ASSESSMENT OF THE KEY COMPETITIVENESS ISSUES AND POLICY REQUIREMENTS FACING THE IRISH ENERGY MARKET

Focus On Irish Electricity Market

Final Report
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Executive Summary

Objectives of the Study

The objective of the study is to assess the key competitiveness issues facing the Irish energy market from an enterprise consumer perspective and to outline appropriate institutional and policy responses. Such a study is particularly opportune at this time, as Irish industrial energy users are facing the prospect of significantly increased prices for energy and the possibility that the electricity supply situation will be precarious.

The original study brief encompassed both gas and electricity markets. Following a preliminary review of available literature and work already completed, it was concluded, after consultation with Forfas, that the issues in the gas market were already well documented and relatively well understood. As a result, this report focuses on the electricity sector.

Energy and the Enterprise Sector

Energy used by Industry accounts for 22% of total final energy consumption. Energy is a key input to industry and access to an adequate supply of energy at competitive prices is essential to industrial development. Some industrial sectors are particularly sensitive to energy costs, as such costs represent a high proportion of output value. The latter include the manufacture of cement, building materials, non-ferrous metals, and iron and steel. For these industries, energy costs represent around 10 per cent of total output value. Viewed from the perspective of profitability, there are a larger number of sectors for which energy costs are in excess of 20 per cent of profit margins.

Industry is not only sensitive to energy costs and prices, but also relies on an uninterrupted supply of energy. This means that the capacity of the energy sector is of vital importance.

Capacity of the Energy Sector

Ireland's gross consumption of primary energy is expected to rise from 14Mtoe in 2000 to 18Mtoe in 2020. Gas will account for 3.5Mtoe (25 per cent) in 2000 and 6.3Mtoe (35 per cent) in 2020. While final energy demand for gas rises from 0.7Mtoe to 1.1Mtoe in the period due to increased customer penetration provided by new gas pipeline infrastructure, the bulk of the gas requirements are to meet increased demand for electricity. Gas will also displace some existing fuels used to produce electricity. While the closure of Irish Fertiliser Industries will reduce gas consumption in the short term, these long-term trends are likely to persist.

Final energy demand for electricity is predicted to rise from 1.8Mtoe to 3.0Mtoe over the period. Unprecedented economic growth has seen peak demand in Ireland growing at rate of 5 to 6 per cent per annum with an increase from under 2,500MW in 1990 to over 3,800MW in 2001.

In relation to gas, a second gas interconnector with the UK became operational in October 2002 and this has enhanced the supply position. While output from the Kinsale field is due to run out over the coming years, two new fields - Corrib and Seven Heads - are expected to be operational before 2005. These indigenous supplies will reduce but not eliminate our dependence on imported gas supplies. However, in general terms, the building of the second interconnector and the development of new gas fields will mean that capacity in the gas sector will not be a problem.

The supply of electricity is less certain. At the beginning of 2001, approximately 4500MW of generation capacity were connected to the transmission network with an additional 275MW of small-scale generation capacity connected directly to the distribution system. Because of the advent of competition in the electricity sector, the ESB is no longer mandated by Government to provide additional generating capacity. The adequacy of future electricity supply is therefore dependent on attracting new private sector generating capacity. So far, there has been very limited success in this regard, putting the adequacy of generating capacity in doubt over the short to medium term.

Eirgrid estimates suggest that approximately 300MW of new generation capacity will be required by 2005, 250MW more by 2007 and a further 150MW by 2009. Current indications are that a shortfall of power during the coming winters of 2002 and 2003 will be averted by the commissioning of the new Synergen and Huntstown generators. However unless the construction of additional new capacity begins soon, emergency generation may be required the following year.

Energy Prices

Irish industrial consumers of gas have tended to enjoy prices that are below the average for Europe. With regard to electricity prices, the picture is more mixed. Smaller and medium sized enterprises have been paying above the average. Electricity price increases are currently in train and these will exacerbate this situation.

Electricity demand is also growing strongly at a time when capacity is constrained. Significant capital investment in generating plant will be required over the short term, and this will tend to increase prices. Ireland is in an adverse position in this regard in that most of our competitors have surplus generating capacity and therefore may be subject to lower electricity price inflation.

Increasing concerns with the environment are likely to lead to policies that will raise energy prices and costs, including carbon taxes and emissions quotas and trading arrangements. Apart from this general trend there are a number of specific factors that will raise prices:

- The need to remunerate additional gas and particularly electricity infrastructure;
- Increased demand for gas across Europe and the consequent in increase in gas prices; and
- The additional costs imposed by reliance on peat fired generation.

The expectation is that energy prices will rise in the short to medium term and that Irish enterprises will face increasingly higher prices than their European competitors.

Structure of the Irish Electricity Market

This upward pressure on energy prices and the uncertainty about the adequacy of electricity generation capacity reinforces the need to ensure that the electricity market is so structured as to deliver an adequate supply of electricity at the lowest cost possible. There is a real concern that the current electricity market structure is not delivering the additional capacity needed and may fail to achieve the cost efficiencies required to minimise price increases.

Traditionally in Ireland, electricity has been supplied through the ESB monopoly, which extended to the generation, transmission, distribution and supply functions. In the past few years, partly as a result of EU legislation, regulatory measures have initiated the unbundling of the industry. However, the degree to which competitive industry structures have been established is limited. ESB PG (Power Generation) is still the monopoly owner of the majority of Irish generation capacity. ESB PES (Public Electricity Supplier) is the monopoly electricity supplier to customers in Ireland. DSO / MRSO are the operators of the Distribution System and Meter Registration Service respectively. These activities are licensed individually, but current licenses are held by the ESB. TSO is the Transmission System Operator, which also provides Settlement System Administrator function. Currently, these services are provided by ESB National Grid, a division of the ESB. The ownership of the transmission system remains with ESB as transmission asset owner (TAO). ESB National Grid will become Eirgrid early in the new year. Eirgrid responsibilities include the delivery of energy from the generators connected to the transmission system, dispatch of generators, running the settlement system necessary for the operation of a competitive market.

IPPs (Independent power producers) are new entrants into the power generation arena. Huntstown Power (owned by Viridian) and Dublin Bay Power (owned by ESB and Statoil) are the two largest new thermal generators while a number of renewable generators have also entered the market such as Airtricity. Eligible customers are those customers who are free to choose their power supply from any licensed supplier There are approximately 1,600 such customers and they comprise 40% of the Irish electricity market by volume. In addition to this threshold, there is 100% opening of the "green" and Combined Heat and Power ("CHP") markets, where such suppliers may supply any customer in the country irrespective of consumption. Non-eligible customers are smaller consumers and represent 60% of the Irish market by volume of electricity consumed but virtually 100% by number of consumers. All of these consumers are obliged to obtain their supply from ESB PES.

From this overview of the structure of the electricity market, it is clear that the market is less than fully competitive from a number of viewpoints:

- The vast majority of consumers do not have a choice as to whom they purchase electricity from; and
- There are only a handful of players competing in the market and the ESB continues to dominate the entire industry.

Apart from these drawbacks, the operation of the market has resulted in further inefficiencies, the bulk of which arise because the market is not structured so that electricity charges reflect the costs of generation, transmission and distribution.

Operation of the Irish Electricity Market

The operation of the Irish electricity market suffers from a number of limitations. These relate to:

- The operational structure;
- The lack of transparency;
- The dominance of the market by one player;
- The lack of incentives to new entrants; and
- Lack of a clear overall framework.

<u>Structure</u>

The Irish model is structured with bilateral contracts between generators and large consumers at its core. Bilateral contracts act to segment the market into smaller pieces. In a market like Ireland's which is already small, this further segmentation creates unnecessary inefficiency. The inefficiency arises because there is no guarantee that the most efficient generators are fully utilised.
The Irish trading model does not optimise the electricity market, rather it optimises the process for balancing the market when day ahead demand estimates do not match the actual demand on the day or when units need to be dispatched to maintain system stability. So, while there is merit order balancing of the system, the overall efficiency of the system is compromised by the fact that the principles of merit order dispatch are not applied.

Top-up and spill are the prices used for balancing the system. They are designed to force down volumes in the balancing market and maximise bilateral contracting. Most customer load is profiled, so to match a non-flat customer load profile a new entrant must either follow the load profile (thereby moving from optimum efficiency levels) or match its load using the top-up and spill services from the ESB. As these services are expensive, new entrants are inhibited. The design of the Irish market has been such that the majority of the ESB generating capacity is not exposed to market pressures, but is instead subject to regulatory cost reducing targets.

Intermittent generators, such as wind or CHP, are unable to predict their output as accurately as thermal generators and are forced to balance their contracts using top-up and spill. This reduces the attractiveness of developing these generation sources.

Current market design means that the impact of congestion and transmission losses on the system is averaged across all generators. Due to these simplifications, the model has inherent discriminatory features that provide opportunities for gaming the system.

International debate on the appropriate arrangements for operation and ownership of the grid continues. The options are the not-for-profit Independent System Operator (ISO) model (operator does not own the grid) and the Transco model where the ownership and operation are combined. The CER, Eirgrid and the ESB have reached agreement on the current ISO model. As there is no clear consensus internationally on the best approach, adoption of the ISO model may not represent a limitation of the current system.

Transparency

There is very little information available to help a potential new entrant into the Irish market assess the level or extent of competition. The lack of a merit order dispatch means that existing market participants are unable to gauge their own competitive position. In addition, the ability of a generator to compete effectively is inhibited by lack of clarity with regard to other features of market operation. These relate to:

- congestion management procedures;
- calculation and allocation of transmission loss factors; and
- factors which influence the calculation of top-up and spill balance prices such as ESB avoided cost of fuel are not readily available

The design of the system is such that the strike price of bilateral contracts between generators and suppliers is not disclosed. This is a feature of bilateral contract design.

The most efficient operation of the electricity system would have all generators ranked in efficiency terms and switched on in merit order as demand increases. While it would be possible to work out cost per kWh for each of the ESBPG generators, this is not done. So rather than the costs of generation at each of the ESB's generation units being available, an all-in cost of production from all ESBPG generation plant is produced. So not alone is merit order dispatch not attempted by the system, this approach means that data relevant to estimation of the merit order of generation plant in Ireland is not even available to potential new entrants.

Dominance of the Incumbent

In addition to the inefficient design of the market, the decision not to break-up ESB PG means that it continues to dominate the market. Of 5,500MW of capacity, 4,580MW (83%) is owned by the ESB. While the CER has accepted ESB's target of reducing market share to 60%, it is unclear how this target will be achieved. It is also fair to point out that ESB has been under conflicting pressures to reduce its share but also to put additional short term capacity in place, as investment by new players has been slower than anticipated.

While recognising the industrial relations issues that would arise if ESGPG were forced to divest, it is clear that competition can only truly exist if there are sufficient competitors.

Lack of Incentives for New Entrants

It is not possible for a generator to compete in a bilateral contract market unless a customer base has first been located. Considering the problem of locating a matched load to maximise output, the first new entrant would have had a choice of the largest industrial users who are more likely to have large flat loads, ideal for matching to generator output. As the market opens however, the larger flatter loads give way to smaller more profiled loads. This makes entry for subsequent new generators into the market more onerous as the number of customers required increases and their load patterns become more difficult to match (relative to a flat load).

Eligible customers are the only customers that new entrant generators can target. Unfortunately, for new CCGT entrants, these customers are also the ones on the lowest ESB tariffs, so while the size of the eligible customer base is attractive to a new entrant generator, these customers are less lucrative than those on higher ESB tariffs. As new entrant generators have been prohibited from targeting these higher tariff customers, the market has been less attractive to new entrants and the SME sector consumers have lost out.

Overall Policy Thrust

The Irish market has suffered from a lack of an over-arching strategic direction. It is clear from discussions with most participants that they are unclear as to how the market is likely to evolve, particularly when transition period ends in 2005. This lack of a robust framework and strategic direction has led to uncertainty for new entrants and a plethora of consultations and reviews on a wide range of topics.

The CER is currently undertaking a major review of market trading arrangements. We believe that this provides a significant opportunity to lay down a long-term framework within which regulatory policy can evolve. The aim of the subsequent sections of this report is to provide an input to this process, as we believe that a such a framework can be established such that generation, transmission, demand and ancillary services could all interact to accommodate future technological and other market changes.

International Experience of Electricity Market Structures

Although, there is considerable variations in the type of market structures operated in developed countries, there are three main variants:

- The single buyer model;
- The pool model; and
- The bilateral contracts model

Each of these models has been deployed very close to Ireland, with the single buyer system operational in Northern Ireland, a pool system in England and Wales up to April 2001 and a bilateral contract system in England and Wales thereafter.

Under the single buyer model, a central body is set-up to assume control of the market. The single buyer agrees long-term power purchase agreements with each generator and takes responsibility for the forward planning of generation capacity. This introduces competition into the generation sector. This model is in place in Northern Ireland and is widely regarded as having led to very high consumer prices and supernormal profits for the generators. Properly developed, the model can provide a framework for ensuring security of supply, while allowing for limited competition in generation. However, other models have more ambitious aims.

Many variations of the pool model exist. In the early 1990s, England and Wales opened up their markets under the pool system, and it was initially perceived as the leading market design. Under this model, a mandatory day-ahead market is organised where all generator offers and all supplier bids are pooled for each trading period during the day. All generators receive the market price regardless of their actual bids into the system. Suppliers all purchase power from the pool at the market price plus an additional cost to cover the costs of capacity payments to generators, transmission losses, ancillary services and congestion management.

This type of pool system allows generators and suppliers to trade, but participants found it easy to manipulate. Generators were able to predict in advance which plant would be the marginal plant and could set the bid for this plant at a high level, resulting in excessive payments to all generators. In addition, generators were able to predict in advance which generation plant would be constrained off by the system operator and were able to adjust their bids to again receive excessive payments both for constrained on and constrained off plant.

Under a bilateral contract model, of which the current Irish model is an example, the starting point is that generators and suppliers are required to get together first and agree terms. These terms are then provided to the system operator who does not know the price agreed between the generator and supplier. The system operator just needs to know what the production and demand volumes are. The system is therefore not based on merit order dispatch, rather it is based upon nominations from the generators and suppliers.

A separate market is then organised to allow the system operator to balance the market in real time. Under this market, the system operator publishes bids and offers to secure either additional or reduced generation.

As with the pool model, the bilateral model seeks to average the effect of transmission issues such as locational losses and congestion

The major problems with each model may be summarised as follows:

- The single buyer model has limitations on the extent to which full competition can develop and can allow generators rather than consumers benefit from efficiency gains.
- The pool model may be easily manipulated by generators to obtain high prices at the expense of the consumer.
- The bilateral model sacrifices merit order dispatch of the entire system which is a big drawback in a smaller market.

None of the models adequately reflect cost structures and, in particular, deal poorly with transmission congestion and losses.

The key goals of the European Union policy in relation to electricity are:

- To improve the competitiveness of the EU on a global stage through the development of efficient and competitive markets. With the US as a key global competitor, the EU is already seriously disadvantaged due to its high import dependency and higher overall energy costs; and
- To reduce the differences in electricity prices between members states to allow a single market to develop.

However, the progress in restructuring electricity markets across Europe is varied and a single market in electricity is not imminent. In contrast, the US is adopting a single market design for the entire country. This design is based on an

Locational Marginal Pricing (LMP) approach used in the Pennsylvania, New Jersey, and Maryland (PJM) region of the USA. This model has strong design features and its adoption across the USA is likely to leave Europe as a whole at a competitive disadvantage.

The Locational Marginal Pricing model merits serious consideration in the Irish context.

Locational Marginal Pricing and the Irish Electricity Market

The Locational Marginal Pricing Model revolves around three concepts:

- Locational Marginal Pricing (LMP);
- Transmission Usage Charge (TUC); and
- Financial Transmission Rights (FTR).

Locational Margin Pricing

The Locational Margin Price (LMP) is the cost of delivering one more Mwh at a specific location. Each point on the transmission network where energy is injected (i.e. where generators connect) or energy is withdrawn (where distribution networks or large consumers connect) constitutes a location. LMP varies by location due to transmission losses and congestion and it is based on bid prices into the system at that time.

Transmission Usage Charge

Transmission Usage Charge (TUC) is the cost of or rent for using transmission infrastructure. It is the economic value to the system of moving energy from an injection point to a withdrawal point. As with the locational and system pricing, TUC is a marginal price. TUC is therefore the cost of moving one more MWh from an injection point to a withdrawal point. So while LMP shows the cost of electricity at each node, TUC shows the cost of moving energy between every node.

Financial Transmission Rights

LMP exposes market participants to price uncertainty during periods of congestion. Financial transmission rights (FTRs) are a financial instrument that restore price certainty by providing a hedging mechanism. They provide the owner with revenues to offset the charges they would pay for their transmission usage.

Benefits of the LMP Design for Market Operation

Because the LMP system embeds price signals throughout the electricity system, it encourages and promotes efficient market behaviour through:

- Optimal short-run supply and demand decisions by market participants;
- Transparent congestion management based on true economic opportunity costs;
- Efficient energy balancing by the system operator;
- Timely investment in generation or transmission infrastructures;

- Optimal siting of generation and transmission infrastructure; and
- Demand side responses.

It addresses the problems in the Irish operation of the electricity market in a number of ways, as follows.

Structure

The LMP model takes the best parts of the pool and bilateral contract market designs to arrive at an optimal market design with the following features:

- Balancing is based on a single price per location set by market bids;
- Locational price incorporates the effects of losses and congestion on the transmission network;
- The model incorporates economic dispatch principles;
- By removing crude simplifications and truly reflecting the economic costs of the system, the LMP system is less susceptible to manipulation and gaming;
- It provides participants with a mechanism (FTRs) to hedge against volatile prices and congestion issues; and
- Critically for a small market like Ireland, it does not segment the market to the extent that a bilateral market does

Transparency

Transparency is at the very core of the LMP model:

- Full disclosure of energy and transmission prices at multiple nodes will allow for the entire system to be modelled accurately by existing participants and potential new entrants;
- The model uses security constrained bid-based economic dispatch to deliver an efficient market. Participants and observers can readily assess the competitive landscape; and
- The model provides clarity on the treatment of losses, congestion and pricing.

Dominance of the Incumbent

The dominance of the ESB is far less of an influence on the market under the LMP model:

- The model provides a framework for introducing competitors;
- Economic dispatch ensures that the most efficient participants come to the fore
- ESB's role in the operation of the market is ended as the market is administered by an independent system operator and balancing is via a market mechanism; and
- As the model is location specific, each of ESBPG generation plant will be subject to competitive pressures, as the protective layer provided by the bundling of ESBPG portfolio of plant together is removed

Lack of Incentives for New Entrants

The model encourages competition by:

- providing a level playing field and by removing risk for potential new entrants;
- entry into the market is made easier as generators are not forced to locate their own matched load and suppliers are free to buy energy from the spot market;
- The adoption of such a market design for Ireland will make it easier for new generators to invest and to fund their projects – a clear and established regulatory framework which is familiar to international operators and financiers would be in place;
- The penalties faced by intermittent generators due to their inability to accurately predict their generation output are reduced as a single price per location replaces the top-up and spill prices;
- By reflecting the true cost of generation per location and by time of day, competition is likely to be encouraged beyond the baseload where it is currently positioned;
- Smaller generation plants may become more viable in that their production inefficiencies may be offset by the distributed benefit they provide through both avoid transmission costs and local voltage support; and
- CHP plant with smaller heat loads may be viable during the peak periods of energy demand. CHP may therefore be better able to compete directly without the need for subsidies and grants.

