SECURITY IN GAS AND ELECTRICITY MARKETS

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n/e/r/a
National Economic Research Associates
Economic Consultants

15 Stratford Place
London W1C 1BE
Tel: (+44) 20 7659 8500
Fax: (+44) 20 7659 8501
Web: http://www.nera.com

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EXECUTIVE SUMMARY

What is energy security?

Security of energy supply for consumers is at root an issue of risk. All energy systems deliver *some* level of security for consumers and the question is then: how much security is enough? This report has examined security of energy supply in the context of the competitive parts of the gas and electricity markets in Great Britain.[1]

Governments, in the UK and elsewhere, have always taken a direct interest in security of supply. The reasons why security in energy supply seems more politically and economically important than in other industries stem from the combination of several factors: the essential nature of gas and electricity and consequent high costs of interruption to supply; the difficulty of obtaining alternative supplies other than via the monopoly pipe and wire networks; and the difficulty for almost all consumers of storing energy. Interruptions to energy supply can therefore be both sudden and have serious consequences.

Characteristics of a secure system will include a mix of diversity (in fuels, sources, technologies etc), sufficient reliability and responsiveness. To some degree these characteristics are substitutes for each other and the mix will reflect both their relative costs and their relative ability to reduce risks. Such systems will be able both to reduce the chances of adverse security events and minimise the impact of such events on consumers.

Defining adequate security

The main starting points in considering the 'right' level of security are:

- Consumers' willingness to pay for higher security levels, which tends to fall as risks to security are reduced
- The costs of providing extra security, where the costs tend to rise as risk levels are reduced.

In principle, an 'optimal' level of security can be calculated from this information, such that the value of extra security to consumers just matches the cost of providing it. In practice, exact calculation is impossible, and for most kinds of security risk there will be a 'zone of adequacy' where both the valuation of security and the extra costs of providing it will be relatively stable. An objective of policy is then to ensure that security levels are within that 'zone'.

.[1] It only considers the regulated network (monopoly) parts of the two industries where the network impinges on the potential ability of the market to deliver adequate security.

However such a policy objective does not necessarily imply Government action. A well functioning market system could well provide adequate levels of security, and would certainly do so under the (restrictive) assumptions of perfect competition[2]. In the real world the question then becomes whether or not barriers to the workings of markets will significantly affect the ability of those markets to provide adequate security for consumers.

Market provision of security

At a general level, there is a widely held view that private markets tend to under-invest due ultimately to their presumed use of a higher private discount rate than the social ('correct') discount rate. This is a large subject with economy-wide implications and we did not consider it warranted a different treatment of the energy economy or energy security in comparison with the economy as a whole. It is therefore not a specific barrier to market provision of energy security.

Under the former state-owned monopoly provision of gas and electricity, security levels were in some respects high, but the corresponding costs of providing such security were also substantial. Under a liberalised market, it may be expected that a *given* level of security will be provided at lower cost than under a monopoly, but it is not clear, on theoretical grounds alone, that security levels will either be higher or lower than under monopoly. The empirical record is not complete, but indicates that security is in some respects at higher levels under liberalisation than under monopoly.

The result that liberalisation *may* produce similar or a higher level of security than monopoly is not the main point. The important question is whether, relative to consumers' willingness to pay (valuation of security), the current market system produces adequate security levels, or whether there are material barriers or obstacles to its ability to do so. There are two main kinds of barrier that are possible:

- Market failures, where the internal workings of the market may prevent the market from delivering adequate security (some markets will be absent)
- Other barriers, generally political or regulatory in origin, and sometimes potentially international, that may have the same obstructive effect.

There may also be intermediate cases. Gas and electricity markets need to be consciously designed and the incentives they offer to market participants can differ substantially from one design to another. It may then be the case that incentives resulting from new forms of market design may interact with actual or expected political behaviours to produce a barrier that contains elements of both a market failure (in that a different market design could

2 The economists' concept of Perfect Competition requires not just a good number of competing firms but also, among other things, an absence of externalities and public goods. It also takes no account of distributional issues such as fuel poverty.

directly remove the barrier) and a political obstacle (in that different political behaviour could also directly remove the barrier). We classify such a case as a market failure in the strict sense that there is or may be an absence of a relevant market. We have therefore continued to draw a distinction between 'market failure' and 'political failure'.

We have examined a wide range of potential barriers, of both types and have asked the general question whether they seem likely to provide a material obstacle to market provision of security. More specifically we have asked

1. Are there *theoretical* grounds for considering that there may be obstacles or barriers preventing consumers expressing their willingness to pay for security, or investors from responding to it?
2. Are there *observable* barriers or obstacles that prevent consumers expressing their willingness to pay for security or, again, investors from responding to it, or which lead to excessively costly ways of providing security?
3. Does meeting the current level of security expose consumers to risks of insecurity or actual incidents that impose a very high cost on them?
4. How material do any such practical barriers appear to be, and is it likely that in trying to overcome them, Government can tackle them directly, or will some less direct method be needed to compensate for the problem to which they give rise?

In a short project, it has not been possible to answer all these questions definitively, and in some areas we point to the need for further work. Our focus has not been primarily on whether or not some risks to security are likely to rise, compared to the past. Rather the focus has been on whether, *given* current or expected risks to security, markets will be *able to respond effectively* in managing those risks, or whether particular barriers will make it difficult for markets so to respond.

We start with the possible market failures and then move to political or regulatory failures.

The 'public goods' issue.

In economics, a 'pure' public good is a commodity where it is impossible to exclude individuals from consumption if the good is provided at all, and where consumption of the good by one individual does not reduce the amount available to others. There are limited but important public good characteristics in gas and electricity supply. For small consumers, provision of service is collective among groups of consumers (all are fed by the same pipe or wire). In the absence of real time metering, it is in practice impossible for different levels of security to be available to those on the same network. More generally, this means that small consumers are unable to make their willingness to pay for different security levels effective in the market place.

The implications of these market failures for the adequacy of security are not clear. While theory suggests that the existence of public goods leads to under-provision of security by markets, a variety of complicating factors means that it is difficult to be definitive about the real world adequacy of GB levels of security. There is little evidence that those who cannot make their valuations of security count in the market would systematically wish to pay for higher security levels than those who can signal their valuations to the market. However a significant proportion of households suffer from fuel poverty and their willingness to pay for more security is limited by their difficulty in affording to keep warm. There is therefore an argument on distributional grounds for saying that wherever security levels are within the 'zone of adequacy', the preferred direction of adjustment, at least marginally, should be towards higher security levels.

Demand side participation in the market

In a well functioning market, the demand side (consumers) will participate actively in helping provide adequate security. Largely because of the public goods problem, small consumers are effectively unable to make their valuation of security count in the market place. Despite efforts under the New Electricity Trading Arrangements (NETA) to facilitate the role of larger consumers in the market (and therefore in security provision), to date such participation has been limited; this is largely because the presence of excess capacity in power generation has made such participation unprofitable. The inability of small consumers to make their valuation of security count is a market failure and its removal would help market participants both to understand consumer valuations of security better, and also allow a wider range of market responses to given security risks. Much of the problem can be tackled directly through encouragement of technological change, mainly better (real time) metering among small consumers.

At a broader level of possible general market failures in relation to energy efficiency investment, it is not clear that enhanced energy efficiency will significantly add to security of supply, except possibly at the margin in relation to reduced imports of gas.

Possible market failures relating to short-term operations

There are several related possible market failures that might arise from the existence of many firms in a market, especially where previously there was only one. These may be in principle more important in relation to achieving adequate security than in relation to other policy objectives. This is because security is systemic - a property of the actions of all market players. As firm size reduces, the influence of individual decisions on security inevitably becomes less.

Market failures here would derive from information asymmetries, or a lack of relevant information. Examples could be the lack of information about planned down-times (for maintenance) of electricity or gas plant, leading to a risk of too low a security level because of simultaneous outages; or a lack of co-ordination between downtimes on offshore gas fields and demand for gas. Another example might be lack of information transmitted between gas and electricity market players, necessary because of increasing interdependence of the two markets. The result might be again too low a level of security provision. OFGEM is seeking to address some of the issues arising from the increasing interdependence of the two markets; in particular, it is proposing to reduce the period over which gas shippers are required to balance their gas inputs and withdrawals from one day to some shorter period of a few hours or even one hour. This has yet to be agreed and we have not assessed the contribution this might, or might not, make to improve security of supply.

In practice, we found little evidence that these effects are important to date, and as a consequence any inability of the market to deliver adequate security for these reasons seems unlikely to be material. The same can be said of our similar inquiry into the possible market failures in areas where gas and electricity markets interact.

Possible failures in long-term investment incentives

The possible market failure here is a 'mixed' case of market and political failure, though we choose to classify it as a market failure. The failure could arise under the wholesale electricity market NETA. Market mechanisms probably encourage sufficient investment in advance of anticipated demand increases. However, when there are transitory shocks, creating sudden shortages and sending prices to very high levels, NETA is vulnerable to the intervention of political or regulatory authority to cap prices (thus removing the market at its peak). Anticipation of such intervention, which is common in electricity markets, will tend to damp investment incentives because potential investors will expect that they cannot recover their full costs.

The problem seems endemic to electricity markets and underlies the various capacity payments and obligations that are used in other markets to smooth out rewards for building capacity and provide a more continuous stimulus to investment. As such it seems a serious potential barrier to security of supply and warrants further investigation. It could be tackled directly by changing market design arrangements.

The gas market has similar characteristics to the electricity market, but the market failure seems much less likely in the gas case. This is because the availability of substitutes for gas on the part of large consumers (plus gas storage) will cap peak prices at much lower levels than in electricity, and minimise the risk of an absent peak market, because political intervention is much less probable. Attention should therefore be primarily directed at the electricity market.

Possible inadequate provision of diversity

Much of the debate about security of supply has focussed on diversity. Diversity is a good general hedge against uncertainty and, other things being equal, a more diverse system will be more secure than a less diverse one, because of risk-spreading. Possible market failures here include the idea that in conditions of uncertainty about the future, market players might all choose similar investment types, fuels, technologies etc., and thus give rise to less diversity than a well functioning market would provide.

The theoretical case here is not strong: in conditions of uncertainty, it may be rational for all players to follow similar paths – the underlying problem being uncertainty rather than market failure. Some evidence is not favourable to this 'herd instinct' idea either. The 'dash for gas' has led to much *greater* diversity of fuels in the electricity generating system, and other dimensions of electricity diversity have also improved.

There has been a move towards greater dependence on gas across the whole energy economy (and this will almost certainly grow) but there is little to suggest that this is an inappropriately high degree of dependence or market failure, given that the 'right' degree of diversity also depends on the cost of its provision. Concerns about gas dependence and the barriers that high gas dependence may raise for adequacy of security derive in practice more from perceptions of the political risks of gas imports (see below) rather than failures of markets to provide diversity.

A second kind of market failure could lead to inadequate diversity in gas facilities (in particular gas reception terminals). The failure could arise in the following way. Large gas reception terminals - the largest two handle some 50% of all GB gas - consist of a number of separate but spatially close sub-terminals. The sub-terminals have been added incrementally, and for the owner of the most recent sub-terminal, the risk of facility failure is a cost only in respect of his/her lost output (balanced against the economies of locating at an established 'hub'). However the loss of output if the whole terminal fails will apply to all other sub-terminal owners, and the probability of a whole terminal becoming vulnerable increases as facility dependence rises. Owners of earlier sub-terminals would therefore have faced lower risks at the time of their decisions and therefore an externality could be present.

