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ASPECTS OF IRISH ENERGY POLICY

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CONTENTS

EXECUTIVE SUMMARY

The challenges facing those responsible for energy policy in Ireland are considerable, spanning a wide range of different areas and a number of difficult economic and organisational problems. This paper considers some of the key energy policy issues facing Ireland over the next decade suggesting how best they might be resolved by policy initiatives. We draw on a range of recent research in The Economic and Social Research Institute and elsewhere that has informed our understanding of how some of these knotty problems in the area of energy policy might best be addressed.

Looking to the future, the rapidly rising demand for energy due to the growth in the world economy is eroding the potential spare world oil and gas capacity. With limited prospects of new finds of fossil fuels over the coming decades it seems quite likely that real oil and gas prices will rise substantially in the longer term. In addition, the need to tackle the problem of global warming will also lead to increasing real prices for fossil fuels. Preparing for a world of much higher energy prices will require significant policy changes. This is the context in which energy policy is being formulated in Ireland.

Ireland does not have a natural advantage in the supply of energy, except in the area of renewable resources where, with the exception of onshore wind, the technologies are not today competitive. As a result, it would not be expected that very energy-intensive businesses would locate here. In order to ensure that increasingly expensive energy resources are allocated among users in an optimal manner it is essential that in all cases business and households should pay the full economic cost of energy: there should be no explicit or hidden subsidies, even if Irish costs are higher than among some competitor countries. However, every effort needs to be made to ensure that the energy required is delivered at minimum possible cost to both business and household customers.

OBJECTIVES OF ENERGY POLICY

The overall objective of the state in regulating the energy sector is to ensure the lowest possible cost of energy in the long term subject to supply being secure and subject to meeting the environmental constraints. In this paper we have adopted a simplified approach by assuming that energy policymakers will take as given certain environmental and security of supply standards and that, conditional on these standards, they will then aim to meet the nation's energy requirements at minimum cost. This avoids the problem of having to consider possible trade-offs or conflicts between these multiple objectives.

The need for state intervention in the energy sector arises for three reasons:

1. The presence of economies of scale in parts of the industry, which make competition difficult.
2. Energy is a vital ingredient of modern life and the state has an important role in ensuring a secure energy supply, including a secure supply of electricity.
3. The negative environmental externalities that arise from energy production and consumption (of which the most pressing is global warming) require state intervention to move the economy to a more sustainable path.

ENERGY NEEDS OF A GROWING ECONOMY

Ireland has seen exceptional economic growth over the last 15 years. However, the growth in energy demand has been much slower. For the future the rate of growth of the Irish economy is likely to slow (Bergin *et al.,* 2003), though still remaining more rapid that that of the EU generally. The growth in the demand for energy is likely to slow further. The two exceptions to this trend are the demand for energy from the transport sector and the demand for electricity.

Demand for energy use from transport is likely to continue to grow for the foreseeable future. While this will require a further increase in the supply of energy, even more important, it will pose significant congestion problems. The solution lies in moving Ireland towards a more sustainable model of development involving less congestion. This would, in turn, deliver significant benefits in terms of reduced energy use and emissions.

While the growth in demand for electricity is slower than that of GNP, it is still significant. This means that for Ireland to have a secure electricity supply, investment in electricity generation and electricity transmission infrastructure will be required for at least another decade. Significant additional investment will also be needed in transmission infrastructure in order to reap the benefits of an integrated all-island electricity market.

This need for new investment makes Ireland rather different from the rest of the EU where capacity is generally adequate. The cost of the new investment will have to be paid by consumers in Ireland over the next decade whereas in many other EU countries the cost of the necessary infrastructure has already been substantially paid off. Thus, policy measures to minimise the cost of financing infrastructural investment will be more important for consumers in Ireland than in much of the rest of the EU.

SECURITY OF SUPPLY

Ensuring a secure energy supply for the foreseeable future is of crucial importance for the health and economic welfare of the country. In the case of oil supplies there is limited action the government can take to ensure physical security. While very unlikely, physical interruption to supply would have grave consequences. In the very unlikely event of it happening it would affect all of the EU and an integrated response at EU level would offer the best chance of minimising disruption.

Over the coming decade Ireland is likely to become increasingly dependent on gas to supply its energy needs. In particular, by 2010 the bulk of electricity generation will depend on gas. This means that any physical interruption of gas supply could have very serious consequences. If such an interruption were to be sustained for more than a few days it could see the island of Ireland lose the bulk of its electricity supply with very serious consequences for the health and welfare of its citizens.

While the chances of a break in an undersea pipeline are very small, if such an event were to occur it would take some considerable time to repair. It is for this reason that the second gas pipeline to Scotland was of major importance to the energy security of this island. The provision of the second pipeline greatly reduces the probability of what was already a very unlikely event. However, the vast bulk of the island's gas supply still goes through a single onshore pipeline in Scotland. As a result, it is important that the supply of gas from the Corrib gas field is brought onshore as soon as possible to enhance the physical security of Irish energy supply. In addition, consideration should be given to strengthening the onshore gas transmission system in Scotland on which nearly all of Irish gas supplies currently depend.

Ireland, along with other developed economies, faces a much greater risk to its economy from sudden shocks to energy prices than it does from a possible interruption in physical supply. For example, even if there were major disruption in the Middle East, oil supplies would still be available – at a price. However, major price shocks could have serious economic consequences and the regulatory authorities need to consider how best to insure against such future shocks. A number of instruments can be used to provide such insurance: fuel diversity and financial instruments both have roles. The National Treasury Management Agency (NTMA) should consider whether the desirability of hedging against such risks should affect policy on the portfolio of the national pension fund. The regulatory authorities should ensure that consumers are aware of potential risks and that, where feasible, suitable instruments for hedging risk are available.

As the price of gas and oil are linked and are both likely to rise in real terms it is desirable to have some diversity in the source of electricity supplies. For example, undue reliance on gas could be limited through a levy on gas used in electricity generation with the proceeds of the levy returned to consumers. The need for some diversification would suggest awarding some premium to renewable energy over and above the market price. This paper provides a model for considering the trade off between risk and price in deciding on the appropriate fuel mix for electricity generation. Fuel diversity should be managed by using market instruments rather than by regulation. Research and Development in alternative energy sources will be important in securing the long-term security of energy supply for the island.

With the full integration of the island gas market consideration should be given to developing gas storage facilities either in the old Kinsale gas field or else in salt caverns near Belfast. At present it does not seem wise for the Irish authorities to specifically encourage facilities for the supply of Liquified Natural Gas. It should be left to market forces to determine if and when such a development should take place.

INTERCONNECTION AND THE GEOGRAPHY OF MARKETS

An all-island electricity market is likely to confer significant benefits on consumers, reducing the long-term cost of a reliable electricity supply below what it might otherwise be. To allow an integrated and efficient all-island electricity market to develop it is essential that there is adequate investment in electricity transmission to physically link the existing separate systems. It seems likely that a second interconnector between Ireland and Britain could produce significant benefits for electricity consumers on the island.

AN ALL-ISLAND ELECTRICITY MARKET

The structure proposed for the all-island electricity market by the two regulators seems likely to provide the best opportunity for securing a competitive supply of electricity for consumers on the island of Ireland over the next decade. The electricity pool into which all generators will sell their electricity, when combined with a suitable regime of capacity payments to electricity generators, should encourage supply at a minimum price. It should also increase the transparency of the regime making for cheaper and more effective regulation.

The cost of capital is a key ingredient in determining the final price of electricity for consumers. The capacity payments regime proposed by the regulators will play an important role in minimising risk for investors and reducing the cost of capital. Investors will know that they will get the bulk of their capital and non-fuel operating costs in the form of capacity payments if stations are available to generate and if they operate efficiently. This regime would provide the right signals for new investment, ensuring the provision of adequate electricity generation capacity at least cost. Nothing in this regime would prevent the electricity market of the island of Ireland being eventually integrated into a British Isles or a northwest European market by the end of the next decade. Under the new regime the regulators should insist on closure of uneconomic plant that is surplus to capacity requirements. For this market to operate it is important that the all-island market go ahead as planned in mid-2007.

MARKET STRUCTURE

The move to the new all-island market will make the electricity sector much more transparent. In the market (pool) each firm will offer to supply electricity at a pre-specified price. All firms will know that they will receive most of their capital and non-fuel operating costs from capacity payments As a result, in the auction to supply electricity to the pool each firm will bid in only their fuel costs. This will greatly facilitate the information flow to the regulator. The regulator will know the price bid by each station and will be able to check that price against the price of the fuel delivered to that station. This will facilitate the regulatory authority in its task of ensuring a level playing field for all market participants.

The research described in this paper indicates that the move to the all-island market will somewhat reduce the ESB's dominant position. In considering the economics of enhanced interconnection to Britain the value of such interconnection in enhancing competition on the island should also be taken into account. The growth in demand for electricity, with further new independent generation coming on-stream over the coming decade, will also reduce the ESB's market share. However, even after these changes the ESB will still be in a dominant position.

The operation of the new market structure is likely to encourage new investment in generation in segments of the market where the existing ESB plant is not very economical. This should see significant closure of ESB plant over the rest of the decade to be replaced by new plant, generally built by different operators. Together with enhanced interconnection to Britain, this should see the ESB's dominant position in the generation sector on this island substantially eroded by early in the next decade.

Finally, the ESB should sell between 500 MW and 1000 MW of plant over the period to 2010. If this happens, with the closure of uneconomic plant, the ESB could be allowed to replace some of the plant that will close. By early in the next decade this would achieve the necessary reduction in the ESB's dominant position.

It is important that the operator of the transmission system for the all-island market should be established on a basis independent of all other players. When this happens consideration should be given to transferring ownership of the transmission system in the Republic to ESB National Grid. Whoever owns the transmission system it will be important that that company would contract with other companies, including ESB, to maintain and develop the system, ensuring competitive pressure on costs. Where possible, ESB distribution and supply should also move to buying in services on a competitive basis. This is the model that was adopted by Bord Gáis Éireann in the late 1980s and it would make the cost structure of operators transparent, facilitating regulation.

THE ENVIRONMENT

In an ideal world one economic instrument would be used to achieve one objective. Using multiple economic instruments to target a single environmental objective is likely to be inefficient and to raise the cost of meeting the objective. However, because of information deficiencies or other constraints it may be necessary to use additional instruments. It is important that the potential costs of using multiple instruments to target a single basic environmental objective are considered before deciding on the use of additional policy instruments.

The single most pressing environmental issue facing energy policymakers is the problem of global warming. Ireland is committed to taking action to reduce emissions as part of the EU. The EU emissions trading scheme, if suitably reformed should provide an appropriate instrument for implementing Kyoto. However, as currently implemented by the EU it has very serious defects. A reform of the emissions trading scheme should require the bulk of permits to be auctioned from 2008 onwards. Failure to do so will distort the electricity market, it will reduce the environmental effectiveness of the measure and it will substantially raise the cost of meeting the environmental objective. Finally, as currently implemented the emissions trading regime discriminates against renewable energy.

The current arrangements with Bord na Móna should be revised to allow for the gradual replacement of peat by wood biomass as the fuel in the three new "peat-fired" power stations. If this is not possible the best alternative from the environmental point of view would be to close these new stations immediately.

A properly designed emissions trading regime should generally provide the appropriate incentive to develop renewable electricity. Under such a regime special treatment of renewables would only be appropriate in so far as it was required to incentivise research and development. However, the current emissions trading regime discriminates against renewables and it may be necessary to offset this defect through a continuing special support regime. Any such regime must properly reflect the true costs and benefits to society of the different types of renewable energy.

For sectors not covered by emissions trading it will be important to introduce a carbon tax. Without such a tax there is a danger that Ireland will either fail to reduce its emissions by the required amount or else it will do so at undue cost, placing most of the burden on the electricity generation sector.

Tackling the rapid growth in emissions in transport will require special measures including the application by the EU of mandatory fuel efficiency standards for new motor vehicles. A rationalisation of the tax rates on vehicles and fuel and introduction of charging for use of road space could simultaneously reduce congestion, which has a high cost, and also reduce emissions. In the long run policy will need to focus more on developing sustainable cities and more energy efficient dwellings.

ENERGY EFFICIENCY AND FUEL POVERTY

The last decade has seen significant improvement in the aggregate energy efficiency of the Irish economy. There has been a modest but steady decline in the energy intensity of GNP. Policies to promote energy efficiency have been directed mostly at the industrial, commercial and institutional sectors and at promoting renewable energy. Energy conservation in transport and by households has been relatively neglected.

Of the main policies for overcoming barriers to energy efficiency provision of information, regulations and economic instruments – economic instruments have been least used. Inefficient subsidies have been granted and emissions trading has begun for energy intensive industrial sectors. However, without targeted policies for improvements in energy efficiency, the result will be patchy and fall short of its potential. Regulation has been the policy most widely employed, but late adoption of energy efficiency standards in buildings, difficulties in ensuring compliance, lack of engagement in energy efficiency by customers and users, and disparities in abatement costs, mean that potential benefits are foregone.

Application of economic instruments, such as a carbon tax, is needed. However, in view of recent energy price rises a sensitive approach is needed. Economic instruments would reinforce the benefits and reduce the shortcomings of regulations and would encourage the take-up of energy efficiency advice. Increased information is needed on examples of energy conservation that can be directly replicated, and on how to access expertise and overcome the final hurdle to implementation. The economic benefits of Sustainable Energy Ireland's energy saving schemes needs more quantification.

Fuel poverty is the inability to heat one's home adequately. It is a significant contributor to overall poverty requiring special measures to enable households to break out of the spiral of inefficient houses, equipment and fuels. Ireland's winter mortality compared to that in the rest of the year is high and it is associated with fuel poverty and poor insulation. Fuel poverty is an important energy and economic issue because of the inefficiency involved. Tackling the thermal performance of dwellings occupied by low-income households would greatly reduce or remove the problem of fuel poverty as a barrier to the introduction of carbon taxes.

A major upgrade of policy on fuel poverty is needed and should be focused primarily on improving buildings and equipment, combined with education and other supports to efficient behaviour and with properly prepared policy evaluation. Fuel poverty should not be seen as a reason for avoiding carbon taxes, but rather carbon taxes should be viewed as a reason and an opportunity for extra funding for policies to tackle fuel poverty. The current very substantial energy price rise necessitates action in any event.

1. INTRODUCTION

1.1 Background

Since the Stone-Age energy has been an essential ingredient for sustaining life. Energy for heat and cooking was first provided by the sun and the burning of biomass – timber. As commemorated in the Christmas carol *Good King Wenceslas*, through the Middle Ages access to timber for fuel was essential for the rich and poor. However, over the last two centuries the increasing complexity of modern life and the growing sophistication of the economy has seen a dramatic increase in energy use, in particular to drive the massive growth in transportation technology. This growth in energy use has been made possible by the discovery and exploitation on a very wide scale of fossil fuels: first coal, then oil and more recently natural gas. Modern life is now crucially dependent on the ready availability of a secure supply of energy in a convenient form – electricity, gas, peat, oil, nuclear and renewable energy.

The complexity of the engineering and economic issues makes energy a particularly difficult area to manage. The purpose of this paper is to consider some of the range of different issues that confront policymakers in the governance of energy policy and to try and simplify some, but not all, of these complex issues. This paper brings together the results of a range of research undertaken in recent years in The Economic and Social Research Institute (ESRI), the results of which contribute to an improved understanding of the appropriate policy response to some of the many energy policy challenges facing Irish society. This paper concentrates, in particular, on the issues for energy policy arising in the electricity and gas markets, while giving very limited attention to the important issues facing the transport sector.

Looking to the future, the rapidly rising demand for energy due to the growth in the world economy is eroding the potential spare world oil and gas capacity. With limited prospects of new finds of fossil fuels over the coming decades it seems quite likely that real oil and gas prices will rise dramatically in the longer term. In addition, the need to tackle the problem of global warming will also lead to increasing real prices for consumers of fossil fuels. Preparing for a world of much higher energy prices will require significant policy changes. This is the context in which energy policy is being formulated in Ireland.

Ireland does not have a natural advantage in the supply of energy, except in the area of renewable resources where, with the exception of wind, the technologies are generally not at present competitive. A consequence of this is that energy prices in Ireland are unlikely to be especially low by the standards of the developed world and that as a result energy intensive businesses would not develop new plant in Ireland. In all cases Irish business should pay the full economic cost of energy: there should be no explicit or hidden subsidies, even if Irish costs are higher than among some competitor countries. However, every effort needs to be made to ensure that the energy required is delivered at minimum possible cost to both business and household customers.

Competitiveness is a key pillar of energy policy along with environment and security of supply. We have seen in the 1980s how problems in the energy markets can have a significant negative impact on Ireland's competitiveness. At the time, the very high cost of electricity in Ireland in the 1980s adversely affected the competitiveness of the economy, especially of the manufacturing sector. This was addressed in the context of the Culliton report. Since the early 1990s there has been a steady improvement in Ireland's position on electricity prices. However, this situation has recently been reversed in the face of major new investment needs and rapidly rising world energy prices.

Just because energy is essential to modern life and to sustaining today's life style does not mean that it should receive special treatment by governments. For example, food is also essential to survival, but the production and distribution of food is largely left to market forces in modern economies.[1] However, energy is rather different from food in the economies of scale and capital intensity of production. There are also geopolitical concerns about the availability of both oil and gas. For the most flexible form of energy, electricity, there is a further complication that it cannot be stored; supply and demand must always be equal.

In most developed countries the government, as regulator, has long played an important role in the development and management of key parts of the energy sector. The role of the state has typically been much greater in this sector than in many other sectors, such as retailing and financial services. Historically, the state's key role in the energy sector is not just a reflection of an out of date ideological stance; rather, over much of the last century, its role developed as a considered response to the need to ensure a cheap and reliable source of energy to underpin economic growth.

In the case of the production of oil the scale of investment and the global nature of the business saw the emergence of a small number of key multinational companies. Some of these companies were owned by governments: BP by the UK government, AGIP, by the Italian government etc. In recent years governments have

[1] In the aftermath of the shocking dislocation of the Second World War an important driving force behind the EEC Common Agricultural Policy (CAP) was the desire to secure Europe's food supply for the future. However, after half a century of peaceful development, this is no longer an important issue as reliance is placed on trade to ensure adequate food supplies for the continent. Another analogy is that when governments intervene extensively in key markets, it takes a long time for them to effectively extricate themselves – it took 50 years in the case of the CAP.

generally divested the bulk of their shareholding in these firms and the marketplace is truly global. However, governments still have major concerns and significant involvement in the sector. These geopolitical concerns relate to the small number of countries responsible for the bulk of oil and gas supply.

This paper considers what the role of the Irish government should be in managing the energy sector. It examines a number of important policy areas and it examines the research evidence on how the future secure supply of energy for Ireland can be ensured at minimum long-run cost to the consumer. The complexity of the issues facing the Irish government (and other governments) has been enhanced by the need to take account of the very negative environmental impact of the burning of fossil fuels. Together with concerns about security of supply this adds further dimensions to the problem facing policymakers.

Generally, in this paper the approach taken is to accept as a given the environmental objectives defined under the Kyoto protocol and also certain security standards. The job of energy policy is then viewed as changing agent's behaviour and trying to minimise the long-run cost of supplying energy in the required form to the Irish economy. Even within this seemingly simple objective the interaction of security of supply with cost means that the appropriate stance of energy policy will not be simple or obvious. At the very least there are choices to be made between cost and security of supply. The separate identification of environmental standards to be met and the cost of environmental damage done can allow the state's environmental objectives to be quantified and, to some extent, integrated into the calculus. However, the complexity of the engineering and economic issues makes energy a particularly difficult area for policymakers. The purpose of this paper is to identify the range of different issues that confront policymakers in the energy field and to try and simplify some, but not all, of the complexity.

1.2 Role of State

The state still has a very important role in the energy sector, both as regulator to guard customer interests and as a producer (as owner of the Electricity Supply Board (ESB), Bord na Móna and Bord Gais Éireann (BGE)). In most countries, the government assumes the responsibility as the provider of last resort with a statutory obligation to take the required emergency action in the case of a sustained energy blackout. In less extreme circumstances, the need for the state to regulate the sector arises from three important features of energy production and distribution. First, many parts of the sector are characterised by increasing returns to scale. Given the size of the Irish electricity system, a high minimum efficient level of output will make it difficult or impossible to rely on the development of competitive markets. This is true at the level of the individual generator – with the exception of Combined Heat and Power (CHP), it is hugely more efficient today to generate electricity in a few large generation plants than for each consumer to generate his or her own electricity using very small generators. While this situation may change in the coming decades with technical developments in the sector, it will remain true for some considerable time to come. It also arises from the related need to transmit electricity from where it is produced and distribute it to consumers.

The perceived importance of scale economies resulted in major state involvement throughout Europe with the development of the electricity sector. In Ireland the initial development of the ESB in the late 1920s was a response to the huge capital requirements needed to fund the initial investment in the Ardnacrusha hydroelectric scheme. At the time the Department of Finance had major concerns about the scale of the project and the funding pressures that it put on the state. However, no other Irish company was in a position to fund such a large investment scheme nor were there international companies willing to undertake it on a merchant basis. Thus one of the key factors driving state involvement was the sheer size of the investment needed.

The electricity and gas markets share two related characteristics. The supply of both forms of energy involves very large capital investment within Ireland. In addition, the capital investment is likely to last a long time: typically at least 20 years for electricity generation stations; up to 40 years or more for electricity and gas transmission infrastructure. These capital assets cannot be moved once constructed so that mistakes in planning capacity can be very costly. Second, in the case of security of supply, there are very important externalities such that the cost of disruption may be less for the players in the market than for society as a whole. There are also serious geopolitical concerns that are the proper remit of government. Third, a more recent concern relates to the negative environmental externalities that arise from energy production and consumption. These require state intervention to ensure an optimal outcome in terms of the sustainability of energy use.

The role of the state as producer is, to some extent, a legacy arising from the development, under very different circumstances, of the electricity and gas sectors. These sectors are highly capital intensive, which makes the management of financial risk a high priority. In the case of network infrastructure there are good arguments for continuing state involvement. However, experience elsewhere has shown that, where competitive markets can be developed, this can benefit consumers through encouraging greater efficiency in production.

The initial position of the state is one of substantial direct involvement in the sector and the restructuring necessary to allow the state to exit from this role cannot be implemented overnight. The combination of the capital intensity of the sector, the need for new investment, and the small size of the market makes the Irish electricity market different from the electricity market elsewhere in the EU. It means that ready-made solutions to Ireland's problems are not available and it is necessary to develop a new "model" of the market to deliver electricity and gas to Irish consumers at minimum long-term cost.

Ireland has a long history of promoting the interests of producers instead of the interests of consumers. This emphasis must be understood in the context of the country's twentieth century history – a dependence on agriculture and a shortage of suitable employment. In their report *Regulatory Reform of the Irish Economy*, the OECD (2001) noted the extent of the "producer focus" in Ireland, and the resulting reduced emphasis on the benefits of competition. The OECD report suggested that if the competitiveness of the Irish economy were to be sustained in the future, action would have to be taken to redress the balance in favour of competition and the consumer. It is from this background that we approach the principles that should inform Irish energy policy. Ultimately, the objective of policymakers should be to minimise the cost of energy without subsidisation to Irish consumers in the long run, while fulfilling environmental responsibilities and ensuring that the supply of energy in its different forms is secure.

In trying to promote a competitive market the state naturally has to focus on the conditions necessary to allow many firms to flourish. Without the active competition of many firms, where many is generally five or more, real competition is unlikely and the consumers' interest in low prices will not be easily delivered. However, there is a danger for policymakers that the focus on creating conditions for many firms to flourish will distract from the ultimate objective – low prices for consumers. In trying to make the market attractive through providing profitable opportunities for investors the advantage of competition for consumers, lower prices, could be negated.

The point of regulation is to ensure that in the long run Irish consumers get the best possible value for their expenditure on energy through keeping prices as low as possible.[2] While Ireland's peripheral location[3] may make the cost of primary energy, especially the price of gas, higher than for our EU neighbours, the objective of policy should be to make Ireland more efficient than much of the rest of the EU. This would mean that, in spite of our peripheral location, Irish consumers could enjoy the lowest possible prices.

The corollary of the focus on the needs of consumers is that employment creation or employment maintenance should not play a significant role in future energy policy decisions. It also means that the needs of individual companies, public or private, should not drive future policy or thwart efficiency gains from competition. They are there to serve the economy by providing secure energy supplies at a minimum long-run cost. Whether they are privately or publicly owned, the profitability of companies operating in the sector should be no more than is necessary to ensure that our energy needs are

[2] As mentioned earlier, consumers should face the full economic cost of the energy they are using. Otherwise they will overuse energy, reducing national income. Because most of the externalities associated with energy use are negative it is more important than in other sectors to ensure that prices facing consumers (both business and households) are not subsidised by the state.

[3] Peripheral with respect to the source of future gas supplies.

met. Where competitive markets are possible this will be delivered without further state intervention. However, what makes the energy sector unusual in the modern Irish economy is that the necessary scale of operations makes competition difficult, and in some cases impossible to deliver.[4] It is for the above reasons that state intervention is essential in regulating the market.

In the past energy policy has from time to time been affected by public policy concerns to promote economic growth and employment. However, it is now generally accepted that it is more appropriate to use other policy levers to promote such goals. Using energy policy as a means of promoting employment growth is likely to prove very expensive. Even in the 1980s, when employment growth was a major policy concern, intervention through the energy sector was generally an inappropriate and expensive mechanism for pursuing such a goal.

In a regional policy context it is also very ineffective to use explicit or implicit energy subsidies to promote development. It will be much more effective to spend available funds on directly promoting regional development through other mechanisms. However, obstacles in the planning system can still act as a significant barrier to development through slowing or preventing the deployment of necessary energy transmission infrastructure where there is a clear economic case for such investment. In recent years this has been the case for investment in electricity transmission in the West and North-West of Ireland where shortage in capacity is constraining development.[5]

1.3 The Evolution of Irish Energy Policy

Three significant events in the 1970s led to a focused interest in Irish energy policy which culminated in the 1978 White Paper *Irish Energy Policy* and also the publication of a separate but identically titled report by the National Economic and Social Council in 1983. Of these events, the first – the massive increase in oil prices in 1973 – brought to an end an era of cheap energy supplies and was further compounded by a second oil crisis in 1979. Second, the discovery of commercial quantities of gas off Kinsale underlined the need for policies on the development, allocation and pricing of indigenous energy sources. Third, there was extensive discussion of the desirability or necessity of nuclear-fuelled electricity generating capacity. The country's obligations as a member of the European

[4] The International Energy Agency (IEA) considers that a conventional fossil fuel generating plant has to be at least 400 MW to achieve minimum efficient scale. However, this is for baseload production (on most of the time) and the opposite argument can also be made that the flexibility of smaller units to follow actual demand (with its peaks and troughs throughout the day) may have been undervalued in the past. It is best left to an efficient market with investment certainty to design the most efficient generation portfolio.

[5] However, in the case of gas it will not be economic to provide transmission infrastructure to all parts of the country. In the case of sparsely populated regions the funds which might be spent on investment in providing gas transmission could achieve a much greater impact on regional development if spent in other ways.

Community and the International Energy Agency also served to focus attention on energy matters.[6] While some public discussion followed the 1978 White Paper, there was no official response to the discussion, partly because the nuclear issue receded following a tapering off in electricity demand.[7]

Over the last decade there have been major changes in the institutional framework of the energy market. The EU, in pushing for increased competition, has been a major force driving change. Even without the EU, change was inevitable, reflecting the evolving needs of the economy. The prospect of a changing market structure has already resulted in major improvements in existing state energy utilities. The establishment of the Commission for Electricity Regulation, now the Commission for Energy Regulation (CER), reflects this need for a continuing public involvement in managing the sector, whatever the ownership of the companies actually providing services. However, the current market structure is far from perfect and it is not clear what is the best direction for future development. There is a danger that the current market structure, unless modified, could deliver a high price and unreliable services to Irish consumers.

1.4 Outline of the Paper

This paper brings together the results from a wide range of energy policy research undertaken by the ESRI in recent years. As reflected in the title of this paper, *Aspects of Irish Energy Policy*, it does not attempt to cover all the important issues facing energy policymakers in Ireland. Instead it focuses on the areas of policy where recent research can make a significant contribution to public understanding. In particular, we provide very limited analysis of the energy-related issues that arise in the case of transport.

This paper first outlines some of the key factors currently driving change in the market. These include, the pressures arising from the rapid growth of the economy, resulting in significant infrastructure shortages. Second, this paper considers how the market structure needs to change to deliver efficient and cheap energy to consumers over the coming decade. The third factor that will drive change over the coming decade is the need to prepare the economy to comply with the requirements of international environmental commitments, including the Kyoto protocol on tackling the problem of global warming. Finally, part of the solution to the pressures which are

[6] The IEA was established in 1974 as an autonomous body within the framework of the OECD to undertake energy monitoring and co-operation.

[7] Prior to 1977 responsibility for energy matters rested with the Department of Transport and Power. In 1977 responsibility was transferred to the Minister for Industry and Commerce which then became the Department of Industry, Commerce and Energy. By 1980 the increased involvement of the state in energy matters gave rise to the creation of a separate Department of Energy with responsibility for energy, mines, minerals and petroleum. In July 1981, a further change resulted in the creation of the Department of Industry and Energy as the responsibility of one Minister.

growing on the energy market will involve enhanced investment in energy efficiency.

In addition to the economic and engineering considerations, there may be other considerations that do not fit within the economic calculus of "least cost" solutions. Two important considerations that make the policy choices more difficult politically are the interests of providing jobs, mentioned above, and the related concern about the industrial relations impact of what may be the "obvious" economic answers. These issues are dealt with later in this paper.

This paper concentrates on energy policy related to electricity and gas. It only considers policy on other fuels where the other fuels may be used in electricity generation.[8] This simplification does not mean that important issues do not exist in the field of oil supply and marketing, but rather that the answers can be determined independently of decisions on electricity and gas. In the case of electricity and gas, the markets for the two fuels are highly interrelated and cannot be considered separately.

Chapter 2 of this paper discusses the energy needs of a rapidly growing economy. The fact that the demand for energy in general and electricity in particular will rise quite rapidly over the coming decade makes Ireland unusual in the context of the wider EU. The need for significant new investment means that policies, which may work elsewhere in the EU, may not be appropriate in Ireland. The important issues underlying the need to ensure a secure energy supply are dealt with in Chapter 3. It considers the problems posed by uncertainty about the future availability of oil, gas and electricity and also by uncertainty about their future price. It also considers the choices to be made between the cost and security of supply.

Chapter 4 considers how future developments in electricity interconnection may transform the isolated Republic of Ireland electricity system initially into an all-island system and possibly eventually into part of a British Isles or a North-West European system. The development of an all-island electricity market from 2007 onwards will require a new market structure for electricity. The implications of different market structures are teased out in Chapter 5. The chapter concludes that the structure being proposed by the two regulators, the Commission for Energy Regulation (CER) and the Northern Ireland Authority for Energy Regulation (NIAER), is broadly appropriate.

With the liberalisation of the electricity market future investment will be driven by the incentives provided by the all-island market. However, the incumbent Electricity Supply Board (ESB) is clearly a dominant player in that market. Chapter 6 examines how the issue of dominance can best be dealt with in an all-island context. Energy policymakers are faced with a range of important environmental

[8] This is not to say that other major areas such as heat and oil for transport are less important, only that they should be subjects of further in-depth research in their own right.

issues that will, of necessity, impact on the energy sector over the coming decade. The implications of environmental constraints and the appropriate economic mechanisms for managing them are discussed in Chapter 7.

Chapter 8 looks at the important issue of energy efficiency and the obstacles to realising potential gains in both the household and the business sectors. The appropriate policy response is also discussed. The chapter also briefly considers the issue of "fuel poverty". Finally, in Chapter 9, the conclusions of the paper are drawn together and summarised.

A glossary of abbreviations used in the paper is provided as Appendix 1.

2. ENERGY NEEDS OF A GROWING ECONOMY

2.1 Introduction

Compared to other European economies, the Irish energy market is relatively small and the electricity and gas systems are isolated geographically. However, trade in energy fuels means that, subject to transport costs, if market forces operate effectively they ensure that prices in Ireland are competitive with those elsewhere in Northern Europe. The isolated nature of the Irish energy supply system has in the past restricted the possibility of competition for fuels and it has potentially imposed additional costs. The next section examines the current cost of energy for Irish users for a range of fuels and compares these costs with those of neighbouring countries. In discussing the future role of Irish energy policy it is useful to assess the evolution of energy demand and supply and Section 2.3 considers the major changes that have occurred in the demand for energy in Ireland over recent years. An understanding of the drivers of energy demand in the past is important in preparing outline forecasts for energy demand over the coming decade. The forecasts are described in Section 2.4.

2.2 Relative Energy Prices

In the 1980s Irish electricity prices moved out of line with those in neighbouring economies. Over the 1990s this position was substantially redressed. However, today Irish electricity prices have again moved above those of other relevant EU economies. By contrast, the price of gas available to the nation was very low in the 1980s relative to the EU price due to a favourable deal over Kinsale gas. As that indigenous gas has run out Irish gas prices have come to follow those in Britain, whence supplies are currently sourced. As prices on the British market have risen dramatically over the last eighteen months (due to supply constraints),[9] prices have accordingly risen in Ireland.

Table 2.1 shows a comparison of the tax exclusive prices of electricity, oil, coal and gas to users for a range of countries in 2004. The prices are shown in euros to facilitate comparisons. With the exception of oil for electricity generation, these data suggest that

[9] Some of these constraints may be relieved with the advent of increased interconnection for gas between Britain and the continental EU market over the coming two years.

transport costs are imposing a premium over and above Ireland's European neighbours.

Table 2.1: Relative Energy Prices (Tax Exclusive), 2004 (Euro)

	Ireland Per kWh	UK	France	Denmark	Netherlands
Electricity – Households	0.1225	0.1055	0.0855	0.0940	0.1015
Electricity – Industry	0.0770	0.0476	0.0356	0.0704	c
			Per 10^7 kilocalories (TOE)		
Gas – Households	404.26	324.20	373.88	376.75	348.79
Gas – Electricity Generation	148.91[a]	116.79[a]	..	c	..
Coal – Electricity Generation	54.13	41.51a	53.60	..	..
Oil – Households	397.19	244.76	321.22	367.88	347.53
Oil – Electricity Generation	150.49	157.22	155.75	..	191.40

Notes: a = data for 2003; c= confidential.
Source: International Energy Agency, *Energy Prices and Taxes*. 1st Quarter 2005.

2.3 Past Trends in Energy Use

A recent report by Sustainable Energy Ireland (SEI, 2005) has analysed trends in energy use in Ireland since 1990. Table 2.2 shows the small scale of Ireland's total energy requirement compared with that of its EU neighbours. Ireland's total requirement of energy is shown at just over 15 million tonnes of oil equivalent (Mtoe) or 3.91 toe per capita. This represents just 1 per cent of the total energy requirement of the EU(15) in 2002. Energy use per capita is slightly higher than that for the UK and Denmark but is lower than that of the majority of the larger EU members.

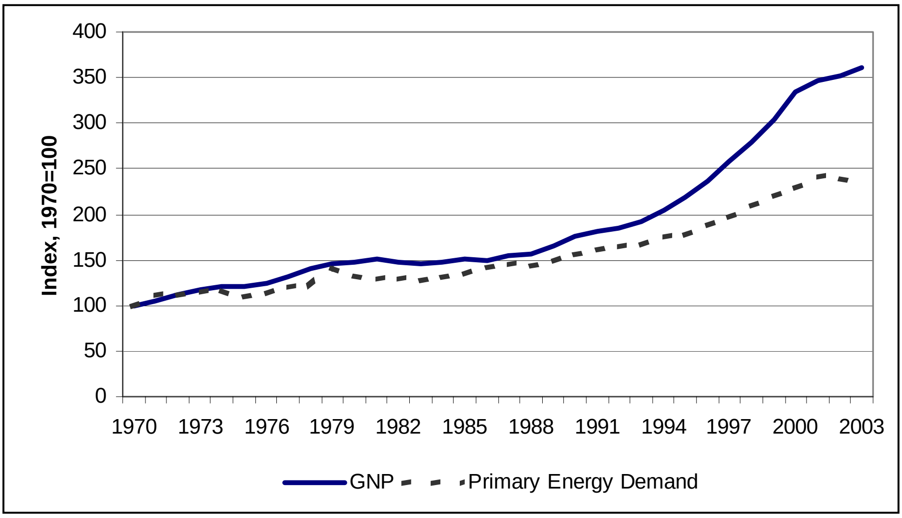
Table 2.2: Scale of Irish Energy Requirement, 2002

	Total Primary Energy Requirement	TPER Per Capita
Ireland	15.3	3.91
UK	257.81	3.83
France	265.88	4.34
Germany	346.35	4.20
Italy	172.72	2.98
Austria	30.44	3.78
Denmark	19.75	3.67
Finland	35.62	6.85
Belgium	56.89	5.51
Sweden	51.03	5.72
Netherlands	77.92	4.83

Source: International Energy Agency, *Energy Policies of IEA Countries* (various years).

The demand for energy in Ireland is a derived demand, driven by economic growth. However, factors such as changing energy prices and technological progress can have a moderating influence on demand by causing a substitution away from energy products, or by introducing more efficient use of fuels. In addition, with rising incomes, patterns of consumption can change, with food and heating accounting for a diminishing share of additional consumption, while other goods and services increase their share. In addition, the structure of the production sector also changes gradually over time reflecting changes in Ireland's comparative advantage. Over the last decade there have been some significant closures of energy intensive manufacturing firms, reflecting the relatively high cost of energy in Ireland compared to some of our EU partners.

Figure 2.1: Irish Energy Demand and GNP

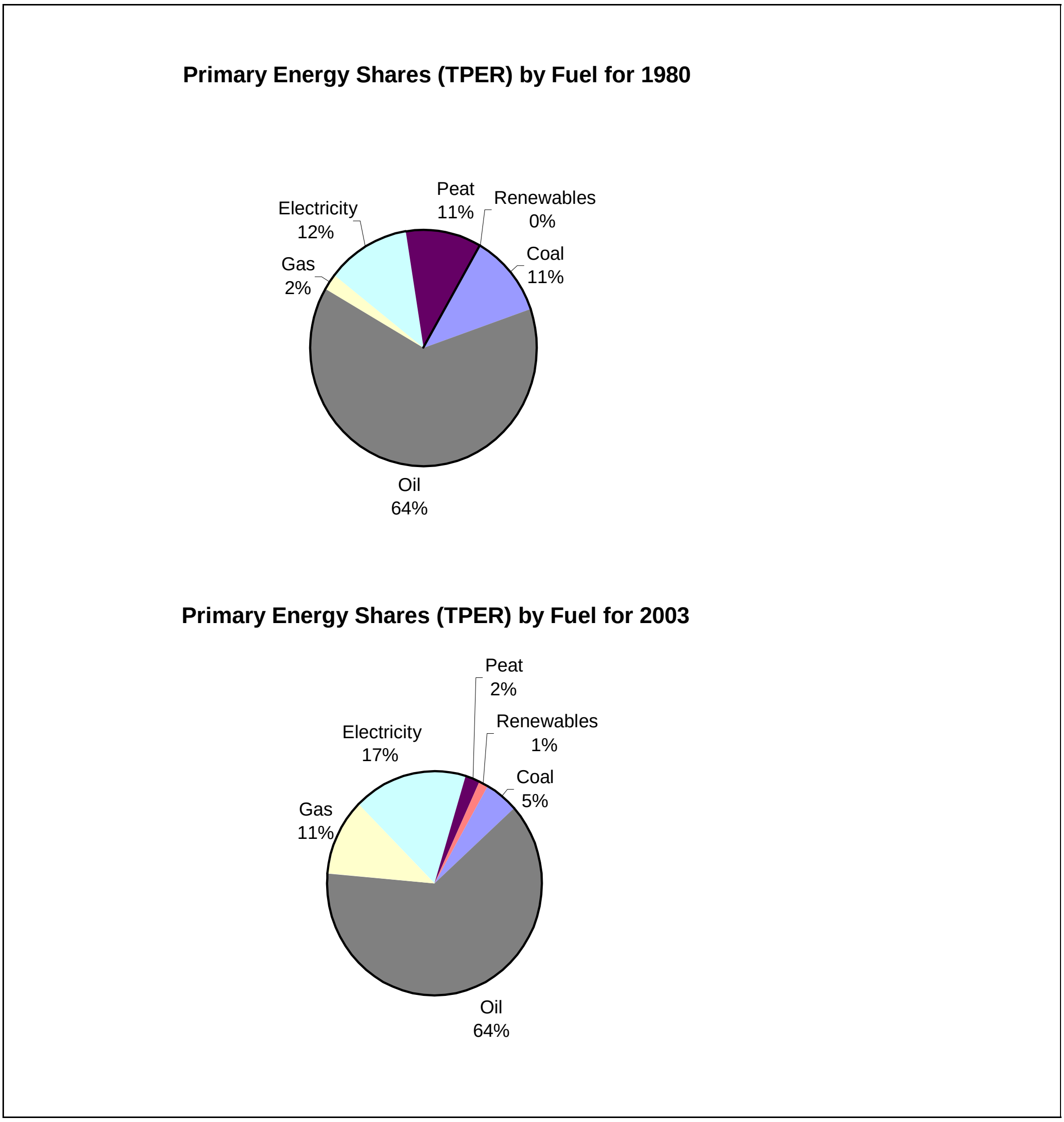


The demand for primary energy broadly kept pace with the growth in real GNP until the 1980s, as illustrated in Figure 2.1. Energy demand actually fell in the mid-1980s as the economy struggled. In recent years the growth in GNP has dramatically outpaced the growth in demand for primary energy. The change in energy intensity can be decomposed into two factors: structural change in fuel use and changes in technical energy efficiency.[10] Gas has significantly increased its market penetration in recent years (Figure 2.2) while energy efficiency accounts for a significant proportion of the improvements in energy intensity (Conniffe, 1993). Most potential for additional future gains in the economic return from energy use rests with this latter effect.

In Figure 2.2 we show the breakdown of total primary energy requirement (TPER) by fuel in 1980 and 2003 showing the changes in the fuel mix over the last 20 years. It is obvious that oil is the dominant fuel in the Irish market, and has been so for the last 20 years. Its share was around 64 per cent in 2003, identical to its share in 1980. Since 1980 the share of final energy accounted for by electricity and gas has risen rapidly, so that in 2003 electricity accounted for 17 per cent of final energy demand and gas accounted for 11 per cent. The share of consumption met from coal and peat has fallen dramatically since 1980, as both firms and households have shifted their consumption to cleaner, more efficient fuels. Although electricity has increased its share, natural gas was the main beneficiary of this shift in consumption patterns, increasing its share from just 2 per cent in 1980 to 11 per cent in 2003.

[10] By technical efficiency we mean the efficiency with which the calorific value of fuel is converted into useful energy, such as heat.

Figure 2.2: Total Demand for Energy by Fuel



During the first half of the 1990s, final consumption[11] of electricity grew by almost 25 per cent, an identical growth rate to that of GNP over the period. However, between 1995 and 2000, final consumption of electricity grew by around 35 per cent while GNP grew by almost 50 per cent in real terms over the same period. This reflects the fact that the rate of growth of demand for electricity (and other energy) is declining relative to the growth in income (GNP). Table 2.3 shows the growth in final energy consumption by sector

[11] Total final consumption of energy (TFC) is the sum of the consumption of each fuel (including electricity) by sector, excluding energy lost in transformation (electricity production, oil-refining etc.).

for the 1980s and for the most recent period 1990-2004. It shows how the growth in demand from the transport sector is very much more rapid than that from all other sectors. While the commercial sector also has quite a high growth rate (reflecting the changing structure of the economy), it is much smaller in absolute size than the demand from transport use. As a result, when looking forward at the drivers in the growth in energy demand and related emissions of pollutants the transport sector should receive special attention. However, this issue is not dealt with in detail in this paper.

Table 2.3: Growth in Final Consumption of Energy by Sector, Per Cent

	1980-1990	1990-2004
Industry	-1.3	0.9
Transport	1.6	5.9
Residential	1.2	2.0
Commercial / Public	5.3	4.1
Agriculture	na	1.6
Total	1.5	3.4

Source: SEI, 2005, *Energy in Ireland 1990-2003*.

Table 2.4: Characteristics of the Irish Electricity System, 2003

	Republic of Ireland	Northern Ireland	All Island
Generating Capacity MW	5,324	1,978[12]	7,302
Peak Demand MW	4,389	1,539	5,928
Peak as % of Capacity	82.4	77.8	81.2
Electricity Generated MWh	25,044,000	8,599,000	33,643,000

Table 2.4 shows the generating capacity available on the island of Ireland in 2003. As can be seen from this table, the electricity system in the Republic of Ireland is substantially larger than the Northern system. In 2003 peak winter demand was over 82 per cent of capacity in the Republic. This represented quite a tight margin, given the low availability of older generating capacity and the possibility of unexpected events affecting station availability. In Northern Ireland the margin over peak demand was significantly greater.

