

THE SCOPE AND LIMITS OF COMPETITION AND REGULATION IN THE IRISH ELECTRICITY MARKET

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1.
Introduction

As regulators and politicians consider the options for promoting competition in the Irish electricity market and the associated regulatory regime, it is tempting to reach for “off-the-peg” solutions on the basis of models already applied in other EU Member States. While there is much to be learned from such examples, the special features of the Irish market constrain the options and suggest that a pragmatic combination of internal and external unbundling would be more appropriate, and that attention should be directed towards greater interconnection.

Electricity has a number of generic economic characteristics that necessitate an element of regulation, whatever the geography, size or level of development of the economy. Demand must be instantaneously met by supply, requiring the provision of a capacity margin to meet peaks, and creating volatility in prices that requires hedging through contracts. The assets are generally long-lived and sunk, also requiring that the risks to investors are hedged either through long-term contracts or financial instruments. The networks have significant natural monopoly, requiring some form of price regulation. All of these problems interact with each other and are complex. But the element which makes them so important is that electricity is complementary to the rest of the economy – a failure to supply affects not just the electricity industry, but the whole of the

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performance of the economy, as recently witnessed in California. Therefore, from the perspective of the economy, overall risk is asymmetric: overprovision is (much) less expensive than underprovision.

In recent years, these “market failures” have been expanded to include environmental constraints. The electricity industry is typically – with transport – the major source of emissions of carbon dioxide, sulphur dioxide and nitrogen oxides. Although there has been some decoupling of economic growth and electricity demand in the 1990s, it is hard to envisage even a stabilisation of CO₂ emissions without significant supply-side substitution. Unless nuclear is chosen, most of the technologies which are non-carbon are also small-scale, embedded in distribution networks. They, therefore, require not only investment in the plants themselves, but also in the transmission and distribution networks.

These characteristics are harder to deal with in small countries that are geographically isolated. The margin of capacity needed to meet peak demands tends to be larger, the smaller the portfolio of plant. The scope for competition in generation is also narrower, since the number of contracts covering physical generation plants is limited, and considerable market power is therefore unavoidable. Discrete individual investments have a larger effect on the total market. So, in addition to the generic problem in designing an electricity supply industry, there are specific problems, and any proposed reform of the Irish electricity industry must solve these too.

The main policy dimension to the design of the electricity supply industry is the European context: in the last decade, significant new initiatives have been taken to liberalise supplies of electricity and gas across Europe, largely with the big economies of Germany, France and Britain in mind. These large and interconnected cases are very different to Ireland, but the rules are general to all players.

This paper is concerned with the way in which small countries should attempt to address these problems in a European context. The paper begins with the European dimension (Section 2), and explains the way its energy liberalisation policies have evolved, and focuses on two less well-articulated aspects of the European market: the immaturity of interconnections and network development; and the emergence of very great market power in the hands of just three companies, EDF, E.ON and RWE. This provides the context for the new policy agenda focused on gas dependency and environmental constraints which is emerging across Europe (examined in Section 3).

The paper then goes on to consider the specific Irish dimension (Section 4) and the ways in which the market failures are reflected within the current market place. The role of vertical integration is discussed (Section 5) in its various (often distinct) dimensions. This analysis then provides the basis for examining the broad range of feasible competitive options for Ireland (Section 6). Finally, a number of conclusions are drawn (Section 7).

2. The European Dimension

The European energy market has developed in a planned way for much of the post-war period. For the period up until the end of the 1960s, the challenge was to build sufficient capacity to meet the demands of the rapid economic expansion. In the 1970s, the era of cheap energy came to an abrupt end with the Yom Kippur War and the quadrupling of oil prices in

1973/74. The oil embargo provided a real threat to physical supplies, and European concerns about import dependency triggered renewed interest in nuclear power, most notably in France. Most of the assets in operation in energy markets today were created against this background, in which demand growth, security concerns and rising oil prices were the dominant themes.