The barrier here could be material – the loss of the Bacton gas terminal would, according to NERA modelling, be the only severe event that might cause a failure to meet expected firm demands for gas supply in Britain. However the probability of such a loss of supply from such a terminal is much more difficult to ascertain from the evidence available to us – there are issues of protection from external threats as well as purely technical risks to weigh. However this is a case where the market failure may well be real, and the materiality issue seems likely to be large (subject to further work for example on the probability of failure). The obvious Government intervention here, and correction to the market failure could be direct – for example, disallowing further sub-terminals where there is already a large concentration of sub-terminals. This would over time directly increase diversity and reduce the consequences of facility failure.

Possible barriers arising from increased dependence on imported gas

Many have argued that increased dependence on imported gas (a virtually certain development over the next 10 to 20 years) will give rise to higher security risks than using only UK-origin gas. Imports in themselves are not evidence of market failure. Rather they are the product of a market working *well* to obtain low-cost supplies. Imports in themselves add to diversity of sources and therefore directly *contribute to* security.

There may be new security risks here, connected to a range of possible sources of interruption to supply: from unreliable political sources; from disruptions to transit routes and facilities; and from the possibility of stalled European energy market liberalisation. Increased but unavoidable *risks* to security are not in themselves *barriers* to *market provision* of adequate security, or grounds for Government intervention. Adequate levels of security may well fall over time in the face of unavoidably increased risks.

The barrier here would therefore be the inability of markets to cope with international political risk. The evidence appears to be that markets are working well to diversify and control security risks as imports approach. Early import contracts are for supplies from Norway and the Netherlands, which represent low political and commercial risks, and minimise the length and complexity of transit routes. The evidence so far is necessarily limited, as net imports are still some years away, but there is no obvious reason to suppose such risks will be not handled adequately by market players.

Because gas will increasingly flow to the UK through the northwest European gas market, there is an issue of European gas market liberalisation, which is not yet as far advanced as liberalisation in the UK. Steady progress in European liberalisation (desirable for efficiency benefits) is undoubtedly in UK consumers' interests, and would assist UK security by developing a deeper and more connected market. This will be especially useful in times of tight market conditions. Slow progress might in such cases provide an extra risk to UK security and the UK Government is already directly pursuing more rapid liberalisation across Europe, (though not only for security reasons). Market actors are however unlikely to rely on such progress and will probably seek their own direct remedies to any extra risks they perceive, such as seeking contractual terms covering security issues whether or not such liberalisation proceeds rapidly.

Possible UK regulatory barriers

Continuing regulation of gas and electricity networks inevitably means that there will be some interactions between the regulated and competitive segments of the market. Some regulatory actions will affect the competitive market and could therefore provide a barrier to the market's ability to provide adequate security.

The interface between the offshore and onshore gas regimes could provide one such barrier, but there is no evidence of any significant effect. There is at least one other area in which new or proposed regulatory changes could possibly act as a barrier. These are the new arrangements for auctioning long-term entry capacity. The impact of these new auction arrangements certainly in the long-term are difficult to judge. It is therefore not clear yet whether this issue will constitute a materially significant barrier. It is possible that it will prove to involve mainly transitional problems of a kind that are inevitable whenever a regulatory change affects market incentives.

Possible UK policy barriers

The main potential barriers here stem from the unintended effects on energy security of policies in other domains. The most important barriers here may be: the impact of environmental policy (for example the Renewables Obligation) on investment incentives; the impact of emissions controls on operating flexibility in electricity; and potential planning problems.

The Renewables Obligation probably constitutes the largest market intervention in electricity currently proposed by Government, involving a prospect of 10% of electricity supply coming from renewables by 2010. The barrier here is that the Obligation will prove a disincentive to private investment through depressing prices in the wholesale market and leading investors to expect further commitments to renewables, compounding the difficulty of incentivising private investment. There is evidence that there will be a need for substantially more investment than that required to meet the Obligation and if only a proportion of future investment is expected to come from the Obligation, the barrier may be of limited materiality, and the displacement effect may in practice be limited.

Environmental restrictions on electricity generation could prove a barrier to using some fuels (especially coal or oil) when markets become tight. However, to the extent that there is flexibility in the application of emission limits, the extent of any such barrier will diminish, and the current direction in environmental control is towards such flexibility. This does not seem likely to be a material barrier.

Finally, the planning system could be a major barrier to the ability of investors to implement projects expressing consumer valuations of security. This will be the case especially if planning delays (and refusals) are uncertain, and different between different projects. In the case of electricity, there are few signs that planning has provided a significant barrier to security: refusal of permission to some renewables is problematic for renewables development and therefore elements of environmental policy, but not material to security.

In gas however the situation is different. Security-related projects in gas tend both to be large and location-restricted. Projects like storage sites are already showing signs of being seriously delayed by the planning system, and it seems probable that without planning reform the problem could become worse.

Planning seems likely to be a serious barrier to gas security, and Government is already actively tackling the barrier directly, by proposed reforms both to the planning system in general, and to approval processes for large infrastructure projects.

Government in the UK has shown willingness to intervene in electricity and gas markets – especially electricity markets - where there have been perceived problems. The most recent example was the Government's 'restricted consents' policy in relation to gas-fired electricity investment after 1998, and Government also intervened in earlier years over fuel and investment choices in the electricity industry. Current policies for renewables and CHP also involve market intervention. Governments elsewhere, including those presiding over liberalised energy markets, have also in recent years intervened where security of supply was threatened. California is an obvious case.

If markets expect Government to intervene in serious enough security events, there will be reduced private incentives for markets to provide as much security as consumers desire - markets will under-provide security. Market expectations that Governments will come to the ‘rescue’ in serious situations are probably a material barrier to adequate security provision and will lead to under-investment in security

Directly tackling this barrier is difficult - markets may not easily be persuaded that Government will stand aside in serious security events when they have failed to do so historically, and continue to fail to do so in other countries. A number of less direct approaches are possible, including the use wherever possible of private contracts, which Government rarely over-rides, and attempts to reduce the rewards for intervening (for instance by designing markets to smooth power prices so that price-capping becomes less necessary). Ultimately however this may be the most difficult barrier of all to overcome.

International experience

Appendix C provides some information on how other countries with liberalised systems have treated security of supply issues. The sample is limited but suggests that direct action in market design for electricity to establish an explicit mechanism to reward capacity (as a means of encouraging investment) is not uncommon. In gas, explicit security regimes are difficult to find.

The longer term

It is difficult to imagine the conditions under which security of supply will be tackled by markets or Government in the period 2010-2020. Further increases in gas dependence seem likely as does greater emphasis on energy efficiency. We tentatively conclude that gas and gas import dependence may be a less serious issue than often supposed, but that (oppositely) enhanced energy efficiency will not be likely to be a very effective tool for promoting more adequate security.

1. INTRODUCTION: PROJECT OBJECTIVES

The DTI has been consulting on a wide range of energy policy issues. Government expects to publish a new White Paper setting out its approach to energy policy early in 2003. As part of its preparation for the White Paper, the DTI asked NERA to carry out a review of security of supply issues. The remit was to cover the competitive or potentially competitive parts of gas and electricity but not to examine directly the security questions that may arise from the operation of the gas and electricity networks. These networks are regulated monopolies, raising different issues from those of the competitive parts of both gas and electricity markets.

The terms of reference for the project[3] outline the tasks to be carried out as consisting of three stages:

- 'What is the appropriate definition of security of supply and therefore what is meant by an "adequate" level of security provision?
- To identify any barriers or distortions affecting the efficient operation of the gas and electricity markets, which may mean that security provision for gas or electricity or both is inadequate or excessively costly; and
- Consider the practical effect of any such barriers or distortions and whether their impact is likely to be material on achieving adequate security.'

A Steering Group, consisting of representatives of the DTI, OFGEM, the Treasury, met on four occasions to review the work.

The work reported here has been undertaken over a period of just over six weeks. This means that while every effort has been made to include relevant evidence, the time constraint has limited our ability to do so.

[3] The terms of reference are reproduced in full as Appendix D.

PART 1: HOW MUCH SECURITY?

2. WHAT IS ENERGY SECURITY?

Energy security of supply is generally expressed in terms of risk. An energy system is secure enough when the risk that consumers will be unable to access energy supplies at price that reflect the cost of provision is sufficiently low. There will be a continuum of symptoms of rising levels of insecurity, from price effects that may be sharp, especially for electricity, through reductions in quality ('brownouts') to short and, eventually, long-lasting physical interruptions, when prices might be very high.

Even if interruptions to supply are then only a last resort, consumers are likely to find substantial periods of high and unstable prices difficult to handle. Determining acceptable levels of risk is not an easy process, especially when many of the risks are difficult to quantify. The determination of 'adequacy' in supply security levels is not straightforward.

2.1. Why are Governments Interested in Supply Security?

Security of supply matters for a wide range of commodities besides energy. Is there anything special about *energy* security? Are there, in particular, reasons why Governments intervene in support of security in energy, when they appear not to do so for other commodities?

For all but the largest consumers it would be prohibitively expensive to duplicate gas pipelines or electrical wires entering a consumer's premises. Competition may be possible for the *use* of these networks, but the networks themselves constitute a 'natural monopoly'. Such natural monopolies arise whenever the costs of providing a service decline continuously as the scale of output increases. Costs can only then be minimised if there is a single producer and single network. Such networks need to be regulated to avoid possible abuses of their monopoly power. In the current and immediately prospective state of technology, gas and electricity can only be efficiently supplied to the vast majority of consumers via single physical networks.

Other services may be characteristically delivered by single physical networks (e.g. telecommunications or water services) but technology changes have meant that consumers have alternatives if the land-based network fails – use of mobile telephony or bottled water being obvious examples.

For gas and electricity consumers, interruption of network supply is particularly difficult because consumers generally lack alternatives in two senses:

- They lack alternative sources for the delivery of the interrupted commodities – gas and electricity
- They lack alternative means of satisfying their energy needs via other energy sources, or by other means.

In relation to the first point, the lack of alternative sources of electricity or gas, batteries are a partial substitute for electricity in a few applications. Some large consumers also have significant electricity standby facilities (e.g. small diesel generators). For gas it is impractical on cost and safety grounds to store gas at customers' premises.

In relation to the second point, alternative means of satisfying energy needs, fuels such as paraffin may substitute for some lighting and heating, but consumers will generally also need alternative energy conversion devices to use them. For some uses of **electricity** in particular – refrigeration, audio/TV equipment and computing – there are no technological alternative routes to the desired end-use, or (as in the case of gas-powered refrigeration) the costs are so high that there is no realistic alternative. Either costs are very high, or there is no feasible alternative ways of satisfying end uses. In the case of **gas** large industrial users may be able to use alternative fuels conveniently. For instance, distillate may be used in place of gas if gas is unavailable or becomes expensive. This highlights one of the interactions between gas and electricity – gas is now a major input fuel for electricity generation. In this case gas and electricity are complements. They may also be substitutes, for instance in various heating uses, though these may be limited in many cases.

Alternatives to network gas and electricity are therefore, for most consumers, very expensive where possible, and often technologically infeasible. For most consumers there are also few possibilities of storing energy as a hedge against interruption. For small consumers there are no practical ways to store either electricity (apart from batteries) or gas, and only the largest gas consumers could even consider gas storage, because storage has high fixed costs.

The storage problem for electricity is also marked at a system level. While pump storage hydro capacity can be used as a system-wide storage device for electricity, the extent of practical storage in the UK is limited. Gas storage is more feasible at lower cost, though geological factors affect possible locations. However, in principle, the possibilities of gas storage ease the security problem compared to electricity. On the other hand, the safety problems, and re-connection difficulties and costs, if gas supply to small consumers is interrupted, are much more serious in the gas case than electricity.

Failures of gas and electricity networks over large areas or for long periods may therefore have very major consequences, ranging from major production losses to looting and civil disorder. Governmental interest in supply security for energy is therefore understandably stronger than for many, if not most, other commodities.