Table 2.5: Oil Consumed in the Irish Economy as Percentage of GNP

	1980	1990	2003
Share of Oil in the Value of GNP	8.0	3.2	1.8
Share of Gas in the Value of GNP	0.4	0.6	0.3

Source: GNP from CSO, *National Income and Expenditure*. Imports of oil and gas in value from CSO, *Trade Statistics*. Domestic production of gas valued at price paid by electricity generators, which may be understated due to undercounting of gas imports in the trade statistics.

[12] Includes 400 MW in capacity for the electricity interconnector to Scotland.

Table 2.5 shows how the share of GNP spent on oil and gas has changed over the last quarter of a century. It shows that the Irish economy in 2003 was very much less vulnerable to the direct effects of shocks in oil prices than it was in 1980. The combination of economic growth in less energy intensive areas and the fall in the real price of oil in the mid-1980s means that it would take a much larger oil price shock than occurred in the 1970s to have a similar direct impact on the Irish economy. However, due to the globalisation of the Irish economy today the economy is obviously more vulnerable today to the indirect effects of such a shock operating through its effects on the world economy.

Gas consumption, which represented 0.6 per cent of GNP in 1990 accounted for only 0.3 per cent by 2003.[13] However, the rapid growth in consumption of gas in the electricity sector combined with a dramatic rise in gas prices means that gas today accounts for a significantly higher share of GNP than two years ago.

2.4 Forecast Demand

The ESRI *Medium-Term Review: 2003-2010* (Bergin *et al.*, 2003) published forecasts for the demand for energy over the coming 15 years. The forecast demand for primary energy under different scenarios is illustrated in Figure 2.3. The solid line represents the Benchmark forecast. However, because of the uncertainty that surrounds the macroeconomic forecasts, a number of alternative scenarios for the growth in potential output were also considered. Here we consider the implications of the scenarios referred to as "High Growth" and "Low Growth" for energy demand.[14] In the low growth scenario primary energy demand would be almost 1 million tonnes of oil equivalent (TOE) less than the benchmark forecast by 2020. In the case of the high growth scenario the Benchmark would underestimate the primary energy demand by over 1 million TOE per annum by 2020.

As a result of forecasting errors at the end of the 1970s[15] a large amount of new electricity generating capacity was built, in particular the Moneypoint coal-fired power station.[16] This new capacity came on stream at a time when the economy was performing poorly and the result was considerable excess capacity lasting throughout the 1980s and the 1990s. The need to finance this excess resulted in very high electricity prices in the 1980s, followed by declining real prices in the 1990s as the existing capacity was gradually paid for and as new capacity was not required. The transmission infrastructure was

[13] There is some uncertainty about these figures because of questions about the reliability of the trade statistics.

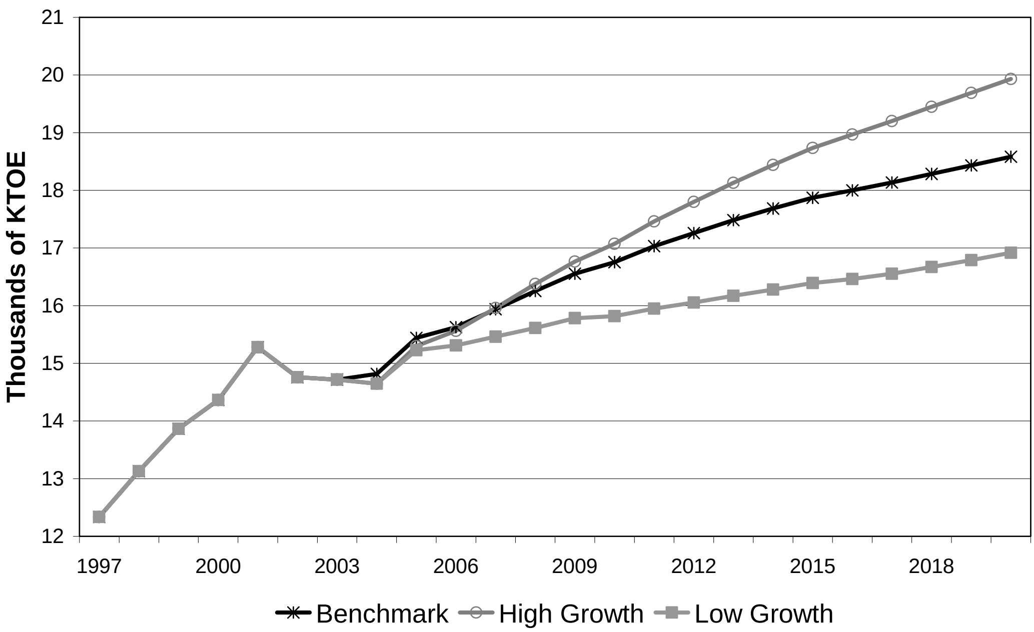
[14] These involve average annual growth rates of around one percentage point above and below the benchmark forecast. Over the last 15 years our medium-term forecasts have underestimated future growth by something over one percentage point a year – hence the margin of error encompassed in the scenarios.

[15] The forecasting errors at the end of the 1970s arose from reliance on official government forecasts which always had a low probability of proving correct.

[16] Coal was the fuel of choice to reduce the dependence of the economy on oil.

also adequate to the country's needs in the 1980s. In the case of gas, major investment was undertaken to extend natural gas supplies to the major urban areas.

Figure 2.3: Forecast Energy Demand



By 2000, the previous excess of electricity generating capacity had been eroded and it was clear that new capacity was required. Given the forecast for electricity demand shown in Bergin *et al.*, 2003, there will have to be up to 2,000 MW of new generation capacity put in place over the coming 15 years. (Each new gas-fired station adds around 400MW, at a capital cost per plant of around €250 million to €300 million.) Already a number of new generating stations have been built or are in the process of development. This need for more generation arises from the recent period of rapid growth and the continuing capacity for the economy to outperform its neighbours, at least up to the end of the current decade. Putting in place a market structure that will deliver this investment at minimum cost to consumers is discussed later in Chapter 6.

The need for new electricity generation also makes Ireland rather different from the rest of the EU. Because of the slower economic growth in most other EU economies electricity demand is rising much more slowly than in Ireland. The result is that there is no need to incentivise major new investment. The rest of the EU is in a situation rather similar to Ireland in the early 1990s; it can coast along on the basis of past investment, with the price of electricity falling somewhat below its long-run cost of production. The Irish electricity price henceforth will have to signal the full long-run cost of production in order to remunerate recent and potential capital investment.

The electricity transmission infrastructure is also inadequate to the needs of a rapidly growing economy. Unless the planned major further investment (Transmission System Operator Ireland, 2002) is delivered on time it could have a wider impact on growth.[17] In a paper on problems with the EU electricity market Newbery, 2002 says:

> The best short-run method of supporting electricity liberalisation is to rapidly increase transmission capacity.
> Newbery (2002), p. 926.

In the longer term the integration of the two electricity markets on this island, and possibly the eventual integration of the Irish system with that in Britain, may be very important in promoting competition. For this to happen transmission capacity will have to be expanded in advance of demand. If transmission capacity is only just adequate for demand, or cannot handle demand, then it will allow generators in each jurisdiction to charge monopoly prices. It was for this reason it was important that gas transmission infrastructure was expanded ahead of demand and the same applies to electricity. Obviously it is possible to over invest in transmission infrastructure, but the EU experience to date has been one of underinvestment. This issue is dealt with in more detail in Chapter 4.

2.5 Summary

- Energy prices are currently higher in Ireland than in neighbouring EU countries. In the case of gas this can be partly accounted for by problems in the UK gas market (and the fact that Ireland is currently importing gas). In the case of electricity the need to undertake major new investment is currently putting significant upward pressure on prices.
- The Irish energy system is the second smallest (after Luxembourg) in the EU(15). Our average energy requirement per capita is lower than the EU average requirement.
- Demand for energy from the transport sector is growing more rapidly than is demand from all other sectors of the economy.
- The demand for energy, and for electricity in particular, will continue to rise quite strongly well into the next decade, while the non-transport demand for energy in other forms will show only moderate growth
- There is a need for major investment in new electricity generation capacity over the coming decade.

[17] The major obstacle to implementation is in the physical planning procedures. There are no engineering or financial obstacles to implementation.

- There is also a need for major investment in electricity transmission, especially to help create an integrated island electricity market.

3. SECURITY OF SUPPLY[18]

3.1 Introduction

Energy plays a vital role in our society, underpinning all areas of economic activity. The economic impact of supply disruptions can be high, affecting all sectors of the economy and it is difficult to insure against such risks commercially. In formulating energy policy governments must recognise this potential market failure with an energy policy to ensure that affordable energy is readily available with minimal risk of supply disruption.[19] This chapter identifies a range of security of supply risks that could potentially affect the Irish economy. There are two different aspects to security of supply of energy. The first involves physical security, highlighted in the war years by the problems in importing oil – it was unavailable at any price. The second aspect is whether, even if available, the price of that availability is dramatically higher than the economy can readily absorb.

As electricity and oil for transport, the hospital sector and other key services are essential to modern life, it is vitally important that a reliable supply is always available. As Ireland becomes more and more dependent on gas to generate electricity the issue of the physical security of the gas supply has grown in importance. The provision of the second gas pipeline to the UK has greatly reduced the previous small risk of a medium-term complete disruption to supply through breakage of the then single under-sea pipeline. This is no longer a significant concern, though the fact that all the island's supplies go through a single short piece of pipeline in Scotland leaves some residual concerns.

Even more important than the price of energy is the reliability with which it is provided to the business and the household sectors. Foreign direct investment has been reassured by the reliability of the system over the last decade, but the growing pressures on supply in

[18] This chapter draws on the analysis in DKM, ESRI and Electrotec, 2004.

[19] Several plans and safeguards are in place including the 'Black Start plan' and the ESBNG 'Generation Adequacy Report' which informs market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate electricity supply in the medium term. They use an internationally accepted methodology for establishing the likely generation required to achieve an adequate electricity supply to balance the risk of supply shortage (Loss of Load Expectation (LOLE) against an accepted security standard of eight hours LOLE per annum.

the sector must give some cause for concern. It is very important that they are addressed to ensure that the past record of reliability is maintained over the course of the coming decade. Apart from the possibility of interruption of the single most important fuel, a failure by the market to deliver the necessary increase in electricity generation capacity could see Ireland facing electricity shortages later in the decade. While not nearly as serious as a loss of supply for a number of months, the potentially disruptive effects of such an outcome mean that a major objective of policy should be to ensure adequate provision for new generation (and necessary transmission). This issue is dealt with later in Chapter 5.

The second security issue concerns excessive dependence on a single fuel where the risk arises from the possibility of shocks to the price of that fuel. If, as seems likely, Ireland becomes more dependent on gas than most other EU countries, then a shock to gas prices would adversely affect Ireland's competitiveness. For a large price shock the adverse economic effects could be quite significant.[20]

As EU gas supplies (especially UK supplies) run out over the coming decade, gas users will become more and more dependent on a handful of sources of gas – Russia (Gazprom), Norway, Iran and Algeria. With so few suppliers this leaves open the possibility that they could use monopoly power to extract high prices from consumers who had committed themselves to gas through major investment in infrastructure.

These separate risks concerning the security of supply can potentially affect all types of energy: there is a risk of physical interruption in the supply and networks of gas and electricity, as well as of oil, and most forms of energy are subject from time to time to quite extreme price movements. These two types of risk are considered separately – quantity risks and price risks. The probability of the two types of shock affecting, for example, gas, are very different and they have very different economic implications.

The types of risks facing the Irish energy market are considered in more detail in Section 3.2. Section 3.3 discusses the benefits of fuel diversification as a means of managing risks. Section 3.4 quantifies the cost-diversity trade-off using a probabilistic approach to managing risk based on modern portfolio theory. Section 3.5 outlines some policy instruments and options for achieving the optimal level of fuel diversity in the short, medium and long terms. Section 3.6 concludes.

[20] See J. Fitz Gerald, 2003, "The Macro-Economic Implications of Gas Dependence", ESRI Working Paper 149.

3.2 The Key Risks

QUANTITY RISKS

The causes of "quantity" insecurity in the energy sector include:

- the operational reliability of energy systems;
- risks related to the scarcity and uneven distribution of primary fuels (leading to a concentration of market power).

In the first very unlikely case, physical interruption of the gas pipelines supplying Ireland could leave the economy without gas supplies. Another example, which could give rise to a physical inability to supply a key form of energy – electricity – would be a breakdown in a particular type of electricity generator due to a lack of technology diversification. The second type of interruption covers cases such as political instability in the Middle East or in the sources of gas supply, which could also see a physical interruption in supplies.

Firms (and households) investing in the Irish economy should consider the risk of physical interruption of fuel supply. For instance, any physical interruption in supply would leave a gas-fired electricity generating plant stranded, losing significant profits while fuel was unavailable. In a competitive market firms will factor in some of this quantity risk into their investment decisions in so far as they are liable for the costs of an interruption. However, the potential losses of individual firms are only limited to their medium-run fixed costs for the time that fuel is unavailable and so long as these risks are not insurable commercially.

However, for the economy as a whole a physical interruption in supply of fuel and electricity would be extremely serious where substitute energy supplies cannot be found in a reasonable time scale. Electricity is an essential ingredient in modern life and this is reflected in its very inelastic demand.[21] A very extensive interruption of output across the economy would be inevitable from a prolonged interruption of electricity supplies. While probably less important than the social impact, if an unanticipated interruption was sustained for much longer, the loss of industrial output could seriously affect domestic and export markets leading to a long-run loss of national income.

According to Tishler (1993), there are four sources that contribute to the cost of an electricity outage: foregone profits (output), possible reduction in productivity due to the outage, damage to materials, and payments to labour during the outage. Lijsen and Vollaard, 2004, estimate that the cost in the Netherlands of an unexpected outage leading to a loss of load of one MWh would be €3,000, over forty times the cost of generating such electricity. Costs are likely to increase exponentially with the duration and scale of the outage – the damage done by a loss of electricity will be small for a limited outage but could be massive for a total failure. For example, a loss of 20 per cent of electricity capacity due to a gas

[21] See J. Fitz Gerald, J. Hore and I. Kearney, 2002, "A Model for Forecasting Energy Demand and Greenhouse Gas Emissions in Ireland", ESRI Working Paper No. 146.

outage could be spread through rationing. A regular rotating curtailment of supply could be controlled to leave crucial sectors, such as hospitals, with continuous supply. However, if the loss of capacity were to rise above 20 per cent the costs and related disruption would be increasingly difficult to avoid through rotating cuts. Thus a loss of 80 per cent of electricity capacity due to gas outage would be more than a third worse than the loss of 60 per cent.[22] While it is clear that such a severe disruption would have a very low probability of occurring, the costs, if it did occur, would be very grave. If this potential risk is to be adequately dealt with, the regulatory authorities cannot leave it to market forces alone, but must take independent action to mitigate the probability of such an interruption.

Historically, geopolitical issues related to the concentration of oil reserves have represented a particularly important concern for governments. Compared with the oil market, the natural gas market is much more constrained by transport infrastructure leading to more region-specific market characteristics.[23] While currently the sources of gas on the EU market are quite diverse, with supplies running out from existing suppliers (e.g. the UK, the Netherlands and Ireland), by 2010 the then fully integrated EU market will be dominated by Algeria, Russia (Gazprom) and Norway. This will be an even more concentrated market than the current OPEC cartel. The switch in sources carries with it further implications for the ability of supply to adjust quickly to changing short-term levels of demand (such as the winter demand fluctuations arising from sudden temperature changes), referred to as the swing capability of the system. The main transnational pipelines that will deliver imported gas are anticipated to have a much lower swing capability than domestic production in these islands. In the European markets, lack of flexibility in contracts and delivery is countered by some gas storage availability in the UK and elsewhere (Oxera, 2004).

While the development of gas storage in Ireland would seem desirable, much would depend on its cost. The geology of the Republic of Ireland is much less favourable than that of Britain or of many other EU countries. However, there are large salt caverns near Kilroot outside Belfast, which could provide suitable storage for significant quantities of gas. With the completion of the North-South gas pipeline in 2007, these caverns could be developed to provide significant gas storage for the island. Such storage could be valuable in smoothing daily and weekly fluctuations in demand and

[22] It is not feasible to quantify these economic costs in a precise manner as they would depend on the extent of the loss of electricity capacity, the length of time power was lost and quantification would require much more economic data than are currently available. See Lijsen and Vollaard, 2004, for a quantification of some of the costs of supply disruption.

[23] Although the emergence of Liquified Natural Gas as an increasingly important means of transport is progressively joining regional gas markets together, pipeline transport remains the predominant natural gas means, limiting the geographic range of international gas trade.

also in providing a buffer against short-term disruption to supply. The possibilities of developing such storage should be examined as part of the development of the all-island energy market.

A relatively low price elasticity of demand for gas in the medium term confers considerable market power on the small number of major suppliers.[24] This leaves open the possibility that gas prices could be dramatically raised for a sustained period through a voluntary restriction of supply. It is this risk of a future price shock lasting months or years that needs to be considered by Irish energy policymakers.

In many cases shocks that are perceived as being quantitative in nature (e.g. a shortage of oil) can readily be turned into price shocks. Price shocks allow for some market response modifying the costs of an interruption. For example, in the late 1970s action by the Irish government in the face of oil price shocks did the reverse – by restricting the price of oil, a price shock was turned into a quantity shock where supplies were not available to meet demand at the going (restricted) price. The resulting disruption magnified the already significant cost to the economy.

Looking out into the next decade, the rapid growth in the world economy, especially in China and India, is likely to put major upward pressure on demand for oil. At the same time discoveries are not taking place at a sufficient rate to keep pace with demand. As a result, it is quite likely that real oil prices will rise rapidly over the next two decades. However, it is most unlikely that the imbalance between demand and supply would lead to any prolonged physical shortage. Rather the market will operate to ensure that oil is available, albeit at an ever-increasing price.

PRICE RISKS

Historically oil and gas prices have been correlated, though with a lag, so that the risk of price shocks in oil or gas are clearly interdependent. As a result, moving dependence from gas to oil or vice versa cannot significantly reduce an economy's exposure to a price shock affecting either fuel. At present gas technologies are the most competitive fossil-fuel form of electricity generation in Ireland and in the immediate future all new thermal generation plant is likely to be gas-fired. The alternatives to increasing gas dependence are coal, nuclear and wind, which have higher capital costs and face other problems (including higher environmental costs, especially for coal and nuclear). Under these circumstances, positive policy intervention to change the fuel shares used in electricity generation will have significant costs. The fact that gas dependence continues to increase in Europe should be seen as evidence that fuel diversity in the power generation industry comes at a price. Electricity generation historically has tended to go through periods lasting

[24] Where the supply pipelines pass through a limited number of countries, such as the Ukraine, it could also confer significant market power on these transit countries.

decades when, driven by technological developments, one fuel appears far more attractive than the rest.

However, if Ireland were more affected than other markets by the price shock, then there would be a loss of competitiveness relative to our EU partners. Such a loss would compound the loss of output and income, with an increased incentive for sensitive production to move to other locations that were less affected by the shock. In the case of businesses, the loss of competitiveness relative to similar electricity-using businesses abroad could be significantly greater, given the much greater gas dependence of the electricity sector in Ireland compared to the rest of the EU. This could be further compounded if they were heavy users of oil and gas, as well as of electricity. Thus, the income loss as a result of a price shock would be aggravated by an enhanced incentive to relocate electricity intensive output elsewhere.[25]

There is a range of different strategies that could be adopted to reduce dependence on gas, or on any one other fuel. Unlike the case of a physical interruption, there would be limited incentive for individual firms with generating plant to take the risk of a major shock to gas prices into account in their investment decisions. Because all producers in Ireland (and elsewhere) would be faced with the same increase, in the long run they could pass it on fully to consumers. While there would be some small reduction in demand due to the higher prices, this would be limited and profitability would not suffer dramatically. It is only if the price rise were sustained for many years that investment in new plant using alternative fuels would take place, stranding existing gas plant. In the end the suppliers of gas, if acting rationally, would ensure that prices did not remain high for so long that their market was permanently damaged by existing consumers investing in new oil, coal or renewables capacity.

In a very gas-dependent economy a sudden rise in gas prices would have the potential to cause significant economic disruption. On the basis of the past behaviour of prices it has a much higher chance of occurring at some stage in the future than a sustained quantity interruption. Such a price shock would potentially damage the competitiveness of the economy. From the point of view of the individual firm there will be some incentive to hedge the short-term exposure to price shocks. However, as the exposure of the firm to price shocks may be much less than the exposure of the economy, too little use may be made of means of insuring against price shocks. This means that security of supply is a regulatory issue. It would be worthwhile paying a limited price to insure against such a risk. Some degree of judgement has to be used by regulatory authorities to determine how much it is worth paying for fuel diversity to avoid the very low probability of severe interruption of fuel and electricity

[25] Individual businesses would not have to physically relocate elsewhere. Much more likely would be a situation where output in the firm declines or ceases in Ireland and the market is met from production by more successful firms elsewhere.

supplies, and to avoid the real possibility of large increases in the prices of particular fuels.

Probably the simplest insurance policy that the Irish economy could take against a price shock would be to invest in shares in gas fields in Norway or possibly Russia (or preferably in companies owning a portfolio of gas fields that supply the European area). An appropriate hedge against oil price shocks could be to invest in the shares of oil companies that own substantial reserves of oil. This would provide a financial hedge against such price shocks.[26] However, this instrument would provide no insurance against physical interruption in supply on these islands. It might also be difficult to get a broad enough portfolio of such investments to provide an appropriate hedge. Nonetheless, the issue of insuring the whole economy against oil and gas price shocks should be taken into account when framing the investment strategy for the national pension reserve fund (NPRF).

3.3 Fuel Diversity[27]

The previous section showed that due consideration should be given to a fuel diversity policy for at least two reasons. First for geopolitical considerations – the control of a substantial share of fossil fuel resources lies with a small number of suppliers. Second, where there is a concentration on one or two key fuel types, the exposure to price volatility could be dangerously exacerbated. Third, there is quite a strong prospect that oil (and gas prices) will rise rapidly over coming decades.

OVER RELIANCE ON HYDROCARBONS

The issue of overdependence on oil loomed very large in the late 1970s in the wake of the oil price shocks of that decade (NESC, 1983). The result was an enhanced emphasis on non-oil fuels for generating electricity. This gave a new lease of life to coal technology. In the Irish case this was a very important factor in the building of the Moneypoint power station in the 1980s. Elsewhere it also gave a major new impetus to the development of nuclear energy for electricity generation.[28] However, the absence of a cost-effective alternative source of energy for transport, together with the fall in

[26] If the insurance policy paid up (i.e. oil prices and shares in oil companies rose dramatically) it would probably be appropriate to pay the benefits to consumers in a way that did not reduce the price of energy below its true cost.

[27] Sterling (1999) provides an extensive discussion on the value of diversity as well as an overview of the different approaches available in the literature to measure diversity.

[28] The NESC Study "*Irish Energy Policy*" (1983) reviewed contemporaneous studies which found that the economics of coal (higher fuel costs) versus nuclear (higher capital costs) showed no clear economic advantage for one over the other. However, the need for backup generation for a notional nuclear plant rendered it unviable in the Irish context and reinforced the view that the correct decision had been made regarding the commissioning of a baseload coal plant at Moneypoint.

the real price of oil in the mid-1980s, has resulted in a continued increase in world dependence on oil for usable energy.

Potential over-reliance on gas has been seen as a key concern in recent years, particularly in large areas of Europe where dependence on non-indigenous natural gas has grown rapidly. However, modern economies are permanently interdependent, both in terms of climate change issues and the sourcing of energy raw materials. Here we consider the example of how a possible gas price shock would impact on the economy. (Many of the issues that arise would also apply in the case of an oil price shock.) If gas prices were to rise suddenly to twice or three times their current level; and if the higher price were sustained for a number of years this would have a quite noticeable effect on the Irish economy. With gas usage costing 0.3 percentage points of GNP before the recent price rise (Table 3.1), the immediate cost to the economy of such a price shock would be an additional 0.8 percentage points of GNP, taking the cost of gas to a total of 1.2 percentage points of GNP. This net cost to the Irish economy of 0.8 per cent of GNP would be paid to foreign suppliers (or owners) of gas, reducing national income. Such a negative shock would have knock on effects for consumption and employment as the economy adjusted to the inflationary shock. However, provided that Irish exposure was the same as the exposure of the country's EU competitors there would be no relative loss of competitiveness.

The possible impact of excess dependence on gas on the economy will depend on the extent of gas dependence in Ireland, and also on Ireland's dependence relative to its trading partners. As long as Moneypoint, a significant coal-burning plant, remains open on full power, the economy will be less exposed to a reliance on gas than would otherwise have been the case. This exposure comes mainly from price fluctuations arising from lack of supply liquidity. The strategy for dealing with the potential for this kind of shock has in the past involved investment in generation using different fuels.

Table 3.1: Gas in the Irish and EU Economies

		Ireland 2001	Ireland 2010	EU 2001e
Gas Consumption – Economy	Mtoe	3,140	5,573	328,364
Price	€ a Toe	102	131	102
Total Cost of Gas Bought – Economy	€ Million	320	731	33,504
GNP	€ Million	96,448	178,572	8,816,000
Gas as % of GNP		0.33	0.41	0.38
Electricity, Gas share[29]	%	35	58	18

e: estimate.

[29] The data for Ireland for 2001 are from the Department of Public Enterprise Energy Balance Sheets. For 2010 they come from ESRI projections. For the EU they are for 2000 and are taken from IEA, 2002, *World Energy Outlook*.

In the case of the danger of physical interruption there are a range of measures, which need to be taken before considering fuel diversity. These include the provision of backup infrastructure. Systematic provision for temporary dual firing of combined cycle gas turbine (CCGT) plants can also, at a cost, provide additional security. This latter requirement should allow the electricity-generating sector to ride out a temporary interruption of gas supply, such as might occur due to problems with onshore gas transmission infrastructure.

In Ireland's case, enhanced international interconnection by gas pipelines has been the key strategy for providing physical security to an otherwise isolated system. The building of the second gas pipeline was important in providing enhanced security against any very unlikely breakage in the single gas pipeline to Britain. There may still be a need to strengthen the onshore infrastructure in Scotland, as while the link to Scotland involves two separate pipes, the onshore link in Scotland is a single pipe. The most important measure that would further enhance physical security of gas supply, which will have zero cost to consumers, is to bring the offshore Corrib gas field on-stream. This would probably see Ireland remaining over 50 per cent self-sufficient in gas supplies well into the next decade. Any further gas finds off the West coast would turn Ireland into a net exporter. While not very likely, this would further enhance security and it would also have implications for gas prices on the island.[30]

When combined with the two pipelines to Britain, the impending pipeline to Northern Ireland, and the potential for gas storage off the South coast or in Northern Ireland, the domestic supply of gas should provide a reasonable level of certainty that gas supplies will not suddenly be cut off. BGE believe that onshore system failures could in most cases be repaired inside 24 hours. However, with interconnection to Britain, and through Britain to the rest of Europe, the Irish gas market will continue to be exposed to any shocks to gas prices on the wider EU market.

Liquified Natural Gas (LNG) supplies are available internationally from a wide range of suppliers and could potentially provide a more diversified source of gas. However, there are considerable economies of scale in the provision of LNG terminals. These scale economies arise not least from the dangers in handling such a flammable fuel. It would appear that because of these economies of scale there is no commercial interest in constructing LNG facilities on the island of Ireland to enhance physical security. Even if such facilities were provided in Ireland the price of gas would still be set by the much larger British and continental European gas markets. Thus if there were any commercial advantage to building such a LNG terminal the benefits would accrue to the developer, not to consumers. In any event, to the extent that LNG

[30] At present, price is set as the UK price *plus* transport. If Ireland were ever to become an exporter, price in the domestic market would be set at the UK price *less* transport.

facilities are provided in Britain they will also benefit Ireland because of the interconnected nature of the two markets. If they reduce the variance in gas prices in Britain they will have a similar impact here. Also if they reduced the impact of a physical shortage in Britain, which would severely impact on prices, this effect on prices would be automatically transmitted to the Irish market. Thus there seems little advantage to the Irish government in promoting such an investment.

EU policies aimed at emission reduction are making fuel diversity more difficult to attain. The introduction of emissions trading is expected to raise the price of emitting carbon dioxide from burning fossil fuels. This will particularly penalise coal and peat, with gas being the "cleanest" fossil fuel. Already this policy stance is further encouraging concentration on gas as the fossil fuel of choice for electricity generation. The Large Combustion Plant Directive, which particularly affects coal plant, is further discouraging investment in coal (or peat) in the future. Some countries, including France and the United Kingdom, are reconsidering the construction of nuclear plant, but the lead times are substantial and planning controversies inevitable. However, such a policy seems unlikely to be acceptable in Ireland in the foreseeable future on environmental grounds. In any event, Fitz Gerald (2004), suggests that because of the large size of nuclear plant and the small size of the Irish electricity system, a nuclear plant would require so much back-up conventional plant as to substantially raise its overall costs, reducing any potential attraction for investors.

3.4 Fuel Price Uncertainty and the Optimal Generation Portfolio

THEORETICAL BACKGROUND

According to Markowitz (1952), investors in financial markets have always had to deal with exposure to risk. Modern Portfolio Theory (MPT) has been developed to help manage this uncertainty based on the concept of an "efficient portfolio" which has the smallest attainable risk for a given level of expected return. In an uncertain world this approach provides a very useful format for considering the trade off between minimising the expected price of electricity and minimising the risk inherent in any particular choice of fuel mix. It reflects the fact that forecasts are always uncertain and what may be forecast to be the best option assuming a particular price scenario may well turn out to be much more expensive than expected in the long run. This approach assumes that, as well as knowing something about the likely future growth in the prices of energy, policymakers have information on the volatility in energy prices and how the volatility in the price of individual fuels is correlated. In the case of energy prices there is good reason to believe that gas and oil prices will continue to be quite highly correlated in the future, as in the past.

The theory focuses on identifying either the return-maximising or the risk-minimising bundle of assets. The methodology uses a mean-variance analysis, based on empirical prices, and compares the average returns of different bundles of assets (portfolios of generation plant) with the associated level of risk. In any economy there are two types of risks that an investor faces, systematic and unsystematic. The former has a similar affect on each player, and is associated with the market environment generally and is, therefore, non-diversifiable. An example of such a risk would be the increasing global dependence on gas. Although some countries will be more exposed than others to gas price increases, each country will suffer a comparable effect in the price of gas from a gas price shock. Unsystematic risk refers to the specific risks that each firm faces. It is up to the individual firm to try to hedge against these risks as best it can. This exposure to price fluctuations is avoidable through portfolio diversification and can be best solved through the use of Modern Portfolio Theory. Adding generation capacity to the portfolio whose fuel prices are uncorrelated with the current mix, acts as a hedging mechanism against future price uncertainty. To the extent that these additional types of generation capacity have higher costs (lower returns) than the ones that they replace, the risk reduction comes at a cost in terms of expected future price (return). In relation to the example given, this could mean using fuels other than gas in electricity generation to reduce risk, even though gas is expected to be the cheapest fossil fuel for electricity generation.

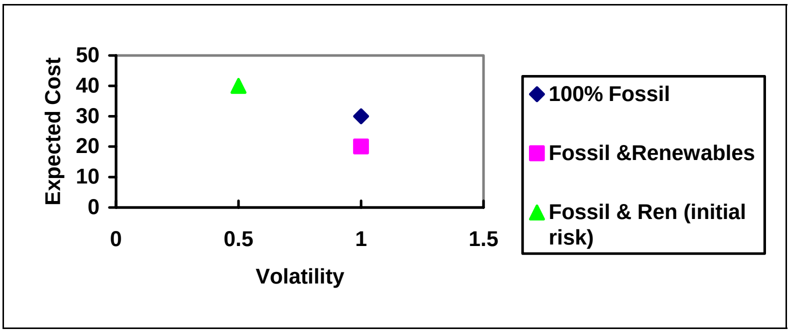
This methodology takes account of expected cost and expected risk, calculated as the weighted average of all possible outcomes. MPT puts an economic value on price stability. An example of the trade-off between risk and price is the choice by many homebuyers to adopt fixed rate instead of variable rate mortgages. The extra interest that is incurred by the guarantee of fixed repayments, is the price of certainty for each customer. Adapting this methodology to the choice of the optimal electricity generation portfolio is potentially useful in identifying the price to be paid for greater price certainty. For example, it permits the comparison on economic grounds of the cost of a wind turbine – characterised by a high capital expenditure, very low operational costs and no fuel cost – with the CER Best New Entrant (BNE) plant, a gas-fired CCGT that incurs relatively lower costs of capital per MW of capacity, but higher operation and maintenance costs and a substantial and uncertain fuel cost element. A well-diversified portfolio of generating assets will include a mix of technologies whose underlying fuel prices are uncorrelated with each other. This is the best means of hedging future uncertainty and similarly ensures that any increase in cost is due to market risk and is unavoidable. However, such hedging behaviour comes at some cost in terms of higher expected prices.

> A generating technology with costs that are statistically negatively correlated to the rest of the portfolio can help mitigate portfolio cost swings… Current evaluation of energy mixes understates the cost of fossil fuels and value of renewables (Awerbuch, 2004).

Most fossil fuel prices, with the exception of peat prices, are to some degree positively correlated, and the volatility that these prices exhibit often has a negative impact on economic activity.

Consequently, increasing the amount of fixed cost generation, such as wind, in the portfolio, whose price is uncorrelated with any other fuel, will add price stability for the future. Greater certainty regarding costs emerges as a reduction in risk in the portfolio analysis, albeit at the cost of an increase in the expected price.

Figure 3.1: Illustrative Portfolio



In Figure 3.1, we show a stylised example of three different portfolios of fossil fuel and renewable generation: all fossil fuel, and two different mixes of fossil fuel and renewables. Beginning with the fossil fuel and renewables (initial risk) mix we can see that in this stylised example it has an expected cost of around 40 and volatility of 0.5. It is significantly lower in volatility (lower risk) than the all fossil fuel portfolio, though having a significantly higher price. However, the alternative mixed portfolio could produce electricity at a lower cost (20) than the fossil fuel only option, while being equally risky as the fossil fuel only portfolio. In other words, for the same risk profile it may be possible to choose an alternative mix of generation that reduces the expected future cost of generation.

The lessons to be drawn from this approach suggest that an optimal portfolio of generation technologies should give an additional premium to technologies where the fuel price is fixed (renewable) or has a negative (peat) or low positive correlation (coal) with the price of gas and oil. If there is concern to reduce the risk of the portfolio there should be more wind, coal and peat than would be implied by a simple analysis based on a single forecast for future energy where prices are assumed to be certain. Obviously the weights in the desired portfolio will also be affected by the forecast movement in prices. For example, if the price of peat is expected to rise rapidly because of its high carbon content, this could offset its advantage in having a fairly stable basic price when carbon emissions are excluded.

PORTFOLIO MODEL ASSUMPTIONS

Here we use a model of portfolio choice to examine the trade-off for different portfolios of generation capacity between risk and price. The inputs required to calculate a cost minimising portfolio of electricity generation rely heavily on past prices and current costs of each of the different technologies, with a view to identifying the cheapest generation option in the long run. The technologies represented in the model are: Coal, Oil, Gas-CCGT, Gas-OCGT, Peat and Wind. The historic price data comes from the ESRI databank and covers the years from 1968 to 2003 inclusive. Fuel costs for 2003 were proxied by the average from the International Energy Agency (IEA) price publication for the first three quarters. The Operation and Maintenance (O&M) costs are estimates based on limited information from the CER's Best New Entrant paper, ESB's Annual Report 1992 (updated) and a paper by the Royal Academy of Engineers, 2004. Most of the disparity in long-run marginal costs emerges in the capital data used (DKM, ESRI, 2004).

The capital cost for coal was assumed to be the €260 million necessary to upgrade Moneypoint to include the installation of flue gas desulphurisation.[31] For both oil and peat, we assume zero capital cost (as the capital is a sunk cost). This is based on the assumption that no new oil or peat stations will be built, with the exception of the two recently completed peat stations. Oil is inefficient due to the availability of cheaper and cleaner fuels to work at base load,[32] so it is assumed that the existing stations will be sufficient to fulfil peak demand. With the introduction of Emissions Trading, peat will become uncompetitive due to its high carbon content. For Gas-CCGT, Best New Entrant figures from the CER were used. Gas-OCGT figures were taken from the Royal Academy of Engineers report. The capital cost for wind also came from The Royal Academy of Engineers figures. These estimates allowed for the variability in wind by building in the cost of backup plant, which proves to be quite significant.[33] The capital costs are assumed to be fixed at our estimate for 2003. The data were standardised to a measure of the cost per MWh, using the CER assumptions on new entrants.

For coal, gas plant and wind long-run marginal cost was used. In the case of coal the capital cost of the desulphurisation plant was included whereas for the other plant the full capital cost of the new plant was used. For all technologies the historical fuel prices were deflated by the GNP deflator to produce an estimate of the real fuel cost over time. An estimate of the real operation and maintenance costs was also used. Together these allowed estimates to be made of the marginal cost of each technology using current efficiencies but historic fuel costs. The resulting variance-covariance matrix,

[31] This reflects the fact that Moneypoint is a "sunk cost". Obviously for a new coal plant all the costs of such a plant, not just the renovation and flue-gas desulphurisation costs, would have to be included.

[32] Baseload electricity generators run most of the time. Baseload plant is normally the only plant running at times of minimum demand known as the off-peak (Stoft, 2002, p.42).

[33] The cost of this "backup" supply is a matter of considerable controversy. ESBNG, 2004a come up with a very high estimate of the cost of wind. However, in their model the electricity system is assumed to be optimised in the long run in a way that would make the cost of wind very high. With high wind penetration the electricity system would develop in a very different manner such as to minimise the marginal cost of wind.

reflecting the variability in the marginal costs over time, was then calculated.

Emissions trading has started from the beginning of 2005 and so the costs of emissions permits, at today's levels of efficiency, were calculated for five prices per tonne of carbon; €0, €10, €20, €30, €40. For simplicity, the price of carbon is assumed to be uncorrelated with fuel prices.[34] However, these five sets of data could be amalgamated into one set if assumptions were made about the expected price of carbon and the standard deviation in that price, but this is outside the scope of this paper. The model is run totally unconstrained with respect to fuel shares and no attention is paid to time of day or seasonal considerations. These assumptions do not properly encompass the characteristics of the market or technologies in question, but the results produce a useful illustration of the possible trade-offs between price and risk.

Table 3.2: Correlation Matrix

	Coal	Oil	Gas-CCGT	Gas-OCGT	Peat	Wind
Coal	1.00	0.43	0.42	0.41	0.39	0.07
Oil	0.43	1.00	0.74	0.75	0.45	-0.24
Gas-CCGT	0.42	0.74	1.00	1.00	0.41	-0.06
Gas-OCGT	0.41	0.75	1.00	1.00	0.41	-0.14
Peat	0.39	0.45	0.41	0.41	1.00	0.01
Wind	0.07	-0.24	-0.06	-0.14	0.01	1.00

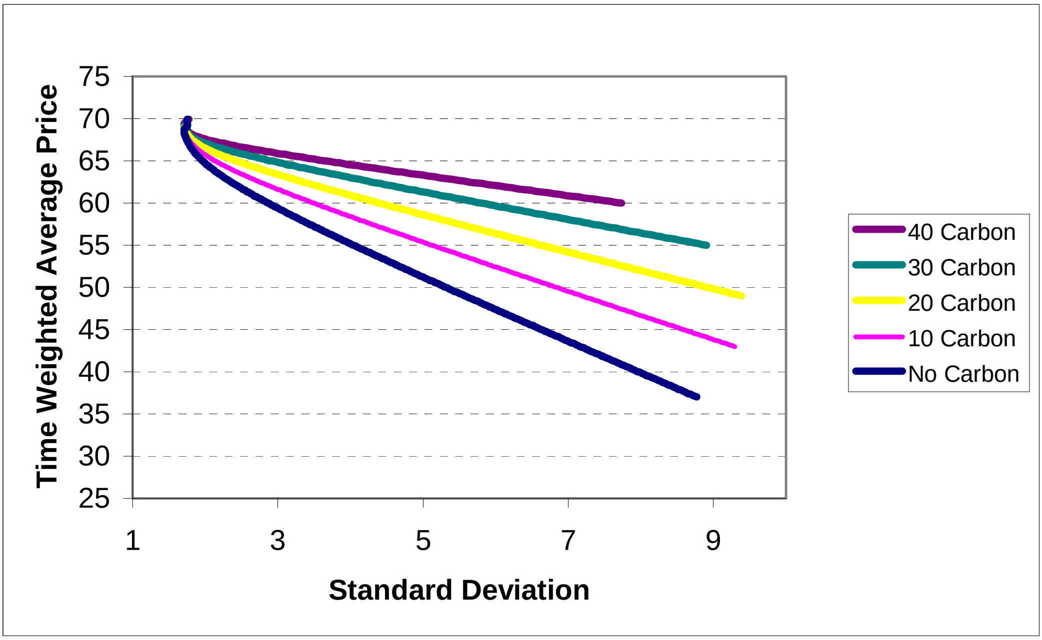
The correlation matrix summarises historical price fluctuations and also allows for the efficiencies of the various technologies. The most noticeable correlation occurs between oil and gas, 0.74 for CCGT and 0.75 for OCGT. It is this relationship that leads to the previously stated conclusion that no more oil stations should be built. Gas is a cleaner fuel and gas stations are more efficient than oil. Because the prices of oil and gas are highly correlated, oil does not represent a good hedge against gas price shocks. At the other end of the spectrum, the price of wind has no connection with the price of peat and is negatively correlated with coal, oil and gas. More importantly, it is the only technology that has negative correlation with gas. Portfolio theory puts great value on any option that perfectly hedges against price shocks. The high certainty about future wind prices should lead to a higher weighting on wind than would be the case if minimising the expected price of electricity was the only criterion. Peat and coal have smaller correlations with each other, and oil and gas. This moderate relationship is also of value because it offers a significant possibility of hedging against gas price shocks.

[34] Because of its lower carbon content, gas is favoured by high prices for carbon. It would appear that this is already happening. This would suggest some positive correlation between gas prices and carbon prices in the future.

MODEL RESULTS

This model uses the fuel and carbon prices discussed above. It also assumes that, with the exception of the price of carbon dioxide, past price behaviour over the 35 years 1968 to 2003 is a good guide to future price volatility. In Figure 3.2, the x-axis represents the standard deviation, which can be thought of as a measurement of risk. The larger is the standard deviation, the bigger is the risk. The y-axis denotes the time-weighted average (TWA) of the long-run marginal costs of generation by the various technologies (€ a MWh).[35] Each line symbolises a different estimated price for carbon permits and measures the level of risk for a given TWA price.

Figure 3.2: Price Risk Trade Off for Different Portfolios and Costs of Carbon



It can be seen from the diagram that the decision becomes a matter of a trade-off between risk and price. A low risk of a price shock would require a high average cost, due to insufficient fuel diversity, with concentration on technologies which are very capital intensive (relative to input costs), e.g. wind. A low cost for generation means that the risk of price shocks occurring increases. Also, it is important to note that as the price of carbon increases, the slope of the trade-off line decreases. This is because carbon at €40 adds more stability to the price of each fuel than carbon at €10. If the model allowed for the uncertainty regarding the price of carbon, this issue would not arise.

[35] The Time-weighted average (TWA) is the marginal cost of production averaged over every hour in the year. The system marginal cost varies significantly over the course of the day, as well as on a seasonal basis.

Table 3.3: Portfolio Weights for Minimum Risk (€68 a MWh)

Carbon price	€0	€10	€20	€30	€40
Coal	0.0032	0.0085	0.0137	0.0126	0
Oil	0.0145	0.0104	0.0051	0	0
Gas–CCGT	0.0066	0.0164	0.0318	0.0488	0.0723
Gas–OCGT	0	0	0	0	0
Peat	0.0148	0.0131	0.0047	0	0
Wind +Back-up	0.9609	0.9517	0.9447	0.9386	0.9277

The graph indicates that the lowest level of risk is attached to an average price of €68 a MWh in all cases. Table 3.3 shows the unconstrained optimum weights for each of the technologies for the point where the associated level of risk is at its lowest. In each case wind would have a very high weight because most of the cost is capital. This cost is known at the time of installation so that there is little uncertainty about the future cost of electricity from a wind generator once it is installed. Obviously, such high penetrations would not be feasible in reality but it does show how a desire to reduce risk will involve greater use of wind power than would be the case if cost-minimisation were the only consideration.

As shown in Figure 3.2, low risk translates into a very high price, €68 a MWh. This is arrived at by including an extremely high percentage of wind in the mix of technologies used for electricity generation. This is unrealistic but it demonstrates the attractiveness of fixed cost technologies in the discussion of security of supply. The output table also highlights the problem of assuming a fixed price for carbon. As the price of carbon goes up, so does the advantage of gas-fired CCGTs. This arises because gas and oil are correlated but, since oil is a more carbon intensive fuel, the price of oil-fired generation increases more rapidly than that of gas. Therefore the pull towards gas-fired CCGTs intensifies.

