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Liberalised Power Markets

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Introduction – the dash for liberalisation

‘Liberalisation of energy markets has brought great benefits to a lot of people. For consumers, it has brought greater choice of products, lower prices and a general improvement in the quality of service. For companies it has meant the freedom to develop new ideas, to build their business and to reap the rewards of success. The benefits of competitive energy markets are now widely accepted in the rest of the EU and there is widespread support for the creation of a policy framework to underpin the establishment of a functioning internal energy market.’

(UK Energy Minister Peter Hain, March 2001¹)

‘Power is now a dirtier word in banking than telecoms. In the USA, UK and Latin America there are no investors, no banks and deregulation is losing credibility.’

(Tony Marsh, EBRD Cofinanciers’ meeting, March 2003²)

For most of the last twenty years there has been a firm assumption that global electricity markets are embarked on an irreversible journey from highly regulated monopolistic structures to competitive markets. The early gains in terms of reduced costs of electricity production (and therefore, to a greater or lesser extent, reduced prices for consumers) in several countries which had liberalised their power markets, coupled with ideological attraction to ‘free’ markets among many governments which exercised power in the 1980s and 1990s, were factors leading bodies such as the European Union, the US Federal Government and the International Energy Agency to take stances encouraging further market liberalisation.

Even so, liberalisation of power markets is still at an experimental stage. Although in the 1970s and 1980s reforms were introduced in some countries

¹ <http://www.dti.gov.uk/ministers/archived/hain070301.html>, Hain P. (March 7, 2001), *Speech to Electricity Association dinner*.

² <http://www.ebrd.com/oppo/syndi/meeting/pres/power.pdf>, Marsh A., EBRD cofinanciers’ meeting (March 11, 2003), *Power and energy*.

(USA, Chile) to allow independent power producers to supply electricity to existing monopoly utilities, usually on the basis of inflexible long-term contracts, widespread liberalisation only began with the introduction of competitive electricity markets in the UK in 1990, Norway in 1991 and New Zealand in 1994. In 2001 the IAE summarised progress with liberalisation in IEA countries as follows³:

Country	Partial opening of retail electricity market	Full opening
UK	1990	2000
Norway	1991	1991
New Zealand	1994	1994
Australia	1994	
Finland	1995	1997
Sweden	1996	1996
Germany	1998	1998
Spain	1998	
USA	1998	
Austria	1999	
Denmark	1999	
Luxembourg	1999	
Netherlands	1999	
Portugal	1999	
Switzerland	1999	
Belgium	2000	
France	2000	
Ireland	2000	
Japan	2000	
Canada	2001	
Greece	2001	

and predicted that by 2007 more than 500 million consumers in OECD countries (about half the total) would have a choice of supplier⁴.

However, in practice, experience of ‘liberalisation’, in its many and varied forms, has been mixed. In some regions, countries and states such as the UK, Germany, the Nordic region, Texas, New England, PJM (Pennsylvania/New Jersey/Maryland), Chile and New Zealand, experience has been largely positive, with lower power prices and no serious long-term disruption of supply for capacity reasons. In others – California, Alberta, Ontario, Italy – liberalisation has brought problems in terms of higher power prices and/or disruptions in supplies. In 2001 the Centre for Responsive Politics (USA) said⁵:

³ <http://spider.iea.org/books/countries/2001/compendium.pdf>, IEA, *Energy Policies of IEA Countries, 2001 Review*.

⁴ <http://www.iea.org/about/emr.pdf>, IEA (2001), *Electricity market reform: California and after*.

⁵ <http://www.opensecrets.org/news/electricity.htm>, Centre for Responsive Politics (2001), *Electricity deregulation – what’s the issue?*

‘Advocates of deregulation say reducing government control of the industry will benefit consumers – lowering prices while expanding services and giving the public a say in who supplies the power that runs their computers, toasters, lamps, and more. But among the 24 States that have enacted electricity deregulation plans, results are mixed. Rising prices, skyrocketing demand, and limited supply in some areas have raised questions about the viability of deregulation.’