Modern economic and social systems are therefore vulnerable if electricity or gas supply becomes unreliable. Where there are major interruptions to either gas or electricity supply, the damage to private consumers, industry and public order can be rapid and large-scale. In the UK, there are increasingly large interactions between gas and electricity. Gas is now a major fuel input to the electricity system, and many gas appliances (e.g. central heating systems) cannot be used if electricity supplies are interrupted.

Governments often act quickly to try and restore interrupted supply, even where they have no ownership or other legally defined responsibilities to do so. In the UK, during the petrol depot 'blockade' of September 2000, and in California, after blackouts in 2000 and 2001, Governments which did not own the relevant networks or energy supplies nevertheless took action to try and ensure minimum disruption. Governments also put in place emergency arrangements of various sorts to cope with exceptional shortages of gas and electricity. These arrangements often involve at least partial suspension of market mechanisms and may include central prioritisation of consumption, and controls on prices. Governments may not always take such action, but if consumers and markets expect them to do so in particular circumstances, this may in itself discourage market players from taking out as much 'insurance' as they would if they were certain they would have to bear all the costs themselves.

A reflection of the same vulnerability in economic terms is the fact that the cost to consumers of a unit of electricity involuntarily *not* supplied is usually much greater than the cost of the same unit supplied. The exact value of lost supply (or 'lost load' in electricity) is variable and not always easy to work out, but under the former Pool system of trading electricity in England and Wales, the value of a unit lost was put at around *100 times* greater than the unit price of electricity. This asymmetrical distribution of valuations suggests that consumers might be willing to pay substantially to minimise the risk of interruption. Overall, there are good reasons why the security of gas and electricity supply is a more pressing concern to Governments than security of other essential commodities.

But while risks of supply interruption may be, according to some agreed criterion, minimised, aiming at zero risk is never seriously attempted. As zero risk is approached, the extra (or marginal) costs of further risk reduction become very large, and there is no evidence that consumers wish to pay the very high premiums that would be necessary even to attempt to reach zero risk. Unexpected events or shocks (such as exceptionally severe weather, or acts of terrorism) occasionally cause electricity or gas systems to break down, locally or more widely, and these risks may not be insurable at all.

These factors mean that 'adequate' levels of security of electricity and gas supply are thus a significant preoccupation of OECD Governments; indeed most espouse adequate energy security as a major policy objective.

The Energy Review conducted by the Cabinet Office and published earlier in 2002[4] explicitly included the achievement of security as a major objective of policy. This does not necessarily imply, as discussed below, that Governments always try to *provide* for given levels of security, but Governments generally regard security as a vital pre-condition for the achievement of other policy objectives in energy. All Governments at least monitor security levels, and all Governments and/or regulators provide at least a security *framework* of some kind (for example specifying emergency arrangements or requiring supply companies to aim for a minimum level of customer interruptions).

Governments may also intervene, more controversially, in markets on an ongoing basis with the aim of promoting greater security. Requiring companies to hold a minimum level of fuel stocks would be an example of such ongoing intervention. A major purpose of this report is to ask whether there are reasons to suppose that the existing and expected structure and operation of markets will or will not provide adequate security – and if not, whether this provides a case for Government to intervene, bearing in mind that Government intervention might in practice either improve or worsen the risks to security of supply.

2.2. Classifying Security Risks

There are many possible causes of interruption to electricity or gas supplies. A common cause, usually leading to small-scale interruption over relatively short periods such as a few hours, is severe weather, leading for example to local power lines being blown down. At the other end of the spectrum, a major technical fault (such as at a gas processing plant) could disconnect a large number of consumers for long periods. At other times there may be several contributory causes: for example at a time of very high demand due to cold weather, a major electricity generator may develop an unexpected fault and have to shut suddenly, leading to interruption of some consumers until replacement power is found, or demand can be reduced.

An important distinction is between anticipated and unanticipated interruptions to energy supply. Where energy supply fails without any prior warning, the consequences are likely to be more serious than if some warning is given. This is because consumers, both household and commercial, can take various kinds of action to protect themselves against some of the consequences of anticipated interruptions. The distinction is particularly relevant to our study. There is usually a difference between failures due to network problems, which usually are unanticipated (e.g. where a local cable is severed during road works) and failures in the competitive parts of the market, where there is often the chance of advance notification, if only of a few hours (e.g. when there is a prospect of a capacity shortage when demand is high).

4 Performance and Innovation Unit *The Energy Review* February 2002, Cabinet Office

Many attempts have been made to classify security risks generically. There is no single agreed classification but for the purposes of this report the following distinctions, similar to many others used before, will be employed:

- Short-term risks, usually of an operational kind, where time is too short for new investment vs. long-term risks, where investment is possible, all in 'normal' market and political circumstances
- The capacity of a system to withstand 'shocks' – unexpected events of uncertain but low probability but potentially high consequence, such as generic failure of a type of generating plant, or the sudden unavailability of a fuel due to strike or political action.

In the former case it will often be possible to calculate the risks of interruption from historic data and knowledge in engineering, economics and meteorology. In the case of shocks, such quantitative calculation may be impossible or at best subjective, due to the absence of prior experience or data, and the fact that some shocks are difficult or impossible to foresee. It is for this reason that when quantitative standards are used as the basis for adequate security levels they inevitably only cover some of the risks involved.

2.3. Characteristics of a 'Secure' System

Without yet entering the debate about what exactly adequate provision of security might be, or whether market provision will deliver such levels, we describe some characteristics of a secure system. Some of the debate about security is conducted in terms of individual technologies e.g. it is often argued that more nuclear power or renewables or coal, CHP, energy efficiency (or *less* gas) would lead to better security. Such arguments may sometimes have merit but they are incomplete without an accompanying analysis of the overall system effect of the proposed change. For example, more gas in power systems may either increase or decrease system diversity, and an increase in diversity is widely thought to bring about more security. Security always needs to be seen in terms of system impacts.

In addition, these technological arguments often consider only one possible route to better security. There are normally several different ways in which security might be enhanced. For example, if there was a perceived security vulnerability due to the failure of a single gas processing plant, responses might include investing in the security of that plant, building a similar new plant in another location, building a base load LNG terminal, switching to using a higher proportion of other fuels and so on. These different options would almost certainly achieve different levels of benefit (risk reduction) as well as incur different costs, but alternatives would be possible and would need to be considered. Any analysis that concentrates on a single solution to a given security problem would be unlikely to advance debate.

There is a range of often ill-defined system characteristics that the relevant literature suggests are important for security of energy supply. Prominent among these in recent public debate is the notion of system *diversity*.

All else being equal, a more diverse system will be more secure than a less diverse system, on the commonsense principle captured in the idea of not putting all one's eggs in one basket.[5] If something goes wrong with one feature of a diversified system, its impact on the system will be less than if diversity is lower. In economic terms, the analogy is with a diversified or portfolio approach to investment. In its 1995 and 1998 White Papers on energy, the UK Government put considerable emphasis on diversity as an important constituent of security.[6]

However, diversity will not inevitably lead to better security, and security may be pursued by other routes. A more diverse system that introduced substantially more unreliable plant could well reduce security (wind power might be a case in point), and there are many other routes to security (e.g. storage). Nor is it always clear *what* exactly should be diverse. Diversity might, and should, refer to any or all of: fuel types; fuel sources (by company or region); technology types; technology sources, at least.

Historically much of this debate has been framed in the UK in the context of decisions on nuclear power construction, so that the issue of fuel type has often been prominent. While there are quantitative approaches to diversity (e.g. the Shannon-Wiener index) none escapes the need for some subjective judgment – for example on how different various technologies are from each other. And deriving a willingness to pay for more security at the margin is also problematic. Nevertheless the idea of diversity is an important one in debates about energy security.

A second idea in the security debate is that of *reliability*. As indicated above, a more diverse system may be less secure if on average it is less reliable – i.e. it experiences higher levels of unplanned or forced outages. It is important to examine the differences in reliability as between different mixes of plant and different market conditions.

The third ideas are those of *resilience and responsiveness*.[7] Resilience is a quality, which helps systems cope with shocks of various kinds: it minimises the impact on consumers of any given system shock. It clearly overlaps with diversity but has some different qualities. While diversity describes a system in a static sense, resilience has to do with ability to cope with a given event in real time. This is why the idea of 'responsiveness' corresponds closely

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5 The economic concept that confirms this commonsense belief is known as 'risk spreading'.

6 DTI and Scottish Office *The Prospects for Nuclear Power* Cm 2860, May 1995 and DTI *Conclusions of the Government's Review of Energy Sources for Power Generation and Government Responses to the 4th and 5th reports of the Trade and Industry Committee* October 1998

7 In the electricity industry, these concepts are discussed under the general heading of 'stability' i.e. the ability of the system to find a new equilibrium after a shock.

to resilience. Responsiveness may be a quality of either the demand side of a system – the ability of a system to reduce demand levels with acceptable impacts on consumers – or the supply side. Storage capacity is an obvious indicator of responsiveness and there can be particular technologies (such as peak-shaving LNG), which are more capable of rapid response to an emergency caused by loss of supply than others.

3. DEFINING 'ADEQUATE' SECURITY OF SUPPLY

All electricity and gas systems provide *some* level of security to consumers. However, whether any given level of security is optimal or even adequate is not easy to assess. The idea of risk, as introduced earlier, is a good starting point in analysing security. There will normally be a trade-off between security and cost. Lower levels of risk (higher levels of security) can only be reached at higher costs. Achieving desired levels of security then involves balancing the benefits of risk reduction against the costs of achieving it.

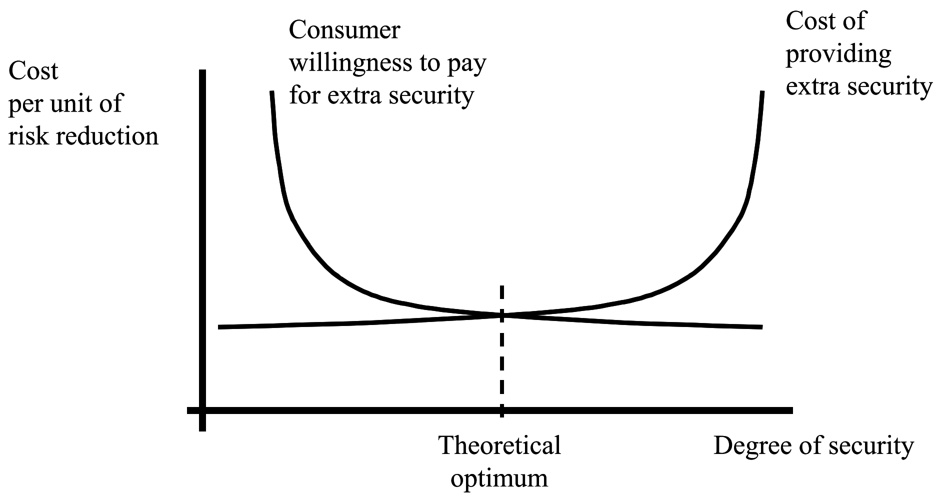
3.1. Defining the Optimum Level of Security

It is possible in theory to describe an optimal level of security, using the conventional "supply and demand" analysis of markets. The degree of risk reduction provided to consumers depends on the cost of providing extra security (the "supply curve"). In Figure 3.1, we show this cost as flat over a wide area, but rising steeply beyond a certain point, when the only remaining risks are difficult and expensive to deal with. This shape implies that where security levels are relatively low, the costs of providing more security may be quite low, but that as risks reach low levels the cost of extra security may be very high. This shape reflects the idea of diminishing returns – that as you repeatedly apply the same level of resources to reducing security risks, the 'return' in improved security becomes progressively smaller as security levels become very high. An example is that in gas or electricity supply, it may become very expensive to reduce very low risks of interruption due to severe weather once those risks are already very small.[8]

The figure also shows a "demand curve" for risk reduction, in the form of consumers' willingness to pay (wtp) for extra security. As in all such conventional analyses, consumers are willing to pay a large amount to eliminate some risks and a smaller amount for eliminating further risks. In Figure 3.1, consumers are willing to pay a large amount to eliminate some risks (for example, of long and frequent interruptions), but their willingness to pay declines rapidly and is low and almost flat beyond a certain point. This is consistent with observations that utility customers are often keen to avoid any reduction in security, but unwilling to pay much for additional security.