Table 3.4: Cost, Risk and Weights

Carbon P.	€0	€10	€20	€30	€40
Min. Cost	€37	€43	€49	€55	€60
Std. Dev	8.7731	9.2904	9.3808	8.9069	7.7328
Coal	0.4606	0.5189	0.4971	0.3252	0.011
Oil	0	0	0	0	0
Gas-CCGT	0.106	0.224	0.3672	0.4892	0.5934
Gas-OCGT	0	0	0	0	0
Peat	0.3091	0.1634	0	0	0
Wind + Back-up	0.1243	0.0937	0.1357	0.1856	0.3956

If the lowest possible cost in each case were taken, then the corresponding risk would be at its highest and the unconstrained weights would appear as shown in Table 3.4. These results indicate that if the risk and the price of carbon were not a concern coal and peat would have a high weighting in an optimal portfolio of electricity generation. However, peat becomes uncompetitive as the price of carbon dioxide goes above €10 a tonne. Coal begins to become uncompetitive over €30 a tonne of carbon dioxide. It is only at €40 a tonne that a large share of wind would begin to become attractive.[36]

The results from this model suggest that even if coal were not the lowest price fuel, which occurs when the price of carbon goes above €20 per tonne, the inclusion of coal in the generation mix would reduce price uncertainty at a relatively small cost up to a carbon cost of €30. The inclusion of both wind and peat also would reduce uncertainty but the cost would be high for wind below a carbon price of €40 and high for peat at a carbon cost of €10 per tonne. However, there is considerable uncertainty about what will be the future price of carbon dioxide emissions over the likely lifetime of new electricity generating plant. This uncertainty would argue for keeping coal-fired generation at its current level and also including some peat and wind generation in the mix of technologies. Such a portfolio would not represent a minimum cost choice of plant, but it would reduce the risks to consumers from fuel price shocks at a relatively limited cost.

Market forces could theoretically continue to deliver a diversified portfolio of electricity generation plant in the future, as they have done in the past. However, given the drive to reduce greenhouse gas emissions it seems probable that market forces, left to their own, would result in a very big increase in the dependence on gas for electricity generation. A second instrument to counter this dependence and the attendant risk of price shocks could be needed by the regulatory authorities. Such an instrument should aim to provide market incentives to encourage a more diversified portfolio.

While such mechanisms may be needed in the future to ensure a sufficiently diversified portfolio of fuels used in electricity generation, the analysis in this paper suggests that it should not be necessary in the immediate future. It seems likely that the announced investment in Moneypoint needed to keep it open will be recovered over the remaining life time of the plant up to a carbon dioxide price of at least €20 a tonne, a level at which Moneypoint would still provide base-load. Even at a price of €30 a tonne it would probably still run as mid-load plant and make a sufficient margin over its costs to justify the investment. It is only at a cost of carbon dioxide of €40 a tonne that it would no longer be economic. As a result, such a large coal-burning station plays an important role as a hedge against price shocks, while simultaneously providing additional insulation against a quantity shock (physical interruption).

While it is for policymakers to use this model to choose the portfolio of generating technologies having the desired mix of price and risk these results would suggest that a diverse portfolio would be better than one which concentrated on a single technology, such as gas. Coal (Moneypoint) is likely to have a value for another decade through reducing risk, even as its price rises through higher costs of

[36] The costing of wind assumes a constant cost over all levels of wind penetration. In practise for low penetration of wind where backup supply is not required the costs would be much lower. At exceptionally high levels of penetration the costs would also be likely to be much higher.

carbon dioxide. The optimal deployment of wind will be somewhat greater than would be suggested by its headline cost; more wind on the system reduces risk at a limited cost. Oil based technologies look to have limited prospects. Finally, peat plant should either be closed or, as suggested elsewhere in this report, gradually converted to burn biomass.

3.5 Policy Instruments and Options for Fuel Diversity

If the market price for gas and electricity fully reflected the risks involved in economy-wide dependence there would be no need for the regulatory authorities (The Commission on Energy Regulation (CER), The Department of Communications, Marine and Natural Resources and Eirgrid) to take specific policy measures to deal with the issue of security of supply. However, it is clear that market prices do not fully reflect the risks from extreme dependence on gas and that, left to itself, the market could deliver an unsatisfactory result from the point of view of national welfare.

Fuel diversity, and the supply security enhancement which it is supposed to bring, confers benefit to which consumers would attach value if the market mechanisms existed to allow them to make such a choice. However, diversity may come at some additional cost. The task of an economically efficient policy is to deliver security up to the point where end-users with full information, are willing to cover the costs, and not beyond.

An unregulated energy market,[37] left to its own devices, could be expected to only partly respond to the public's demand for supply security. It may not be able to respond adequately for a range of reasons and the public's actual demand (willingness to pay) for supply security may not be efficiently revealed in a real-world market structure due to the public good quality of security of supply. It is important to realise that markets have partially responded to real demands for 'qualitative' features such as supply security or fuel diversity in the past e.g. companies buy standby generators and hedge fuel price risk. The issue is whether the 'socially optimal' amount of supply security as well as the optimal private level of fuel diversity will emerge without explicit intervention in this regard. Further, electricity markets are typically subject to market-dominant players and (hence) intrusive regulation associated with that, as well as structural features that inhibit efficient pricing.

There is undoubtedly a security of supply case for intervention into the capacity planning side of the energy market to correct an obvious market failure. This issue is dealt with in Chapter 5. The uncertainty about future market prices and the future price of emissions will militate against new investment, especially investment aimed at replacing inefficient plant. It could be some considerable time before new plant would come on-stream to replace existing plant. With an uncertain market, failure to invest in time would see the consumer rather than the producer carrying the cost of the

[37] Assuming that such a market could actually exist.

inefficient production. Business and household (private) sectors will respond to the price signals in the marketplace. In a less than perfect market, their responses may not be socially optimal, and the responses of supply-side players may be constrained. However, state action to provide supply security over and above market provision needs to be justified in terms of cost; the oil crises of the 1970s resulted in expensive policy actions in many countries, including Ireland, aimed at reducing exposure to oil price shocks and supply disruptions, which in the event, did not materialise.

In the longer run, as the electricity market faces greater liberalisation, it is likely that some incentives will be needed to ensure that there is sufficient diversity in fuel (including renewables) used in electricity generation. If such incentives were felt to be necessary these could take the form of a special levy on gas used in electricity generation (or any other fuel that would be over represented) with the resulting revenue being used to provide a subsidy per MWh for all electricity consumers. If the levy were set at an appropriate level this would incentivise new investors to use the next cheapest technology to gas for the next generation of electricity generation. This would leave it to the market to choose the most efficient means of finding a diversified portfolio of generation.

The alternative of using regulation to impose a solution could give rise to substantial windfall gains for existing players, at the cost of a higher overall price of electricity for consumers. For example, if the regulator were to require that the next electricity generator to be built should use oil (which is more expensive than gas), then the price of electricity (the system marginal cost) would rise to allow that generator to recoup all its costs. The result of such a rise would be that all existing generators that were allowed to use lower cost gas would make bigger profits.

In the case of the levy, if chosen at an appropriate rate, the profits of the gas and oil generators would be similar and the revenue from the levy could be used to ensure that the rise in the consumer price of electricity was held to a minimum. However, in the example chosen, no mechanism could avoid the additional costs for consumers arising from the use of oil rather than gas in the new generating station, but at least the additional cost would be confined to the electricity generated in that station.

3.6 Conclusions

PHYSICAL SECURITY

Physical security of energy supply is very important but, in so far as the Irish government can do so, appropriate measures have already been taken to secure oil and gas supplies. In the case of oil supply, the main risks are geopolitical and totally outside the government's control. In the case of a major international upheaval EU policy would be particularly important in ensuring appropriate burden sharing within the EU. The provision for storage of a significant strategic oil reserve that is already in place could help ease the adjustment costs in the event of a major international shock, but it will never be able to deal with a prolonged international dislocation of supplies.

Physical security is not just dependent on the availability of fuel but also on having a reliable transmission system to transport the fuel to where it is required. Ongoing investment in domestic infrastructure (including interconnection to the North and Britain) will serve to enhance security of electricity supply. Having adequate capacity to allow efficient scheduling of infrastructural maintenance will lower the risk of outages and non-availability. In the case of gas, the building of the second gas interconnector was important to secure Ireland's supply against the very low probability risk of a breakage in a single undersea pipeline. Such a breakage could have taken a significant amount of time to fix and, as a result, it could have proved very costly. However, this still leaves the island of Ireland dependent on a single onshore compressor station and pipeline in Scotland and consideration should be given to whether these facilities should also be doubled.

The development of the Corrib gas field will provide another very important independent source of supply, further enhancing the physical security of the system. As such it is important strategically that the pipeline and resulting infrastructure is completed reasonably rapidly. Its completion could obviate the need for further investment in transmission infrastructure onshore in Scotland.

In addition, the possibility of using the old Kinsale gas field or salt caverns in Belfast for gas storage should be explored. Such storage could not insulate Ireland against a prolonged interruption to gas supplies or a long-term major price increase. However, it could enhance short-term security as well as helping to avoid seasonal and peak our spikes in prices. Even if there are adequate supplies of gas and oil there is always the danger that there could be inadequate electricity generation capacity to meet peak demand. This issue is dealt with in detail in Chapter 5, which considers the appropriate market structure needed to ensure that there is adequate investment to meet expected future demand over the coming decade.

DEALING WITH PRICE VOLATILITY

The issue of security of energy supply is much wider than merely ensuring that energy is available. There is an important role for the regulatory authorities in ensuring that the supply of energy is available at reasonable cost. Moreover, there is a wider concern that the cost of energy in Ireland should not vary dramatically and unpredictably relative to the cost in competing countries.

The outlook for both oil and gas markets suggests that there is a real possibility of very substantial increases in real prices over the next 20 years. The continuing growth in the world economy is putting ever-increasing pressure on the markets for fossil fuels. To a significant extent responsibility for insuring against energy price shocks lies with consumers. In the short to medium term it is open to larger consumers to hedge their risks, either through choosing a diversity of different fuels, or through entering into financial contracts to hedge their risks. Theoretically individuals, companies and even the state have the possibility of hedging the risk of major increases in gas and oil prices through buying shares in oil and gas fields. However, such insurance policies are not an easy option for many consumers, especially for households. In addition, as outlined above, there is reason to believe that the costs to society from energy price shocks may be greater than for the individual. The rate of time discount for individuals may be different from that for society as a whole and, in any event, financial instruments are not easily available to hedge energy price risk far into the future. Security of supply has features of a public good (non-rivalrous, non-excludable) and the regulator must be charged with monitoring the cost-risk balance that electricity consumers face and may not be in a proper position to assess.

In the case of electricity generation a key question is the extent to which the regulatory authorities should incentivise a diversity of fuels and technologies. The analysis in this chapter provides a framework for considering this issue. For the current situation where the cost of carbon emissions is between €20 and €30 per tonne, the Irish electricity system is quite diversified. However, with the prospect of higher carbon prices over the coming decade there will be a tendency for new investment to result in increasing dependence on gas-fired technology. While the encouragement of wind will provide some hedge against future price volatility, undue dependence on that technology could prove expensive.

The risk of undue concentration on gas for electricity generation must be considered in the context of developments in the energy markets of our competitors. While a serious shock to energy prices would have adverse consequences for the economy, its impact would be magnified if Ireland were much more seriously affected than its competitors. Such a differential shock could affect competitiveness and could have a more detrimental impact on medium-term growth than if the shock were shared by all Ireland's EU neighbours. Thus the issue of security of supply must be seen in a wider context, taking account of developments elsewhere in the EU.

While the provision of Liquified Natural Gas (LNG) processing capacity could help reduce exposure to gas price shocks, because Ireland is part of a British Isles (and increasingly a European) market for gas, that investment can take place in Britain or even on the continent. The benefits of such investment (if any) will accrue firstly to the investors and then to all consumers in the market where the market is very broadly defined. Because such investment is likely to be expensive to implement and because of the economies of scale involved it would not be appropriate for the Irish government to devote resources to promoting such investment in Ireland. If the market provides such infrastructure in Ireland on a commercial basis, and provided that sufficient environmental safeguards are put in place, then there could be some minor advantages in terms of enhanced competition and some enhancement in the already fairly high level of security against interruptions in physical supply.

The analysis in this chapter suggests that where it is necessary, the regulatory authorities should use a market instrument to incentivise greater diversity in fuel (and related generating technologies) into the future. This would allow the market to decide on the least cost method of meeting the regulator's objectives. To some extent such a mechanism may work counter to the incentives provided by emissions trading. If it does so, this will reflect the competing priorities of policymakers facing multiple objectives. Providing there is just one instrument for each objective (emissions trading/carbon tax for promoting a reduction in carbon emissions and a fuel diversity levy for security of supply), the market should deliver the least cost solution to the regulator's specified objectives. However, if there is not clarity on the objectives or if the objectives are inappropriate then no configuration of policy will produce the "right" answer.

In the very long run the real price of fossil fuels, especially gas and oil, will rise worldwide. On its own this will encourage investment in alternative sources of energy supply. However, the private market may be slower to undertake research than is desirable from a public policy point of view. As a result, as discussed in Appendix 2 there is a case for promoting research in alternative energy sources. However, such alternatives should only go into production on a significant scale when they are approaching commercial viability. Providing that the incentives for such investment in alternative energy infrastructure are appropriately designed, this should ensure that the Irish energy system evolves towards long-term sustainability without disruptive shocks to supply or to prices.

3.7 Summary

- Individual firms and households do not have an adequate incentive to invest in security of supply despite the potential for significant economic disruption arising from a sudden surge in fuel prices. This market failure makes security of supply a regulatory issue.
- It is important that the supply of gas from the Corrib gas field is brought onshore to enhance the physical security of Irish energy supply.
- Also for physical security reasons, consideration should be given to strengthening the onshore gas transmission system in Scotland on which Irish gas supplies depend.
- Consideration should be given to the economics of developing gas storage in either the old Kinsale field or in salt caverns near Belfast.
- As the price of gas and oil are linked and are both likely to rise in real terms it is desirable to have some diversity in the source of electricity supplies.
- The regulatory authorities need to consider how best to insure against future price shocks. A number of instruments can be used to provide such insurance: fuel diversity and financial instruments both have roles.

- The regulatory authorities should ensure that consumers are aware of potential risks and that, where feasible, suitable instruments for hedging risk are available.
- It does not seem wise for the Irish authorities to specifically encourage a major increase in supply of Liquified Natural Gas. This should be left to market forces.
- The portfolio modelling approach can help identify the price risk trade-off facing the regulatory authorities in the electricity sector: what is the appropriate mix of fuels and technologies to use in generation?
- The results in this chapter suggest that a diverse portfolio of generating technologies and fuels would be better than one which concentrated on a single technology, such as gas. Coal (Moneypoint) is likely to have a value for another decade through reducing risk, even as its price rises through higher costs of carbon dioxide. The optimal deployment of wind will be somewhat greater than would be suggested by its headline cost; more wind on the system reduces risk at a limited cost. Oil based technologies look to have limited prospects. Finally, peat plant should either be closed or gradually converted to burn biomass.
- Fuel diversity should be managed by using market instruments rather than by regulation. For example, undue reliance on gas could be limited through a levy on gas used in electricity generation with the proceeds of the levy returned to consumers.
- Research and Development in alternative energy sources will be important in securing the long-term security of energy supply for the island.

4. Interconnection and the Geography of Markets

4.1 Introduction

Unlike many other goods, electricity and gas cannot be carried from one market to another by the normal means of transport. In the case of electricity transmission wires are needed and in the case of gas[38] pipelines are needed to get them to market. Thus the geographical delimitation of the market for gas and electricity depends on the transmission system in place. Even if there are some wires connecting two different electricity markets, unless their capacity to carry electricity is adequate relative to the market size, the two markets may continue to operate separately (albeit synchronised and technically interdependent). A single electricity market is characterised by a transmission system that does not place serious constraints on the movement of power within the geographical limits of the system. Similarly, a single gas market relies on there being adequate pipeline capacity.

In the case of Ireland an interconnector between the electricity systems in the North and the South was constructed in the early 1970s. However, terrorist action rapidly put it out of action and kept it from being used until the latter half of the 1990s. The capacity of the interconnector is limited and the capacity of the transmission system linking the interconnector to the rest of the system in the Republic is also very congested. The interconnector between Northern Ireland and Scotland also does not have the capacity to make the Northern Ireland system part of the British system.

The fact that the electricity networks on either side of the border are separate systems is most obviously manifested in the very different prices of the two systems. If there were infinite interconnection capacity between the two systems North and South the wholesale price of electricity of the two systems would end up identical, unless other artificial barriers were put into place. Similarly, with enough interconnection between Britain and Ireland, Ireland would become part of the British system. Given the relative size of the two systems such integration would see Ireland becoming a price taker on that joint market.

[38] Except in the case of Liquified Natural Gas – LNG.

In the case of gas, the construction of the pipeline between Ireland and Scotland in 1994 effectively made Ireland part of the British gas market. From the time the pipeline opened, in a liberalised market the Irish wholesale gas price had to be equal to the British price plus the cost of transmission. This reflected the fact that the capacity of the pipeline was large relative to the domestic demand. Until 1998 the British gas system was effectively isolated from that of the rest of the EU and gas prices were lower in Britain, and hence in Ireland, than in the rest of Europe. This benefited Irish consumers, just as it did British consumers. However, with the opening of the Zeebrugge-Bacton gas pipeline in 1998 the British price rose to European levels. The construction of the interconnector benefited shareholders in gas fields in Ireland and Britain at the expense of consumers. This shows that, while enhanced interconnection is likely to be globally welfare enhancing, it may not enhance the welfare of all players in the market. Where two gas or electricity systems are isolated from one another problems in one system cannot affect the other neighbouring system. However, once they are linked together a problem on one system can propagate through the other system. This highlights the importance of getting the market structure and regulatory arrangements right where two or more markets are being integrated.

It would not be necessary to have infinite interconnection between two networks to make them one system. It is an empirical question just how much capacity would be needed to produce a single market. In the case of electricity, in addition to the need to have adequate carrying capacity on the interconnection, at the very least there would have to be two interconnectors to ensure that the integration of the systems was secure – that it could survive an accidental breakdown in one interconnector. In the case of gas a single interconnector may be acceptable because of the much lower vulnerability of such a pipeline to interruption than in the case of electricity wires.

This highlights the importance of transmission infrastructure in producing an integrated market on this island. Without adequate capacity linking the two networks they will remain separate systems and will have to plan their development on the basis of their isolated status. To produce an all-island market it will be essential to build a second significant interconnector between the two systems and also to strengthen the transmission system in the Louth area of the Republic.

A further dimension to the choices facing policymakers on whether and when to put in place additional interconnection between the North and the South (and between Ireland and Britain) is that delay in decision making can be costly. The up-to-date position on the provision of the North-South interconnector is that ESB National Grid and Northern Ireland Electricity are working together on putting one in place. However, there are a number of obstacles facing them and, as a result, the timing of its completion remains unclear.

It is still not clear when the East-West interconnector to Britain will go ahead, much less be completed. This means that investors are uncertain about the size of the market they will face in five years time and how that market will be organised. This uncertainty raises the cost of capital for investors and raises the long-term costs facing consumers. This indicates the importance of bringing the project to completion, a point made in the report on the East-West interconnector for the CER by DKM *et al.* (2003). What is needed is a decision, either to build the enhanced interconnector capacity to Britain now, or else a decision not to build it until the next decade. Indecision is likely to be costly.[39]

This chapter first outlines the options on interconnection for both electricity and gas. It then considers the evidence on the costs and benefits of enhanced interconnection. The appropriate strategy for financing and pricing the interconnection infrastructure is then considered and the final Section brings together the conclusions reached in the chapter.

4.2 Interconnection Options

If the two Irish electricity systems are to reap the benefit of integration it will be necessary to put in place an additional interconnector. While the present interconnector could theoretically carry much more power than at present, it is severely constrained by the capacity of the transmission system in the Republic of Ireland. The result is that no more than 330 MW of power can flow from North to South and around 100 MW from South to North. Thus enhanced integration would also require significant further investment in transmission in the Republic to allow power to flow in both directions. The interconnector between Northern Ireland and Scotland, which has a maximum capacity of 500 MW, also does not make the Northern Ireland system part of the British system.

A single interconnector on its own would pose a significant risk to the security of the system in both parts of the island. A single strike by lightning could put a single interconnector out of action. If it was carrying a large volume at the time there could be dramatic effects on the availability of electricity on the whole island in the immediate aftermath of the failure. The presence of a second interconnector provides a completely different level of security because of the exceptionally low probability of both interconnectors failing simultaneously.

Generally, considerations about security of supply suggest that the loading on a single electricity interconnector should not exceed the size of the largest stand-by unit (or other interconnector). On the Irish system this would amount to around 400 MW. However, with the greatly enhanced security with two interconnectors each line

[39] As of Summer 2005, a consortium has been appointed by the CER to advise on the financial, technical, commercial and procurement aspects of a 500-1,000 MW interconnector to Britain on a regulated, merchant or hybrid basis.

could carry more than 400 MW without endangering the security of electricity supplies in either part of the island.

Similar arguments apply to linking the Irish and British systems. At present there is a single interconnector between Northern Ireland and Scotland which carries up to 400 MW. The government have announced that an interconnector to Wales will be built with a capacity of up to 1,000 MW. However, there are a number of reasons for suggesting that, at least initially, a single interconnector of 500 MW would be appropriate.

First, as outlined above the size of the flows permitted to operate safely on an interconnector are related to the size of the alternative sources of supply in the event of a sudden and unexpected breakdown. With the interconnector to Scotland having a maximum flow of 500 MW and with many of the unit sizes on the Irish system being around 400 MW, it is unlikely that a 1,000 MW interconnector would be used up to anywhere near its capacity.

Second, the transmission infrastructure on both sides of the Irish Sea would need strengthening, especially for an interconnector of 1,000 MW (DKM, *et al.*, 2003). In the case of Wales it is unlikely that planning permission would be given for any new over-ground lines so that reliance would have to be placed on the limited infrastructure already in place (with a capacity for only around 500 MW of power).

The benefits of an additional interconnector of 500 MW would probably outweigh the costs of building it (DKM, *et al.*, 2003).[40] However, the marginal benefits of an additional 500 MW of interconnection will be less than for the first 500 MW and it could well be the case that such an investment, even if feasible, would not be warranted in the immediate future. This issue must await further research to establish the possible costs of different levels of interconnection and the likely impact on the Irish electricity system of different levels of interconnection.

In purely engineering terms, transmitting electricity over long distances is costly due to losses in waste heat from the wires. The losses of energy are much less when gas is transmitted than when electricity is transmitted. Thus, faced with a simple choice between transmitting gas to generate electricity or transmitting the electricity, the losses in transmission will be minimised where the gas is transmitted and the electricity is generated locally. However, many other issues may intervene requiring interconnection of both electricity and of gas systems to develop satisfactory markets.

In the case of gas, the markets are simpler. The transmission infrastructure has been put in place, including considerable capacity to Britain. The infrastructure between the Republic and Britain should be capable of handling all the demand for gas in the

[40] However, account would have to be taken of the cost of strengthening the onshore transmission infrastructure.

foreseeable future. In addition, as the capacity is shared over two pipelines there is security against physical breakage.[41]

With the opening of the first pipeline between Ireland and Britain in 1994 Ireland effectively became part of the British gas market. With the decline in the domestic supply of gas, the price in Ireland became the price on the UK market plus the cost of transmission through the pipeline. With the connection of the British market to the Continental market through a pipeline to Belgium in 1998 the British price rose to close to the Continental price.

The Northern Ireland gas market is separately connected to the British market. Because both the Northern Ireland and the Republic gas markets are connected to the British market, the price of gas throughout the island is linked to the British and wider European price.[42] The two gas systems North and South are to be connected directly by a new gas pipeline over the next two years. This is unlikely to change the price or security levels of the system in the Republic but it will significantly enhance the security of the Northern gas system, which is today reliant on only a single pipeline. With the likely integration of the two electricity systems on the island the security of the integrated electricity system will come to depend on the reliability of the gas supplies to power stations North and South.

4.3 Costs and Benefits

There are a number of reasons for believing on *a priori* grounds that increased integration of the electricity and gas systems in Europe can confer benefits on consumers in the long run. First, there are considerable economies of scale in electricity production. In addition, trading in electricity can ensure that the benefits of efficient generation plant are fully exploited. Second, if properly managed, with an integrated system there would be less likelihood that problems with a single fuel or technology could cause a major black out. The larger the market, the more likely it is that the power will be generated by a range of plant using a variety of technologies and fuels, providing enhanced security. Third, larger systems are more likely to support a range of competitors, each having a portfolio of plants. It is only with a substantial number of players that the full benefits of competition are likely to be realised. Newbery, 2002c suggests that at least five independent players are needed to assure a reasonably competitive market and states that an

[41] This is true for the under-sea pipeline. However, the onshore infrastructure in Scotland is not fully duplicated and may need upgrading in the future to provide adequate security.

[42] Since the pipeline from Britain to Belgium was completed in 1998 British gas supply from the North Sea has fallen while demand has risen. As a result, in the Winter of 2004/5, because of capacity constraints on the pipeline to Belgium, the price of gas in Britain and Ireland on certain days rose well above the European price. However, new pipeline developments and investment in LNG facilities in Britain should remove this constraint, resulting in the price of gas on these islands reverting to its past behaviour – tracking the European gas price.

oligopoly with fewer than five players can be worse than a well-regulated monopoly In small isolated markets, such as the two existing Irish markets, economies of scale will make it impossible for such a number of independent players to develop and prosper.

So far no comprehensive study has been published of the costs and benefits of enhanced interconnection of the two electricity systems on the island. A rough guesstimate of the costs of providing an additional interconnector would put it around €150 million. The costs would be affected by the route chosen, which in turn could be affected by physical planning issues. The cost of strengthening the transmission system in the Republic to allow flows of power in both directions could be at least €100 million. These guesstimates are provided to give an idea of the order of magnitude of the costs. There is a wide margin of error around them, with the actual outturn being probably somewhere between two-thirds and double these estimates. The purpose in providing them is to gauge the significance of any quantification of likely benefits.

McCarthy (2005), using a model of both electricity systems on the island, considered what the average cost of generating electricity would have been in 2003 if there had been an integrated island system. She compared the resulting average price per MWh of electricity generated by the all-Ireland system with the model's estimate of what a competitive market would have delivered for the Republic of Ireland market on its own. The estimate for the all-Ireland average price was €32.5 per MWh whereas for the Republic on its own it was €34.4, a reduction in price of 5.5 per cent.

The estimate for the Republic of Ireland on its own assumed no interconnection between the two systems in 2003. In fact in that year significant flows of power took place from North to South (the transmission constraints are much more binding for flows in the other direction). As a result, the Republic already enjoyed some of the significant benefits that integration of the two systems would bring. Thus these estimates of the gains from trade as a result of enhanced interconnection are biased upwards.

The estimate discussed above for the reduction in electricity prices as a result of enhanced interconnection would amount to over 5 per cent.[43] Given that the Republic consumed around 25 million kWh of electricity in 2004, the saving in costs that would have been produced by moving from a totally isolated Republic of Ireland system to an integrated all-island system would have amounted to just under €50 million a year. The paper does not consider the benefits to Northern Ireland from the enhanced interconnection. To arrive at a full assessment of the benefits from enhanced trading, the effect on electricity prices North and South would have to be taken into account. However, even if two-thirds of these benefits are

[43] The savings would be much greater if, as is discussed in the next chapter, generators bid a price into the market that covered, not only their fuel costs, but also their operating costs. However, as argued in that chapter, such high prices would not actually occur if the market used other instruments to cover generators' operating costs.

already being realised through the existing flows across the interconnector, this would still leave significant gains to be reaped from enhancing the interconnector capacity.

The second way that improved interconnection can confer benefits on consumers is through enhancing the security of the island-wide system. A larger integrated system could operate at the specified security standard with a smaller installed generating capacity. This saving in generating capacity should translate into a saving in electricity bills for all consumers. Without integration of the two electricity systems consumers in both parts of the island will have to finance unnecessary additional investment in reserve capacity to ensure security of supply.

Fitz Gerald (2004b) has examined the potential savings in the generating capacity needed to meet the security standard currently underlying system planning in the Republic.[44] The paper considered a range of options on interconnection, including the current situation. The results set out in the paper indicate that electricity consumers on the island are receiving a very significant benefit from the operation of the, albeit constrained, existing interconnector between the North and the South. These benefits, in terms of reduced investment in generation capacity, are worth about €251 million. They arise as a result of the increased security provided by a more integrated island electricity system. This is likely to be substantially more than the replacement costs of the current interconnector.

The model results also suggest that the construction of a second interconnector, combined with reinforcement of the transmission system in the Louth region of the Republic, would result in further potential savings in capacity worth around €132 million. The strengthening of the transmission in the Louth region is likely to bring marginally greater benefits, in terms of increased security, than will the construction of a second interconnector. These savings of €132 million, on their own, would be likely to account for a significant part of the cost of a second interconnector and of the strengthening of the transmission in the Republic.

A third channel through which enhanced interconnection could bring benefits to consumers is through the potential for a larger market to enhance the level of competition. It could also somewhat reduce the problems of ESB dominance in the market. McCarthy (2005), considers this issue and concludes that there would be significant additional gains through this channel. This issue is discussed in more detail in Chapter 7.

The estimates of the potential benefits from enhanced interconnection on this island are drawn from different sources. One additional factor that has not been taken into account above is the possible saving in spinning reserve that an integrated system could realise. The estimates given here were derived as by-products of other research. Before deciding finally on the integration of the two

[44] That is a Loss of Load Expectation (LOLE) of 8 hours in the year.

electricity systems on the island it would be important to carefully study the results of a formal cost-benefit analysis of the project. However, our preliminary estimates of the costs and benefits suggest that there are likely to be significant potential static benefits from creating an all-Ireland electricity system. While the estimates of the security benefits shown above are presented in terms of a reduction in the capital investment, the estimated savings from enhanced trading are presented in terms of the annual reduction in the cost of electricity.

The estimates of the security savings could amount to half the capital cost of the enhanced interconnection. Even if only part of the estimated trading benefits were still to be reaped by further interconnection, they are sufficiently large on their own to suggest that further interconnection is warranted. On top of these benefits are the potential gains from increased competition.

The study undertaken on the costs and benefits of an additional East-West interconnector to Great Britain (DKM *et al.*, 2003) suggested that the benefits would probably outweigh the costs, though further detailed research was needed on the costs of a specified routing. It was anticipated that the benefits would not come from base-load power flowing from Britain to Ireland but rather from enhanced security and additional trading benefits.

While interconnection may well bring substantial economic benefits to offset the costs of interconnection (and losses in transmission), it will also leave the individual systems vulnerable to the possibility of regulatory failure in the wider market. For example, if the market structure in the Republic does not produce adequate investment, or produces very expensive investment, resulting in exceptionally high consumer prices, this could be worse for consumers in the North than if the two markets remained separate with separate prices. The same applies in the other direction if mistakes were made in the North (or in Britain). The potential for such regulatory failure must be taken into account in planning the development of an all-island market. It argues for agreement on a workable single market structure for any all-island market prior to integration taking place (see Chapter 5).

In the case of greatly enhanced interconnection to Britain, it seems likely that the very small Irish market would be absorbed into whatever market structure already exists there. However, the prospect of such an integration into the British market could further discourage investment in Ireland, posing problems in guaranteeing supply in the period before such integration actually took place. This issue will need to be considered in reaching an early decision on whether or not to go ahead with this investment.

While it seems probable that an all-island electricity system will reduce the total costs of electricity generation on this island no research has been undertaken into how the costs and these benefits are likely to be shared on a regional basis. This will need to be considered before an all-island market is finally implemented.

In the short to medium term, for Northern Ireland a strengthening of the electricity transmission in the Louth area of the

Republic is likely to confer much greater benefits in terms of enhancing security of supply than will the construction of a new interconnector between the two jurisdictions (Fitz Gerald, 2004). For the Republic the priority lies in developing the second interconnector. The benefits from an East-West interconnector will probably be greatest if there is already an all-island system. This would allow the all-island electricity system to optimise simultaneously the use of the two interconnectors to Britain.

4.4 Financing and Pricing of Infrastructure

Over the last three years both the electricity and the gas interconnectors between Northern Ireland and Britain have been bought back by a mutual company from their previous private sector owners. The mutual company specially established to take over the interconnectors is very similar in character to a state enterprise. The corporate governance of the new company ensures that it acts purely in the interests of Northern Ireland's energy consumers. The advantage of this arrangement was that the new company, having no equity stake, requires a lower rate of return on capital than a private sector company would accept. In addition, because the two interconnectors are essential for the welfare of Northern consumers the regulator has guaranteed that any losses on operation will be made good by a levy on all consumers. As consumers were already carrying all of the risk this does not represent any additional burden for consumers.

In return for these guarantees, the company has been able to borrow funds at a rate of interest very close to the government bond rate. The resulting significant savings in capital costs have already been passed through to Northern Ireland consumers as a reduction in the price that they would otherwise have had to pay. As the company has very small operating costs, there is no danger that the *de facto* nationalisation of the interconnectors will lead to inefficient operation.

This experience has important lessons for the Republic of Ireland. It highlights the fact that transmission infrastructure is best considered as part of the regulatory asset base and financed accordingly. In the Republic this means that any additional electricity interconnectors to the North or Britain should probably be financed by Eirgrid/ESBNG like the rest of the transmission infrastructure. As the Northern experience has shown, the Public Private Partnership approach might raise the costs for consumers, and it can be expensive and difficult to unwind. What makes transmission different from generation investment is that the consumers will always carry most of the risk of failures in the transmission system whereas the cost of bad decisions by investors in generation plant will fall on shareholders. If consumers are in any event going to carry the risks then they should benefit from the lower cost of capital they can achieve through borrowing by the publicly owned Eirgrid/ESBNG.

With the development of an all-island market the cost of electricity interconnectors within Ireland should probably be considered as part of the regulatory asset base and paid for by consumers in their use of system charges. In the very long run it may be appropriate for Interconnectors to Britain to be considered in a similar manner if they provide adequate capacity for all normal commercial flows. However, if they are all paid for by Irish consumers and if, as is likely, some of the benefits of their existence will accrue to British consumers, then a different method of accounting may be required. At present space on the Scotland-Northern Ireland interconnector is auctioned. Where capacity constraints on the interconnector remain binding this may continue to be the appropriate mechanism. However, where the interconnector is not fully utilised throughout the day a rather different pricing regime may be appropriate.

The pricing of the gas transmission infrastructure can have important implications for incentives in the domestic market. At present, all the cost of the currently largely empty second gas pipeline is charged on all imports from Britain through the pipeline. This raises the domestic cost of gas through that source. It also raises the price that domestic producers can get on the Irish market. As long as they produce less than the total requirements of the Irish market the Irish price will remain equal to the British price **plus** the transmission cost. The obverse of this charging mechanism is that it raises prices for domestic consumers.

As the second pipeline was required to provide enhanced security of supply, all consumers in Ireland potentially benefit, whether or not their gas comes from Britain or from domestic sources. Under these circumstances the cost of the second pipeline should be charged to all consumers. If such a policy was adopted then the cost of transmission would be lower and the price obtained by domestic producers would also be lower, with consequential benefits for Irish consumers.

The situation would change if domestic supplies exceeded domestic demand. In that case domestic producers would get the British price less the cost of transmission. The existence of very large export capacity in the gas pipelines enhances the attractiveness of exploration. Previously, gas finds off the Irish shore would have only had the limited domestic market available, without major further investment. Now the capacity to export is guaranteed. However, the physical planning difficulties in Mayo may prove a serious discouragement to further exploration and are a cause for serious concern.

As discussed in Chapter 1, provision of gas infrastructure should not be used as a policy instrument for promoting balanced regional development. If such investment were not commercially viable the implicit subsidy payable to achieve the deployment of gas infrastructure would almost certainly be better used to finance other forms of infrastructure more conducive to regional development.

4.5 Conclusions

The development of a single electricity system for the island of Ireland through enhanced interconnection seems desirable from an economic point of view, with the potential gains likely to offset the potential costs. The total cost of producing the island's electricity would be marginally reduced if the system were dispatched on an island-wide basis (McCarthy, 2005). It is likely that an all-island electricity system would allow significant savings in capital investment through enhancing security of supply. It would also provide some limited scope for increased competition. However, further work needs to be done to quantify these costs and benefits. In addition, there will be an issue as to how the costs and benefits will be shared between consumers.

To bring about a single island electricity system will require substantial investment in transmission to integrate the systems from the points of view of engineering and network planning. It will require a single market operator and it may also be desirable a move to a single system operator taking on board the functions of Eirgrid and SONI (System Operator Northern Ireland). It should also involve the development of an integrated approach to regulation. This latter will involve significant difficulties. There will have to be both agreement on a common market structure (easier to achieve) and a clear delineation of reporting relationships between the regulator and the political systems in both jurisdictions. This latter requirement will be important to ensure the accountability of the regulator(s) to the taxpayers North and South.

It also seems very likely that consumers in Ireland could benefit from the construction of a second interconnector to Britain. The costs and benefits of such a project also need further investigation.

In terms of sequencing decisions the first decision should be about the development of the interconnection of the two electricity systems on the island. Such an integrated system will require a new market structure to realise the benefits for consumers. This is discussed in Chapter 5. While the decision on a second interconnector to Britain is less important than the decisions on developing an Irish electricity system, it is very desirable that a decision is also taken quite rapidly. Delays in decision-making translate into uncertainty for investors and costs for consumers.

4.6 Summary

- An all-island electricity market is likely to confer significant benefits for consumers, reducing the long-term cost of a reliable electricity supply.
- To allow an integrated and efficient all-island electricity market to develop it is essential that there is adequate investment in electricity transmission to physically link the exiting separate systems.
- It seems likely that a second interconnector between Ireland and Britain could produce significant benefits for electricity consumers on the island.

5. An All-Island Electricity Market

5.1 Introduction

For over 50 years the electricity market in the Republic of Ireland was internalised within the ESB. While generators did not "sell" electricity on an open market and suppliers did not "buy" it, there was effectively an internal market within the company. The output of each plant was chosen in such a manner as to minimise the cost of production over the day. Investment decisions were made by the planners within the company with the intention of minimising the long-run cost of production. While this arrangement ensured that Ireland had a secure supply of energy over the decades, it did not provide appropriate incentives to encourage the monopoly firm and those working within it to minimise costs or to minimise the long-run price for consumers.[45]

Over the last 20 years major changes have taken place worldwide in the electricity sector. In many countries the liberalisation of the market has allowed new entrants to build generating stations, providing a measure of competition. In many cases the way the market was liberalised has resulted in a significant reduction in costs. For example, Markiewicz, Rose, and Wolfram (2004), estimate that, in anticipation of enhanced competition, or because of such competition, the US liberalisation has resulted in a reduction in labour and materials input costs into power generation of around 5 per cent in privately owned utilities and by between 15 to 20 per cent in publicly owned utilities. However, they found no evidence of savings in energy input costs, suggesting that existing utilities were not particularly inefficient in how they actually operated their generating plant. (Their data did not allow them to consider the cost of capital employed.)[46]

Even though there have been significant cost savings from reform within the ESB and from the liberalisation process, these savings have not necessarily resulted in lower prices of electricity for consumers. In the case of Northern Ireland the nature of the liberalisation process meant that, while the industry has been run

45 In fact public policy in the late 1970s actively encouraged the ESB to hire additional staff.

46 Newbery and Pollitt (1997) found that the UK CEGB privatisation process equated to at least a 5 per cent reduction in total costs which they argued would almost match the full value of the company when discounted at a rate 5 per cent over the lifetime of the capital.

more efficiently with lower costs since privatisation in the early 1990s, consumers have had to pay much higher electricity prices over the last two decades than has been the case in either the Republic of Ireland or in Great Britain (McGurnaghan, 1995).[47] In the case of the British liberalisation of the late 1980s, the efficiency gains accrued first to shareholders and the UK government, with relatively little savings for consumers in the early years of privatisation (Newbery and Pollitt, 1997).

Thus, while liberalisation may reduce costs, it is not necessarily a foregone conclusion that the benefits will accrue to consumers. The experience elsewhere indicates that the way the liberalised market is designed and regulated can play a very important role in determining who gains from the changes. From the point of view of policymakers in Ireland it is essential that the bulk of any efficiency gains are passed through to consumers. This chapter considers how the all-island electricity market can be designed so as to bring adequate downward pressure on operating costs, while still ensuring that most of these gains are passed on to consumers.

Table 5.1: Unit Cost Structure for a "Best New Entrant" Gas CCGT Generator

	€ MWh
Cost of Capital	9.38
Operating Costs	6.13
Fuel Costs	4.84
Carbon Costs	1.7
Total	66.10

Source: CER, 2005 (CER/05/110, 26 July 2005).

In designing a liberalised electricity market for Ireland it is crucial that the risks for new investors are minimised. Where a market is perceived to be risky new investors will require a much higher rate of return on capital to warrant building new plant. Table 5.1 shows the Commission for Energy Regulation's estimate of the cost structure for a new Combined Cycle Gas Turbine (CCGT) providing 3,050 GWh of electricity annually running on natural gas (CER, 2005). This shows that the cost of capital at €9.38 per MWh is slightly larger than all the non-energy operating costs – labour and materials. The research quoted above, if applicable in an Irish context, suggests that the scope for efficiency savings in materials and labour could have been close to 15 per cent in an old state owned monopoly. However, these figures published by the CER are for a new plant operated under best practice so that they already include the bulk of such potential savings.

[47] The Northern Ireland generators were sold off with long-term contracts which meant that consumers would have to pay a very high price for electricity for the following 20 years. The British taxpayer got a much higher price than they would otherwise have done. All the benefits of the major efficiency gains which the new owners achieved then flowed to the new shareholders. Because the price for consumers was effectively fixed they could not reap any of the benefits of the efficiency gains.

The capital costs assume a reasonably certain environment for investors where they plan to make their return over 15 years. However, if the market were perceived to be much more risky than the CER are assuming, resulting in investors looking for a payback over, say, 8 years, this would raise the cost of capital by approximately 50 per cent.[48] Thus the effect of risk on the cost of capital can potentially have a much bigger impact on the cost of electricity production than any likely efficiency gains or losses in the actual operation of a generation station. This means that a very important priority in any market design is the requirement that it should minimise the cost of capital.

While there is significant research which suggests that liberalisation can result in a reduction in operating costs of firms in the electricity sector, there is much less evidence on the importance of economies of scale. It is clear that the historical development of the sector throughout much of the world was partly driven by the considerable economies of scale in the industry. In Ireland and Britain the earliest private sector electricity companies were eventually taken over by public monopolies. This change was significantly driven by the scale economies, rather than by any ideological stance.

In the case of the British liberalisation of the 1980s the initial configuration saw three large generating companies and many more regional supply companies. However, over the last decade the industry has reorganised itself into five big re-integrated electricity companies, which each have significant generation capability, as well as each having an average of five million customers. When compared with the potential all-island Irish market with less than three million customers in total, this raises the issue of how realistic or efficient (in terms of reaping the economies of scale) it is to envisage a similar number of players being sustainable in the long term. This issue must be taken into account in designing an alternative electricity market for the island of Ireland.

The economies of scale in electricity generation, while difficult to quantify, stem from a range of different factors. The most obvious factor giving rise to scale economies in the industry is the physical characteristics of the production technology, especially its engineering characteristics.[49] For example, gas fired CCGTs come in units of around 400 MW. For security it is important to spread generation over a significant number of units so that the risks of unexpected breakdowns are minimised. Fitz Gerald (2004b), suggests that the small size of the Northern Ireland market and the large size of the generating units relative to the market size may require higher security margins there. A much larger market would not face these problems as it could reap the benefits of economies of scale.

[48] This uses the same formula and parameters used in the CER Best New Entrant approach.

[49] In the case of electricity transmission and distribution the high capital cost makes duplication of transmission a natural monopoly.

Possibly even more important than the engineering factors which give rise to scale economies is the issue of commercial risk. This factor has been significant in driving the reintegration of the British power companies (Newbery, 2003). If generating companies operate on their own they are exposed to the risk of fuel price shocks, and also to very considerable volatility on the market for their electricity. To some extent they can hedge the risks by having a portfolio of different generating stations and also through financial hedge contracts for their fuel. However, such measures require significant scale of production and it is not possible to hedge all risks. The use of such financial instruments also requires the employment of a range of financial and legal experts by all the parties involved.

Supply companies are also exposed to the possibility of very large spikes in the price of the electricity that they buy, while their sale price cannot be varied rapidly. The example of California shows how regulatory failure and bad planning by supply companies can result in their bankruptcy in such an environment.[50] While supply companies could theoretically hedge much of their risks through appropriate financial contracts with generators, such contracts can be expensive to draw up. Also it assumes that there are a sufficient number of players to make for a liquid market in such financial instruments. There is evidence that the British market does not have adequate liquidity to facilitate such an approach (Power UK, 2004).

While it was theoretically possible for the British electricity industry to deal with these risks through supply companies entering into a wide range of contracts with generating companies, in practise they have chosen instead to merge into integrated power companies which internalise these risks within the companies. This obviates the need for a wide range of financial contracts. This pattern of integration is replicated elsewhere in many other liberalised markets.

