energy prices is unclear. While those companies switching to suppliers other than ESB have presumably done so to lower their prices, the regulated prices for industrial customers staying with ESB have risen. This price rise is largely an attempt to bring tariffs in line with costs and hence avoid under-recovery and should not therefore be seen as a direct result of market reform. The prices paid by customers switching suppliers are confidential.

VIRTUAL INDEPENDENT POWER PRODUCER (VIPP) CAPACITY

In an effort to facilitate access to the market by independent players in advance of new plants coming on line, temporary control of the output from portions of ESB capacity has been auctioned off. Since ESB still maintains complete ownership and operation of the capacity, these auctions have been termed the Virtual Independent Power Producer (VIPP) auctions. They are administered by the CER. VIPP auctions have been held annually in October 2000, 2001 and 2002. In each auction, 600 MW of capacity has been offered up to bid. Bidders submit the price at which they would be willing to ensure rights to the capacity through the buying of options. The energy price for electricity from this capacity is specified before the bid. While the price of securing capacity (*i.e.* buying the options) is, in theory, determined by the competitive bidding, a reserve (or minimum) price is set. The combination of the reserve price and the energy price is set so that the total price of electricity is approximately 8.5% below the generation and supply components of the tariffs for customers currently eligible to choose third-party suppliers.

For the first two VIPP auctions in 2001 and 2002, the capacity was offered for one year. In the 2002 auction, 75 MW (out of 600 MW total) were offered for a period of two-and-a-half years. Bidders to the VIPP auctions are bound by certain restrictions to ensure that the capacity offered is spread among multiple companies. No bidder may obtain more than 350 MW from the VIPP and no bidder may obtain VIPP capacity that, combined with actual capacity under its control, would give it more than 400 MW total. In the 2002 auction, four companies bid and successfully secured some of the available capacity: *i)* Bord Gáis Éireann, *ii)* Viridian Energy Limited (Energia), *iii)* Duke Energy International and *iv)* ESB Independent Energy Ltd. The auction was undersubscribed with only 530 MW being sold out of 600 MW being offered and all capacity was sold at the reserve (minimum) price. The CER will continue to conduct these auctions until February 2006 at the latest.

MARKET BALANCING MECHANISM

As part of the market reform process, a trading mechanism was established whereby independent power producers could buy and sell power to/from ESB when their demand did not meet their available supply. Power producers with surplus power, or spill, sell to ESB when their generation exceeds their demand, and they purchase needed power, or top up, from ESB when their generation falls short of demand at any point. The pricing scheme for these power sales, termed the energy imbalance pricing arrangements, is determined by the CER.

In September 2001, a review of the original market balancing system was begun in by the CER after it had received comments from market participants that the existing scheme was putting independent suppliers at a disadvantage. These critics of the system claimed that they were being insufficiently compensated for the spill power they sold to ESB while at the same time having to pay too much for the top-up power they needed to meet their demand. The CER reviewed this issue and, in August 2002, issued its decision on the pricing arrangements to the effect that the spill price will now contain a capacity-related element. This effectively raises the spill price (although it is nevertheless capped by the top-up price) so that independent generators can earn from the surplus power they sell to ESB or, in any event, minimise net losses they incur when balancing their supply with demand.

CREATION OF A TRANSMISSION SYSTEM OPERATOR (TSO)

The European Communities (Internal Market in Electricity) Regulations 2000 (S.I. 445 of 2000) provided for the establishment of an independent transmission system operator (TSO) known as EirGrid. EirGrid was established in February 2001 and issued with a TSO licence by the CER in June 2001. While transmission system ownership remains with ESB, EirGrid is an independent statutory company, licensed by the CER. It will have responsibility for operating, developing and ensuring the maintenance of the transmission system, as well as power station dispatch, and act as the System Settlement Administrator (SSA). As of Q1 2003, the TSO functions are being carried out by ESB National Grid (a ring-fenced business unit within ESB), until such time as the Infrastructure Agreement and Transfer Scheme between the ESB National Grid and EirGrid are put in place.

The creation of EirGrid and the separation of transmission and dispatch functions from ESB have given rise to a series of conflicts between market participants. Distribution of responsibilities between ESB and the newly created EirGrid were at the heart of the dispute. Particularly important was which entity would determine the timing and nature of any improvement or expansion to the system. This issue has been resolved, allowing plans for the full establishment of EirGrid to proceed as envisaged. EirGrid is expected to begin complete operations as a wholly separate entity in 2003.

As a result of compromise between all parties, the process of transmission system expansion has now been determined. EirGrid initiates the process by giving a preliminary design to ESB which in turn provides the detailed design, construction and cost information. EirGrid then has the right to veto any final design made by ESB. Under the compromise agreement, ESB must be selected as the company to carry out all construction work. The plan for expansion must be approved by the CER.

INDEPENDENT GENERATION COMPETITORS

In 2002, two independent power producers brought generating stations on line. These are the Synergen and Huntstown plants discussed above. Neither project represents the introduction of new players into the Ireland/Northern Ireland market since Synergen is majority-owned by ESB and Huntstown is owned by Viridian, the incumbent utility in Northern Ireland. While Aughinish Alumina announced plans to construct a 140-MW CHP plant on its site, to be completed by 2005, no other major player is at present expressing serious interest in entering the Irish generation market with a newly constructed plant.

In order to better understand this lack of interest from the private power industry, the CER engaged NCB Corporate Finance to look at the attractiveness of the Irish market from an investor's point of view. NCB produced a report describing its findings, *Issues Facing Those Considering Investing in the Irish Electricity Market*.

NCB offered its opinion on which aspects of the market would or would not attract the type of private power producers that the CER felt to be necessary to create a competitive market. The report cites the strong interest in developing new generation that followed the announcement of market reform, stating that over 4 000 MW of new capacity was initially proposed by different interested parties. The report goes on to try to explain why this generation never materialised, citing three major attributes of the market that made it unattractive to investors: *i)* Ireland's relatively small size, *ii)* ESB dominance and *iii)* uncertainty over future trading arrangements.

The report advises that future trading arrangements should abandon the currently used bilateral market arrangement by replacing them with another system such as a power pool. It also suggests that ESB divest some of its generation portfolio, either through asset sales or lease of assets, and its output for a period of ten to fifteen years.

A separate CER consultation paper, *Investment in New Electricity Generation Capacity*, issued on 24 October 2002, also looks at the lack of expressed interest in the Irish generation market and, in particular, whether and how sufficient generation can be brought on line to meet the expected shortfall in capacity in 2005. The paper identifies four factors which may be discouraging generators from entering the Irish electricity market. These are: *i)* the poor global investment climate for this sector, *ii)* the small size of the Irish market, *iii)* the scale of ESB's share of the Irish market, and *iv)* continuing uncertainty over trading arrangements and market rules.

The paper goes on to offer three options to induce new generators into the market in time to meet the expected capacity shortfall. These are:

- ESB would offer a power purchase agreement (PPA) to the next large-scale generator entering the market. This contract could be of limited duration (5 years) and taper off until the new plant eventually sold all output into the market.
- The TSO would offer a "capacity payment" for a number of years. Potential independent power producers (IPPs) would bid into the TSO the amount of additional revenue they would require over and above expected market receipts. The IPP(s) with the lowest bid would receive the money that it (they) requested.
- The CER could implement other means of assuring adequate capacity such as requiring that suppliers be obliged to either own or have specific commitments to purchase firm capacity of, say, 120% of their customers' peak load.

CRITIQUE

Ireland's electricity industry has a sound historical record, providing the country over the years with reliable, reasonably priced electricity. This performance comes despite a number of natural disadvantages such as scarce indigenous fuels, relative isolation, little or no chance for international power exchange, dispersed demand centres and a small economy limiting economies of scale and scope. In addition to the reliability and reasonable prices, the Irish electricity sector showed few signs of overbuilding their generation or transmission assets, as was the case in many state-owned or regulated power industries in other IEA countries. As a result, the reserve capacity in Ireland is far below the EU average.

The impetus for the country's market reform has not come from within Ireland. Neither the electricity consumers nor the incumbent utility nor potential competitors have pushed for the liberalisation that is currently taking place. The main motivation for reform of the sector has been Ireland's need to comply with the EU directives on the internal market.

The market reform process is heading in the right direction. An independent regulator has been established and given a mandate to promote competition through a variety of regulatory means. Despite some now-resolved legal disputes, operation of the transmission system and dispatch of generators have been placed in the hands of the transmission system operator that is independent from the incumbent utility. Efforts have been made to reduce the generation market share of the incumbent utility, ESB, through both the VIPP auctions and ESB's agreement to reduce its market share to 60% by 2005. An increasing number of customers are being given the right to choose suppliers, and the market was opened to all customers who wished to choose electricity from renewable energy technologies or CHP plants. Lastly, arrangements have been made for bilateral electricity contracts as well as for a market balancing mechanism.

Another positive step towards effective market reform has been an increase in electricity tariffs. Under-recovery of ESB costs through lower tariffs amounts to a subsidy that distorts the market. It makes competition more difficult because new entrants will have to compete with artificially low prices. Despite the price increases, Ireland still appears to face under-recovery in the residential sector. While this sector has historically under-recovered the most, it has been the industrial and residential prices that have risen most in the last two years. Elimination of any under-recovery, or the cross-subsidisation of one customer class for another, must be eliminated to have an effective competitive market and to ensure efficient consumption and investment decisions on the demand side.

While market reform has enjoyed some successes, it has also encountered a number of obstacles. While there has been some supplier switching, the majority of customers now getting their electricity from companies other than ESB receive power from Viridian, the incumbent in Northern Ireland, or from ESB Independent Energy, a subsidiary of ESB. It is disappointing that, with the exception of Airtricity, the presence of motivated, independent competitors in the generation and supply market has been negligible. Even the VIPP auction, which grants the rights to ESB capacity at prices below tariff rates, has drawn little interest with bids coming mainly from established players at the minimum bid prices. The VIPP auction in the autumn of 2002 failed to sell all available capacity. Without the participation of competitors, market reform will not bring the intended benefits and could, in fact, harm what has been a relatively successful operation under a regulated regime. Further re-structuring of the market will be needed to attract viable competitors. Therefore, the government should develop a clear vision for the overall market design and structure with a firm implementation timetable to provide market certainty and encourage investment in new generating capacity.

The reports by both NCB Corporate Finance and CER provide insightful analysis of this issue. While the lack of interest in the Irish market is due in part to the dramatic slowdown seen globally in the private power industry, specific characteristics of the Irish market appear to be deterring new entrants from investing in the country's power sector. Certainly the small size of the country's market makes it less attractive to potential investors. With the exception of Luxembourg, Ireland's power sector is half the size of the next smallest EU country (Greece). As a result, a moderately-sized plant of 400 MW will have a disproportionate effect on lowering prices, hence making the investment less attractive. In addition, the small size means Ireland will be controlled by a limited number of players, reducing market liquidity and hence increasing the risk to investors. The small size also makes it very difficult for competitors to develop a true portfolio of plants that would allow them to gain economies of scale in operation and mitigate risk through diversification.

While Ireland cannot, of course, arbitrarily increase the size of its electricity market, it can effectively increase its size by continuing to improve interconnections with other markets. The easiest such interconnection would be with Northern Ireland. While work has been carried out in recent years, bottlenecks still exist which limit actual transfer capabilities to well below possible and easily achievable levels. Ireland should work with Northern Ireland to further improve transmission connections.

The question of the UK east-west interconnector is less clear. Despite the recent cost reduction due to technological advancements, this would nevertheless still be an expensive venture. Before taking any such decision, further information needs to be gathered on the capital and operating costs for such a transmission link. This information should be gathered quickly and a decision taken as soon as possible since the lingering uncertainty of such a project deters new generation investments in Ireland as linkage with the UK would profoundly affect the Irish market and market prices. The CER should seriously consider making the TENs-funded report available in order to enrich the needed public discussion of this issue. An undersea UK interconnection could also serve to export power. While such exports are unlikely to be economically feasible for fossil fuel-fired generation, wind farms in Ireland could potentially send electricity to the UK. However, no wind plants will be built in the hope that an interconnection is built and so the lingering uncertainty of such a link acts to deter investment in Irish fossil generation without truly encouraging investment in wind generation.