[8] These curves are stylised and are meant to give a general representation of the shape of the two functions. While the position and shape of the functions might be different for gas and electricity markets, it would involve spurious precision to attempt to draw separate functions for gas and electricity.

Figure 3.1
Theoretical Optimum Based on Costs and Benefits of Security



At the point where these lines intersect, consumers' willingness to pay matches the cost of providing extra security. Further attempts to increase security would cost more than consumers are willing to pay. The point represents the theoretically optimum level of security. If there were a perfectly competitive market in security and risk reduction, market mechanisms would call forth this optimal level of security.

3.2. Information and Other Problems in Policy Making

Economic theory also provides a way of thinking about the circumstances in which a market system could provide such an optimal level of security. If markets were fully competitive ('perfectly' competitive in economists' jargon) and complete, then a market system would provide the optimal level of security.

The conditions for perfect competition include: complete information about all security risks and the costs of reducing them; all consumers able to express their preferences in the market for desired security levels, and to insure themselves against security risks; and the absence of 'public goods' or other market failures, such as market power. In such a world, it would be impossible to make any consumer better off without simultaneously making another consumer or shareholder worse off. Consumers could be assured that their willingness to pay for security levels would be reflected in market decisions and the question of Government intervention over levels of security need not arise.

Such perfect markets do not exist, and the practical policy issues require judgments about whether existing markets exhibit sufficient 'imperfections' to argue that markets do not reflect willingness to pay for security. Such 'sub-optimality' might mean that security levels were too high and should be reduced, and not necessarily that they were too low and should therefore be raised.

Even if such sub-optimality were demonstrably substantial, this would not in itself make a case for Government corrective action. A further case would then be needed to demonstrate that the effect of Government intervention would be more likely to improve security than diminish it (due to the possibility of 'Government failure' which exists alongside the possibility of market failure.) An example of such a failed attempt to improve security by Government might be public spending on new generating capacity designed only to improve security. This could, instead of lowering the risk of capacity shortage, simply displace private investment in equivalent capacity and lead the market to expect further public spending on security, thus reducing the long-term likelihood of private sector responses to consumers' desire for different security levels.

Relatively complex models of energy security, based on optimality ideas, may not be of practical use to policy-makers. Economists have used a range of at least partially relevant optimising models in the past – examples are the models developed by Professor Ulph (based on the capital asset pricing model)[9] and by Dr. Stirling (an optimal diversity model).[10] NERA reviewed these models in its 1995 DTI report[11] and while both models have strengths, NERA concluded that neither offered a reliable basis for security policy. Given that these models dealt only with diversity – a component of security, but nevertheless only one component – any attempt to model optimal security as a whole would be more difficult and liable to lead to equal or greater difficulties in application.

The question then is how to use the insights of Figure 1 in a practical way. There are problems in both determining consumers' willingness to pay and in establishing, for some security risks, the position and shape of the cost reduction curve.

The problem of establishing consumers' willingness to pay and of determining the optimal level of security from such data, has several dimensions:

- there is no explicit market in 'energy security' and values have to be derived by indirect methods;
- because (as argued in Chapter 5) security has some 'public good' characteristics, consumers have incentives to under-report their true willingness to pay, expecting to be able to 'free-ride' on any security enhancements provided;
- different consumers will have different levels of willingness to pay. This will vary for the *same* consumer both according to the timing of avoided interruptions and whether (and how much) notice the consumer receives. Some kinds of security (e.g.

9 A. Ulph *Notes on the Use of the CAPM Model to Value Diversity Benefits* Document S4165, Hinkly Point C Public Inquiry 1989

10 A. Stirling 'Diversity and Ignorance in Electricity Supply Investments' *Energy Policy* March 1994, pp. 195-216.

11 NERA *Diversity and Security of Supply in the Electricity Market* 2 Volumes. Report for DTI, February 1995.

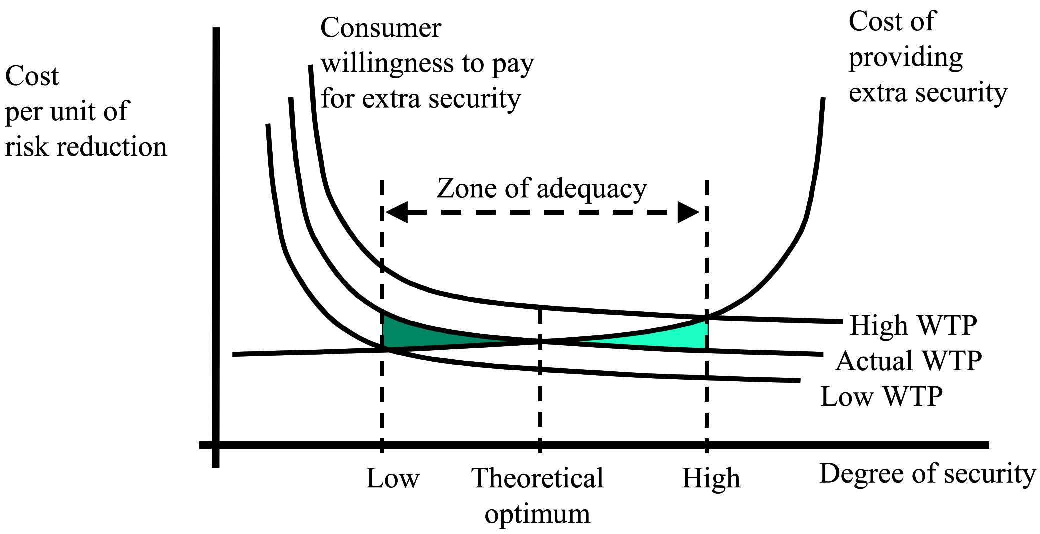
as delivered through local networks) have to be provided collectively given the current state of some metering technology.

3.3. Optimal Security and Optimal Policies

Given these problems, neither the "wtp curve" nor the cost curve shown in Figure 3.1 is easy to estimate. Furthermore, as we discuss further below, it is not always possible to separate the level of security offered to different consumers, as a result of which any single optimum level may be too high for some consumers and too low for others. Hence, rather than representing consumers' willingness to pay as a single wtp curve as in Figure 3.1, it is more accurate to conceive of the wtp curve as a range of estimates, as shown in Figure 3.1. Here, although consumers' "actual wtp" is shown as the middle of three wtp curves, we have allowed for the possibility of policy makers either over- or underestimating how much consumers are willing to pay.

If they overestimate consumers' wtp, as per the line marked "High WTP", policy makers will mistakenly identify the optimum level of security to be at the point marked "High" on the horizontal axis. On the other hand, if they underestimate consumers' wtp, as per the line marked "Low WTP", policy makers will mistakenly identify the optimum level of security to be at the point marked "Low" on the horizontal axis.

Figure 3.2
Cost to Society of Small Differences in the Level of Security



Such errors are an inevitable outcome of the information problems listed above. However, Figure 3.2 illustrates that such errors may not be important, and that effort and cost spent trying to pin down an exact estimate of the optimum level would not be worthwhile.

- Consider the possibility of over-estimating wtp. The extra security implicit in the "High" standard has a cost indicated by the upward sloping supply curve ("cost of providing extra security"). The benefit of this risk reduction to consumers is defined by their willingness to pay, in this case the "High WTP" curve. The net cost to society of raising security above the optimum is the difference between the costs and benefits, which is equal to the lightly shaded area between the two curves, on the right.

- Similarly, an underestimation of consumers' wtp saves costs, as defined by the cost curve, but also foregoes some benefits to consumers defined by the "Actual WTP" curve. The net cost to society of cutting security below the optimum is the difference between the costs and benefits, which is equal to the darkly shaded area between the two curves, on the left.

The size of the two shaded areas is as difficult to estimate as the position of the curves themselves, but one feature stands out. As long as security remains within the range marked as "zone of adequacy", both the wtp curve and the cost curve are relatively "*flat*", which means that the net costs represented by the shaded areas must be relatively "*small*". In practical terms, this observation means that policy makers do not need to concern themselves overly with estimating the optimum level of security, because the cost of doing so would be very great, whilst the potential benefit from doing so (avoiding the losses implied by the shaded areas) would be small. Thus, the best policy is not to aim at any optimal level of security, but instead to ensure that the energy market stays within the "zone of adequacy".

3.4. Time Dimensions

The context for adequacy of energy security is also time-related in several ways. Security policy will evolve against a changing market and policy context in the future. A level of security that seems adequate at one time may become excessive or inadequate because events, technologies or markets change over time. The time frame for this project is 10 and even 20 years into the future. It is impossible to forecast many of the possible circumstantial changes, which might affect future security levels. However some changes seem highly probable, and others are anticipated by Government as a result of its own policies and targets. Relevant changes by 2010 will include:

- a probable continuation, in electricity, towards more local, decentralised generation (Government has a target for 2010 of 10GW of installed CHP);
- a Government target that 10% of electricity should come from renewables by 2010[12];

[12] This is discussed further in Chapter 15

- a high probability that net gas imports will start before 2010 and gather pace subsequently;
- a virtual certainty that nuclear capacity will fall significantly from its current level;[13]
- the probability that there will be new gas reception terminals, including those supplied by LNG.

Such changes will have significant effects on security levels. The direction of change in security levels will often be difficult to forecast in the absence of much further study, but for example:

- gas imports add to diversity (good for security) but may increase producer risk (bad for security);
- new gas reception terminals and the use of LNG will add to diversity and security;
- less nuclear power will reduce technology and fuel diversity (bad for security) but will remove increasingly unreliable plant (good for security, as long as it is replaced by more reliable plant);
- More decentralised generation adds to diversity (good for security) but will also affect networks in ways that could be good or bad for security (depending on location and reliability of new plants).

Another important time dimension is that analysis of market failures and other barriers and obstacles to improved security sometimes takes place in a static context. However three kinds of change over time need to be considered in deciding on adequacy of security levels:

- Most of the barriers to consumers' ability to express their willingness to pay for security derive from the interaction of technology and cost (e.g. the currently high costs of real-time metering for households, which would allow consumers to respond directly to price signals). Over time the development of new technology has tended to reduce, and in future will probably continue to reduce, such barriers. High transactions costs, preventing some kinds of market signalling, may therefore be expected to reduce in the longer term.
- Markets are not simply static allocation devices but rather adaptive mechanisms. This means that while a particular security risk may emerge (say for example in relation to new sources of gas) it is reasonable to expect markets to adapt to the risk and to succeed in reducing the risk. Not all such adaptations will be smooth or automatic, but the process of market evolution over time cannot be ignored by using only a formal or static analysis.

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13 In the longer term, capacity could well fall further after 2010, but could subsequently rise again.

- Perceptions that new security risks lie ahead complicate the analysis. Two of the major risks currently perceived by some commentators (of gas imports, and the adequacy of investment levels for future capacity) are areas in which judgments are needed, as empirical evidence of risk is necessarily limited or absent. But if there is consensus that such future risks are potentially large, spending much time and effort getting security levels precisely right for more familiar risks may be not worthwhile.

Adequacy of security therefore needs to be evaluated in relation to such evidence as there is about consumers' willingness to pay for existing or alternative security levels - assessing the extent and significance of barriers and obstacles to this process, their probable significance and any adaptations over time that markets may make. Any significant barriers that seem likely to reduce security levels below what consumers might be prepared to pay for need to be assessed further. In some cases, policy makers may need to analyse specific interventions for overcoming these barriers.