Economies of scale also apply to the purchase of fuel. Big consumers of gas or coal can command a much more competitive market price than small players. Also bigger players can afford to source fuel from different suppliers with different types of contracts, including contracts that involve fixed prices for fuel deliveries some distance into the future. However, this does not mean that players must achieve large scale operation on a single market, such as the Irish market. It is also possible to reap the benefits of large purchasing power where a player has generation plant spread across a number of different European markets.

Another way of looking at this issue of economies of scale is the transactions costs that are involved in moving away from a vertically integrated firm to a world of many different independent players. In some of the examples discussed this must include the cost of all the

[50] California introduced competition to its retail and wholesale power markets in 1998 but experienced a major crisis during 2000 and into 2001. This crisis has provoked a major debate about the effects of deregulating markets to allow competition but the consensus has emerged that California's power crisis was a failure of market design and of regulation, which neglected adequate capacity planning (World Bank, 2001).

expertise, financial and legal, to make a fragmented or decentralised industry structure operable. Depending on the chosen market structure, the transactions costs of making the market work can be quite substantial. These transactions costs represent a cost to both producers and consumers. If they prove large they can seriously impact on the efficiency of the industry and on the welfare of society at large. Thus in choosing an appropriate market design for an all-island market it will be important to ensure that the costs of operating that market for all those involved are kept to an absolute minimum. Fears about the possible costs of operating the market structure proposed by the CER for the Republic in 2004 were important in persuading the regulator to abandon those plans.

In this chapter we first consider the problems of ensuring adequate generation capacity in a liberalised market. We then discuss four different ways of organising an Irish electricity market considering, in turn, their advantages and disadvantages. We then outline what we feel is likely to be the most practicable model for current Irish circumstances. In the concluding section we consider how future developments, including greater interconnection to the British electricity system in the next decade, could affect any developing Irish market.

5.2 Ensuring Adequate Generation Capacity

Before deregulation, it was the responsibility of the vertically integrated monopoly to insure that enough generation capacity was available and usually there was a system of centralised planning. The traditional approach to this was to build planning reserves based on the forecasted load, the loss of load probability (LOLP) and an estimate of the value of lost load (VOLL). Then, the costs of the extra capacity required were allocated implicitly among customers. In a deregulated, restructured electricity industry there is no central planning for new additions to capacity. There are no guarantees given for the return on investment in generation but the generation companies do not have to give any capacity guarantees that there will be a minimum overall level of capacity available. Each new investor makes estimates of its own risks in an independent assessment, akin to any other industrial investment. Since the structure of the electricity generating industry is far from a perfect competition model and closer to an oligopolistic one, total private supply will frequently be less than the socially optimal level or total demand. Hence the so-called supply adequacy problem emerges.

Investment in new generation is a risky activity in an uncertain environment of deregulated electricity markets. Investors are more interested in short-term returns on investment and are justifiably reluctant to commit to large long-term investments with a long recovery period for their investment which has increasing uncertainties as time goes on. Investors have to take into account the fact that the investment environment could change at any point depending on future electricity demand, spot market prices, variations in regulatory policies and financing costs and availability.

No two electricity markets are the same when it comes to inducing sufficient capacity into the future. It depends greatly on the market arrangements and the regulatory situation prevailing (or likely to prevail). Capacity deficiency will cause the market to be very different compared to a market with excess capacity and may even cause the market to breakdown completely as it did in California.

Examples of energy-only markets (where there is no special payment, direct or indirect, for capacity) include California, Norway, Alberta and Australia where, the only revenue source for the recovery of capacity costs is the difference between the market clearing price and generators' production costs. In a perfectly competitive market where prices of electricity vary continuously to reflect the supply and demand status at each moment, payment to inframarginal generators (above system marginal cost) should cover their capacity costs. Peaking plants need opportunities for profit to invest – they will produce electricity whenever the difference between the electricity price and the fuel cost is favourable.

Short-term capacity deficiencies occur because of the long construction time of new power plants. Without capacity markets or payments there is no way of controlling long-term capacity availability directly. Without capacity payments peaking plants may not recover their investment costs from the market. Experience in California and elsewhere has shown that even where a market may work in theory, the reality may be very different for three main reasons:

(a) the application of price caps, although necessary in some situations, distorts the price signal for investment. As a result, some peaking generators may not be able to recover their fixed cost;

(b) the electricity market is akin to an oligopoly rather than perfect competition where it is common practice for oligopolists to underinvest so as to raise market prices when barriers to entry are strong:

(c) demand may be exceptionally inelastic where large consumers are largely disconnected from the true market price (due to contracts etc.) and there are only very weak channels for real-time price signals to influence demand side power response.

5.3 Alternative Models

Four possible options or models for structural reform of the electricity market are considered here:

- Find yourself a customer.
- A single buyer model.
- Planned parenthood.
- A pool with capacity payments – the preferred option.

FIND YOURSELF A CUSTOMER

The first of these models is the one favoured by the EU in its legislation and it was initially believed by some policymakers to be the solution to Ireland's problems. Under this EU legislation, any private sector firm can build a new generation station and find customers for their output. From February 2005 all customers are free to choose different electricity suppliers.[51] It was originally expected that lots of new entrants would build generating capacity and then compete for the favour of the roughly two million customers in the Republic of Ireland. However, this model suffered from a number of disadvantages.

Even with the business sector there is considerable inertia among customers. Even if electricity is on offer at lower cost from an alternative supplier, customers may be slow to shift allegiance. In the case of electricity the ESB "brand" is very strong – they have a reliable track record. This makes it difficult and expensive for new businesses to build up a customer base.

In addition, a single generator on its own cannot supply the commodity that consumers want – electrical supply that varies in line with the very different demand profiles of customers over the day. As a result, a single generator company will have to contract with other generators to provide these additional services that consumers want. Finally, individual generators can face huge costs buying in power to meet their contractual obligations to customers in the event of a breakdown in their own plant.

Given the scale economies in generation, new power plants involve major additions of capacity. However, as it takes time to build a customer base it potentially makes it difficult for new entrants to match supply with demand when a new plant opens. As an interim measure to deal with this the CER arranged sales of "virtual power" to potential new entrants. This meant that they could build a customer base in advance of opening. However, this remained a rather unsatisfactory mechanism for reducing uncertainty for investors mostly because independent power purchasing capacity was very difficult to acquire.

Probably the most serious problem with the current market is that new customers are not prepared to sign contracts for power supply with new entrants for periods longer than two or three years. This means that new entrants cannot guarantee themselves a market in advance of investing. As the capital costs in building generating stations are very large, this makes investment very risky, increasing the cost of capital. The normal way to finance a new power plant is to borrow with long-term contracts for sales of electricity providing security. This is not possible in the Irish case because of the impossibility of obtaining matching long-term contracts for sales.

The electricity supply sector is concerned with the purchase of bulk electricity on wholesale markets and the delivery of this electricity to customers. The metering of all consumers is handled separately. Supply is a distinct operation from the transmission and distribution system, which provides the wires to deliver the

[51] Northern Ireland domestic customers will be free to choose their supplier from 2007 onwards.

electricity. This supply business accounts for around 5 per cent of the delivered cost of electricity so that it is a low margin business and it does not, on its own, provide much scope for efficiency gains from competition.

All of these factors make it very difficult for a new independent generator to enter the market through building a generation plant and developing a supply business through building its own customer base.

Significant uncertainty is also added because of the behaviour of the government as a player in the electricity market. The most obvious cause of uncertainty arises from government interference in pricing decisions by the dominant player, the ESB. In June 2000, the government announced a package of measures to combat inflation, including a commitment that electricity prices would not rise later in the year.[52] This raised the prospect that new entrants would face unfair competition in the future due to government's use of its power as shareholder in ESB to restrict price increases. For the future new entrants should be protected from such behaviour by handing over responsibility for minimum as well as maximum prices to the CER.

A further major concern for new entrants is the fact that the ESB controls the bulk of generating capacity. By manipulating availability such a dominant player could potentially exert huge market power. Under government ownership the ESB has generally not acted to use its market power to maximise its profits. Instead it has generally acted as a public sector utility with a broad remit to act in the "public good". However, the possibility that the ESB might be privatised in its present form raises the prospect of major future dangers for new entrants. This is an additional reason for making a clear commitment not to privatise the ESB in its present form. This issue of dominance and how it can be dealt with is addressed in the next chapter.

For all eligible customers (eligible to buy from any supplier) they will pay the current long-run marginal cost for generation, plus whatever charges are set for use of transmission and distribution systems. If a new entrant could undercut the ESB, the ESB would eventually have to react by matching that price for all categories of eligible customers; otherwise all eligible customers would move to new entrants, possibly resulting in substantial stranded capacity or stranded contracts. This would mean that the ESB on its own could no longer internalise cross subsidies to peat or wind generation and other social obligations. This has been reflected in the bundling of many of these costs into a new Public Service Obligation (PSO), payable by all consumers.

The result of these uncertainties is to greatly increase the cost of capital for new plant and to reduce the incentive to invest. This is a problem common to all electricity systems (Castro-Rodriguez,

[52] http://www.ireland.com/newspaper/finance/2000/0628/archive.
00062800123.html

Marin, and Siotis, 2001). This market structure makes it safer and, therefore, more profitable for individual players in the generation market to under-provide rather than to over-provide capacity. The result of pursuing this model without offsetting measures to ensure security of supply could be significant shortages of generation capacity over the next decade. With a very low price elasticity of demand for electricity, this would translate into a major increase in prices and much bigger profits for incumbents. Clearly, from the point of view of the consumer, this is not a satisfactory prospect.

SINGLE BUYER

In a market structured round a single buyer, some of the problems with the existing model could be overcome. While this was originally a possible option under EU legislation, it was not favoured in Ireland and has since been ruled out by the development of the Irish market. In a single buyer model that independent buyer (independent of generators) would be required to buy electricity at the minimum possible price and that single buyer would then sell it on to suppliers at the purchase price. (In the Irish case such a buyer could have been the transmission system operator, EIRGRID.) The buyer would have to set transparent rules for the dispatch of generating stations. Existing players and new entrants, who would know their own cost structure and those of their competitors, could then predict reasonably accurately their likely sales.

Such a model would get over many of the problems for new firms breaking into the market as they would not have to market themselves to a disparate consumer base. Instead they would know that if their product came in cheapest it would all be sold. This would reduce one element of the uncertainty facing new entrants. At the point where investment decisions are made it should be possible to predict reasonably accurately sales in the first few years of production.

However, as described here, under this model the availability of long term contracts for sale would have depended on there being a range of significant supply companies. This uncertainty would have maximised the pressures on existing participants to reduce their cost base, but, due to the uncertainty, it would still have made the cost of capital for new investors quite high.

By preventing direct sales to consumers by generators it would also have prevented possible innovations through new products or methods. For example, the sale of electricity from renewable sources at a premium price might not be possible under this model. Also there would be less incentive to offer flexible or interruptible contracts to consumers to reflect the variations in cost of production by time of day. New products, exploiting profitable opportunities in such areas, could have found themselves ruled out.

Finally, it would have reduced the possibility for competition in electricity supply as all suppliers would have paid the same price for the electricity that they purchase. However, as discussed above, the evidence from elsewhere suggests that the scope for major savings from enhanced competition in supply is much less than the scope for savings in generation.

A variant on the single buyer model would have been to allow ESB as the supplier of the franchise market – the bulk of electricity consumers – to buy electricity from all producers, including new entrants.

Newbery (2002) argues that the EU approach to electricity markets, in dismembering the monopoly supply business, risks two unattractive alternatives:

> Without a new Directive, distribution companies retaining a domestic franchise and subject to yardstick regulation of their power contracts could provide countervailing power against generating companies. … However, opaque markets … may lead to an old German-style equilibrium … – safe but rather expensive.
>
> With the new Directive, the end of the franchise by 2005 is likely to encourage generators to integrate forward into supply, and risks removing the counter-parties to longer-term contracts that would facilitate entry. …. then it will be profitable for companies to reduce the spare capacity margin, with possibly Californian consequences (worse if the regulators lack the legislative powers to intervene).

The first problem – opaque markets, would have certainly required the separation of ESB electricity supply from generation. As Newbery says, this could have been safe but could have incurred additional costs. The alternative, which is the route initially pursued in Ireland of relying on new independent generators entering the market and finding customers, risked undersupply for the reasons already discussed.

PLANNED PARENTHOOD

One of the key problems with the existing market model is that it is in danger of producing a serious shortage of investment in generating capacity in the medium to long term. While eliminating some of the uncertainty facing investors, the Single Buyer model would produce some improvements. However, it would still have left significant uncertainty for any new investors, militating against adequate provision in the medium term.

While long-term contracts would greatly reduce uncertainty for investors they could also greatly reduce competitive forces in the market (Newbery, 2002). In the case of Northern Ireland, the long-term contracts granted at the time of privatisation have meant that the price of electricity for consumers in Northern Ireland has been among the highest in the EU for the past decade. Clearly this has been a disaster for consumers.

What is required is a model that will significantly reduce investment risk, while still ensuring that competitive pressures reduce costs and that the resulting savings are passed on to consumers as lower prices. One possibility would be to leave responsibility for ensuring that there is adequate capacity in the long term to the transmission system operator (Eirgrid) as planner of the system.

Where the current market model is not delivering adequate investment the planner (possibly the CER or Eirgrid) would have the task of commissioning new plant to be built. However, the operation of the plant would be subject to a separate contract determined in a tendering process. Private sector companies would compete for the right to manage the new plant. This would minimise the capital costs for new operators of power stations, while still keeping downward pressure on operating costs. The sales of electricity would still be undertaken on a competitive basis with producers seeking customers. However, the market would probably work much better if the supplier of the franchise market was also required to buy its supplies of electricity on the market, rather than taking it from its own generators. A separation of ESB electricity supply from generation would be desirable and this would be met if all plant were managed on contract by private sector firms.

In addition to planning new plant it would be desirable to take the ownership of the sites of all existing ESB generation stations into the ownership of the planning authority (possibly Eirgrid). The NCB report (2002) identifies problems in obtaining planning permission for new sites as a major obstacle to new entry. By putting the ownership of the sites of generation plants under independent management, incumbents would not be allowed to prevent new entrants from gaining easy access to suitable sites. Obviously payment for the sites would be made in relation to normal market prices, but the special advantage of access to planning permission for generation would not be built in to the price.

AN ELECTRICITY POOL AND CAPACITY PAYMENTS

Now that market opening has been completed, the basic outline of the Irish electricity market is in place. There is the potential for competition in supply. New entrants can and have built independent power plants. To date these major changes have been accommodated in an *ad hoc* fashion. What is needed is a transparent market structure that can apply to an all-island market and can minimise the uncertainty for investors, and the transactions costs for all the players.

Here we outline a suggested market design that is very similar to the design agreed by the two regulators in All Ireland Project (AIP) (2005a). While it is a hybrid of the different models already outlined, it should deal with many of the problems with these individual models identified above. It is not a fully worked out model, rather concentrating on the essential features that will ensure that it delivers reliable electricity supplies at least cost in the long term. There is, necessarily, very considerable complexity in making any such model operational and many important details are left to the regulatory authorities to develop.

As with the draft market structure proposed by the CER for the Republic in 2003-2004, the market should be centred on a gross pool. That is, all electricity produced in Ireland should be sold through the pool. Each generator will bid a volume and price pair[53] into the market for each hour (or even 15 minutes) and the market operator will choose sufficient output to meet demand on an hourly basis. The choice (or dispatch) of the generating stations operating will be made on the basis of the prices bid in by their owners – the prices are stacked in ascending order and the market operator moves up the stack till the cumulated supply meets demand.

Each supplier is paid the price bid by the marginal plant operating and this is referred to as the system marginal price. Depending on the way the players bid in the market, during the night-time this price can be very low – say €30 per MWh – but during day-time peaks in winter, when supply is very tight, it could go very high – up to at least a hundred times the minimum price.

Suppliers then contract to buy tranches of electricity by the period to meet their expected demand. It will be up to the system operator to deal with short-term deviations in demand or supply to ensure that the market is in balance second by second. The handling of these balancing measures and how they are remunerated is outside the scope of this paper which concentrates on the broad outline of the market.

Another unknown is how the gross pool market arrangement will deal with renewable energy (RE) intermittent generators. In practice, there is very little empirical data or experience of RE intermittent generators participation in this market type. RE generators have, in the main, either opted for policy mechanisms which placed them outside the scope of market participation or have been granted non-dispatchable or must-run status. The issue of the treatment of intermittent generation needs to be thought through carefully to ensure that the market delivers the correct signals to RE generators.

In the original CER scheme proposed in 2003 (CER, 2003), it was proposed that generators would receive all their remuneration from their sales on the pool (or spot market). Thus their prices would have to be high enough for them to receive revenue, not just to cover their short-run marginal cost (the price of the fuel used), but they would also have to generate a sufficient surplus over fuel costs over the year to pay their operating and maintenance costs and to pay off the cost of the capital employed.

Each generating company (possibly owning a portfolio of generating plant) would have to assess how many hours each plant would run in the year for any given pricing strategy. They would choose their price for each period such that *ex post* the numbers of hours run in the year multiplied by the hourly system marginal price would cover all their costs, including capital costs. They would

[53] e.g. 100 MW of electricity from 03.00 to 04.00 on the 1 August 2005 at a price of €50 per MWh.

normally not bid in a price below short run marginal cost – the price of the fuel.[54]

In any single time period individual generators could often make more money by cutting the price (while still keeping it above short-run marginal cost) to ensure dispatch ahead of another generator that was pricing to cover its operating and capital costs. While such a strategy would be successful in enhancing revenue in that time period, the competitor would be forced to respond in the same way. Such a competitive rush for lower prices could work in the short run. However, our simulations with a model of the Irish electricity market (McCarthy, 2005) would indicate that, under these circumstances, the vast bulk of plant would not even cover its operating costs and would have to close. The result would be a significant shortage of electricity for peak periods.

However, knowing that such would be the outcome of a competitive race for the bottom in prices, it is much more likely that each operator will bid a price knowing that every other operator faces the same need to cover capital and operating costs. As a result, the alternative equilibrium is one where everyone bids a price that takes account of their need to stay in business by covering operating and capital costs.

The implication of such a bidding strategy is dramatically different from the case where firms only bid a price to cover their short-run marginal cost. For example, for an electricity generating plant specially designed to handle peak load the short-run marginal cost (cost of fuel used) could be around €90 per MWh. However, if the plant only ran for one hour in the year to handle an exceptional peak load, each MWh of electricity generated would have to produce revenue of between €40,000 and €50,000 per MWh for that one hour – 500 times the short-run marginal cost. This price arises purely from the need to stay in business and would in no way be driven by issues of dominance or market power. Thus a pool where players have to get all their income from direct sales of electricity can expect to see huge volatility in hourly electricity prices across the year.

Because all electricity sold in the pool in a given hour receives the system marginal price, base load plant, which runs all of the time, will make a significant part of the surplus needed to cover its non-fuel operating and capital costs in these few hours of exceptional prices. For the bulk of the day they will probably bid in a price close to their system marginal cost.

If regulators were to find such exceptional spikes in electricity prices unacceptable and cap them, then a significant number of players would end up making a loss and having to close. If investors had any concerns about regulatory authorities operating in such a manner it would seriously discourage investment in such a market.

[54] Under a locational marginal pricing regime there might be circumstances where firms would bid in a price below the cost of fuel.

Even if there were no such fears this extreme volatility can be very difficult for market participants to handle. Of its nature such spikes in power prices would be difficult to predict. In some years there could be few if any, while in others there could be quite a number. The extremes in volatility and their uncertain occurrence pose serious problems for all players, buyers and sellers, and it can be difficult to hedge all such risks with financial contracts.

The risks for buyers and sellers in this market, arising from the extreme volatility in prices, can theoretically be handled by means of bilateral financial contracts. For example, a buyer could agree with a generator that if the market price for peak electricity on a Wednesday in January is below a specified threshold then the buyer will compensate the seller. In the case that it is above the threshold specified in the contract the seller would compensate the buyer. This would mean that effectively the two parties have a firm contract for electricity at a specified price (such a contract is referred to as a "contract for differences"). Provided that there are many buyers and many sellers and that the cost of writing such financial contracts is small relative to their value (the transactions costs are low), then it will be possible for the market to organise itself to share risk. Given a fully flexible market in financial instruments, by using such instruments sellers will effectively make payments to generators to cover their costs of being available to produce.

By allowing generators to cover their costs outside the market by means of such financial instruments the generators would no longer need to price in the market to cover their operating costs and capital costs. Under these circumstances, if all the players know that all the other players have covered their operating and capital costs by such contracts, then they will all bid in their short-run marginal cost.

However, experience in the British market suggests that the transactions costs involved in organising financial markets by means of financial contracts may not be as effective in practice as it is in theory. Power Economics (2004), suggests that in practice the British market for such contracts has proved illiquid. In the Irish case, with one very large supply company and one very large portfolio producer, even if they were separate independent companies, the availability of financial contracts to allow the market operate would depend heavily on the behaviour of these two companies. If they did not offer the range of contracts needed to allow independent suppliers and generators to hedge their risk the market would be seriously distorted. In addition, the very small scale of the Irish market will make the size of the contracts much smaller than in Britain and much more expensive in terms of transactions costs. The fact that the British electricity market has reintegrated generation and supply companies, again internalising these transactions costs, illustrates their significance.

The alternative approach to this issue is to have a scheme of capacity payments that mirrors the "ideal" set of financial contracts outlined above. These capacity payments would be made by the market operator to all generators based on a formula outlined below. They would be funded as part of the use of system charges levied on all consumers. The payments would be conditional on plant being available to generate electricity, not on whether the plant actually runs.

A range of possible approaches to capacity payments schemes is set out in AIP (2005b). Here we consider one possible example of such a capacity payments scheme. In this example there would be serious penalties for plant that is unexpectedly unavailable to generate. (All plant must be serviced during the year and is, as a result, unavailable on a planned basis for about 10 per cent of the year. No penalties would be payable and no payments would be made for planned shutdowns.) As discussed in the next chapter the penalty for unexpected unavailability is important to discourage any attempt by dominant players to game the system.

By making the payments conditional on availability it would provide a significant incentive for plant to ensure high levels of availability. ESBNG (2004b), has estimated that the low levels of plant availability in 2003 in the Republic imposed a significant cost on the system. Fitz Gerald (2004b) estimated that for every 0.8 percentage points increase in average availability of generation plant there is a potential saving in the capital cost of spare generation capacity of €50 million. If there were a significant response by generators to such incentives for enhanced availability of existing plant this could save consumers a significant amount of money in the long term. The experience in Northern Ireland on privatisation was that the introduction of incentives for availability produced a very big response from the newly privatised industry. However, because of the inappropriate structure of the contracts, the benefits all flowed to the shareholders in the companies owning the generation plant and consumers ended up paying exceptionally high prices.

The model of capacity payments considered here is one that is calibrated to ensure that adequate generation capacity is available to meet the specified standard on security of supply. Currently, the Irish system is designed to meet a loss of load expectation (LOLE) of 8 hours a year or better. That means that, on average each year, demand should only exceed supply for 8 hours, necessitating power cuts for some consumers.

The proposed annual capacity payments should be equal to the annual operating and capital costs per MW of capacity of a peak generator multiplied by the generation capacity required to meet a LOLE of 8 hours at a high average availability of ideally 90 per cent in any year. This sum of money would be divided between the generators on the basis of actual availability in terms of MW per hour over the year, with heavy penalties for unplanned failures.[55] If the actual capacity were exactly equal to planned capacity then a new peak generator would receive exactly the right amount to cover its operating and capital costs for the year. If actual capacity were

[55] As discussed later, the treatment of wind would need special consideration under such a regime.

inadequate to meet the security standard then new investors would receive more than their costs making a profit. When plant was greater than needed new peak plant would make a loss.

Such a scheme would clearly send the right signals to investors in peak generation. NERA (2002), also suggests that on theoretical grounds the incentives for mid load and base load generation should also be appropriate. In the next section we examine how such a model of the Irish electricity market would have performed if it had been implemented on an all-island basis in 2003. To do this we use a newly developed model of the Irish electricity market, which is described in more detail in McCarthy (2005).

In this paper we model this scheme on the basis that the payments are made equally for all hours a plant is available in the year. However, it may well be appropriate to profile the payments in such a way that it would incentivise availability when the balance between demand and supply is likely to be tightest (see AIP, 2005b).

The advantage of this scheme of capacity payments is that because it would be centrally administered the transactions costs would be relatively low. There would be no need for all the individual players to employ legal and financial personnel to manage the alternative – a portfolio of financial contracts needed to allow them to operate safely in the Irish market. In addition, if the scheme were designed optimally, it should mirror an optimal set of financial contracts, though probably having much lower transactions costs than the alternative of organisation by financial contracts. In addition, because of the transparency of the scheme it could give added certainty to new investors, reducing their cost of capital, with significant advantage for consumers in the long run.

Already the island electricity system is connected to the British system by one interconnector. It is likely that the existing interconnector will be supplemented by a second interconnector early in the next decade. The issue will then arise as to how exports and imports of power should be treated in a market with capacity payments. The British market operates on the basis of bilateral contracts between generators and suppliers (with much of this taking place within the large integrated power companies). These contracts ensure that generators receive their full costs, including operating and capital costs. If Irish generators were allowed to sell spare power into that market while receiving capacity payments they would be compensated twice for their non-fuel costs. As a result, it would probably be appropriate for no capacity payments to be paid for capacity that sells its output in the current British market (referred to as BETA). Similarly, there will be an issue as to whether capacity payments should be payable on imports from Britain.

Because of the complexity of the issues involved we do not attempt to resolve the issue here as to how trade in electricity should be treated. For example, because capacity payments would be aimed at incentivising availability of generation to provide a secure energy supply, an issue would arise as to whether the capacity in Britain exporting to Ireland was "secure" and could be relied on. Similarly, where spare capacity in Ireland exports to Britain it may still be available to the Irish system in case of shortage.

Finally, the treatment of wind power under such a regime would need to be considered. Because the availability of wind on any particular day in the year is not known a year in advance wind might not be eligible for any capacity payments under this scheme. However, this would be an inappropriate extreme outcome – wind power certainly provides some capacity credit to the system. The treatment of capacity payments for wind would need to be handled in a consistent manner with the treatment of charges for reserves on the system. Further research would be needed to determine the appropriate treatment of wind generation in such a regime.

5.4 Modelling the Proposed Market

A model of the Irish electricity system, North and South has been developed and is described in more detail in McCarthy (2005). The model includes all electricity generators on the island and it can be used to simulate either the two systems on the island as separate entities or as a fully integrated network. The model uses half-hourly data for actual demand in 2003.

When it is used to model future years the daily and seasonal profile of demand is maintained, with the overall level of demand in each half hour being scaled up by the expected rise in aggregate demand for electricity for the year (Bergin *et al.*, 2003). Conditional on forecast demand for a particular year, a separate model, described in Fitz Gerald, 2004b, is used to determine what is the appropriate level of generating capacity needed to meet a specified security standard. Additional generating stations can then be added to the basic model of the system to ensure that there is adequate generating capacity. The additional stations are of a representative nature, generally based on the specification in the CER's paper on "Best New Entrants", CER, 2004.

The model is static in the sense that it does not automatically introduce new stations where it would be profitable to do so. However, for the newer stations the cost of capital employed is also known and it is possible to estimate whether the stations are covering their long-run costs and whether it would be profitable for new investment to be undertaken in base load, mid load or peak load plant.[56] The model can be run a series of times in an iterative fashion to take account of new entry where it would be profitable, and exit of old plant where it no longer covers its operating costs.

Two approaches to bidding by generators are considered in the model. In the first it is assumed that firms only bid in their fuel costs – the short-run marginal cost. The model can also be run iteratively

[56] Plant that runs almost full-time throughout the day and throughout the year is referred to as base load. Plant that runs for a limited number of hours in the year is referred to as peak plant. In between plant that runs for of the bulk of the daylight hours each day is referred to as mid load plant. Obviously there is a whole spectrum of utilisation rates and this three way distinction is used for convenience of exposition.

to derive the prices each generator would bid in for each half hour such that over the year they would each cover their operating costs as well as their fuel costs. To simplify the model the half-hourly price is capped at €2,000 a MWh. This means that a few peak stations that actually run in the year may not cover their costs for the year. However, this does not detract significantly from the analysis set out below.

In this section we first consider for 2003 what the effect would have been in an all-island market where generators bid in only their fuel costs or where they bid in sufficient to cover their operating costs. We consider the Time Weighted Average (TWA) price for electricity over the year in each case. That is the average over the year of the half-hourly output of electricity multiplied by the system marginal cost for the relevant half hour. We also consider the cost of the fuel used and the operating surplus or deficit of generating stations.

Figure 5.1: All-Island System Marginal Cost Function

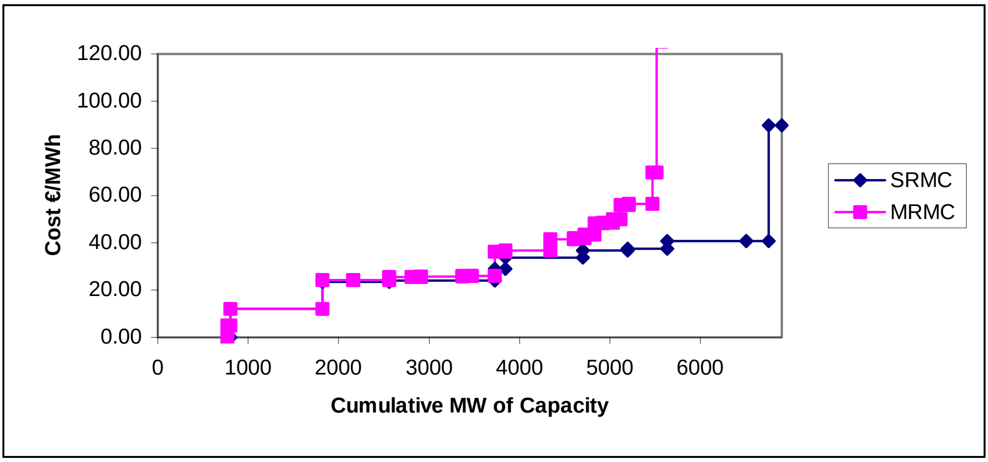


Figure 5.1 graphically illustrates the difference between the two different bidding strategies. The System Marginal Cost Function shows how many megawatts can be purchased for a given price. Where firms bid a price to cover their operating cost it is referred to in Figure 5.1 as the medium-run marginal cost MRMC. The fuel only bidding price is referred to as the short-run marginal cost SRMC. The diagram illustrates that under both bidding strategies a small tranche of power comes at zero marginal cost – basically the output of the hydro and wind stations which have no fuel cost. Then approximately 1,000 MWhs can be bought for just less than €20 per MWh under both bidding strategies. As the market gets closer to full capacity, the deviation between the two bidding strategies becomes more apparent. This arises because the peaking stations are bidding a much greater price per MWh in order to allow them to recoup their true variable costs. For the last tranche of output the marginal cost is off the scale of the graph where firms have to bid enough to get back their operating costs. This just reflects the fact that such plant would operate for very few hours in the year and would have to get

an exceptional surplus in those hours to earn enough to pay the permanently employed staff of the plant and its other operating costs. Under this regime in most years there will be some plant that never runs if the electricity capacity is adequate to meet the required security standard. Such plant would inevitably make a loss as it would not produce any electricity.

Table 5.2 shows the results of running the model for 2003 for the All-Island Market under the two different bidding strategies by firms. The most striking feature of the results shown in the Table is the difference in the Time Weighted Average Price (TWA) between the different strategies. On average, the wholesale price of electricity would be just under four times higher if firms had to recover all costs on the market, compared to the case where they only recover their fuel costs. The total cost of fuel is identical under the two bidding strategies. This indicates that the change in bidding strategies does not change the merit order of the plant – the order in which it is chosen to run. This is important as it means that the dispatch of plant is equally efficient under the two strategies.

Table 5.2: Electricity Model Results for All-Island Market 2003

	All-Island	
Bidding Strategy	**SRMC**	**MRMC**
Time Weighted Ave. Price, €	32.50	115.1
Total Revenue, € million	1,093	3,871
Total Losses of Stations (gross), € million	126	50
Total Fuel Cost, € million	565	565
Total Surplus,[57] € million	197	2,844

The figures shown in Table 5.2 for Total Losses of Stations represent the gross losses (difference between revenue and fuel and operating costs) that would have been incurred by stations, without subtracting the surpluses that would have been made by some of the base-load stations. It is this "loss" figure, which would have to be eliminated if the portfolio of power generators were all to stay in business. As shown in the last row of Table 5.2, under the regime where firms only bid in their fuel costs (SRMC) even though many plants would not cover their operating costs, the electricity generating system as a whole would have made a net surplus of nearly €200 million. While this would not have been enough for all stations to remunerate their capital, it does reflect the fact that some base-load plant might actually have earned enough to warrant new investment.

Moving to the case where firms bid in a price to cover their operating costs, the price would be dramatically higher under that regime in order to ensure that every generating plant at least covered its fuel and operating costs. As a result, the surplus would be more than €2.6 billion greater than under the simple fuel only bidding. Clearly, if the problem were to ensure that sufficient plant stays in

[57] Surplus = Profit Before Remuneration of Capital = Revenue minus fuel and O&M Costs.

business by covering its operating costs this strategy of bidding would be massive overkill, at huge expense to the consumer.

The scenario where firms bid in their operating costs as well as fuel costs does not represent a stable equilibrium. With profits inflated to the extent shown in Table 5.2, there would be major entry of new generating stations. This would gradually whittle away the excess profits and also lead to some firms exiting the industry. However, the magnitude of the changes which would be required, as reflected in the massive price differential, is such that the adjustment process could take a very long time leaving consumers with an exceptionally high price of electricity in the immediate future.

As discussed in the previous section, the electricity market, if faced with the prospect of paying such prices to secure a reliable electricity supply, would rapidly move to put in place bilateral financial contracts between suppliers and generators to ensure a certain supply at a much lower cost. Suppliers, by entering into suitable contracts (technically called contracts for differences) would effectively pay the owners of the plant making losses in column 1 of Table 5.2 enough to keep them in business. The result would be that generators would all know that as everyone was getting their operating costs they would all revert to bidding in terms of their short-run marginal cost (price of fuel). Finally, even if the gross losses were actually covered by the financial contracts the system might not be sufficiently profitable to encourage new investment. Because of the riskiness of the market, as evidenced by the potential volatility in prices, investors may be loath to invest unless supply companies could offer longer-term financial contracts. However, because consumers themselves are not subject to such contracts, having the freedom to switch suppliers as and when they choose, suppliers would only be able to offer relatively short-term contracts.

While it would be possible for the market to reorganise itself using a range of different financial contracts so as to ensure a reliable supply of electricity at a reasonable cost, as argued earlier this may involve very considerable transactions costs and may work imperfectly in a market as small as the Irish market is likely to be. Theoretically, the same result could be achieved by means of an appropriate capacity payments regime. As argued earlier, such a regime could prove more certain for investors than reliance on bilateral contracts, as well as being more transparent.

If a scheme along the lines outlined in the previous section were implemented, the total capacity payments in 2003 would have been around €300 million.[58] This would raise the Time Weighted Average

[58] This assumes a payment of €55,000 a year per MW of capacity – an estimate of the capital and operating cost per MW of a new peak plant. With an installed capacity on the island of around 6,000 MW and assuming plant was available 90 per cent of the time (and ignoring penalties), this would have cost around €300 million in 2003. This assumes that the installed capacity was only just adequate in that year – it was probably a bit more than was needed in practice. Also actual availability in the Republic was way below 90 per cent. As a result, this estimate is on the high side.

price of electricity by 27 per cent above what it would be with firms bidding only their energy costs, though dramatically lower than under the alternative bidding strategy. This would probably eliminate the bulk of the gross losses and give rise to a total net surplus for generation of around €500 million. This would probably have been more than enough to compensate for capital costs on existing plant and it would have incentivised some new entry. As discussed later, if modelled dynamically, the new entry would, in turn, result in some exit of less efficient plant.

What is very clear is that such a scheme of capacity payments, resulting in firms bidding in only their energy costs, would have a dramatically lower cost for consumers than would be the case where all compensation for operating and capital costs has to come from the pool. Even with financial contracts, they at best can replicate the results of a properly designed capacity payments scheme. At worst, because of high transactions costs and illiquidity due to the small size of the Irish market, they could add to the cost of electricity for consumers.

McCarthy (2005), suggests that the disparity between the two bidding strategies would be even greater if the Republic of Ireland market was examined on its own, rather than the all-Island market. In 2003, the state of affairs in the two electricity systems on the island was very different; the South was in a position of under-capacity whilst the North had sufficient spare capacity and was exporting some electricity across the border. In a state of under-capacity, a system operator would need to employ nearly all of the available generation in the country and would therefore have to travel much further down the merit order of generators' bids. The last station on the list would be the most expensive and if it was deployed to produce energy all other stations would make profits, and some would make very significant gains. If this happened on a regular basis, it could have serious cost implications for the consumer in the short run.

Finally, the suggested market structure has important advantages in terms of transparency. With major concerns about the dominance of one or more players on the Irish electricity market it is important that the market structure should maximise the flow of information to the regulatory authorities and that the behaviour of the different agents on the market should be easily understood by all involved. A market that relied on a wide range of bilateral financial contracts would be far from transparent. It would still leave open the danger that one or two dominant players could control that market through withholding or granting consent to suitable contracts. By contrast, a scheme of centrally administered capacity payments would be transparent. Everyone would see how the benefits of the capacity payments scheme were distributed.

In moving the pool to a basis where all firms were incentivised to bid in only their fuel costs it would also be much more easily understood and regulated by the appropriate authorities. It is relatively easy to check the value of expenditure on fuel in different generating stations whereas it would be much harder to check the logic of a bid which was designed to cover operational cost based on the forecast annual demand and forecast of the bidding policy of all other generators. The latter type of market would make it much easier to disguise a bidding strategy designed to exploit a dominant position in the market.

5.5 Conclusions

The small size of the Irish electricity market, the relatively large size of generating units relative to peak demand and the presence of a dominant player in that market means that market structures that may work elsewhere may not be appropriate for Ireland. In addition, some of the options that might have been available a decade ago, for example the single buyer model, are now ruled out by EU or domestic legislation (e.g. market opening).

In this chapter a range of different models for organising the Irish electricity market are considered. On balance it is concluded that a gross pool, the market structure proposed by the two regulators (AIP, 2005a), would be the most appropriate basis for organising an all-island market. Under such a market regime all electricity would be sold in the pool (and all electricity bought in the pool). In addition to the pool there should be a scheme of centrally administered capacity payments. The cost of these capacity payments would be levied on all consumers. Subject to certain restrictions outlined earlier in the chapter, these payments would be made to all generators that are available to generate, whether or not they are actually called upon to supply electricity. Failure to meet promised commitments would incur a heavy penalty payment, (which would be used to reduce use of system charges). The formula for calculating the total amount of the payments would be based on the total capacity needed to guarantee a secure supply multiplied by the cost of a peak generator.

This regime would be both transparent and relatively certain for new investors. This aspect of certainty, reducing the cost of capital for investment, will be essential in a market that will require continuing investment in new generating capacity over the coming decade. Failure to provide a reasonably transparent and predictable market could substantially raise the cost of capital for investors. Inevitably that would be passed on to consumers as higher prices. However the electricity market is organised, the bulk of the risk inherent in the market will be passed forward to consumers rather than carried by shareholders. The market structure must reflect this.

While strategies to minimise the cost of capital for investment will play the primary role in controlling electricity prices for consumers, nonetheless measures also need to be put in place to minimise operating costs. The market design suggested here will also incentivise efficiency in operating costs. Failure to deal with overstaffing could leave open an opportunity for a new entrant to profitably enter the market, squeezing out inefficient incumbents. However, the strategy suggested in Chapter 6 for dealing with the issue of dominance in the market should also play an important role in encouraging greater efficiency in the sector.

A final consideration in designing any new market structure for the island of Ireland is whether the island itself is likely to become part of the British electricity system in the next decade through enhanced interconnection. If Ireland had sufficient interconnection to Britain *de facto* Ireland would become part of the British market. As is the case with gas today, the price for electricity would be set on the much larger British market and no Irish players on that market, including the ESB, could significantly influence that price.

As discussed in Chapter 4, it now seems likely that a second interconnector will be built early in the next decade. Whether or not this would be sufficient to make Ireland part of the British system is not clear. This needs significant additional research to understand where the critical threshold would lie. On the basis of current information, with an additional interconnector of 500MW, it would appear that Irish prices would still diverge significantly from British prices for much of the normal day, leaving market players still dependent on the design of the Irish market to determine average price and return on capital.

This issue is important for all potential investors. As their investment will be expected to last at least 20 years their expectations about the market structure will affect their assessment about the likely rate of return on capital. The study done on the costs and benefits of an East-West interconnector (DKM *et al.*, 2003) did suggest that it should go ahead. However, the study also stressed the urgency of making a firm decision on the project so as to reduce uncertainty for potential investors.

5.6 Summary

- The structure proposed for the all-island electricity market by the two regulators seems likely to provide the best opportunity for securing a competitive supply of electricity for consumers on the island of Ireland over the next decade.
- The electricity pool, when combined with a suitable regime of capacity payments, should encourage supply at a minimum price. It should also increase the transparency of the regime.
- The capacity payments regime will play an important role in minimising risk for investors and reducing the cost of capital. The cost of capital is a key ingredient in determining the final price of electricity for consumers.
- This regime would provide the right signals for new investment ensuring the provision of adequate electricity generation capacity at least cost.
- Nothing in this regime would prevent the electricity market of the island of Ireland being eventually integrated into a British Isles or a north-west European market by the end of the next decade.

6. MARKET STRUCTURE

6.1 Introduction

The electricity and gas sectors in both parts of the island of Ireland are characterised by firms that have dominant positions in particular segments of the market. To some extent their position arises from the nature of certain parts of the business – transmission of gas and electricity is a natural monopoly.

While recent years have seen some new entry in electricity generation and supply, competition remains limited. In the Republic of Ireland the ESB owns the bulk of the generating capacity, the transmission[59] and distribution systems and it is responsible for most of the supply. In the North of Ireland the structure is rather different, having developed through the break up and privatisation of the single monopoly business in 1992/3. There are now three companies owning generation capacity (together with a capacity to import from Britain) and there is also limited competition in supply. However, as part of the privatisation deal the bulk of the output of two of the generators in the North is contracted on a long-term basis to the power procurement business of Northern Ireland Electricity (NIE).

Chapter 1 discussed how the structures North and South reflect their origins deriving from the original state-owned integrated monopoly producers. For some time there has been a concern in Ireland, and elsewhere in Europe, that increased efficiency and lower costs could be realised by a restructuring of the industry. The need for a restructuring of the industry in Ireland is also being highlighted by the prospective changes needed to produce an all-island electricity market.

Here we consider the extent to which a restructuring of the industry in Ireland could produce an environment where competing companies would thrive and drive down costs. This chapter also considers how other aspects of the industry can be restructured in a different way to facilitate the necessary regulation to deliver some of the benefits of competition.

Section 6.2 considers the background to the current industry structure. Section 6.3 then examines the disadvantages of monopoly producers and it discusses where efficiency gains could be expected from a restructuring. Section 6.4 sets out the empirical evidence on how restructuring could be expected to change the competitive environment. Section 6.5 suggests an approach to restructuring that

[59] While the ESB owns the transmission system, it is operated by a separate company ESB National Grid – Eirgrid.

could realise significant gains for consumers while, where appropriate, realising the benefits of scale economies. Conclusions are drawn in the final section.

6.2 Background

Under the old monopoly producer model the country was provided with a reliable electricity supply. However, that model of organising the industry had a number of defects from the point of view of the consumer. Most notable among the defects was the relatively high cost base of the ESB and the resulting effects on the price of electricity. In turn, the high cost of electricity adversely affected the competitiveness of the economy with negative consequences for employment.[60]

In addition to higher prices, over the 1970s and the 1980s there were periodic interruptions to supply due to industrial action. The cost of such interruptions to society is very high.[61] The partnership approach applied to industrial relations over the last 15 years has seen a major improvement in this situation, with few if any industrial relations related shortages. However, there remains a concern about the potential threat to security of electricity supply from potential industrial disputes in the future which might affect the dominant generating company. There are also concerns at the price of achieving such industrial peace in terms of inflated labour costs.

In Northern Ireland the industry was privatised in 1992 (McGurnaghan, 1995). The generation capacity was sold off to four different generators,[62] with the transmission, distribution and supply business remaining a single integrated firm – Northern Ireland Electricity. However, in return for substantial payments to the government, the firms buying the generation capacity received very generous long-term contracts. These long-term contracts, designed to enhance the value of the assets being sold, have resulted in very high electricity payments for consumers in Northern Ireland ever since. It will not be until 2011 that the effects of these legacy contracts will finally drop out of the Northern Ireland cost base, relieving consumers, and the Northern Ireland economy generally, of the heavy burden.

While the privatisation in Northern Ireland resulted in significant improvements in operating efficiency, the gains accrued to the UK Treasury (through the high sale price) and especially to the shareholders rather than to customers. Thus there was no offset for customers for the high premium resulting from the long-term contracts entered into as part of the privatisation.