Overall Policy Thrust

The model provides a coherent strategic framework within which the market can develop:

- Provides a model that can transition out of regulated market to a liberalised market in time;
- Supports active demand side involvement in the market; and
- Is consistent with anticipated future developments such as distributed generation and hydrogen-powered generation.

Issues in the Application of the LMP Model to the Irish Market

A number of concerns do exist with the LMP model:

- To obtain market prices at each location, sufficient competitors must exist, each one bidding in competitive prices. In the Irish context, this will be difficult to achieve initially due to the lack of competitors. However, effective regulation of bids from individual ESBPG generators can be used to simulate a competitive market;

- The LMP model is complex and not as easy to understand as other models. While this can be suggested as a reason to prefer other models, experiences in California have shown that critical market failures resulted from ignoring the complexities of the market. By reflecting what actually happens during system operation, the complexity of the LMP model is simply reflecting the complexity of electricity grid operation; and

- A concern has been raised that the shape of the Irish transmission grid is such that LMP prices could be volatile and the price signals may not be easily understood. This concern can be addressed by ensuring that market participants have the appropriate information available to allow them to model the system and 'see through' the volatility to the actual competitive landscape.

Benefits of the LMP Design for Energy Policy

Provision of Capacity

An LMP based system would encourage the market to develop capacity as required:

- Large generators, who have been reluctant to enter the market to-date would now have the market knowledge and the certainty of demand that they previously lacked;

- The availability of comprehensive transmission information could allow the distributed benefits of smaller scale generation to be assessed against the costs of transmission system upgrades;

- The viability of CHP would be improved by the ability to get a market price for output without being forced to match a customer load; and

- Finally peak demand levels could reduce as some consumers may choose to opt out of flat rate tariffs in favour of optimising their consumption in line with intra-day variations in price, effectively lowering peak demand and the associated capacity requirement.

Regional Capacity
Additional local generation capacity or improved transmission infrastructure are alternative ways of meeting demand for power in the regions. The LMP system would allow for open and transparent modelling of available capacity at each location and the comprehensive analysis of the options and costs of meeting future demand at those locations. This capability will tend to provide electricity supply at lower costs than current structures would.

Energy Prices
An LMP based model would allow competitive pressures to be brought to bear on the bulk of the electricity market. While regulatory cost and performance controls will still be required, exposure of individual ESB generators to competitive pressures and incorporation of transmission into the market will help maximise efficiency gains for consumers.

Regional Prices

While the LMP model would allow the true costs of energy at each location to be understood, it does not necessarily follow that consumers in each region have to be exposed to different prices. Consumers who choose to remain with ESB PES could continue to be subject to a country-wide averaged flat tariff. Auctioning of ESB PES demand on a nodal basis could help the benefits of a competitive market to be passed through to PES customers.

As losses and congestion are the cause of LMP price differences, it does not necessarily follow that the cost of power in economically disadvantaged areas such as the BMW regions will have higher prices. A modelling exercise would reveal the high cost locations, providing the signals for transmission upgrades or for new generation capacity.

Energy Security

A properly structured and efficient domestic electricity system would improve the security of supply by expanding the number of domestic generators and the energy sources that they use. This would permit decisions as to the desirability and cost effectiveness of UK interconnector to be made on more informed grounds. In advance of measures to ensure the better working of the domestic electricity market, a decision to progress with an interconnector would appear premature.

Private Sector Involvement

The LMP model provides a vehicle for private investor funds to be attracted to the electricity sector not only in the provision of new generation capacity but also in the transmission network. The model allows the economic benefit to the entire system of additional generation capacity, transmission improvements or investment in demand side management to be assessed in detail. This would allow, for example, a large consumer in an area of high prices to weigh up the cost of on-going high prices against the costs of building local capacity or improving transmission to his location.

Overview

The current electricity market arrangements are failing to both deliver the necessary capacity and to minimise price increases;

As electricity prices are likely to be forced upwards by the cost of providing infrastructure and by environmental policies, the inefficiencies of the current market structure has serious consequences for the enterprise sector;

This is particularly the case, as the US is likely to adopt a market structure with significant advantages over structures operating in Europe, including the Irish system;

The emerging US system based on locational marginal pricing has many desirable features that would redress the current deficiencies in the Irish system;

Serious consideration should be given to adopting this system for the Irish electricity market.

1 Introduction

1.1 Objectives of the Study

The objective of the study is to assess the key competitiveness issues and policy requirements facing the Irish energy market from an enterprise consumer perspective.

Such a study is particularly opportune at this time, as Irish industrial energy users are facing the prospect of significantly increased prices for energy and the possibility that the electricity supply situation will be precarious.

There are increasing concerns over the impact that rising energy costs will have on the long-term economic development of the country and the availability of a robust energy infrastructure to accommodate the needs of energy intensive industries and projects.

Given that a reliable secure and competitively priced energy supply is a vital ingredient in the competitiveness of Irish industry and the long term economic development of the country, there is a need to examine whether the current energy institutional and regulatory structures continue to be appropriate.

1.2 Terms of Reference

The unprecedented growth of the Irish economy over the past decade has placed considerable strain on the Irish energy market and its associated infrastructure resulting in concerns over the ability to accommodate recent and projected economic growth and the needs of energy-intensive industries and projects. In addition, although new entrants are now free to enter the energy market, there remains a lack of competition within the energy sector.

Given that a reliable, secure, efficient and low-cost energy market is a requirement for long-term economic development, Forfás commissioned Goodbody Economic Consultants to assess the key competitiveness issues and policy requirements facing the Irish energy market from an enterprise development i.e., consumer perspective.

The original brief extended to analyses of both gas and electricity markets. Following our preliminary review of available literature and work already completed, we concluded after consultation with Forfas that the issues in the gas market were already well documented and relatively well understood. Structural reform is proceeding in this area with reference to an established regulatory model. As a result, this report concentrated heavily on the electricity sector.

1.3 Energy and the Enterprise Sector

Energy used by Industry accounts for 22% of total final energy consumption. Energy is a key input to industry and access to an adequate supply of energy at competitive prices is essential to industrial development. Some industrial sectors are particularly sensitive to energy costs, as such costs represent a high proportion of output value. Table 1.1 shows a breakdown of Irish companies and employee ranked by their sensitivity to energy.

Table 1.1: Importance of Energy to Irish Enterprise

Energy as a % gross output	No Employees	No Companies
2%	206775	3697
4%	35001	934
6%	5554	97
8%	3660	144
10%	1491	30
12%	1226	17
14%	1976	56
16%	577	16
18%	9863	34

Source: Goodbody analysis of 1999 Census of Industrial Production

The high sensitivity sectors comprise the production and supply of electricity and gas (18% band), the manufacture and processing of iron steel and ferro-alloys (16% band), the collection purification and distribution of water (14% band) and the manufacture of building materials, cement, lime and plaster (10-12% bands).

Viewed from the perspective of profitability, there are a larger number of sectors for which energy costs are in excess of 20 per cent of profit margins[1].

Industry is not only sensitive to energy costs and prices, but also relies on an uninterrupted supply of energy. This means that the capacity of the energy sector is of vital importance.

1.4 Study Methodology

The study comprised the following elements. A survey of the very comprehensive literature in the area was carried out. A particular focus of the survey was to identify best practice abroad in relation to institutional and regulatory structures. Much of the emphasis in the survey was on electricity, as it quickly became apparent during the course of the study that it is in this sector that significant change is required.

The study methodology also encompassed an extensive consultation process. Key stakeholders were met and contacts were made with energy industry executives and experts abroad.

The study team drew together the information gathered through the interviews with participants and their research and analysis to form a preliminary view as to possible policy changes. Follow-up discussions were held with industry participants to ensure that the direction in which the study's conclusions were heading would not be deemed unworkable in a practical context.

[1] See 'Competitiveness and Environmental Impact of Energy Taxation on Irish Industry' Farrell Grant Sparks 1999.

1.5 Layout of the Report

The layout of the report is as follows:

Section 2 presents an evaluation of the competitiveness of Irish energy prices and an overview of the factors driving pricing now and in the future.

Section 3 explains why electricity markets requires special consideration and describes the typical models used.

Section 4 introduces the Irish electricity market and highlights the weaknesses in terms of
- Structure
- Transparency
- Dominance of the ESB
- Encouragement of competition
- Overall policy thrust

Section 5 briefly summarises international developments and contrasts the diversity of the EU with the adoption of a standard market design based upon Locational Margin Pricing (LMP) by the US regulatory authorities.

Section 6 provides a explanation of the workings of the LMP via a number of worked examples. The benefits for Ireland of adopting such a model are details and suggestions as to how a smooth transition might be achieved are explained.

Section 7 presents the conclusions of the study.

2 Irish Energy Prices

2.1 Introduction

This section of the report examines current and prospective Irish energy prices and makes comparison with prices in other European countries. Energy prices are influenced both by underlying costs and demand and supply conditions in the market. The section first provides a brief examination of demand and supply conditions in the Irish market as a background to consideration of the other factors influencing prices.

2.2 Demand and Supply Conditions in the Energy Market

2.2.1 Demand

Estimates compiled by the EU Commission indicate that Ireland's gross consumption of primary energy is expected to rise from 14Mtoe in 2000 to 18Mtoe in 2020. Gas will account for 3.5Mtoe (25%) in 2000 and 6.3Mtoe(35%) in 2020.

While final energy demand for gas rises from 0.7Mtoe to 1.1Mtoe in the period due to increased customer penetration provided by new gas pipeline infrastructure, the bulk of the gas requirements are to meet increased demand for electricity. Gas will also displace some existing fuels used to produce electricity as illustrated in Figure 3.1. While the closure of Irish Fertiliser Industries will reduce gas consumption in the short term, these long term trends are likely to persist.

Final energy demand for electricity is predicted to rise from 1.8Mtoe to 3.0Mtoe over the period. Unprecedented economic growth has seen peak demand in Ireland growing at rate of 5-6% with an increase from under 2,500MW in 1990 to over 3,800MW in 2001.

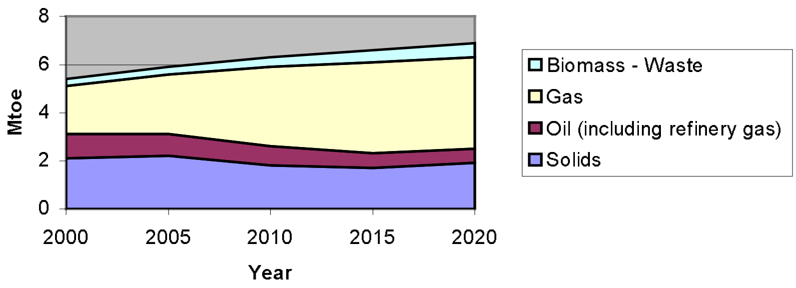
Peak demand is expected to continue to increase as the following estimates illustrate. Although these estimates do not reflect the recent slowing down in economic growth, significant increases in demand may still be expected.

Table 2.1: Peak Electricity Demand

Year	Peak Demand (MW)
2001/2	4,018
2002/3	4,218
2003/4	4,394
2004/5	4,593
2005/6	4,727
2006/7	4,863
2007/8	5,000

Source: Eirgrid Generation Adequacy Statement 2001-2007

Figure 3.1: Irish Thermal Energy input



Source: EU Energy Outlook to 2020 (PRIMES)

2.3 Supply

2.3.1 Gas

With regard to gas supplies, the current position is relatively good. While output from the Kinsale field is due to run out over the coming years, two new fields - Corrib and Seven Heads - are expected to be operational before 2005.

Reserves of the Corrib Field are currently estimated at about 1 trillion cubic feet or 1 quadrillion BTU. Should the project progress, Corrib gas is likely to be released over a 15-20 year period. Accurate estimates of reserve levels for the Seven Heads site are unavailable. In the context of total consumption in Ireland for the year 2000 of 0.59 quadrillion BTU, these indigenous supplies will reduce but not eliminate our dependence on imported gas supplies

A second gas interconnector with the UK became operational in October 2002. While this has enhanced the supply position, the need for BGE to recover the capital costs will lead to upward pressure on prices. The recent Forfas report[2] deals with a number of key issues in this regard. This element of cost is generated from decisions taken within Ireland and the tariff increases are subject to CER approval. In this context, indigenous gas prices can rise again while still staying below the cost of imported gas.

As the commodity price of gas itself is already linked to the competitive UK spot market price, resolution of the high level gas transportation issues highlighted in the Forfas report is the major concern.

2.3.2 Electricity

The ESB is required to fix charges for the sale of electricity and for goods and services rendered so that commercial break-even is achieved. The mandate that ESB "break even" has meant that during a long period where it was not permitted by the Irish government to raise its tariffs, ESB complied with the break-even mandate by reducing investments, which, together with rapidly expanding demand, resulted in constraints on generating capacity.

2 "Policy Issues Arising from the Completion of a Second Scotland-Ireland Gas Interconnector", Forfas, Sept 2002

At the beginning of 2001, approximately 4500MW of generation capacity was connected to the transmission network with an additional 275MW of small-scale generation capacity connected directly to the distribution system. Generation capacity will be increased by the introduction of two new generators in Dublin, a 400MW station at Irishtown and a 343MW station at Huntstown.

Eirgrid estimates suggest that approximately 400MW of new generation capacity will be required by 2007/8. Current indications are that a shortfall of power during the coming winters of 2002 and 2003 will be averted by the commissioning of the new Synergen and Huntstown generators. However unless the construction of additional new capacity begins soon, emergency generation may be required the following year.

The need to attract new generation capacity into the market means that there will be upward pressure on electricity prices, as the cost of operating new plant will exceed that of some of the existing plant. Thus, the domestic demand and supply situation will be a key factor driving electricity prices upwards. In this context, Ireland is in an unusual position, in that most of our European competitors have surplus generating capacity.

2.4 Current Energy Prices

2.4.1 Gas Prices

Eurostat data for gas prices across 13 European countries suggest that Irish small and large industrial consumers of gas have enjoyed a delivered cost of gas that is below the average (see Table 2.2). Smaller industrial consumers have enjoyed a stable price over the past few years. while prices for larger users have tended to rise. The latter may be due to the liberalisation of the market and the fact that prices now reflect the price of gas on the international markets and the impact of commercially negotiated prices rather than BGE tariff prices.

Table 2.2: Gas Prices Facing Industrial Users in the European Union, 1999-2002

	Small industrial (max daily off take 21GJ)				Larger industrial (max daily off take of 167GJ)		
	1999	2000	2001	2002	1999	2001	2002
Belgium	4.26	5.22	7.06	6.03	2.6	6.72	4.37
Denmark	4.41	7.55	10.49		2.65	5.99	4.49
Germany	4.77	6.01	7.88	7.52	3.99	6.49	5.51
Spain	3.18	4.38	5.87	4.68	2.7	5.42	4.22
France	5.27	5.01	6.03	6.7	3.1	4.88	
Ireland	5.66	5.66	5.66	5.67	3.09	4.65	4.88
Italy	4.9	5.97	7.77	7.44	3.34	6.38	5.67
Lux	4.78	5.03	6.99	5.99	3.74	5.4	5.14
Holland	4.8		5.59		3.09		
Austria	6.23	5.67	6.82	6.98		5.35	5.18
Finland	2.51	4.53	8.76	7.87	2.11	5.55	4.61
Sweden	3.86	5.56	9.95			7.91	5.69
UK	3.82	4.3	4.95	5.74	3.18	3.79	5.16
Portugal	5.92	13.16		8.95	5.92	9.22	8.6
Ireland Rank (out of 13)	12	8	3	2	5	2	5
Mean	4.60	6.00	7.22	6.69	3.29	5.98	5.29
% Deviation from mean	23%	-6%	-22%	-15%	-6%	-22%	-8%

Source: Eurostat / Forfas report. Note: prices exclude Vat.

2.4.2 Electricity Prices

There is no shortage of comparative information on electricity prices. However, some of the data sources are less than reliable because of their failure to reflect the full range of prices facing the consumer. This has become a problem since the liberalisation of electricity markets and the resulting proliferation of prices in the market place. The European market research group INRA has published a set of prices for the year 2001, which has been collated in a manner that ensures their representativeness [3]. In particular, prices in liberalised markets were based on an audit of the electricity invoices of a sample of consumers.

The report details prices paid during year 2001, by residential and non-residential customers across 18 European countries and the key data are reproduced in Table 2.3.

Table 2.3: European Electricity Prices, 2001

	Residential prices (electricity + taxes + VAT)			*Non-Residential prices (electricity + taxes) excluding VAT*				
Prices/kWh in Eurocents	Band 1 <=2000kWh/year	Band 2 >2000kWh/year <=7000kWh/year	Band 3 <7000kWh/year	Band 4 <=0,5GWh/year	Band 5 >0,5GWh/year <=1GWh/year	Band 6 >1GWh/year <=9GWh/year	Band 7 >9GWh/year <=20GWh/year	Band 8 >20GWh/year <=100GWh/year
Austria	16.56	15.03	13.28	11.35	9.46	8.48		
Belgium	18.27	14.65	11.38	12.39	10.87	8.49	7.31	4.65
Czech Republic	10.99	8.23	6.29	8.13	5.91	4.81	4.2	
Denmark	27.8	20.56	19.13	15.7	15.08	13.95	13.36	
Finland		8.03	6.32	4.67	4.34	3.68		
France	15.18	11.53	10.24	8.73	7.16	5.99	4.03	3.73
Germany	19.11	14.91	11.41	10.19	7.8	5.85	4.85	4.7
Greece	7.51	6.2	6.06	8.7	8.78	6.49	5.91	5.31
Hungary	9.17	7.33	6.5	6.82	7.43	5.91	5.36	
Ireland	15.29	10.94	8.06	13.46	10.15	6.82		
Italy	9.35	16.5	17.77	11.72	10.69	9.43	8.32	
Luxembourg	17.77	11.54	9.3	12.02	10.85	8.08	7.19	
Netherlands	25.37	19.21	16.5	11.5	9.5	6.78		
Portugal	13.85	12.62	8.66	9.56	8.27	6.82	5.81	4.79
Spain	14.5	10.99	8.4	9.52		5.92	5.09	4.47
Sweden		10.62	7.77	4.92		2.58		
Switzerland	25.46	14.92	11.68	14.25	12.45	10.63	10.11	
UK	13.88	11.41	9.9	9.18		5.38		
Ireland rank (out of 18)	9	6	6	16	10	11	N/A	N/A
Mean	16.25	12.51	10.48	10.16	9.25	7.01		
% Deviation from mean	-6%	-13%	-23%	33%	10%	-3%		

The Irish consumer in the residential sector generally enjoyed competitive prices below the average in 2001. With regard to industrial consumers, the picture is more mixed. While the larger non-residential electricity consumers also fared well, the smaller and medium sized enterprises paid significantly more than the average.

The INRA report covers the period Jan 2001 to December 2001. Irish electricity prices have been subject to increases in October 2001 and in October 2002. Table 2.4 highlights the changes in ESB tariffs announced by the CER. The CER has made efforts to re-balance the tariffs applied to Irish consumers as well as incorporating the increases sought by the ESB.