3.5. Conclusions

Given the difficulty of finding the optimal level of security, the time and effort of policy makers is best spent addressing other, more practical questions, in order to ensure that the level of security stays somewhere within the zone of adequacy described in Figure 3.2. The most important questions are:

1. Are there *theoretical* grounds for considering that there may be obstacles or barriers preventing consumers expressing their willingness to pay for security, or investors from responding to it?
2. Are there *observable* barriers or obstacles that prevent consumers expressing their willingness to pay for security or, again, investors from responding to it, or which lead to excessively costly ways of providing security?
3. Does meeting the current level of security expose consumers to risks of insecurity or actual incidents that impose a very high cost on them?
4. Do any practical barriers appear to be material? If so, is it likely that in trying to overcome them, Government can tackle them directly, or will some less direct method be needed to compensate for the problem to which they give rise?

If the answer to any of these questions is "yes", the market is, or is in danger of, moving out of the zone of adequacy and, in all likelihood, some kind of corrective action is desirable. In the following chapters, therefore, we will be trying to discuss possible security problems in ways that provide answers to these questions.

4. MARKET PROVISION OF SECURITY

We have seen in Chapter 3 that under certain conditions the operation of markets could provide adequate levels of security. This would involve reflecting both consumers' willingness to pay for security and the costs of reducing security risks. In this chapter we consider some general issues of market operation in relation to security provision, bearing in mind that real markets are very different from those of the perfect competition model. We introduce some issues of market theory and look at recent UK experience.

4.1. Monopoly, Competition and Security

Policy makers have made concerted and mostly successful efforts to introduce more competition[14] into British energy markets that, at the time of privatisation, were largely monopolistic. In some areas it is widely agreed that there has been a progressive reduction in market power (e.g. in electricity generation, and in supplying gas and electricity to large consumers). However potential market power may still be present in both gas and electricity markets, which continue to be subject to quite high levels of producer concentration. All these changes could affect security of supply, especially where security is related to the level of investment in productive capacity.

The classic theory of an *unregulated private monopoly* suggests the monopolists have an incentive to restrict supply and to raise prices, in order to maximise their profits. The tendency to restrict supply, compared with an ideal or "competitive" outcome, suggests that monopolies would offer a lower level of security than competitive markets. However, the situation in the energy sector is not so simple.

Monopolies in the energy sector are used to operating with *regulated prices* designed to curb their rate of return. A well-known theory predicts that such regulation encourages over-investment (relative to the efficient level), as a way for the company to increase its total profits.[15] In practice, most real regulatory systems contain mechanisms to counteract this tendency, but this incentive to invest is not necessarily undesirable, if it overcomes the monopolist's initial reluctance to expand supply. Whether a private regulated monopoly over- or under-invests depends upon the incentives offered by its own particular regulatory system.

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14 The concept of 'more competition' is often loosely, or not at all, defined. It could refer to the replacement of monopoly with competitive markets; splitting companies to reduce market power; or reforming market institutions to foster more efficient decision-making. The ultimate test of whether a change in markets leads to more competition is whether or not it improves efficiency. While all three uses of the term "more competition" are included in the discussion in this chapter, we generally regard a change as pro-competition if it enhances efficiency. .

15 This is known as the Averch-Johnson effect.

In Britain, however, the norm prior to the liberalisation of energy markets was not a private regulated monopoly (or at least, not for very long). Britain's energy sector was previously managed by *state-owned monopolies*, for which the profit motive was not an over-riding objective. How such organisations behave is hard to predict, but we note that an objective of privatisation was to overcome financing constraints that caused some utilities to appear cash constrained. These *cash constraints* may have translated into a lack of investment (although not noticeably in electricity generation), or inefficient choices among alternative methods of providing security. Governments also intervened to support the domestic coal industry, which led almost certainly to less diversity in electricity generation than might have occurred in more competitive structures.

Several of these pressures would have increased the cost of providing *any given level of security*. Conversely, the pressure for efficiency in competitive markets should lead the energy sector to offer a given level of security at lower cost. However, it is difficult to judge on theoretical grounds the net effect of all these pressures on the adequacy of security. There are several arguments to suggest that competition should help to produce improved security:

- More competitive markets force energy suppliers to pay closer attention to the needs of their customers, who will be attempting to express their preferences for security in the market place – thus for example large consumers may find existing security levels inherited from a less competitive regime too high, and may be given the choice under more competitive conditions to pay less, and receive lower security levels.
- More competitive markets will lead firms to pay closer attention to plant reliability as forced outages in capital-intensive industries have a serious effect on profits.
- More competitive markets lead to a wider range of suppliers (itself a direct increase in diversity), and to more liquid, deep and connected markets, using more sophisticated financial instruments to hedge risks, for example in futures markets. These factors should improve security by increasing the ease with which market participants can solve each other's supply problems.

However there are other arguments that could mean that more competition will lead to lower security:

- Security is a property of the system as a whole, and not of the actions of any one market participant. As more competition develops, individual firms have less and less influence on the market and therefore on security. In the limiting case of perfect competition, firms by definition have no influence on market outcomes. Earlier work by NERA for DTI in 1995 established that in relation to diversity, more competitive market structures would be likely to lead to *lower* levels of diversity, and therefore security, than lower levels of competition. The reason for this is that a security threat such as higher input fuel costs would harm competitive producers' profits less than a monopolist's and so provide less incentive to diversify away from a risky fuel.

- If energy markets are not "perfectly competitive" larger firms may have more interest in security than smaller firms. In this case the mechanism could be reputational: large firms expect to be 'blamed' if security is poor and they could experience loss of customers as a result. Equally it might be argued that vertically integrated firms may have more reputational interest in security on the grounds that they are responsible for both production and delivery to consumers and hence are more susceptible to reputational loss in the event of interruptions. More generally, it can be argued that oligopolistic firms may have an interest in a 'quiet life' and enough market power to make that interest operational. They may therefore choose to invest relatively more heavily than competitive firms in reducing security risks, and more competitive market structures could lead to lower security-enhancing investment. It is also sometimes argued that small, competitive firms may have less incentive to guard against low probability/high consequence events (e.g. failure of a large gas terminal).

Are there structural or other features in electricity or gas markets, which render them more liable to oligopoly than other markets? Arguments are sometimes made that economies of scale are important in both industries and mean that the minimum economic size of enterprises are large relative to the size of the whole market.

In gas production and electricity generation economies of scale seems a weak argument. The largest gas fields or electricity plant sizes appear to be relatively small in relation to the whole market. Even if these production units were relatively large, there are no obstacles to ownership of single facilities being shared among two or more different companies (as happens frequently in the UKCS). The only possible exception to the argument about the relatively small scale of investments in relation to the whole market might be in relation to some gas facilities (e.g. storage) but such possible exceptions seem limited.

In gas or electricity retailing, an argument is also sometimes made that the minimum economic size of customer base may be relatively high (a figure of 5 million, over 20% of the market, is sometimes used). The argument is that overhead systems such as customer billing do not reach lowest unit costs except at large customer numbers. This argument is difficult to evaluate but an alternative interpretation of retail company mergers is that it may be an attempt to gain some market power where margins have sometimes been low. The arguments that oligopoly is inherently more likely in gas and electricity than other industries does not seem strong. Even if the argument were strong however, and oligopoly were necessary for productive efficiency, this does not necessarily imply a lack of competitive *behaviour* in markets, as competitive behaviour does not depend solely, or necessarily very much, on the *number* of companies in a market.

Whatever the extent of oligopoly in current British liberalised markets, there is more competition now than under the former state monopoly system. However, if there were a fall in security levels under more competitive conditions, this would not mean that competitive markets were necessarily irrational and provided inadequate security.

Competitive markets might combine lower security levels with lower costs overall. This would be an efficient outcome, if the new situation accurately reflected the balance between consumers' willingness to pay for security, and the costs of providing security.

These various arguments suggest that theory alone will not predict whether competitive energy markets are more or less secure than monopolies. The *efficiency* with which a *given* level of security is delivered is likely (on theoretical grounds) to have improved. However competition does not guarantee any particular new *level* of security in theory, so this aspect needs empirical study. As far as *actual* security levels are concerned partial indicators suggest a slight improvement in some areas since liberalisation (e.g. total duration of customer interruptions as a result of electricity network failure, [16] or – in the competitive parts of the industry – a large electricity plant margin above peak demand).

4.2. Private Markets and 'Under-Investment'

4.2.1. 'Short-termism' and high discount rates

An argument often made about private competitive markets is that they may under-invest compared to a socially desirable level, because of an inbuilt 'short-termism'. Private capital markets are thought to be interested in short–term cash flows and returns, and not sufficiently interested in long-term profitability.

More formally, the private sector may use a discount rate (which may be expressed in private markets as the 'cost of capital') that will be higher than the 'social' rate. This will mean literally discounting the future 'too heavily' and neglecting the longer term consequences of today's decisions. The relevance of this to energy security is that long-term security depends on capacity, which in turn depends on adequate levels of long-term investment. This argument therefore suggests that competitive markets may under-invest in security and provide too little electricity and gas production capacity in the long-term.

These arguments are usually applied quite generally across the economy, and if accepted, they would imply a major re-orientation in economy-wide resource use away from current consumption and towards investment. At such high levels of generality, the application of such arguments to energy supply security seems limited. However the reason why energy may be seen as a special case is that it is inherently a capital-intensive sector, so that the impact of short-termism would be more acute in energy than elsewhere.

One of the consequences of a high cost of capital is likely to be a change in the capital-intensity of investments towards systems that use less capital per unit of output. Whether this effect is good or bad for security is difficult to determine. A counter –argument to the 'short-termism-insecurity' idea is that the highly capital-intensive systems that might be

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16 See JESS *First Report* June 2002, para. 28, pp.6/7.

produced by low discount rates under state monopoly systems might be inflexible and thus adverse for security.

The overall debate about short-termism would take us into territory well beyond the scope of this project and into a large literature on the economics of time.[17] It is, further, difficult to test propositions about short-termism in any definitive way. So far as energy may be a special case, we have chosen to deal directly with issues of potential under-investment in the specific circumstances of current electricity and gas markets (see Chapter 4.3 below).

4.2.2. Under-investment on the demand side

A version of the argument about unwarrantedly high discount rates is that discount rates may be particularly high when investors consider demand-side investments in energy compared to rates used for the supply side. The market failure here would be that a lack of information available to demand side participants (including households) would lead to under-investment in profitable energy efficiency projects. The context here is that a large number of consultees to the DTI have recently suggested that, over the long term, energy efficiency is the best guarantee of adequate energy security.

We return to this issue later in the context of post-2010 issues, but the important point here is that whether or not there is such serious under-investment in the demand side of the energy market in general, it is not clear what would be the mechanism for improving security. If demand turns out to grow more slowly or to fall, energy supply systems will be expected in a market economy to adapt accordingly, and expand less quickly. There seems no general capacity argument for better security at lower levels of energy demand. Another possible argument would be that at lower levels of demand, there might be less need for fuel imports in future, especially gas. This argument itself depends on the idea that imports are bad for security, and we return to this issue later in Chapter 13. Even if there are objections to imports, it is not clear that the level of *dependence* on imports will fall at lower levels of energy demand, even if there is a smaller absolute level of fuel imports.

There seems therefore no generic argument in favour of the idea that more energy efficiency investment would improve security. There are different arguments, about the participation of consumers more specifically in the provision of security that may be a more serious market failure in relation to energy security, and this is explored in Chapter 6.

4.2.3. Low risk/high consequence events

The final generic issue is the idea that markets may be poor at handling risk issues where the probabilities are very low but the consequences may be high. An example might be a catastrophic failure of the gas pipeline system. It is again difficult to generalise. It is not clear that public decision-making will necessarily be better than market decision-making,

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[17] See for instance P.Portney and J. Weyant (eds.) *Discounting and intergenerational equity* for an up to date account.

and there are large 'grey areas'. These mostly refer to the differing probabilities that different players may attach to the size of the (low) risk under consideration.