ESB's dominant role in the liberalised electricity market should also be addressed. The company's vertical reach (generation, supply, distribution and an ongoing influence on transmission) and its large share of the generation market have given certain investors the impression that ESB will use its entrenched incumbency to their disadvantage.

Regarding ESB's vertical integration, resolving the question of effective operation of the TSO is most important. Many countries have systems such as Ireland's where the operator (EirGrid in this case) is separate from the owner (ESB). Such arrangements can work well and act to prevent the over-building or gold-plating of the transmission system that can occur when ownership and operation are in the same hands. In fact, ESB's own subsidiary, ESBI, acts as the transmission operator in the province of Alberta, Canada in a system where the assets are still owned by the incumbent utility. However, great care must be taken to ensure that the incumbent (who still is an important generator and supplier) cannot influence the transmission system to its advantage. It appears that ESB still has that power to a certain extent since it is, by law, the only company that can provide construction services to the TSO and, as a result, influence their cost and ultimately the decisions made on expansion. Construction services for all such system expansions or upgrades should be competitively bid in order to remove the impression that ESB could influence transmission in this way.

Many countries have bundled (or re-bundled) the operation and ownership of transmission assets. For example, the UK National Grid owns and operates the transmission system and yet is completely separate from all generation concerns. These transmission companies have all their operations and expansions regulated. Such systems can work effectively, and Ireland may wish to consider such a structure in the future. For the present, however, it seems that the influence ESB can exert on the transmission system is not so great and is, in any event, not the biggest challenge currently facing successful Irish market reform. The government should monitor and amend, if necessary, the current arrangements for separation of the operation and ownership of the grid to ensure that the objectives of an efficient and secure grid are not compromised.

ESB's participation in the supply market also raises vertical integration issues. Even if these companies are effectively ring-fenced from ESB's generation activities, the use of the ESB brand when competing for customers puts new market entrants at a disadvantage. In addition to ensuring effective "Chinese walls" that separate ESB business units, the CER should examine whether the ESB brand provides this unregulated supply unit with an unfair advantage.

Horizontal market power in generation is equally important to address. Even if ESB decreases its market share to 60% by 2005 without any divestiture or net plant closure as it intends, the company would still be too dominant in the market. Much of the other 40% would either be under contract to ESB (*e.g.* the Edenderry peat plant and many wind plants), would not participate actively in the market (*e.g.* inside-the-fence CHP plants) or act merely as price takers without the ability to influence the market price (*e.g.* wind farms). While the theory and practice of market power analysis in the electricity sector continues to evolve and no consensus has yet been reached, a rough rule of thumb states that a market needs a minimum of four or five roughly equal generating companies and ease of entry for new parties before effective competition can take place. The UK's experience with three players showed that such a limited number of players can still influence prices in an anti-competitive manner. Ideally the portfolios of each of these companies would be diverse and spread across the resource stack to ensure that no one company can dominate production at any given demand level. In order to achieve this standard, control of ESB's generation portfolio would have to be split up although this need not come in the form of full ownership divestiture. One option would be a series of long-term leases of ESB plant to other operators. Alternatively, ESB's generating assets could be dispersed among a number of newly created competing companies, all of which would continue to be 100% state-owned. Such an arrangement of strong competition among state-owned entities has been developed in New Zealand and Norway. At the same time, the benefits of any competition in the Irish market must be recognised, even if the perfect competitive market is not immediately reached. Even one or two additional players in the generation market could reduce costs and prices while at the same time providing the regulator with additional information as to how best create a more fully competitive market.

When considering the creation of several multiple smaller generating competitors, however, care must be taken to ensure that individual competitors are sufficiently large to achieve a minimum scale for efficient operation. Below a certain size, companies lose economies of scope and scale and this will generally increase their costs to develop and operate plants. In a competitive market, such cost increases would be passed along to consumers in the form of higher prices. Therefore, a balance must be struck between creating a sufficient number of competitors and ensuring that the small size of these competitors does not create unwanted cost increases.

The current trading arrangements as well as the uncertainty over the final form these arrangements will take also make the Irish market less attractive than it might otherwise be. Bilateral markets do not offer generators the relative security and liquidity that a power pool or a single buyer system might. In addition, the imbalance pricing mechanism, while improved thanks to the latest revision, still acts to the disadvantage of new suppliers or generators. Those companies facing the market must still pay more than ESB to balance their load with supply. These issues and others are being addressed in the overall review of trading arrangements now being undertaken by the

CER. This review is both comprehensive and admirably consultative so that it is highly probable that the new market rules will be much better designed to accommodate successful competition in the sector. The commission wisely accelerated the timing of this review in an effort to remove some of the uncertainty from the market.

The unsuccessful implementation of effective market and regulatory structures could undermine the benefits of competition as noted above. However, the greatest concern to the market now is the expected capacity shortfall in 2005. It appears highly unlikely that, given the market situation now or in the coming year, any independent company will build a private plant in time to meet this need. If that is the case, Ireland will either have to turn to ESB to build another plant or offer inducements for a private generator to enter the market. Both of these steps, or the least desirable alternative of power shortages, would impede market reform and/or harm the Irish economy.

Adding to ESB's share of the country's generation would undermine competition in the Irish energy sector. While providing inducements to private plants to enter is also antithetical to the precepts of a fully liberalised market, such an action can be done in a way that minimises the harmful effect on the market reform process. In its October 2002 consultation paper, the CER explored three such options to induce generation investment. These included a short-term power purchase agreement from ESB, an auction where independent power producers bid for an available capacity revenue and the introduction of a requirement that all suppliers own or contract for the peak demand of their customers plus a reasonable reserve margin. All three methods employ market forces to induce investment and, as such, can minimise costs to the final consumer. All three methods can also be designed to ensure that new players enter the market, an essential development for the successful operation of a truly competitive, liberalised market. While shorter-term measures (such as contracts covering solely those winter months where shortages are expected) can minimise the long-term effect of any such regulatory influence in the generation market, they tend to be very costly and result in high-priced inefficient plants. These high costs will be ultimately borne by the consumer. A balance needs to be struck, therefore, between longer-term capacity inducements (which bring lower total cost but can have a lingering regulatory influence in the market) and shorter-term inducements (which bring higher-cost plant but less long-term effects on the reform process).

Another important task for the Irish government and regulator is to oversee fuel diversity within the power sector. If all the proposed measures in the country's NCCS are implemented, Ireland will produce 80% of its electricity from gas-fired generation by 2010. This raises energy security concerns and should be closely monitored. There should be closer co-ordination between the policy-makers in charge of climate change and policy-makers in charge of the electricity sector. The government should further develop a clear policy on security of fuel supplies through diversity of fuels, generation technologies and dual-fuelling in order to avoid over-dependence by the power sector on imported gas in the long term.

RECOMMENDATIONS

The government of Ireland should:

- *Decide as a matter of urgency how best to ensure the construction of new generating capacity to meet the imminent supply shortfall. Ensure that this next increment of capacity is owned and operated by an independent power producer to facilitate market competition.*

- *Continue the process of strengthening the transmission grid, including around the north-south interconnection.*

- *Develop as a priority a clear vision for the overall market design and structure, with a firm implementation timetable to provide market certainty and encourage investment in new generating capacity.*
  - *Monitor and amend if necessary the current arrangements for separation of the operation and ownership of the grid to ensure that the objectives of an efficient and secure grid continue to be met.*
  - *Work towards a clear and coherent set of long-term market rules for trading, including providing for transparent, non-discriminatory market-clearing wholesale prices.*
  - *Consider a means of dispersing control of ESB generation among competing companies, particularly for mid-merit (*i.e. *price setting) plant. Alternatives for break-up include privatisation, setting up competing state-owned companies (with independent commercial boards), or leasing or auctioning off management rights to individual plants.*

- *Take an early decision on whether the East-West interconnector will be constructed, taking into account supply security and competition concerns, in order to facilitate decisions on market structure and to provide market certainty, especially for new investors.*

- *Continue efforts to develop an all-island electricity market, including by increasing the usable capacity of the North-South interconnector, in the interests of security of supply and competition.*

- *Develop a clear policy on security of fuel supplies for electricity generation, including through diversity of fuels, generation technologies and dual-fuelling, to avoid over-dependence on imported gas in the long term.*

PRODUCTION AND POTENTIAL

The use of renewable energy in Ireland remains low compared to other IEA countries. In 2000, renewable energy accounted for 1.8% of the country's TPES, compared to the average contribution for all IEA countries of 11.5%. Figure 21 shows the extent of renewables contribution to TPES for all IEA countries.

Renewables' use in electricity generation in Ireland is also lower than that found in other IEA countries. In 2000, electricity from renewables accounted for 5.0% of the country's total generation compared with the average in other IEA countries of 14.7%. This is primarily due to the absence of natural configurations that would support hydropower facilities and the historical absence of large biomass power plants use as seen in Finland and Austria.

The majority of Irish renewable energy comes from biomass. In 2000, biomass accounted for 64% of all renewables production. (This amount equalled only 1.1% of the country's TPES.) Hydropower was the second largest contributor with 28.3% of total renewable energy production and wind power was third, with 8.1%. No other renewable energy made significant contributions to TPES.

Although still making a very small contribution to the Irish energy sector (0.14% of TPES and 1.0% of the electricity market as of 2000), wind energy is the country's fastest growing renewable energy. From 1997 to 2000, power generation from wind technology grew at an average annual rate of 51%. In 1992, the first commercial wind farm of 6.45 MW was commissioned and began supplying power to the electricity grid. It remained the only wind farm in Ireland until 1997 when a further 6 facilities were commissioned with a combined generating capacity of 44 MW. Of these, four wind farms were built under the Alternative Energy Requirement I (AER I)[18] programme and two were built with EU support under the THERMIE programme. From 1997 to 2000, a further 5 wind farms were built including the first AER III wind farm and the first wind farm whose electricity was sold directly to final customers. As of June 2000, the country had 12 operational wind farms with a total capacity of 69.49 MW, representing 1.4% of total national electricity capacity. The majority of these plants are located in the western half of the country.

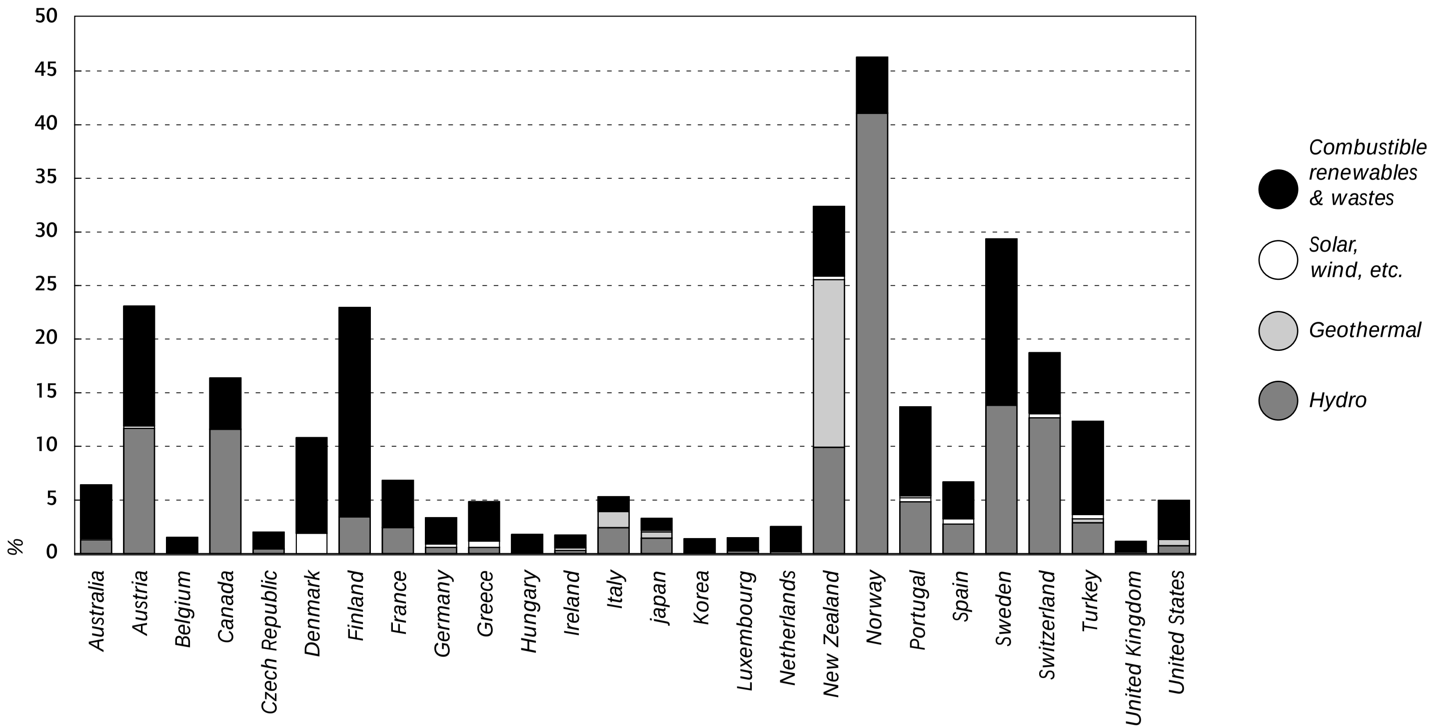
Strong wind resources in Ireland make it one of the cheapest countries in the EU to generate wind power, as Table 8 shows.