[60] See Fitz Gerald and Johnston, 1995, p. 12.

[61] For an estimate of the cost to households and business see Leijsen and Vollaard, 2004.

[62] Since privatisation two of the plants have closed (Belfast West and Coolkeragh). New plant has been installed in Coolkeragh and in Ballylumford since privatisation leaving three different locations where there is generating capacity owned by three different companies, one of which is the ESB.

In the Republic in the early 1990s consideration was given to undertaking a similar privatisation exercise to that in Northern Ireland. However, as a result of a more cautious approach, the Republic was able to learn from the experience in Northern Ireland. This experience made it clear that privatisation was not a simple panacea for the ills of the electricity system in the Republic. The "option value" of delaying a decision was seen to be significant: better to delay making a decision rather than to make the wrong and irrevocable decision. However, the combined impact of EU legislation and the drive to create an all-island market to realise potential efficiency gains is raising in a much more acute form the issue of the dominant position of the ESB. In addition, the experience in Ireland and elsewhere over the last 15 years means that the appropriate way forward is somewhat clearer than it was in the 1990s.

The forces driving change in the sector are threefold. First, there is a broad "liberalisation" agenda, which has grown up in developed economies over the last 25 years, that promotes efficiency gains through industrial restructuring. Very often this involves privatisation, but the two agendas are not identical. Fitting within these agendas is a desire to improve the competitiveness of the Irish economy through driving down costs. Second, the related EU liberalisation agenda, is also driving change. While these forces are on a "convergent" path they are not always fully compatible. For example, the direct costs of market opening, required by EU law to introduce competition in electricity supply, may prove greater than the potential benefits to consumers. Finally, as discussed in Chapter 2, the Irish market for electricity is growing quite rapidly and is likely to continue growing out to the end of the decade. This means that there is a need for continued new investment in generation capacity and also in transmission and distribution. This is a rather different situation to that in the rest of the EU and in North America where there has been excess capacity for the last decade. The result is that the price of electricity in Ireland must be high enough to fully remunerate the capital employed. In much of the rest of the EU, where the assets have already been significantly depreciated (Helm, 2004), the price, albeit temporarily, may have fallen below long-run marginal cost.

The nature of the electricity sector is such that there is no simple solution that will introduce perfect competition. No single model of best practice has been developed elsewhere in the developed world. There are some significant markets where for a sustained period reformed market structures have realised significant gains for consumers. For example, the Nord Pool[63] arrangements covering the Scandinavian electricity market have worked well for over a decade (Olsen, 1995). Similarly the British electricity market of the last decade realised relatively low electricity prices for consumers. In

[63] On 1 January, 1990 Sweden joined the Norwegian electricity exchange to form the first multinational market for trade in electricity. Four years later Finland and Denmark became members of Nord Pool.

the US, the PJM market in the North-East United States has generally been successful. However, no single model has proved to be clearly superior to any other model and all of these models have suffered from significant problems in recent years.

The small size of the Republic of Ireland market, or even of an all-island market, poses special problems in introducing the disciplines of competition. It means that a specifically Irish model must be developed, taking account of the lessons learned elsewhere. This model must also allow for the possibility that over the course of the next decade the all-island market will eventually become part of a wider British Isles, or even of a North-West European electricity market.

It is likely that whatever the market structure, the small size of the electricity system on the island of Ireland will make an environment of competition difficult to achieve. As a result, if the market is to work in the interests of consumers it will need to be regulated on a fairly continuous basis by the appropriate authorities. To make regulation effective it will be desirable to make the market system that evolves as transparent as possible. This requirement for transparency to facilitate regulation should be a significant consideration in market design for the future. The need for transparency to increase the flow of information to the regulator(s) should inform any restructuring of the industry.

6.3 The Problems with Monopolies

A market dominated by a single monopoly producer carries certain inherent defects compared to a market where there are many competing firms. Monopolies will tend to charge higher prices than will be possible where competition reigns and is actively pursued. The result will be lower levels of output and the ultimate sufferers will be consumers – paying more for less.

The counterpart to higher prices charged by monopoly producers will be some combination of four possible outcomes:

- The shareholders can benefit from the higher prices arising from monopoly power through higher profits.
- The employees of the monopoly firm may benefit through some combination of higher wage rates and higher employment (staffing ratios).
- Suppliers of goods and services may benefit through higher prices for their inputs or otherwise favourable supply conditions.
- Without the disciplines of competition, the monopoly may also be run in an inefficient manner involving waste and badly planned investment.

These are the disadvantages for consumers of monopoly power on the part of existing firms and these are the ways that the revenue raised by higher prices paid by consumers may flow back to the key stakeholders. These disadvantages must be considered against any benefits that accrue from the increased scale of operation. In the case of natural monopolies, such as electricity transmission, the benefits from having only one transmission system are likely to exceed any potential savings from competition between competing infrastructures. However, in other sectors of the electricity and gas industries, such economies of scale do not exist, or are much less obvious than in the case of transmission.

In the case of private sector monopolies the benefits from higher prices go substantially to the shareholder in the form of higher profits.[64] In the case of state owned monopolies, such as the ESB and BGE, if the price charged were the same as for a privately owned monopolist and efficiency of production were the same, the dividends paid to the government (shareholder) could be used to reduce more economically distorting taxes. However, even if used in this way there would still likely be a welfare loss. In the case of the ESB it is clear that not all the revenue from higher prices charged arising from the use of monopoly power accrue to the taxpayer as owner of the monopoly. The major area where the higher prices have allowed "inefficiency" in the past has been through over-staffing, and through facilitating wage rates remaining above market levels. The level of profitability in these monopolies has been broadly adequate to fund the growing capital needs of these enterprises. In BGE there was major progress in dealing with the problem of overstaffing in the late 1980s and early 1990s through contracting out the provision of key services. While there has been substantial progress in the ESB over the past decade in reducing the level of overstaffing it is clear that significant further reductions in costs are possible.

Suppliers of the monopolist are more likely to obtain terms that would not be possible in a competitive market (e.g. for peat). Over the last 30 years some of the revenue arising from the higher prices charged for energy (as a result of monopoly power) has been used to pay the costs of peat-fired electricity and to extend the gas transmission network into regions that would otherwise have been considered uneconomic. In the past it has been much more costly to produce electricity using peat rather than coal or gas (Nic Giolla Choille, 1993). While the new peat-fired generation stations are much more efficient at converting peat into electricity than the retiring plants, it is clear that in a competitive market, without further regulation, such new peat plants would not have been built. While there is an undoubted argument that peat-fired generating stations provide security through diversifying fuel supplies, it seems most unlikely that this is the most appropriate means of meeting the security of supply objective in a world where greenhouse gas emissions will carry an increasing penalty. Whether or not this use of

[64] This need not always be the case. In the case of Dublin Gas in its latter years the bulk of the benefits of its monopoly position appear to have gone to its employees at the expense of its customers. The 2005 CER Consultation Paper on the "Regulation of ESB's Power Generation Business until the Establishment of the Single Electricity Market" [CER 05/111], suggests that the high labour costs that are embedded in the ESB Power Generation business are *not* currently passed on to consumers.

resources to fund the peat industry is wise, it is clear that current public policy would still insist on maintaining these plants in operation in a more competitive environment. To this end the substantial subsidy to new peat plants is now provided for through the Public Service Obligation (PSO) charge paid by all consumers.

These potential excess costs would automatically be eroded if it were possible to introduce competition into the electricity and gas sectors. However, the nature of the sector is such that competition is not easy to introduce. As discussed earlier, the transmission systems are natural monopolies and the small scale of the Irish electricity system(s) means that the number of independent generators in the system is likely to be limited. Also the experience of the UK, where the supply business has seen major consolidation, suggests that the scope for competition in supply may be limited in Ireland because of economies of scale. The five major supply companies in Britain have a minimum of around five million customers each whereas the total number of electricity customers on the island of Ireland is less than three million.

The major area where efficiency gains could potentially be realised in the energy sector in Ireland through a change in market structure is in the area of labour costs.[65] Such a reduction would benefit consumers in the long run by allowing enhanced energy supply at lower prices. Any reform of the market structure for the energy utility sector must tackle this problem, while ensuring that efficiency gains that are realised are passed on to consumers as lower prices, rather than all going to shareholders as higher profits. This is the appropriate yardstick against which to judge any market reform.

Labour costs in the generation of electricity may account for a smaller part of the long-run cost of electricity than do capital costs, reflecting the capital intensity of the sector (see Chapter 5, Table 5.1). As a result, anything that increases risk, raising the cost of capital for investors, will also increase the costs of electricity. Market reform must balance the need to minimise the cost of capital through reducing unnecessary risk against the need to incentivise increased efficiency in using inputs, especially labour.

In recent years the ESB has ceased to be the monopoly provider of electricity in the Republic. There has been new entry in generation and there is limited competition in supply.[66] This has transformed the Irish market into an oligopoly bringing new issues for players in the liberalised market. The ESB remains the dominant player in the market and all other players must take account of the ESB's actions. As discussed in the previous chapter, new entrants have found it difficult to develop in acquiring customers for electricity at the retail level, in the face of inertia and loyalty to the incumbent ESB. For

[65] As discussed earlier, more efficient dispatch consequent on movement to an all-island market could also deliver significant efficiency gains.

[66] Competition between suppliers has been in place for business consumers of electricity for some time. It is only since February that firms other than the ESB have been allowed to compete to supply the household sector. However, there is no sign of new entrants to the market competing against the ESB for such business.

new investors in generation there is also the issue of how the ESB will react to their entry in the market. Without regulation it would be possible for the dominant player to squeeze out new entrants, resulting in significant losses for them. The fact that this has not happened reflects the importance of the independent regulator in ensuring proper conduct and also the legacy of the public service ethos of the state-owned ESB.

For the future, if the market is to progress with new entry, such new entrants will have to be reassured that the nature of the regulatory regime will prevent any abuse by ESB of its dominant position. The best way of guaranteeing this would be if the dominant position were to gradually disappear through new entry. However, this may not be realistic in the next decade without further intervention by the regulatory authorities.

In designing a structure for the electricity industry to provide incentives for producers to minimise the cost of electricity in the long run, there are a number of objectives:

- While risk is inherent in investment decisions, the structure of the industry must avoid creating unnecessary uncertainty for investors – minimising the cost of capital. There is a trade off between regimes that penalise bad investment decisions and ones that reduce risk to investors. However, in many cases the full risks arising from bad investment decisions are not carried by the investor but are actually shared with consumers. For example, if a generation station suffers a serious malfunction the owner may lose revenue but the consumer will suffer higher prices and possibly a very expensive loss of power.
- The structure of the industry should incentivise producers to minimise the cost of the labour input.
- Reforms to introduce competition must also take account of the role of economies of scale in the energy sector.

In restructuring the electricity sector the solution will involve some combination of the following:

- Restructuring the industry to separate different parts of the business into separate companies. The extent to which such a restructuring is desirable will depend on the extent of economies of scale and scope in the business.
- A further increase in the contracting out to independent companies of the supply of services to the different business units of the ESB as is currently the case in BGE.
- New entry into potentially competitive segments of the market as well as the possible divestiture of some assets and the exit of plant which is uneconomic in potentially competitive segments of the business.

As discussed in Chapter 4, in the long run, if technical change reduces the cost of extensive interconnection with the British electricity system,[67] this could see Ireland becoming part of a much wider competitive market. However, even with the British electricity market there is no certainty that just because it is competitive today this will always be the case in the future.[68]

BGE, which had major industrial relations problems when it took over the household gas supply business in the early 1980s, undertook a major reorganisation over the course of the rest of the decade. The policy adopted was one of contracting out the supply of services maintaining a limited core of employees to service head-office functions and to maintain safety standards. This has meant that the bulk of the work on extending and maintaining the distribution and supply infrastructure has been undertaken by outside contractors.

As well as putting pressure on costs, this approach has maximised the flow of information to the regulator about the true costs of the gas industry. This has meant that it has been easier in BGE to regulate the business and to establish the appropriate pricing for services provided than is the case for electricity.

Over the course of the late 1980s and the 1990s BGE used its position as a monopoly supplier to build its business by extending the coverage of its distribution network. Because of the competitive price of gas at that time[69] the firm used its monopoly position to price gas at a level that would attract consumers from competing fuels, while realising sufficient profits to fund the expansion of the business. In the business sector the pricing policy was also aimed at increasing the customer base through setting different prices for the different markets segments.

However, with the maturity of the business in recent years pricing policy has become more transparent. With the run-down in the Kinsale gas field, the rapid rise in gas prices in recent years has meant that the company has a much more limited margin which is subject to regulatory oversight.

With the availability of adequate transmission for gas between Britain and Ireland the Irish gas market has, for competition purposes, already become a part of the wider British and EU gas markets. There are a number of significant gas suppliers in the industry. The ESB is the largest purchaser of gas to supply its own business. A number of other large consumers purchase their own gas supplies on the British market. BGE is still the supplier of the domestic market.

In Northern Ireland the gas industry has developed much later than in the Republic. It did not have the benefit of a supply of cheap gas which would allow the monopoly supplier, Phoenix Gas, to

[67] There is already an interconnector between Northern Ireland and Scotland but the limited size of the interconnector and the weakness of the transmission network on the island of Ireland means that it does not make the Irish electricity system part of the British system for purposes of competition.

[68] Helm, 2005,

[69] BGE had a favourable long-term contract for the price of gas from the Kinsale gas field.

incentivise and fund a rapid deployment of gas distribution in the Belfast area.

NATURAL MONOPOLIES

The transmission of gas and electricity is a natural monopoly. Competing networks would be hugely inefficient. These networks are central to the energy system and any serious failure will have very substantial costs for consumers. This infrastructure is a 'must-have' for consumers and, as a result, consumers *de facto* carry a substantial part of the risk of failure. Under these conditions the regulatory authorities have a crucial role in ensuring the adequacy and reliability of the networks.

In addition, as consumers carry a significant part of the risk of failure in transmission they have a role in guaranteeing the future performance of the infrastructure. A guarantee by consumers that the cost of authorised infrastructure will be repaid can greatly reduce the cost of capital. While it also greatly reduces the risks to investors, potentially leading to inefficient decisions, the consumer has often more to fear from inadequate investment and from a high cost of capital.

The experience in Northern Ireland has been that the mutualisation of the gas and electricity interconnectors to Britain over the last 2 years has greatly reduced the cost of capital, resulting in significant savings for consumers. As consumers had already effectively guaranteed that the capital would be repaid, little additional risk was taken on by consumers in providing an explicit guarantee of repayment. The mechanism chosen was the acquisition by a mutual company of the interconnection assets. The acquisition of the assets by the mutual was funded by borrowing from the bond market. With the benefit of the guarantees from the regulator on behalf of consumers, the borrowing was achieved at a very tight margin over the then prevailing government bond rate.[70] As these assets have very low operating costs and they were already built, the potential downside for consumers was minimal. This experience highlights the importance of minimising the costs of capital in funding very capital-intensive assets.

The privatisation of the existing monopoly players *in situ* would not be the best option for promoting market reform. A swapping of a public monopoly for a private monopoly, while realising efficiency gains, could see the bulk of these gains accruing to shareholders rather than to the consumer. This was the option pursued in Northern Ireland, with disastrous consequences for Northern consumers in the case of electricity generation (McGurnaghan, 1995). If the privatisation were also to raise the cost of capital, this would more than likely offset any gains in efficiency in a very capital-intensive business.

[70] The option of an acquisition by a state company was not open to the regulator. The use of a mutual company to undertake this task has additional complications in terms of corporate governance.

The prospect of privatisation has itself had a negative effect on the behaviour of a number of existing state monopolies. In the case of Aer Rianta, and to a lesser extent in the case of the energy utilities, the possibility of privatisation has encouraged the state monopolist to increase profitability at the expense of the consumer. Employees' appetites have also been whetted by the experience with the privatisation of Telecom Éireann. It is important that the prospect of privatisation of state monopolies be ruled out so that the management of the existing firms know that their objective is to minimise the price to consumers in the long run,[71] not to maximise profitability.

Instead of privatising the natural monopoly elements of the energy sector, what is needed is a reform that will tackle the problems of the existing market structure. Where competition is possible under new market structures it could be appropriate to end state involvement, through selling off relevant parts of existing firms or through new entry by private sector operators. However, the natural monopoly elements, such as transmission, should remain in state ownership, with efficiency gains being incentivised through appropriate contracting out of service provision.

This does not mean that the natural monopoly elements of the electricity system should be left untouched. Instead what is required is an alternative approach which will still reap the benefits of a low cost of capital while at the same time putting strong downward pressure on operating costs. An obvious approach to this task would be for the ownership of the transmission system to be transferred to the independent system operator) and for them to contract with other players, including the ESB, for all the services needed to maintain and develop the transmission network. As in the case of BGE, this would ensure that there was adequate downward pressure on costs and it would also help increase the flow of information to the regulator. This approach should also be adopted where the nature or scale of the operation makes it unrealistic to expect the early development of a competitive market through divestiture or other forms of restructuring.

INTRODUCING COMPETITION

The experience of liberalisation in the UK and economic theory both suggest that to achieve a competitive market in electricity generation it is necessary to have quite a number of players, each with pricing power in the relevant range of the merit order. At a minimum, 5 separate generating companies would be needed to ensure proper competition (Helm, 2002). Given the significant scale economies in the electricity generating business, this is clearly not an easy or even a realistic objective for Irish policymakers and the issue facing the authorities responsible for implementing the liberalisation of the market is how best the market can be regulated to ensure that

[71] The long run means that the firms must cover the full cost of necessary investment through making adequate profits.

consumers experience the benefits which a more competitive market might produce.

In the absence of a suitable competitive environment, very heavy regulation will be needed if there is to be any chance of competition. It will be important that the developing structure of the industry should aid regulation through enhancing transparency and the resulting flow of information to the regulatory authorities. What is likely to happen is that new entrants will appear gradually (as has happened in the case of Viridian at Huntstown), building a CCGT (combined cycle gas turbine) plant. The current state of technology and the relative price of the different fuels mean that throughout much of the EU, especially in the UK, CCGTs provide the best value in generating technology. At the very least the new entrants provide a benchmark against which the regulator can measure costs in the dominant incumbent, the ESB.

It is likely that the advent of new entrants, or the threat of more new entrants, will ensure that the staffing of new plants will be fairly similar whoever runs them, well below the staffing of equivalent older plants in the current system. This threat of new entry should help put pressure for further cost savings in the existing ESB plants. While the advent of new firms in the generating industry has lent credibility to the calls for efficiency gains, as discussed below, there are major problems with the market model currently in place.

A clear strategy for managing and reducing the ESB's dominant position in electricity generation is required to reassure new investors. A clear statement is required that the monopoly elements of the ESB will not be privatised at any future date, removing this potential risk for new investors, while also introducing substantial changes to allow new entrants to compete for business against the other elements of the ESB's business, especially in the case of generation.

6.4 Evidence on Gains from Restructuring

This section describes the results of a study of the effects on the market for electricity generation of options for restructuring the ESB generation business. Full details of the study are given in McCarthy (2005). A range of theoretical approaches to restructuring the ESB's generation portfolio was considered. These involved a series of options on divestiture where the ESB's portfolio of generation was broken up to form three or more different companies. In each case the portfolio assigned to each company was chosen on an arbitrary basis and was not intended to be realistic. The intention was to model the Irish electricity market to discover how radical a change would be needed to achieve a "competitive" market where no firm, including the ESB, could significantly alter the market price to its advantage through its own independent behaviour.

In the electricity sector, above-cost pricing may not be a symptom of the exercise of market power since scarcity pricing is a characteristic of any market where the total available supply is capped in the short run. Scarcity pricing refers to those times of the day or year where demand is very close to the system's total capacity and so the price of electricity on the spot market will be exceptionally high to reflect this scarcity and the closeness to full capacity. Excess demand is not a possibility in an electricity market as it will cause a 'black out', so preventative measures must be taken to maintain total available supply equal to demand. The need for such "exceptional measures" is signalled by the price as the price incentivises additional short-term supply. In a competitive market many generators rely on these periods to recover the bulk of their fixed costs.

Although the Herfindahl-Hirschman Index (HHI) and market share indices are internationally recognisable standards for measuring dominance, as static measures they do not represent the real-time aspect of electricity markets very well. Furthermore, they only examine the supply side of the market. For instance, there may exist some market with a HHI value below 1,000. This figure would typically characterise an unconcentrated market where the threat of abuse of market power is low. However, even the smallest generator can possess some level of power to affect prices. This may be the result of harsh weather, breakdowns, transmission failures etc. When suppliers are essential for the certain and adequate provision of electricity, they possess significant market power regardless of their company size relative to the market. This occurs most often when the system is close to full capacity. For example, if a supplier knows demand will be high and that their electricity will more than likely be required, they can effectively name their price. [72]

This study uses the Residual Supply Index (RSI) as a measure of potential market power.[73] It was developed by the California Independent System Operator (CAISO) as a continuous metric that could represent the likelihood of an abuse of market power by a generator. The RSI for a company X measures the per cent of supply capacity remaining after subtracting company X's capacity of supply (less contract obligations). An individual company's RSI of above 100 per cent implies that the company is not pivotal and vice versa. Therefore a low RSI is of more concern to the market than a high RSI. Sheffrin *et al.* (2001, 2002a, 2002b, 2002c, 2004) established the existence of a relationship between hourly RSI and hourly price-cost mark-up in the California market. Empirically, the

[72] Gorecki (2005) defines dominance as significant market power and the ability, on a sustained basis to raise prices above the competitive level. A necessary condition is that entry (actual or the threat of it) is not sufficient to compete away the 'super high' rate of return. Firms have to abuse their dominance to fall foul of competition law. This is different from the need for regulatory intervention to ensure adequate competition in a market to the benefit of consumers.

[73] The RSI is defined as the ratio of residual supply to demand for an individual supplier S, RSI_S = (Total Available capacity – Available capacity from Supplier S)/ Demand. "The RSI measures how pivotal suppliers may be in setting prices based on the residual supply left, without their capacity, to serve demand. A supplier is deemed "pivotal" if it can withdraw its capacity from the market and induce a shortage" (Sheffrin *et al*, 2004). This tool was initially created to assess the Californian electricity crisis of 2000/2001.

correlation between the two indicates that on average, an RSI of approximately 120 per cent will result in a market price outcome close to the competitive benchmark.

In the analysis of different options on restructuring, the RSI index was calculated for all the players in the generation market: an index of above 120 for all players was taken to indicate a market where no player had serious market power.

To undertake this analysis a model of the Irish electricity sector was developed (McCarthy, 2005). This model, which was also used in the analysis in the previous chapter, uses details of all current and potential future generators on the Irish system, North and South. Given the cost and engineering characteristics of each generator, the model estimates the short-run marginal cost of each plant. The input to the model contains the half-hour demand figures for the chosen year. In the first set of simulations using the model it was assumed that all generators bid in their fuel (short-run marginal cost) into the market. (Other pricing strategies were also examined but this approach was felt to be the most realistic, given the current proposed structure for the all-island market.) The model assumes that the stations are dispatched (their potential output is used) in the order of their bids, up to the point at which the half-hourly demand is satisfied. No account is taken in the model of constraints in the transmission system or of engineering restrictions on the ability of individual stations to change load over short periods. (See Doherty (2005), for an example of a model that takes some of these engineering considerations into account.)

The model was used to simulate the effects of different configurations for the future ownership of the ESB. In each case the RSI index was calculated for all the players. In addition, simulations were carried out to establish if any portfolio player in the generation market could increase their profitability by reducing supply in a significant number of half hours. This increase in profitability could potentially occur if the margin between demand and potential supply is very small and if the portfolio player has a significant number of stations in its portfolio.[74]

The changing structure of the generation market was considered in the context of both a Republic of Ireland market and of an all-island market. It was also considered on the basis of today's market size and the likely market size in 2010. The potential effects on the Irish electricity market of increased interconnection between the Irish and the British electricity systems were not considered. However, it seems likely that a significant increase in interconnection capacity will be put in place over the coming decade and this possibility must be taken into account in considering the results of this research.

[74] Obviously a player with only one generation station can not increase its profitability by shutting down production in that one plant.

Table 6.1: ESB Portfolio of Generation 2003[75]

	Republic of Ireland	All-Island
Price Setting Ability	91%	67%
% Generation Capacity	73%	58%
% MW Generated	64%	45%
RSI Average	0.39	0.66

The situation of the ESB in the market is illustrated in Table 6.1 for both the case of a Republic of Ireland market and of an all-island market. This shows that if the market structure proposed by the two regulators (CER, NIAER, 2005) had been in place in 2003 in the Republic, ESB plant would have set the system price in 91 per cent of the hours in that year. The ESB would have accounted for around 73 per cent of the generation capacity. However, because much of their plant was suitable only for running as mid-load or peak load, the ESB would have generated only around 64 of the power consumed in the Republic. Because the ESB would have controlled the key surplus of electricity in periods of peak load it would have been in a very strong position to influence the price. This is reflected in the very low RSI index of 0.39. (A value of 1.2 would be needed if the ESB were no longer to control the price in the crucial peak periods.)

Table 6.1 also shows that if there had been an all-island market in 2003 the ESB's dominant position would have been significantly reduced, with the ESB accounting for a minority of the power generated. However, the low value of the RSI index indicates that the ESB would still have been in a position to influence the price in crucial periods when the capacity margin was tight.

An experiment was carried out assuming a hypothetical divestiture arrangement that involved splitting ESB Generation into three companies with roughly equal portfolios of plant.[76] This was carried out for the year 2003 in the context of an all-island market. As shown in Table 6.2, this divestiture arrangement would have increased the RSI index to the crucial threshold of 1.2 for all three artificial groups. It would have left the largest group with under a quarter of the generation capacity on the island. While this would have eliminated the ESB's power to influence the peak price, account would have to be taken of the costs of divestiture and of any potential costs arising from the reduced scale of operation.

Table 6.2: Statistics for ESB Generation Split into Three Groups

	Group 1	Group 2	Group 3
RSI Index	1.2	1.32	1.29
% Generation Capacity	0.23	0.16	0.19

A further experiment was carried out in the context of how the all-island market might look in 2010. Assumptions were made about

[75] The ESB portfolio excludes Synergen and Collkeragh.

[76] Further details of the portfolios assumed for each of the artificial groups are given in McCarthy (2005).

further new generation, assumed all to be provided by independent producers, and about electricity demand in 2010. The simulations carried out for 2010 assume no further interconnection to Britain by that date.

With the growth in the market and the construction of new generation by firms other than the ESB, the ESB's dominant position would in any event be significantly eroded by 2010 (Table 6.3). However, even though it would have under half of the generation capacity on the island by that year, it would still be in a position to influence the price in key periods of shortage of capacity, as reflected in the value of the RSI index of 0.90. However, if 900 MW of plant were divested by that date, for example Moneypoint, the RSI index would rise to 1.12, quite close to the threshold where the ESB would lose its influence on peak pricing.

Table 6.3: Statistics for ESB, 2010 With and Without Moneypoint

Indicator	ESB with Moneypoint	ESB without Moneypoint
% Generation	43	34
% Generated	33	17
RSI (average)	0.96	1.12

More recent work using the model suggests that when the all-island market is simulated with a capacity payments regime, the effect is to incentivise significant new entry, possibly in the area of mid-load plant. This new entry would displace existing ESB mid-load plant which is very expensive. Providing that economically redundant ESB plant was closed, this could well see ESB's generation portfolio reduced by between 500 MW and 1,000 MW of plant by 2010, taking the RSI index close to the threshold of 1.2, greatly reducing the company's ability to influence peak prices. However, to the extent that the ESB's mid-range plant is potentially uneconomic because of inefficient operating practises, the ESB might respond to these market pressures by reducing its costs to retain these plants in business.

From the point of view of the consumer, at the very least such a regime would put pressure on the ESB to increase the efficiency of its older mid-range plant. Under the new all-island market regime, failure to improve efficiency would see this plant close,[77] to be replaced by new independent power producers. Even without a reduction in the ESB's dominant position, such a reduction in costs would be passed back to consumers through the reduction in the time-weighted average (TWA) price of electricity on the all-island market.

In the early years of the next decade, with the an all-island market and the construction of an additional 500 MW interconnector to Britain and some further rationalisation and new entry, it seems likely that the ESB's existing generation portfolio will lose its dominant position, as measured by the RSI index. Unless the ESB

[77] It will be important that the regulators insist on the closure of inefficient plant through preventing cross-subsidisation within an individual company's portfolio.

builds new plant, over the next decade a significant part of its existing portfolio will close, leaving the ESB with a much smaller share of Irish generation. As discussed in Chapter 4, an additional 500 MW interconnector is unlikely to make the island of Ireland fully part of a British Isles electricity market. However, such an investment will significantly change the operating environment for all the players. Much further research, engineering and economic, needs to be undertaken to ascertain how such interconnection will change the drivers of energy policy in Ireland. However, because of the long lives of the major assets in the electricity sector, policymakers need to take account of such developments in determining the appropriate response to today's problems.

The modelling work, described above, suggests that, with no new construction of generation by the ESB, there will be a gradual erosion of that company's dominant position as measured by indices such as the RSI index. However, experience with such markets suggests that even if no firm has a dominant position in a significant number of time periods there remains the possibility that *de facto* co-ordination of pricing by firms might evolve so as to increase the market price. In the case of the electricity market the pricing "game" will be played out repeatedly every time period in the new market and each firm will come to understand the characteristics of the plant of all the other firms and of their pricing behaviour. Under such circumstances, even if the RSI index were just above the critical threshold, there would remain the danger of co-ordinated behaviour by a number of players to raise prices. Such behaviour would not require any overt collusion between the players.

As a result, it seems likely that there will be a key role for regulators in overseeing the market for the foreseeable future. To this end it is important that the market is structured in such a manner as to make it as transparent as possible and to maximise the information which the market reveals to the regulator and to all the players. The planned all-island market should facilitate such transparency, especially because much of the payment for capacity will be effected in a fully transparent manner by capacity payments.

6.5 Appropriate Restructuring

If a competitive market could be created, ignoring the problem of scale economies and transactions costs, then the efficiency losses would be eliminated through competition, and profit levels would be reduced to "normal" levels. In the case of the break-up of a state owned monopolist the result would be likely to be a substantial reduction in operating costs, including the cost of labour (Gorecki, 2005).[78] However, if there was significantly increased uncertainty for investors this could greatly increase the cost of capital for new plant (Castro-Rodriguez, Marin, and Siotis, 2001).

[78] X-inefficiency – without the spur of competition this occurs reducing the incentive to introduce new technology and constantly seek the most efficient production method with the result that costs drift upwards.

In the case of electricity in Ireland it is clear that the monopoly position of the ESB had led to significantly higher than necessary labour costs over decades of operation up to the end of the 1980s. However, the prospect of competition and a changing operating environment has seen a significant improvement in efficiency over the last decade, though still leaving substantial room for further improvement.

In looking at the possible gains from the creation of a competitive market the major savings could be expected in lower operating costs.[79] However, the creation of a competitive market through fragmenting the industry, if it could be achieved, would also have costs, in particular in raising the cost of capital. In a mature industry where new investment is not required this would not be a problem. This has been the case for much of the mature European electricity market over the past decade. There the potential gains from increasing operating efficiency dominate gains from the lower cost of capital. For Ireland the situation is very different, with many billions of Euro of investment required over the coming two decades.

One aspect of the scale economies of a monopolist is that there is greater certainty that the capital costs of a new investment will be recovered. For example, there is no possibility of a number of competing suppliers expanding capacity simultaneously, resulting in excess capacity. This greater certainty of cost recovery makes it easier to finance such investments, with the result being substantial reductions in the cost of capital.

However, as discussed in Chapter 5, in the current situation in Ireland, where new investment is going to be required on a continuing basis over the coming decade, any policy that increases the cost of capital will have serious implications for consumers. For example, using the CER's assumptions on the cost of capital, in particular assuming a pay-back period for new investment of 15 years, the capital cost per kWh of a new gas generation station would amount to around €0.0091 while the non-fuel operating cost (labour cost) would amount to around €0.0700. However, if increased uncertainty were to lead firms to seek payback over 7 rather than 15 years the cost of capital would rise to €0.0152. This increase in capital costs would almost equal the total operating non-fuel cost of the plant.

In the case of ESB generation, while a break up of the current portfolio would reduce or eliminate the ESB's dominant position there are also possible disadvantages to such an approach. Experience elsewhere shows that there are economies of scale in managing generating stations. For example, large operators can obtain much better terms for supply of fuel, including gas, than can smaller purchasers. However, some of these diseconomies may be overcome if the independent generators are acquired or built by

[79] Albeit, operating costs today are lower than a decade ago, leaving smaller potential efficiency gains.

large operators from outside the Republic who can draw on their international resources.

Thus in an environment where large-scale investment is a continuing requirement, the factors affecting the cost of capital are likely to dominate any issues concerning operating efficiency. Under these circumstances, if forced to choose between either monopoly provision or a fragmented "competitive" market, consumers could find themselves better off under the monopoly regime. However, the policymakers do not have to choose between these two polar cases but can seek to provide a market structure that would combine incentives for efficiency of operation with low cost of capital.

The current proposals from the regulators for the all-island market appear to provide a reasonable compromise between incentivising competition and reducing the uncertainty of financing new investment in generation.

In the case of ESB generation, time and an all-island market will help provide a more competitive market. However, this will not be enough to address its dominant position. Provided it is required to close plant that is uneconomic there will be significant reductions in its portfolio. From both the point of view of the ESB and the consumer it would be better if this process were hastened by selling off between 500 MW and 1000 MW of capacity over the next few years. Closures for economic reasons would sufficiently reduce the footprint of ESB generation such that the firm could be allowed to develop some new capacity. In the longer term, this would leave the company with a more sustainable portfolio of plant over the course of the next decade.

Consideration could also be given to transferring the ownership of the ESB sites to a separate state company to create a land bank. These sites represent the cheapest and easiest location for new generating plant to be established, given the way that the planning system currently operates. The owner of the sites could then provide access to new entrants on a non-discriminatory basis.

In the case of electricity transmission it would be better if the ownership of the infrastructure passed to ESB National Grid (EIRGRID) or even to an all-island transmission company. That company would then contract on a competitive basis with ESB, Powerteam (Viridian) or any other company to maintain and develop the infrastructure. This would make the cost base transparent and provide incentives to minimise costs.

For the rest of the ESB, distribution and supply, the regulator should encourage an increase in the share of the business that is bought in from outside companies on a competitive basis. This would increase the transparency of operation.

It is not clear just how much interconnection will be economic and how much will be needed to make Ireland part of a British Isle or North-West European electricity market. However, in the next decade increased interconnection to Britain will further enhance competitive pressures on the island.

6.6 Conclusions

- Decide at an early date on the integration of the electricity systems on the island.
- Put in place a market system that provides guaranteed payments for capacity, reducing the cost of capital for new investment and increasing the transparency of the new all-island market.
- The regulators should insist on closure of uneconomic plant that is surplus to capacity requirements.
- Additional interconnection of the Irish and British electricity systems would help enhance competition on this island.
- The growth in demand and the operation of the new market structure should see significant closure of ESB plant over the coming 5 years to be replaced by new plant, generally built by different operators. Together with enhanced interconnection to Britain, this should see the ESB's dominant position in the generation sector on this island substantially eroded by early in the next decade.
- The ESB should sell between 500 MW and 1,000 MW of plant over the period to 2005. It should be allowed to replace some, but not all of this plant by new plant.
- Ownership of the transmission system should be transferred to ESB National Grid or a similar all-island company and that company should contract with other companies, including ESB, to maintain and develop the system.
- Where possible, ESB distribution and supply should move to buying in services on a competitive basis.

7. ENVIRONMENT

7.1 Introduction

Today energy policymakers face an exceptionally difficult task, not only due to the complexity of the energy sector itself, but also due to the wide range of objectives that policymakers want to target. It is not a simple question of minimising the cost of providing energy to the economy. A wide range of other objectives is important, especially objectives concerning the environment.

First, because of the uncertainty inherent in any forecasting exercise there is no simple answer to what will be the least cost solution to providing energy in the future. In particular, uncertainty about the stability of infrastructure and about future input prices means that there is no single "right" answer. The effects of this uncertainty are summed up in the debate about security of supply, discussed above in Chapter 3.

Second, there are major environmental side effects from the production and use of energy. Burning fossil fuels, the chief source of electricity today, produces large quantities of greenhouse gases – the primary culprit in global warming. In addition, burning fossil fuels produces sulphur dioxide, nitrogen oxides, carbon monoxide and dust, among other emissions, that lead to adverse health effects and acid rain. Other emissions are also harmful; in particular the waste from nuclear reactors used to generate electricity potentially poses a serious environmental problem for future generations, and power transmission causes visual intrusion on landscapes. Reducing one set of emissions may not necessarily reduce other harmful emissions. In some cases reducing carbon dioxide emissions can actually increase other harmful emissions and vice versa.

Third, there are social objectives. In the past, concern for domestic employment drove the investment in peat-fired electricity. However, with the advent of near full employment, the justification for such a policy is significantly reduced. If the Forfás framework for assessing the value of employment in new projects had been used (Honohan, 1998, and Murphy, Walsh and Barry, 2003) the new peat-fired power stations would almost certainly have failed to meet the required rate of return.

Another important concern is the effect of energy policy on poverty. In these islands poorer households tend to spend a higher share of their income on energy than the average (Scott and Eakins, 2004). Thus higher energy prices are likely to be bad for such households. In this case the objective of minimising the cost of energy can also help achieve the wider social objectives. However, this is not always the case. Where action to tackle global warming uses economic instruments, such as taxes or tradable permits, Scott and Eakins show that poor households are likely to be disproportionately affected unless additional policy measures are taken.

The environmental objective for energy policy should be one of long-term sustainability encompassing damage limitation and commitment to internationally agreed standards for the management of climate change. The specific environmental goals of EU energy policy on environmental integration (as detailed in the European Commission communication, 1998) are to reduce the environmental impact of energy production and use, promote energy saving and efficiency and to increase the share of production that uses cleaner energy.[80] This broadly encapsulates the environmental objectives in the energy field of successive Irish governments. In particular, the objective of combating the threat of global warming is likely to be the single most important environmental driver of energy policy over the coming decade.

This chapter considers some of the environmental issues which have to be taken into account in formulating energy policy for Ireland over the coming decade. It concentrates largely on the environmental problem of global warming. Section 7.2 briefly considers the existing policy framework, both at an EU level and a domestic level. The issue of policy instruments to use in implementing environmental policy is dealt with in Section 7.3.

The chief long-term environmental issue facing energy policymakers throughout the world is the effect of burning fossil fuels on global warming. With the signing into law last winter of the Kyoto protocol the EU, and with it Ireland, is committed to taking significant action to tackle this problem. In tackling this problem some of the solutions may also contribute to enhancing the security of energy supply. However, this will not always be the case. Section 7.4 considers current policy on tackling global warming and how it needs to evolve over the coming decade if the environmental objectives are to be met at minimum cost.

Section 7.5 discusses policy on renewable energy. The logic of targeting renewable energy is not that such energy is "desirable" in its own right; renewables of themselves do not confer obvious benefits on society. Rather their value lies in how they can contribute to meeting the long-term policy objectives of providing security of supply and minimising emissions of harmful greenhouse gases. The developed world needs to wean itself off its dependence on fossil fuels, especially oil. The price of oil is likely to rise significantly in real terms, causing a move away from oil in the long term. With emissions trading the rising price of carbon is also likely to incentivise the reduction in emissions.

In a world where the cost of capital was low and investors in research into energy faced a reasonably certain future it would probably not be necessary to consider a "renewables policy" at all.

[80] The EU White paper on Renewable Energy noted the important role for renewables in responding to security of supply concerns and this theme is again reiterated in the EU Green Paper on Security of Energy Supply.

The optimal investment in renewable energy would occur as a by-product of a suitably constructed set of policies to tackle global warming and security of energy supply. However in a second best world, as in all other areas of economic activity, the energy sector suffers from considerable uncertainty and the potential gains from research may not all be captured by those who invest in the research, leading to sub-optimal levels of energy research. As a result, there may be a need for some additional incentives to encourage research and development in renewable technologies. Part of such development can include the early deployment of such technologies on a trial basis.

There are other environmental issues facing the energy sector which are discussed briefly in Section 7.6. First, there are other emissions to air, including emissions of gases that cause acid rain. Second, in the area of transport there are other environmental problems over and above the problem of emissions of greenhouse gases: in particular, the problem of congestion.

Some conclusions are drawn in Section 7.7 on the priorities for policymakers in tackling the environmental agenda.

7.2 Policy Background

The key drivers of Irish environmental policy, in so far as it affects the energy sector, are the international commitments defined in EU law. The first and most important is a consequence of the Kyoto agreement and EU burden-sharing agreement whereby Ireland is committed to limiting greenhouse gas emissions for the period 2008-2012 at 13 per cent above their 1990 levels. A second driver is the EU Directive 2001/77/EC on the promotion of electricity produced from renewable energy resources in the internal electricity market, where Ireland has a 13.2 per cent target for the share of renewable energy sources in consumption by 2010. This equates to having just over 1,400 MW of installed renewable energy capacity. As argued later, it is not clear that this second instrument is actually wise. If properly implemented, the Emissions Trading Regime and the pricing of security of supply could well be sufficient (and efficient) to produce an optimal deployment of renewable technologies. Finally, there are the directives which regulate emissions of gases that cause acid rain, including the Large Combustion Plant Directive (2001/80/EC).

The commitment by the EU to take real action to combat global warming represents a major political achievement. This agreement to implement the Kyoto protocol has been made in the face of the limited support, or even opposition, of other major powers. The EU's burden-sharing agreement involves a country-by-country commitment to limit emissions of greenhouse gases. The single most important policy instrument to bring this about is the scheme of emissions trading covering all EU members, which was agreed in December 2002 and which commenced in January this year. The extensive economic evidence available indicates that the actual cost to the EU of taking the lead in undertaking action to tackle global warming will, in fact, be small.

While the Emissions Trading Regime has the potential to achieve a significant reduction in emissions in the relevant sectors at least cost to the economy there are serious defects in the way the EU is actually implementing the scheme (see Fitz Gerald, 2004a, for details).

In the case of Ireland the government formulated a strategy for tackling Global Warming, published in 2000. This policy statement included a number of measures affecting the energy sector. However, while the EU emissions trading regime has gone ahead, some important commitments have since been shelved or dropped. In particular, plans for a carbon tax were dropped in 2003. In the long term a failure to introduce such a tax to cover the sectors not covered by emissions trading could prove very serious. It will result in either a failure to implement the reduction in emissions required under the Kyoto protocol or else a very inefficient distribution of the burden of meeting those requirements.

Over the last decade successive governments have taken initiatives to promote renewable energy. Policy in this area is described in *Renewable Energy – A Strategy for the Future* in 1996 and developed further in 1999 in the *Green Paper on Sustainable Energy*. There were two important domestic commitments made:

1. to support the building of up to 500MW of renewable energy based electricity stations to be connected to the electricity network by 2005;
2. to explore other renewable energy technologies not supported at that time, e.g. offshore wind, bio energy etc.

The EU Directive asserts the EU's need to promote renewables due to their contribution to: *…environmental protection and sustainable development. In addition this can also create local employment, have a positive impact on social cohesion, contribute to security of supply and make it possible to meet Kyoto targets…(Preamble 1).* Ireland has opted for a 13.2 per cent target for renewable electricity sources in consumption by 2010 consistent with the aspiration that it would have had the 500 MW of renewable electricity generation in place by 2005.

As argued elsewhere in this paper, under current economic circumstances, energy policy and related policy initiatives should not be used to target employment creation. The best contribution that energy policy can make to economic development is through ensuring that a secure energy supply is provided at minimum long-term cost to society. This definition of "cost to society" must take into account any external cost imposed by the production or consumption of such energy.

7.3 Policy Instruments

Generally, market based instruments are to be preferred to regulations. Because the regulator is not infallible and has limited information it is very difficult for the regulator to assess the cheapest means of meeting a specified objective. However, if the value of an objective (or the cost of environmental damage) can be translated into a price signal to the market, then market participants can choose themselves what is the least cost solution (see Fitz Gerald, McCoy and Hore (2001), for a discussion of the literature).

Economic theory suggests that in an ideal world with perfect information each policy target would be addressed by a single policy instrument. The use of multiple policy instruments can significantly increase the cost of meeting the desired objectives. It can give rise to uncertainty for all the players in the market, raising the cost of capital. In addition the cost of administering and complying with multiple regulations or price regimes can be very onerous. In some cases these transactions costs, which are a waste of resources, can dominate the other costs of a policy regime. However, in the real world with many constraints on policy and limited information, a second best solution may be necessary involving more than one instrument broadly targeted at the same objective.

The instruments currently being used or considered in Ireland include the EU Emissions Trading Scheme (ETS) (a quantity-based measure, implemented since January 2005); a possible carbon tax (a price-based measure); schemes to promote alternative energy (a series of Alternative Energy Regimes, AERs) and regulations affecting such things as housing insulation standards. Of these the most significant is the EU ETS.