In a number of places – California, Arkansas, Arizona, Montana, Ontario, Queensland, Switzerland, Thailand – steps have been taken to delay, reject or reverse liberalisation. In perhaps the most dramatic example, the Dominican Republic renationalised key elements of its power industry in 2003, just four years after they had been sold off.

Whether this pause is a sign of growing disillusionment with the concept of liberalisation or a short-term response to a series of problems (very high price spikes in Scandinavia, Netherlands, California, Alberta, Ontario, New Zealand, Argentina, blackouts in New York, Copenhagen, Italy, Victoria, Auckland, London, Birmingham, Athens) is not yet clear. However, by early 2004 statements such as that of Craig Goodman (President of the National Energy Marketers Association, USA) were becoming more frequent:

‘A utility that uses its scarce capital and credit rating to buy and sell a commodity as volatile as gas and electricity and all the risks associated therewith, that has zero upside potential, zero profit and a likelihood that they’ll never recover the costs of that function, is not acting prudently on behalf of their shareholders⁶.’

The peculiarities of competitive electricity markets

Electricity is a unique commodity. It cannot be stockpiled in large quantities and yet secure supplies on a moment-by-moment basis are enormously important. Recent blackouts round the developed world – Auckland, Victoria, California, the eastern seaboard of North America, London, Birmingham, Copenhagen and south Sweden, Greece and Italy (twice) – have both demonstrated that major outages are possible in rich countries and reminded us that the effects of such outages, in economic, social and health terms, can be significant.

The introduction of competition into electricity supply systems – variously referred to as ‘liberalisation’ or ‘deregulation’ though such terms are something of a misnomer – has become the predominant trend in the markets of developed and, increasingly, developing countries in the period since about 1990. Many major organisations, such as the European Union, the Federal Energy Regulatory Commission (USA) and the International Energy Agency, have encouraged countries to increase the extent to which both generation and supply of energy are open to market forces, while recognising that some elements of the process, notably transmission and distribution, are of their nature natural monopolies and must therefore continue to be regulated. The details of liberalisation vary

⁶ *Restructuring Today* (February 3, 2004).

significantly from country to country, but broadly most models share some or all of the following features:

- unbundling of the natural monopolistic elements of provision of electricity from those elements which are amenable to competition – generation and supply (i.e. sales directly to the consumer);
- to a greater or lesser extent barriers on vertical integration between generation and supply and also measures to prevent single players winning too large a share of either or both of these subsectors;
- introduction of a competitive market in generation, with a range of contracts available in the marketplace (e.g. ‘long-term’ contracts of up to a few years; futures markets; spot markets, often ‘day ahead’; ‘regulating’ markets in which plant is called up at very short notice to maintain voltage and frequency within acceptable limits, perhaps because there is a sudden surge or decline in demand or a major plant has broken down);
- bilateral ‘over-the-counter’ trading;
- an independent system operator responsible for managing the spot market and dispatching plant in real time;
- competition in the retail market, at least for consumers with large power demands;
- a regulator to oversee such issues as fair competition and mitigation of market power, monitoring of capacity margins etc.

Despite the passage of nearly fifteen years since the advent of competition and in some cases privatisation of the electricity supply industry in countries like the UK, New Zealand and Norway – rather longer in the case of Chile – liberalisation of power markets remains something of an experiment, the outcome of which is uncertain. In most cases liberalisation was initiated at a time of considerable overcapacity of generating plant – indeed, one of its main rationales was to improve the economic efficiency of investment in power capacity, since the previous arrangement of power markets as vertically integrated monopolies tended to result in the ‘gold plating’ of security measures and therefore significant higher capacity margins than were necessary to keep the lights on. The costs of this overcapacity had to be borne by taxpayers or electricity consumers: in either case this represented a drain on the economy as a whole.