18. The AER programmes are Irish government initiatives to encourage renewable energy. They are discussed below.

Figure 21

Renewable Energy Contributions to Total Primary Energy Supply in IEA Countries, 2001*

(%)



* preliminary data.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2002.

Table 8

Costs Estimates for Wind Power Generation in the EU

	Country Generation Cost, euro ¢/kWh	
	Onshore	*Offshore*
Austria	7.59	n/a
Belgium	6.97	8.59
Denmark	6.47	8.50
Finland	6.66	9.29
France	6.29	8.61
Germany	6.67	8.58
Greece	6.80	10.07
Ireland	*5.68*	*7.18*
Italy	6.96	11.08
Luxembourg	7.68	..
Netherlands	6.46	8.44
Portugal	6.62	9.93
Spain	6.90	9.08
Sweden	6.86	9.46
United Kingdom	5.58	7.69
Average	**6.68**	**8.96**

Source: "Final Report of the Project ElGreen (Organising a Joint European Green Electricity Market)", Energy Economics Group (EEG), Vienna University of Technology, 2001.

The *Green Paper on Sustainable Energy*, published in September 1999 by the Department of Public Enterprise, produced the following table showing historical and projected contributions from renewable energy technologies.

Table 9

Renewable Energy Electricity Generation, 1997 to 2005

(GWh)

	1997	*1998*	*2000*(1)	*2005*(1)
Hydro	793	923	810	861
Wind	50	169	503	2 001
Landfill Gas	89	85	112	372
Waste-to-Energy	0	0	30	253
Total RE	932	1 177	1 454	3 487
Total Electricity	19 737	19 317	23 058	28 146
RE %	**4.72**	**6.09**	**6.31**	**12.39**

(1) Projections.

Source: *Green Paper on Sustainable Energy*, Department of Public Enterprise, September 1999.

Ireland has two separate targets for the increase in renewable energy capacity. The first arose from the *Green Paper on Sustainable Energy* (1999). This document establishes Ireland's plans to increase electricity generation capacity from renewable energy sources by an additional 500 MW by 2005 with wind energy as the dominant technology. This is expected to increase green electricity production towards 12% of total generation and account for 10% of the required emissions reduction needed to meet Kyoto commitments. The second target to increase renewable energy is derived from the EU. The government intends to comply with the target for Ireland in European Union Directive 2001/77/EC which establishes Ireland's target as increasing the consumption of electricity from renewable energy sources to 13.2% of total electricity consumed nationally by 2010.

GRID CAPACITY AND INTEGRATION

Integrating large amounts of wind power into the national electric grid poses certain challenges. These challenges fall into two separate, but related, categories. The first set of issues involves potential difficulties from large quantities of intermittently unavailable renewable power and its effects on energy security. The second set of issues involves the short-term quality of wind power and its effect on system stability.

Unlike more conventional technologies, such as coal- or gas-fired plants, it is difficult to project the actual production of wind power over short time frames. While planners can forecast long-term average output with a large degree of accuracy, that power may not be available on any given day owing to unpredictable weather conditions. In order to compensate for this, additional capacity must be brought on line as back-up in case the wind fails at a time of high demand. This inability to rely on wind capacity decreases as more plants are brought on line and dispersed across a wider geographical region. Such a breadth of wind farms combined with stochastic analysis regarding the probability of wind in given regions, can minimise but not entirely eliminate the need for additional capacity to back up wind power in the interests of energy security.

The second challenge when incorporating substantial wind power into the national system concerns the quality of electricity from wind plants and its short-term integration into the electricity transmission system. This poses few problems as long as the amount of wind power relative to the overall system generating capacity remains small, as is currently the case in Ireland. However, when the percentage of system capacity derived from wind technology reaches the levels proposed by the Irish government, certain issues can arise regarding system stability.

In order to maintain a stable system and system frequency, generation must always meet instantaneous system demand. Therefore, as demand of the system changes, some generating plant will have to change power output (by either ramping up or ramping down) to accommodate this change. Not only is wind power not well suited to such ramping, the power it delivers into the system is itself fluctuating, calling upon other generators to ramp up or down to compensate.

In a 2000 government report entitled *Strategy for Intensifying Wind Energy Deployment*, the issue of wind power system integration is examined. The report analyses two separate studies on this subject. One study, performed by the Irish Wind Energy Association (IWEA), maintained that wind energy penetration up to 20% of total system capacity in Ireland was not problematic. The other study, performed by ESB, concluded that the current targets proposed by the government could in fact pose significant challenges. Solving this problem will not simply be a matter of providing significant generation to compensate for the vagaries of wind power production. It can also be addressed through strengthening the transmission grid so it can handle changes in system frequency without failing. The costs involved with such system upgrades were not included in this study.

AIRTRICITY

The premier wind power company currently operating in Ireland is Airtricity. The company is developing wind farms in Ireland, Northern Ireland and Scotland and, at present, supplies customers in Ireland and Northern Ireland with electricity from green resources. Airtricity has two operating plants in Ireland. The first is Culliagh, officially opened in November 2000. It consists of 18 wind turbines with maximum output of 660 kW each for a total capacity of 11.88 MW. The second is Corneen, opened in August 2001, with two 1.5 MW turbines. Airtricity also has two wind farms under construction, with a planned maximum capacity of 38.5 MW, and 11 other onshore plants under development. In addition to its onshore wind plants, Airtricity is also developing what it calls the world's largest offshore wind farm consisting of 200 turbines with a combined nominal capacity of 520 MW off the west coast of Ireland.

GOVERNMENT INVOLVEMENT

POLICY OBJECTIVES AND TARGETS

The government is seeking to promote renewable energy technologies to help achieve the following objectives:

- Reduce environmental damage.
- Obtain energy from indigenous sources to promote security of supply.

- Further diversify energy sources.
- Contribute to the objectives of the National Climate Change Strategy.
- Reach the target of the EU directive on renewable energy.
- Ensure that the added value of these indigenous resources is maximised for the country.

In November 1999, the Renewable Energy Strategy Group was formed by the Minister of State at the Department of Public Enterprise to "examine all aspects of, and obstacles to, the further deployment of renewable energy technologies". The group published a report in 2000 entitled *Strategy for Intensifying Wind Energy Deployment*. In this report, the group made a series of recommendations including:

- Research into public attitudes towards acceptance of the technologies.
- Development of a digitised wind resource map.
- Introduction of a grid upgrade programme.

In addition, the establishment of SEI on a statutory basis will contribute positively to ongoing assessments of policy. The publication of the National Climate Change Strategy and the *Assessment of Offshore Wind Energy Resources in the Republic of Ireland and Northern Ireland* will also contribute to future assessments.

GOVERNMENT SUPPORT OF RENEWABLES

Government support for renewable energy technologies are described below.

Alternative Energy Requirement (AER) Programme

The AER programme was established to encourage renewable energy technologies to enter the market. The programme was intended to address difficulties that renewable facilities encountered when seeking financing. The AER offers guaranteed demand contracts awarded in a competitive bidding process. Competitions are hosted from time to time by the Department of Communications, Marine and Natural Resources (DCMNR). Companies bid prices at which they are willing to sell electricity generated from various eligible renewable energies. The contracts are awarded to those who bid the lowest prices in particular technologies up to quantitative limits in that technology decided by the minister.

The guaranteed demand contracts (or power purchase agreements, PPAs) resulting from the AER oblige the ESB to purchase all the output from selected new renewable energy-based electricity generation stations for up to fifteen years at each applicant's bid price. These contracts give a reasonably guaranteed revenue stream to ensure the projects are bankable and can thus obtain financing. They also remove any doubts concerning the final regulatory shape of the electricity market. That is, the revenue streams for these projects will be unaffected by the final shape and scope of the liberalised trading arrangements which are still being developed.

Table 10 shows the results for the first three AER auctions of power purchase agreements.

Table 10

Results from the First Three AER Auctions

AER Competition	*Overall Target (MW)*	*Total Installed Capacity (MWe)*	*Technologies Supported (MWe)*	
AER 1	75	70.62	Wind:	45.8
			CHP	10.72
			Hydro	2.3
			Landfill Gas	11.8
AER II	30	0	Biomass(1)	0.0
AER III	105	42.1	Wind	37.5
			Hydro	1.67
			Landfill Gas	2.93
			Wave	0.0

(1) The target for AER II was one biomass waste-to-energy plant although no plants were built with the contracts offered.

Source: Country submission.

The gap between the target capacity and final total installed capacity reflects the difficulties companies have had in successfully developing plants, even with a guaranteed contract. Such difficulties involved the inability to obtain local planning consent or financing for the plant.

In AER IV, only gas-fired CHP plants received support.

AER V is the most recent competition, the results of which were announced in February 2002. This round of the AER programme had an initial target of 255 MW. A primary precondition of entry to the fifth AER competition was the existence of the requisite planning consents from local authorities and licences from the CER. This requirement was introduced to improve the low yield rates of actual plants seen in AER II and AER III. In order to ensure that the target of 255 MW of installed renewable capacity was met, 360 MW of contracts were offered. This assumes that 105 MW of contracted power will not be successfully developed. Details of the technologies supported are outlined in Table 11.

Table 11

Results of AER V

Technology	*Published Target (MW)*	*Capacity Offered [1] (MW)*
Large-scale Wind	200	309.8
Small-scale Wind	40	35.795
Hydro (small-scale)	5	0.949
Biomass (including landfill gas)	10	8.008
Total	**255**	**354.55**

(1) This column includes simply the amount of contracts offered to projects; some of these will fail to be successfully developed.

Source: Country submission.

In February 2003, AER VI was launched to secure an overall national target (with AER V and AER VI) of 500 MW of additional renewable capacity in the period 2000 to 2005.

The PPAs offered to the projects that bid successfully in the AER are to last at most fifteen years, but not extend beyond year end 2018. The contract prices offered in response to the bids received are shown in Table 12.