The distinctive difference between a quantity- and price-based solution is that, while as a regulator one is fairly sure of the outcome with quantities (such as permits), one is unsure at what cost this is achieved. The alternative, with price-based solutions, is that the outcome in terms of quantity is uncertain but the costs are likely to be minimised as individual agents make informed decisions given the price facing them. When permits are tradable among participants they can also possess the efficiency properties of price-based mechanisms (Baumol and Oates, 1988). Under conditions of certainty about costs and benefits the tradable permit system is equivalent in efficiency terms to a price-based system.

Weitzman (1974) demonstrated that when there is uncertainty about the marginal benefits of pollution abatement (that is, there is uncertainty about the damage being done by the pollutants) there is no difference in terms of economic efficiency between a quantity or price-based approach. When there are uncertainties about the marginal costs of abatement (that is the regulator is uncertain about the costs faced by agents) then the relative sensitivity of marginal benefits to marginal costs determine which system is preferred. Where the marginal benefits are more sensitive than marginal costs to additional abatement the quantity based system is preferred. It would be fair to say that the marginal benefits of abatement, or damage to Ireland from marginal emissions of carbon dioxide, do not rise steeply in the medium term and that a price-based approach is preferable.

Price mechanisms lead to uncertain emission outcomes but there is the option of 'learning by taxing' (Helm, 2005), while quantity mechanisms give rise to uncertain cost considerations but the target is more explicit. It has been shown that the nature of the uncertainty is such that price mechanisms are preferable in the context of the problem of global warming. Pizer (2000) estimates that price mechanisms generate up to five times the net expected benefits associated with a prudent quantity control. However, when the EU attempted to introduce a carbon/energy tax in the early 1990s (Fitz Gerald and McCoy, 1992) they failed to get agreement. Since that failure the EU has concentrated on other approaches and on the alternative scheme regulating quantities, the Emissions Trading Scheme (ETS). The idea of marketable or tradable permits was first put forward by Dales (1968) and these have been successfully implemented in the US for trading in lead and sulphur emissions.

The EU scheme that came into force in January 2005 covers a limited number of sectors including electricity generation. It involves a requirement that at least 95 per cent of the tradable quotas be allocated free to firms involved in trading. This procedure of free allocation is commonly referred to as "grandparenting". The requirement that the allocation be free rather than auctioned will seriously aggravate the cost to the Irish and other EU economies of implementing the scheme (Bergin, Fitz Gerald and Kearney, 2004). This is because no revenue will be available to the governments of the EU to offset the negative competitiveness and social effects of the rise in energy prices that the trading regime entails. If the original EU Commission proposal for a tax had been followed, or if the bulk of the quotas were auctioned, the economic cost of reducing emissions could have been greatly reduced. The original EU Commission proposals (for a tax) and the EU Parliament's own preferred amendments to the ETS (to increase the amount auctioned) have shown greater wisdom than have the collective ministers for the environment of the EU who designed the policy that is actually being implemented today.

In accordance with the EU directive, the Irish government has drawn up its own National Allocation Plan to allocate emissions quotas to all domestic firms in the relevant sectors for the period 2005-2007. Over the next 3 years a similar plan will be prepared for each member state for the period 2008-2012. Under the ETS, firms in the sectors covered by emissions trading have to ensure that they maintain their emissions within the required limits or potentially face heavy penalties. If emissions are less than required, firms can sell their spare quota or permits on the EU market; where quota is inadequate additional permits must be acquired on the EU market. All the permits allocated to firms are freely tradable throughout the EU. If firms find it difficult to reduce emissions they will have to buy permits if they do not have enough. However, where the cost of abatement is low the firms will be able to sell surplus permits, providing a strong incentive to make the necessary investment in abatement.

The emissions trading regime, if properly implemented could, in theory, serve to advance the EU's environmental objectives while not imposing a significant cost on the bulk of EU producers and consumers. In principle, a trading scheme, or a carbon tax, by raising the cost of polluting, should persuade those who can reduce their emissions at least cost to do so, minimising the burden for the economy as a whole. In the case of a scheme of tradable permits, if the permits were initially allocated by auction then the governments of the EU would have the revenue to reduce distorting taxes elsewhere in the economy and to compensate the poorest losers. Such a regime would have minimised the costs to society. If this allocation of permits were done on a once-off basis, with no prospect of future free permits, then the scheme would at least provide the appropriate incentives to reduce emissions in the most efficient way possible. However, by promising repeated rounds of free permits for polluting firms thereby encouraging them to hold back on abatement, the EU scheme greatly reduces the incentive for the dirtiest firms to reduce emissions, raising the potential cost of achieving the necessary reduction in emissions for the economy as a whole.

The trading regime only covers a few sectors that are heavy energy users. If the competitiveness effects of achieving the required reduction in emissions are to be minimised and the social costs addressed, it is essential that a carbon tax be introduced to cover the sectors exempt from the ETS regime, in particular the household sector. A carbon tax represents the least cost method of reducing carbon emissions in those sectors not included in the trading scheme (Bergin *et al.*, 2004). In the long run the tax rate should approximate the cost of carbon permits under the trading scheme. This would ensure that the burden of adjustment is carried equally by all sectors of the economy in a manner that will minimise the economic costs.

The tax should only apply to sectors that are not covered by emissions trading. As a result, it should not apply to electricity. This is because the price of electricity will, as outlined above, already reflect the cost of carbon dioxide emissions. To apply a carbon tax on top of this would mean that electricity users would end up carrying a disproportionate share of the cost of compliance, raising the overall cost to the economy.

It is useful to consider the approach taken to the implementation of environmental objectives in a number of other jurisdictions. The United Kingdom is an example of a country where a wide range of different policy instruments have been deployed to target the same objective – reducing emissions of greenhouse gases. According to Sorrell (2003), the experience from the UK has pointed out many contradictions and deadweight losses from this approach, showing instances where policy co-ordination would have achieved the same outcome at lower cost to electricity consumers. Some of these policy interactions have been the result of policies directly affecting the renewables sector. In addition, to the EU Emissions Trading Scheme (ETS), the UK had its own emissions trading scheme, a climate change levy, introduced in the UK in April 2001, and a renewables obligation (ROCs). The Renewables Obligation is expected to lead to higher electricity prices: the Department of Trade and Industry (DTI, 2001) estimate that average UK prices will increase by a maximum of 4.4 per cent by 2010 as a result of the ROCs. There are also the legacy effects of previous schemes which still affect the energy sector through raising costs. The combination of all these schemes involves substantial compliance costs, they create uncertainty for investors, and they add significantly to the cost burden for energy consumers over and above what would be needed to meet the given environmental objective. It is estimated that the different schemes designed to promote renewables in the UK account for about 2 per cent of household electricity bills in the UK (Simpson, 2004).

Similar problems have arisen in other countries where multiple instruments have been used. In the case of Belgium a series of "voluntary agreements" with key industrial sectors effectively removed those sectors from the ambit of other policies. As the sectors excluded were those where the cost of emissions reduction was likely to be lowest, by shifting the burden of adjustment to the rest of the economy it substantially increased the potential cost to the economy as a whole of meeting the environmental objectives.

The lesson to be drawn from experience elsewhere is that governments should avoid using multiple instruments to target the same objective as they are likely to increase the costs of compliance and the overall burden on the economy of meeting the specified environmental objective. In many cases the transactions costs and compliance costs of operating multiple schemes are high. To some extent the complexity of these regimes masks the waste and inefficiency that they involve.

The Alternative Energy Regime (AER) operated in Ireland has involved competitive tendering or bidding by potential suppliers. On invitation, renewable energy suppliers bid in terms of the minimum subsidy which they would need to operate. Each round of the AER called for a prespecified amount of electricity generating capacity. This is an effective way to support renewables in the early phases, for as long as price-correcting economic instruments are absent.

7.4 Combating Global Warming

The single biggest environmental issue facing energy policymakers is the need to tackle the problem of global warming. Given the uncertainties surrounding the causes and impact of global warming, the costs and benefits from the abatement of greenhouse gas emissions are also uncertain. The implementation of cost-effective risk reduction strategies in such a context becomes of central importance. While the arsenal of economic solutions for environmental problems is broad, ranging over prohibitions, issuing of standards, application of subsidies, the use of charges, taxes, fees, the creation of quasi-markets for tradable permits: they essentially boil down to price or quantity based solutions. As discussed, while it would have been preferable to adopt a common carbon tax across the EU (see Fitz Gerald, McCoy and Hore, 2001) the EU has instead adopted the Emissions Trading Scheme (ETS) that restricts the quantity of emissions.

The EU adopted the ETS as it avoids disturbing the sensitivities of individual member states concerning their rights to decide on taxation. In addition, tradable permits can (and are) being implemented to confer a valuable property right, implicitly viewed as a gain rather than a loss. The revenue from trades accrues to the owner provided that the owner can pass on the marginal cost of the permits in the price of output. The State would only receive revenue if it decides to allocate initially through auction.

The EU emissions trading scheme as actually implemented is the product of a very long process of lobbying and debate. While the initial proposals of the EU Commission had a coherent economic basis, the scheme, as now implemented in law, will impose significantly higher economic costs on the EU economy than are necessary to meet the environmental objectives it sets out to address. It will adversely affect competition in the sectors affected through favouring incumbents. The EU scheme will also involve substantial transfers of resources from the bulk of companies and citizens in the EU to the shareholders in many of the plants covered by the scheme (Parry, 2003). In the case of the UK and Ireland the costs due to price rises are likely to fall disproportionately on poor households because they spend a much higher than average proportion of their income on energy (Scott and Eakins, 2004, and Smith, 1992).

The key problems with the EU scheme are: the decision to give the permits for free to the relevant companies (referred to as "grandparenting" them) rather than to auction them; the decision to have multiple rounds of grandparenting – 90 per cent of permits will be given for free in the second period 2008-2012; the failure to ensure sufficient harmonisation of the scheme across different countries to minimise the negative effects on the single market; and, finally, the choice of a scheme of tradable permits with application to a limited number of sectors, rather than a scheme applicable to all sectors (or else a carbon tax applying to all sectors), involving a significantly greater burden on the regulating body.

Economic theory suggests that a once-off allocation of quota, while having undesirable distributional effects, will still provide appropriate incentives to firms to reallocate resources efficiently to meet the environmental objective. Having received the allocation firms could then choose, either to use the quota themselves and to continue in production, or else to close and sell off the quota. This would provide an incentive for the environmentally less efficient firms to close, helping achieve the reduction in emissions at least cost.

However, the scheme as implemented by the EU moves away from this ideal by providing for at least a second round of allocations, where the allocations may be based on historic emissions. This means that existing "dirty" firms that stay in business will receive another "free gift" from government in the form of permits for the period 2008-2012 (see Fitz Gerald, 2004a). As implemented there is effectively a "use it or lose it" provision, where firms would forego the free allowances if they abate seriously, or shut down, further incentivising dirty firms to remain in business, at least to the end of the relevant trading period.

The prospect of a second round of allocations will initially result in a lower than planned reduction in emissions in the key sectors.

The very plants that are expected to close throughout the EU will only receive windfall gains in the form of free allowances in the future if they remain open. As the forecasts for reductions in emissions for the EU rely on such "dirty" firms abating or closing, their failure to do so will make the reduction in emissions more difficult, increasing the price of emissions permits throughout the EU. The result could be much higher prices for permits on the EU market than would otherwise be the case, with consequential higher prices for consumers. The value of the windfall gain to shareholders in the firms engaged in trading could also be enhanced by this higher price.

A second very serious cost arising from the failure to auction the quotas or permits is that the loss of potential revenue from an auction means that EU governments will not have the resources to cut other taxes. As a result, the distortions arising from the imposition of the regime will not be offset by a reduction in distortions elsewhere in the economy. Economic theory (Goulder, Parry, Williams and Burtraw, 1999) and a series of empirical studies for the US (by the Congressional Budget Office, 2000), for Ireland (Bergin, Fitz Gerald and Kearney, 2004) and for Belgium (Bossier *et al.*, 2000) show that this is likely to be an important additional cost, aggravating the negative effect on the competitiveness of the EU economy in general, and of the Irish economy in particular. Bergin, Fitz Gerald and Kearney (2004), estimate that the additional cost of "grandparenting" compared to auctioning the permits, if applied to the economy as a whole, would amount to between 0.3 per cent of GNP and 0.5 per cent of GNP in the medium term. While the current scheme applies only to the most energy intensive sectors, it is clear that it will have a significant negative effect on GNP.

A third problem with the scheme is that the granting of free tradable permits that can effectively be sold through **raising** the price of output, constitutes a very important capital **subsidy** to fossil fuel generators (see Fitz Gerald, 2004b, Appendix 1). While renewables generators will benefit from the higher price, no such capital subsidy is available to renewables generators.[81] The net effect of these different offsetting implicit subsidies will be to give an unfair advantage to conventional carbon-intensive incumbents thereby displacing new entry and leading to a lower penetration of renewables than is economically efficient.

In addition to the problems outlined above, implementation of the trading scheme will involve substantial compliance and verification costs. As the allocation plan for the UK recognises, this could be good for the City of London, which would help operate the EU market in permits. However, the benefits for the financial sector and the City of London will simply reflect a significant transactions cost burden that will ultimately be paid by the consumers of Europe as a result of the costs in actually operating the market. The

[81] The allocation of permits and the manner in which the cost of carbon is "passed through" impacts on the economics of Renewable Electricity (RES-E) generators in the market.

verification of the scheme will also involve a firm-by-firm audit to ensure compliance, further adding to costs. Compared to an across the board carbon tax, or an emission scheme imposed on producers or importers of primary energy ("upstream"), the costs of compliance of the current scheme applied at the level of individual firms will be significant. This is because of the need to verify each plant's behaviour. For this reason the Consultation Group on Greenhouse Gas Emissions Trading, set up by the Department of the Environment, recommended in 1999 against operating a trading scheme at the level of such "downstream" firms, preferring an "upstream" scheme involving very few firms that currently pay excise tax on most of their imports and which would have made use of the existing excise tax administration.

As discussed in McCarthy (2003), good policy should be designed to minimise the incentive for corruption. The current scheme of emissions trading involves granting huge gains to individuals or companies through the allocation of emissions quotas and, therefore, has certain dangers. The Irish and UK governments, by adopting a consistent methodology in their plans, applied rigorously across all sectors, guard against this danger. By ruling out exceptional treatment for any individual plant, the process can be kept transparent, ruling out such dangers. However, if a similar approach is not adopted in all other countries, this could leave open the possibility of corruption. If, instead, permits were auctioned, the process would become completely transparent, provided that the auction is set up properly.

These defects will significantly raise the cost of meeting the objective of reducing emissions in the period 2005-2007. It is urgent that the review of the current regime by the EU should deal with these problems by reforming the ETS to be implemented for the second commitment period of 2008-2012. Reform would simultaneously ensure that the costs suffered by the European economy would be minimised and that the desired reduction in emissions would actually be achieved.

EU Ministers for the Environment, while showing admirable zeal in tackling the problem of global warming through the introduction of emissions trading, have shown scant regard for the economic and social effects of their chosen policy. Instead of designing the scheme in the interests of European taxpayers, they were unduly influenced by the strong lobbying of the large European firms that are major energy consumers. The economic "price" for getting political agreement was very high. A consequence of this is that the trading scheme will impose a much greater economic and social cost on the EU than is necessary in order to achieve the crucial reduction in emissions of greenhouse gases.

The potential for distortions in the operation of environmental policy North and South of the border in the context of an all-island electricity market has been dealt with earlier in Chapter 4.

A consequence of the introduction of emissions trading is that the cost of peat used in electricity generation has risen dramatically. As discussed elsewhere, this is likely to render the continued operation of the new peat-fired electricity generation plants very uneconomic. Already consumers are paying a high price for this. However, recent work by Coford (O'Carroll, 2005) suggests that at the current price of carbon dioxide of over €20 a tonne it will become increasingly economic to substitute wood biomass for peat in these generating stations. The supply of potential wood biomass is likely to rise rapidly over the coming decade.

This would suggest that at the very least the peat stations should be gradually moved to burning biomass. By 2012 up to a quarter of the peat currently used for electricity generation could be replaced by wood biomass, with the prospect of significant further reductions over the rest of the next decade. Under the current high prices for emissions of carbon dioxide this would simultaneously reduce the cost of electricity for consumers and also reduce greenhouse gas emissions.

For a substitution of peat by wood biomass to happen it will require the state as the shareholder in Bord na Móna to agree to renegotiate the current agreement. This would allow for an orderly wind down in the peat industry while simultaneously providing a growing market for the domestic production of wood biomass.

7.5 Renewables

Renewable energy sources are those which are effectively inexhaustible (such as wind, wave, solar, hydro etc.) or which are replenished at or about their rate of consumption (such as managed forests and energy crops and other forms of biomass). The reasons for promoting renewables are first to provide advance signals to the market to invest in the new technologies in advance of the price rising and second to help fund new technologies that might not be fundable at a reasonable price – through support for research and development (R&D). Third, as discussed above, implementation of the EU ETS discriminates against renewables and fossil fuel prices inadequately reflect environmental damage so that, *faute de mieux*, it may be necessary to rebalance the playing field through limited additional intervention by the regulatory authorities.

Sorrell (2003) lists three theoretical arguments for supporting renewables to enable them to compete with conventional fossil fuel generation:

(i) the inability of private players to capture the positive externalities of R&D and adoption;

(ii) the 'option value' of bringing forward technologies to mitigate the risk of continuing to use environmentally damaging technologies in a context of uncertainty and ignorance about the risks of climate change; and

(iii) the scope for encouraging scale and learning economies that will drive down unit prices and form the basis for stand-alone viable industries with significant export potential.

Other key justifications for promoting renewable energy forms include: changes in the plant mix and operation of the power system to introduce fuel diversity; and hedging against fossil fuel price volatility for security of supply reasons.[82] Policy on renewable energy sources should aim to establish equilibrium between the gains, costs and impacts involved and not distort or interact in a contradictory manner with complementary policies affecting the same agents. The most important issue in designing high-level policy for renewables is that it ultimately promotes efficiency simultaneously within the renewable and non-renewable markets. The support mechanism should aim to operate in a competitive and transparent way, guaranteeing some degree of certainty into the future but subject to progress reviews.

The AER schemes over the last decade have helped to produce significant investment in renewables, chiefly in wind. However, the schemes have not produced nearly as much investment as had been hoped or expected. In many cases those bidding and getting contracts have been unable to deliver for a variety of reasons, including problems in getting planning permission.[83] Thus the mechanism has produced less investment than anticipated, while at the same time ensuring that what investment has taken place has been at relatively low cost to the electricity consumer.

There is a danger that the combination of the market structure and of direct support for renewables could either provide too little or too much support for wind energy at the expense of other renewables. To get the balance right within renewable sources of energy it is important that the issue of intermittency is reflected appropriately in the pricing of the market and the nature of the special support provided for renewables. The associated costs of wind in terms of necessary backup increase for a large deployment of wind generation. The total cost of wind (capital cost plus subsidy plus reserves) makes other forms of renewable power sources, which are readily dispatchable, gradually more competitive compared with wind. As a result, there is a danger that the consumer may end up paying a higher price than necessary to meet a given environmental objective. The volume and structure of support for renewables ought to be appropriately designed and calibrated, having regard to the marginal costs of carbon abatement of all options, including energy efficiency.

Any policy or support mechanism in this jurisdiction must take account of the development of corresponding strategies in Northern Ireland to which the Republic is currently (albeit weakly) interconnected. It must also take account of the existing link to the British system, to which Ireland may become more fully interconnected in the future. Interconnected systems involve

[82] Additional less justified drivers for supporting renewable energy have centred on arguments related to indigenous industry effects and/or rural development with associated net job creation, to satisfy consumer demand (without compelling consumers to pay the premium cost).

[83] This issue was covered in the proposals of the Report of *The Renewable Energy Strategy Group,* 2001. Department of Communications, Marine and Natural Resources.

economic interactions that could be distorted if a policy in one system creates opportunities for arbitrage by stakeholders.

The availability of a very high level of support for wind in Northern Ireland through the UK ROCs system will incentivise significant wind development there. With the gradual integration of the all-island electricity system this may well see a disproportionate share of the economically viable wind generation being located in the North. This could put undue pressure on the Northern Ireland transmission system if these pressures are not reflected in the pricing of the All-Island Market infrastructure.

The design of a suitable system of support is not attempted in this paper. Appendix 2 outlines some of the possible mechanisms that may be used. Whatever scheme is chosen the objective must be to ensure that the long-term cost to consumers of achieving the given environmental target is minimised. Were it not for the defects in the EU ETS it might provide adequate support for renewables on its own. As a result, in designing a support system for renewables the first objective should be to offset the existing disabilities arising from the operation of the EU ETS. The system of support should be neutral between the different types of renewables. In the case of wind, where nearly all the costs are incurred up front, it would be desirable to provide the support in the form of a capital subsidy. However, as the cost of wind increases with the volume of wind on the system such a support system would not be practical. For example, if the capital subsidy were to fall with the volume of wind generation on the system the result would be a significant economic gain for those who invest first.

7.6 Other Environmental Objectives

Global warming is not the only environmental issue facing the energy sector in Ireland. Two other important problems affect the use of energy and its ultimate impact on the environment. The first of these is the problem of gases that cause acid rain and the second is a range of topics that come under the broad heading of sustainable living.

ACID RAIN

Emissions of some gases, especially sulphur dioxide, give rise to acid rain when they mix in the air. The rain can cause significant environmental damage where it falls, in the form of acidification of soils and surface waters. Unlike the case of greenhouse gases, acid rain has a localised rather than a global impact, though it can travel. In the case of Ireland, with the prevailing westerly winds the damage from emissions in Ireland is caused either within Ireland or in the United Kingdom. Much of the acid rain actually falls in the Irish Sea or the North Sea without causing major damage. Acidification of surface waters is not a problem within Ireland, with a few exceptions due to acid rain that probably originates mainly from abroad (EPA, 2000, 2004).

Because of the potential damage from acid rain across borders the EU Commission introduced regulations to reduce emissions and limit the damage caused. These regulations are applied on a similar basis across all EU jurisdictions. This application of similar rules is in spite of the evidence from Newbery (1990) that emissions should be reduced where benefits exceed costs of abatement and co-ordinated payments be made to overcome the 'free-rider' problem. McCoy (1991), showed that in the case of Ireland the revenue could probably best be applied to investing in abatement in Central Europe rather than in Ireland. This was due to the fact that so much of the acid rain generated in Ireland falls harmlessly in the sea whereas in Central Europe all of it falls on land.

Whatever the economic logic of the regime, the EU regulations have now been in force for many years. They involve major tightening in emissions standards for existing plant. Existing plant must either invest in abatement by 2008 if they are to stay in business indefinitely or else plan a phased closure of the plant. In Ireland Moneypoint was the biggest plant affected by this directive. It has been decided to invest in the necessary abatement technology for that plant at a cost of around €250 million.[84] This will allow the plant to remain operational into the next decade.

SUSTAINABLE LIVING

The fastest growing area of demand for energy is the transport sector. With the advent of emissions trading there will be a brake put on growth in emissions from the energy-intensive electricity sector but unless there is a significant change in policy stance the growth in the transport sector's demand for energy, and resulting emissions, is likely to continue for the foreseeable future.

There is a range of strategies that can be adopted to modify this trend. One of the more important possible policy changes is the responsibility of the EU. If the EU were to introduce mandatory standards for fuel efficiency in cars beginning early in the first half of the next decade it could have a very significant effect on the motor industry. The adoption of such an approach in the past by the California administration saw major R&D undertaken by motor manufacturers.[85] With a far larger market in the EU, the adoption of tighter emissions standards would evoke a major response in terms of R&D to ensure compliance on a least cost basis. Already the EU has a voluntary agreement with manufacturers calling for a small improvement in efficiency. If any individual member of the EU were to try and go it alone their small size would mean that no motor manufacturer would take them seriously. Thus, it would only be possible to use this instrument at EU level.

Motor fuel is currently highly taxed in the EU. The tax paid is substantially greater than the environmental damage done in terms of global warming and maybe still somewhat greater when other motoring damage costs are included, though a total reckoning

[84] An additional €100 million will be spent on a refit of the plant.

[85] Research produced greater fuel efficiency but car owners decided to take the substitution benefit of the new technology in the form of bigger cars.

remains to be undertaken. However, the major environmental cost is the congestion that it causes. In the long run it would be better to partially replace the current tax on fuel with a charge for use of road space along the lines of the congestion charges in London. A comprehensive programme of charging for use of the road infrastructure would encourage more sustainable lifestyles while making better use of the existing road space. Such a move to calibrating charges and taxes more directly to the environmental damage done by cars would bring significant advantages. It would probably see drivers in rural areas paying less than today with significantly higher charges for urban driving.

In the long run, with the growing urbanisation of Ireland the key to sustainability will lie in the development of denser cities with the appropriate infrastructure. With the cost of energy likely to continue rising in real terms for the foreseeable future it is appropriate to plan for cities which are denser and which rely to a much greater extent on public transport. It is important to signal today that a world of long-distance commuting may not be sustainable in twenty or thirty years time.

Finally, as discussed in the next chapter on energy efficiency, the standards of insulation on new dwellings need to be tightened and enforced. With the housing stock growing at a very high rate, a change in standards today could make a big difference to the energy efficiency of that stock for the next century. In 15 or 20 years time, when the rate of growth is likely to fall or even stop it will be too late to influence the quality of the housing stock through influencing the quality of a limited volume of new build. Retrofitting the existing housing stock will be a much more expensive option.

7.7 Conclusions

- In an ideal world one economic instrument would be used to achieve one objective. Using multiple economic instruments to target a single objective is likely to be inefficient and to raise the cost of meeting the objective. However, because of information deficiencies or other constraints it may sometimes be necessary to use additional instruments. It is important that the potential costs of using multiple instruments to target a single basic environmental objective are considered before deciding on the use of additional policy instruments.
- The single most pressing environmental issue facing energy policymakers is the problem of global warming. Ireland is committed to taking action to reduce emissions as part of the EU.
- The EU emissions trading scheme, if suitably reformed, should provide an appropriate instrument for implementing the Kyoto agreement. However, as currently implemented by the EU it has some serious defects.
- The emissions trading scheme needs to be reformed to mandate the auctioning of the bulk of permits in the period

from 2008 onwards. Failure to do so will distort the electricity market, it will reduce the environmental effectiveness of the measure and it will substantially raise the cost of meeting the environmental objective. Finally, as currently implemented the emissions trading regime discriminates against renewable energy.

- The current arrangements with Bord na Móna should be revised to allow for the gradual replacement of peat by wood biomass as the fuel in the three new "peat-fired" power stations. The best alternative from the environmental point of view would be to close these new stations immediately.
- A properly designed emissions trading regime should generally provide the appropriate incentive to develop renewable electricity. Under such a regime special treatment of renewables would only be appropriate in so far as it was required to incentivise research and development. However, the current emissions trading regime discriminates against renewables and it may be necessary to offset this defect through a continuing special support regime. Any such regime must properly reflect the true costs and benefits to society of the different types of renewable energy.
- For sectors not covered by emissions trading it will be important to introduce a carbon tax. Without such a tax there is a danger that Ireland will either fail to reduce its emissions by the required amount or else it will do so at undue cost, placing most of the burden on the electricity generation sector.
- Tackling the rapid growth in emissions in transport will require special measures including the application by the EU of mandatory fuel efficiency standards for new motor vehicles. A move away from charging high tax rates on fuel to charging for use of road space could simultaneously reduce congestion, which has a high cost, and also reduce emissions. In the long run policy will need to focus more on developing sustainable cities and more energy efficient dwellings.

8. ENERGY EFFICIENCY AND FUEL POVERTY

8.1 Introduction

Ireland's expected overshoot of its Kyoto target for emissions reduction could be halved by a mere 10 per cent improvement in average energy efficiency.[86] A figure of 10 per cent is instanced simply to show that widespread small improvements in energy efficiency could significantly help Ireland to achieve its commitment on Greenhouse Gases.

Energy efficiency, however, does not have the attraction for investors compared to that of renewables and new technology. Energy conservation or 'negawatts' do not have the same allure as windmills. Yet opting for negawatts can be cheaper and environmentally superior, requiring less subsidies, fewer resources and having less impact on landscapes and biodiversity. When everything is counted in, energy efficiency can be a better investment. The more worthwhile opportunities for energy saving have a modest net cost when lifetime calculations are made, some can be costless and some advantageous even in private cost terms as will be discussed. Taking external costs into account improves their viability further. Given these opportunities, what should be the role of energy policy in relation to energy efficiency?

The role to date, in broad terms, has been to seek out worthwhile energy efficiency opportunities and, failing spontaneous take-up by the public for whatever reason, to direct policy to encourage or impose their exploitation. This chapter looks at strategies within this context, while mindful that unpaid-for costs of external environmental damage underlie the problem. The damage in question includes all the well-documented negative side-effects of energy combustion, in addition to climate change (EPA, 2004, Chapters 14 and 15).

Before proceeding, a brief definition of energy efficiency is required. Energy efficiency is achieved if the purposes of the energy use, be they lighting, motive power, warmth and the like, are

[86] ICF and Byrne Ó Cléirigh (with ESRI), 2004. In terms of million tonnes of CO_2 equivalent of Greenhouse Gases, emissions in 1990 were 53.4 and the Kyoto target for 2008-2012 is 60.4. The currently projected annual outcome in the target period is 69.5, giving an overshoot of 9.1. Energy's part of the projected outcome is 53.8 so that a pro rata 10 per cent saving on projected energy (ignoring carbon intensity) would cut the overshoot by 5.4, which is a reduction of more than half in the overshoot.

supplied at minimum cost in terms of resources. The resources in question should comprise all those that have a value, including such environmental resources as urban air quality and the now-tightening assimilative capacity of the atmosphere. Improvements to energy efficiency can come about through investments. The investments can be of many kinds ranging from investments of time to learn about one's energy use and modify one's behaviour, to investments in equipment and in infrastructure, and to investment in development that takes the effects of location fully into account. Results of investments take time to materialise though in some cases the time can be quite short.

The three main generic policy options available to policymakers are kept in mind, namely, education/exhortation, regulations, and economic instruments, including their variants and combinations. The discussion proceeds as follows. The next section sketches efficiency in its historic context and outlines its potential. There follows Section 8.3 that summarises current policies aimed at promoting energy efficiency and conservation. The chapter proceeds by outlining a selection of pertinent research results under two headings: Section 8.4 on the residential sector and Section 8.5 on the industrial and public sectors.[87] Section 8.6 considers briefly the issue of fuel poverty. The concluding section, 8.7 evaluates the directions of policies on energy efficiency that are suggested by this chapter.

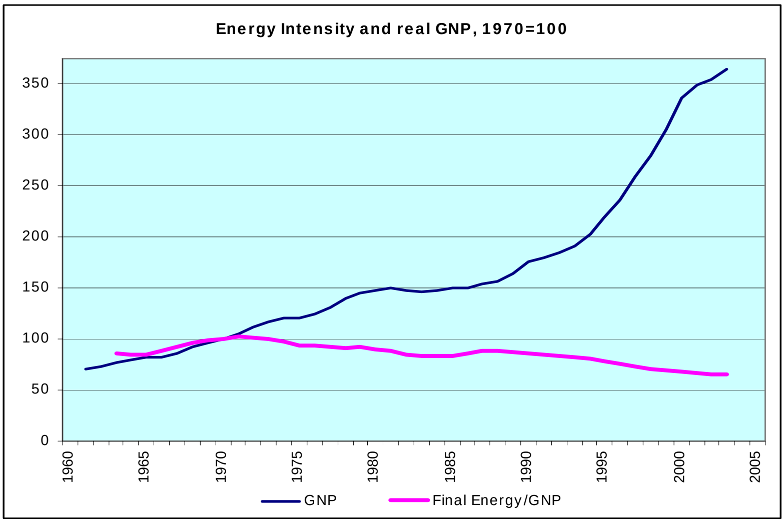
8.2 Efficiency in Context – Historic and Potential

HISTORIC

Given the long-run nature of the challenge posed by global warming and the time it takes for the energy-use effects of investments and infrastructure to materialise, sketching past movements in efficiency is informative. Ideally in looking at trends in energy efficiency one would look at the disaggregated uses of energy, such as areas heated or passenger miles travelled. One would then see how the technical improvements have improved efficiency, separate from the effects of shifts in activity as some sectors grow faster than others and final uses and preferences alter. In the absence of such information it is worth viewing the record of energy intensity in national terms. Without a more detailed decomposition, energy intensity is a useful proxy for the inverse of energy efficiency, provided that the shifts are noted. Figure 8.1 shows energy intensity of GNP since the early sixties. Energy intensity is expressed in terms of final energy divided by GNP – that is, it omits the energy used in producing final energy, so that the large efficiency gains by electricity generation are not factored in.

[87] The transport sector is not covered here. Studies laying out issues in transport include *Redirecting Transport Taxes* (Scott, 1998) and *Study of the Environmental Implications of Irish Transport Growth and of Related Sustainable Policies and Measures* (Department of Public Enterprise and CIE, 1999) and *Review of Transport Infrastructure Investment Needs* (CSF, 1999).

Figure 8.1: Energy Intensity, 1970=100



Note: Energy intensity is measured as Final Energy consumption divided by real GNP and a 3-year moving average is used (placed in year 3) owing to short-term variation in energy figures, especially in the earlier years when fuel stock changes were difficult to separate from figures for consumption.

The first noteworthy point to emerge from the graph is the remarkable decline in energy intensity since its peak just before the OPEC energy price hike of 1973. Energy prices had been falling in real terms prior to the price hike and this decline in energy intensity after the price hike was also widely observed in other countries.[88] The price increase, which provoked unease about security of supply, stimulated the investigation and installation of energy efficiency measures and alternatives. Energy intensity declined but, as the pressure eased and general inflation caused energy prices to fall in real terms, the decline in energy intensity slackened and even reversed momentarily in 1978. Energy intensity returned to its downward path after the second OPEC price rise which occurred in 1979.

Through much of the 1980s, real energy prices declined again and the economy stagnated in the face of internal and external imbalances. Encouraged by the slump in world energy prices in 1986, energy intensity started to rise again.

Turning to the steady decline in energy intensity during the 1990s, this can be attributed to a number of factors. Price was in fact not conducive to energy efficiency, in so far as price generally continued to decline in real terms. Had it been conducive the result could have been very powerful owing to the investment drive that took place. The overwhelming factors were structural change in the economy, which saw the rapid growth of the service sector, and

[88] The International Energy Agency (2002) describes how there has been a 38 per cent decline in energy intensity (total final consumption/GDP of OECD countries) since 1973, driven by improvements in end-use energy efficiency and by shifts in economic structure and consumer behaviour.

strong investment in equipment imported from countries where the drive towards improvements in energy efficiency impacted on the technology they developed. Other factors were increased penetration of natural gas, which is more efficient in use than the solid fuels, and the introduction of Integrated Pollution Control licensing. There was also some increased awareness of environmental and energy issues due to high profile events during the1990s, such as the Rio Declaration of June 1992, the coming into force of the United Nations Framework Convention on Climate Change (UNFCCC) in March 1994, the adoption of the Kyoto Protocol in December 1997 and the EU share-out of targets in the EU's burden-sharing agreement of June 1998. The Irish Energy Centre (pre-cursor of Sustainable Energy Ireland or SEI) had a variety of schemes in place, such as the initiatives in hospitals and public sector buildings (Lawlor, 1998), the steam boiler schemes,[89] and public awareness campaigns. Schemes were funded under the Sub-Programme on Energy Efficiency in the *Operational Programme for Economic Infrastructure 1994-1999,* with EU-supported funding of £34 million over the period.

For recent years the graph suggests rather modest improvements in energy intensity. By contrast the dramatic decoupling between energy-related carbon dioxide emissions and economic growth since 2001, noted in the recent release of *Energy in Ireland 1990-2003* (SEI, 2005a, page 9), does not so much reflect efficiency improvements in final energy consumption as the use of less carbon intensive fuels, especially the introduction of high efficiency gas-burning electricity power plant in 2002 and 2003. The move is one of the actions presaged in the Climate Change Strategy.

This overview of energy intensity illustrates the importance of remembering that there are many factors playing a role in the evolution of energy intensity, as demonstrated by results of econometric studies of energy over the last few decades. These studies have told a consistent story that while energy consumption is closely bound to economic growth, it is also being influenced by changes in the shares of sectors, by fuel availability and advances in technology and by price (Scott, 1980; Conniffe and Scott, 1990; Scott, 1991; Conniffe *et al.,* 1997; Fitz Gerald *et al.,* 2002; Bergin *et al.,* 2004). The effect of price is perhaps not so noticeable immediately but is likely to occur after a time lag. In addition the manner in which price rises encourage technological development is likened to a ratchet effect in that advances in technology are not unlearnt, so that improvements encouraged by price hikes can persist systemically (Conniffe, 1993).

[89] The *Steam Boiler System Evaluation Scheme* ran from 1997 to 2000 and targeted the 420 largest operators. One in seven had an audit completed, which identified average fuel savings of 9.5 per cent with half of these achievable at low cost, i.e. with a payback period of less than six months. This indicates that worthwhile savings exist and, importantly, that there is much variation according to individual circumstances.

POTENTIAL

There is wide variation in the potential for energy efficiency in individual applications, though there may be some exaggeration of stated benefits when hidden costs are included. Nevertheless, there are significant profitable opportunities for investment in private terms. If external costs are taken into account the potential is improved of course.

The Intergovernmental Panel on Climate Change (IPCC, 2001) pointed to the potential options where benefits in terms of reduced energy costs and local and regional pollutants would be at least as great as the costs of the required investment. These would be termed 'no-regrets' actions because even in the event of global warming not being a threat they would still be worthwhile.

The UK's Best Practice Programme, now run by the Carbon Trust,[90] which identifies good investments in energy efficiency, states:

> The Carbon Trust has worked with thousands of companies to identify savings of 10 per cent – 30 per cent of their energy bills. The recommended measures include many NO and LOW cost actions that pay for themselves immediately or within a few months.

On the question of scope for savings and the value of savings the Trust states:

> A 20 per cent saving in energy consumption – realistically achievable by most businesses – can have the same positive effect as a 5 per cent increase in sales.

Of the options for mitigating CO_2 release, ranging from wind power to Combined Heat and Power (CHP) to building efficiency, it is claimed that energy efficiency initiatives in the EU with respect to major refurbishment programmes and new build, using existing and proven technology, are amongst the most cost-effective measures available to policymakers (CALEB, 1999). The best option is collective refurbishment and new building, with a positive lifetime saving net of investment. Their calculations are based on an 8 per cent discount rate. The incorporation of lifetime savings gives more positive results than would be obtained by the short payback rule of thumb that is usually employed in private calculation, but this is counter-balanced to some extent by the quite high discount rate in real terms that is employed.[91]

[90] www.thecarbontrust.co.uk

[91] The results are presented graphically as 'cost per tonne of CO_2 saved annually' in ascending order against 'ascending cumulative annual tonnes of CO_2 saved'. This type of analysis provides a sound basis for selecting and prioritising energy efficiency measures and could usefully be replicated on an annual basis covering all reasonable CO_2 abatement options in Ireland, rather than calculated *ad hoc* as in Conniffe *et al.,* (1997) p. 48, ERM (1998) pp. 13-14 and reproduced in *Sustainable Energy* (1999).

The preamble to a proposed EU Directive on "energy end-use efficiency and energy services" reports that energy consumption is potentially about 20 per cent higher than can be justified on economic grounds (CEC, 2003). The recent Green Paper that aims to stimulate debate on the topic, "Energy Efficiency or Doing More With Less", says that saving 20 per cent on energy consumption by 2020 would allow the EU to save an estimated €60 billion on its annual energy bill (CEC, 2005). It was estimated that the average cost in many Member States of investment in saving a unit of off-peak electricity in the domestic sector works out at around 2.6 cents/kWh. This is compared to the average off-peak price for delivered electricity of 3.9 cents (the average on-peak price is 10.2 cents/kWh). Similar cost advantages to be derived from investment in energy saving exist for the other energy carriers. It was also proposed that instead of dealing merely with the sale of energy, suppliers should be encouraged to offer a certain level of 'energy services'. If the suppliers sold energy services, examples being:

- Indoor thermal comfort.
- Lighting comfort.
- Hot water.
- Transportation.
- Product manufacturing.

they would compete among themselves to provide end-use energy services more cheaply through enhanced efficiency. For example, if annual lighting services were sold by different companies and priced in euro per square metre, or thermal comfort, or hot water priced in euro per cubic metre, the suppliers would compete through the efficiency of equipment, maintenance and fuels. The idea then is that the reform of the energy market should promote competition not only between different energy sources, as at present, but also between investments in energy end-use efficiency, on the one hand, and investments in energy supply, on the other.

Other estimates of savings potential are cited in the proposal for the directive and in the Green Paper. Due to the many market barriers and market imperfections that still exist, there is said to be economic potential in the form of unrealised energy savings for industry of approximately 17 per cent of current final consumption, realisable by 2010. For the domestic and tertiary sector, the estimate is 22 per cent and for transport 14 per cent, excluding modal shifts. These are generally economically viable savings. By contrast the technical potential for savings is put at about 40 per cent, obviously higher than the economic potential.

Turning to the academic literature, the study by Brown *et al.* (2001), analysed "hundreds of technologies and approximately 50 policies" that can significantly reduce carbon emissions and inefficiencies in energy production and end-use systems at essentially no net cost to the US economy. They concluded that over time energy bill savings could pay for the required investments.

This brief summary indicates that there is good potential for improved energy efficiency. This could probably be the case at any time, given the ingenuity of the human race, but funding for development of energy efficiency technologies over the past decade has probably enhanced the potential. The recent decline in energy intensity in Ireland has been fairly steady but not strong. Leaving aside the efficiency gains in electricity generation, the decrease in final energy intensity recorded in the 5 years since 1998, at 7.7 per cent, represents an annual reduction of 1.6 per cent. In the context of the baseline or 'business as usual' assumption in ICF *et al.* (*op. cit.*) of a 2 per cent per annum decline in energy intensity of GNP, recent performance is relatively modest.

It can be noted at this stage that, setting aside a few energy intensive sectors of the economy, the share of energy in total expenditure is not large. Users are unlikely to be readily aware of how much they are consuming at any given moment or in any particular use. On average, household expenditure on home fuels and on transport fuels is 3.8 per cent and 3.5 per cent of disposable income, respectively. Expenditure by industry on fuel and power averages some 2.1 per cent of its expenditure on all "industrial inputs". Leaving aside the energy intensive sectors it would appear that most people do not become exercised about energy efficiency. By contrast, new energy technologies and renewables on the other hand enjoy connotations of innovation and adventure.

8.3 Current Policy on Energy Efficiency

Ireland's policy on energy efficiency has been spelt out in a series of documents over the last decade. The task facing the policymaker is to incentivise action on the part of energy 'managers' and purchasers in all sectors and to introduce measures to achieve this. The main official policy documents have been:

1997 Sustainable Development – A Strategy for Ireland (Government of Ireland).

1999 Green Paper on Sustainable Energy (Department of Public Enterprise).

1999 The National Development Plan 2000-2006, Operational Programme for Economic and Social Infrastructure (Government of Ireland).

2000 National Climate Change Strategy – Ireland (Department of the Environment & Local Government)

2002 The National Spatial Strategy (Department of the Environment, Heritage and Local Government).

These policy documents are now outlined under the three main policy mechanisms listed above.

(a) INFORMATION/EXHORTATION

The provision of information has been central to policy on energy efficiency. *Sustainable Development* stated that the Irish Energy Centre will continue to develop, and that its work will include "promoting energy efficiency in industry, the provision of technical advice, and information campaigns and support measures".

The *National Climate Change Strategy* fleshed out an information strategy that was broadly based. The proposed measures addressed all major sectors through an appropriately wide variety of policy approaches. Education was highlighted, such as awareness programmes and energy efficiency rating of households.

The National Spatial Strategy, by way of exhortation, emphasised the importance particularly in urban areas of combining location of housing with good transport facilities. In relation to housing in rural areas the strategy provides guidance on the different policy responses appropriate to different circumstances, with a view to bringing people, employment and services closer together. It pointed out that this would mean better quality of life – less congestion, less long distance commuting, more regard to the quality of the environment and increased access to services.

The National Development Plan, in the Operational Programme for Economic and Social Infrastructure, included the Sustainable Energy priority which allocated €156 million for an intensified energy conservation and efficiency programme. This was to be spent:

1. on the newly named energy agency Sustainable Energy Ireland (SEI), the task of which is to prepare multi-annual programmes, with quantification of benefits and regular evaluation (30 per cent);
2. on R & D (24 per cent); and
3. on stimulation of energy efficiency awareness in relation to pre-1980 buildings and to develop an energy rating system to make energy performance explicit.

Sustainable Energy Ireland's mandate is to promote and assist environmentally and economically sustainable production, supply and use of energy, in support of government policy, across all sectors of the economy. It sees itself as having two main means of advancing these objectives, namely, by achieving more energy conservation and more renewable energy.