It is only now that the capacity margin in some developed countries is reaching the point at which major new investment will be required in the near future. Even in the unusual case of the UK – where liberalisation was accompanied by a major increase in investment in gas-fired generating capacity – investment slowed significantly at the turn of the century, though in that case not before considerable new reserves of capacity had been added. (In November 2003, Ofgem reported a drop in gas- and coal-fired projects described as ‘planned’ from 10 300 MW to 6500 MW over the previous year. Only 800 MW was actually under construction, plus 760 MW of Combined Heat and Power and 90 MW of windpower⁷.)

⁷ http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5078_JESS_report_12nov03.pdf, Ofgem (2003), *Joint Energy Security of Supply Working Group (Jess) third report*.

Of course, reducing the costs of power cannot be the only aim of electricity policy. Modern economies require secure supplies for both business and residential purposes. Energy production and use have major environmental implications, notably for atmospheric challenges such as climate change and acid rain. Personal safety, public perceptions and political issues also shape energy policy in important and sometimes unpredictable ways.

Emerging themes in liberalised power markets

There is, then, little empirical evidence of how liberalised markets will develop when the initial circumstances in which they were instituted have changed. Nonetheless, a number of themes are emerging which require careful consideration and which may point the way towards energy policies of the future. These involve a number of issues.

- *The adequacy of signals for new investment within liberalised power markets* – what will happen when capacity margins become sufficiently tight to threaten chronic power cuts?

Since electricity cannot be stockpiled, there tend to be long periods, when demand is relatively low, in which prices (especially for power traded through spot markets) fall towards the avoidable costs of the marginal generator. To compensate, in order to provide a reasonable return on capital employed, there will need to be periods in which prices are significantly above avoidable costs. However, periods of very high prices bring political risk and loud cries for an end to the ‘profiteering’ of the power companies. There is evidence from a range of countries that when the political temperature rises in this way governments, either directly or via regulatory bodies, do indeed intervene to cap price rises or otherwise ‘guide’ the market. For someone considering making the sizeable investments involved in power generation, the extra risk associated with second-guessing the actions of regulators will inevitably delay, or perhaps even drive out, necessary investment, or (which is in effect the same thing) increase the required rate of return.

One model for attracting investment is one in which future customers provide the initial investment and then buy power, in proportion to that initial investment, at or near avoidable cost. TVO’s proposed new nuclear plant in Finland is to be financed on such a basis, as is Intergen’s Rijnmond CCGT in Rotterdam. However, investment in ‘merchant’ power plants, selling electricity on an open market, may be more problematic. Long-term power contracts between generators and consumers also bring potential problems, as illustrated for example in the market in England and Wales in 2001/2.

Put succinctly, can liberalised markets manage the inherent tension between the needs of governments, who wish to guide electricity markets to fulfil political requirements such as secure supplies and low prices, and the needs of potential investors who need a stable investment environment in which governments have credibly divested themselves of powers to intervene?

- *The implications of growing vertical integration and of increasing concentration at both generation and supply levels – is competition possible (or desirable) in a commodity with the unique characteristics of electricity, without determined regulatory effort?*

Except where regulators have made major efforts to prevent it, mature liberalised power markets are increasingly characterised by growing concentration – both through consolidation at both generation and retail levels and through growing vertical integration across generation and supply, in many cases involving local distribution networks as well. There has also been a growing trend towards integration of gas and electricity industries. Inevitably, larger companies will have greater market power, which can be used both to erect barriers to new entrants and to manipulate prices to higher levels than they might have been in a more competitive environment.

Yet it can be argued that the nature of investment in electricity generation, with its associated risks, is such that it can only be funded by large, probably cross-border, operators such as those which are emerging within western Europe. It is not yet clear what would be the appropriate level of competition (or the appropriate number of competitors) to fulfil the dual goals of creating downward competitive pressure on prices while also retaining entities large enough to contemplate timely investment in new plants.