These assumptions of energy policy turned out to have been wrong in the 1980s and 1990s. After the subsequent oil price shock in 1978/79, caused by developments in Iran, there was an almost complete reversal – oil prices fell, demand moderated, and energy sources were in abundant supply. Gradually, as it became apparent that the priority had shifted from investment to cost reduction, with the renewed interest in completing the internal market in the mid-1980s, and with industrial customers pushing for lower prices to protect their international competitive position with the US, the policy framework shifted towards a more market-oriented framework. Liberalisation, competition and (for some) privatisation displaced franchises, monopoly and public ownership as the preferred structures for the European Commission, and, in particular, the Internal Energy Market team.

The early ambitions of the Commission were thwarted by the combination of lobbying by the dominant energy companies, notably Ruhrgas, RWE and EDF, and the political interests of the French government to protect its nuclear programme and the German government's interest in external supply security and its (uneconomic) coal miners. As a result, the excess supply position in electricity did not result in lower prices until the end of the 1990s, and Directives to facilitate the Internal Energy Market were not agreed until 1996 (for electricity) and 1998 (for gas). Neither of these had much effect, except that they forced all member countries to pass new legislation, and it was these *national* initiatives that quickened the pace of liberalisation. Various compromises – such as the single-buyer model – were introduced along the way, but, by the turn of the century, the main components were: a progressive market opening in supply; separation of transmission; and third-party access (TPA) regulation of transmission pricing. Competition for new generating plants was also encouraged.

This model of competition, and the Commission's focus on its main components, neglected the key roles played by infrastructure and merger policies. The fundamental difference between policies to liberalise national markets and those designed to create a *Europe-wide* market were that, while the former was interconnected, the latter was much less so. Interconnection is a necessary condition for competition to develop – without physical connections, access to markets is necessarily limited. Though the Commission encouraged infrastructure development, it did not give it precedence or priority over liberalisation. The optimal level of interconnection will not be delivered by competition and markets: it is a public good, and utilities do not normally volunteer to physically open their markets to others, especially when this risks stranding assets. The latter was particularly relevant in a period of excess supply. For European customers, interconnection meant lower prices and more security of supply, but there was no substantial public champion of the European interest capable of limiting those of the major utilities.

A further complication came through merger policy. The “British model” of competition, upon which the Commission’s Internal Energy Market was largely based, required that there was a sufficient number of buyers and sellers. In response to the threat that the Directives posed to their home markets, the major European energy utilities began to consolidate. In this they were facilitated by the Competition Directorate’s approach to defining the market for the purposes of merger policy as *national*. Thus, when EDF made acquisitions in Germany or England, this was regarded as *increasing* competition, as EDF had no direct stakes in either. The consequence of failing to take a European view consistent with the objective of creating an internal *European* market was that the utilities were able to create very significant market power, to the point where three companies – EDF, E.ON and RWE – dominate the European energy markets, all the more so with E.ON’s proposed acquisition of Ruhrgas. These companies are the largest electricity companies Europe has seen to date, and have created a market structure similar to that of oil.

The consequences of this consolidation are fundamental to the future of the internal market. The “British model” is no longer a feasible option, since it depends upon the existence of sufficient competitors upstream and downstream without market power, so that a futures market can develop to hedge upstream sunk costs through the financial market, rather than passing them on to customers, as the franchises had done in the twentieth century. Investments in capacity and long-term, take-or-pay contracts now have to be written against equity, and only the big players have enough market power to carry these risks. Entry by independent power producers is now more likely to arise for cosmetic reasons (to give the illusion of competition), and then only on the basis of long-term power purchase agreements with dominant incumbents.

At the supply end, the Internal Energy Market envisaged new retail businesses, challenging incumbents. This ambition has also been largely undermined by consolidation. For stand-alone suppliers to compete, they need access to electricity on terms at least as good as those of the incumbents, and they need competitive cost bases too. In an open compulsory pool, such as the British model in the 1990s, where all power must be despatched centrally and suppliers have open access, this was, in principle, possible. Under its successor, NETA, and similar trading arrangements in Europe, this is not the case, and again the parallel with oil is instructive. Retailers of petrol have found it virtually impossible to take on the incumbents on a competitive basis. These are important factors that will need to be taken into account in considerably different types of market structure for energy trading in Ireland.