[3] Report available from INRA website at www.inra.com

Table 2.4: ESB Tariff Increases and Re-balancing, 2001-02

Category	Price Sept 01 (cent/kWh)	October '01 increase %	Oct '02 increase %	Combined increase %
Domestic	9.32	8.9	13.25	24.8
General Purpose	11.01	3.0	3.56	15.3
Low Voltage Maximum Demand	7.64	13.9	8.42	17.9
10-20kV Maximum Demand	6.19	16.1	3.46	10.9
38kV Maximum Demand	5.42	19.0	4.2	10.9
110kV Maximum Demand	4.93	9.0	4.2	9.8
Average		8.6	9.85	14.9%

The INRA report takes account of 3 months of the increases in October 2001. While the CER breakdown of tariff categories does not exactly match those used by INRA, it is clear that there will be a tendency for Irish consumers to drop down the rankings when the full impact of the October 2001 increases and some of the October 2002 increases are reflected.

To illustrate the impact of the re-balancing and increases in tariffs on competitiveness, an estimate of 5% increase was applied to all countries except Ireland. The Irish tariff increases were then compared to international tariffs so inflated as set out in Table 2.5.

Table 2.5: Illustrative Impact of Tariff Increases and Re-balancing

Prices/kWh in Eurocents	Band 1 <=2000kWh/year	Band 2 >2000kWh/year <=7000kWh/year	Band 3 <7000kWh/year	Band 4 <=0,5GWh/year	Band 5 >0,5GWh/year <=1GWh/year	Band 6 >1GWh/year <=9GWh/year
EU increase	5%	5%	5%	5%	5%	5%
Irish Tariff Review	24.80%	24.80%	24.80%	15.30%	17.90%	10%
Ireland new rank (out of 18)	11	11	9	17	13	12
Mean	17.26	13.26	11.09	10.74	9.80	7.37
% Deviation from mean	11%	3%	-9%	44%	22%	2%

While the re-balancing exercise has diluted the impact of tariff increases on the non-residential sector, the tariff levels are still much higher than applicable elsewhere in Europe. As will be seen from the estimates for Bands 4 and 5 in Table 2.3, the SME sector moves from a position of 33% above the EU average before the increases and re-balancing to 44% above the EU average in our model. The largest consumers move less significantly from 2% below to 3% above.

If the liberalisation of the electricity sector across the EU proceeds, then tariffs may fall across Europe in the coming years, particularly as most EU countries are starting from a position of excess capacity. Steady or falling EU average prices at a time when Irish prices are rising would be seriously detrimental to Irish competitiveness.

2.5 Prospective Energy Prices

2.5.1 Introduction

This sub-section of the report examines the prospects for energy prices in the future. As indicated at the outset, energy prices may increase because of increases in underlying costs, or changes in the balance of supply and demand. These drivers of price increases may derive from the domestic or external causes. They may also apply to energy as a whole, or to gas or electricity separately. The following sub-section reviews a number of factors that are likely to affect energy prices generally before proceeding to a discussion of factors of particular relevance to gas and electricity prices individually.

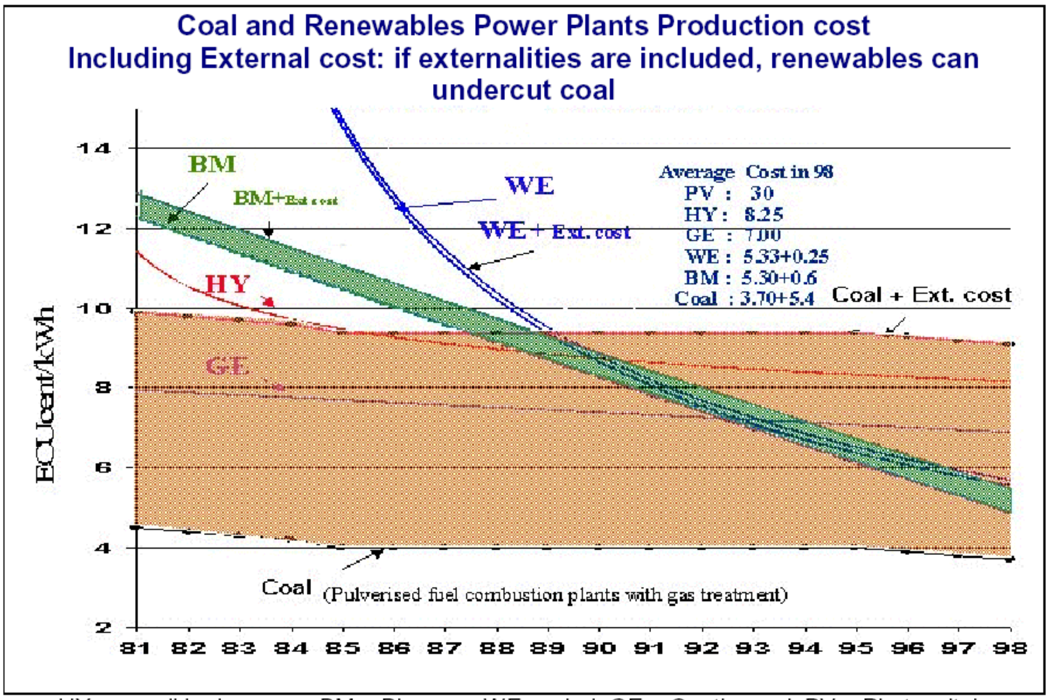
2.5.2 General Drivers of Energy Prices

There are a number of international factors that could add to the overall cost of electricity for Irish consumers. Most of these derive from concerns with the environmental impacts of energy use.

It is widely recognised that there are external impacts associated with energy use that are not reflected in energy prices. The ExternE project is a research project set up by the EU Commission as the first comprehensive attempt to use a consistent 'bottom-up' methodology to evaluate the external costs associated with a range of different fuel cycles. Examples of external costs include damage to the natural and built environment, such as effects of air pollution, occupational disease and accidents. There is also growing concern about the external costs of waste clean-up from nuclear power-generation plant. Again, these costs are not reflected in the prices charged for the electricity produced.

Figure 3.2 illustrate some of the findings of the project. These indicate that traditional energy sources, such as coal, are more expensive than renewable energy sources, once externalities are included in the cost of coal use. This evidence about the externalities associated with traditional energy sources will promote Government and EU actions to ensure that energy prices reflect such costs.

Figure 3.2: ExterniE Project Cost Estimates



HY = small hydropower; BM = Biomass; WE = wind, GE = Geothermal; PV = Photovoltaic

The most obvious of these actions relate to the Kyoto Protocol[4], the proposed European Union carbon tax, emission trading regime and European Union Large Combustion Plant (LCP) Directive.

Under the Kyoto protocol, signatories to the agreement are required to restrict their emissions of greenhouse gases within certain limits. As is widely acknowledged, greenhouse gas emissions in Ireland are on course to substantially exceed the limits set. Government is faced with implementing corrective actions over the medium term. Such actions may include changes in the tax regime to ensure that fuel use reflects the external costs involved.

2.5.3 Prospective Gas Prices

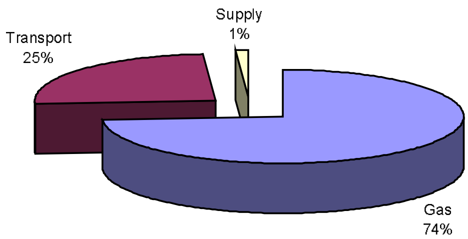
2.5.3.1 General

The main constituents of gas prices to the Irish consumer are the cost of the gas itself and the cost of transporting the gas to the point of consumption. Relative to the cost of the gas and transport, supply costs are minimal. Figure 2.3 illustrates the typical breakdown.

Larger customers who are eligible to ship their own gas have additional overheads in administering their gas deliveries while smaller customers are subject to a supply cost from Bord Gais.

[4] See appendix 3 for details on the status of the Kyoto agreement

Figure 2.3: Breakdown of the Cost of Gas



2.5.3.2 Price of Imported Gas

Currently, the bulk of Irish gas (over 80%) is imported from the UK with the remainder sourced from the Kinsale field brought ashore at Inch. The price of gas itself is essentially imported from the UK where the spot market price for gas is competitive with the cost of European gas. Irish consumers are largely unable to influence this price. For the future, Irish gas prices will be set by prices prevailing internationally.

Across Europe, the cost of gas is set to rise as increased overall demand depletes old reserves and requires new sources to be located. Table 2.6 outlines where the EU15 member states could potentially source gas over the next twenty years.

Table 2.6: Potential sources of EU imported gas for EU15

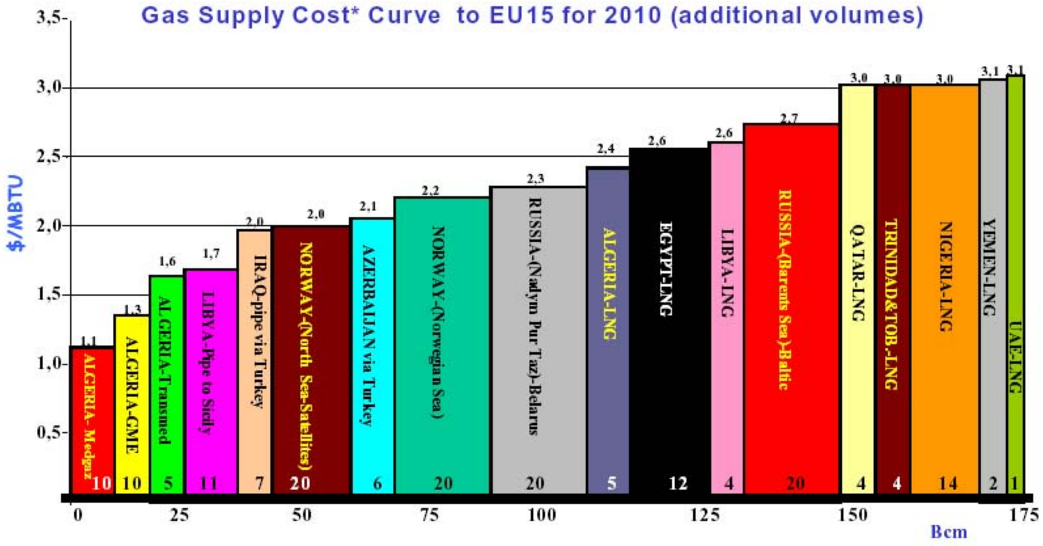
(bcm per annum)	Actual imports 2000	Potential imports 2000-2010	Potential imports 2000-2020
Norway	50	40	40
Algeria	55	27	27
Libya	1	10	10
Egypt	0	12	12
Russia	73	40	40
Azerbaidjan	0	6	6
Turkmenistan	0	0	0
Iran	0	0	0
Qatar	1	4	4
UAE	1	1	1
Oman	0	0	0
Yemen	0	2	2
Iraq	0	7	7
Nigeria	1	14	14
Trinidad&Tobago	1	4	4
Total Supply:		**167**	**297**
Import needs		**112**	**239**
Surplus(bcm)		**55**	**58**
Surplus (%)		**49%**	**24%**

Source: EU Commission DGTREN

In order to meet the 112bcm annual import demand of the EU in the current decade, infrastructure needs to be in place between the gas sources listed and the EU's borders. Some infrastructure is already in situ, but substantial new build will be required to bring much of the gas to Europe, with a corresponding upward pressure on delivered prices

Analysis of the size of each reserve and the cost of transport to the EU borders allows a gas supply cost curve to be derived which shows the cost of bringing gas to the EU border rising steadily. This is clearly not good for EU competitiveness or for Irish consumers on the periphery of Europe, far from these gas sources.

Figure 2.4: Projected costs of bringing gas to EU Borders



Source EU Commission DGTREN

2.5.3.3 Remunerating Domestic Infrastructure Costs

Irish consumers will also be required to meet the costs of a €1.4bn infrastructure upgrade by BGE. This new infrastructure comprises:

- a second interconnect between Dublin and Scotland to help improve supply security. About 80-85% of gas is currently supplied via this connection with the remaining 15-20% coming from Kinsale.
- A new pipeline is planned to connect up the Corrib field and complete a national ring network, improving security with another supply as well as providing increased access to the gas network

These costs will be recovered from consumers of gas through BGÉ transmission tariffs.

Slower economic growth and the closure of IFI have meant that the interconnector is operating below anticipated capacity. As the cost of the interconnection infrastructure between Ireland and the UK is met by the transport charges for the gas transported through it, less gas transported means that the infrastructure cost is spread over less volume, pushing up the cost of gas to individual users.

There is a danger of a vicious circle of less demand, higher price, less gas emerging. Irish consumers will already be exposed to the increased cost of delivering gas to the EU borders. It is important that this situation is not exacerbated. Unlike electricity, consumers have realistic alternatives to gas, most notably oil. Implementation of carbon emission controls should help encourage the use of gas over oil and coal. Increased gas consumption is the key to reducing the impact of high transport charges and bringing the cost of gas to Irish consumers to levels that are comparable with our EU neighbours.

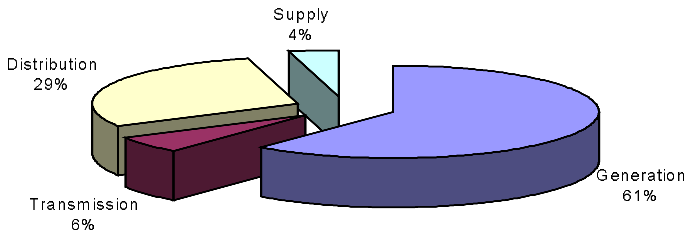
In this report, we highlight the need for pricing for electricity to take account of congestion on the network because of the scale of impact that congestion can have on the operation and price of electricity. While a similar analysis could be applied to the gas network, the impact of congestion for gas is not as great allowing for a uniform or postalised approach to be adopted.

2.5.4 Prospects for Electricity Prices

2.5.4.1 General

The overall price of electricity to consumers comprises generation, transmission, distribution and supply costs. The breakdown of these final costs of electricity from ESB to the Irish consumer is illustrated in Figure 2.5 below[5].

Figure 2.5: Breakdown of Irish Electricity Costs



2.5.4.2 Remunerating Capital Costs

In Section 2, the need for investment in additional generating capacity over the next few years was made clear. A considerable proportion of Ireland's baseload is generated from cheaper coal in Moneypoint, where the capital expenditure is well depreciated. New generation plant coming on-stream, while considerably more thermally efficient, and enjoying substantially lower operating costs, runs on a more expensive fuel (gas) and requires its capital cost to be remunerated. Both of these factors lead to a situation where the newest plant's cost of generation at €48/MWh is only slightly below ESB Powergen's average cost at €51/MWh, but is certainly well below the cost of generation at ESBPGs cheapest generators such as Moneypoint. Again, new investment will tend to drive prices upwards.

A significant investment in transmission infrastructure of €612M was approved by the CER in 2001. The majority of the spend is on reinforcement of existing transmission (€450M). To illustrate the scale of the investment, full replacement cost of the existing transmission network is estimated at c.€1.4bn. The costs of the TSO in operating and ensuring the maintenance and development of the transmission system and this capital expenditure costs are recovered through Transmission Use of System (TUoS) Charges.

[5] Calculation based on data in ESB PES Price Review, CER/01/114. Published Sept 2001

A substantial capital expenditure in distribution infrastructure of over €1.5bn was also approved by the CER in 2001. This is made up of approximately €500M of new business, €590M of reinforcement to the existing wires and €500M on non-load related capital expenditure.

Remuneration of this increased capital spend will inevitably drive electricity prices upwards.

2.5.4.3 Additional Costs Imposed by Peat Fired Generation

Peat is one of Ireland's main sources of indigenous energy and is a resource very close to the end of its life. The value of peat was evident during the oil crises of the 1970s and 1980s when it provided a hedge against soaring oil import prices as a fuel for electricity generation. Unlike imported fuel, peat is not subject to international fuel price volatility. Under EU Electricity Directives, up to 15% of the fuel mix used in electricity production may be reserved for indigenous sources. This directive also provides for a Public Service Obligation (PSO) mechanism relating to security of supply.

Using these two facets of the EU Directive, the Irish Government approved the construction of two new peat stations. The ESB's old peat-powered stations at Rhode and Ferbane are being closed down..

Of the total generation capacity currently connected to the transmission network, approximately 8% is peat-fired. While the new plant leaves overall peat fired capacity broadly unchanged, it is much more efficient, using bubbling fluidised bed technology to reach efficiency levels of 38% compared to 20-25% for the older plant.

This security of supply from locally produced but inefficient fuel carries a cost to consumers. CER estimates of the cost of the peat levy to be imposed on all electricity consumers to be as shown in Table 2.7.

Table 2.7: Costs of Peat Levy 2002-2004

Year	2002	2003	2004
PSO levy	€41M	€93M	€91M

2.6 Summary

Energy demand is growing strongly. Demand for gas supplies is being driven both by extension of the gas network and the increased use of gas for electricity generation. The position with regard to the supply of gas is relatively good. However, the need to remunerate new capital spend will result in upward pressure on prices.

Electricity demand is also growing strongly at a time when capacity is constrained. Significant capital investment in generating plant will be required over the short term, and this will tend to increase prices. Ireland is in an unusual position in this regard in that most of our competitors have surplus generating capacity.

Irish industrial consumers of gas have tended to enjoy prices that are below the average for Europe. With regard to electricity prices, the picture is more mixed. Smaller and medium sized enterprises have been paying above the average. Electricity price increases are currently in train and these will exacerbate this situation.

The expectation is that energy prices will rise in the short to medium term and that Irish enterprises will face increasingly higher prices than their European competitors.

Increasing concerns with the environment are likely to lead to policies that will raise energy prices. Apart from this general trend there are a number of specific factors that will raise prices:

- The need to remunerate additional gas and particularly electricity infrastructure;
- Increased demand for gas across Europe and the consequent in increase in gas prices; and
- The additional costs imposed by reliance on peat fired generation.

This upward pressure on energy prices reinforces the need to ensure that energy is supplied in as efficient a manner as possible, and that existing excessive cost structures are altered. This requires development of a structure for energy supply that both promotes competition and where the real costs of alternative sources of supply are transparent.

This report assesses the current structures operating in Ireland from this viewpoint, analyses best practice abroad and makes recommendations for change.

3 Electricity Market Designs

3.1 Features of electricity which Impacted on Market Structures

As in any commodity market, a market for electricity involves interaction between supply and demand of electrical power. Generators of electricity provide the supply of electrical power and the electrical power consumers provide the demand side. On the one hand, electricity can be viewed as a perfect commodity in that it is impossible to distinguish between electricity generated from one source and another. On the other hand, well-established commodity market designs cannot be applied to electricity market design due to the unique physical characteristics of electricity.