SEI is less of a grant-giving body than its predecessor, the Irish Energy Agency, rather promoting and encouraging the application of knowledge and research. A prerequisite of properly functioning markets is full information and SEI's role therefore can be viewed as filling this difficult and important gap. Its Annual Report for 2003 describes its programme, which consists of four main programmes of work dealing with energy conservation:

1. The built environment.
2. Customer services.
3. Industry and
4. Sustainable energy services.

An example of one of SEI's schemes is the Large Industry Energy Network (LIEN).[92] In this scheme SEI works in partnership with 80 or so major energy users. This is a voluntary scheme for companies who are committed to reducing their energy intensity. There is a structured approach to energy auditing and management, and firms present an annual statement of energy accounts. In 2002 these firms saved about 2 per cent on their energy expenditure. In the 7 years of the scheme's operation the energy intensity of the

[92] LIEN replaced the earlier Self Audit and Statement of Energy Accounts Scheme.

firms (the composition of which shifts somewhat from year-to-year) has decreased by about 1.8 per cent per year. The LIEN Annual Report for 2003 says that energy use avoided due to energy efficiency measures in 2003 was 123.6 GWh. This energy would have cost in the region of €5 million to €6 million had it not been saved, or an average of €65,000 to €75,000 per firm. It is probably fair to say that the measures were good investments from the firms' points of view, in the sense that the measures had positive net present values. The cost incurred by SEI in administering the schemes was but €0.12 million and the reduction in CO_2 was about 43.5 thousand tonnes, or under €3 per tonne, so that this looks like a reasonable return to the state as well as to the firm. However, there is the issue of whether some of these changes would have taken place even without the benefit of the scheme.

SEI's Public Sector initiative under the Built Environment programme has no figures of energy saving though, in the example quoted of a school building, the building's performance is said to be 20 per cent above best practice.

SEI's scheme of R&D on the House of Tomorrow addresses the fact that one-quarter of Ireland's energy related emissions of CO_2 are accounted for by the residential sector. A grant of €2,400 is awarded to houses designed to fulfil a target reduction of 20 per cent relative to the building regulations of 2002 (€5,000 for 40 per cent reduction) and these supports are based on an estimate of 50 per cent of the anticipated extra building costs. The Century Homes case-study aims to produce a 'Formula 1 House' using approximately 80 per cent less energy than houses built to 2002 building regulations. These schemes have usefully exposed a number of weaknesses in the home-building industry, namely, scepticism about demand for superior energy performance, difficulty in introducing new building systems, delays in certification of products and systems, scarcity of energy efficiency expertise, and lack of training and certification of systems installers.

Under various initiatives for improving energy efficiency in homes of low-income households, by 2003 over 6,000 homes had been improved. No figures are given, however, on the impacts on comfort levels and energy use.

Many other information schemes, not detailed here, are undertaken and the awareness raising, education and information roles are of fundamental importance. For example energy labelling of household goods, such as refrigerators and tumble-dryers, under the European Framework Directive 92/75/EEC, helps shoppers to buy machines that are economical to run.

Analysis of the outcomes of schemes in general, listed as number (1) of the National Development Plan's remit for SEI above, is central to efficient decision making, and needs to be taken more seriously.[93]

(b) REGULATIONS

Regulations have been widely introduced. Regulations relating to house building have been strengthened twice in the recent past. In 1996 Local Authorities had been requested to assign high priority to energy conservation in their housing programmes and housing stock. Work on the possibilities had been outlined and to a considerable extent energy conservation did not involve advanced technology (*Green Design: Sustainable Buildings,* Stationery Office, 1996).

In 1997 the Technical Guidance to the Building Regulations was strengthened (Stationery Office, 1997) to come into effect on 1 July 1998. This was expected to yield savings in the order of 5 per cent in energy used for space heating, according to *Sustainable Development*.

On transport, *Sustainable Development* stated that there would be closer co-ordination of transport and land use planning, the aim being to promote higher residential densities, particularly in redeveloping brown-field sites and in proximity to town centres, public transport nodes and access points.

Statutory Instruments are in force, covering minimum efficiency requirements for new hot water boilers and efficiency requirements for household appliances, under regulations that were transposed into Irish law during the late 1990s.

Meanwhile the *National Climate Change Strategy* (2000) announced that the technical standards in the 1997 Building Regulations, Part L Conservation of Energy and Fuel, would be adjusted and radically amended. It was foreseen that over the succeeding decade the number of dwellings would increase by at least 30 per cent and that therefore "appropriate insulation standards can achieve an impact on a very high proportion of the housing stock in a short space of time" (Fitz Gerald, 1999).

These changes, aiming at a 20 per cent reduction in fuel use, were applied to work on or after 1 January 2003. Although too late to impact on the large increase in the housing stock that had already occurred, these regulations are projected to reduce CO_2 emissions by 0.3 million tonnes by 2012.

Architects point also to the need for concern about design faults, workmanship during construction and the operational management of buildings (Stuart, 2004). Unless the owner or occupier, or some body representing them, is engaged by the issue of energy efficiency,

[93] Analyses should be available to the public and to other researchers. Despite requirements on Freedom of Information, studies in other important areas are often not readily available, such as the full reports on the environmental effects of transport growth (Department of Public Enterprise, 1999) and on costs and benefits of water infrastructure (Department of the Environment, Heritage and Local Government, 2004).

the outcome can be disappointing. To take an example from the UK, the Building Research Establishment recently released results of tests carried out on newly-built homes. It found that almost a third of new properties failed to achieve the air permeability level required by the regulations. Luxury homes tended to reveal more shortcomings than average. A telling finding was that most householders were unable to produce any documentation relating to the specific installed boiler, heating systems and controls, indicating an absence of persons in the home who would be in a position to 'take control' of their energy consumption.

It is not known to what extent the technical guidelines regarding energy efficiency in the building regulations are complied with here. There are three compliance mechanisms in place: The Building Control Authority (the Local Authority) is pressed by the Department to inspect 15 per cent of buildings and possibly 80 per cent of authorities meet that target. Second, any new building receiving support, such as stamp duty relief, needs a Certificate of Compliance from the Department. These cases indirectly require compliance with the building regulations, and most of these new buildings are inspected at some period. Third, at point of sale a Certificate of Compliance with building regulations as a whole is requested. These mechanisms focus more on fire and safety aspects, however.

To ensure compliance with energy efficiency regulations requires regular inspection *during* the building process, which would need to be resourced, as it is in some Nordic countries. The pressure for enforcement could logically come from house purchasers and such pressure would be forthcoming if they were truly engaged by the issue of energy efficiency. In its application to the High Court in 2001, the Office of the Director of Consumer Affairs obtained a judgment that certain house purchase contract terms were "unfair". The potentially relevant unfair term was that which gave substantial powers to the builder to rescind the contract and offer the premises for sale elsewhere if a consumer queries the quality of workmanship prior to completion of the transaction. The problem of inspection remains, however.

A system of Integrated Pollution Prevention and Control (IPPC) licensing came into effect in Ireland in 2004, replacing an earlier less comprehensive licensing system for bodies with significant polluting potential The primary aims of IPPC licensing are to prevent or reduce emissions to air, water and land, to reduce waste and to use energy efficiently. Consideration must be given to energy efficient techniques and practices and to the efficient use of raw materials, chemicals and water. Measures such as in-plant changes, process recycling and reuse, improved material handling and storage practices, must be employed to effect reduction in emissions. The extension of IPPC to the power generation sector means that all large-scale new and existing power generation plants (greater than 50 MW) are required to operate using the 'best available technology' (BAT). In the identification of best available technology, emphasis is placed on pollution prevention techniques, including cleaner techniques and waste minimisation, rather than end-of-pipe treatment. There is a list of activities that require a licence from the EPA. The list is quite wide-ranging and would include all those that are relatively energy intensive. Licences are enforced by the Office of Environmental Enforcement utilising a variety of surveillance mechanisms.

An analysis of the earlier licensing system points out that, unlike uniform regulation, integrated pollution control in principle takes into account the individual characteristics of the plant (Clinch and Kerins, 2002). Applying the principle of Best Available Technology Not Entailing Excessive Cost (BATNEEC) this system set out to balance the environmental benefit with the financial cost. The analysis found the environmental performance of the licensing system to be impressive, except in the case of greenhouse gases, which were not covered in the licensing process at the time. The costs incurred by firms, mainly in 1998, consisted largely of current expenditure. The reason for this was that the administrative work involved was considerable and the capital costs were small, as many firms were already compliant with the prior licensing system. The benefit-cost ratio was found to be more than 1.2 (in terms of private costs presumably) based on the 46 firms analysed. However, the disparity in costs per tonne of pollution was also calculated from a selection of firms for which data were available and disparities were found to be high. The authors suggest that the costs incurred were five times higher than the costs that would have been incurred if abatement expenditure per unit of pollution were equalised across these firms, a result closer to that of flexible mechanisms such as carbon taxes or tradable emissions permits. They show that the result is in line with similar findings by Tietenberg (1990) and it strengthens the argument for using flexible mechanisms. It is noted, however, that only a small number of firms were investigated and that a final judgement would need to consider the fact that damage costs can vary geographically, so that different abatement costs might be justified in some places.

(c) ECONOMIC INSTRUMENTS

Sustainable Development stated that "Ensuring sustainability in the long term will require the use of a range of measures to complement the regulatory approach" including the use of fiscal instruments. Endorsing this line, the International Energy Agency stated in its review of energy policies in Ireland that the government should:

> Develop a programme of energy efficiency measures…, which includes the use of pricing and mandatory regulations, and is based on quantitative analysis of possible cost-effectiveness. (IEA, 1999.)

The rationale for use of economic instruments and their particular suitability for energy efficiency was spelt out in the *Green Paper on Sustainable Energy.* It pointed to the fact that CO_2 abatement costs vary, meaning that energy conservation measures in some applications will be better than in others and the same applies to sectors. Policy should also encourage adoption of least cost measures first.

Economic instruments would thus be an essential element to achieve Kyoto targets. These would include a planned and steady rise in energy taxes, with mitigating measures for vulnerable households and sectors, and potential recycling of revenues to reduce other taxes or charges such as PRSI.

Other economic issues surrounding energy were discussed in *Sustainable Energy*. In particular it described (1) the need for monopolies (electricity, gas) to have associated regulation to encourage renewables and CHP and (2) the issue of under-provision of public goods such as Research and Development and information. Energy efficiency is encouraged by the availability of relevant information, but such information is difficult for individual consumers to come by; and (3) externalities in the form of unpriced damages and benefits means that they are not usually taken into account in decision making, and that "recognising the cost…of externalities… is closely related to ensuring sustainable development. In the absence of some mechanism that recognises the value of avoided emissions, this will lead to a level of consumption higher than that which is optimal." It added that " … it is also important for competitiveness to ensure that externalities are dealt with in the most cost-effective way to avoid unduly burdening the economy."

On the subject of grants, *Sustainable Energy* discussed the possibility of grants that were standardised in order to contain administrative costs, funded by a levy on all energy consumption. In determining the sources of funds, the 'polluter pays' principle should apply, so that costs of emissions are borne by energy consumers (p 158). Second, public funding should be available for those activities that have 'public good' characteristics.

There are some grants that are currently available. The *National Development Plan* under the *Social Infrastructure Operational Programme* provided €12.7 million for energy efficiency initiatives in public sector buildings.

On the topic of transport, as mentioned, *Sustainable Energy* recognised that measures related to land use planning and transport development should be an immediate focus of attention. A broad range of short-term recommendations was put forward; along with economic polices that included road charging and development of infrastructure in the long term. The *National Climate Change Strategy* included the provision of incentives and disincentives (such as rebalancing of motor taxes), and public investment and activities at the level of Local Authorities (such as investment in suburban buses and waste management).

The *Climate Change Strategy,* in addition, proposed emissions trading for the enterprises that are responsible for large quantities of emissions. Finally, and for the first time a 'cross-sectoral' carbon tax was proposed for introduction in 2002 on a phased and incremental basis. This proposal was endorsed by bodies with an important role in the strategy. The EPA's *State of the Environment* report for 2004 described the use of appropriate fiscal instruments as a 'key component of the NCCS' (page 246). SEI's Annual Report for 2003 lists instruments to encourage energy efficiency and in first place is "price signals", via an emissions trading scheme and a carbon tax, adding "… without such price signals, it is very difficult for any other policy instrument combination to succeed."

Success also depends on the manner of introduction. The environmental tax reform aspect needs to be highlighted – the rise imposed in one payment allowing a decline in some other payment such as taxes on labour. The amount paid in environmental tax is then seen to be recycled as a reduction in some other tax. This would differ from the manner in which income taxes were reduced and bin charges were introduced, for example, where the link between the two was unfortunately not made explicit by the policymaker. There would be losers but these would be the large energy users. Amongst industrial sectors, losers would be high energy and low labour users such as manufacture of metals. Gainers would be, for example, the Credit and Insurance Services sector and the Building and Construction sector, because like most of industry they use more labour than energy.

As of now the introduction of the carbon tax has been abandoned, out of concern for "… some adverse economic and social effects that would not be fully dealt with by compensatory measures" and having regard also to the recent increases in the international oil price (Minister for Finance, 10 September 2004).

Meanwhile the UK government have released an independent evaluation of the effects of the Climate Change Levy since its announcement in the Budget of 1999 and introduction in April 2001. The main conclusions are that the levy is expected to deliver 3.5 as opposed to the original estimate of 2 million tonnes of carbon reduction in 2010. It also concludes that there was an "announcement effect" that brought about a 1.2 per cent reduction in energy demand in 2000 in the commercial and public sector. Third, because renewables and CHP (combined heat and power) are exempt from the levy and therefore enjoy a comparative advantage, the increase in CHP capacity by 2010 due to the levy is estimated at 1.2 gigawatts (HM Treasury, 2005; Cambridge Econometrics, 2005).

CURRENT POLICY DEVELOPMENTS

The main energy saving policy due for adoption is the *Energy Performance of Buildings Directive.* The Directive will apply to almost all buildings, residential and non-residential, both new and existing. Member States are allowed to exempt certain categories of buildings, such as buildings of historical or architectural importance, religious buildings, and buildings of low occupancy or size. The requirements of the Directive are outlined in Box 8.1

Probably the best-known requirement is item 5, i.e. the mandatory provision of energy certificates or labels to prospective purchasers of buildings or tenants. This is set to have high visibility and to have an impact on the property sector. A rough estimate suggests that in Ireland over 100,000 sale or rental transactions per year will be affected (SEI, 2004).

The concept of "energy rating" of buildings has been in operation on a voluntary basis for several years in Ireland and other EU countries, most notably Denmark, and was signalled in the *National Climate Change Strategy* in 2000. But as well as being mandatory, the scope of the Directive is considerably wider.

Box 8.1: Energy Performance of Buildings Directive

The main provisions of the Directive are as follows:

1. It sets out a general framework methodology for calculating the energy performance of buildings. Provision is made for a review of this methodology.
2. It requires Member States to set minimum energy performance standards (both for new build and major refurbishment) using a methodology based upon the general framework methodology. These standards are to be reviewed regularly.
3. For new buildings over 1000m², the feasibility of alternative energy measures is to be considered.
4. For buildings over 1000m² undergoing renovation, energy performance is to be upgraded as far as is technically, functionally and economically feasible.
5. For almost all buildings, an Energy Performance Certificate (or energy rating) is to be supplied by the owner to a prospective buyer or tenant when constructed, sold or rented. This certificate may include a CO_2 indicator.
6. The Certificate is to be accompanied by recommendations for cost-effective improvements to energy performance. (However, there will be no legal obligation on vendors or prospective purchasers to carry out the recommended improvements).
7. For buildings of over 1000m² "occupied by public authorities and by institutions providing public services to a large number of persons", an energy certificate is to be posted in a prominent place.
8. Regular boiler inspection for particular classes of boiler or alternatively the provision of advice on best practice in boiler use and replacement. Inspection of large air-conditioning systems.
9. Assistance from the Commission for measures taken by Member States to provide information on heating systems and best use of energy in buildings.

www.sei.ie

The Directive will be transposed into national law on 4 January 2006, with an additional period of 3 years to apply fully the provisions on energy performance certificates and inspection of boilers and air-conditioning systems.

A major new policy is the proposal for the EU *Directive on energy end-use efficiency and energy services* and the subsequent green paper designed to launch debate (introduced above, CEC, 2005). The

European Commission proposed in December 2003 to improve the way in which energy is used to achieve its purposes, such as heating, lighting and motive power. The Commission also proposed to promote the market for energy services (sometimes called ESCOs or energy service companies). Mandatory targets and obligations were proposed, including annual energy end-use savings targets of 1 per cent, in absolute terms or compared to business-as-usual in the case of economic growth (1.5 per cent in the public sector). Other proposals in the directive include the creation of conditions for the development of a market for energy services and for the delivery of other energy efficiency measures to end users such as reader-friendly meters and energy bills as suggested by O'Malley *et al.* (2003). Apart from these worthwhile proposals to help overcome the problems of awareness and information, the targets would appear to be better achieved by less cumbersome means such as by carbon taxes or by extending and improving emissions trading.

The details in the proposed directive on energy efficiency and energy services are revealing. The need for a framework and procedure for defining and measuring the 'energy savings' and for agencies to oversee the framework, verify the savings and report the results achieved points to the fact that energy use is determined by millions of micro-decisions. Influencing these is made simpler when the underlying pricing problem is addressed.

Indeed the Green Paper on *Energy Efficiency or Doing More With Less* highlights the lack of appropriate incentives and financing mechanisms and lack of information. In its list of key actions that might be taken is a suggestion of "… improving taxation, to ensure that the polluter really pays, without however increasing overall tax levels." The Green Paper invites discussion on a number of pertinent questions, such as could the emissions trading mechanism be better harnessed to achieve energy efficiency.

8.4 Residential Sector

This section looks at lessons learnt from recent research. Several studies have been undertaken in Ireland on the subject of energy and the residential sector. Some of the relevant findings about energy efficiency yielded by this work are now outlined. Research papers in this field include studies on:

- Ownership of energy saving items in the home (Scott, 1997).
- Cost-benefit analysis of upgrading energy efficiency of the housing stock (Brophy *et al.,* 1999).
- The survey of housing quality (Watson and Williams, 2003).
- Energy consumption and low-income households (SEI, 2003; Scott and Eakins, 2004; Healy, 2004).
- Recent energy data (SEI, 2005a).

The study of energy-saving items was based on a survey undertaken in 1992 that ascertained the levels of ownership in a sample of some 1,200 households (Scott, 1993). The survey also recorded subjective respondents' opinions. Several predictions were confirmed.

The importance of education and income levels, which are linked, was underlined by this survey. People that did not have energy-saving items despite their being highly worthwhile, such as insulation of their hot water cylinders or lofts, tended to have only completed primary level education and to have low incomes. The level of education is also a useful indicator of the respondent's general knowledge and ability to use advice on energy conservation. Another important factor, namely, the ability to reap the benefits of one's investment was well demonstrated by the low level of energy saving items in private rented accommodation. Having a mortgage was another positive factor that could be indicative of potential access to credit, which in turn meant that households could make investments in energy efficiency. There being a reasonable level of potential saving to be reaped is associated with owning central heating, which was another significant variable associated with take-up. The costs in terms of the effort required to get round to obtaining the item, the 'transactions costs', were only limited deterrents. Perceptions too were important in that respondents generally had to feel that owning the item would save them money.

Overall the report pointed to the existence of reasonable levels of knowledge but that education in energy matters would improve ownership levels of energy efficiency items, as would the ability to reap the benefits of energy efficiency.

The cost-benefit analysis looked at the economics of upgrading houses to the energy efficiency standards in the 1997 building regulations. A 10-year programme was seen to have sizable net benefits, not only in reduced emissions but also in increased warmth and comfort for the inhabitants.

The Housing Quality survey obtained detailed information from a representative sample of over 40,000 householders on characteristics and problems of the dwelling, and on the household members. Information on the presence of insulation and other energy-saving measures was collected. One fact to emerge strongly was that the building had less energy-saving characteristics the older the dwelling. This reflects the improvements brought on by the building regulations and a low level of retrofit. The survey revealed too the low level of ownership of energy-saving items, especially of low-energy light bulbs, which stood at only 36 per cent of households. The ownership of hot-water cylinder insulation, at 78 per cent, also looks surprisingly low but the figure in fact also includes those not owning a cylinder, so that no clear-cut judgement can be made.

Turning to recent data, according to the SEI (2005a) report on *Energy in Ireland 1990-2003,* energy consumption per dwelling declined by only 2.3 per cent in all over the whole period from 1990 to 2003. Most of the reduction occurred in the early 1990s when more efficient fuels and appliances were supplanting open fires and back boilers. By contrast there was an increase in floor area of new houses starting in 1994 and in new flats starting in 1997, which would have slowed the decline in fuel consumption per dwelling. The 10 per cent decline in the real price of energy products in the consumer price index would also have discouraged energy conservation.

Electricity consumption per dwelling rose by 30 per cent over the 1990-2003 period, owing to the increased ownership of household appliances and external lighting. Despite this growth, with reduced carbon intensity of electricity generation from 2001 onwards and the above mentioned switch from open fires and back boilers, carbon dioxide emissions per dwelling, taking account of electricity generation, decreased by 3.9 per cent over the whole period.

In sum this indicates steady but very small improvements in household energy efficiency. These studies build up a picture that suggests that there is considerable scope for efficiency gains in the residential sector and that these could be encouraged by information, conviction that financial savings can be made and assistance with investment costs for low-income households.

8.5 Industrial and Public Sectors

This section reviews the findings of a research project that examined energy efficiency in selected private sector companies and public sector organisations in Ireland. The research sought in particular to identify what are the main barriers or obstacles to better energy efficiency in companies and public organisations. Full details of this research in Ireland can be found in O'Malley *et al.* (2003). In addition, comparable studies were carried out at the same time in the UK and Germany as well as in Ireland, and findings from all three countries are given in Sorrell *et al.* (2000); Sorrell *et al.* (2004).

The starting point for this research was the claim by many analysts that there are numerous unexploited opportunities for companies and other organisations to invest in measures that would improve their energy efficiency. Furthermore, it is claimed that investment in many of these measures would be cost-effective, meaning that there would be a good financial return from such investment. This raises the question why do organisations not take up these cost-effective opportunities to improve their energy efficiency. What are the *barriers* that impede them from doing so?

The claim that there are many cost-effective energy efficiency opportunities that are not being exploited arises particularly from technologically-oriented analysts who use engineering-economic models (Sorrell *et al.* 2004). Some of these analysts have suggested that the common neglect of such energy efficiency opportunities is caused by barriers, such as a shortage of capital or a lack of information, which prevent markets for energy and energy-using technologies from operating efficiently.

On the other hand, many economists claim that the markets for energy and energy-using technologies are broadly efficient. They suggest that if energy consumers do not invest in energy efficiency measures that are claimed to be cost-effective, then perhaps the real barriers lie in the fact that there are risks attached to these investments. Or perhaps there are "hidden costs" associated with the measures concerned, meaning costs that are not included in the engineering-economic models, such as the cost of management time required to identify and implement the measures or the cost of disruption to production. Thus, in this view it is questionable whether there really are many unexploited energy efficiency opportunities that are genuinely cost-effective, when all the enterprise's costs and risks are fully taken into account.

The study reported in O'Malley *et al.* (2003) examined these issues in the context of the Irish industrial and public sectors. It considered whether it is true that there are many opportunities for cost-effective energy efficiency investment that are being neglected. And it assessed the importance of a range of possible barriers to energy efficiency that have been suggested to explain why this happens.

To examine these issues, case studies were used from a variety of sectors. These case studies were drawn from the mechanical engineering, brewing and higher education sectors in Ireland. The mechanical engineering industry was selected as an example of light industry that has only low to average energy-intensity. The brewing industry was selected as an example of an industry with above-average energy-intensity. The higher education sector was selected as an example from the public sector; in this case energy-intensity is low to average but distinctive decision-making frameworks are in place and the availability of capital is constrained by public policy. A summary of findings from the case studies now follows.

EXISTENCE OF ENERGY EFFICIENCY OPPORTUNITIES

In considering the question whether many cost-effective opportunities to improve energy efficiency are being neglected, it is important to note the meaning of the term "cost-effective" in this context. Cost-effective here means that an investment in energy efficiency would have a significantly better rate of return than the cost of capital to the organisation, when one takes account of the readily quantifiable costs such as capital costs and energy costs (and therefore ignores any risks or "hidden costs" that could be difficult to measure).

The findings from the organisations in the three sectors studied indicate that there are many such cost-effective opportunities, in this sense, still available in most of the organisations concerned. A majority of interviewees in each of the three sectors agreed that there were many energy efficiency opportunities available in their organisations that would have quite short payback periods (namely 3 years, or 5 years in the case of brewing). Investments with such short payback periods would have a much higher rate of return than the cost of capital. Comparable research that was carried out on the same three sectors in the UK and Germany also concluded that there were many such unexploited opportunities to improve energy efficiency.

Companies in the brewing sector generally considered that there were fewer energy efficiency opportunities still available compared to those in the other two sectors. Since brewing is a more energy-intensive sector, which should cause it to pay more attention to energy efficiency, it is not surprising that the brewing industry would already have taken up more of the available energy-efficiency opportunities.

THE RELATIVE IMPORTANCE OF DIFFERENT BARRIERS TO ENERGY EFFICIENCY

A review of existing literature indicated that fifteen different barriers to energy efficiency were previously suggested as being potentially important. For each of the three case-study sectors, it was attempted as far as possible to rate the importance of each of these fifteen potential barriers. Table 8.2 shows that eight of the fifteen barriers were found to be of high importance in at least one of the three sectors.

Within the group of eight barriers that appear at least once in Table 8.2, two stand out as being particularly important, namely access to capital and hidden costs. These two are very important in all three of the sectors studied. Imperfect information is very important in two of the sectors, while the other five barriers are of high importance in one sector each. It is also worth noting that seven other potential barriers to energy efficiency were identified and considered, and although these are not included in Table 8.2, they are all of at least some importance in some sectors.

These findings from Ireland are similar in three significant respects to the results from comparable studies of the same sectors in the UK and Germany. First, access to capital and hidden costs were found to be the most important barriers in all three countries. Second, imperfect information was found to be commonly of high importance in the three countries. Third, although two or three types of barrier were of widespread importance across the three sectors, a substantial number of other types of barrier were also important in at least one sector.

Table 8.2: Barriers Considered to be of High Importance in the Different Sectors

Barrier	Mechanical Engineering	Brewing	Higher Education	Total
Access to capital	*	*	*	3
Hidden costs	*	*(1)	*	3(1)
Imperfect information	*		*	2
Split incentives			*	1
Principal-agent			*	1
Form of information, credibility & trust			*	1
Values & organisational culture	*			1
Power or status of energy management			*	1

Notes: * The asterisk means that the barrier is identified as being of high importance in this sector.
(1) Hidden costs can be of high importance for smaller brewing firms, but not for large firms.

It is noticeable in Table 8.2 that the number and range of barriers of high importance varies between sectors, with the widest range occurring in higher education and the narrowest occurring in brewing. It is perhaps not surprising that interviewees in the brewing industry perceived only one or two really important barriers to energy efficiency while those in the other sectors identified more, since this is probably a reflection of the fact that brewing is more energy-intensive. Since energy accounts for a larger part of total costs in brewing, the benefits that it can gain by investing in energy efficiency would amount to savings of a greater proportion of total costs than in the case of less energy-intensive sectors. Compared to these relatively large benefits in brewing, most potential barriers to energy efficiency in the other sectors would appear quite small to an energy manager in that industry, and it would not be considered worthwhile to undertake the effort and expense required to overcome such barriers. Consequently, a range of barriers that would be overcome in a more energy-intensive sector may appear sufficiently great to actually prevent investments in energy efficiency in less energy-intensive sectors, and hence such barriers would be rated as very important.

CAPITAL CONSTRAINTS

A strong general message from the research is the importance of *limited access to capital* as a barrier to energy efficiency. This can apply at two levels: (1) an overall limitation on access to capital for the organisation as a whole; and (2) restricted access to capital for energy efficiency within internal capital budgeting procedures. The result of either or both of these factors, from the perspective of those responsible for energy management, is that they lack sufficient capital to invest in energy efficiency improvements.

The limitation on access to capital tends to take different forms in the different sectors. In the higher education sector, there were overall constraints associated with public sector funding, especially in the Institutes of Technology, as well as internal budgeting constraints. But in mechanical engineering and brewing, the firms in principle have access to commercial capital markets. There was practically no evidence that the case study firms had difficulties in borrowing capital at reasonable rates – as would be the case if there were capital market failures. Instead, the restrictions on access to capital were largely self-imposed internally through a reluctance to take on additional borrowing. These self-imposed restrictions mainly took the form of applying tight payback criteria (typically payback periods of just a few years) when assessing proposed investment projects, including investments in energy efficiency as well as other investments.

There are a number of possible explanations for companies' use of such stringent investment criteria. For example, this could be a method of making some allowance for risk – whether business, financial or technical risk. It could be an attempt to deal with "principal-agent" control problems by ensuring that only very clearly cost-effective projects are undertaken. Or it could be a method of recovering some of the "hidden costs" such as the salary costs associated with energy management. Thus, firms' use of very stringent investment criteria could, in principle, be quite a rational reaction to factors such as risks, concerns about financial gearing, or hidden costs. On the other hand, such factors never seemed to be explicitly identified and put forward as a carefully considered basis for the application of very stringent investment criteria. Consequently, it seems that the use of tight investment criteria represents a rather crude and imprecise rule of thumb that may be partly, but not entirely, rational.

TIME CONSTRAINTS

A second strong general message from the research is the importance of management time constraints as a barrier to energy efficiency. The general importance of "hidden costs" as a barrier (Table 8.2) is primarily a reflection of the hidden costs that involve putting demands on management time. When it is claimed that certain energy efficiency investments would be cost-effective, such claims may not take full account of the cost of management time that would be required to put such investments into effect. But it can take significant amounts of time for managers to keep up to date with technical information, to identify energy efficiency opportunities and to implement energy efficiency projects. Many interviewees across the different sectors emphasised that there were many competing demands on their time. Thus, their time is valuable and it cannot be regarded as costless.

INDICATIONS FOR PUBLIC POLICY

The most widespread barriers to energy efficiency were identified as being: access to capital (in the private sector, specifically the use of very stringent payback criteria), and hidden costs (especially demands on management time). A feature of both of these barriers is that they may imply that organisations are behaving rationally in their own interest, at least to a certain extent, in allowing such barriers to deter them from investing in greater energy efficiency.

However, governments need to have a different perspective. The basic reason why governments should aim to improve energy efficiency is because of the need to reduce greenhouse gas emissions so as to combat undesirable climate change. If energy users cause environmental damage through greenhouse gas emissions, thereby imposing costs on society at large that are not reflected in a commensurate penalty or cost attached to the use of energy, this is a form of market failure. In this situation, there is a good case for policy intervention to improve energy efficiency and reduce energy consumption.

The importance of some types of barriers varies considerably across sectors or companies. Therefore, effective policy solutions need to address the differing circumstances of energy using sectors and organisations. It is unlikely that there will be a single best policy solution for all. Consequently, for each of the individual sectors studied by O'Malley *et al.* (2003), a range of possible policy recommendations was indicated.

At the same time, that report also pointed out that there are certain broad-based national-level policy approaches that can influence many sectors or even all sectors. For example, a carbon tax would tend to raise energy prices across the range of sectors. The Integrated Pollution Prevention and Control (IPPC) licensing system requires a range of important industries to use energy efficiently, as well as control their emissions of pollutants in general. These types of broad national policy measures are suited to addressing the two most pervasive barriers to energy efficiency, namely the access to capital barrier resulting from tight payback criteria, and the hidden costs barrier associated with management time. These types of measures would have the effect of increasing the incentive to invest in energy efficiency, while at the same time giving organisations cause to allocate more management time to energy efficiency matters.

The broad national-level policy measures such as carbon taxes could also assist in overcoming some of the other barriers at the same time. For example, such measures should increase the importance of the energy management function within organisations, thereby helping to overcome the barriers associated with values and organisational culture and the power or status of energy managers.

In addition to these broad national-level measures, O'Malley *et al.* (2003) also indicated in the individual sector studies how other more specific measures at sector or firm level could address other barriers to energy efficiency that arise. Sectors with low energy intensity can ill-afford management time to become experts on energy matters. Informative energy labelling, meters and bills as well as demonstration case studies and encouragement to undertake audits could be targeted at these enterprises. Their industry associations may be the best conduits for this task, and these associations may need help to focus their organisations. More energy intensive enterprises could be encouraged to avail of energy service companies (ESCOs), as is occurring now in the higher education sector, provided that ESCOs can gain trust and expand their activities into genuine energy efficiency, with appropriate contracts. It would also be useful to promote more widespread application of energy audits and of industry-specific or technology-specific guidelines, and calculations of benchmarks of energy use.

In addition in the public sector there is the issue of allowing energy managers to have discretion as to improvements in their energy technology. By contrast with the universities that had more control over their decisions, the Institutes of Technology would have difficulty making efficient investment decisions owing to the manner in which they were funded. Annual budgets and no realistic possibility of funding for energy saving items meant that energy use remained inefficient. The inadequate framework for funding has meant that efficient investment decisions could not be taken.

8.6 Fuel Poverty

Fuel poverty provides an extreme example of the energy efficiency problem. Most of the barriers to achieving energy efficiency, and affordability in particular, are stronger with fuel poverty. The 'merit good' aspect of fuel poverty alleviation has detracted attention from its broader economic aspects and the fact that fuel poverty alleviation can be well or badly addressed. Fuel poverty, or its potential aggravation, is also often cited as an important reason for not introducing carbon taxes,[94] out of concern for social effects.[95]

DEFINITION

Fuel poverty is the term used to describe the situation faced by low-income households who are unable to afford adequate home heating. In addition to facing the general problem of reduced ability to afford fuels, low-income households are caught three ways where fuel efficiency is concerned. The cheapest fuels at point of purchase are the solid fuels – apart, that is, from gas, which may not be available in their location. In terms of the "useful heat" that they produce however, such seemingly cheap fuels are relatively expensive. Second, these households are often stuck with equipment that can only use these solid fuels and they would face difficulty accessing funds to invest in equipment that would burn more efficient fuels. Third, their houses tend to be badly insulated and the problem of access to credit to invest in improving the building fabric applies again. Inadequate income underlies the problem but other factors play a role.

Despite improvements, due largely to new house building and to a small extent to upgrades, a national estimate of the number of households suffering fuel poverty stood at 226,000, according to a national household survey of Ireland undertaken in 2001 (Healy, 2004). These were the households that declared an inability to heat the home to an adequate temperature. The figure is somewhat less than that obtained by using the definition which classifies households as fuel-poor if they spend in excess of 10 per cent of disposable income on domestic energy requirements. The latter definition proposed by Boardman (1991) is also frequently used. The 226,000 households represent some 17 per cent of total households. Over a quarter of these fuel-poor households were estimated to be constantly unable to heat their home adequately, being caught in a persistent fuel poverty trap.

IMPLICATIONS

Apart from the unpleasantness of cold conditions, and the problems they pose to domestic life, including difficulty for school children carrying out homework for example, there are also clear health associations. Identifiable groups with high incidence of fuel poverty include the long-term ill and disabled, lone parents, households with four or more dependent children, local authority tenants, the unemployed, one-person households, the elderly and those who completed their education at primary level. It is the association

[94] Or, as in the UK, for exempting domestic fuels from VAT or again, later, exempting electricity in the application of the Climate Change Levy, to shield the fuel poor from electricity price rises.

[95] Another prominent reason given for not introducing carbon taxes is the effects on industrial competitiveness, which is the subject of a project called COMETR, currently underway for the European Commission (www2.dmu.dk/cometr/).

between fuel poverty and health that merits particular attention. The inability to heat the home adequately is associated with higher instances of poor health in the EU states analysed. While it would be incorrect to attribute this simply to fuel poverty, twice the level of poor health is reported among fuel-poor households. It was also found that the least energy efficient housing stocks tend to suffer from the highest levels of poor health (Healy, 2004).

In Ireland too, fuel-poor households report lower levels of health status and higher levels of poor or impaired health than other households. The fuel-poor households are up to four times as likely to suffer from specific chronic conditions. With respect to respiratory conditions in particular (other than asthma), 27.5 per cent of households in fuel poverty record such conditions, compared with 7.1 per cent of other households. Increased incidence is also found with arthritis and with chronic depression. These were subjective measures of health status. Using objective measures it was seen that the fuel poor are more likely to visit their GP regularly and to be admitted to hospital.

As stated, the associations of fuel poverty with health conditions do not point to fuel poverty being the cause of poor health. Rather, broad socio-economic circumstances are the cause, of which fuel poverty is an aspect.

A stronger message and further insights are gained when considering excess winter mortality. Excess winter mortality is defined as the surplus number of deaths occurring during December to March inclusive, compared to the average for non-winter seasons. Most countries experience higher mortality in winter, in a range of 5 to 30 per cent compared to the rest of the year. Excess winter mortality is found to be highest in Southern Europe, Ireland and the UK, ranging from 18 to 28 per cent. These are the countries with the mildest winters and poorest thermal efficiency standards in housing. Scandinavian and other north-European countries are relatively unaffected by the problem. The implication is that both income and housing play a role in people's ability to protect themselves in winter.

These associations suggest that excess winter deaths could be reduced through improved protection from the cold by means of better thermal standards alongside other improvements such as increased public spending on healthcare and better socio-economic circumstances. Healy concludes that, though his research did not prove causality,

> … improving the thermal efficiency of housing in southern and western Europe could play a strong role in reducing the large seasonal variations in mortality found in these countries.

Perhaps a measure of the lack of importance attached to the issue is the small amount of research afforded to examining the consequences for health, wellbeing and energy use of energy efficiency interventions by governments. The seeming absence of serious engagement here is exemplified by the lack of proper analysis of schemes. Such analysis requires that there be adequate assessment of the situation before as well as after the intervention. The Institute of Public Health in Ireland (2004) says that ideally the same persons should be engaged in the analysis of the situation before and after the intervention to ensure consistency. Their experience with evaluating a project dealing with rural fuel poverty in Northern Ireland, where they found that data relating prior to the project was inadequate for proper analysis, is a familiar case in point. Participating households in the Northern Ireland scheme receiving full upgrades numbered 65 and a further 225 households received lesser energy efficiency upgrades, and the scheme was based on community partnership which was an important factor in the scheme's success. The outcomes of the scheme showed increased satisfaction with the temperature in the home and a decrease in reported illness.[96]

POLICY

The issue of fuel poverty and thermal efficiency of fuel poor housing has received some attention in formulation of energy policy. However, it has been mainly viewed as an issue under the heading of social welfare, and domestic energy efficiency *per se* was seen to be a largely private issue. Indeed the likelihood that a sizeable share of any efficiency gain from thermal upgrades would be taken up in the form of higher indoor temperatures detracted from the value of implementing improvement schemes as a climate change strategy. This ignored the fact that, were the fuel poor to become better off, their fuel use would grow, with its inefficiency intact.

With regard to the efficiency of social policy, it was noted that state expenditure on fuel allowances should allow households flexibility as to fuel, which was duly introduced. The question also arose as to whether a better return on the state expenditure could be gained from thermal upgrades. Technically this was found to be the case (Scott, 1996) and the argument for home upgrades for the fuel poor, in terms of wellbeing and general economic efficiency, was found to be compelling.

Attention was paid to fuel poverty in the discussions on carbon taxes and in the *National Climate Change Strategy*. The strategy included increased enforcement of standards in private rented dwellings and tighter application of reliefs. It also pointed to strengthened government assisted schemes, operated by local authorities and Health Boards, to improve the housing conditions of those considered most at risk of fuel poverty, of local authority tenants (80 per cent of whom were on social welfare) and the elderly. Schemes included the Essential Repairs Grant Schemes and the Remedial Works Scheme. Increased funding was made available

[96] Expenditure by the National Health Service in Northern Ireland on cold related illnesses is assessed at £21 million per year (NEA, 2004).

to Energy Action, the body that provides insulation to homes of the needy and provides training on insulation.

Fuel poverty is now being addressed through SEI's Low Income Housing programme with funds disbursed under the Warmer Homes Scheme. The designated budget for the 2002 to 2006 period is €7.62 million (SEI, 2002). The programme focuses on installation of energy efficiency services in low-income households and on building up installation capacity, awareness and partnership, and is undertaken by community-based installer agencies. Over the period of the programme it is intended that 18,000 low-income households will benefit from improvements carried out on their homes. There are now eight community groups delivering thermal efficiency services and expenditure on the programme in 2004 amounted to about one million euro. SEI would like to see the programme accelerated (SEI, 2005b).

It is noted that SEI's call for proposals from community-based organisations to undertake installation of energy efficiency measures lists the tasks, which include the identification and surveying of target households, but does not indicate the integration of third-party collection of baseline and subsequent economic and important other information (www.sei.ie). This means that "before and after" economic analysis cannot be applied to indicate the effectiveness of the expenditure.

As described, the proposed carbon tax was abandoned out of concern for some adverse social effects " … that would not be fully dealt with by compensatory measures" (Minister for Finance, *op. cit.*). The decision did not seem to allow for the fact that the total revenues from the carbon tax would come to over six times the carbon tax paid by households in the entire lower half of the income distribution. This means that there would be good opportunities for compensating the vulnerable households, for house upgrades and additionally for advancing some of the other general anti-poverty measures, as advocated by Combat Poverty, or for enhancing the efficiency of the economy, as advocated by some economists (Bergin *et al.,* 2004).

One analysis found that with existing systems over 90 per cent of households in income deciles 1 to 5 could be targeted for carbon tax compensation through increases in fuel allowances and by reductions in income tax where this applies. Compensating all households on social welfare payments and reducing tax on low incomes, by an amount equal to the national average household carbon tax paid, would use but 21 per cent of the revenue from a carbon tax (Scott, 2004). It was suggested that some additional amounts of the revenue be used to help households adapt their homes and equipment and provide help-lines and domestic energy advice to those still losing out.

The Combat Poverty Agency made similar recommendations in its submission to the Department of Finance on the introduction of a carbon tax. The Agency also said that in addition to providing compensation, other revenues from the tax should be used to upgrade the energy efficiency of low-income homes. They added that remaining revenues should be used to raise general social welfare payments to work towards achieving the National Anti-Poverty Strategy target. Combat Poverty also viewed the carbon tax as an opportunity for a high-profile publicity campaign to improve take up of benefits (Combat Poverty Agency, 2003, 2004).

In a study for the UK, Dresner and Ekins (2004) find that the average result after compensation schemes conceals wide differences in net gains and losses, even though the compensated households are gainers on average. They find that some 20 per cent of the lowest decile would end up being net losers. Scott (2004) found a similar 16 per cent of targeted households in decile 1 in Ireland could be net losers, with 21 per cent of the carbon tax revenues used and no assistance to alter energy use.

In writing on the subject of compensation schemes to mitigate the effects of a carbon tax on the fuel poor, authors have emphasised the care that is needed to ensure that the issue is addressed seriously. This should not be interpreted to mean that mitigation through compensation topped up by improving energy efficiency in low-income homes is infeasible. As Healy (2004) states:

> In conclusion the carbon tax clearly presents challenges but also real opportunities to policymakers to improve the position of low-income homes.

RECOMMENDATIONS

Policy on fuel poverty needs to concentrate on the underlying problems of low incomes, on the thermal inefficiency of homes and energy-using equipment and on energy awareness. Healy found that over half of respondents lacking various energy-saving measures were unaware of the benefits or did not know of the existence of these measures. Trying to keep energy prices low because of the fuel poor has too often taken the place of action on improving social welfare take-up and other improvements, on thermal upgrades of homes and equipment, and on information.

Many countries have implemented grant schemes to low-income households (Denmark, Germany, Netherlands) or tax credits, which are more limited in their effectiveness (Denmark, Norway and the US). The main UK instrument employed by the *UK Fuel Poverty Strategy* (DTI, 2001) is the Warm Front programme – which is a replacement for an earlier home energy efficiency scheme. Operating as a capital assistance initiative, this scheme aims to end fuel poverty among vulnerable households as far as reasonably practicable by 2010. Funding of £251 million is envisaged in 2007-2008 to tackle fuel poverty. It is noted that the scheme has been criticised by the National Audit Office and the Public Accounts Committee for not being sufficiently targeted on the fuel poor (DEFRA, 2004), indicating the importance of careful co-ordination with social welfare services and indeed with the many organisations involved. But the schemes have been able to demonstrate appreciable improvements.

In sum, policy options for addressing fuel poverty include the same generic three, namely, information (on energy use and energy efficiency), regulations (on landlords and utilities), and economic instruments. The main economic instruments appropriate for fuel poverty are cash-based fuel allowances that might incorporate carbon-reducing incentives, and subsidised schemes for capital investment. The type of policy and manner in which schemes are applied can vary widely and studies, properly prepared before the schemes start up, could tell us how effective they are and what works best.

The elimination of fuel poverty plays a role in curbing emissions from the domestic sector, as the fuel poor tend to use the highest carbon-intensive fuels. The fuel poor could become increasingly marginalised as the rest of the population grows richer. Further, due to the expected price rises for fossil fuels due to market circumstances and the EU Emission Trading Scheme, measures to promote carbon and energy efficiency are all the more urgent.

8.7 Conclusions

This chapter has looked at energy efficiency in its historic context, at the potential for improved efficiency, at policy to date and at important pointers for policy that are highlighted by research.