On costs, it is widely argued that there are economies of scale in supply, related to customer handling, billing and purchasing. In England and Wales, the conventional wisdom is that 5 million customers is the minimum efficiency of scale. While the precise number is open to dispute, there appears to be little scope for competitive entry below the 1 million mark. Finally, supply competition requires the risks of price fluctuations to be hedged, and the vertically integrated suppliers have the advantage of physical hedges (so that they can balance their own actual generation with actual demand), in the absence of a developed futures market.

For these reasons, in all European countries, the concept of supply competition has become one of oligopolistic competition between a smaller number of vertically integrated players. The exception was thought

by many commentators to be provided by Centrica, the gas and electricity supplier in Britain, which was spun out of British Gas; but, in practice, the early successes of its supply-only approach were explained by the very great excess supply of gas as a result of the bubble of the late 1990s. Centrica is now quietly vertically integrating through long-term contracting and the acquisition of storage and generating assets.¹

As the excess supply unwinds in Europe, the experiment with competition in energy markets has settled down into a more mature, albeit somewhat messy, pattern of a small number of vertically integrated players, with a limited fringe of smaller competitors. The core problem of risk allocation in generation and supply is being addressed through equity and market power. The markets are being *liberalised* – as they are in oil – but *de facto* market power is replacing *de jure* franchises. Market power provides the basis for long-term, take-or-pay contracts (especially for Russian and Norwegian gas), and the ability of suppliers to hedge risk physically. Trading is increasingly a method for the dominant players to sort out their imbalances, rather than a gateway for independent entry. In some cases, it may even facilitate collusion.

Whether this model is better than the alternatives is increasingly an academic rather than a practical question. The mergers *have* taken place, the market *is* consolidated around just three very large companies, and there is no realistic prospect of break-up. The “British model” no longer applies to Britain, and it has never really applied in much of Europe. It is hard to envisage much scope for successful *disintegrated* companies in this context, and, where they exist, the scope for acquisition of the parts by these consolidated few is considerable. Restructuring of the Irish market has to be set in *this* context, not the “British model”.

For the main European economies, the 1990s was a decade of excess supply. Generation assets built in the 1970s and 1980s proved more than adequate to meet demand in France, Germany and Britain. As a result, the priority was to sweat these assets, rather than invest. There were exceptions – such as Ireland – but their requirements were not a primary focus for European policy.

By the end of the 1990s, this agenda began to change, and two new priorities began to assert themselves – the problems of gas import dependency and the environment. Other changes in background conditions added to these concerns. The tripling of the price of oil at the end of 1999, and the impact on gas prices, ended, at least temporarily, the era of cheap fossil fuels. Problems in California raised the issue of long-term contracts, which the British model – on which Californian liberalisation was based – found hard to facilitate, while the undeveloped state of European networks in electricity and gas reduced security of supply.

The gas imports problem had been apparent to Germany for some time, and Ruhrgas had led the way with a direct stake and boardroom seat at Gazprom. The Commission was concerned about the political dimension, while the companies focused on the sunk costs involved in

¹ Ofgem (2002), “Centrica’s Completed Acquisition of Dynegy Storage Limited and Energy Onshore Processing Limited: A Consultation Document”, 77/02.

infrastructure developments and the impact of liberalisation on their ability to sign the long-term, take-or-pay contracts that Gazprom demanded. The solution that emerged was the creation of market power described in the previous section: these contracts could only be signed if the companies were big enough to carry the risk on equity, as the oil companies traditionally did. This in turn encouraged national governments to support the creation of national champions, of which E.ON, RWE and EDF/GDF are the main examples.

The environmental problems posed even greater challenges for European energy policy. If the scientific consensus was that major cuts in greenhouse gas emissions would be needed, then most of the non-nuclear European electricity assets would have to be replaced. Moreover, to the extent that renewables would play a significant part in the solution, the electricity transmission and distribution networks would have to be re-engineered. Global warming required a major investment programme, rather than the asset-sweating of the 1990s. This, in turn, required the traditional investment problems to be overcome – how to design long-term, take-or-pay² contracts for the new assets – but with the added complexity that non-fossil-fuel sources of supply were typically more expensive than conventional ones. In the absence of a carbon tax, the solution across Europe has been *compulsory* take-or-pay contracts, imposed via obligations for quotas of designated fuel sources. The Renewables Directive³ is the first step in this direction, probably to be followed in due course by nuclear and energy efficiency obligations in a number of countries.