Before we can assess a design for an electricity market, it is important to understand the unique features that play an important role in the operation of (and therefore in the design of) electricity markets:

3.1.1 Inability to Economically Store Electricity

As electricity cannot be economically stored, and demand cannot be predicted in advance, demand and supply must be matched by supply in real time, and the system must provide a balancing mechanism. However, electricity demand and the cost of meeting that demand vary greatly with the seasons and in particular with the time of day. Figure 3.1 shows the daily demand profile for overall consumption of electricity in Ireland in 2000. The most efficient operation of the electricity system would have all generators ranked in efficiency terms and switched on in merit order as demand increases. Other factors such as the ability of a generator to ramp up or down quickly are also be important considerations in the peak areas of the curve. The most efficient generators would therefore be contributing the maximum while less efficient generators would be forced up the order from the baseload into the mid-merit and peaking section of the load. If we simplistically assume that:

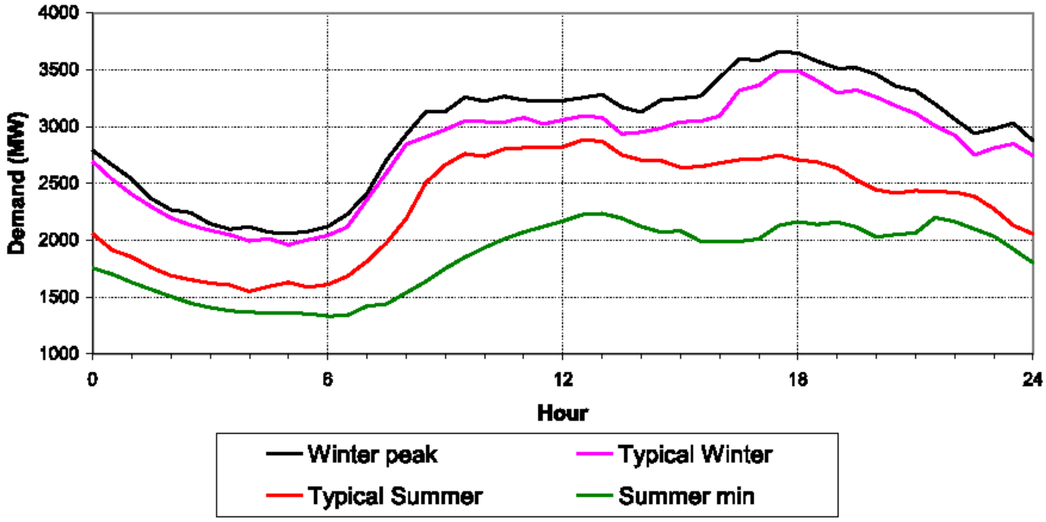
- baseload covers 24hrs of the day
- mid-merit covers 12hrs of the day (8am-8pm)
- and peaking covers 3 hrs (4-7pm),

we can see how the price of delivering power varies depending on the time of day. So as generators switch on, moving up the merit order stack from most to least efficient:

- the marginal (variable) cost of generation increases as the less efficient plants provides the additional power and
- discontinuous running hours at these plants also push up the cost of this power even further, as fixed costs have to be spread over a shorter operating period than at base-load plants.

This means that decisions must be made in relation to what plants are switched on and off to balance supply and demand. A good market structure will send appropriate signals so that this happens in the most efficient way

Figure 3.1: Daily Electricity Demand Profile in Ireland



Source: Eirgrid Adequacy Statement 2002-2007.

3.1.2 Inability to Control the Flow of Electricity

Another feature of electricity is that it is not possible to direct specific output from a generator through the transmission wires to arrive at a specific customer for consumption. Electricity flows through transmission and distribution wires according to Kirchoff's laws. Electricity pumped into the transmission network follows the path of least resistance, determined by the physical characteristics of the wire such as its length, material and thickness. At the threshold capacity of a transmission wire, electricity flow through the wire is at a maximum and that path becomes congested i.e. no further energy flow is possible without damage.. Active grid management is therefore required to ensure that stability of the grid is maintained within threshold limits. Congestion in the grid is resolved by instructing specific generators to raise or lower output as required. Generators involved are described as being 'constrained' on or off.

3.2 Pre-requisites for Transition from Monopoly to Competition

Because of the features described above, the typical organisation of the electricity industry for most of its history has comprised vertically integrated utilities (VIU) with a monopoly over generation, transmission, distribution and supply functions. Under a VIU, the costs of operating the entire system could all be lumped in together.

Monopolies, by their nature, are less efficient than companies that operate in competitive markets. In a competitive market, companies develop higher levels of efficiency across a range of categories:

Productive (or technical) efficiency	Ensures products are sold at the lowest possible cost to consumers
Allocative efficiency	Ensures that resources are allocated to their most productive use
Dynamic (or adaptive) efficiency	Ensures that they adapt in response to changing circumstances, improve their products and innovate to reduce costs

Competitive forces tend to improve a company's efficiency resulting in lower prices better quality products and services for the consumer. A well-documented development of competitive electricity markets has taken place over the last three decades.

With the onset of competition and the requirement for non-discrimination between market participants, the various costs associated with the operation of the electricity system must be understood and fairly apportioned. In particular the treatment of important operational issues such as scheduling and dispatch, system balancing and congestion management need to be conducted in an open and non-discriminatory manner. This matching of the physical realities with market design has been a challenging process.

In going from a VIU monopoly to open competition, a number of pre-requisites need to be addressed:

- **Transparency** so that market participants can understand how the market is working, how congestion is managed, and assess their relative position in the competitive landscape
- **Dominance of incumbent** must be addressed to ensure that there is no exercise of market power
- **Competition must be encouraged** during the initial phases to build up enough market participants for competition to survive
- There must be an **overall policy thrust** from government and the regulator which provides a clear long-term map of the route from monopoly to competition for all participants

In the following sections we review the issues in the Irish market, and how the might be resolved, under these four headings.

An efficient market requires an optimal balance between supply and demand. As will be demonstrated in Section 4, undue focus on the particular sections of the market such as generation, while ignoring other critical elements of the supply-demand interaction such as transmission management and demand-side activities makes for poor market design. Imperfect markets lead to opportunities for abnormal profits and unrealised efficiency gains.

3.3 Models for Electricity Market Design

Armed with an understanding of the fundamentals, we can look at they types of market designs that have been employed in liberalising electricity markets. The Main categories are:

- Single buyer model
- Pool model
- Bilateral contracts model

By sheer co-incidence, each of these models has been deployed very close to Ireland, with the single buyer system operational in Northern Ireland, a pool system in England and Wales up to April 2001 and a bilateral contract system in England and Wales thereafter.

3.3.1 Single Buyer

Under the single buyer (SB) model, a central body is set-up to assume control of the market. The single buyer agrees long-term power purchase agreements with each generator and takes responsibility for the forward planning of generation capacity. This model is a small move away from the old VIU model, with competition introduced into the generation sector. Under the VIU monopoly, all risks lie with the consumer. Under the SB model, all risk will lie with the SB except for a small risk of generation plant operation. The single buyer typically requires government backing so the risks eventually fall back on the consuming public. This model is in place in Northern Ireland and is widely regarded as having led to very high consumer prices and supernormal profits for the generators. Properly developed, the model can provide a framework for ensuring security of supply, while allowing for limited competition in generation. However, other models have more ambitious aims.

3.3.2 Pool model

Many variations of the pool model exist. In the early 1990s, England and Wales opened up their markets under the pool system, and it was initially perceived as the leading market design. Under this model, a mandatory day-ahead market is organised where all generator offers and all supplier bids are pooled for each trading period during the day. The trading period is typically every half hour. Bids and offers are stacked in merit order and a single price, called the system marginal price (SMP), is calculated based on the highest generator in the stack for the demand in the period. All generators receive the SMP price regardless of their actual bids into the system. Suppliers all purchase power from the pool at the SMP price plus an uplift cost to cover the costs of capacity payments to generators, transmission losses, ancillary services and congestion management.

As this model does not provide generators with long-term power agreements, generators and suppliers developed agreements in the form of Contracts for Difference (CfDs) which effectively allowed then to bypass the pool for an amount of their respective volumes.

This type of pool system allows generators and suppliers to trade, but participants found it easy to manipulate. Generators were able to predict in advance which plant would be the marginal plant and could set the bid for this plant at a high level, resulting in excessive payments to all generators. In addition, generators were able to predict in advance which generation plant would be constrained off by the system operator and were able to adjust their bids to again receive excessive payments both for constrained on and constrained off plant. This was possible because of the averaging across all participants of location and congestion factors.

3.3.3 Bilateral contract model

Under a bilateral contract model, the starting point is that generators and suppliers are required to get together first and agree terms. These terms are then provided to the system operator who does not know the price agreed between the generator and supplier. The system operator just needs to know what the production and demand volumes are. The system is therefore not based on merit order dispatch, rather it is based upon nominations from the generators and suppliers.

A separate market is then organised to allow the system operator to balance the market in real time. Under this market, the system operator publishes bids and offers to secure either additional or reduced generation.

In 1997, a review of the England and Wales pool found that the system was flawed, uncompetitive and susceptible to manipulation. It was agreed that a new set of trading arrangements would be designed and in April 2001, NETA (New Electricity Trading Arrangements) went live. NETA is a bilateral model with the following features

- forwards and futures markets that allow contracts for electricity to be struck over time-scales ranging from several years ahead to on-the-day markets. These are intended to lead to the emergence of forward price curves, providing generators and suppliers with clearer signals of when entry is likely to be profitable – thereby facilitating new entry and enhancing security of supply.
- a Balancing Mechanism by which the National Grid Company (NGC), the operator of the transmission system, accepts offers and bids for electricity close to real time to enable it to balance supply and demand. This is intended to ensure short-term quality and security of supply,
- an Imbalance Settlement process for making payments to and from those whose contracted positions do not match their actual metered electricity production or consumption and for clearing certain other costs of balancing the system. This is intended to provide more accurate cost targeting and sharper cost incentives to manage risks.

Under NETA, each bilateral contract must submit 10 bid-offer pairs which allow the system operator to compensate for deviations between real time and day-ahead volumes. The aim of NETA was to force participants to agree prices first and make less volume subject to the SMP price in the pool. During the initial periods of operation, wide spreads in the balancing market meant that inaccurate estimates of volumes notified to the system operator were very expensive to balance. This has been found to favour larger portfolio generators who can net off their imbalances across their portfolio of generation plant and load, but found to be penal on single plant generators and on renewable generators which are by their nature intermittent and difficult to predict. The spreads on NETA are reducing however and the model may yet prove effective for the UK. The table below should the narrowing of NETA spreads during its first year of operation

Table 3.1: NETA Dual-Cash Out Balancing Prices

	Median System sell price	Median System buy price	Spread
April 2002	10.01	21.11	11.10
April 2001	7.68	30.55	22.87

Source: Elexon

As with the pool model, the bilateral model seeks to average the effect of transmission issues such as locational losses and congestion. A Transmission Network Use of System (TNUoS) charge is applied to generators (27%) and consumers (73%) to cover the capital and maintenance costs of the network. This charge is differentiated locationally using a technique called Investment Cost Related Pricing and provide signals for generators and loads.

3.3.4 Bilateral Versus Pool – Key Trade-Offs

The key issues with the **pool model** are:

- a failure to take location factors and **congestion** into account, and
- the knock-on impact of a **single market price**

In the **bilateral contract** model, the single market price risk is moved from the pool operator to the bilateral contract between the generator and the supplier, but at the **expense of the merit order dispatch** of the pool system.
Both models tried to simplify the design for it ease of understanding, without realising that the simplifications would lead to inefficiencies and opportunities for abuse. The pool with a single price sought to average their impact across all participants while the NETA bilateral model could be viewed as translating costs of congestion management into an accuracy or flexibility penalty/reward system. By moving the single price risk to the market participants, the bilateral model has to sacrifice merit order dispatch of the entire system. This may not be an issue in a large market but is important in a smaller market. The bilateral process essentially subdivides the market into smaller segments with the net result of lowering overall system efficiency.

3.4 Summary

The physical features of electricity means that well-established commodity market designs cannot immediately be applied to electricity markets.

Specially, there is a need for grid balancing of active grid management to ensure efficient resource allocation.

The traditional approach to handling these issues was the development of vertically integrated utilities. In recent decades competitive market models have evolved creating a successful path from VIU to competition inevitably involves certain features:

- A new **structure**
- Greater **transparency**
- Steps to reduce the **dominance** of the incumbent
- Steps to **encourage new competitors**
- An **overall policy thrust** to provide a clear framework within which the participants can negotiate.

Three key models have evolved:

- Single Buyer
- Pool
- Bilateral Contracts

The latter two are closer to a true competitive model, both have their strengths and drawbacks.

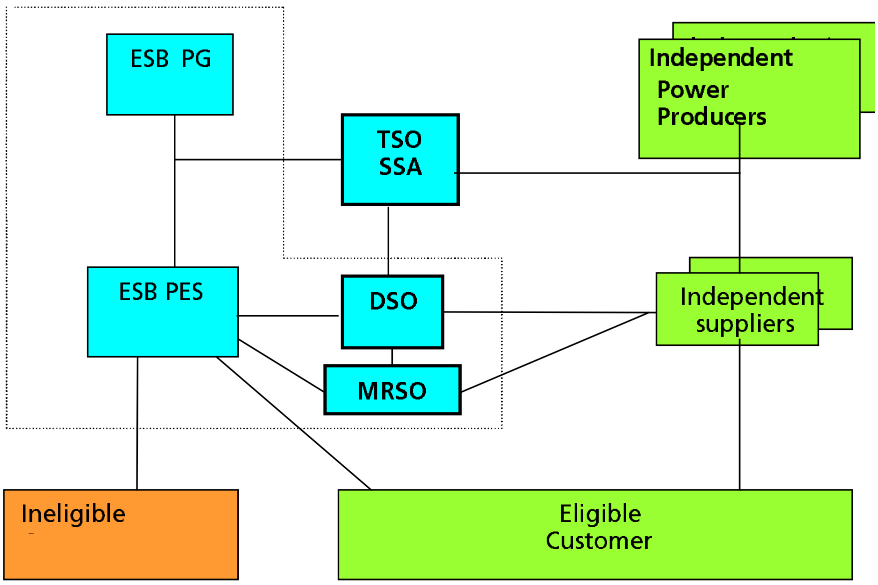
4 Irish Electricity Market

4.1 Introduction

In July 1999, the Minister for Public Enterprise issued a policy direction to the CER relating to Proposed Electricity Trading Arrangements. A copy of this policy direction is included in Appendix 1. This policy direction set the framework for the design of the Irish electricity market. The key roles of the players in the market are outlined below:

4.2 Market Structure

Traditionally in Ireland, electricity has been supplied through the ESB monopoly, which extended to the generation, transmission, distribution and supply functions. In the past few years, partly as a result of EU legislation, regulatory measures have initiated the unbundling of the industry. However, the degree to which competitive industry structures have been established is limited. ESB PG (Power Generation) is still the monopoly owner of the majority of Irish generation capacity. ESB PES (Public Electricity Supplier) is the monopoly electricity supplier to customers in Ireland. DSO / MRSO are the operators of the Distribution System and Meter Registration Service respectively. These activities are licensed individually, but current licenses are held by the ESB. TSO is the Transmission System Operator, which also provides Settlement System Administrator function. Currently, these services are provided by ESB National Grid, a division of the ESB. The ownership of the transmission system remains with ESB as transmission asset owner (TAO). ESB National Grid will become Eirgrid early in the new year. Eirgrid responsibilities include the delivery of energy from the generators connected to the transmission system, dispatch of generators, running the settlement system necessary for the operation of a competitive market.



IPPs (Independent power producers) are new entrants into the power generation arena. Huntstown Power (owned by Viridian) and Dublin Bay Power (owned by ESB and Statoil) are the two largest new thermal generators while a number of renewable generators have also entered the market such as Airtricity. Eligible customers are those customers who are free to choose their power supply from any licensed supplier There are approximately 1,600 such customers and they comprise 40% of the Irish electricity market by volume. In addition to this threshold, there is 100% opening of the "green" and Combined Heat and Power ("CHP") markets, where such suppliers may supply any customer in the country irrespective of consumption. Non-eligible customers are smaller consumers and represent 60% of the Irish market by volume of electricity consumed but virtually 100% by number of consumers. All of these consumers are obliged to obtain their supply from ESB PES.

From this overview of the structure of the electricity market, it is clear that the market is less than fully competitive from a number of viewpoints:

- The vast majority of consumers do not have a choice as to whom they purchase electricity from; and
- There are only a handful of players competing in the market and the ESB continues to dominate the entire industry.

The following sections present some of the key issues with the operation of the market as presently constituted. These are subdivided into the categories introduced in Section 1.

4.3 Operational Structure

4.3.1 Bilateral Contracts and Market Segmentation

The Irish model is structured with bilateral contracts at the core. Although similar in may respects to the NETA model deployed in England and Wales, the Irish model was designed well before the NETA model was implemented in April 2001. Under both models, generators and suppliers form contracts between themselves to match supply to demand. Both parties then provide volume information in advance to the system operator on the energy injections to the grid and energy withdrawals from the grid to allow the TSO to determine the day-ahead dispatch schedule. The full rules of the Irish market are set out in the Trading and Settlement code available from the CER web-site.

Bilateral contracts act to segment the market into smaller pieces. In a market like Ireland's which is already small, this further segmentation creates unnecessary inefficiency. This problem is at a maximum at 100% bilateral contracting and reduces as a problem as the level of spot trading increases.

4.3.2 Merit Order Balancing

The policy direction sets out details of the balancing arrangements for the Irish market. It explains how two prices (top-up and spill) should be calculated and how generators and suppliers must avail of top-up and spill services from the ESB at these prices to balance the system. Top-up price is intended to reflect the long-term average cost of generation and is linked to the estimated cost of a best new entrant (BNE). Top-up prices are profiled according to estimates of ESB avoided fuel cost plus a capacity element linked to the loss of load probability for each trading period. Spill price is equivalent to the most expensive decremental (DEC) bid for each trading period[6]. Unlike NETA, where the market sets these dual "cash-out" prices and where high prices and wide spreads have been the subject of controversy, the market does not set the prices in the Irish system.

The Irish trading model does not optimise the energy market, rather it optimises the process for balancing the market when day ahead demand estimates do not match the actual demand on the day or when units need to be dispatched to maintain system stability. While generators make their nominations to the system operator ex-ante, they provide the system operator with incremental (INC) and decremental (DEC) information which includes both volume and price. This information allows the SO to balance the system. **So while there is merit order balancing of the system, the overall efficiency of the system is compromised by the fact that overall merit order dispatch does not exist.**

It is questionable whether dual cash-out prices are optimal. Dual cash out prices are designed to force down volumes in the balancing market and maximise bilateral contracting. In Ireland, top-up and spill provided by ESB PG are dual cash-out prices. While the single cash-out price of the pool based on system marginal price was an issue in the England and Wales pool, its replacement with dual cash-out has been subject to criticism.

According to Stephen Littlechild commenting on the design of NETA, "*In most cases, therefore, it is not clear that a dual cash-out price is called for. Here I agree with Larry[Ruff] and Bill [Hogan] about the potential inefficiencies that could be caused by significantly divergent prices.*" [7]

A market which forces bilateral contracting via dual cash-out prices to very high levels (approx 98% of NETA is based on bilateral with only 2% traded on spot) means that the most efficient plant on the system will maximise its output only if it has customers to take all the output from it. This would require a customer base with a flat load. Most customer load is profiled. So, to match a non-flat customer load profile, a new entrant must either ensure that its peak customer demand can be met by the capacity of its generation or drop its output to a level where its own plant is not maximising its output. Any peaking on the customer load side will require the generator to move from its peak efficiency level or compensate using top-up or spill services from the ESB.

4.4 Transparency

4.4.1 Opaque Market Structures

There is very little information available to help a potential new entrant into the Irish market assess the level or extent of competition. The lack of a merit order dispatch means that existing market participants are unable to gauge their own competitive position. In addition, the precise details surrounding many important factors that impact on the ability of a generator to compete effectively are unclear, for example:

- congestion management procedures

[6] For further details on trading in the Irish market, the reader is referred to the guides on www.eirgrid.com

[7] "Electricity: Regulatory Developments Around the World" Presentation by Stephen Littlechild at The Beesley Lectures on Regulation Series XI, Oct 2001.