The evidence indicated that energy use has many determinants and that the potential for raised energy efficiency is large in engineering terms. In economic terms the prospects are also good when all costs, including external damage costs, are taken into account. Evidence from various schemes and studies indicates that even without including the public benefits (externalities) there exists broad potential for private gain from investment in energy efficiency.

The barriers to energy efficiency are wide-ranging. The policies that Ireland has implemented so far are applied on a broad front with a large number of different schemes and approaches that are well-targeted. However, of the main generic policies available, namely, information policies, regulations and economic instruments, it is economic instruments that hold out most promise. They address the underlying problem that we over-pollute because we are not *directly* affected. Of the economic instruments, subsidies and, recently, limited emissions trading have been applied, but carbon taxes, arguably the best economic instrument, have been avoided (Helm, 2004, Parry, 2003). An unbalanced mix of policies has been employed.

Recommendations are made here to improve some of the information schemes. Regulations are becoming more extensive though it is the inadequate application of economic instruments that is at the root of some of the difficulties that regulations aim to address. As a consequence, existing schemes have had to operate without the benefit of a framework where correct costs helped to motivate energy managers.

More emphasis needs to be put on incentives. Without it policy on energy efficiency is still 'not for real' and the level of engagement by many people is low. The other two main policy tools, information and regulations, are quite comprehensively applied although improvements are still possible as suggested below.

In meeting the Kyoto requirements on greenhouse gases, policy on energy efficiency can learn from the rationale for government intervention in energy efficiency. The rationale includes the fact that the requisite information for efficient energy use is more effectively provided by experts and could be under-provided if left to individuals, and that a combination of regulations and price corrections (economic instruments) is needed to take external damage and its costs into consideration. The balance between regulations and price corrections should be informed by the extent of variation in abatement costs, the costs of bureaucracy, administration, supervision, verification and enforcement (which apply to regulations in particular). It has to consider how to deal with losers, the flexibility of the policy in the face of developments in technology and indeed the long-term encouragement to that development.

INFORMATION

Sustainable Energy Ireland has a useful broad programme that provides information targeted at many sectors. Improvements in the residential sector were seen to have been modest and an important area where information could be stepped up is the provision of advice to households. Research on house-building techniques is providing valuable information and there is some information for householders,[97] but enhanced advice that helps householders in the final hurdle of implementation of energy efficiency improvements would be valuable.

Meters that are more easily read and that provide helpful information, as with utility bills, are among the proposals in a directive currently under discussion. Energy is one of the few items where consumers usually cannot tell what they are using, in conflict with sound economic principles. The directive on the energy efficiency of buildings will require home energy rating. This could be helped by encouraging people to familiarise themselves with the important facts of their energy consumption, for example during energy awareness week, with such subjects as what is one's "usage in terms of kWh/sq metre or kWh/day" – of heating fuels and all fuels. At present SEI is not concentrating strongly on the domestic sector.

One of the most useful aids to energy efficiency, judging from the responses from businesses and public sector organisations, was to have relevant case studies. More case studies of investments in energy efficiency would help people to take the opportunities for improving efficiency themselves but this requires more emphasis on documenting the results of SEI schemes. People need convincing

[97] The "MyHome" information from the Carbon Trust www.thecarbontrust.co.uk in the UK is another practical example.

verified examples. Clearer statements of the lifetime or net present value of investments would help, with explicit statements to the effect that the investment cost has been taken into account.

SEI has a programme of research that informs both the public and its own approaches. The estimation of marginal abatement costs of different energy saving options, readily capable of translation into carbon reduction options, needs to be put on to a regular basis. These calculations would help to show how to apply policies to get the best results for the least national cost. They would be especially helpful in ranking policies that award subsidies to various types of carbon reduction.

REGULATIONS

While regulations and standards are vitally important they will prove totally ineffective unless there is adequate enforcement. There is little information about the extent to which new buildings comply with the building regulations. It is still difficult for purchasers of newly constructed buildings to ensure that they are being supplied an energy efficient building. The energy conservation aspect of the building regulations does not appear to have the resources for inspection required to ensure that it is adhered to. Even then it would help if house purchasers were engaged in the energy efficiency aspect of the house they are buying.

More flexibility appears to be needed as to the house building options. More emphasis should be placed on the training of personnel in the building sector, including heating system installers and design personnel.

Forthcoming legislation that will require house transactions to be accompanied by a Certificate of Energy Rating will increase the amount of attention paid to energy efficiency, provided that the scheme is implemented in such a way as to engage with the householder. For example, the suggestion for improvements to the dwelling that will be contained in the certificate should be accompanied by information on fuel reductions/money saved, derived from case studies.

The proposed EU directive on energy efficiency includes helpful actions on information and for promoting a market in energy services (heating, lighting and so forth).

ECONOMIC INSTRUMENTS

Economic instruments put a price on externalities. These instruments include grants and subsidies, taxes on carbon, fuels and on energy-using equipment, and tradable emissions permits. The Emissions Trading Scheme has recently come into play for large energy users.

With some exceptions, energy is not usually a major item of expenditure and is not likely to be given much consideration. Among the priorities that people face, reducing energy costs rarely feature highly. Studies of grant schemes operating in the past found that this had implications for policy, in that schemes offering small grants received low uptake, possibly because the time spent on reading details and on form-filling are real costs that lower the scheme's attractiveness. By contrast a generous grant scheme was over-subscribed, leading to criticism of wasteful use of public funds and deadweight: people were being grant-aided to do what they would want to do anyway, had they thought of it. The point to be drawn is that it is hard to raise the profile of energy and grants would have to be high to have much effect. A grant scheme requires taxes to be raised to fund it, which, unless raised on 'polluters', is unfair to those practicing good environmental behaviour.

Promotion of renewables as a higher priority than energy conservation such as energy-efficient building is sub-optimal, judging from other studies. Priorities for promotion should be the cheapest options on the marginal abatement cost schedule. In so far as renewables cause disruption to scenery and to other assets these are costs that need to be factored in.

Apart from direct subsidies, there are other economic instruments currently in operation that need to be investigated. A priority is to check for, and reform, taxes and fiscal provisions that operate on energy efficiency in a perverse way, in particular the relative taxes on fuels, inclusive of rebates.

The remaining economic instrument, a carbon tax, is a highly precise instrument. It would remove the need for policymakers to pick winning technologies. It would also reduce the need for calculations of marginal abatement costs to prioritise activities. The impact on low-incomes can be addressed by using part of the revenue for that purpose and there are various means of addressing competitiveness concerns.

Ireland's performance on energy efficiency suffers from being unbalanced, particularly in relation to economic instruments and in relation to the residential sector. Lessons from analyses at home and abroad are being learnt too slowly. Opportunities for introducing optimal policies at the crucial time before the start of the investment boom of the mid-1990s were lost and a more balanced policy is as urgent as ever.

9. SUMMARY AND CONCLUSIONS

The challenges facing those responsible for energy policy in Ireland are considerable, spanning a wide range of different areas and a number of difficult economic and organisational problems. This paper considers some of the key energy policy issues facing Ireland over the next decade suggesting how best they might be resolved by policy initiatives. We draw on a range of recent research in The Economic and Social Research Institute and elsewhere that has informed our understanding of how some of these knotty problems in the area of energy policy might best be addressed.

Looking to the future, the rapidly rising demand for energy due to the growth in the world economy is eroding the potential spare world oil and gas capacity. With limited prospects of new finds of fossil fuels over the coming decades it seems quite likely that real oil and gas prices will rise substantially in the longer term. In addition, the need to tackle the problem of global warming will also lead to increasing real prices for fossil fuels. Preparing for a world of much higher energy prices will require significant policy changes. This is the context in which energy policy is being formulated in Ireland.

Ireland does not have a natural advantage in the supply of energy, except in the area of renewable resources where, with the exception of onshore wind, the technologies are not today competitive. As a result, it would not be expected that very energy-intensive businesses would locate here. In order to ensure that increasingly expensive energy resources are allocated among users in an optimal manner it is essential that in all cases business and households should pay the full economic cost of energy: there should be no explicit or hidden subsidies, even if Irish costs are higher than among some competitor countries. However, every effort needs to be made to ensure that the energy required is delivered at minimum possible cost to both business and household customers.

OBJECTIVES OF ENERGY POLICY

The overall objective of the state in regulating the energy sector is to ensure the lowest possible cost of energy in the long term subject to supply being secure and subject to meeting the environmental constraints. In this paper we have adopted a simplified approach by assuming that energy policymakers will take as given certain environmental and security of supply standards and that, conditional on these standards, they will then aim to meet the nation's energy requirements at minimum cost. This avoids the problem of having to consider possible trade-offs or conflicts between these multiple objectives.

The need for state intervention in the energy sector arises for three reasons:

1. The presence of economies of scale in parts of the industry, which make competition difficult.
2. Energy is a vital ingredient of modern life and the state has an important role in ensuring a secure energy supply, including a secure supply of electricity.
3. The negative environmental externalities that arise from energy production and consumption (of which the most pressing is global warming) require state intervention to move the economy to a more sustainable path.

ENERGY NEEDS OF A GROWING ECONOMY

Ireland has seen exceptional economic growth over the last 15 years. However, the growth in energy demand has been much slower. For the future the rate of growth of the Irish economy is likely to slow (Bergin *et al.,* 2003), though still remaining more rapid that that of the EU generally. The growth in the demand for energy is likely to slow further. The two exceptions to this trend are the demand for energy from the transport sector and the demand for electricity.

Demand for energy use from transport is likely to continue to grow for the foreseeable future. While this will require a further increase in the supply of energy, even more important, it will pose significant congestion problems. The solution lies in moving Ireland towards a more sustainable model of development involving less congestion. This would, in turn, deliver significant benefits in terms of reduced energy use and emissions.

While the growth in demand for electricity is slower than that of GNP, it is still significant. This means that for Ireland to have a secure electricity supply, investment in electricity generation and electricity transmission infrastructure will be required for at least another decade. Significant additional investment will also be needed in transmission infrastructure in order to reap the benefits of an integrated all-island electricity market.

This need for new investment makes Ireland rather different from the rest of the EU where capacity is generally adequate. The cost of the new investment will have to be paid by consumers in Ireland over the next decade whereas in many other EU countries the cost of the necessary infrastructure has already been substantially paid off. Thus, policy measures to minimise the cost of financing infrastructural investment will be more important for consumers in Ireland than in much of the rest of the EU.

SECURITY OF SUPPLY

Ensuring a secure energy supply for the foreseeable future is of crucial importance for the health and economic welfare of the country. In the case of oil supplies there is limited action the government can take to ensure physical security. While very unlikely, physical interruption to supply would have grave consequences. In the very unlikely event of it happening it would affect all of the EU and an integrated response at EU level would offer the best chance of minimising disruption.

Over the coming decade Ireland is likely to become increasingly dependent on gas to supply its energy needs. In particular, by 2010 the bulk of electricity generation will depend on gas. This means that any physical interruption of gas supply could have very serious consequences. If such an interruption were to be sustained for more than a few days it could see the island of Ireland lose the bulk of its electricity supply with very serious consequences for the health and welfare of its citizens.

While the chances of a break in an undersea pipeline are very small, if such an event were to occur it would take some considerable time to repair. It is for this reason that the second gas pipeline to Scotland was of major importance to the energy security of this island. The provision of the second pipeline greatly reduces the probability of what was already a very unlikely event. However, the vast bulk of the island's gas supply still goes through a single onshore pipeline in Scotland. As a result, it is important that the supply of gas from the Corrib gas field is brought onshore as soon as possible to enhance the physical security of Irish energy supply. In addition, consideration should be given to strengthening the onshore gas transmission system in Scotland on which nearly all of Irish gas supplies currently depend.

Ireland, along with other developed economies, faces a much greater risk to its economy from sudden shocks to energy prices than it does from a possible interruption in physical supply. For example, even if there were major disruption in the Middle East, oil supplies would still be available – at a price. However, major price shocks could have serious economic consequences and the regulatory authorities need to consider how best to insure against such future shocks. A number of instruments can be used to provide such insurance: fuel diversity and financial instruments both have roles. The National Treasury Management Agency (NTMA) should consider whether the desirability of hedging against such risks should affect policy on the portfolio of the national pension fund. The regulatory authorities should ensure that consumers are aware of potential risks and that, where feasible, suitable instruments for hedging risk are available.

As the price of gas and oil are linked and are both likely to rise in real terms it is desirable to have some diversity in the source of electricity supplies. For example, undue reliance on gas could be limited through a levy on gas used in electricity generation with the proceeds of the levy returned to consumers. The need for some diversification would suggest awarding some premium to renewable energy over and above the market price. This paper provides a model for considering the trade off between risk and price in deciding on the appropriate fuel mix for electricity generation. Fuel diversity should be managed by using market instruments rather than by regulation. Research and Development in alternative energy sources will be important in securing the long-term security of energy supply for the island.

With the full integration of the island gas market consideration should be given to developing gas storage facilities either in the old Kinsale gas field or else in salt caverns near Belfast. At present it does not seem wise for the Irish authorities to specifically encourage facilities for the supply of Liquified Natural Gas. It should be left to market forces to determine if and when such a development should take place.

INTERCONNECTION AND THE GEOGRAPHY OF MARKETS

An all-island electricity market is likely to confer significant benefits on consumers, reducing the long-term cost of a reliable electricity supply below what it might otherwise be. To allow an integrated and efficient all-island electricity market to develop it is essential that there is adequate investment in electricity transmission to physically link the existing separate systems. It seems likely that a second interconnector between Ireland and Britain could produce significant benefits for electricity consumers on the island.

AN ALL-ISLAND ELECTRICITY MARKET

The structure proposed for the all-island electricity market by the two regulators seems likely to provide the best opportunity for securing a competitive supply of electricity for consumers on the island of Ireland over the next decade. The electricity pool into which all generators will sell their electricity, when combined with a suitable regime of capacity payments to electricity generators, should encourage supply at a minimum price. It should also increase the transparency of the regime making for cheaper and more effective regulation.

The cost of capital is a key ingredient in determining the final price of electricity for consumers. The capacity payments regime proposed by the regulators will play an important role in minimising risk for investors and reducing the cost of capital. Investors will know that they will get the bulk of their capital and non-fuel operating costs in the form of capacity payments if stations are available to generate and if they operate efficiently. This regime would provide the right signals for new investment, ensuring the provision of adequate electricity generation capacity at least cost. Nothing in this regime would prevent the electricity market of the island of Ireland being eventually integrated into a British Isles or a northwest European market by the end of the next decade. Under the new regime the regulators should insist on closure of uneconomic plant that is surplus to capacity requirements. For this market to operate it is important that the all-island market go ahead as planned in mid-2007.

MARKET STRUCTURE

The move to the new all-island market will make the electricity sector much more transparent. In the market (pool) each firm will offer to supply electricity at a pre-specified price. All firms will know that they will receive most of their capital and non-fuel operating costs from capacity payments As a result, in the auction to supply electricity to the pool each firm will bid in only their fuel costs. This will greatly facilitate the information flow to the regulator. The regulator will know the price bid by each station and will be able to check that price against the price of the fuel delivered to that station. This will facilitate the regulatory authority in its task of ensuring a level playing field for all market participants.

The research described in this paper indicates that the move to the all-island market will somewhat reduce the ESB's dominant position. In considering the economics of enhanced interconnection to Britain the value of such interconnection in enhancing competition on the island should also be taken into account. The growth in demand for electricity, with further new independent generation coming on-stream over the coming decade, will also reduce the ESB's market share. However, even after these changes the ESB will still be in a dominant position.

The operation of the new market structure is likely to encourage new investment in generation in segments of the market where the existing ESB plant is not very economical. This should see significant closure of ESB plant over the rest of the decade to be replaced by new plant, generally built by different operators. Together with enhanced interconnection to Britain, this should see the ESB's dominant position in the generation sector on this island substantially eroded by early in the next decade.

Finally, the ESB should sell between 500 MW and 1000 MW of plant over the period to 2010. If this happens, with the closure of uneconomic plant, the ESB could be allowed to replace some of the plant that will close. By early in the next decade this would achieve the necessary reduction in the ESB's dominant position.

It is important that the operator of the transmission system for the all-island market should be established on a basis independent of all other players. When this happens consideration should be given to transferring ownership of the transmission system in the Republic to ESB National Grid. Whoever owns the transmission system it will be important that that company would contract with other companies, including ESB, to maintain and develop the system, ensuring competitive pressure on costs. Where possible, ESB distribution and supply should also move to buying in services on a competitive basis. This is the model that was adopted by Bord Gáis Éireann in the late 1980s and it would make the cost structure of operators transparent, facilitating regulation.

THE ENVIRONMENT

In an ideal world one economic instrument would be used to achieve one objective. Using multiple economic instruments to target a single environmental objective is likely to be inefficient and to raise the cost of meeting the objective. However, because of information deficiencies or other constraints it may be necessary to use additional instruments. It is important that the potential costs of using multiple instruments to target a single basic environmental objective are considered before deciding on the use of additional policy instruments.

The single most pressing environmental issue facing energy policymakers is the problem of global warming. Ireland is committed to taking action to reduce emissions as part of the EU. The EU emissions trading scheme, if suitably reformed should provide an appropriate instrument for implementing Kyoto. However, as currently implemented by the EU it has very serious defects. A reform of the emissions trading scheme should require the bulk of permits to be auctioned from 2008 onwards. Failure to do so will distort the electricity market, it will reduce the environmental effectiveness of the measure and it will substantially raise the cost of meeting the environmental objective. Finally, as currently implemented the emissions trading regime discriminates against renewable energy.

The current arrangements with Bord na Móna should be revised to allow for the gradual replacement of peat by wood biomass as the fuel in the three new "peat-fired" power stations. If this is not possible the best alternative from the environmental point of view would be to close these new stations immediately.

A properly designed emissions trading regime should generally provide the appropriate incentive to develop renewable electricity. Under such a regime special treatment of renewables would only be appropriate in so far as it was required to incentivise research and development. However, the current emissions trading regime discriminates against renewables and it may be necessary to offset this defect through a continuing special support regime. Any such regime must properly reflect the true costs and benefits to society of the different types of renewable energy.

For sectors not covered by emissions trading it will be important to introduce a carbon tax. Without such a tax there is a danger that Ireland will either fail to reduce its emissions by the required amount or else it will do so at undue cost, placing most of the burden on the electricity generation sector.

Tackling the rapid growth in emissions in transport will require special measures including the application by the EU of mandatory fuel efficiency standards for new motor vehicles. A rationalisation of the tax rates on vehicles and fuel and introduction of charging for use of road space could simultaneously reduce congestion, which has a high cost, and also reduce emissions. In the long run policy will need to focus more on developing sustainable cities and more energy efficient dwellings.

ENERGY EFFICIENCY AND FUEL POVERTY

The last decade has seen significant improvement in the aggregate energy efficiency of the Irish economy. There has been a modest but steady decline in the energy intensity of GNP. Policies to promote energy efficiency have been directed mostly at the industrial, commercial and institutional sectors and at promoting renewable energy. Energy conservation in transport and by households has been relatively neglected.

Of the main policies for overcoming barriers to energy efficiency provision of information, regulations and economic instruments – economic instruments have been least used. Inefficient subsidies have been granted and emissions trading has begun for energy intensive industrial sectors. However, without targeted policies for improvements in energy efficiency, the result will be patchy and fall short of its potential. Regulation has been the policy most widely employed, but late adoption of energy efficiency standards in buildings, difficulties in ensuring compliance, lack of engagement in energy efficiency by customers and users, and disparities in abatement costs, mean that potential benefits are foregone.

Application of economic instruments, such as a carbon tax, is needed. However, in view of recent energy price rises a sensitive approach is needed. Economic instruments would reinforce the benefits and reduce the shortcomings of regulations and would encourage the take-up of energy efficiency advice. Increased information is needed on examples of energy conservation that can be directly replicated, and on how to access expertise and overcome the final hurdle to implementation. The economic benefits of Sustainable Energy Ireland's energy saving schemes needs more quantification.

Fuel poverty is the inability to heat one's home adequately. It is a significant contributor to overall poverty requiring special measures to enable households to break out of the spiral of inefficient houses, equipment and fuels. Ireland's winter mortality compared to that in the rest of the year is high and it is associated with fuel poverty and poor insulation. Fuel poverty is an important energy and economic issue because of the inefficiency involved. Tackling the thermal performance of dwellings occupied by low-income households would greatly reduce or remove the problem of fuel poverty as a barrier to the introduction of carbon taxes.

A major upgrade of policy on fuel poverty is needed and should be focused primarily on improving buildings and equipment, combined with education and other supports to efficient behaviour and with properly prepared policy evaluation. Fuel poverty should not be seen as a reason for avoiding carbon taxes, but rather carbon taxes should be viewed as a reason and an opportunity for extra funding for policies to tackle fuel poverty. The current very substantial energy price rise necessitates action in any event.

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APPENDIX 1. GLOSSARY OF TERMS

AER	Alternative Energy Requirement/Regime
AIP/M	All-Island Project/Market
BGE	Bord Gais Éireann
BNE	Best New Entrant
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CER	Commission for Energy Regulation
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DCMNR	Department of Communications, Marine and Natural Resources
DTI	Department of Trade and Industry
DSO	Distribution System Operator
EPA	Environment Protection Agency
ESB	Electricity Supply Board
ESBNG	ESB National Grid – renamed Eirgrid
ETS	Emissions Trading Scheme
FGD	Flue-gas desulphurisation (for coal burning plant)
GB	Great Britain
HHI	Herfindahl-Hirschman Index
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
MW	Mega Watt (measure of generation capacity)
MWh	Mega Watt hour (measure of electricity)
NAP	National Allocation Plan
NESC	National Economic and Social Council
NI	Northern Ireland
NIAER	Northern Ireland Authority for Energy Regulation
NIE	Northern Ireland Electricity
NPRF	National Pension Reserve Fund
OCGT	Open Cycle Gas Turbine
O&M costs	Operation and Maintenance costs
OPEC	Organisation of Petroleum Exporting Countries
PPA	Power Purchase Agreement
PJM	Pennsylvania Jersey Maryland – electricity market (US)
PSO	Public Service Obligation

PV	Photovoltaic
TWA	Time-Weighted Average
R&D	Research and Development
REDG	Renewable Energy Development Group
RES-E	Renewable Energy Sources for electricity
ROC	Renewables Obligation Certificate
ROI	Republic of Ireland
RSI	Residual Supply Index
SEI	Sustainable Energy Ireland
SEM	Single Electricity Market
SO	System Operator
SONI	System Operator for Northern Ireland
t	Tonne
TFC	Total Fuel Consumption
TPER	Total Primary Energy Requirement
TSO	Transmission System Operator
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
VOLL	Value of Lost Load

APPENDIX 2. THE CURRENT RENEWABLES SITUATION

Wind farms with a combined capacity of almost 400MW together with 24MW landfill gas and 237MW hydro brings the total to over 650MW of renewable electricity actually operating at present in the Republic of Ireland. There is also significant renewable energy capacity currently under construction: connection agreements exist for a further 550MW and connection offers are currently issuing to a further 330MW of applications. Further applications are currently queuing with the System Operators (North and South) to bring an excess of 2,000MW of wind potentially on the All Island system. With the 2005 deadline upon us and having achieved the 500MW Irish RES-E target, it is timely to examine the issue of renewable energy in Ireland.

RES-E Installed Capacity Currently Generating (August 2005)

Technology	Republic of Ireland [1]	Northern Ireland[2]	All-Island
Wind	382 MW	107 MW[3]	489 MW
Biomass	24 MW	3 MW	28 MW
Hydro	237 MW	3 MW	240 MW
Ocean	0 MW	0 MW	0 MW
Solar PV	0 MW	<1 MW	<1 MW
Totals	624 MW	113 MW	737 MW

1. All RoI data from DCMNR website
2. All NE data from NIAER (2005)
3. Includes Snugborough (located in RoI but connected to NI system)
4. As of beginning of July 2005, there was approximately 46 MW of wind with connection offers in NI (NIE).

Generation based on fluctuating renewable energy sources (wind, solar and wave) are characterised by relatively high investment costs and relative low running cost. The various technologies are at very different levels of economic maturity. Typically, more than 85 per cent of the total production costs of wind power are investment costs, while fossil fuel systems are well under 50 per cent. Fuel for wind turbines is free and the maintenance costs are recorded as low. The implication is that once a wind turbine is installed, market competition cannot make it work more efficiently. This implies high investor risks in an uncertain competitive market context. After market liberalisation, competition has reduced production costs of traditional systems, mainly through reducing the numbers of employees. This possibility does not exist for wind generation. Competition in the field of wind power is only related to production costs where turbine costs have decreased very significantly during the past 20 years.

The contribution from wind power to national electricity demand in 2003 was 465 GWh, up 20 per cent on 2002. The 2003 annual percentage contribution of wind to gross national electricity demand was 1.84 per cent. In July 2005, there was almost 400MW of wind turbines connected in the ROI and a further 1,300MW with signed connection agreements but not guaranteeing their construction. This gives a potential total of approximately 1,700MW.[98] In Northern Ireland there are 107MW of wind generation connected as of 1 July 2005 with a further 46MW of committed capacity and over 500MW of connection enquiries. This suggests a potential wind capacity on an all-island system of up to 3GW – a threefold increase on what is currently in place – though there are doubts whether all the planned capacity is likely to go ahead.

Ranking of Countries by New Wind Installation in 2004

Rank	Country	Population (Million)	Installed in 2004 (MW) (new)	Installed in 2004 (watts/capita)
1	Spain	39.4	2,065	52.4
2	Ireland	3.7	148	40.0
3	Luxembourg	0.4	14	35.0
4	New Zealand	4.0	132	33.5
5	Germany	82.0	2,037	24.8
6	Austria	8.0	192	24.0
7	Portugal	10.0	226	22.6
8	Norway	4.5	59	13.1
9	Netherlands	15.8	197	12.5
10	Australia	19.3	182	9.4

Source: Windpower monthly, New Zealand, February 9, 2005
http://www.windenergy.org.nz/FAQ/global04percap.htm

This growth in wind generation is largely in response to government support and incentives designed to promote renewable technologies to meet EU commitments under the Renewable Energy (RES-E) Directive[99] and the Kyoto Protocol. There is still considerable work to be undertaken to meet the 2010 targets with approximately 769MW required by the end of 2009 to meet the ROI commitment and approximately half this to meet the Northern Ireland commitment. There are a number of instruments in place to

[98] ESB NG Response to Consultation Document "Options for Future Renewable Energy policy, Targets and Programmes", February 2004. It is very unlikely that this amount will actually be delivered.

[99] Directive 2001/77/EC on the promotion of electricity produced from renewable energy resources in the internal electricity market

support these targets. However, 83MW (36 per cent) of the wind generation installed trades as merchant plant without government price support or green credits and another 82MW was under construction in early 2005. Other positive effects of increased wind powered generation include short construction times, its distributed nature and as a hedge against traditionally volatile fossil fuel prices improving both the security of supply and fuel diversity in energy sources.

In addition to providing benefits some challenges will be associated with an increased penetration of wind into total electricity generation. There are a number of physical, technical and controllability characteristics that are very different to the conventional generation it can displace. These engineering characteristics are noted as:

- A lack of inertial response
- A limited ability to provide reserve
- Intermittent and potentially unpredictable electrical output that is highly correlated with that from other windfarms; and
- A varied ability to ride-through system faults.

These characteristics of wind increase the requirement for reserve. The extra costs associated with intermittency have two components: the capital cost of the plant and the additional running cost (operational and environmental) that is incurred when this plant provides reserve. The reserve plant may be operating at part load and reduced efficiency and hence incurring higher costs. OCGT plant is considered one of the most suitable and complementary operational reserve sources for use with wind as this type of plant can start and stop quickly without significant NOx effects from running at less than full output.

Milborrow (2004) estimated that the extra costs associated with wind backup increase (albeit at a declining rate) with additional wind resources on the system.[100] ESBNG carried out a study which used a concept of "capital cost for extra capacity". This unusual benchmark was based on the assumption that at times of peak demand, 100 per cent of the rated output of the wind plant is expected to be available (ie. 100 per cent rather than 35 per cent standard capacity credit for wind implying 65 per cent of the rated output must be provided as backup).[101] On the basis of the ESBNG study, the CER implemented a request from ESBNG for a moratorium on the signing of new wind connection agreements on

[100] The extra costs imposed by wind comprise costs due to extra start-ups, ramping, regulating reserve and replacement reserve. The SEI ILEX and Brattle studies for SEI both produced estimates for the first three and found them to be relatively minor. The ESBNG study was the only one to look at the cost of replacement reserve and it used pessimistic assumptions. Part of the problem was the assumption made about the rest of the electricity generating system. In the ESB National Grid study the bulk of non-wind generation was assumed to be gas-fired CCGTs, which are very inflexible and mix badly with wind.

[101] This study assumed a system based substantially on the use of CCGTs which would neither be realistic nor appropriate reserve capacity supporting wind.

3 December 2003. The moratorium was subsequently renewed until the publication of a Grid Code for Wind in Summer 2004.[102] The grid code for wind involves stringent requirements regarding dynamic modelling both at the level of the individual turbine and the effect on the entire system. These models are proving problematic. The cost of complying with the Grid Code for Wind has been estimated at between 5 and 12 per cent of total new wind farm costs.[103]

The economics of wind is invariably intertwined with the market value for carbon. The carbon dioxide savings that result from the introduction of renewable energy depend on which fuel is displaced. At high carbon price levels, substantially higher wind penetration becomes more economic. The Eirgrid analysis on the "*Impact of Wind Power Generation in Ireland*" suggests the reduction in CO_2 emissions for a 6,500MW system with 1,500MW of wind powered generation (over the case with no wind) was found to be 1.42 million tonnes. However, total generation cost was modelled to increase by €196m (due to the retention or installation of surplus conventional capacity for system security reasons). This implies a cost per tonne of carbon mitigated by wind to be €138 per tonne. The study for SEI by ILEX Energy Consulting suggests that the displacement cost of wind would be substantially less.

POLICY INSTRUMENTS FOR RENEWABLE ELECTRICITY

The following sections discuss the design elements in three widely used policy instruments: i. feed-in tariffs, ii. quota obligations in combination with a green certificate system, and iii. tendering/bidding schemes. Besides the primary support instrument, there are complementary or secondary mechanisms possible which include investment subsidies and fiscal measures. Some schemes conform better to the market than others and some are claimed to be more efficient at promoting the penetration of renewable energy. As a consequence of no general agreement at EU Commission level on the preference for different schemes, the EU Commission has postponed its plans of harmonisation in relation to this market. It would probably be best if they avoided any attempt to design a harmonised instrument and, instead, concentrated on reforming the emissions trading scheme.

Feed-in Tariffs

In April 2005, the Minister for Communications Marine and Natural Resources announced that the next market support mechanism for renewables will be based on a fixed feed-in tariff system. This support system will be designed specifically to

[102] CER "Wind Generator Connection Policy: Draft Decision", 11th May, 2004 (CER/04/183). The DSO grid code will be published in early Autumn 2004 but it is expected to have similar requirements to the TSO Grid code.

[103] Personal communication Dr. P. O Kane, IWEA, September 2004.

encourage new capacity development and will only apply to newly built projects. Feed-in tariffs (FITs) were a commonly used policy instrument for the promotion of renewable electricity production and have proven to be the most effective at bringing forward capacity in the short and medium term. They are typically used where the market structure is characterised by monopoly suppliers or vertically integrated utilities. The term feed-in tariff is used to cover a minimum guaranteed price per unit of produced electricity to be paid to the producer, as well as the premium in addition to market electricity prices that may be paid. The support is set with an agreed rate of return. It is not surprising that the renewable energy industry tends to favour this option. Regulatory measures are usually applied to impose an obligation on electricity utilities to pay the (independent) power producer a price as specified by the government. The market players determine the quantity forthcoming of renewable electricity.

The FIT system can be criticised on a number of key dimensions which should be considered in putting together the finer details of the new scheme for Ireland. A potential mistake would be to lump all our renewable technologies together, discouraging development of the less mature technologies. Second, in assigning the number of years to operate the tariff, it should be noted that investors will push for a longer period to give them income security for a substantial part of the project lifetime. A longer guaranteed market lowers their risk at an increasingly uncertain but exponentially increasing cost to the taxpayer/consumer. Third, supply companies will complain that it loads them with extra costs based on their purchase obligation, which is not market determined and may not reflect consumer preferences. A major problem with the FIT is that a fixed price level does not conform to traditional market principles and it generally is not reduced in step with technological development. The level of the tariff does not have to be directly related to either cost or price, and is generally chosen at a level to motivate investors for green power production. The Danish government regretted that windfall profits accrued to wind generators who availed of the Danish scheme.

Some adaptations of the instrument can be applied to correct for past mistakes including taking into account the best technology on the market and benchmarking the tariff at regular intervals. This would introduce an element of competition into the system. As the market share of wind power increases, the burden of the feed-in scheme on government finances or electricity consumers could become politically unacceptable. It is also possible to design a feed-in mechanism that gives producers a fixed premium on top of the market price of all electricity.[104] Such a fixed premium per kWh of

[104] The German utilities have never been happy with the feed-in schemes in Germany claiming that they conflicted with EU rules for state aid. It was referred to the European Court of Justice and it was ruled in 2001 that the scheme did not constitute State Aid.

"renewable benefit" was financed in Spain from a tax on all electricity consumption with the remainder of the price reflecting current market electricity prices.

The administrative costs and complexity involved for governments in implementing fixed feed-in tariffs are low; however this instrument does not ensure that consumers will be paying the lowest cost possible. There is no competitive mechanism to determine a fair price and prices tend to be set for many years in advance with little scope to reduce prices paid even when costs are falling. This instrument is not consistent with liberal markets without some mechanism in place to distribute the obligation of purchasing highly priced power to all electricity suppliers. FITs are certainly not consistent with developing a pan-European support system for renewables which would be easier to harmonise if a developed certificate trading system was in place.

- There are some very real dangers which persist with the FIT support instrument: the feed-in tariff price will not relate to the cost structure of the firm and will be set at the marginal cost of the last firm to meet the target. This means that the inframarginal plant could make substantial profits out of fixed tariff set *ex ante*. The cost to consumers of the last few MW could be very high and the provision of a feed-in tariff effectively derisks the investment at consumers' expense.
- The price set for the FIT is critical in obtaining a certain target but in order to set the correct price many assumptions have to be made including the relevant Best New Entrant (BNE); the weighted average cost of capital for each of the technologies; the length of the power purchase agreement; the relevant rate of return; the assumption of the distribution between equity and debt financed capital.

Quota Obligations/Green Certificates

The aim of the certificates trading model is to introduce conditions of market competition into the production of green energy for technologies that are not fully competitive with the traditional supply systems. Quota obligations are set to impose a minimum production or consumption of electricity from renewable energy sources. Prices are set by the market that produces, sells and distributes the stated amount of energy from renewable sources. The obligation is imposed on consumption (often through distribution companies) or production. Governments may choose to establish 'technology bands' in order to protect technologies from strong competition by lower cost options. The quota can usually be traded between companies to avoid market distortions. A tradable green certificate is needed for this system. These green certificates provide an accounting system to register production, authenticate the source of electricity, and to verify whether demand has been met.

A green certificate market has operated in Holland since the beginning of 1998 and is supported by a voluntary consumer quota of green electricity. Since 2001, Dutch consumers have a free choice of suppliers of renewable electricity. At the same time, they have been exempted from paying environmental tax on their renewable electricity consumption. This corresponds to a rebate of about 6.7 cents per kWh and puts renewable electricity at the same price level as traditional energy sources. The demand for renewable electricity has increased dramatically and the Dutch suppliers cannot fulfil this demand domestically. Since 2002 Dutch electricity suppliers have imported renewable electricity from abroad subject to the condition that it is certified as green; it cannot have received subsidies in another state and the market opening in the exporting country is at least the same level as in the Netherlands. The relatively high Dutch rebate on renewable electricity may have the consequence that it is supporting renewable electricity installations in the exporting countries.

Sweden, Italy and Belgium have also initiated green certificate trading schemes. However, the success of the schemes has more been driven by whether the green certificate markets operate in conjunction with an obligatory consumer quota or not. Where quotas do exist, the price of green certificates has fluctuated significantly and at times are a very scare commodity. The uncertainty about the price has been regarded as a disincentive to investors in renewable technologies. In the Danish system, minimum and maximum prices[105] are defined for green certificates to allay some of the investor uncertainty. The problem is also alleviated by long-term electricity supply contracts and the use of financial instruments including futures trading.

Voluntary buying in excess of renewable electricity obligatory quotas is known as green pricing. It may be accommodated in a certificates trading model if voluntary green electricity consumption absorbs over-quota green consumption. Otherwise consumers who do not fulfil their obligations would be “let off” their obligation at the expense of the over-subscribed green pricing customers. This ‘free-rider’ potential may dissuade the over-achievers if some additional incentive is not in place (e.g. exemption from green taxes). Transactions costs are also very high with a certificates trading system.

Tender Systems

This was the approach used by the Irish government in successive AER schemes. This approach was first developed in the UK[106] and uses a competitive bidding procedure to select beneficiaries for support (investment or production – such as price-adders or feed-

[105] The minimum price is specified by law but the maximum price is equal to the penalty for not fulfilling the consumer quota.

[106] The British tender system based on the so-called Non-Fossil Fuel Obligation (NFFO) dates from the early 1990s.

in-tariffs), or for other limited rights – such as sites for wind energy. The criteria for the evaluation of the bids are set before the bidding round. The government decides on the desired level of electricity from each of the renewable sources, their growth rate over time, and the level of long-term price security offered to producers over time. In Ireland the cost of the scheme continues to be funded through a Public Service Obligation (PSO). In the UK, the bidding was accompanied by an obligation on the part of electricity providers to purchase a certain amount of electricity from renewable sources at a premium price (power purchase agreement). The difference between the premium and the UK market price is reimbursed to the electricity provider, and is financed through a non-discriminatory levy on all domestic electricity consumption. In each bidding round the most cost-effective offers will be selected to receive the subsidy. The mechanism therefore leads to the lowest cost options for consumers. The UK has since abandoned its tender system and replaced it by a certificates trading model.

Investment Subsidies

Investment subsidies can help to overcome the barrier of a high initial investment. Section 486B of the *Finance Act* 1998 offers tax relief for Irish corporate investors in renewable energy projects. This type of subsidy is commonly used to stimulate investments in less economical renewable energy technologies. Investment subsidies are usually 20-50 per cent of eligible investment costs, but in some cases subsidy is given over the total eligible investment sum, however within the limitations of the Community guidelines on State Aid for environmental protection. We also consider loans with a low interest rate to be investment subsidies.

Fiscal Measures

Some EU countries support renewable electricity by means of the fiscal system. These schemes may take different forms. They range from rebates on general energy taxes, rebates from special emission taxes, proposals for lower VAT rates, tax exemption for equity funds, to attractive depreciation terms but within the EU they must be in line with the Community Guidelines on State Aid. The USA stimulated significant levels of new renewable (primarily wind) energy electricity using such an instrument. Owners' federal tax liability credits per unit of production exported to the transmission system were given for the first 10 years of production at a fixed price fully indexed to inflation. The mechanism does not limit the total capacity which the grid can accommodate and in the state of Texas wind-farms are being asked to constrain export for grid reasons. The investor must have a large tax base in order to fully benefit from the incentive and only strategic investors have filled this role in the USA where a small number own a large portion of the new renewable energy capacity. As with all tax schemes their cost is uncertain in advance. The *Commission on Taxation* recommended against such an approach to incentivising investment as long ago as the early 1980s.

Other Secondary Measures

In the Republic of Ireland, market opening for green suppliers was introduced in February 2000 in advance of full market opening (February 2005), giving them a beneficial head start. In addition, the balancing regime for green sales and green energy was set generously but in terms of a higher margin and for a longer period to assist new entrants. There are more favourable arrangements in place in the trading rules for green generators than brown.

Experience in Other Countries

In promoting the use of electricity from renewable sources the greatest penetration has been achieved with the FIT in Denmark, Germany and Spain, which relied heavily on this instrument to get the initial capacity in place. The European Environment Agency (2001) found that 80 percent of new EU wind energy output occurred as a direct result of this instrument in these countries. Some accession countries, notably Czech Republic, Hungary, Latvia and Estonia have recently introduced a renewables feed-in tariff.[107] Denmark subsequently moved to a certificate-trading scheme once its capacity was in place in anticipation of an EU wide green certificate trading system but later reverted back to a FIT with some competitive features artificially imposed on the FIT system to share the premium tariff between electricity consumers and the government budget. Benchmarking was instituted to help take technological developments into account. On the other hand, benchmarking was criticised because it dilutes the investment certainty that is the FIT scheme's strongest characteristic.

Overview of Promotional System for Renewable Electricity by EU(15) in 2001

	AU	BE	DK*	FI	FR	GE	GR	IR	IT	LU	NL	NO	PO	SP	SW	UK	Total
FIT	X		X		X	X	X			X			X	X			7
Tender								X									1
Green																	1
Pricing				X													
Certs		X	X						X		X	X			X	X	7

Irish Experience of Incentivising Renewables

The most recent policy for renewables in Ireland comprised of a competitive tendering system – the Alternative Energy Requirement (AER) programme. In addition, the Electricity Regulation Act 1999 introduced full market opening for green electricity generators and suppliers.[108]

[107] Latvia guarantees the electricity price for eight years after grid connection and has set the tariff at twice the average electricity selling price at close to 5 euro cents.
[108] Green electricity suppliers only have to balance supply and demand on an annual basis rather than by the half hour for conventional generators.

Alternative Energy Requirement

The AER mechanism is an example of a bidding system and is the only dedicated subsidy system for production of renewable energies that operated in Ireland. It combines grant aid from the European Regional Development Fund (ERDF-subsidies) with price support above avoided fuel costs. The objective of each AER round was to compete for rights to generate electricity and to sell it to the ESB at agreed rates over a fifteen-year period. Prospective generators were invited to compete based on a price per unit of electricity. The advantage was that the guaranteed bankable support for projects would provide confidence to investors. The tendering process was used as it promised the delivery of renewables-based electricity at lowest cost.

Actual bids of the winning projects in the AER rounds are confidential. AER V projects should have been installed by the end of 2004 and the target installation for AER VI is December 2005.[109] As a number of fiscal incentives used by renewable energy developers to attract investment under their AER V projects were no longer available, some applicants were allowed to submit fresh bids in AER VI. These differences related to the use of price indexation, which was the full consumer price index (CPI) in AER VI and the option for generators to apply for an accelerated upfront payment in the latest round. Up to 35 per cent of the funding for the second half of the contract could be claimed upfront in the first seven years as an accelerated capital recovery mechanism. As such, revenues and outgoings are matched more closely over the life of the contract. The reason for introducing the accelerated payment option followed from the finding that developers found debt providers were in most cases confident to provide funds at an early stage in the project while equity providers were found not to be as confident. Developers were therefore finding it very difficult to bridge the difference between the full capital costs and debt available. The accelerated payment allowed developers to source additional sources of finance, which in many cases is relatively short-term.

[109] Excluding two offshore wind demonstration projects and the biomass-CHP category which must be installed and selling electricity by 31 December, 2006.

Outcome of the AER Competitions

	AER I	AER II	AER III	AER IV	AER V	AER VI
Date	**1996**	**1996**	**March 1997 – April 1998**	**Sept 1997 – Aug 1998**	**May 2001 – Feb 2002**	**Feb 2003- July 2003**
Technologies supported	Wind, small scale hydro, biomass (landfill gas), CHP waste to energy	Waste to energy	Large Scale Wind (>5 MW), Small scale wind, biomass (landfill gas), small scale hydro and wage energy	Combined Heat and Power (CHP)	Large scale wind (>3 MW), small-scale hydro, biomass (landfill gas)	Large scale wind (>5 MW), small scale wind (<5MW)., offshore wind, small-scale hydro, biomass (landfill gas), biomass CHP, biomass (anaerobic digestion)
Total MW targeted	75 MW	1 plant between 10 and 30 MW	100 MW	25 MW new + 10 MW existing	255 MW	500 MW (Green Paper)
Applications selected	34	1	30	19 (17 new + 2 extensions)		48
Total MW supported	22 MW	Did not proceed	158.75	52.6 MW	363 MW	365 MW
New Capacity installed	70.62 MW	0 MW	42.11	18.353 MW	109.076 MW	
Breakdown:						
Wind	7 projects (45.8MW)	-	6 projects (37.51 MW)	-	354.095 MW	279.42MW onshore + 50 MW offshore
Small Scale Hydro	6 projects (2.304 MW)	-	4 projects (1.67 MW)	-	0.949 MW	1.309 MW
CHP	4 projects (10.716MW)	-	-	3 new projects + 2 extensions	0	26.83 MW
Land fill gas	5 projects (11.804MW)	-	1 project (2.928 MW)	-	8.008MW	7.507 MW
Wave energy	-	-	0	-	-	-

The success rates of the various AER rounds were largely dependent on projects receiving planning consent and on secondary supports available, particularly capital supports. A Renewable Energy Development Group was established to accompany this process of target setting and policy formulation with the specific 13.2 per cent target set for renewable electricity for Ireland by 2010 set in the context of the EC Renewables Directive (2001/77/EC). The key design objectives for the continuing policy must be to ensure that this target is met at least cost to consumers while providing fair returns to attract investors.