This new investment agenda – in gas and in non-fossil-fuel sources – shifts the focus of energy policy, so that the liberalised market created by the Directives (actual and proposed) is gradually being boxed in by a series of contracts, supported by policy interventions. Investment is gradually beginning to take priority, as it becomes apparent that the Kyoto targets are increasingly demanding on Member States, many of which made easy gains by reducing coal-fired generation in the 1990s, and as the North Sea gas supplies begin to decline. A more active energy policy – as opposed to competition policy – is beginning to emerge, and an element of planning reasserts its role through the need to set source-specific generation obligations and to underwrite infrastructure developments.

4. The Irish Dimension: The Context

All of the above considerations apply to the Irish context. It cannot escape the fundamental characteristics of the electricity sector described in the introduction, nor can it avoid the problems of long-term, take-or-pay contracting for new infrastructure and generation investments. It must also address the climate change problems.

As a small country, there are a number of *additional* constraints that further reduce the policy options. Two of these are generic to all small countries. The portfolio of plant requires a greater capacity margin (because the insurance provided by the diversification of geography and

² Take-or-pay contracts involve purchasers paying whether they take the product or not.

³ “Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market”, *Official Journal* L 283, 27/10/2001, P. 0033 – 0040.

plants is less), and the fixed costs of operating pooling and trading arrangements are proportionately larger relative to the customer base.

The capacity margin requirement creates special investment problems. In a NETA-type market (with no explicit capacity payments), peaking plant earns its return only at points where supply and demand come into a tight balance. *Provided* price spikes are permitted to balance demand and supply at peaks, such plants will earn very high returns on these occasions – but *only* on these occasions. Provided that these peaks in price are expected, suppliers will contract for peaking plant, *provided*, too, that such contracts are capable of being written against a relatively secure customer base. These conditions clearly do not hold in the Irish context – investors will expect sharp peaks to be curtailed by political and regulatory intervention (as they were in California). As a result, some form of compulsory contracting will probably be required. The fact that the capacity margin requirement is relatively greater in the small-country case makes this *more* important.

With regard to the fixed costs of pooling and trading, this has the implication that the costs of introducing a “British model” to Ireland will be correspondingly greater, and there is an obvious and inevitable trade-off between these costs and the benefits that may result. With around 50 million people to spread the costs of the England and Wales Pool and then NETA, the costs per customer are much less than when applied to 4 million in Ireland.

Within the small-country context, there is a further constraint on competition – the number of competitors that can be accommodated, given the small number of generating stations and sets. Inevitably in the Irish context, generation will be at best oligopolistic, with considerable incentives to collude. Northern Ireland provides a good example of what happens when the number of generators is below five.⁴

The consequence of the small number of generating stations is that the impact of a new plant is proportionately much greater. If a new CCGT is added to the England and Wales system, its effects are marginal. If such a plant were added to the Irish system, it would affect the economic value of *all* other plants and have a significant impact on prices and capacity margins. Therefore, if the market were “competitive”, an investor would seek to hedge the risk that someone else might *subsequently* add new plant. The consequence is that a particularly fixed long-term, take-or-pay contract would be required.

The small-country case places a greater importance on co-ordination benefits because the ability of the system to absorb shocks is correspondingly weaker. Failure by any one plant is more significant, and the ability of the economy as a whole to adjust to power shortages is much weaker. The lack of interconnectors means that there is no external support in times of crisis. Thus, it is likely that intervention will have the greatest economic benefit among investment opportunities.

The final impact of the small-country characteristics is on supply. We noted in the previous section the economies of scale. Thus, if a sufficient number of players is to be created to have a competition, there will

⁴ There is considerable theoretical and empirical evidence on the likelihood of collusion as the number of competitors rises. It turns out that fewer than five creates much greater incentives to collude. On this, see Newbery (2000).