- calculation and allocation of transmission loss factors
- factors which influence the calculation of top-up and spill balance prices such as ESB avoided cost of fuel are not readily available

Transmission is paid for via the Transmission Use of Service (TuoS) charge which is currently levied 25% on generators, assessed on a locational basis using a methodology called 'reverse MW mile' and 75% on customers. All costs of ancillary services and constraints are charged to customers on a per kWh basis[8]. While this does provide a locational signal, it is a static value assigned on a yearly basis to each generator. Details of the calculation methodology are unclear and as a static annual value, the TLF does not take account of changes in demand, generation or transmission that occur during the year.

4.4.2 Non Disclosure of Bilateral Strike Price

The design of the system is such that the **strike price of bilateral contracts between generators and suppliers is not disclosed**. This is a feature of bilateral contract design.

4.4.3 Building of ESBPG Costs

The most efficient operation of the electricity system would have all generators ranked in efficiency terms and switched on in merit order as demand increases. While it would be possible to work out cost per kWh for each of the ESBPG generators, a different approach was adopted for the assessment of ESBPG costs. The CER documentation on ESBPG costs (Sept 2001[9]) bundles all ESB power plant costs and a range of other market services together to calculate a demand weighted average price of €0.051/kWh. A subsequent CER document (May 2002[10]) describes the bulk power agreement between ESGPG and ESBPES and directs that the ESBPG allowable revenue will be set out on a €/kWh basis and be profiled by time of day. So rather than the costs of generation at each of the ESB's generation units being available, an all-in cost of production from all ESBPG generation plant is produced. **So not alone is merit order dispatch not attempted by the system - this approach means that data relevant to estimation of the merit order of generation plant in Ireland is not even available.**

It is clear that as an incumbent, ESB PG's costs must be subject to scrutiny by the regulator, and in doing this, the CER evaluated them against two models designed to calculate a market price for electricity[11]:

- ESBPG pricing was benchmarked against a notional system comprised of CCGT plant for baseload and OCGT plant for mid-merit and peaking. The model assumes that CCGT plant would be used below a 50% load factor and OCGT above.
- IPA Consulting provided a more detailed model assuming a range of generation plant with varying thermal efficiencies, different fuels, designed to assess ESBPG costs relative to similar plant elsewhere

The CER used the data from these models to regulate the all-in ESBPG electricity price at a level that would be reflective of market prices. It is this price that

8 CER "Transmission Price Review Proposals 2001-2005" P44.
9 ESB Power Generation Price Review, Final Proposals CER/01/116. Published Sept 2001.
10 Bulk Power Agreement between ESB Power Generation and ESB PES, CER/02/04. Published May 20027
11 Fuller details can be found in Appendix 1, ESB Power Generation Price Proposals, CER/01/116

ESBPG is paid by the PES, and as such it is a key determinant of overall tariffs for ESB.

While this price comes out only slightly above the BNE price which is calculated on the basis of new, efficient gas plant, the components are very different:

- **Lower Capacity Charge:** Due to the fact that much of the generation plant in the ESBPG portfolio is already depreciated, the capacity charges for most would be substantially less than the BNE figure. The IPA model assumed all ESB plant had been fully paid off with the exception of the new Poolbeg CCGT plant.
- **Higher energy charge:** Energy costs would need to be analysed by fuel type as the BNE assumed gas while the ESB portfolio covers a range of fuels. New CCGT plant reaches efficiency of up to 58% while older plant are much less efficient. The following table[12] outlines typical efficiencies for plant in the ESB portfolio:
  - Old peat plant 25%
  - Distillate Oil plant 27%
  - Heavy fuel oil plant 32%
  - Coal plant 32%
  - Open cycle gas turbine plant 37%
  - New peat plant 38%
  - Older CCGT plant 47%
  - New CCGT plant 55-58%
- **Higher operating costs:** Older plant are less automated and therefore require greater levels of manpower to operate them. A new 400MW CCGT plant can be run with less than 25 people (0.0625 staff per MW) whereas station number for older plant are much higher. In 1992, ESB manpower costs per MW of installed capacity were as follows[13]:
  - Peat at 1.9 staff per MW is 30 times less efficient than a new CCGT
  - Coal and Oil at 0.5 staff per MW is 8 times less efficient
  - Gas 0.45 staff per MW is 7 times less efficient

While there has been a significant reduction in headcount at ESB in the intervening period through rationalisation programmes, the number of staff required to operate older plant still far exceeds newer plant. Operating costs are higher due to inefficient work practices. ESB has put programmes in place aimed at bringing these costs into line.

However, data from the CER do not make clear to what extent this element of costs diverges from best practice, and we are left with anecdotal data in relation to continued employment of personnel in decommissioned stations and reports of highly inflexible work practices.

4.5 Dominance of the Incumbent

4.5.1 Dominance of ESB

In addition to the inefficient design of the market, the decision not to break-up ESB PG means that it continues to dominate the market. ESB Powergen (ESBPG)

[12] Efficiency values based on inputs to IPA modelling of ESBPG costs

[13] 1992 ESB Annual Report

owns some 4,300MW[14] of generation capacity connected to the transmission network in Ireland although some of this is inefficient peak load plant. The remainder of the market comprises Edenderry peat (115MW), Huntstown (383MW), Synergen (400MW) and close to 300MW of embedded generation (i.e. connected to the distribution network, rather than the transmission network). In addition, 70% of Synergen is owned by ESB. So of 5,500MW of capacity, 4,580MW (83%) is owned by the ESB. While the CER has accepted ESB's target of reducing market share to 60%, it is unclear how this target will be achieved. It is also fair to point out that ESB has been under conflicting pressures to reduce its share, but also to put additional short term capacity in place as investment by new players has been slower than anticipated.

While recognising the industrial relations issues that would arise if ESGPG was forced to divest, it is clear that competition can only truly exist if there are sufficient competitors. However, as this section explains, the design of the Irish market is such that the playing field is tilted against new entrants.

4.5.2 Opportunities for Abuse of Market Power

Current market design in Ireland assumes that the transmission system is not a part of the market. The impact of losses and congestion in the transmission grid are artificially removed by simplifications:

Transmission Congestion

- At the end of each day, the Settlement System Administrator (SSA) determines the Ex-Post Unconstrained Schedule (EPUS) based on the known actual demand for the day. EPUS calculates how the system would have been dispatched if there had been perfect foresight of the demand while optimising the balancing of the system i.e. balancing the system in a merit order on the basis of the INC and DEC prices available. EPUS is designed to average out the impact of congestion in the system. As EPUS assumes no constraints on the system, there will be differences between what the SO dispatched on the day to resolve congestion issues and what the SO would have dispatched if there were no constraints. These are called instructed imbalances and are settled with each participant on the basis of the EPUS output. In effect, **the impact of congestion on the system is removed and averaged across all generators.**

Transmission Losses

- Transmission losses occur when energy is transported from one part of the grid to another. In the Irish system, a notional point at the interface between the transmission system and the distribution system is used as the point for energy withdrawal. A transmission loss factor (TLF) is applied to each generation point as a measure of the losses incurred between the point of energy injection at the generation site and the notional withdrawal point. TLF values can be negative or positive depending on the impact that the associated generation has on the system. A generator in a location with a positive TLF will essentially have the output of the generation plant increased by a percentage for the purposes of calculating trading volumes while negative TLF generators have their output scaled down.

The current market design ignores the realities of the system by excluding both

[14] Data based on Eirgrid Generation Adequacy Statement 2002-2007.

the transmission network from the market and crudely averaging the effect of transmission losses and congestion. Due to these simplifications, the model has inherent discriminatory features that provide opportunities gaming the system

4.5.3 Provision of Balancing Services by ESB

There may be differences between what the SO instructed a generator to produce and what the generator actually did produce on the day. These imbalances are called uninstructed imbalances. Generators and suppliers are required to balance these differences through the top-up and spill service provided by ESBPG. The SSA advises all participants of their actual generation or demand on the day following which the generators and suppliers submit their bilateral contract nominations. Generators and suppliers are required to make up the difference between their nominations and their actual volumes through the top-up and spill service provided by ESBPG.

It is generally accepted that the administration and operation of the system should be conducted by an independent entity. **The current market design is such that ESBPG is the provider of top-up and spill balancing services to the market, while the preferred approach is that the balancing of the system should based upon a non-discriminatory market model.**

4.5.4 Lack of Exposure of Monopoly Inefficiencies

The design of the Irish market has been such that the majority of the ESB is not exposed to market pressures, but is instead subject to regulatory cost reducing targets.

Table 4.4 below shows CER estimates of ESBPG costs for 2002-04 reducing 18% from €994M to €820M giving the appearance of efficiencies being realised. While there is insufficient data available to carry out any substantial analysis, it is evident that this cost reduction is primarily as a result of a 49% reduction in fuel costs. Payroll and station operations and maintenance costs remain unchanged at €158M.

Table 4.1: CER view on ESBPG costs (€M in 2001 prices)

	2002	2003	2004	% change
Total Costs	994	884	820	-18%
Fuel	483	342	246	-49%
Payroll + Station O&M	158	150	158	0%

4.6 Encouraging Competition

4.6.1 Generators require a Customer Base

It is not possible for a generator to compete in a bilateral contract market unless a customer base has first been located. Considering the problem of locating a matched load to maximise output, the first new entrant would have had a choice of the largest industrial users who are more likely to have large flat loads, ideal for matching to generator output. As the market opens however, the larger flatter loads give way to smaller more profiled loads. **This makes entry for subsequent new generators into the market more onerous as the number of customers required increases and their load patterns become more difficult to match (relative to a flat load).**

4.6.2 Price Signals Not Reflective of Market Conditions

A fundamental principle of any market is that price moves in line with supply and demand. Scarce product will push the price up while surplus product will push the price down.

The design of the Irish market, however, is such that the looming shortfall of electricity is not matched with an increasing price of electricity. **As bilateral strike prices are not disclosed and the balancing market prices are not market prices, there is simply no way for the scarcity value of electricity to be reflected in the system.** If there was a real-time market which allowed prices to reflect the reality, a natural consequence would be the emergence of a forwards market. As we move closer to generation capacity shortfall (envisaged by Eirgrid in 2005), the forward cost of electrical energy should be rising significantly, providing the signals for investment in new generation. Irish top-up and spill balancing prices do not provide this real time signal and forward markets have not and will not emerge as a result.

4.6.3 Opening - Eligible customers are on Lowest Tariffs

Eligible customers are the only customers that new entrant generators can target. Unfortunately, for new CCGT entrants, these customers are also the ones on the lowest ESB tariffs, so while the size of the eligible customer base is attractive to a new entrant generator, these customers are less lucrative than those on higher ESB tariffs. Section 2 outlined how the large non-residential consumers paid 3% less than the EU average in 2001 while the smaller non-residential consumers paid 33% above the EU average. **As new entrant generators have been prohibited from targeting these higher tariff customers, the market has been less attractive to new CCGT entrants and the SME sector consumers have lost out.**

4.6.4 Dual-cash Prices Penalise Intermittent Generators

The dual cash-out balancing prices are intended to force generators into bilateral contracts. **Intermittent generators, such as wind, are unable to predict their output as accurately as thermal generators and are forced to balance their contracts using top-up or spill**. The alternative of a single cash-out price would allow settlement of imbalances at a single price rather than paying away the spread between higher top-up and lower spill prices.

4.7 Overall Policy Thrust

4.7.1 Lack of Strategic Framework

The Irish market has suffered from a lack of an over-arching strategic direction. It is clear from discussions with most participants that they are unclear as to how the market is likely to evolve, particularly when transition period ends in 2005. This lack of a robust framework and strategic direction has led to

- Uncertainty for new entrant generators
- A plethora of consultations and reviews on a wide range of topics

The CER is currently undertaking a major review of market trading arrangements. We believe that this provides a significant opportunity to lay

down a long-term framework within which regulatory policy can evolve. The aim of the subsequent sections of this report is to provide an input to this process, as we believe that a such a framework can be established such that generation, transmission, demand and ancillary services could all interact to accommodate future technological and other market changes.

This issue is not confined to Ireland. Again, Littlechild notes of NETA:
"*The designers of NETA will no doubt have had to consider certain broader issues. For example, would the pricing principles in the balancing mechanism be consistent with changing the attitudes, awareness and opportunities of market participants so as to promote a more competitive market in both generation and supply?*" [15]

Consideration of such matters is key to developing long term policy in Ireland. In the following section we look at developments in other markets to establish what current best practice might be applicable to Ireland, and address the issues outlined above.

4.8 Summary

Structure

- Irish electricity market is currently structured as a bilateral contracts market.
- Efficiency is compromised by the absence of merit order dispatch.
- It is questionable as to whether final cash-out prices are optimal.

Transparency

- A lack of transparency makes it difficult for participants to gauge their competitive position.
- The strike price of bilateral contracts is not disclosed.
- ESB Powergen pricing is bundled, so the merit order of generation plant is not visible.
- Greater visibility of the operating costs of ESB Powergen plan could help towards future efficiency.

ESB Dominance

- ESB continues to have a dominant share of generation.
- The market structure ignores the economic realities of the system by both excluding the transmission from the network and by averaging the effect of losses and congestion.
- The ESB rather than an independent contracts, is the provider of top-up and spill.
- ESB’s share of the market means that pressures on it remain largely regulatory rather than truly competitive.

Encouraging Competition

- It is increasingly difficult for new entrants to build demand profiles for their bilateral contracts.
- The price of electricity does not reflect market conditions
- Intermittent generators are penalised by dual cash out pricing.

Overall Policy Thrust

[15] See earlier reference to Beesley lectures.

- There is a wide perception that the market has evolved in an "ad hoc" fashion rather than along lines which would allow participants greater certainty and less regulatory interaction.
- The current CER review is an ideal opportunity to put a longer term framework in place.

5 International Developments

5.1 Approaches adopted by EU Countries and some others

A review of the approaches adopted by other countries highlights the diversity in market designs deployed across the globe. Table 5.1 outlines the market arrangements in a number western European countries and some others[16].

Table 5.1: Summary of Market Structures in Selected Countries

Country	Owner	Transmission Network Ownership	Transmission Network Development	System Operation	Centralised Dispatch or not	Imbalance arrangement operator	Imbalance Market or not	Short Term energy market	Measure congestion
Germany	four integrated companies	private	the TSOs	the TSOs	no	the TSOs	yes	European PX Leipzig PX	effectively 1 Zone
Italy (proposal)	TERNA/GRTN	private	TERNA/GRTN	TERNA/GRTN	no	GRTN	quasi	GME	expected initially 1 zone
France	RTE	government	RTE	RTE	centralised	RTE	no	Powernext	
Netherlands	TenneT	government, but may be privatised	TenneT	TenneT	no	TenneT	quasi	Amsterdam PX (Owned by Tennet)	1 price zone
Spain	Red Electrica	private	Red Electrica / Other owners	Red Electrica	no	Red Electrica	no	OMEL	1 price zone
England & Wales	NGC	private	NGC	NGC	no	BSC Panel/ Elexon	no	UKPX and APX	1 price zone
Norway	Statnett	government	Statnett	Statnett	no	Statnett	yes	NordPool	1 or 2 price zones
Sweden	Svenska Kraftnät	government	Svenska Kraftnät	Svenska Kraftnät	no	Svenska Kraftnät	quasi	NordPool	1 price zone
Finland	Fingrid	government	Fingrid	Fingrid	no	Fingrid	quasi	NordPool	1 price zone
Eastern Denmark	Elkraft	LDCS	Elkraft	Elkraft	no	Elkraft	quasi	NordPool	1 price zone
Western Denmark	Eltra	LDCS	Eltra	Eltra	no	Eltra	quasi	NordPool	1 price zone
Argentina	Transener	private	system users + BOM Tender	CAMMESA	yes	CAMMESA		none	LMP
Australia - Victoria	PowerNet	private	VenCorp + BOM tender	NEMMCO	yes	NEMMCO		Sydney Futures and Options	5 zones
Australia - NSW	Transgrid	NSW government	Transgrid	NEMMCO	yes	NEMMCO			
New Zealand	Transpower	government	System users	Transpower	yes	M-Co		none	LMP

Note – "quasi" means that they are not supposed to be used as markets of last resort as scheduling co-ordinators are supposed to provide balanced schedules.

Thus far, the EU experiment has resulted in fifteen separate markets. In 1998, the European Commission set up the "Florence Forum" to look at the issues of creating a single market across Europe that were not addressed by the EU Electricity Directive. Top of the agenda for the Forum are the harmonisation of cross-border tariffs and the allocation and management of scarce inter-connect capacity, based upon principles of transparency, simplicity, cost reflectivity and non-discrimination. The European Association of Transmission System Operators (ETSO), members of the forum, have struggled to find a way to deliver on these principles. In a paper entitled "*What can the US learn from the European experience in the construction of a real integrated electricity market?*", Yves Smeers of the Harvard Electricity Policy Group[17], highlights the flaws in approaches suggested by ETSO in their 1999 and 2001 publications[18].

While ETSO appears no closer to a coherent solution now, it did publish a draft vision statement in February 2002. It is now focussing on a co-ordinated

[16] Extracted from "Lessons from the institutional framework of transmission, System operation, and energy markets in most West European Countries and some other countries – The case for transcos", Henney & Russell 2002.

[17] http://www.ksg.harvard.edu/hepg/Standard_Mkt_dsgn/smeers%20presentation%20paper%209-21-01HEPG.pdf

[18] "Evaluation of congestion management methods for cross-border transmission" Nov 1999 and "Co-ordinated Use of Power Exchanges for Congestion Management" June 2001.

transmission auction as a way to deliver on its stated goal of "*providing a practical market-based mechanism to manage congestion between region while allowing the co-existence and evolution of different market structures within regions*". With a single market as the overall goal, it is ironic that the resolution of the critical interconnection issues assumes separate market structures. EU markets are likely to remain separate for the foreseeable future.

Two key goals of the EU electricity directive are:

- To improve the competitiveness of the EU on a global stage through the development of efficient and competitive markets. With the US as a key global competitor, the EU is already seriously disadvantaged due to its high import dependency and higher overall energy costs
- to reduce the differences in electricity prices between members states to allow a single market to develop

While steps to introduce competition within each member state may succeed in lowering the overall average cost of electricity for Europe, it is likely that neither of these goals will be delivered. **The US approach of adopting a single market design for the entire country (see Section 5.2 below) is likely to leave Europe as a whole in a less competitive position and the inability to integrate markets and harmonise prices between member states means that differences between member states will remain.**

Unlike Europe, the structure of the US electricity market is such that monopoly market areas do not have logical state boundaries. The regulatory authorities in the US have struggled for years with the issues that arise when trying to trade electricity between two separate markets with little or no success[19]. Europe is only now coming to grips with these market-to-market interconnection issues.

If Europe follows the principles of cost-reflectivity, competition and non-discrimination as it works through the issues, the result will most likely be a replication of the US SMD across Europe.