The prices offered through these contracts are higher than the costs ESB would incur to generate power from other sources. According to the Public Service Obligation (PSO) Order, ESB is allowed to recover these net additional costs through the PSO levy, an amount added onto all customer bills[19]. The levy is determined by taking the price ESB paid through the AER contracts and subtracting the cost of power from a hypothetical best new entry, assumed to be a gas-fired CCGT producing power at €48/MWh. In 2003, the CER

19. The PSO levy actually includes both additional cost from AER contracts and the additional costs to ESB from those required to purchase peat for power generation (see Chapter 7). The total cost for AER purchases is €6.568 million, the total costs for peat are €39.9 million while administrative costs are €1.076 million. Therefore, if administrative costs are split in a weighted fashion, peat accounts for 85.6% of the PSO levy while AER purchases account for 14.4%.

calculates that the net additional costs incurred by ESB from the AER contracts will be €6.57 million. Table 13 shows the total PSO levy (including the amount intended to recover peat costs) and the amount attributable to the AER contracts

Table 12

Purchase Prices Offered under AER V

Technology	*Power Price Range (euro ¢/kWh)*	*% of Total Contracts in Corresponding Range*
Large-scale Wind (> 3MW)	4.6 or less	11
Price cap as specified in tender document	4.6 to 4.7	13
was 4.812 euro ¢/kWh	4.7 to 4.8	39
	4.7 to 4.812	32
	4.812	5
Small-scale Wind (< 3MW)	5.0 or less	13
Price cap as specified in tender document	5.0 to 5.1	3
was 5.297 euro ¢/kWh	5.1 to 5.2	7
	Other < price cap	59
	5.297	18
Offshore Wind	Approx. 8 euro ¢/kWh Biomass	
Biomass	5.5 or less	12
Price cap as specified in tender	5.5 to 5.7	0
document was 5.297 euro ¢/kWh	5.7 to 5.9	12
	Other < price cap	63
	5.916	12
Hydro	Weighted average of received bids	
Price cap as specified in tender document	was 6.41 euro ¢/kWh	
was 6.475 euro ¢/kWh		

Table 13

PSO Levy for Recovery of AER Contract Costs

Customer Category	*Total PSO Levy*	*PSO Levy Attributable to AER*
Domestic Profile	€11.49 / customer / yr	€1.66 / customer / yr
Small & Medium Profile	€35.67 / customer /yr	€5.15 / customer / yr
Large Profile	€5.94 / kVA / yr	€0.86 / kVA / yr

Source: Country submission.

Grid Upgrade Development Programme

One constraint to wider deployment of renewable energy is the capacity of the electricity network to accept renewable energy. In the case of wind, for example, the network tends to be weakest along the western seaboard where the wind resource is strongest. A major element within the Renewable/Alternative Energy measure in the Economic & Social Infrastructure Operational Programme to 2006 of the National Development Plan is the investment in strategic reinforcement and upgrade of the network to enable delivery of the 500 MW of additional green electricity capacity called for in the *Green Paper on Sustainable Energy*. A grid reinforcement Steering Group was established to oversee the selection of grid upgrade investment projects. The Steering Group has selected priority clusters which have been studied in depth by the ESB. The CER has since published a consultation paper, *Funding of Grid Upgrade Development Programme for Renewables*, in order to determine the most appropriate funding mechanism.

Liberalised Green Market

Since February 2000, the entire green electricity market (generation and supply) has been liberalised. As a result, suppliers are free to contract for the sale of electricity from their renewable plant to any electricity consumer, provided that they comply with the authorisation and licensing requirements of the CER. This gives renewable plants a potential pool of offtakers for their generation, thus making it easier to develop and operate such facilities.

Tax incentives

Section 62 of the Finance Act 1998 provides limited tax relief for corporate equity investment in an eligible company undertaking qualifying renewable energy projects. The scheme ended in March 2002 and a similar incentive measure was introduced in the Finance Act 2002. State aids clearance must be obtained from the European Commission, however, before the measure can be implemented.

SEI Renewable Energy Information Office

The Renewable Energy Information Office is a national service of SEI, established to promote the use of renewable energy resources and provide independent advice and information nationwide on financial, social and technical issues relating to renewable energy development.

CRITIQUE

While Ireland's current use of renewable energy is modest by EU standards, it has the potential to expand renewable use, primarily through its very strong wind resources which would greatly benefit the country.

- Wind power is emissions-free and, as such, can help the country meet its Kyoto targets.
- Wind is a domestic resource which will increase the country's energy security.
- The technology could soon become the least-cost option for electricity consumers (although costs for the needed back-up capacity would have to be factored in when making such an assessment). While wind does not currently offer the lowest prices, costs have fallen substantially and will continue to fall as the technology improves and companies gain size and experience in the Irish market. Wind power will become even more financially attractive if either a carbon tax or a market for carbon emissions is introduced.
- While not yet fully developed, an international renewable energy certificate market could allow Irish wind plants to trade "green certificates". Although the final shape of such a system is unclear, such trade could occur without the actual transmission of power, allowing Ireland to trade with any country regardless of its position.

Wind power potential and its degree of penetration into the market will be heavily influenced by four factors. The first is the percentage of wind power the system can accept. This is largely a technical question, closely related to decisions on investment in the transmission and distribution systems. Ireland has begun various analyses of how best to address this issue and is encouraged to continue to do so. At the same time, efforts to strengthen the transmission system to better accommodate wind power cannot be separated from the ongoing upgrade of the transmission system currently taking place in all parts of the country to help keep up with the growth in electricity use seen in the last decade. Two studies (described above) have examined this issue. Ireland should continue to work towards a conclusion in this subject as well as keeping account of the costs entailed in accommodating large wind power penetration.

The second factor influencing wind power penetration are the rules which will govern the liberalised electricity market. This is largely a regulatory question. Ireland is to be commended for the liberalisation of all electricity coming from renewable sources, thus opening up the way for "green power" to grow and serve customers. However, other issues still require clarification. Most of these are discussed in greater length in Chapter 7, but certain regulations that would particularly apply to wind power development include top-up/spill payments (*i.e.* balancing charges) and any type of capacity payment that might be introduced. Electricity regulators should consider all the effects that market rules will have on wind power development.

The third issue influencing the success of wind power in Ireland will be the means by which such capacity is backed up by more conventional sources.

Unlike other EU countries, Ireland does not at present hold substantial electricity generation reserve capacity. On the contrary, it will face generation shortages in the coming years if new capacity is not added. While new wind plants can address this potential shortage, the vicissitudes of their generating potential must be addressed through providing reliable capacity to replace them if wind is not present when needed. An analysis is needed of the extent of required back-up, involving a stochastic study of both the probable wind power availability and the variability of electricity demand. In general, low capital cost combustion turbines are best suited to backing up wind power (in the absence of imported power).

The fourth factor influencing wind power use in Ireland will be its cost. Currently wind is supported by a subsidy through the AER which costs consumers over €7 million per year. The willingness of the government, and ultimately consumers, to continue paying this price for support of renewables will influence their degree of use.

The AER has been successful in spurring wind power development with over 340 MW being contracted for in the AER announced in February 2002. With nearly 9 MW of other renewable energy technologies supported, this represents over 70% of the goal set by the government to introduce 500 MW of new renewable capacity by 2005. While not all of this contracted capacity will be built, the newly introduced requirements that all bidders must already have planning consent will improve the percentage of contracted capacity eventually brought on line. This new capacity also comes at a time when the country is facing potential electricity generation shortfalls for the electricity sector as a whole. While long-term power purchase agreements with the national incumbent utility are inconsistent with the country's goals of liberalisation, it does not appear that such contracts have in any way impeded the path towards a competitive market. On the contrary, they may have encouraged competition by supporting new entrants into the market place. On the whole, the AER have been a very effective tool in the Irish energy market.

Despite the many benefits of the AER programme, care must be taken to ensure that the prices in AER PPAs accurately reflect production costs for the most up-to-date, efficient wind technologies. Since the contract prices are determined by the bids of the companies competing for the contracts, the government cannot directly control the prices (except for putting a cap on prices, which it does). If there is insufficient competition for these contracts, the prices will be too high, *i.e.* at levels above what an efficient wind plant would require. On the other hand, fierce competition for these contracts could lead to bidding which is too aggressive. That is, the available contracts will be given to companies with bids below the actual price required to profitably run a wind farm. This could happen if the bidders are anticipating further technological and cost improvements or if they simply err in their revenue requirement or performance projections. In this case, the companies that win the AER contracts would be unable to operate their wind farms because the contract price is too low. At the same time, however, they would have effectively squeezed out higher-priced bidders who *would have been able* to operate their plants at the (slightly higher) power prices they submitted to the AER competition.

This situation should be monitored closely with especial attention paid to the actual number of plants brought on line compared to the volume of contracts awarded in AER V. If the market bidding procedure currently in place cannot guarantee a price that reflects the true costs of an efficient wind plant, another support mechanism will be required. One alternative would be to incorporate a fixed feed-in tariff as seen in Germany and Austria. Under such a system, the government sets the prices that various renewable energy technologies receive for their power. If this option is seriously explored by Ireland, care must be taken to ensure that costs, as fixed by the government, decline over time to both reflect and motivate further reductions in production costs. It should always be recognised, however, that the AER (or any subsequent support scheme) is indeed a temporary measure, incompatible over the long term both with a liberalised market and with technologies (such as wind) that must prove themselves in the market without the aid of subsidies.

Offshore wind farms also hold great promise. Their situation is slightly different from the onshore technologies in that, in addition to facing the technical and regulatory challenges that onshore plants face, they are at present considerably more expensive than onshore turbines. However, given Ireland's natural resource in the form of a very windy coastline, this option remains extremely attractive in the long term.

RECOMMENDATIONS

The government of Ireland should:

- *Develop a strategy to facilitate the increased penetration of wind power and other renewables into the national electricity market, taking into account back-up requirements.*
- *Ensure that any support schemes for renewables are market-based and incorporate proper incentives for further cost reduction.*
- *Continue to explore the potential for development of offshore wind parks, while taking into account the additional cost factors involved with grid interconnection.*

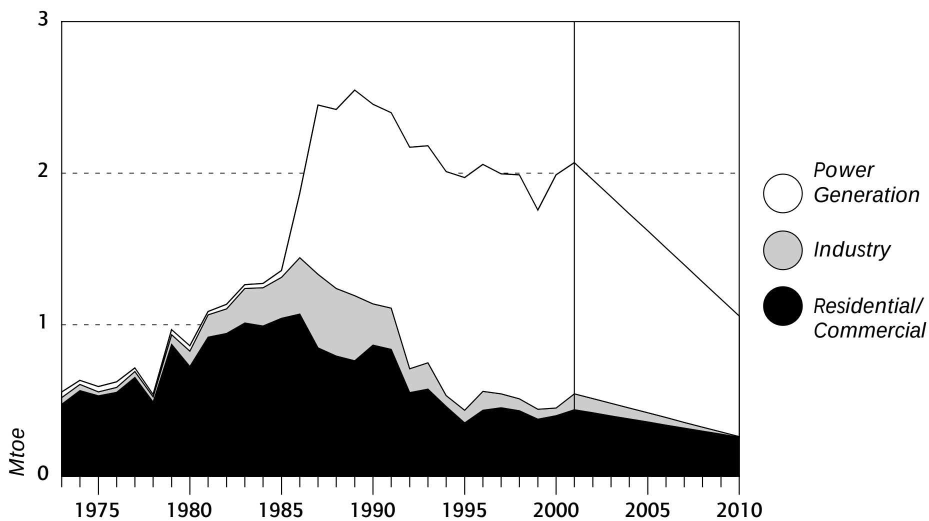
COAL

SUPPLY AND DEMAND

In 2000, TPES of coal in Ireland was 1.9 Mtoe, or 12.7% of the country total. Coal use has fallen substantially in Ireland in recent years. From 1990 to 2000, absolute coal use fell by over 20%, dropping as a share of the country's TPES from 22.7% to 12.7%. From 1996 to 2000, coal use fell by 7%. The government projects that coal use will fall further in the future, decreasing to 0.9 Mtoe in 2010 when it will account for only 5.2% of the country's TPES. Ireland has no indigenous coal production. All coal is imported, primarily from Poland, the UK and the US.

Figure 22

Coal Supply Use by Sector, 1973 to 2010



Source: *Energy Balance of OECD Countries*, IEA/OECD Paris, 2002.