By definition, events of low probability happen so rarely that there will often be no empirical record by which to reach reasonably objective estimates of risk. There is then much legitimate room for disagreement on the magnitude of such risks. There is always a point where both markets and Governments decide that a risk is so remote that it is not worth taking action against it. As in the case of 'short-termism' we take no general position on this subject but refer to specific cases as necessary, especially in relation to gas in later Chapters.

4.3. Conclusions

The recent history of the British electricity and gas industries has been of a transition (aside from the networks) from state monopolies to private competitive markets, in which some market power may still exist. In terms of theory, there is no clear reason to suppose that a competitive system will provide higher levels of security for consumers, though it will normally supply a given level of security at lower cost. Partial indicators suggest slightly rising levels of security in electricity and gas in recent years.

But given a significant level of competition in these markets, can we expect actual market conditions to bring about *adequate* security? In this chapter we examined general arguments about market behaviour: in relation to 'short-termism' and a possible inability of competitive markets to guard sufficiently against low probability/high consequence security risks. There is no clear case for either of these propositions at a general level.

However later Chapters review more specific market failures and other barriers to security, including issues of long-term investment incentives for capacity in both gas and electricity (Chapters 9 and 10).

PART 2: POSSIBLE BARRIERS AND OBSTACLES TO MARKET PROVISION OF ADEQUATE SECURITY

5. BARRIERS AND OBSTACLES: INTRODUCTION

Markets are, in the current British context, the primary vehicle for delivering adequate energy security. In the previous chapter we found no over-riding or general reason to suppose that markets will generically fail to provide adequate security. However there may be specific barriers or obstacles that prevent markets from working to provide adequate energy security, and the remainder of this report is mainly about those barriers and their possible significance.

Economic and political impacts of security levels that are less than adequate may be much more pronounced than the impacts of security levels that are more than adequate. This is because less than adequate security could result in disconnections on a significant scale, while the impact of 'over-adequate' security is limited mainly to extra costs, which are not always immediately visible. However, in principle, barriers could lead to security levels that are 'too high' as well as 'too low'. While both kinds of impact need to be examined, in practice Governments will tend to be concerned more with security levels that are below adequate than above adequate.

The barriers and obstacles to consumers' ability to enforce their willingness to pay for security in markets may derive from a large number of sources. Recent debates identify many such possible barriers. Some of these fall into the category of 'market failures' in economists' terms and others derive from other sources that can be characterised as Government or regulatory failures. The latter may not necessarily be 'failures' in the sense of *direct* failure to achieve objectives. Government 'failures' in relation to energy security could arise from conflicts of policy objectives. For example, environmental policy may raise difficulties for the achievement of adequate security. All of these barriers or failures are potentially important in considering the adequacy of security.

Our task has been to consider all those barriers and obstacles that are frequently cited and to consider their relative importance, from a theoretical and, as far as possible, empirical perspective. We have chosen to classify the various barriers in a number of categories, starting from economic 'market failure' arguments and moving towards more 'political' (or Government failure) categories.

Chapter 6 considers the classic economic arguments about 'public goods' and in the course of so doing, also considers limitations on the ability of consumers, especially small consumers, to express their willingness to pay for security.

Chapter 7 looks at possible market failures in relation to some issues in short term security for electricity and gas separately.

Chapter 8 examines similar issues but this time from the perspective of interactions between gas and electricity markets

Chapter 9 considers the issue of market failure in relation to investment incentives in electricity markets

Chapter 10 covers similar ground in relation to gas investment. It concludes with a comparison between electricity and gas in relation to the investment incentive issue.

Chapter 11 considers the issue of whether markets will provide enough diversity in general and then examines diversity issues in electricity.

Chapter 12 then looks at diversity issues in relation to gas supply within the UK

Chapter 13 stays with gas but considers possible international barriers to security

Chapter 14 moves on to regulatory/political barriers, and examines barriers that may arise at the interfaces between the regulated and competitive parts of the electricity and gas industries.

Chapter 15 analyses policy barriers, in particular the ways in which environmental policy and the planning system may provide barriers to security.

Chapter 16 examines wider and more generic political barriers to adequate security provision by markets.

Chapter 17 briefly reviews the extensive evidence in Appendix C on international approaches to security in liberalised markets in relation to its relevance for the UK.

Chapter 18 then provides a brief look at the longer term issues from 2010 to 2020.

Chapter 19 presents conclusions.

The coverage given to subjects in each chapter is deliberately variable and reflects the relative importance of the different arguments about barriers. The categories are far from watertight.

Any significant and material barriers could in principle be the basis of a case for Government intervention. Note that we do not include *general* imperfections in information, including information about the future, as a separate barrier. Such imperfections are pervasive but as they in principle affect all participants (including Government), they cannot by definition tell us anything about any desirable directions of change in security levels (we cannot know what we cannot know) and they do not provide any basis, by themselves, for Government intervention.

6. PUBLIC GOODS

The idea of public goods has a specific meaning in economics. It does not mean any good that is provided in the public sector. Instead it means a good that exhibits two sorts of characteristic:[18]

- It is non-rival, in other words consumption of the good by one party does not reduce the amount available for other consumers
- It is non-excludable, in other words once it is provided to one consumer, there is no way that other consumers can be prevented from getting access to the good.

By contrast, private goods can, at any time, benefit only a single user. The classic example of the public good is defence, though research is also sometimes quoted. 'Pure' public goods represent the most acute form of market failure – a pure public good may not be produced at all by a private market, and if it is produced, it will tend to be seriously under-provided. This is because consumers will rationally 'free-ride' wherever possible – i.e. they will try to consume the good without paying for it, knowing that they will be able to benefit from any provision made.

Only Government, it is then argued, can ensure efficient provision, though in practice it has to be demonstrated that Government will not fail, and be able to improve on inefficient market outcomes. A fundamental problem with public goods is getting consumers to disclose their 'true' preferences (due to their incentive to free ride and therefore to suggest, if asked, that their valuations are lower than they really are). Governments need to find ways of getting consumers to disclose their true preferences if they are to provide public goods efficiently.

However it is doubtful whether any good represents is a completely 'pure' public good and in practice goods tend to be either private or, to some degree or other, 'impure' public goods. Some public goods become increasingly 'impure' as consumption rises due to congestion effects.

The question is then to what extent can 'security of energy supply' be regarded as a product that could fall within the category of a public good (however impure). The relevant product is derived from two aspects of security of supply on which consumer welfare will depend:

- "physical" security of supply, i.e. the risk of interruption and

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[18] The key recent text on this subject is G.D. Myles *Public Economics* Cambridge University Press, 1995 (reprinted 2000).

- the "financial" security of supply, i.e. the financial compensation received in the event of being cut off, sufficient to leave consumers indifferent between being interrupted and having continuous supply.

Financial compensations depend on market rules, while the primary determinants of physical security of supply are of a technical nature. In order to determine the extent to which security is a public good it is necessary to look separately at small (in practice household) consumers, and larger consumers, and to consider both physical and financial aspects of security

6.1. Household Consumers

For household consumers, there is a high degree of non-excludability in relation to physical security. For technical reasons (the disproportionately high costs of providing real time meters and switches) it is generally impossible for individual household gas or electricity customers to be interrupted while leaving neighbours supplied. This means that individual customers cannot have a probability of interruption which is different from the probability of other households in the same network area, however different their preferences may be.

At low levels of energy demand, physical security of supply is “non-rivalrous” (i.e. more security can be ‘consumed’ through higher energy use, without compromising others’ security). However, physical security is vulnerable to congestion since the reduction of reserve capacity through increasing demand at already high demand levels entail an increasing probability of interruption.[19] Each consumer therefore runs the risk that increasing his or her own demand will trigger an interruption of his or her own supply, though it is extremely doubtful that except in emergency conditions,[20] such knowledge is likely much to affect individuals’ behaviour. At the domestic customer level, physical security of supply therefore has the characteristics of an impure public good.

Financial security – the provision of insurance[21] to compensate for physical interruption – would, if available in the market, be excludable and rival in consumption, making it a private good. To compensate customers efficiently for interruptions (i.e. leaving them neutral in welfare terms with respect to having the interruption or not) financial measures would have to reflect the valuation individual customers place on physical security of supply.

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19 Congestion may, for technical reasons, also occur at non-peak demand times.

20 For this reason, Californians became very responsive to instructions to reduce their demand during 2001.

21 Insurance here refers to conventional insurance i.e. spreading the impact of adverse events, rather than the different idea (sometimes labelled insurance in energy security debates) of taking physical action to reduce the probability of adverse events taking place.

Real-world compensation or insurance schemes for household consumers appear not to be available. In principle a supplier might offer a higher regular tariff (the increment over regular tariffs being the insurance) and could then pay compensation in the event of supply failure. Because customers with highest risks of interruption would be the most likely clients of such insurance, the costs of providing it would probably be prohibitively high. This is a case of market failure – an absent market due to the costs of provision being too high.

In addition, the apparent gap in the insurance market could be due to:

- consumers' having genuinely low valuations of security
- the transactions costs of seeking out and obtaining insurance could outweigh the benefits obtainable from having it
- consumers' being unable, due to limited historical experience of actual unanticipated interruptions (except of a short and geographically limited nature), to place a value on the whole range of possible security risks,
- consumers valuing primarily the impact of interruptions only on their own welfare and being unable to factor in the external effects of interruptions that affect whole districts (e.g. inability to get help from neighbours, or risk of increased crime in blackout conditions). This is an example of an externality – a cost that private individuals have no incentive to factor into their own decision-making.

Absence of available insurance may or may not therefore necessarily indicate that public good characteristics are important.

There may be genuine difficulties for households expressing their real valuations. Not only is there the problem that collective provision of some kinds of security (via the networks) makes expressing individual preferences problematic, it is also the case that the widespread existence of fuel poverty in the UK (where households spend 10% or more on domestic fuel bills) means that a large group of consumers may have difficulty in paying for more security. In these circumstances, there is an argument that the sum of consumers' valuations of security may be lower than the social valuation.

Finally, however, security levels for households have been high for some years in the UK. As argued earlier security risks from the competitive part of the electricity and gas industries are more likely to be notified in advance than those from network failures. For these reasons, household valuations of additional security may still be at low levels.

6.2. Large Consumers

For large, mainly industrial customers, it is possible for different customers to consume different levels of physical security of supply. They can choose lower levels of security than offered by the network supply and they can sign interruptible contracts in return for lower prices. These allow the supplier to interrupt the individual customer in response to price signals. However, the presence of interruptible contracts, while making *voluntary interruptions* possible, does not do away with the physical security issues captured by *involuntary interruptions* (that is interruptions not covered by the terms and conditions of the supply contract and hence not agreed with the customer in advance).

With respect to involuntary interruptions, individual industrial customers generally face the same probability of interruptions as other customers connected to the same network area. The same congestion issues also apply as for domestic customers, though the willingness of larger consumers to switch off at times of approaching emergency may be greater than for households. However large customers also have the choice, in electricity but not gas, of achieving higher levels of security by installing back-up generation facilities.

At the large consumer level, physical security of supply has some of the characteristics of an impure public good, though it is closer to a private good along the spectrum than is household physical security. Customers are able to consume different levels of physical security of supply by signing interruptible contracts but will nevertheless be exposed to involuntary interruptions.

Financial security for large consumers is, as for households, excludable and rival in consumption, making it a private good. Since interruptible contracts are generally associated with price advantages, they reveal customer preferences with respect to compensation levels (in this case price reductions for increased customer flexibility) for supply interruptions notified in advance. With respect to non-predictable supply interruptions, the same comments apply as for domestic customers.

6.3. Summary and Conclusions

Financial security is excludable and rival in consumption, making it a private good. However, physical security of gas and electricity supply has characteristics of an impure public good, especially for small consumers such as households.