5.2 US Standard Market Design - Emerging Best Practice in Market Design

Experiences in the US now all point to the fallacy of simplifying market design. The well known problems in California over the past two years are a case in point. In January 2002, the California Independent System Operator (CAISO) initiated a project to review its market design[20]. Here the CAISO concludes

> " *in reality the "simplicity" of the zonal system only appears so because the complexity is assumed away, allowing market participants to ignore it in scheduling while the CAISO must manage it through real time adjustments and periodic modifications to the rules to mitigate novel gaming strategies as they arise. The MD02 team believes that it will be far simpler, and more transparent, to design forward CM [congestion management] to be as consistent as possible with the real-time operating needs of the grid.(Page 14)*"

The CAISO also explicitly links ignoring constraints to gaming of the system:

[19] The reader is directed to the flowgates section of Harvard University Electricity Policy Group for details.

[20] CAISO "Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal," January 8, 2002 available at http://www.caiso.com/docs/09003a6080/13/58/09003a6080135879.pdf

For example, ignoring intra-zonal constraints in establishing forward schedules has allowed "the DEC game," whereby suppliers can over-schedule a constrained intra-zonal pathway and then exercise local market power to receive a premium payment in real time to eliminate the overload.(Page 14)"

Given the problems in California and other markets, and the well-publicised difficulties of electricity providers such as Enron, additional urgency and political will has been injected into the issue of market design in the US. The challenge of coming up with a working market design has exercised some of the brightest minds in the world and based on the wide-ranging views on the matter, it might sometimes appear that an optimal solution is a long way off. The issues appear to stem from the conflicting interests of the parties charged with coming up with a solution:

- Engineers from the electricity companies with system security on top of their agenda
- Academics from a competition background with theories and assumptions on how markets should work
- Investors with business minds intent on maximising profits

The single buyer model is attractive to security-conscious engineers, and while academics have been in the driving seat during the development of the pool and bilateral model, the former allowed business to make super-normal profits while the latter has scared investors away. Convergence of the three mindsets is required to arrive at a market design that will actually work.

While the pool model in England and Wales was being replaced with NETA, a different revision of the pool model was taking place in the Pennsylvania, New Jersey, Maryland (PJM) region of the US. Here, the PJM system operator developed a model which eradicates the assumptions and simplifications of the academics by incorporating the physical realities of what happens on the electricity system, effectively reconciling the academics with the engineers. The key innovation is the incorporation of Locational Marginal Pricing (LMP), which allows for more efficient decisions on dispatch and balancing in the short-run and timely investment in generation and transmission in the long run. The operation of the system is outlined in Section 6. Once the playing field could be demonstrated to be level, the investors came on board.

This success of the PJM model since its implementation in 1998 has led to the decision by the US Federal Regulator (FERC) in July 2002 to adopt the majority of its principles and to impose this market design on all regions of the US. This is now known as the Standard Market Design (SMD). Commenting that "We have learned from mistakes in California and successes in places such as PJM and New York", FERC describes the SMD as the result of an unprecedented stakeholder process to develop the ideas.

While there is a wealth of complex data available to support the success of the PJM market[21], the following two excerpts underscore its success forcefully

[21] For example, the "PJM State of the Market report 2001" available from http://www.pjm.com/market_monitoring/reports/2002/june/200206_som_01_emc_presentation.pdf

"At the end of the day, the true test is one of use. Billions of dollars in trades have occurred on our [PJM] system. Although we have a $1,000 bid cap in place, 99% of the time our prices have cleared below $100/MWh, and 71% of the time our prices were less than $30/MWh. System reliability has improved since we became an independent system operator. In 2000, our region experienced extremely high temperatures in May, usually a month when plants are out for maintenance. Even with these shortages in generation our prices only reached $400/MWh for 4hours. And the marketplace is supporting our market, as witness the dramatic number of planned generation and transmission projects in our area".[22]

"When I look at the PJM market as it has performed since it became an independent system operator with substantially market-based pricing, I have seen a continuation of reliable service at energy prices that are generally consistent with what one would expect in a competitive energy market. The average spot energy price in PJM was below $50 per megawatt hour (or 5 cents per kilowatt hour) in more than 86% of the hours in both the years 2000 and 2001. Even when energy prices go up sharply in PJM, as they did at various times this past summer, they seem to do so in response to forces of supply and demand. We have not been immune from market manipulation in PJM – as I believe was evidenced in the energy market in July 1999 and the capacity market in the winter of 2001 – but, because PJM is operated on a truly independent basis with a very strong and effective market monitoring unit, I believe that efforts to improperly exercise market power are more readily detectable and remedied in PJM."[23]

At a high level**, SMD can be thought of as an evolution of the single price pool where**

- the effects of **losses and congestion** are included giving rise to separate prices at every node on the electricity network
- the model **incorporates bilateral contracting** recognising the need for generators and suppliers to hedge pricing risk
- The **role of the transmission network and of the demand side** are placed on an almost equal and level footing with generation

According to FERC documentation[24], the goals of SMD can be summarised as follows:

[22] Testimony of Phillip Harris, President and CEO, PJM interconnection, LLC, Hearing on the impact of Electric industry restructuring on system reliability United States Senate Committee on Governmental Affairs. June 28 2001. http://www.pjm.com/about/news/testimonies/20010628_pgh_senate_testimony.pdf

[23] Testimony Of Sonny Popowsky, Consumer Advocate Of Pennsylvania, Before The United States Senate Committee On Energy And Natural Resources Regarding FERC Standard Market Design September 17, 2002. http://www.oca.state.pa.us/tmony/sept1702.pdf

[24] FERC SMD presentation available from http://www.ferc.fed.us/Electric/RTO/Mrkt-Strct-comments/discussion_paper.htm

- Reduce wholesale electric prices - Make markets work, not protect competitors
- Incentivise investment in infrastructure - Transmission, generation, and demand response
- Incentivise development of technology development of technology - Demand response and efficiency gains
- Protect the environment - Encourage demand response and use of more efficient generation

And the principles of SMD are rooted in the same set of rules for all users of the grid

- Open access and flexible transmission service - Administered by fair and independent entity
- Market rules protect against market manipulation - Addresses Enron trading strategies
- Customer protection through market power mitigation measures and oversight
- Clear transmission pricing and planning policies for grid expansion

The views of the Electricity Advisory Board (EAB) on SMD in the US are also worth noting. In November 2001, the US Dept of Energy set up the EAB to provide independent advise on electricity policy issues. The EAB is comprised of some of the most senior and influential industry participants in the US. In a September 2002 publication, the EAB describes LMP as **"an essential tool for wholesale markets"**. An extract of relevant text from the report has been provided in Appendix 2 for information.

The PJM model has been in operation since 1998 and while the core concepts have not changed, it has continued to be refined. While the PJM model is not perfect, the SMD appears to have addressed many of the outstanding issues. ELCON, founded in 1976, is a US association of large industrial consumers of electricity whose members consume nearly 6% of all electricity used in the US. In its first submission to FERC on SMD in November 2001, ELCON included affidavits of several ELCON member companies with facilities in PJM highlighting issues and concerns with the PJM market[25]. Following consultations and refinement of the SMD, ELCON produced an updated submission accompanied by a press release in which ELCON's Executive Director John Anderson notes *"From the consumer perspective, FERC is generally proceeding along the right path"*[26].

5.3 Summary

EU policy aims to:

- Improve EU competitiveness
- Reduce price differentials between countries

[25] Comments and Affidavits/Electricity Market Design and Structure Rulemaking Docket - Docket No. RM01-12-000, November 26, 2001. www.elcon.org/Documents/FERCFilings/ELCON-RM01-12.pdf
[26] ELCON Press release June 28, 2002.

The US is evolving a system which is likely to leave the EU at the competitive disadvantage. Following the high profile problems in the US sector, there is increased political and administrative urgency to find an optional model for progress. FERC has adopted a Standard Market Design (SMD) as its preferred approach, a key feature of which is Locational Management Pricing (LMP), based on the PJM model. This aims to combine the best features of the Single Buyer Model, which priorities security of supply, the Pool Model, which has been subject to gains, the Bilateral Model, which has not encouraged investment.
SMD can be seen as an evolution of the single price pool, but it additionally accounts for:

- Losses and congestion
- Bilateral contracts
- The role of transmission network and demand side being increased relative to generation

After much debate there has been general approval of FERC's move from many areas of the industry.

6 A Road Map for Development of the Irish Electricity Market

6.1 Introduction

Unlike the gas market where Ireland already imports competition through the gas price, Ireland does not import competition in the electricity sector (interconnection to the Northern Ireland market is constrained and represents only a fraction of demand). The electricity sector is a complex system where a multitude of costs and the design of the market play a role in the end price of electricity to the consumer. We need to ensure that there is an effective market structure to apply pressure on costs and push through efficiencies across all of the above cost areas, while at the same time incentivising new market entrants to meet growing demand.

Ireland has understandably focused on attracting new generating capacity to meet shortages over the last few years. While this will continue to be a primary challenge, the market design towards which we move should be one which encompasses signals from **all** contributors to supply and demand in the market, and encourages them to react appropriately.

We believe that the basics of SMD can provide a common framework to allow the policy makers, engineers and investors in the Irish industry debate the finer points of an Irish electricity market design. Before looking at whether it addresses the issues identified in Section 2.2-2.5, we describe through worked examples in Section 4.2 below how the model works

6.2 Understanding Locational Margin Pricing Through Worked Examples

The dynamics of the SMD market revolves around three concepts[27]:
- Locational Marginal Pricing (LMP)
- Transmission Usage Charge (TUC)
- Financial Transmission Rights (FTR)

6.2.1 Locational Margin Pricing

In the old pool model, the System Marginal Price (SMP) was the cost of producing the last MWh of energy to meet the demand in the system at that time. The SMP can also be considered to the cost of producing the next MWh of electricity if demand was to increase by 1MWh. In the same fashion, the Locational Margin Price (LMP) is the cost of delivering one more MWh at a specific location. Each point on the transmission network where energy is injected (i.e. where generators connect) or energy is withdrawn (where distribution networks or large consumers connect) would constitute a location. LMP varies by location due to transmission losses and congestion and it is based on bid prices into the system at that time. Locations on a network are often referred to as nodes.

6.2.2 Transmission Usage Charge

Transmission Usage Charge (TUC) can be thought of as the cost of using transmission infrastructure. It is the economic value to the system of moving energy from an injection point to a withdrawal point. As with the locational and system pricing, TUC is a marginal price. TUC is therefore the cost of moving

[27] See FERC SMD NOPR docket RM01-12-000 for further details.

one more MWh from an injection point to a withdrawal point. So while LMP shows the cost of electricity at each node, TUC shows the cost of moving energy between every node. The examples which follow will show that the TUC between two nodes on the network equals the difference in LMP between the nodes. Like LMP, TUC varies for each section of the transmission network due to losses and congestion

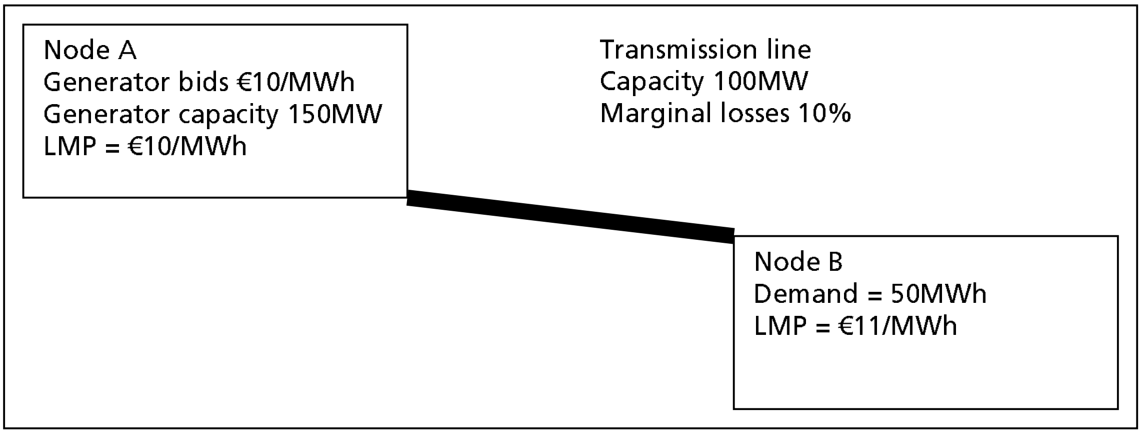
6.2.3 Financial Transmission Rights

Financial transmission rights (FTRs) are a financial instrument that allow the owner to lock-in long term transmission point to point transmissions prices just as bilateral contracts lock in energy prices. LMP exposes market participants to price uncertainty during periods of congestion. FTRs restore the price certainty by providing a hedging mechanism. They provide the owner with revenues to offset the charges they would pay for their transmission usage. The owner of an FTR receives the associated revenues whether or not they use the transmission service. This allows hedging and preserves the short run price signal. Where costs are high, a participant may choose not to generate, but simply to collect the FTR revenues. This promotes voluntary congestion management

The following examples explain how LMP, TUC and FTRs all work together to allow an energy market operate efficiently. Further examples and explanations of the concepts can be found in

- The basic concepts are described in "Competitive Electricity Market Design: A Wholesale Primer" [28]
- A more complex example is available on from the training section of the PJM website[29]
- For further analysis on the treatment of congestion, readers are directed to "Optimal Congestion Treatment for bilateral electricity trading"[30].

6.2.4 Example 1 - Losses, No Congestion.



To deliver one extra MWh of energy to node B, 1.1MWh must be generated at node A as 10% will be lost during the transfer from A to B. Therefore the marginal cost to deliver 1MWh at B is the marginal cost of producing 1.1MWh at

[28] William Hogan, Dec 1998 available from http://ksghome.harvard.edu/~.whogan.cbg.Ksg/empr1298.pdf.

[29] PJM training material available at http://www.pjm.com/training/lmp_ftr/lmpftr1.ppt

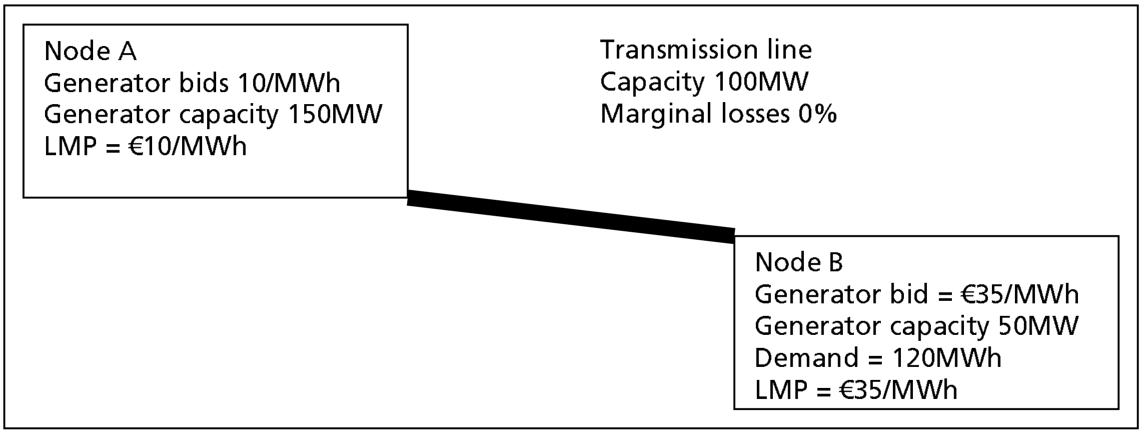
[30] Karsten Neuhoff, April 2002 available http://www.econ.cam.ac.uk/electricity/publications/wp/EP05.pdf

node A = 1.1MWh * €10/MWh = €11. Therefore LMP at B is €11/MWh.

Under the LMP system, the losses incurred in the transfer of energy from node a to node b are a cost to the system. This cost is reflected in the form of a charge for the use of the transmission line to transport energy from node a to node b. In the example above, the cost of moving one more MWh from node a to node b is €1/MWh so the transmission usage charge is €1/MWh.

In this example, we have transmission losses across the line, but there is no congestion as the transmission capacity of €100MW is well over the demand or 50MW at B.

6.2.5 Example 2 - Congestion, No Losses.



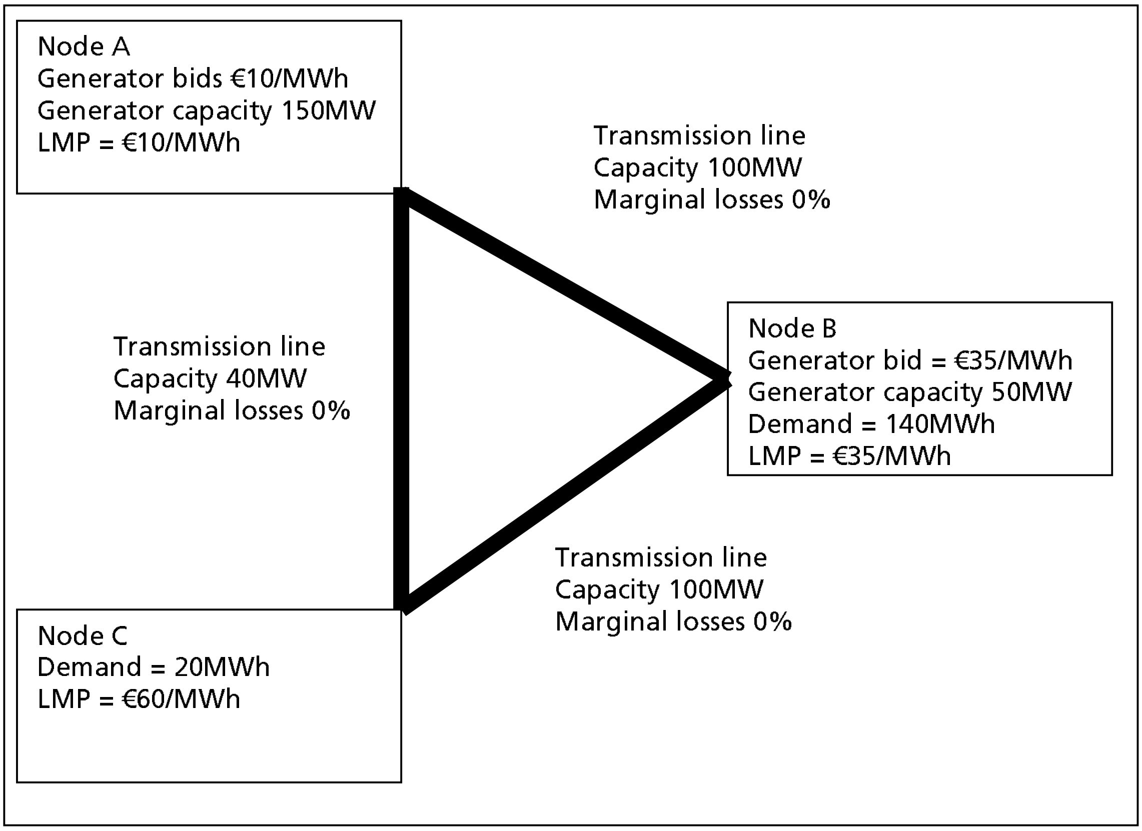
Now consider the same example except this time we introduce a generator at node B and we push the demand at node B up to 120MWh. For simplicity, we will assume no transmission losses in this example.

To meet the demand of 120MWh at node b in the most efficient manner possible, 100MW of cheaper generation from node is required and 20MW from node B. Any demand at B over 100MWh can only be met by generation at B. Therefore the LMP at B is €35/MWh.