- *Potential consumer responses to price spikes.*

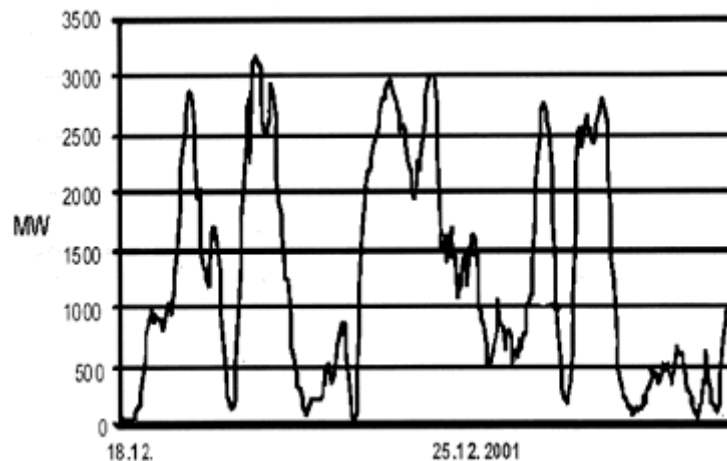
Although the price elasticity of electricity demand is notoriously low – many of electricity's uses are essential for which no substitute fuel is available – when capacity margins are very tight a small increase in demand or reduction in available capacity can have a major upward effect of prices. If prices could be transmitted to major consumers in real time it is likely that demand reductions could be found which would serve to control price rises. There is indirect evidence for this in the major demand reductions that followed price crises in California, Norway and Brazil. By contrast, price caps and long-term contracts serve to protect the consumer from price spikes and so dampen potential demand-side responses. Real-time metering is expensive but may be a more effective approach to managing supply security than attempting to retain high reserve capacity margins.

- *The influence of different fuel mixes on price spiking – are some combinations of generating fuels more susceptible than others to price spiking and/or outages?*

Any power plant can come off line, either predictably or unpredictably, for a variety of reasons – maintenance needs, labour strikes, unavailability of cooling water (especially for thermal/nuclear plants) etc. However, there is evidence that two power fuels – renewables (hydropower) and imported gas – have been particularly associated with problems. Periods of low rainfall have led to reductions in the reliability of output from hydro plants in many countries such as New Zealand, Chile, Norway and Sweden and the western USA. The volatility of

gas prices led to severe problems in areas such as California and Alberta in 2000/2001. (Texas, with significant gas reserves of its own, was much less affected by the crisis which beset the western USA at the turn of the century.) By contrast, systems more reliant on domestically-mined coal and nuclear power appear to be much less prone to price spiking with its associated political and economic effects. This may be of particular importance in Europe, which is likely to become more dependent on gas, imported from the former Soviet Union, and renewables which like hydropower tend to be intermittent in their output, although generally on different timescales.

Although renewables such as windpower will not suffer chronic problems such as prolonged droughts, and so will not be unavailable for the long periods which have characterised hydropower in many countries, in the short term they can be considerably more intermittent. In some cases, such as tidal power, output is likely to be predictable but not constant. In the case of wind, output is not only intermittent but also unpredictable beyond a few days' notice. For example, E.On owns 3500 MW of wind capacity in Germany. This plant generates practically no electricity at all for short but significant periods of time in a typical winter.



Windpower feed-in to grid of E.On Netz, Germany, winter 2001 (3500 MW installed capacity at that time)⁸

Managing this intermittency in the absence of a large-scale method of storing electricity represents a challenge, especially at times of high windspeeds when wind generators may need to be immobilised rapidly to prevent damage and alternative capacity must be brought on line very quickly. It may be expected that at times when the renewables are not available, expensive peaking plant using fossil fuels will have to be dispatched, with potentially large effects on system marginal prices (and also potentially on emissions).

⁸ http://www.tu-berlin.de/~energiesysteme/downloads/publications/sacharowitz_2003_challenges_integrating_wind_power_iaee_mexico_speech.pdf, Sacharowitz S. (2003), *Challenges and costs of integrating growing amounts of wind power capacity into the grid – some experiences dealing with 12,000 MW in Germany.*

The potential problems associated with overdependence on unreliable electricity sources were illustrated in the summer of 2003 in Europe during the hot spell in June. Increased demand for air conditioning etc. was coupled with drought and a significant reduction in availability of power from other sources, notably large windfarms (and also from inland conventional power stations including French and German nuclear plants). This led not only to very high prices but also a major reduction in exports from France and Germany which led to blackouts in Italy, highly dependent on such imports. Although on this occasion the contribution of the shortage of wind was not the crucial factor, it would have been more important had there been considerably more reliance on windpower in the area.