Demand for coal comes primarily from ESB's 915-MW power generation facility, Moneypoint. In 2000, Moneypoint consumed 84% of all coal burned in Ireland. Coal-fired generation accounts for over 28% of all electricity generated in Ireland. The residential sector consumed 13% of all Irish coal and the industrial sector consumed 3%. Coal use in all sectors except electricity generation has been falling significantly. In 1990, residential coal use was 645 Mtoe, or nearly three times the current level in that sector. Similarly, industrial coal use in 1990 was 250 Mtoe, or almost five times the level in 2000. By contrast, coal use for power generation has increased over the same period. From 1990 to 2000, coal use for power generation rose by 17% in total. Figure 22 shows the historical and projected uses of coal in Ireland.

Coal use in the coming years depends largely on the future of Moneypoint. If Moneypoint is shut down or fuel-switched to natural gas, as envisaged in the NCCS, coal use will drop precipitately.

With its purchase of Coal Distributors Ltd. (CDL), Bord na Móna (BNM), the state development and marketing agency for peat, has become the largest importer in the residential coal market.

COAL POLICIES

Over the past decade, the government has introduced a range of environmental policy instruments affecting the supply and consumption of coal. A ban on the marketing, sale and distribution of bituminous "smoky" coal currently applies in twelve areas (Dublin since 1990; Cork since 1995; Arklow, Drogheda, Dundalk, Limerick and Wexford since 1998; and Celbridge, Galway, Leixlip, Naas and Waterford since 2000). The ban areas were chosen on a precautionary basis following an analysis of air quality data. Since the ban, these areas have shown considerable improvement in the recorded smoke levels.

On 5 June 2002, the Minister of State at the Department of Environment and Local Government and the Solid Fuel Trade Group (SFTG, which represents all the main importers and distributors of solid fuel north and south of the border) signed an agreement on various aspects of coal use. This agreement is the culmination of a consultation process which commenced in October 2001 on a potential national ban on bituminous coal and petcoke. The principal features of the negotiated agreement are:

- A maximum sulphur limit of 0.7% to apply to bituminous coal from 1 August 2002 (with four companies derogated until 1 August 2004 at the latest).

- The maximum sulphur content of petcoke to be 2.9% from August 2002, with a phased reduction to 2% by January 2005.

- Phased increased penetration (minimum 25% of total sales) of smokeless fuels in eight areas (Athlone, Bray, Carlow, Clonmel, Ennis, Kilkenny, Sligo, Tralee) from 1 October 2002.

- Ban on the sale of bituminous coal in Bray, Kilkenny, Sligo and Tralee from 1 October 2003.

- Penetration of smokeless fuel in the remaining towns (Athlone, Carlow, Clonmel and Ennis) to increase to 75% by 1 October 2004.
- Review of the agreement in December 2003 and a second review no later than December 2004.

It is estimated that full implementation of the agreement will improve national ambient air quality and reduce the annual emission of sulphur dioxide by approximately 6 500 tonnes.

PEAT

SUPPLY AND DEMAND

In 2000, peat[20] accounted for 0.8 Mtoe of Irish TPES, or 5.5% of the country total. Like coal, peat supply has declined in recent years. In 1990, peat supplied 1.3 Mtoe (12.3% of the country total) and as recently as 1996, it supplied 1.1 Mtoe (9.2% of the country total). The peat supply of 0.8 Mtoe in 2000 was the lowest level since before 1973. The government forecasts that absolute peat supply will rise slightly, reaching 0.9 Mtoe in 2010 when it will account for 5.1% of national TPES.

All peat is domestically produced and consumed. There are no imports and negligible exports of peat. Production depends heavily on weather conditions and thus varies from year to year (see Figure 2). For example, peat production in 1997 was 0.7 Mtoe, while production in 1999 was 1.2 Mtoe, despite the fact that actual peat supply had declined over that time. These variations in production capability are made up with changes in stocks.

The majority of peat in Ireland is used to fire power generation facilities. In 2000, electricity generation accounted for 66% of total peat consumption in Ireland. In the same year, peat-fired generation accounted for 7.5% of the country's total electricity production. In absolute terms, peat use for power generation has been declining in recent years. From a peak of 642 ktoe in 1996, the amount of peat used in power plants has fallen to 525 ktoe in 2000, an average decline of nearly 5% annually. Because of peat's diminishing use in other sectors, however, the share of supply going for power generation is rising. In 1990, 43% of peat burned in Ireland went to power generation, and 59% in 1996.

20. Peat is a soft organic material consisting of partly decayed plant matter together with deposited minerals. Peat occurs mainly in wetlands where micro-organisms promoting the decomposition of dead vegetation are unable to decompose all the material, often owing to lack of oxygen in waterlogged areas. Peat is generally a few thousand years old, and is often classified for this reason as a fossil fuel although substantially younger than coal which varies from 15 million to some 400 million years old. Peat is sometimes classified as a biofuel. Its combustion and handling properties are similar in some respects to those of certain brown coals.

Residential heating makes up the other major use of peat in Ireland. Its use for this purpose has been declining rapidly. Peat use in the residential sector has fallen from 638 ktoe in 1989 to 253 ktoe in 2000. From 1996 to 2000, peat use in the residential sector fell by nearly 10% annually. Peat used for residential purposes comes either in the form of processed briquettes or as unprocessed peat. Its decline in use by residences is attributed in part to changes in demographics. The move to denser population centres makes smoke from solid fuel less tolerable and the increase in homes where both parents work makes it more burdensome for families to stock and clean the boiler.

BORD NA MONA

In 1946, BNM was established as a statutory body by the Turf Development Act. BNM was created to develop peat resources in the national interest through the production and marketing of turf and turf products. On 1 January 1999, BNM became a public limited company although still owned by the State.

BNM owns approximately 85 000 hectares of peat bogs with combined usable peat reserves in the neighbourhood of 80 million tonnes. The company employs an average of 2 300 people although this figure varies seasonally with the peat harvesting months.

BNM sells to three different types of customers. In 2001, it sold 3 million tonnes of milled peat to power stations, 0.3 million tonnes of peat briquettes for heating and 0.4 million tonnes of peat used for horticulture. Peat for power production goes to four power plants owned by ESB and one privately-owned plant that sells power to ESB under a long-term contract.

CAPACITY OF PEAT-FIRED GENERATORS

In February 2000, the Department of Public Enterprise, ESB Management and ESB Unions negotiated a Tripartite Agreement which set out important guidelines for the future of the electricity industry insofar as the ESB was concerned. As part of the agreement, future policy concerning electricity generation from peat was elaborated. A Public Service Obligations Order was introduced in respect of peat-fired electricity generation. Under this PSO Order, closure of the existing six peat generating stations was accelerated in line with the commissioning of two more efficient stations of 100 MW and 150 MW. The new peat-fired power stations (250 MW in total) will be more efficient than the existing plants which are to be retired. They are expected to have an overall efficiency upwards of 37% compared to an average efficiency of 26% for the plants to be retired. These two stations are in addition to the 120 MW plant at Edenderry commissioned in the fourth quarter of 2000.

Table 14 shows the proposed closure timetable for the existing peat stations agreed upon in the PSO Order. Two plants, Ferbane and Rhode U3, have already been closed.

Table 14

Proposed Closure of Peat-fired Generating Stations

Unit in Power Plant	*Projected Closure Date*[1]
Ferbane	2000
Shannonbridge U1	2003
Shannonbridge U2	2004
Shannonbridge U3	2004
Rhode U3[2]	2003
Cahirciveen	2003
Lanesboro U2	2004
Lanesboro U3	2004
Bellacorick U1	2004
Bellacorick U2	2004

(1) Closure date assumed to be 31 December in each case.

(2) Rhode peat station already closed in 2002.

Source: Country submission.

PEAT COST AND RECOVERY

Peat is more expensive than competing fuels, even taking into account high efficiency of the newest peat-fired power stations. The cost competitiveness of peat versus alternative fuels for power generation is displayed in Table 15 showing information provided by BNM.

These costs do not include the capital or operating costs of the different plants. In general, such costs for peat and coal plants will be comparable, but both of them will have considerably higher costs than a gas-fired facility.

Table 15

Cost Comparisons between Fuels for Power Generation

Fuel	*Fuel Price (€/GJ)*	*Efficiency of Power Plant (%)*	*Fuel Cost of Electricity Generated (€/MWh)*
Coal	1.33	38	12.59
Heavy Fuel Oil (HFO)	4.18	36	41.79
Natural Gas	4.15	55	27.17
Peat	2.86	38	27.10

Source: BNM.

BNM sells its peat to ESB under long-term contracts at prices intended to allow BNM to recover all its costs. The prices in these contracts have two components. The first component includes the base price and reflects the BNM labour and material costs. This component includes incentives for efficiency improvements in peat harvesting. The second component includes an indexation factor which depends on a mix of the three-year moving average of coal, natural gas and oil prices, weighted by the amount these fuels are used in the Irish electricity market.

The PSO Order provides that the additional costs borne by ESB to purchase peat for power generation are to be recouped by way of a levy on final electricity customers. This levy, termed the PSO levy, is assessed by CER and was introduced on 1 January 2003. It is calculated by taking the actual cost to ESB of generating peat power and subtracting the cost of power from a hypothetical best new entry, assumed to be a gas-fired CCGT producing power at €48/MWh. In 2003, CER calculates that the total additional costs incurred by ESB resulting from their purchase of peat for electricity generation will be €38.9 million[21]. This covers 1 910 GWh of peat-fired generation, or €20.28/MWh. Adding this to the cost of the best new entry (€48/MWh) means that peat-fired generation costs ESB €68.28/MWh. Table 16 shows the total PSO levy (including the amount intended to recover AER costs) and the amount attributable to peat generation.

Table 16

PSO Levy for Recovery of Peat Costs

Customer Category	*Total PSO Levy*	*PSO Levy Attributable to Peat*
Domestic Profile	€11.49 / customer / yr	€9.83 / customer / yr
Small & Medium Profile	€35.67 / customer / yr	€30.52 / customer / yr
Large Profile	€5.94 / kVA / yr	€5.082 / kVA / yr

Source: Country submission.

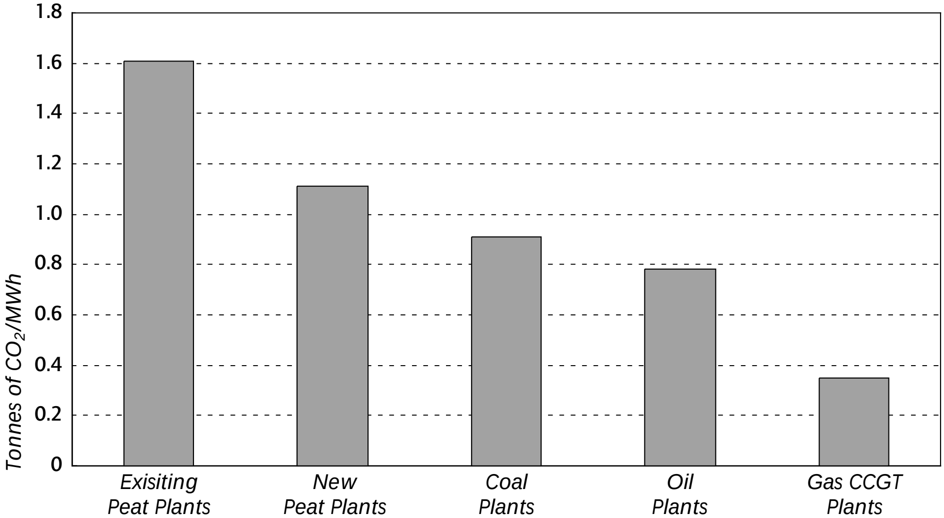
PEAT GHG EMISSIONS

Peat, when burned, emits significantly higher levels of CO_2 than do other fossil fuels. Figure 23 shows the ESB estimates of CO_2 emissions per unit of electricity generated.

21. The PSO levy actually includes both additional cost from peat and additional costs to ESB through the mandatory purchase of power from renewable energy plants that have won AER contracts (see Chapter 8). The total cost for AER purchases is €6.568 million while administrative costs are €1.076 million. Therefore, if administrative costs are split in a weighted fashion, peat accounts for 85.6% of the PSO levy while AER purchases account for 14.4%.