The transmission usage charge is the difference between the LMPs at the two nodes. If the generator at A had entered into a bilateral contract with a supplier at B, the energy flow from A to B would be subject to this transmission usage charge LMP(B) - LMP(A) = 35 - 10 = €25/MWh. This is the short-run cost of moving energy cost from A to B while the line is congested because if any other party wanted to use the line to move an extra 1MWh or energy across the wire, the transmission operator would have to back down 1MWh of at node a at €10 and ramp up 1Mwh at node b at €35. The marginal cost of moving energy from node a to node b during this congested situation is therefore €25.

Now suppose some load at A entered into a deal with the €35/MWh generation at B giving rise to an flow of energy from B to A. The impact of this generation would be to alleviate the congestion and save other participant €25 so the price for transmission from B to A is negative. Participants would be paid money to transport energy from B to A, in this case €25/MWh.

6.2.6 Example 3 – A Three Node Network



In this example, we explain the impact of increasing the demand at B to 140MWh and then adding demand of 20MWh at C.

Now, when generation is injected at node A and withdrawn at node B, not all of it is transported down the A-B transmission wire. It is not possible to direct the flow of electricity through the wires once it is injected at A. The introduction of the second route to B allows more of the cheaper generation at A to serve the demand at B. The proportions of energy that flows along each route depends on the resistance or impedance of the lines. In this example, if we assume that all three transmission lines have equal impedance, two thirds of the energy will flows along the shorter A-B route and the remaining one third flows along the longer route. As a result, we can now transmit 120MWh from A to B as two thirds (80MWh) will go the direct route A-B and one third (40MWh) will flow A-C-B without exceeding the transmission capacity thresholds of any one of the transmission lines. 120MWh is the maximum that can be transported from A to B because any additional generation at A would result in more energy being pushed down the A-B route, exceeding its 40MW threshold and damaging the transmission line.

So a maximum of 120MWh of demand at B can be met by generation at A. Any additional demand at B will have to be met by the more expensive generation at B. To meet a demand level of 140MW at B, 120MWh of cheap energy would be generated at A and 20MWh of expensive energy at B is required. This is because of congestion on the A-C transmission line.

Until we hit the congestion limit, the LMP at all three nodes is €10MWh, assuming zero losses. At the congestion limit on the A-C line, the LMP at A stays at €10/MWh and the LMP and B becomes €35/MWh. With this information, we can calculate what the LMP at C to be €60/MW during the congested period because to deliver an additional 1MWh of energy at C you would have to generate 2MWh at B and back down 1MWh at A at a net cost of €60/MWh (2 by €35 less €10).

The Transmission Usage Charges between each node are the difference between the LMPs at each node and are direction specific. So if a participant held a financial transmission right from A-B for 1MWh, a payment of €25 would be due during this period. Similarly a right from A-C would be paid €50. The operation of Financial Transmission Rights has been proven to work in areas such as PJM and New York to date. In these markets, holding an FTR places an obligation on the holder to pay out when the value is negative. Consideration is being given to the concept of a non-obligatory FTR or optional FTR whereby the holder could receive revenues for positive congestion but would not have to pay out for negative congestion. In the above example, the holder of an obligation right from C-B would be obliged to pay the transmission system operator €25. The holder of an optional FTR between C-B would not have to pay anything for this negative congestion.

Another form of financial transmission right other than the receipt point to delivery point is the notion of flowgate rights. Under this mechanism, the right applies to the entire segment of transmission line, rather than a right to an energy flow through the line. This is a good deal more complicated, but can be viewed as the extra economic benefit or the reduction in energy costs that would result if you expanded the transmission line by one MW. In the example above, there are three flowgates, two of which are not congested and therefore have no revenues associated with it. The congested line is line A-C, but it is congested by the requirement to transfer from A-B. A holder of a flowgate right on the A-C transmission line would be paid the revenues associated with that transmission line. This revenue is calculated as the economic benefit that would result if this line was expanded by 1MW. A 1MW expansion on this line would allow 1.5MWh to flow from point A to point B. This would result in an net reduction in energy costs of €75 and this is the value of the congestion revenue associated with this flowgate.

Ancillary Services

While ancillary services are typically provided by generators while they generate energy, it is possible to supply certain ancillary services without producing energy. Ancillary services can therefore play an important role in overall supply-demand balancing. We have seen how transmission impacts on the price of energy at a location and how the value of transmission can be looked as an integral part of the market via the Transmission Usage Charge. Ancillary services can be applied to the transmission network to increase of decrease the transmission capacity at section of the network.

While this is unlikely to feature in the Irish market, a merchant project based on this concept in understood to be near completion in New York. This has been made possible as the market design explicitly recognises the additional benefits to the system of an increase in transmission capacity. The merchant operator or this ancillary service can therefore participate in the market on the exact same basis as a generation, transmission or demand.

6.3 The Benefits of LMP Market Design for Ireland

The benefits of LMP market design incorporating FTR's have been proven from the operation of LMP in PJM and New York for many years now. In summary, there are key benefits in both the short run and in the long run:

In the short-run, these markets encourage and promote efficient behaviour:
- Optimal supply and demand decisions by market participants
- Transparent congestion management based on true economic opportunity costs
- efficient energy balancing by the system operator

The prices signals are such that participants are incentivised to curtail transmission across congested lines on a voluntary basis.

In the longer term, the price signals encourage and promote
- timely investment in generation or transmission infrastructures
- optimal siting of generation and transmission infrastructure
- optimal demand side activities

We outline in the following sections how an LMP market design could overcome the issues identified in Sections 4. Section 4.3.5 describes the additional benefits which come from the inclusion of transmission system issues into the model.

6.3.1 **Structure** of LMP Market Design

The LMP model takes the best parts of the pool and bilateral contract market designs to arrive at an optimal market design with the following features:
- Based on bilateral contracts with a spot market for energy.
- Balancing is based on a single price per location set by market bids
- Locational price incorporates the effects of losses and congestion on the transmission network
- The model incorporates economic dispatch principles
- By removing crude simplifications and truly reflecting the economic costs of the system, the LMP system is less susceptible to manipulation and gaming.
- The model does not require artificial devices to deliver a level playing field.
- It provides participants with a mechanism (FTRs) to hedge against volatile prices and congestion issues.
- Critically for a small market like Ireland, it does not segment the market to the extent that a bilateral market does
- Finally, the LMP model provides a mechanism for all aspects of the electricity market to play a part and applies strong transparent competitive pressures to each part.

6.3.2 **Transparency** no Longer an Issue

Transparency is at the very core of the LMP model.

- Full disclosure of energy and transmission prices at multiple nodes will allow for the entire system to be modelled accurately by existing participants and potential new entrants.
- The model uses security constrained bid-based economic dispatch to deliver an efficient market. Participants and observers can readily assess the competitive landscape
- The model provides clarity on the treatment of losses, congestion and pricing.
- The transparency provides information to highlight incumbent inefficiencies which can then be addressed by the regulator in the period before fuller competition evolves.

6.3.3 **Dominance** of ESB is Reduced

The dominance of the ESB is far less of an influence on the market under the LMP model

- The model provides a framework for introducing competitors
- Economic dispatch ensures that the most efficient participants come to the fore.
- ESB's role in the operation of the market is ended as the market is administered by an independent system operator and balancing is via a market mechanism.
- As the model is location specific, each of ESBPG generation plant will be subject to competitive pressures as the protective layer provided by the bundling of ESBPG portfolio of plant together is removed

6.3.4 **Competition** is Encouraged

The model encourages competition by providing a level playing field and by removing risk for potential new entrants. Entry into the market is made easier as generators are not forced to locate their own matched load and suppliers are free to buy energy from the spot market.

6.3.4.1 Standard Model and Uncertainty and Risk

It is often argued that the features of a particular electricity system require a customised model and that a one-size fits all solution is not possible. However, the physical realities of electricity system operations are identical in every country. As the LMP model is based upon the physical realities of the system, it can be employed in any situation. The adoption of such a market design for Ireland will make it easier for new generators to invest and to fund their projects – a clear and established regulatory framework which is familiar to international operators and financiers would be in place. While it is clear that substantial transition would have to be negotiated from the present position, at least a clear end point would be visible, something which our discussions suggest that virtually all players in the market would welcome.

Indeed, it is likely that the EU will eventually have to adopt this model if it is to follow through on its requirement for open non-discriminatory access. It might even be possible for the rollout of this model in Ireland to be a pilot test for the EU and thereby qualify for EU funding.

The shifting of emphasis away from providing new entrants with comfort in the form of Power Purchase Agreements or other concessions towards open market risk assessment will allow the true risks of market entry to be determined and an accurate and competitive cost for electricity to be arrived at.

6.3.4.2 Single Nodal Price Encourages Intermittent Generators

The model allows for the dual cash-out prices to be replaced with a single price for energy at each location. This price at each node applies to generation and demand alike. Any mismatch in nominations by a generator are settled at the market price at the time. This means that the penalties faced by intermittent generators due to their inability to accurately predict their generation output are reduced. Competition is therefore likely to be encouraged beyond the baseload where it is currently positioned

6.3.4.3 Smaller Scale Generation Because Cost Effective

It has been assumed that the best way of meeting the increasing demand in Ireland is the introduction of a 400MW generator. While such a plant may be the cheapest way to produce electricity, it does not necessarily follow that it is the best option for Ireland. 400MW is a significant percentage of the overall capacity in the country and a strong transmission grid is required to transport 'lumpy' concentrated generator output such as this to the demand centres on the grid.

Recognising that a proportion of the investment in transmission infrastructure is the replacement of existing infrastructure, some of the upgrade is required to ensure that sufficient capacity exists to allow such large generators to pump power around the grid.

While it may well turn out that the 400MW generator and transmission infrastructure plans do provide the optimal solution for Ireland, the LMP model would allow effective validation of these assumptions. It may transpire for example that the production inefficiencies of smaller generation plants dotted across the country may be offset by the distributed benefit they provide through both avoid transmission costs and local voltage support. A recent report by the Long Island University School of Public Service[31] concluded that small generators provided a means of rapidly meeting a projected shortfall in Long Island.

6.3.4.4 Level Playing Field for CHP

It is testimony to the failure of the current arrangements that a clean highly efficient process such as CHP is unable to compete while polluting low efficiency oil plant continue to pump energy into the grid. Efforts to allow the efficiency benefits of CHP to be realised have centred on measures such as guaranteed purchase contracts, subsidies, grants or other exemptions.

[31] "Peakers as a Step To Re-Powering", Centre for Management Analysis, Long Island University. Oct 2002.

The LMP model however could allow CHP to compete directly without the need for subsidies and grants. Because the LMP model provides cost-reflective energy prices on a time of day basis, CHP plant with smaller heat loads may be viable during the peak periods of energy demand. Arrangements available in Northern Ireland for trading of CHP electricity have demonstrated that CHP can be an effective solution. The bilateral system in the south and the penal dual cash-out prices act against the adoption of CHP. The LMP model provide an effective solution to allow CHP benefits to be realised without special arrangements. As well as getting over the issue of having to locate a client base, the single cash-out price and the ability to compete in the peak market will allow CHP to develop on a competitive basis.

6.3.5 **Transmission** incorporated into the Supply-Demand Balance

A critical aspect of the LMP model is that it includes the transmission network in the market. This has a number of benefits for Ireland:

6.3.5.1 Vehicle to Meet the Needs of the National Spatial Strategy

The LMP model can address concerns over the ability of the existing infrastructure to meet the needs of economic growth and the needs of energy-intensive industries and projects.

The National Spatial Strategy, rooted in government regional policy objectives of the National Development plan, is designed to help reduce the disparities between the BMW regions and the southern/eastern regions of the country and to develop the potential of both regions. High quality physical infrastructure, including inter-urban transport and energy transmission systems, have been identified as one of the key determinants of sustained economic performance. Mapping of energy supply and demand patterns and inter-linking these with spatial development requirements is intended to highlight barriers to enterprise development. It is clear that grid infrastructure development plans need to be well co-ordinated to take these future development needs into account.

The Eirgrid Generation Adequacy Statement 2001-2007 provides a detailed map of grid strength across the country as well as direction on the development of grid strengths as the grid reinforcement plans are implemented. Enterprise development has been hindered in the past as businesses with high electricity consumption levels have been prevented from locating in weak areas. Given the high costs involved in building grid infrastructure, the provision of infrastructure in advance of actual need is inherently risky. Mitigating these risks is the key to ensuring that infrastructure is made available for enterprise development. The development agencies have identified priority regional centres for expansion, but in some cases, the network programme plans do not provide the required transmission capacity.

Implementation of the LMP system would provide a basis upon which independent analysis of the grid infrastructure rollout program can be evaluated. In addition, the system allows for open and transparent modelling of the options and costs of meeting future demand at specific locations on the grid. The model would provide clarity on the level of available demand capacity at specific locations across the country and allow accurate assessments of the optimal ways of delivering the infrastructure to meet the projected demand. The development of forward markets for energy would allow investors to become involved in the provisioning of this infrastructure, thereby meeting the demands of the National Spatial Strategy with private funding.

6.3.5.2 Private Sector Funds

The LMP model allows for private investor money to be attracted into the electricity sector not only in the provision of new generation capacity but also in the transmission network. Other market design models do not allow for the real benefit in transmission investment to be reflected.

A typical infrastructure project would see the costs covered by a usage charge. This logic is difficult to apply to a new section of transmission infrastructure due to the complexities of electricity flows. The LMP model provides a basis on which the true economic benefit can be accurately calculated thereby increasing the likelihood of a project being viable.

6.3.5.3 Ireland-UK Interconnect

A transmission network interconnection linking the Irish transmission system to the UK system would be a welcome development for Irish consumers. Once the Irish grid has been strengthened sufficiently, a large interconnection to the UK could allow surplus UK energy meet any Irish generation capacity shortfall. More importantly, **it could provide the back-up required for wind-farms and expose the ESB to competitive pressures from the liberalised UK market, which has surplus generation capacity**. This interconnect could also help to attenuate or counteract a growing import dependency through the use of renewable energy sources.

How this interconnect would be paid for is the key issue. A review by the ESBNG and the National Grid Company in the UK to assess the viability of an interconnection project on a merchant basis is understood to have concluded that it would be too risky and therefore not viable. GEC were not granted access to this report due to the inclusion of commercially sensitive data. It is understood that the CER has plans to investigate the possibility of a regulated project to build the interconnect.

In light of the shortfall in capacity in the Irish market, and the need to attract a new generator as quickly as possible, discussions with regard to interconnection to the UK need to be treated very sensitively. The possibility of significant additional capacity being made available from the UK where substantial excess capacity and unsustainable low electricity prices exist at present, would be a significant deterrent to potential new generators in Ireland.

6.3.6 A Coherent **Overall Policy Thrust**

6.3.6.1 Coherent Strategic Framework

Unlike the bilateral market and the pool market, the LMP model allows all aspects of the electricity market to play a part. Neither the bilateral nor the pool system effectively includes the role of transmission in achieving an overall balanced market.

By including the impact of all elements on an equal and transparent basis, the LMP model provides a clear method of transitioning out of a regulated market price to a liberalised market in time.

6.3.6.2 Active Demand Side

An active demand side involvement in the market is a critical element of delivering an optimal balance between supply and demand. The transparency on intra-day energy cost can provide an incentive for customers to optimise their consumption. Under the LMP model, customers with controllable demand can choose to either minimise their energy costs by matching their consumption to variable energy prices or to actively participate in the market by submitting demand bids into the system.

6.3.6.3 Consistent with Future Technological Advancements

The LMP model is consistent with the anticipated future developments in energy, in particular, the concepts of wide-scale distributed generation and the hydrogen economy.

6.4 Overcoming Obstacles to a Smooth Transition

We recognise that it is impracticable to switch over seamlessly from the current structure to the model proposed. Intermediate steps need to be taken to recognise the realities of Ireland. The purpose of this report is to propose a framework. The detail must be put in place by the CER in consultation with the participants. In our consultations, various players have suggested some of the problems which they envisage in adopting the LMP model. The following sections describe how some of the short term issues might be addressed along a path to a competitive LMP model.

6.4.1 **Structural issues** are not daunting

The implementation of an LMP market design for Ireland can be thought of as a logical progression from our current trading arrangements. At a high level, the major change is that the top-up and spill balancing arrangement would be replaced with a real-time spot market where prices reflect losses and congestion. In the absence of dual cash-out prices (i.e. top-up and spill), the market would be expected to migrate to a 75:25 split between bilateral contracting and spot market transactions.

Implementation of a market design based upon LMP will require detailed assessment of many important factors not covered in this document. For example the allocation of FTRs is a difficult and complex matter. In the US, annual auctioning of FTRs has emerged as the most equitable solution. Other areas of special interest to Ireland might include how reserve capacity margin would be maintained and how market power monitoring and mitigation would be conducted.

Positive aspects of the Irish market that can be viewed as facilitating a transition to an LMP model include:

- **Bilateral contracting processes are already in place**. The LMP model has bilateral contracts at its core.

- Following the resolution of the CER-Eirgrid dispute, **the creation of an independent system operator is well underway.**
- **The existing day-ahead scheduling process is a close match to the day-ahead scheduling market that an LMP model requires**.
- The concept of **locational factors being incorporated in the model is already familiar** due to the existence of transmission loss factors in the Irish market.

The following are the basic features that would need to be put in place to implement the model:

6.4.1.1 Organised Spot Market run by the System Operator

The system operator would organise and operate a spot market to manage congestion and balance generation and load. The spot market will support bilateral and spot transactions, operating on a day-ahead basis and in real time. There will be separate settlement of each market i.e. a two settlement process will apply. To ensure that the day-ahead schedules are realistic, the day-ahead transactions will be financially binding, but will clear at real-time market prices. Real time spot transactions also clear at real-time market prices.

6.4.1.2 Locational Prices calculated every half-hour

Based upon bids into the system by participants, prices are calculated for every node on the system per trading period (every half hour). Nodes on the system are taken down to substation level resulting in hundreds of pricing points e.g. 3000 in PJM, 250 in NZ, estimated 200-300 in Ireland. Nodes can be aggregated together to create zones if the extent of congestion and losses between the nodes is minimal. Note that if a transmission network had no losses and no congestion, the LMP system and the pool system are virtually the same.

6.4.1.3 Voluntary bidding unless required to mitigate market power

As prices and schedules are based upon participant bids, it would be important to ensure that ESB bids into the system were appropriate. **Bidding into the system should be voluntary, but it may be necessary to force certain generators to bid in to ensure that prices are actually reflective of the market.**

6.4.2 **Transparency** is a must during transition

To ensure a smooth transition, it will be critically important to ensure that market participants are comfortable with the details of the model and have confidence that it will provide a level playing field. As a first step, suitably qualified independent practitioners should be engaged to facilitate debate and discussion on the model. While Eirgrid would be expected to play a major role, its historical links to the ESB are such that extra efforts would be required to ensure openness and transparency during the transition and ensure buy-in from all participants.

While it may appear more complex than other systems, because it is rooted in physical reality, the LMP model provides a solid framework. . The LMP design reduces opportunities for gaming and market manipulation and is inherently less discriminatory than the other models.

It has been suggested that the small size of the Irish market would give rise to highly volatile prices on each node and that it would be difficult to understand the resulting price signals. However, as the design provides full transparency into demand and generation at every node and every stretch of transmission network, it would be possible for potential investors to accurately model the entire system and the impact of potential new projects. It may be necessary to develop an LMP model of the Irish system to help participants understand the detailed working of the model in an Irish context.