Congestion is an aspect of physical security of supply, which has both short-term and long-term implications. In the short term the increase in the probability of supply interruptions caused by high and increasing electricity demand increases the value of measures available to mitigate interruptions (such as additional generating capacity or gas storage). However, the resulting price increases for these mitigating factors primarily induce short-term supply responses. It is an empirical question to what extent mitigating factors with long lead-times (such as capacity investment) receive sufficient price signals from the short-term price hikes cause by congestion effects in physical security. This issue is explored further in Chapters 9 and 10.

Different consumer groups are likely to place different valuations on security of supply, and these valuations will tend to be lower if interruptions are pre-notified. Duration of interruptions will also influence valuation: longer interruptions will attract proportionately higher valuations than short interruptions (for instance, if freezer food becomes unusable). Lack of recent experience of major or long-lasting unanticipated interruptions probably contributes to the difficulty predicted by theory of getting consumers to reveal their true preferences for different levels of security.

Security of supply, especially for household consumers, has 'impure public good' status. The public good characteristics of supply security for household consumers is the most important single reason, in terms of theory, for consumers' potential inability to express their willingness to pay for security of supply. General public goods theory suggests that the existence of important public good elements in household security provision would lead normally lead to the market providing less security than consumers would genuinely like. However in reaching a view on whether security is under-supplied in current UK conditions due to the public goods argument, other factors also play a part:

- In both electricity and gas, elements of market power, which originated in the old state monopolies, have taken time to eradicate. This means that the residual impact of the former state monopoly system, where security was not provided by private markets at all, still exists to a degree
- There are interactions between those (larger) consumers who can and do express their willingness to pay for security, and those (smaller) consumers who generally cannot. Consumer valuations of security, as argued earlier will vary widely according to circumstances. Suppose that: the range of security valuations of larger customers overlaps those of smaller customers; larger customers' valuations are reflected in security provision; and there is a physical connection between security provision for the two groups (e.g. both types of consumer may be connected to the same part of a local network). Then the security provided to larger consumers will most likely reflect the security valuations of smaller consumers, and the market may well provide adequate security.

Hard evidence on actual consumer willingness to pay, especially in the critical household consumer group, is scarce. The House of Commons Trade and Industry Committee found little evidence on household willingness to pay in this critical group.[22] On balance, therefore, the public good argument, which mostly applies to household consumers, and only to a limited extent to other consumers, may or may not suggest under-provision of security by current markets. However there is one reason to suppose that, within the zone of adequacy shown in Figure 3.2, policy-makers might have a preference at the margin for trying to move the system towards higher rather than lower levels of security than obtain at

22 House of Commons Trade and Industry Committee *Security of Energy Supply* Session 2001/2002

any moment. This derives from the fact that only one level of security may be provided within certain network areas, despite different valuations of security (in Figure 3.2, the three levels of high, actual and low could be re-interpreted as three different valuations). This means that providing the theoretical optimum in Figure 3.2 would mean under-providing security for those whose willingness to pay is shown as high. In practice, it may be difficult to make such fine adjustments given the difficulties of measurement. While the public good argument is an important market failure, we conclude that it does not suggest that market provision of security will necessarily be inadequate. It does not provide a strong practical argument for Government intervention.

7. POSSIBLE MARKET FAILURES IN SHORT-TERM OPERATIONS

7.1. Introduction

There are several related possible market failures that might arise from the existence of many firms in a market, especially where previously there was only one. These may be in principle more important in relation achieving adequate security than in relation to other policy objectives. This is because security is systemic - a property of the actions of all market players. As firm size reduces, the influence of individual decisions on security inevitably becomes less. Market failures here would derive from information asymmetries, or a lack of relevant information and solutions to any problems would not be likely to require significant investment.

7.2. System Reliability

Operational reliability of the electricity and gas production facilities impacts on security of supply. If reliability levels are poor, much productive capacity may be unavailable for use at the same time, in which case the sector will need a larger volume of production capacity to ensure supply at all times. The possible market failure here is possible information failures, so that relevant parties are unable to co-ordinate their plans for outage.

The reliability of individual units is unlikely to be subject to market failure. Competitive pressures will tend to force companies to pay greater attention to the underlying causes of forced outages, because the profit implications of plant being unavailable, especially at periods of high prices, will be severe. Forced outages, by their nature, occur at any time on the network, potentially even at times of system shortage. Forced outages are less important when they occur for reasons that are independent of each other and the size of each productive unit is small relative to the size of the overall system. In general, for the electricity and gas system, production units are small compared to the size of the system and any single forced outage will have a small impact on the overall levels of security. However, any system remains vulnerable to common ("type") faults that affect a large number of similar productive units at the same time.

In the electricity market, participants in NETA pay penalties if they do not generate their contracted volumes. Once the market has closed, one hour before the start of each half-hour settlement period, participants are unable to change the predicted volumes of production or off take. For settlement periods more than one hour ahead, participants can trade electricity volumes to make up any shortfall due to forced (unplanned) or planned outage, but the premium on such short-term trading (due largely to illiquidity) preserves the incentive for reliability.

In relation to planned outages, reliability could be a concern, if information is not widely available about scheduled maintenance plans. Gas and electricity producers prefer to take their planned outages for maintenance at times of low market prices. All companies respond to the same price signals and, if they unknowingly select the same outage periods, overall levels of security may suffer if too many units take an outage or if a reduction in spare capacity makes the system vulnerable to a forced outage.

When the electricity system was operated by few players (e.g. British Gas for the gas system and PowerGen, National Power and Nuclear Electric for the electricity system), information flows were straightforward and it was relatively easy for them to co-ordinate outages via the system operator to prevent shortfalls in available production. With increased fragmentation in the electricity generation market, it is possible that all production units would wish to take their outage at the same time. The system operator will have less influence over smaller companies, but a liquid trading market would provide the price signals needed to co-ordinate outages. Each company will face barriers to changing the timing of its planned outage (i.e. limited availability of sub-contractors), but forward markets would allow them to anticipate shortages and to take advantage of any remaining flexibility in their maintenance plans. In practice there is enough information- sharing in the electricity market between NGC and generators to make this an unimportant market barrier for electricity

Reliability in gas supply might also be affected by new annual profiles of production under a competitive market. In the regime of state monopsony, production was at low levels in summers, due to low demand, and at higher levels in winter in response to peaks. Maintenance could then be undertaken at times of low demand in summer. With the advent of the UK-Belgium interconnector and pressures to maximise profits under liberalisation, production is often now at higher levels in summer than in the past, in response to higher prices elsewhere in Europe. As maintenance may be less easy to accommodate in summer, this could potentially lead to lower reliability of the gas system in delivering at UK winter peak times. There is no requirement on offshore operators to inform OFGEM or other parties about their planned maintenance periods. However we have found no evidence that this possible absence of information about maintenance regimes has had any effect on system reliability to date.

Reliability of the system could also be affected by bankruptcy, which was not a possibility under the old monopoly regime. The market failure would be an inability of the market to respond quickly enough to information about bankruptcy to maintain continuous supply. Within the last two years, there have been a number of bankruptcies in the electricity and gas industry. Independent Energy went bankrupt in 2000 and Enron in 2001. British Energy is currently close to insolvency and other generators are in a difficult financial position.

If bankruptcy were to be a problem for security it would be more likely to have effect where physical rather than financial assets were at stake. In general, therefore, bankruptcy in the retail supply market is unlikely to pose any major problem (and did not do so when Independent and Enron went under).

In the Enron case, there were physical assets as well, and there was no interruption to supply. In general, it would be expected that a company facing bankruptcy would be able to sell some or all of its assets to other parties (British Energy and nuclear power are exceptional cases largely for safety reasons). In the transition to new ownership there could conceivably be problems that might affect supply (credit risks for example) but it is difficult to see that these will have constituted major barriers to security. In practice, bankruptcy has not been a security issue and there is no sign that it will be so in the future.

7.3. Responsiveness – Demand

7.3.1. Small consumers

An absence of markets for customers to adjust their energy use at times of system stress (or a physical inability to do so) would be a clear market failure in relation to achieving adequate security. Chapter 6 on public goods already established that small consumers (especially households) are currently unable to participate in such adjustments because they lack information on wholesale prices and lack technology (meters) through which they could use such information to participate in the market when the system is stressed.

While there are technical possibilities that might allow suppliers to give incentives to small consumers to reduce demand when wholesale prices are high, these are not yet widely diffused. At present the costs of real-time meters are excessive, for small consumers, relative to benefits that could be gained. Electricity and gas bills form a small proportion of domestic spending for most households, so the "transactions costs" are high relative to the potential savings. Small consumers are therefore likely to respond only to: (1) large changes in prices over a sustained period; or (2) the imminent threat of blackouts. (Both factors affected demand in California in 2000.) While this limits demand-side responsiveness, it is not a product specifically of a liberalised system, and over time it is reasonable to expect small-consumer demand responsiveness to increase as metering and other technology advances.

7.3.2. Large consumers

The rest of this section concentrates on issues surrounding larger customers who are able to participate in this market. Voluntary interruption can improve security of supply and lower market prices. Customers impact on security of supply in three important ways: (1) by reducing consumption in response to price signals; (2) by switching fuels in response to price signals and (3) by the daily and wider 'shape' over time of customer demand. This section also considers the impact of involuntary disconnection.

For all products, each consumer will have a price at which it is willing to reduce or eliminate demand. Response to prices is dependent on the price signals being received by customers and the relative cost of the product in relation to overall costs. In principle, the electricity market distinguishes prices for every 30-minute period during the day, whilst the gas market provides prices every day (and in future, may provide price signals on a shorter-term basis).

When NERA surveyed 200 industrial gas customers, we found that *at peak* 70 percent of demand (including domestic demand) is unresponsive to short-term price signals.[23] This relative unresponsiveness is due to the high volume of fixed price, uninterruptible contracts held by domestic and industrial customers. But among industrial customers, demand management is more important and potential responsiveness much greater. First, each customer has a large demand compared to domestic customers and so makes a larger difference to overall consumption. Second, large customers have metering which allows real-time or near to real-time monitoring of demand, providing some demand and price signals. Third, the transactions costs of arranging interruptions are smaller relative to the potential savings.

Industrial customers tend not to have access to real-time trading information for the energy market and so do not have access to the value of energy in any settlement period. In electricity, under the Pool regime, prices were published once *ex-ante* for a 24 hour period. Industrial customers had some time to re-schedule their production processes (and hence demand) in response to market price signals. Implicitly, industrial customers were able to respond to demand signals for a 24-hour period in a relatively simple process, by evaluating market prices once every day and changing their consumption pattern for the subsequent day. The customer benefited from lower overall electricity costs and the downside risk was limited to paying the *ex-ante* market price for electricity. NGC compensated for implicit demand response in its forecast of demand (and hence customers' reaction fed back into market prices, albeit imperfectly).

Under NETA, there is no single price for a settlement period and so prices depend on the time at which the product trades. Equally, markets for individual half-hourly settlement periods do not open up until close to real time. Price discovery is more complicated and more time consuming and is likely to reduce direct demand side participation. Industrial customers who do reduce demand, in response to market signals, face different risks under NETA.

One of the founding principles of NETA was an explicit desire to involve consumers more directly in the market. Experience to date – due to over-capacity - has been of very limited demand-side bidding practice. This however is probably mainly due to the large system over-capacity that currently exists, and the consequent lack of incentives for demand-side participation by large customers. NETA contains contractual possibilities that would allow much wider participation in demand side provision of short-term security if markets become more stressed.