Figure 23

Emissions by Fuel for Electricity Generation



Source: BNM.

Life-cycle analysis of fuel emissions adds several factors to the comparison between fuels. If unharvested, peat bogs will absorb CO_2 and emit CH_4. Additionally, after peat has been removed, bogs can be afforested or allowed to revert to wetlands, in both cases providing carbon sinks. No definitive study exists which quantifies the full life-cycle emissions effects of peat (or other fuels) although studies on this subject are now taking place in Ireland, Finland and Sweden. The Irish project, CARBAL (from carbon balance), is being undertaken at the University College Dublin as part of a five-year programme to study this issue.

CRITIQUE

COAL

Coal use in Ireland is dominated by ESB's power generation station, Moneypoint. In 2000 it accounted for 84% of all coal consumed in the country and this percentage figure is expected to increase as coal use in other sectors (mainly residential heating) continues to decline. In its capacity as a power generation fuel, coal provides competitive rates and, even though all coal is imported, a source of energy security.

Despite these advantages, coal-fired generation may be stopped in Ireland owing to environmental reasons. As explained in Chapter 4 (Energy and the

Environment), closure or fuel-switching of the Moneypoint plant in 2008 is one of the major measures envisaged in the NCCS. If generation from Moneypoint is replaced by electricity from gas-fired plants, CO_2 emissions will indeed be substantially reduced.

The disadvantages of implementing this measure would be the increased cost of electricity and the loss of a secure energy source for the power sector. The extent or amount of higher electricity costs have not been publicly expressed, but they are likely to be substantial given the size of Moneypoint relative to the market as a whole and the fact that Moneypoint will be largely depreciated by that time. There is no doubt that coal provides a secure energy source and an important tool to ensuring energy diversity. If Moneypoint were to be shut down, the government projects that up to 80% of Irish electricity would come from natural gas by 2010. The energy security concerns of such a strong reliance on a single fuel to generate the country's power must be incorporated into any decision on coal use.

PEAT

Peat's importance to the Irish energy sector is clearly in decline. While peat once accounted for 18% of Irish TPES (in 1975), that figure is now less than 6%. From 1990 to 2000, peat's share of TPES has fallen from 12.3% to 5.5%. This decline has come as a result of the recognition of the negative environmental consequences of peat burning and a growing movement away from solid fuels for heating. Despite these trends, peat continues to be important as one of the few indigenous fossil fuel resources available to Ireland. In 2000, peat accounted for 45% of fossil fuel production (with the remainder being gas). This percentage will likely increase as gas production from Kinsale Head declines and before the Corrib gas field is brought on line.

Despite the energy security advantages of peat, it has two main disadvantages. The first is its CO_2 emissions compared to other fuels. The CO_2 emissions per unit of electricity generated from peat are significantly higher than all other fuels. This will remain the case, even with the new peat plants coming on line that will increase overall efficiency and consequently reduce emissions. Certain analyses suggest, however, that the life-cycle emissions of peat are not as bad comparatively as the simple "end of pipe" tabulation of emissions for the different fuels. These studies are, as yet, inconclusive and could not be used in a policy context to argue for allocating less emissions to peat than is now the case. However, continuing with the ongoing research in this area may provide a degree of scientific certainty which could reduce GHG emissions allocated to peat-burning countries such as Ireland.

The second significant disadvantage to peat use is its cost. Peat use costs Irish consumers €38.9 million per year. This added cost of peat compared to alternative fuels for power generation will continue to be borne by electricity users via a cross-subsidy between ESB to BNM. This subsidy is in part motivated by the government's desire to aid the citizens of the Midlands area which has been historically under-developed. However, it should be kept in mind that such support policies inevitably distort competition in electricity markets and result in higher electricity prices. The higher electricity prices that consumers pay as a result of the continuing peat support may act to offset potential decreases in electricity prices due to market reform. There could be other, more efficient, methods for distributing scarce financial resources to regions that require assistance rather than the current policy supporting peat extraction and use.

The creation of a surcharge levy imposed on consumers' bills is a positive step in that it makes the extent of support for peat explicit to consumers. Nevertheless, it seems unlikely that this subsidy will be discontinued in the near or medium future now that new peat-fired power plants are being built locking peat into the fuel mix for the power sector. Under such circumstances, it is very important that BNM is continually encouraged to improve its productivity through the efficiency incentives in the contracts between ESB and BNM. In this way, peat can continue to provide a measure of energy security and act as a development tool for the Midlands region while minimising the financial burden placed on the country's electricity consumers.

RECOMMENDATIONS

The government of Ireland should:

- *Evaluate the role of coal in the energy mix, striking a balance between energy security and greenhouse gas mitigation.*
- *Identify the impact on greenhouse gas emissions of the full cycle of peat production and use.*
- *Ensure that Bord na Mona continues to improve peat production efficiency in order to reduce peat subsidies and the distortive effect this has on the market.*
- *Keep under review the role of peat in the energy supply mix, taking into account its contribution to energy security, impacts on the electricity market and greenhouse gas emissions.*

OVERALL POLICY OBJECTIVES

Ireland undertook a review of its energy technology R&D policies in the *Green Paper on Sustainable Energy*, published in 1999. This report examined the challenges the country was facing in its effort to achieve compliance with the Kyoto Protocol and to move towards a more sustainable market-based energy economy. It concluded that R&D in energy technology should be an important tool in achieving these goals and that spending on research and development could assist Ireland in reducing CO_2 emissions. The report also highlighted R&D's contribution to national competitiveness through the development of new products and cost reduction resulting from improved energy efficiency. The report stressed the importance of early efficiency improvements in the main end-use sectors – housing, commercial and public sectors, industry and transport – and a more competitive contribution from renewable supply sources. The Green Paper went on to identify the objectives of energy R&D to be:

- Supporting the development and deployment of energy technologies and skills relevant to Ireland in the medium to long term.
- Developing the technical basis for the policies necessary to support these needed energy technologies.

The Green Paper concluded that since Ireland does not produce much of the capital equipment needed by the energy supply and demand sectors, the scope and need for R&D is correspondingly narrower than in other, larger countries. The report advocated a rigorous consultative approach in selecting R&D topics, which would lead to a short list of national priorities to be advanced through R&D efforts. It called for I£ 40 million[22] (€50.7 million) to be spent on energy R&D over the period 2000-2006.

The Sustainable Energy Act 2002 gave Sustainable Energy Ireland (SEI), formerly the Irish Energy Centre, the remit to oversee all R&D activities in Ireland. The government felt that the historically low rate of provision for RD&D in Ireland had contributed to a relative failure to exploit the full range of sustainable energy opportunities, on both the demand and supply sides. The new RD&D programmes administered by SEI aim to address this failure by assisting in the exposition and development of a least-cost path to achieving CO_2 emissions reduction in a more sustainable energy economy.

22. The Irish pound has been replaced by the euro. The last exchange rate between the two currencies was 1 euro = 0.787564 Irish pounds.

Specifically they are designed to deliver solutions to Irish needs which:

- Accelerate the development and deployment of improved energy-related products, systems, practices and services in the Irish market, on both the demand and supply sides.

- Provide a technical and analytical basis for informing, shaping and implementing policies for sustainable energy, including policies relating to security of supply, enterprise and services competitiveness, energy-efficient use of space and environmental protection.

The process of supporting research, development, demonstration and associated projects which deliver these results will also help to stimulate and establish a capacity among providers of energy RD&D and energy services. Such capacity building within the Irish research, industry and policy communities is necessary to continue innovation and competitiveness as part of the wider sustainable development agenda. The Programme for Government states that the government will work to ensure that Ireland develops a world class research capacity, will recognise the importance of encouraging a dynamic research culture and will build the capability of firms to carry out and manage R&D in Ireland.

SEI will allocate a budget of approximately €60 million to four main sectors, described below in section on the Major Research Programmes: over the period 2001-2006.

- Housing, through the "House of Tomorrow" programme: budget of €21.06 million.

- Renewable Energy for Power & Heat Supply: budget of €16.25 million.

- Industrial & Commercial: budget of €12.7 million.

- Transport: budget of €8.25 million.

This indicative sectoral budget allocation is based on:

- The scale, character and potential of the sectors to contribute to a sustainable energy economy, taking account of the assessment in the Green Paper on Sustainable Energy.

- The scope for R&D activities to address market failures in the sectors, through enabling introduction of effective new products, systems, practices, services, standards and policies.

- The existing national capacity to access, develop and apply R&D in the Irish context – and the ability to develop such a capacity.

The portfolio of projects supported will balance shorter- and longer-term perspectives, ranging from near-market R&D addressing urgent issues of market failure to developing technologies and capabilities with the prospect of medium- and longer-term strategic benefit to Ireland. The RD&D themes and priorities represented in this portfolio have been, or will be, developed by SEI, informed by a structured consultative process with practitioners, influencers, users and providers of R&D services. This process will also help to ensure that early implementation and uptake of results can be facilitated.

The scheduling of these portfolios also takes specific account of:

- Assessments of market and policy needs to identify key knowledge gaps addressable with the help of RD&D – including gaps identified by the new authority's sectoral specialists.
- The need to access and successfully undertake the transfer of appropriate technology developed within the EU and the wider international arena.
- The need to inform and contribute to implementation of the NCCS (*i.e.* the relatively short-term Kyoto imperatives), through to the need to align RD&D activities with longer-term strategic development opportunities informed by exercises such as Technology Foresight.

FUNDING AND MANAGEMENT

FUNDING DELIVERY MECHANISMS

The level of funding support to RD&D projects within each category will be related to project costs, and will vary according to the time frame, nature and specificity of the accompanying benefits and risks. Funding will be grouped by delivery mechanism as set out in the Green Paper.

Public Good

Public good spending will principally include projects relating to the built environment, renewables-oriented power and heat supply, and transport. Such areas contribute to the public good because of their strategic, mass market or other large-scale nature, or the lack of a commercial dividend from the research clearly confined to specific parties. Activities in this area will include work commissioned to inform public policy relevant to the sustainable energy agenda. Typically, public good projects will qualify for support of up to 100% of eligible contract costs. The Green Paper allocated 25% of the total R&D budget to spending through the Public Good mechanism although it did not include a specific target for the amount of private funds that should be leveraged with this amount.

Shared Cost

This will engage private and public sector interests and resources in the accelerated development and application of least-cost solutions in energy supply and demand, applied principally in the built environment and industry. These projects are partly funded in order to share the risks associated with RD&D investments which are expected to yield benefits in the short to medium term. Such projects are aimed at the development, adaptation, demonstration and commercial deployment of innovative and competitive products. They would apply to Irish and, potentially, overseas markets. Typically, shared cost projects will qualify for support of up to 40% of eligible contract costs. The Green Paper allocated 50% of the total R&D budget to spending through the Shared Cost mechanism.

International Collaboration

This category will mainly include high-risk, high-reward projects that are open to sharing, or where the additional public good benefit from international collaboration is worthwhile. Such projects, relating to problems and technologies in the built environment, renewables-oriented power and heat supply systems, and transport, will add value to Irish efforts while containing financial risks. The Green Paper allocated 25% of the total R&D budget to spending through the International Collaboration mechanism.

PROGRAMME MANAGEMENT

The supports in each sector will be organised and managed by SEI which will be responsible for overseeing the selection of projects following public notification. Funding for all eligible categories of project will be available following cycles of published calls for proposals and a process of expert assessment and recommendation.

Where appropriate, data collection, strategic studies and other policy-oriented work in the "Public Good" category may be directly commissioned through calls for tenders to be launched according to public procurement rules. This mechanism may also apply to specialist services to promote the diffusion, exploitation, transfer and take-up of RD&D results.

Sustainable energy-related RD&D projects from Ireland supported under EU or other international programmes will invite consideration for possible funding support in the "International Collaboration" category.

Opportunities to participate will be available to public, private and international entities carrying out projects in Ireland. In exceptional cases, funding of work overseas may be supported where there is a demonstrable contribution to resolving specific Irish problems.