5. Vertical Integration and Demand Expansion in Ireland

inevitably be an increase in costs. Such competition would have the effect of making price equal (the higher) costs, and, in a system in which considerable cross-subsidies exist, the small-country case is likely to exacerbate the visibility and political reactions to such redistributive tariffs.⁵

These considerations imply that the costs and benefits of various competition possibilities in Ireland will need to be very carefully evaluated before significant structural change is introduced. Competition is a means, not an end. It has costs as well as benefits, and, where investment is a priority, there needs to be scope for long-term, take-or-pay contracts. The combination of the need for an element of planning to ensure that there is sufficient supply and infrastructure, and long-term, take-or-pay contracts for major new investments, constrains the options very considerably.

While most of Europe is in excess supply, Ireland is in excess demand, with the urgent need to add new generation capacity. In this context, it is important to consider whether, in contemplating structural change, vertical integration is more or less likely to facilitate investment.

The advantages of vertical integration are well known: it creates *flexibility* within a structure that nevertheless provides for security of contracting between generation and supply where generation investments are typically sunk costs. Generation can be matched to supply without the need for a fixed-price contract, enabling co-ordination of the component parts without the transactions costs associated with arm's-length market transactions. It is for this reason that it is the natural business structure not just for electricity, but also for oil, glass and brewing, and why car sales typically operate within a franchise set of networks.

These efficiency gains need to be set against the disadvantages of vertical integration, notably the market power it confers and the ability to limit entry. The balance of these advantages and disadvantages cannot be known *a priori*: it depends upon the size of the market relative to the minimum efficiency of scale upstream and downstream; and the relative importance of investment versus cost reductions. In the Irish case, the scale and investment needs would tend to place more emphasis on the advantages of vertical integration.

There are, however, a number of different *forms* of vertical integration, and the fact of separate ownership of different parts of the vertical chain does not necessarily imply that the structure is disintegrated. It depends where the risks are located. Long-term, take-or-pay contracts are themselves a *form* of vertical integration, since they transfer risk from one level of the vertical chain to another. Thus, the Northern Ireland system is in fact vertically integrated through the Power Plant Agreements (PPA) contracts. PPA contracts, however, lack the full benefits of vertical integration in one important respect – by using contracts rather than ownership, flexibility is reduced, and, as a result, there have been significant difficulties in “solving” the Northern Ireland electricity market problem, and much regulatory intervention has resulted.

⁵ Supply competition here refers to the *economic* kind, based upon competitive advantage, and not the artificial exploitation of cross-subsidies created for social and political reasons.

6. Feasible Competition Options for Ireland

The co-ordination benefits of vertical integration can also be retained through the identification of a planning and co-ordination function within a system operator (SO), typically the transmission operator as well. If the SO has a duty to supply then contracting can be centrally organised, both for baseload and peaking plant. In most European systems, this model is gradually emerging. In the Irish context, FitzGerald (2002) proposes such a model.

While the SO function is important to the system as a whole, it is important to recognise that this contracting approach requires a *counterparty* to the investor. If there are many buyers and many sellers, with complete liberalisation of supply, no obvious counterparty exists. This highlights the importance of the other dimension of vertical integration, namely market power. If the Irish system is too small to carry the costs of a NETA or pool-type market, and if there are not enough players for a futures market to develop in a liquid, transparent and standardised way, then a counterparty to contracts will only emerge if it has enough of the supply market – and enough confidence that it will continue to enjoy that market share – to take the risk on equity.

This last consideration seriously constrains the options for competition and restructuring of the Irish electricity market. There are three broad options that could be introduced, given the constraints:

- an SO model with PPA auctions and *de facto* supply market power;
- a vertically integrated structure with liberalisation and entry at the margin;
- an all-Ireland oligopoly, with features of both vertical integration and an all-Ireland SO function.

Although the CER is actively considering the introduction of trading mechanisms, there are major obstacles to introducing a NETA/pool British model: the transactions costs would be a very considerable deadweight cost; there would not be enough players to have a competition; a futures market would be very weak; and investment incentives would be very weak too. The risks of investment and therefore system failures would be very great, and, given the asymmetry of risk and cost from undersupply to the economy as a whole, this model would have potentially serious consequences for the Irish economy.