Considerations of this nature were behind the decision, for example, taken in December 2003 by the Irish energy regulator to halt connections of windpower to the Irish grid. The Managing Director of ESB National Grid said that wind connections ‘pose an increased risk to the security and stability of the power system which exceed the level normally likely to be acceptable by a prudent system operator’.

- *The growth of cross-border trading in electricity and the development of regional market* – what are the implications of using cross-border interconnectors, generally created to enable well-coordinated bilateral electricity trading between neighbouring countries, as major components in international power markets in which large numbers of relatively uncoordinated trades take place on a continual basis?

The growth of regional markets has been one of the most notable developments of the liberalised era. Regional markets offer a number of advantages, not least in creating a larger market which may stimulate more effective competition and also in reducing the demand for each participating nation to retain such a large capacity margin – for example, unscheduled plant breakdown might be compensated by imports, while in geographical areas which are extended over several longitudes the time of peak demand will be different in different parts of the regional market, so allowing net east-west or west-east flows at different times to replace reserve capacity.

However, with rare exceptions, although the interconnectors and national wires involved are in effect playing the part of a grid serving a single market, there is no single regional transmission operator to ensure smooth running. In August and September 2003 transmission system failures underlay major power outages in the northeast of North America, in England (London and Birmingham), in Copenhagen and south Sweden and in Italy, while a reduction in the availability of imports (coupled in some cases with anomalous pressure to increase exports despite shortages of power at home) were important factors in crises in Italy in June 2003, in California in 2000/2001 and in Victoria in 2000.

As a result a number of questions are arising. Will the cost requirements to strengthen cross-border interconnectors and national grids outweigh the savings in generating capacity? Who should bear the cost of such strengthening and how will it be financed? At the other extreme, is there a danger that growing reliance on interconnection will further undermine investment in generating capacity,

resulting in a very efficient grid but insufficient power to drive it? How can differences in national markets within a regional interconnection be managed (a major issue for example during the power crises in California and Victoria in 2000/2001)?

- *The consensus that liberalisation is both inevitable and desirable.*

Liberalisation is still very much the dominant direction in global electricity markets. However, following the California crisis there have been varying degrees of reversal of competition measures in countries and States as diverse as Arizona, Arkansas, the Dominican Republic, Montana, Ontario, Queensland, Switzerland and Thailand. Should there be no similar experiences in the near future confidence in liberalisation may well be restored, but should there be another California-style event, it is an open question as to whether more countries would retreat from liberalisation and return to some degree of central planning.

Conclusions

The implications for investment of a major restructuring of markets would be profound, if not easily predictable, but might well result in a change in emphasis from short-term returns to long-term supply security. Heavily capital-intensive sources of electricity, of which nuclear power is a clear example, are inherently unattractive for 'merchant' power plants which will sell their output into uncertain markets for several decades. This is not to say that a 'merchant' nuclear fleet cannot be built, but it is noticeable that the decline in new orders for nuclear plants in the market economies has coincided with growing liberalisation of power markets. But if the next few years bring experiences which suggest that highly fragmented power markets are incompatible with early investment to prevent power cuts, then the most basic current assumptions about investment in new generating capacity may prove to be invalid. A return to command-and-control power markets is not the only option, and indeed at present looks highly unlikely, but an acceptance that, say, a European electricity market characterised by the 'seven brothers' (EdF, RWE, E.On, Enel, Vattenfall, Endesa and Electrabel), each with considerable market power and each with significant involvement in supply as well as generation, could well create an environment in which longer-term investment is attractive. A sensible approach to future electricity production might well involve planning for this scenario, for example by ensuring that technical options are ready to be deployed if and when required, rather than leaving everything to the short-term forces which now predominate.