HOUSING ENERGY RD&D PROGRAMME

Following the recommendations of the Green Paper, a €21.1 million research scheme in advanced domestic energy efficiency developments, entitled the "House of Tomorrow" programme, was launched by SEI in September 2001. This programme offers support for research, development and demonstration projects aimed at generating and applying technologies, products, systems, practices and information leading to more sustainable energy performance in Irish housing. The main focus of the programme is on stimulating widespread uptake of superior energy planning, design, specification and construction practices in both the new home building and home improvement markets. The demonstration component of the programme aims to support the construction of 2 500 superior energy performing dwellings and the refurbishment to optimum energy performance standards of a further 500 units.

The programme is open to a wide range of proposal types – including policy studies, field research, feasibility studies and technology RD&D – in the fields of:

- Understanding and improving the technical standards and conditions, professional and trade practices, user behaviour and public policies bearing on the energy and environmental performance of housing in Ireland.
- Model projects for new build, refurbishment or retrofit of housing, demonstrating superior energy design and technology implementation in homes or groups of homes under real operating conditions, with the potential for market influence and replication.
- Research and development of products, systems and services applicable to improving the energy and environmental performance of housing in Irish, and possibly other markets.

RENEWABLE ENERGY RD&D PROGRAMME

Also animated by the *Green Paper on Sustainable Energy*, the main aims of the Renewable Energy Research, Development and Demonstration (RE RD&D) programme are to stimulate deployment of renewable energies that are close to market and to assess and develop technologies which have prospects for the future. Proposals for this programme were developed in 2001 and were the subject of public consultation prior to its launch in July 2002.

The programme, managed by SEI, has an indicative budget of €16.25 million up to 2006 for funding in renewable energy and is expected to support projects in wind energy, biomass, solar, ocean energy, small hydro, ambient heat (heat pumps), geothermal energy and fuel cells. It includes provision for hybrid or cross-sector RD&D actions and for community renewable energy schemes.

The programme focuses on stimulating the application and further deployment of renewable energies close to market viability. Priority will be given to supporting:

- Research aimed at developing policy options for enhanced deployment.
- Research to define the market structure for RE technologies with high penetration potential.
- Research aimed at cost reduction, improved reliability and/or opening new markets.
- Demonstration of non-technical innovation.
- Feasibility studies for renewable energy projects.
- Demonstration aimed at high-risk, high-reward projects.

As stated earlier, such projects can be an important precursor to other actions aimed at meeting national targets for renewable energy deployment within an existing committed time frame and beyond.

INDUSTRIAL & COMMERCIAL ENERGY RD&D PROGRAMME

This is under development by SEI, with a view to fully launching in 2003.

TRANSPORT ENERGY RD&D PROGRAMME

This is under development by SEI.

ENVIRONMENTAL RESEARCH

Environmental research in Ireland is led by the Environmental Protection Agency (EPA) as part of its functions under the Environmental Protection Agency Act 1992. Under the Environmental Research, Technological Development & Innovation (ERTDI) Measure of the Productive Sector Operational Programme of the National Development Plan 2000-2006, the agency supports a wide range of research in key environmental areas (*e.g.* biodiversity, climate change, environmental economics, land use, waste management and water quality). A significant amount of the research budget is committed to air pollution and climate change issues. Since the programme commenced in 2000, over €5.25 million has been allocated. As part of this process, the agency has developed links with other bodies (*e.g.* Teagasc, the Irish Agriculture and Food Development Authority, the Marine Institute) in order to maximise the level of co-operation on issues of common concern and to avoid duplication of research activity. The research is generally carried out by multidisciplinary teams from academic institutions in Ireland. In many of the larger projects these teams include partners from other EU member States.

RD&D CO-ORDINATION AND INTERNATIONAL LIAISON (EU AND IEA)

SEI provides national representation and advice to the DCMNR on a number of EU committees relevant to RD&D. As the national contact point, SEI provides information (including briefing meetings), orientation and other advice to prospective proposers from Ireland for the relevant parts of these programmes.

These roles enable the efficient and effective development and management of a portfolio of programme activities so as to achieve synergies and integration, and to leverage external expertise and best practice. This is particularly important under the forthcoming EU Sixth Framework Programme for R&D, with the impetus being given to the European Research Area (ERA) concept. International representation from macro to specialist level is necessary to maximise focus, alignment and value from EU and other policies and programmes. Moreover, international collaboration enables the leveraging of existing knowledge within other organisations and the benchmarking of programmes and activities against best practice abroad.

In 2001, SEI conducted a review of IEA Implementing Agreements (IA) with a view to prioritising activities most appropriate to Irish participation. Ireland is now a member to IAs for bioenergy, wind and ocean energy.

CRITIQUE

Ireland's small size and historically low levels of investment support for energy R&D have largely made it a technology taker. To date, Ireland has not been active in pioneering new energy technologies or systems. With the publication of the Green Paper, this approach to energy R&D has changed substantially. The country is now taking a much more proactive role in energy R&D. This change is prompted by the demands that the Kyoto commitments place on the energy sector and by the country's strong economic performance which has created greater revenue for government programmes.

Ireland's commitment to spend approximately €60 million in this area over the period 2001-2006 is a sharp departure from past practices. This proposed expenditure is even greater than the amount called for in the Green Paper. In 1990, by contrast, Ireland spent about I£ 0.7 million (€0.89 million) on energy-related R&D. Government expenditure was not believed to have risen considerably during the 1990s. Anecdotal evidence suggests that private expenditure on energy R&D was also quite low. The renewed attention being paid to energy R&D and the ways that new technology can help solve issues in all parts of the energy sector is commendable.

Ireland's renewed commitment to energy R&D appears to be largely driven by two related goals: *i)* to ease the cost of the country's compliance with its Kyoto commitment (relatively short-term goals) and *ii)* to build capabilities with the prospect of medium- and longer-term strategic benefit to Ireland. There seems to be very little effort to use energy R&D as another form of industrial policy to promote selected industry as Denmark has done with wind power and Germany has done, to a lesser extent, with photovoltaic cells. Such a mixed long-term/short-term perspective working independently from industrial and social policy is commendable in that it offers the most promising means of developing usable technology for the country's specific energy circumstances.

Three areas that could lower GHG emissions may benefit most from the technology R&D funding. The first is analysis of the limits of wind power penetration into electricity systems. Ireland has tremendous natural wind resources which are being exploited both with and without government assistance. However, there are very real limits to the extent of wind power penetration into the national electric system. These limits involve both the reliable availability of wind power and the stability of the system accepting wind power, both of which are discussed in Chapter 8. These issues have been studied but many assessments put forward have come from parties with stakes in the outcome of wind power and hence have not as yet established any type of conclusions. Research into this area would allow Ireland to make the most of its wind resource.

The second area that could benefit from R&D resources is the study of life-cycle peat emissions. While it is generally recognised that burning peat will create greater CO_2 emissions than almost all other fossil fuels, some analyses suggest that the life-cycle emissions of peat may be comparable to competing fuels. This issue is discussed further in Chapter 9. Since Ireland is committed to continue peat use for the next fifteen or so years, a definitive analysis of this issue that it recognised internationally could allow the country to reduce the allocated CO_2 emissions when it burns peat.

A third area promising reduced GHG emissions which could benefit from R&D spending is the transport sector. Ireland is in the midst of expanding and upgrading its transport sector which creates a rare opportunity to introduce and hence develop new, more energy-efficient transport technologies. At the same time, the transport sector is a major contributor to Irish GHG emissions which are expected to grow substantially in the coming years. The money allocated by SEI to the transport sector will help in this regard, but it is disappointing to see that the transport R&D programmes have yet to be initiated.

Both research into wind power penetration and new transport technologies will not only help reduce GHG emissions, but will likely improve the country's overall economic position. Wind power is a vast natural resource that can provide inexpensive power and enhance national energy security. Transport has expanded and will continue to expand and thus uses a growing share of the country's import of oil and oil products.

Given Ireland's small size and its historically low levels of participation in energy R&D, it would be unrealistic and imprudent to expect major developments to take place solely as a result of this increase in funding. Ireland's best chance for effecting positive R&D developments may lie in international co-operation. Work within the EU and IEA frameworks can be very helpful in this regard and should be expanded. Bilateral projects can also allow limited resources to go further. In the case of wind power penetration, significant work has already been done in this area by Denmark and other countries and building and expanding on the existing body of work offers the best chances for Ireland to apply it to its own situation. For the life-cycle emissions analysis of peat, Finland, among other countries, is studying the same issue.

Another means of leveraging limited public R&D budgets is through co-operation with the private sector. The "Shared Cost" funding mechanism allows the government to do just that and benefits from this co-operation should be maximised. The historically low levels of energy R&D in the private sector may initially hinder the effectiveness of such programmes, but Ireland should persevere in this area. Such public-private partnership will not only help Ireland leverage public funds, but may also spur further private-only energy R&D activities. Such public-private partnerships can take place at all stages of the research process, from basic research to final demonstration of commercial products and services.

RECOMMENDATIONS

The government of Ireland should:

- *Prioritise activities on a limited number of projects and concentrate resources on them with a view to meeting national energy policy objectives.*

- *Engage in active participation in R&D activities at the international level, including participation in EU and IEA programmes.*
- *Stimulate co-operation between the public and private sectors in R&D areas such as demonstration projects in the transport sector.*

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2000	2001P	2010	2020	2030
TOTAL PRODUCTION		**1.120**	**3.359**	**2.197**	**1.802**	**2.899**	**..**	**..**
Coal[1]		0.045	0.016	–	–	–	..	..
Peat		1.020	1.411	0.981	0.883	0.881	..	..
Oil		–	–	–	–	–	..	..
Gas		–	1.872	0.958	0.660	1.590	..	..
Comb. Renewables & Wastes[2]		–	–	0.164	0.179	0.168	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.055	0.060	0.073	0.051	0.069	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	0.021	0.029	0.191	..	..
TOTAL NET IMPORTS[3]		**5.901**	**7.353**	**12.304**	**13.956**	**14.346**	**..**	**..**
Coal[1]	Exports	0.073	0.023	0.039	0.007	0.008	..	..
	Imports	0.578	2.286	1.738	1.969	0.907	..	..
	Net Imports	0.505	2.263	1.699	1.962	0.899	..	..
Peat	Exports	–	–	–	0.008	0.010	..	..
	Imports	–	–	–	–	–	..	..
	Net Imports	–	–	–	–0.008	–0.010	..	..
Oil	Exports	0.472	0.680	1.006	1.327	1.423	..	..
	Imports	5.956	5.788	9.278	10.547	10.409	..	..
	Bunkers	0.092	0.018	0.152	0.127	0.089	..	..
	Net Imports	5.392	5.090	8.120	9.093	8.897	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	–	–	2.477	2.931	4.470	..	..
	Net Imports	–	–	2.477	2.931	4.470	..	..
Electricity	Exports	0.002	–	0.006	0.025	–	..	..
	Imports	0.006	–	0.015	0.003	0.090	..	..
	Net Imports	0.004	–	0.009	–0.022	0.090	..	..
TOTAL STOCK CHANGES		**0.168**	**–0.250**	**0.121**	**–0.564**	**–**	**..**	**..**
TOTAL SUPPLY (TPES)		**7.189**	**10.463**	**14.623**	**15.194**	**17.245**	**..**	**..**
Coal[1]		0.565	2.371	1.857	1.920	0.899	..	..
Peat		1.020	1.288	0.800	0.875	0.871	..	..
Oil		5.545	4.871	8.264	8.571	8.897	..	..
Gas		–	1.872	3.435	3.591	6.060	..	..
Comb. Renewables & Wastes[2]		–	–	0.164	0.179	0.168	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.055	0.060	0.073	0.051	0.069	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	0.021	0.029	0.191	..	..
Electricity Trade[4]		0.004	–	0.008	–0.022	0.090	..	..
Shares (%)								
Coal		*7.9*	*22.7*	*12.7*	*12.6*	*5.2*	..	..
Peat		*14.2*	*12.3*	*5.5*	*5.8*	*5.1*	..	..
Oil		*77.1*	*46.6*	*56.5*	*56.4*	*51.6*	..	..
Gas		–	*17.9*	*23.5*	*23.6*	*35.1*	..	..
Comb. Renewables & Wastes		–	–	*1.1*	*1.2*	*1.0*	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		*0.8*	*0.6*	*0.5*	*0.3*	*0.4*	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	*0.1*	*0.2*	*1.1*	..	..
Electricity Trade		*0.1*	–	*0.1*	*–0.1*	*0.5*	..	..