6.4.3 **Dominance of ESB** can be reduced with effective regulation and PES auction

6.4.3.1 Option available if forced divestiture of ESBPG plant is unpalatable

In order to make any market work, there has to be sufficient competitors in the market. The ideal solution would be to break-up the ESB Power Generation into a number of independent generation companies and ensure a reasonable geographic dispersion of generation plant between them. This approach would be fraught with industrial relations issues. In the current market, it would also be difficult for the shareholder to achieve reasonable value for a partial disposal of ESB's plant, particularly in the light of its average age. However, it is possible that the LMP market design might allow for competition to develop without embarking on this difficult course of action. **The transparency of the LMP model is such that it may allow for participants to be reasonably confident that the playing field is level while leaving ESBPG intact**.

To achieve this, comprehensive and effective regulation of the bids from each of the ESB generators would be required. New entrants would need to be assured that ESBPG generators did not act in concert and provided bids into the system that were reflective of the true costs of generation. The strength of the LMP model is such that any abuse of its dominant market position could be identified much more readily.

6.4.3.2 Annual Auction of PES demand on a nodal basis

Because losses and congestion in the network is actually reflected in the market, the value of load at different parts of the system to a generator will vary depending on generator location. **An auction of PES demand on a nodal basis would therefore provide a useful way of introducing competitive price pressure to a large part of the market**. The New Jersey Auction for Basic Generation Service provides a useful example[32].

Acceptance of the notion the energy prices for consumers should vary by location is a normal feature of electricity markets in many countries. In Ireland however, it may be politically unpalatable to implement a change like this. To overcome this problem**, the results of the PES auction could be aggregated together and an average cost passed through to PES consumer bills**.

6.4.4 **Competition** will be encouraged during transition

Recognising that there is a short-tem need for new generation capacity, the CER has recently issued a consultation document considering potential options to

[32] See New Jersey Auction for Basic Generation Service project profile at http://www.nera.com/wwt/publications/5538.pdf

bring this about. A likely outcome may be that a new generator would be offered a guaranteed power purchase agreement for a number of years. This is a material step backwards in the development of a competitive market. While we would expect that certain compromises may be required in the transition to competition under the LMP model, a more explicit framework would reduce the need for short-term 'fixes' such as these

6.4.5 **Incorporating transmission in the market** is unlikely to pose problems

6.4.5.1 ESB skills in LMP are already developed

The recent success of the ESB in becoming the preferred candidate for the Independent System Administrator for SE-Trans in the US, suggests that the ESB will have all of the required skills to implement an LMP model. Assuming that the US Federal regulator gets its way, ESB will be required to implement the Standard Market Design (SMD) based on LMP for SE-Trans and will have all of the skills and expertise readily available.

It is worth noting however that the Southeastern Association of Regulatory Utility Commissioners ("SEARUC") has just published a report (8th Nov 2002) on the cost-benefit of Standard Market Design in the Southeastern United States. The initial findings are that the benefits are uncertain and it is unclear whether there will be resistance to SMD implementation.

6.4.5.2 Existing systems may be upgraded

The Irish EPUS system run is carried out by a company called Henwood, based in Sacramento, California on a software product called PROSYM. Only a very small proportion of the functionality of the software is currently used (of 74 system available system parameters, only 14 are used in the EPUS run[33]). In April 2002, Henwood announced a strategic alliance with another company, PowerWorld Corporation, to deliver a nodal-pricing software solution[34]. According to Henwood, the integration of its software with PowerWorld's Simulator software will deliver an effective means of forecasting nodal prices and the value of firm transmission rights.

Henwood are therefore well positioned to meet our needs from a system perspective and as they currently provide a service, not a software package, obtaining a full LMP system may prove to be a relatively straightforward service upgrade.

6.4.6 Consultation on **overall policy** is already in progress at CER

The CER has just recently engaged a team of consultants to carry out a review of electricity trading arrangements for 2005. While there are unlikely to many arguments put forward in defence of the existing trading arrangements, there appears to be little consensus among market participants as to what should be done.

[33] See "Guide to the Ex-Post Unconstrained Schedule" at www.eirgrid.com

[34] Henwood press release, April 15, 2002. www.henwoodenergy.com

The LMP model described here would, we believe, provide a benchmark framework against which participants can debate the way forward for Ireland.

In the early stages of a similar review of market design in New England, concerns over the complexity of LMP prompted a vote between a LMP model and an as-yet undefined but less complex model. The first vote was 67-3 in favour of the undefined simple model. Several months later, after many alternative models were rejected, the LMP model was finally voted in by a two thirds majority. Most of the alternatives proposed failed one of the principles of open market design, that of non-discriminatory access.

6.5 Summary

An explanation of the proposed system's workings is provided. We see many benefits that its adoption could bring to the Irish system, including;

Structure

- it provides the benefits of a balanced approach between pool and bilateral contract models
- it removes simplifications which can encourage gaming
- it does not segment the market the way that the current model does

Transparency

- Full disclosure of nodal pricing will allow accurate modelling by participants
- Information made available by the structure can be used by the regulator to increase efficiencies prior to the evolution of competition

Encouraging competition

- the adoption of an internationally accepted standard model should help reduce uncertainty for new investors
- competition above base-load would be stimulated by more cost reflective pricing
- smaller scale plant could become economic

Transmission would be incorporated into the equation

- the needs of the National Spatial Strategy could be more explicitly recognised
- Private sector funds could be encouraged into transmission as well as generation
- A UK-Ireland interconnect could be more accurately evaluated. It would appear to offer advantages in the medium term; expose the market to UK competition and help wind generation export to the UK

Overall Policy Thrust

- An active demand side could be incentivised, particularly important in a market with low reserve margins
- The model is consistent with expected technological developments

We recognise that this is a long-term approach and that there is a need for transition from the status quo. We believe, however, that there is an achievable path to competition using this model.

Structure

- SMD can be seen as a logical progression from the present structure with many current features facilitating the transition
- A spot market operated by the system operator would need to be established and locational prices calculated on an half-hourly basis
- It may be necessary to have mandatory bidding by certain generators to allow the model to develop

Transparency

- Buy-in from participants may need to be enhanced by the use of independent practitioners to ensure that the historic links between Eirgrid and ESB are seen to be broken

ESB dominance

- it is recognised that there are many obstacles to a break-up of ESB Power Generation. We believe that the LMP market design can provide many benefits without this step being necessary
- For example, the auctioning of PES demand on a nodal basis would be a useful way of introducing competitive price pressures. This would not necessarily require location dependent pricing at a retail level

Encouraging competition

- we would hope that a more explicit framework would reduce the need for short-term ‘fixes’ such as those currently under consideration to encourage a new generator in the short term.

Incorporating Transmission

- we believe that the requisite skills are in place within the various parts of the ESB
- Furthermore, it would seem that the EPUS systems can be upgraded to handle the SMD approach

Finally we believe that the timing for a new approach is appropriate given the fact that a CER review of market trading arrangements has just commenced.

7 Conclusions and Recommendations

Infrastructure investments and environmental factors are pushing energy prices up and rising prices will negatively impact the competitiveness of Irish enterprise

Energy demand is growing strongly. Demand for gas supplies is being driven both by extension of the gas network and the increased use of gas for electricity generation. The need to remunerate this capital spend will result in upward pressure on prices. Electricity demand is also growing strongly. Significant capital investment in generating plant will be required over the short term, pushing up prices.

Irish industrial consumers of gas have tended to enjoy prices that are below the average for Europe. With regard to electricity prices, smaller and medium sized enterprises have been paying above the average. Electricity price increases are currently in train and these will exacerbate this situation.

Increasing concerns with the environment are likely to lead to policies that will raise energy prices.

The expectation is that energy prices will rise in the short to medium term and that Irish enterprises will face increasingly higher prices than their European competitors.

While competition in the electricity market could stem the tide of increases, effective electricity market designs have proved elusive

Upward pressure on energy prices reinforces the need to ensure that energy is supplied in as efficient a manner as possible. This requires development of a structure for energy supply that both promotes efficiency and competition.

The physical features of electricity means that well-established commodity market designs cannot immediately be applied to electricity markets.

In recent decades, three competitive market models have evolved

- Single Buyer
- Pool
- Bilateral Contracts

While the latter two are closer to a true competitive model, both have their strengths and drawbacks.

Flaws in the Irish electricity market have prevented competition from developing

The bilateral contracts design of the Irish market has resulted in the absence of merit order dispatch and a segmented market. A lack of transparency makes it difficult for participants to gauge their competitive position and the dominance of the ESB is unwelcome from a competitive viewpoint.

The market structure ignores the economic realities of the system by both excluding the transmission from the network and by averaging the effect of losses and congestion.

As a result factors such as the need for a new generator to find a matched customer load, new entrants have been deterred and competition has not developed.

There is a wide perception that the market has evolved in an "ad hoc" fashion rather than along lines which would allow participants greater certainty and less regulatory interaction.

Results at an EU level are poor, but hope emerges from the US

EU policy objectives of improving EU competitiveness and reducing price differentials between countries have not been successful to date. The current approach has resulted in separate market for each country and an integrated single market is unlikely to emerge.

The US is evolving a system which is likely to leave the EU at the competitive disadvantage. FERC has adopted a Standard Market Design (SMD), based upon Locational Management Pricing (LMP), as its preferred approach.

SMD can be seen as an evolution of the single price pool, but it additionally accounts for:

- Losses and congestion
- Bilateral contracts
- The role of transmission network and demand side being increased relative to generation

After much debate there has been general approval of FERC's move from many areas of the industry in the US.

Adoption of a design based on Locational Margin Pricing provides many benefits for Irish Energy Policy

<u>Provision of Capacity</u>

An LMP based system would encourage the market to develop capacity as required:

- Large generators, who have been reluctant to enter the market to-date would now have the market knowledge and the certainty of demand that they previously lacked;

- The availability of comprehensive transmission information could allow the distributed benefits of smaller scale generation to be assessed against the costs of transmission system upgrades;

- The viability of CHP would be improved by the ability to get a market price for output without being forced to match a customer load; and

- Finally peak demand levels could reduce as some consumers may choose to opt out of flat rate tariffs in favour of optimising their consumption in line with intra-day variations in price, effectively lowering peak demand and the associated capacity requirement.

Regional Capacity
Additional local generation capacity or improved transmission infrastructure are alternative ways of meeting demand for power in the regions. The LMP system would allow for open and transparent modelling of available capacity at each location and the comprehensive analysis of the options and costs of meeting future demand at those locations. This capability will tend to provide electricity supply at lower costs than current structures would.

Energy Prices
An LMP based model would allow competitive pressures to be brought to bear on the bulk of the electricity market. While regulatory cost and performance controls will still be required, exposure of individual ESB generators to competitive pressures and incorporation of transmission into the market will help maximise efficiency gains for consumers.

Regional Prices
While the LMP model would allow the true costs of energy at each location to be understood, it does not necessarily follow that consumers in each region have to be exposed to different prices. Consumers who choose to remain with ESB PES could continue to be subject to a country-wide averaged flat tariff. Auctioning of ESB PES demand on a nodal basis could help the benefits of a competitive market to be passed through to PES customers.

As losses and congestion are the cause of LMP price differences, it does not necessarily follow that the cost of power in economically disadvantaged areas such as the BMW regions will have higher prices. A modelling exercise would reveal the high cost locations, providing the signals for transmission upgrades or for new generation capacity.

Energy Security

A properly structured and efficient domestic electricity system would improve the security of supply by expanding the number of domestic generators and the energy sources that they use. This would permit decisions as to the desirability and cost effectiveness of UK interconnector to be made on more informed grounds. In advance of measures to ensure the better working of the domestic electricity market, a decision to progress with an interconnector would appear premature.

Private Sector Involvement

The LMP model provides a vehicle for private investor funds to be attracted to the electricity sector not only in the provision of new generation capacity but also in the transmission network. The model allows the economic benefit to the entire system of additional generation capacity, transmission improvements or investment in demand side management to be assessed in detail. This would allow, for example, a large consumer in an area of high prices to weigh up the cost of on-going high prices against the costs of building local capacity or improving transmission to his location.

A smooth transition to a competitive market is achievable

We believe that smooth transition from our current structure is achievable. The key steps are the development of a spot market operated by the system operator and the calculation of locational prices on an half-hourly basis

We believe that the LMP market design can provide many benefits without the need to tackle the difficult issue of ESB divestiture. In addition, the auctioning of PES demand on a nodal basis provides a useful way of introducing competitive price pressures. This would not necessarily require location dependent pricing at a retail level.

The skills to implement the model are readily available and it may be possible to upgrade existing systems to meet the new market needs.

Finally we believe that the timing for consideration of a new approach is appropriate given the fact that a CER review of market trading arrangements has just commenced.

Appendix 1 - 1999 Policy Direction on Electricity Trading Arrangements

1. The following is a Policy Direction issued by the Minister for Public Enterprise to the Commission for Electricity Regulation in accordance with Section 9(1)(a) of the Electricity Regulation Act, 1999.

General

2. The main objective of the trading arrangements is to promote efficient competition amongst licensed generators and suppliers within the market segment being opened to competition.
3. All suppliers (other than the Public Electricity Supplier) and all generators (other than ESB generating plant contracted to the Public Electricity Supplier) constitute the independent sector and will be subject to the same trading arrangements.
4. For a transitional period ending on 19 February 2005, a regime for the provision of "top-up" and "spill" will be introduced. Under this regime, the independent sector will be able to purchase power shortfalls ("top-up") from and sell power surpluses ("spill") to ESB Generation whenever the production of independent power producers does not exactly match the aggregate demand of the customers of the independent sector.
5. Generators and suppliers in the independent sector will be able to trade electricity amongst themselves at mutually agreed (i.e. unregulated) prices prior to settlement of aggregate "top-up" and "spill" with ESB Generation.

Pricing

6. The independent sector will in all normal circumstances be able to purchase "top-up" from ESB (Generation) in sufficient quantity to provide adequate back-up supplies to the independent sector at prices that average out over the year to the estimated full cost of a best new entrant (BNE). These prices will be profiled according to published ex ante estimates of ESB's avoidable fuel cost, plus an extra capacity element weighted according to the expected loss of load probability (LOLP), at the appropriate time of day, week and season. The actual BNE price has yet to be determined.
7. The independent sector will be able to sell "spill" to ESB (Generation) at ESB's avoidable fuel cost for an initial tranche of 25% of total eligible customer demand. This is currently estimated to be approximately 200 MW in 2000/2001, but the figure will of course increase with eligible customer demand growth from 2001 and with further market opening in 2003. Any spill beyond the initial tranche will be priced at the best new entrant's avoidable fuel cost, subject to a cap of ESB's avoidable fuel cost.
8. ESB Generation, once it has satisfied its regulated contract with the Public Electricity Supplier and the top-up requirements of the independent sector, will be allowed to enter into voluntary commercial arrangements with independent suppliers, including ESB Independent Supply, subject to regulatory oversight and normal competition rules.

Review

9. Early in 2002, the Commission for Electricity Regulation will review the effectiveness of the pricing arrangements, which may be modified at that time if it is found that they are not meeting the main objective of the trading arrangements.
10. The Commission for Electricity Regulation will carry out a review of the overall

trading arrangements early in 2004, with a view to introducing, after completion of the transitional period, appropriate wholesale market arrangement applying equally to all bulk electricity generation and supply in Ireland.

Next Steps

11. The Commission for Electricity Regulation will consult on the detailed arrangements associated with the transitional trading regime in accordance with the Electricity Regulation Act, 1999

Appendix 2 LMP—An Essential Tool for Wholesale Markets

The following extract "LMP – An Essential Tool for Wholesale Markets" from the US Electricity Advisory Board's Transmission Grid Solutions Report, September 2002.

As part of its Standard Market Design for transmission services,4 the Federal Energy Regulatory Commission has proposed to use "bid-based, security constrained locational marginal pricing" (the pricing regime is known by its initials, LMP) to address transmission congestion costs. LMP reflects three unique and distinct elements of the cost of electricity. The first element is the price of the power at the source of the generation. The next element is the cost of the transmission from the generation source to the ultimate user. Finally, LMP reflects the time element of the transportation (the cost of redirection of the transportation when at specific times the volume is higher than the system can handle and the "overflow" must follow a different path). Thus, LMP is the transparent price of energy at a specific point and at a specific time on the transmission grid, and the purpose of an LMP system is to reveal the true cost of congestion in a power system. LMP systems also provide for financial transmission rights ("FTRs"), which are called "Congestion Rental Rights" in the SMD NOPR, that reflect the economic value of congestion between two points on the transmission system. An investor in transmission between congested points on the Grid would be awarded the economic value of the associated FTRs created by the investment. An LMP system with FTRs gives players the clearest information necessary to make economic decisions regarding generation and transmission placement. We applaud FERC's efforts to continue to implement LMP systems throughout the country, recognizing that LMP alone cannot address all bottlenecks.

Improper pricing signals lead to additional congestion. LMP will assist in identifying the facilities necessary to relieve congestion. However, LMP alone will not solve all of the problems of an inadequate transmission infrastructure. More needs to be done, as outlined in this Report, to ensure that congestion is relieved and that consumers benefit. In the meantime, we support FERC's initiative to implement LMP, with the goal of minimizing the adverse impact of congestion on consumers, and particularly consumers in load pockets (A load pocket is an area that has undue constraints in the transmission system that limit the ability to import generation to serve customers in that area.)

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Appendix 3 - Kyoto Protocol

From December 1 through 11, 1997, more than 160 nations met in Kyoto, Japan, to negotiate binding limitations on greenhouse gases for the developed nations, pursuant to the objectives of the Framework Convention on Climate Change of 1992. The outcome of the meeting was the Kyoto Protocol, in which the developed nations agreed to limit their greenhouse gas emissions, relative to the levels emitted in 1990. At the time, the United States agreed to reduce emissions from 1990 levels by 7 percent during the period 2008 to 2012. The EU pledged to reduce emissions by 8 percent by 2012 through legislation to promote cleaner energy and shift traffic to less polluting transportation such as rail or water.

In March 2001, President George W. Bush's administration pulled the United States out of the accord last year, saying it would be too harmful to its economy. The EU and Japan ratified the protocol in May and June 2002. In order to come into force, the Kyoto Protocol requires ratification by 55% of parties by number, and 55% of developed countries by 1990 emissions. As at June 2002, the Kyoto Protocol had been ratified by 72% of parties by number, and the inclusion of Europe and Japan brings its ratification by 1990 emission levels to 36.0%.

The remaining developed countries (referred to as Annex I countries) who have not yet ratified the Protocol are (with their percentages of 1990 emissions of developed countries):

United States	36.1%
Russian Federation	17.4%
Poland	3.0%
Canada	3.3%
Australia	2.1%
Bulgaria	0.6%
Hungary	0.5%
Estonia	0.3%
Switzerland	0.3%
New Zealand	0.2%
Latvia	0.2%
Liechtenstein	0.0%
Monaco	0.0%

Ratification by the Russian Federation and Poland would be sufficient to bring the ratification level up from 36.0% of countries by emissions to beyond the required 55% of countries by emissions. Australia and Canada are concerned about their international competitiveness and trade impacts if a major trading partner or trading competitor, such as the USA, were not to ratify the Kyoto Protocol.

If the Kyoto Protocol comes into force without ratification by a country, it would not be binding upon that country. However, if a country does not ratify, emission reductions achieved in that country cannot be traded for the benefit of other countries' targets.