The scope for choice between the models is further limited by the European Directives. These require three core components:

- the liberalisation of supply;
- the creation of a separate transmission function (in practice, an SO), with TPA;
- competitive tendering for all major projects.

As noted above, these requirements were developed with large-country cases in mind, but they are inescapable for small ones too. Once they are taken into account, the choice reduces to the structure which is most likely to provide co-ordination and investment incentives to meet the small-country constraints and the excess demand. This turns on how much vertical integration is permitted and the degree of practical separation of powers between the SO function and ESB in the south.

In the first two options, new-entrant generators can be facilitated. For the entrant, faced with the market power of the incumbent, some form of long-term, take-or-pay contract will be needed, and that in turn requires a counterparty. With liberalised supply, this creates problems, since customers are not committed to a specific supplier. For the SO to carry out auctions, it would have to auction both the generation *and* the supply sides of the contract. It can only do the latter *if* it either faces many competing suppliers *willing* to commit, or it can compel suppliers to purchase through some form of obligation (such as the Renewables Obligation in Britain), or through a levy (in practice, these are rather similar).

The other counterparty is ESB, which has a dominant position, but this might require closer regulatory supervision since it would face less supply-side competition in the bidding. In any PPA-type contracting, the economic question is: who bears the risk? In the Irish contract, the candidates are the investor in new generation, ESB and customers. Since it is unlikely that a purely merchant plant would be built, it is the ESB and customers, and it is inevitable that the regulator – given the influence exercised over price – will be a *de facto* party to the outcome. (It is assumed here that the SO would be unable to bear the generation and supply risk, for obvious reasons.)

In the current deliberation of the Irish Commission for Electricity Regulation (CER/02/184), the urgency of bringing forward new generation capacity by 2005 has motivated an attempt to consider a series of contracting options. However, the consultation paper provides no detailed analysis of risk allocations or the associated costs of capital. Given the time constraints, these issues will need to be addressed very quickly.

The third approach – the all-Ireland option – has a number of clear attractions. A larger all-Ireland system would facilitate a reduction in the capacity margin, and create greater scope for competition. With further interconnections to Scotland, and perhaps Wales too, more insurance and more competition would be provided. Given the presence of ESB and Viridian as separate companies, an all-Ireland SO function would be required, and the interconnectors would create a (limited) integration of an all-Ireland and British SO function.

These benefits are likely to be very considerable, and, in any event, will be much greater than the potential gains made by splitting up the 4 GW or so of capacity in the south. The result would be an oligopoly around a single SO, with liberalisation and competitive tendering providing the threat of fringe entry without so disturbing the market as to make investments unduly risky.

7. Conclusions

The debate about competition and the structure of electricity industries has often been theoretic and failed to take proper account of the contexts to which such theoretic insights are applied. The Irish context includes:

- the inherent characteristics of electricity markets, including the instantaneous balancing, centralised dispatch, capacity margins and contractual requirements for sunk-cost investments;
- the additional constraints of the small-country case, including the limited number of plant, the greater capacity margins, the marginal impacts of discrete investments, and the economies of scale in supply;

- the environmental constraint, requiring very significant investment;
- the take-or-pay contracting problem for gas supplies and infrastructure investments;
- the Irish peculiarities of excess demand and limited interconnections;

Given these market failures and the requirements of EU Directives, the options for re-structuring the Irish electricity market are limited to a pragmatic combination of internal and external unbundling. It is pragmatic, in the sense that there is a trade-off between the inefficiencies that significant market power creates, as against the increased risk to investors and the consequent higher costs of capital that imposing a competitive structure on a small-country system, such as that in Ireland, would create. In practice, this is a trade-off between higher operating costs (largely driven by labour and the industrial relations problems which come with monopoly) and capital costs. In the Irish context of excess demand, investment is the priority and a few percentage points on the cost of capital are likely to swamp the operating cost inefficiencies. Within this context, there is a very strong case for retaining elements of vertical integration, and taking a gradualist approach to change, given the tight margins between demand growth and supply. The greatest gains are likely to be with an all-Irish solution and greater interconnection with Britain.

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