0 is negligible, – is nil, .. is not available, P is provisional.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2000	2001P	2010	2020	2030
TFC	**5.416**	**7.732**	**11.102**	**11.617**	**14.037**	**..**	**..**
Coal[1]	0.520	1.137	0.451	0.545	0.262	..	..
Peat	0.408	0.427	0.117	0.127	0.127	..	..
Oil	3.856	4.149	7.070	7.277	8.691	..	..
Gas	0.103	0.998	1.587	1.689	2.384	..	..
Comb. Renewables & Wastes[2]	–	–	0.140	0.156	0.128	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.529	1.021	1.737	1.823	2.445	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*9.6*	*14.7*	*4.1*	*4.7*	*1.9*	..	..
Peat	*7.5*	*5.5*	*1.1*	*1.1*	*0.9*	..	..
Oil	*71.2*	*53.7*	*63.7*	*62.6*	*61.9*	..	..
Gas	*1.9*	*12.9*	*14.3*	*14.5*	*17.0*	..	..
Comb. Renewables & Wastes	–	–	*1.3*	*1.3*	*0.9*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*9.8*	*13.2*	*15.6*	*15.7*	*17.4*	..	..
Heat	–	–	–	–	–	..	..
TOTAL INDUSTRY[5]	**1.920**	**2.324**	**2.765**	**2.703**	**2.967**	**..**	**..**
Coal[1]	0.044	0.272	0.051	0.106	0.004	..	..
Peat	–	–	–	–	–	..	..
Oil	1.662	0.879	1.093	0.918	0.734	..	..
Gas	0.025	0.787	0.856	0.893	1.154	..	..
Comb. Renewables & Wastes[2]	–	–	0.100	0.109	0.088	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.189	0.386	0.665	0.677	0.987	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*2.3*	*11.7*	*1.8*	*3.9*	*0.1*	..	..
Peat	–	–	–	–	–	..	..
Oil	*86.6*	*37.8*	*39.5*	*34.0*	*24.7*	..	..
Gas	*1.3*	*33.9*	*31.0*	*33.0*	*38.9*	..	..
Comb. Renewables & Wastes	–	–	*3.6*	*4.0*	*3.0*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*9.8*	*16.6*	*24.1*	*25.0*	*33.3*	..	..
Heat	–	–	–	–	–	..	..
TRANSPORT[6]	**1.406**	**2.031**	**3.987**	**4.311**	**5.590**	**..**	**..**
TOTAL OTHER SECTORS[7]	**2.090**	**3.377**	**4.351**	**4.603**	**5.480**	**..**	**..**
Coal[1]	0.476	0.865	0.400	0.439	0.258	..	..
Peat	0.408	0.427	0.117	0.127	0.127	..	..
Oil	0.788	1.240	1.993	2.050	2.370	..	..
Gas	0.078	0.211	0.730	0.796	1.230	..	..
Comb. Renewables & Wastes[2]	–	–	0.040	0.047	0.040	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.340	0.634	1.071	1.144	1.455	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*22.8*	*25.6*	*9.2*	*9.5*	*4.7*	..	..
Peat	*19.5*	*12.6*	*2.7*	*2.8*	*2.3*	..	..
Oil	*37.7*	*36.7*	*45.8*	*44.5*	*43.2*	..	..
Gas	*3.7*	*6.2*	*16.8*	*17.3*	*22.4*	..	..
Comb. Renewables & Wastes	–	–	*0.9*	*1.0*	*0.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*16.3*	*18.8*	*24.6*	*24.9*	*26.6*	..	..
Heat	–	–	–	–	–	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2000	2001P	2010	2020	2030
ELECTRICITY GENERATION[8]							
INPUT (Mtoe)	**1.766**	**3.135**	**5.033**	**5.239**	**5.369**	**..**	**..**
OUTPUT (Mtoe)	**0.632**	**1.224**	**2.036**	**2.119**	**2.740**	**..**	**..**
(TWh gross)	7.348	14.229	23.673	24.634	31.859	..	..
Output Shares (%)							
Coal	*1.0*	*41.6*	*28.8*	*29.7*	*13.6*	..	..
Peat	*23.9*	*15.8*	*7.5*	*7.9*	*6.0*	..	..
Oil	*66.3*	*10.0*	*19.6*	*21.1*	*1.4*	..	..
Gas	–	*27.7*	*39.1*	*37.1*	*69.0*	..	..
Comb. Renewables & Wastes	–	–	*0.4*	*0.4*	*0.5*	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	*8.8*	*4.9*	*3.6*	*2.4*	*2.5*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	*1.0*	*1.4*	*7.0*	..	..
TOTAL LOSSES							
of which:	*1.649*	*2.259*	*3.459*	*3.577*	*3.208*	..	..
Electricity and Heat Generation[9]	1.134	1.911	2.997	3.121	2.629	..	..
Other Transformation	0.329	0.041	0.014	0.011	–	..	..
Own Use and Losses[10]	0.186	0.307	0.448	0.445	0.579	..	..
Statistical Differences	**0.124**	**0.473**	**0.061**	**–**	**–**	**–**	**–**

INDICATORS

	1973	1990	2000	2001P	2010	2020	2030
GDP (billion 1995 US$)	26.92	52.88	106.63	112.92	173.69	..	..
Population (millions)	3.07	3.51	3.79	3.83	4.18	..	..
TPES/GDP[11]	0.27	0.20	0.14	0.13	0.10	..	..
Energy Production/TPES	0.16	0.32	0.15	0.12	0.17	..	..
Per Capita TPES[12]	2.34	2.98	3.86	3.97	4.13	..	..
Oil Supply/GDP[11]	0.21	0.09	0.08	0.08	0.05	..	..
TFC/GDP[11]	0.20	0.15	0.10	0.10	0.08	..	..
Per Capita TFC[12]	1.76	2.21	2.93	3.04	3.36	..	..
Energy-related CO_2 Emissions (Mt CO_2)[13]	21.0	30.3	41.2	..	46.0	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	1.1	1.1	2.1	..	2.0	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–00	00–01	01–10	10–20	20–30
TPES	3.6	1.5	3.4	3.9	1.4	..	..
Coal	6.9	9.9	–2.4	3.4	–8.1	..	..
Peat	2.1	1.0	–4.7	9.4	–0.1	..	..
Oil	2.3	–2.4	5.4	3.7	0.4	..	..
Gas	–	13.6	6.3	4.5	6.0	..	..
Comb. Renewables & Wastes	–	–	–	9.1	–0.7	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	4.3	–1.5	2.0	–30.1	3.4	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	38.1	23.3	..	..
TFC	4.3	0.9	3.7	4.6	2.1	..	..
Electricity Consumption	5.8	2.9	5.5	5.0	3.3	..	..
Energy Production	4.6	7.8	–4.2	–18.0	5.4	..	..
Net Oil Imports	2.9	–2.0	4.8	12.0	–0.2	..	..
GDP	4.9	3.6	7.3	5.9	4.9	..	..
Growth in the TPES/GDP Ratio	–1.3	–2.0	–3.6	–1.9	–3.3	..	..
Growth in the TFC/GDP Ratio	–0.6	–2.6	–3.3	–1.2	–2.6	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

FOOTNOTES TO ENERGY BALANCES AND KEY STATISTICAL DATA

1. Peat is shown separately.
2. Comprises solid biomass and biogas. Data are often based on partial surveys and may not be comparable between countries.
3. Total net imports include combustible renewables and waste.
4. Total supply of electricity represents net trade.
5. Includes non-energy use.
6. Includes less than 1% non-oil fuels.
7. Includes residential, commercial, public service and agricultural sectors.
8. Inputs to electricity generation include inputs to electricity and CHP plants. Output refers only to electricity generation.
9. Losses arising in the production of electricity and heat at public utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of 100% for hydro.
10. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
11. Toe per thousand US dollars at 1995 prices and exchange rates.
12. Toe per person.
13. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2000 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

ANNEX

INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

Member countries* of the IEA seek to create the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants.

In order to secure their objectives they therefore aim to create a policy framework consistent with the following goals:

1. **Diversity, efficiency and flexibility within the energy sector** are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2. Energy systems should have **the ability to respond promptly and flexibly to energy emergencies.** In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3. **The environmentally sustainable provision and use of energy** is central to the achieve-ment of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government inter-ventions should where practicable have regard to the Polluter Pays Principle.

4. **More environmentally acceptable energy sources** need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The develop-ment of economic non-fossil sources is also a priority. A number of IEA members wish to retain and improve the nuclear

* Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5. **Improved energy efficiency** can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6. Continued **research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7. **Undistorted energy prices** enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8. **Free and open trade** and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9. **Co-operation among all energy market participants** helps to improve information and understanding, and encourage the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at their 4 June 1993 meeting in Paris.)

GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention and abbreviated subsequently, this glossary provides a quick and central reference for many of the abbreviations used.

AER	Alternative Energy Requirement
ABP	An Bord Pleanala
BGÉ	Bord Gáis Éireann, the state-owned gas pipeline and supply company
BNM	Bord na Mona, the state-owned peat company
CCGT	Combined-cycle gas turbine
CDM	Clean Development Mechanism
CER	Commission for Energy Regulation
CHP	Combined production of heat and power; sometimes, when referring to industrial CHP, the term "cogeneration" is used
DCMNR	Department of Communications, Marine and Natural Resources
DoELG	Department of the Environment and Local Government
DTO	Dublin Transportation Office
EPA	Environmental Protection Agency
ERDF	European Regional Development Fund
ERTDI	Environmental Research, Technology Development and Innovation
ESB	Electricity Supply Board
ESRI	Economic and Social Research Institute
EU	The European Union, whose members are Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom
GDP	Gross domestic product
GHG	Greenhouse gas
GJ	Gigajoule, or one joule $\times 10^9$

GW	Gigawatt, or one watt × 10^9
IEF	International Energy Forum
INPC	Irish National Petroleum Corporation
IPP	Independent power producer
IWEA	Irish Wind Energy Association
JI	Joint Implementation
kl	Kilolitre (one kilolitre = 6.289 bbl)
kVA	Kilovolt-ampere
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas; refers to propane, butane and their isomers, which are gases at atmospheric pressure and normal temperature
mcm	Million cubic metres
Mt CO_2-Eq	Million tonnes of CO_2 equivalent
Mtoe	Million tonnes of oil equivalent; see toe
MW	Megawatt of electricity, or one Watt × 10^6
MWh	Megawatt-hour = one megawatt × one hour, or one watt × one hour × 10^6
NCCS	National Climate Change Strategy
NORA	National Oil Reserves Agency
PES	Public Electricity Supplier
PPP	Purchasing power parity: the rate of currency conversion that equalises the purchasing power of different currencies, *i.e.* estimates the differences in price levels between different countries
PSO	Public Service Obligation
RE RD&D	Renewable Energy Research, Development and Demonstration
RTF	Regulated Tariff Formula
SEI	Sustainable Energy Ireland
SFTG	Solid Fuel Trade Group
TENs	Trans-European Networks
TFC	Total final consumption of energy; the difference between TPES and TFC consists of net energy losses in the production of

	electricity and synthetic gas, refinery use and other energy sector uses and losses
toe	Tonne of oil equivalent, defined as 10^7 kcal
TPA	Third-party access
TPES	Total primary energy supply
TSO	Transmission System Operator
TW	Terawatt, or one watt $\times 10^{12}$
TWh	Terawatt $\times$ one hour, or one watt $\times$ one hour$\times 10^{12}$
VIPP	Virtual Independent Power Producer
UNFCCC	United Nations Framework Convention on Climate Change

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