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23 When compared to peak demand in a 1 in 50 winter. Information from NERA report, *Study to investigate the likelihood of firm load self-interruption in a severe winter*, May 2002

However, when offered an incentive, customers will respond. In the electricity market, customers respond to the triad signals and will reduce demand on a number of occasions to ensure a lower demand during the triads.[24]

Some industrial customers may find it difficult to reduce demand, on their own, using market signals, but will find it easier to act in conjunction with their supplier. In the gas market, industrial customers often have an interruptible contract with either their supplier or Transco. When requested, these customers would interrupt their consumption for up to 45 days per year. The customer receives a lower price for their gas overall, in exchange for some flexibility. The supplier then chooses to interrupt customers in response to price signals.

7.3.3. Conclusions

There is a market failure (related to the public goods issue of Chapter 6) that small consumers cannot participate actively in the market at times of system stress, due to information failures reflected in current metering technology. Whether or not there is then an overall problem for adequate security then depends on whether the more active participation of larger consumers can provide adequate responsiveness on the demand side. There is considerable activity in interruptible contracts in the gas market, while lower activity levels in the electricity market are mostly due to over-capacity and a lack of current need for active demand management. The materiality of this barrier to adequate security therefore seems unlikely to be very great.

7.4. Responsiveness – Supply

The main issue raised here concerns the responsiveness of the gas supply system in the short term. Under the old monopsony regime, contracts for field depletion specified a 'swing' factor, so that UKCS fields could raise output levels to 132% of normal production levels. This was a common feature of old gas field sales contracts. Under liberalisation, such provisions no longer apply, and firms are free to produce up to field capacity if they choose. In practice, most fields do now produce close to capacity most of the time, partly due to the greater opportunities for exporting gas. It is not clear that this constitutes a market barrier in the normal sense, though it could be argued that this is a source of increased risk due to the move from monopsony to a more competitive buying structure

The implication of the change is that there is a reduced ability in the gas supply system to increase production in tight market conditions. However, the ability to export gas (part of the apparent problem) is matched to an increasing extent by the ability to import, which in itself is an added source of security. More generally, whether or not this change in

[24] The triads are the three peak half hour periods in the electricity market. Individual demand during each of these periods is used to determine the annual capacity charges paid by customers to the electricity network operator for use of the network.

production profiles increases security risks depends on the capacity of other parts of the system, including demand-side responses in interruptible contracts, to provide sufficient response to difficult conditions. It is difficult to argue that this change in production profiles is a barrier to the market provision of security, nor is it clear (in the absence of full information about possible compensating changes elsewhere in the market, such as import prospects or storage) whether it is as yet a source of increased risk to security levels

7.5. Conclusions

For short-term system operation, a number of market failures are possible, including a lack of a market for demand-side participation in security in times of system stress and a potential lack of information that might affect system reliability.

In the case of small consumers, there is a clear market failure in their inability to participate in the market. However given the ability of larger consumers to participate, the impact of this barrier seems likely to be small in practical terms.

In the case of supply reliability or responsiveness, a lack of information about maintenance plans in a more fragmented market could constitute a market failure and so a potential barrier, but in practice there seems little problem. New production profiles for UKCS gas production in a more liberalised market are not in themselves evidence of a market failure, and there is no conclusive evidence that they represent a greater security risk than under the old monopsony regime.

8. INTER-RELATIONSHIPS BETWEEN GAS AND ELECTRICITY MARKETS

In this Chapter we discuss possible barriers or obstacles that may arise from the fact that gas and electricity markets are increasingly interdependent. The market barrier would be a lack of information shared between market participants in the increasingly complex market interactions between gas and electricity. The main areas of concern are:

- the possibility that simultaneous peaks in demand for both commodities may not be well handled by market mechanisms;
- the possibility that supplies of standby fuel (usually distillate oil) for CCGTs may not be available in the event of high gas demand, even if burning distillate fuel would be economic.

8.1. Simultaneous Peaks in Electricity and Gas Markets

Gas fired power generation now accounts for over 40% of power generation in Britain[25]. As a result, gas used in power stations now accounts for about 30% of the total gas consumed in the UK. Many of the older CCGTs buy their gas on interruptible contracts. This means that in periods of peak gas demand these power stations could be interrupted for up to 45 days to enable the gas to be supplied to those customers on firm contracts including residential customers[26]. In many cases these CCGT stations have standby fuel that means they can in principle switch to alternative fuels and keep generating electricity, at least for a time. This is important because it is likely that if there is a period of peak demand for gas (e.g. due to colder than normal weather) then this will occur at the same time as a peak demand for electricity.

The ability to switch from gas to alternative fuels also means that power station operators can, in principle, take advantage of movements in market prices to voluntarily switch fuels and sell natural gas into more valuable markets. Whether this happens in practice will depend on particular market circumstances and gas supply contracts but the technical flexibility is now there for this to happen.

NERA developed a dynamic model of the electricity and gas market to study the impact of a severe winter on the gas market for Transco. This model assesses the impact of gas and electricity demand over the 70 days of highest gas demand and optimises the use of gas and electricity to assess likely market prices for gas and electricity. We developed this model to

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25 In the second quarter of 2002, gas accounted for 43% of UK generation output. See DTI *Energy Trends* September 2002, Section 5 chart.

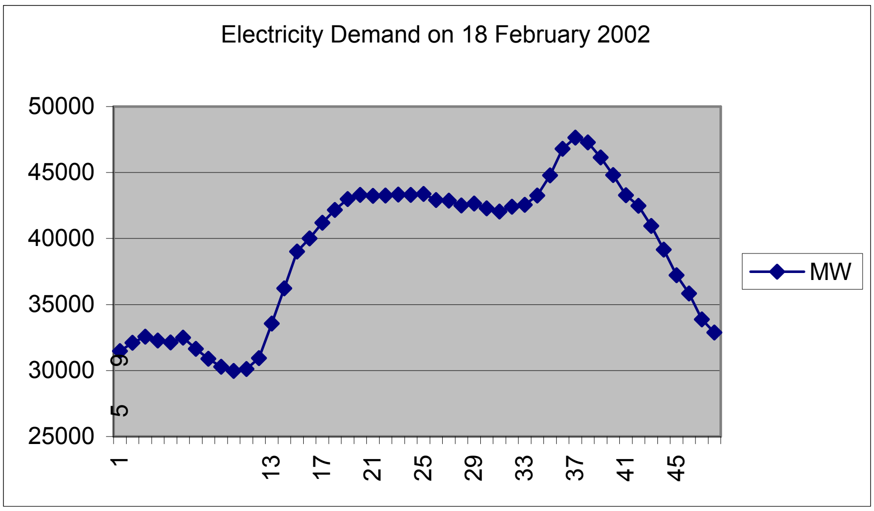
26 Historically, interruptible contracts have allowed for 45 days' interruption per year. Future contracts may be much more varied in the extent of interruption permitted.

evaluate a 'normal' winter and a 'severe' winter and then applied a number of scenarios to assess the short-term security of supply conditions. The model applies the supply and demand conditions for 2002, although it could be adapted for future supply and demand patterns.

One of the findings was that power station operators are potentially the most responsive group of gas consumers to high prices, which is important as they account for 15 percent of demand at peak. However, under normal circumstances[27] ("the base case") we found that generators do not curtail their demand because the market price for gas remains at a relatively low level, but their response is important in other scenarios we looked at. Generators are able to reduce their demand and sell gas into the market without jeopardising the electricity market, mainly because some stations are able to switch to alternative fuels (distillate).

Furthermore, at times of peak gas demand, gas generation is running on the margin within the electricity market cost merit order and is able to release gas during certain periods in the day (such as night-time or weekends) while still being available to meet the within day electricity system peak. We used a standard demand profile to estimate how much gas could be released to the system, by 2-shifting of gas stations without requiring gas to be replaced by other generation in order to meet electricity demand. The changes in electricity demand within a typical winter day are shown below:

Figure 8.1
Winter Electricity Demand in England and Wales



Source: BMRA data <www.bmreports.com>

[27] "Normal" here means that all available facilities in 2002 such as gas storage, UKCS gas production, the gas interconnectors, and power stations are operating as expected.

Even at times of more or less simultaneous peaks in both gas and electricity, gas fired power operators can still potentially sell gas to other parts of the market.

NERA has looked at a range of possible circumstances to test the flexibility of the market to respond and to understand the impact on gas and electricity prices in those circumstances.

The modelling indicated that gas and electricity markets appeared to respond flexibly to changing market demands and price movements. The modelling used 2002 supply and demand data and so is not necessarily a guide to how the market will work in future years when the supply/demand balance may tighten. It is important to emphasise that the results are from a modelling exercise. We have not seen a severe winter in the last 10 years to provide empirical evidence to support our results.

We have only discussed the interactions between gas and electricity markets in terms of power stations and the security of supply. It is likely that in times of severe weather, some customers, particularly larger customers, will also curtail their gas demand and electricity use[28] which will reduce some of the demand pressures on power generators. In particular, customers with interruptible connections to Transco's network or with interruptible supply contracts will experience interruptions to their gas supply.

In the time available we have not looked at the impact of future changes that might affect the results, for example a reduced availability gas from the UKCS as existing fields decline or increases in demand that may affect the ability of gas storage to meet peak gas demands.

8.2. Availability of Stand-by Fuels

An important assumption in this analysis is that power station operators will continue to have access to supplies of distillate oil when switching from natural gas firing. Fuel switching may well occur at times of severe weather, when the necessary road transport or rail links required to re-supply the power stations with distillate fuels could be affected by such weather. It is also necessary that the oil industry is able to respond to meet a rapid and possibly unexpected increase in demand for distillate oil. This might reduce the flexibility available to gas fired power station operators to switch fuels and maintain electricity supplies to the grid.

The amount of stand by fuel held at CCGT stations may vary but is likely only to be sufficient for much *less* than the 45 days that they could be interrupted for. They would therefore need to find new distillate oil supplies to replenish their fuel stocks in the event that they are interrupted for the full contractual period. We have not assessed the available volume of storage for standby fuels at particular power stations. Nor have we assessed the

[28] As part of the work for Transco we undertook a survey of industrial users to help understand the impact of higher prices at times of higher gas demand during severe weather periods.

volumes of standby distillate fuels that might be required if all power stations were to be interrupted for the full 45 days.

It would be prudent to make such an assessment to be able to: estimate whether the oil industry could supply such volumes; assess what impact these greater volumes might have on the price of such oil products; understand the impact of physically moving such volumes (probably by road tanker) to power stations at times of severe weather. The results of such an assessment should serve to further understand the degree of responsiveness that the gas and electricity industries might have in the event of severe weather.

8.3. Conclusions

Evidence of market failure in the interactions between gas and electricity markets seems limited. The problems that might arise from simultaneous peaks in gas and electricity demand seem likely to be small. The flexibilities in the market (especially the possibility of power stations switching fuel away from gas, and having a market incentive to do so) mean that risks to security seem likely to be limited.

The main qualification to this result might apply if it proved difficult to re-supply CCGT power stations with distillate if there were relatively long periods when power station operators wanted to switch away from gas. In the absence of recent evidence of severe weather coinciding with gas and electricity systems under stress, it is difficult to be certain of this conclusion. However this is an area worth further study, and if there are indications that stocks of standby fuels are low relative to risk, Government could consider a range of fairly direct remedies at relatively low cost.

9. INVESTMENT IN ELECTRICITY CAPACITY

9.1. Introduction

The role of markets in providing security of supply is perhaps nowhere a subject of greater concern in the UK than in relation to long-term investment in electricity.

The level of investment and production in electricity capacity depended on central planning by monopolies until 1990, and monopolies over retail customers did not disappear until 1998/9. During the 1990s, electricity generation did not suffer from a shortage of willing investors. However, with such limited experience of full scale competition, the definition of security of supply, and the means necessary to ensure it, remain matters of debate.

Competitive markets affect decisions about production of electricity (generation) at power stations and its consumption by retail consumers. A variety of wholesale markets now provide the conduit for consumers to call forth generation. However, the special features of the electricity sector suggest that closer examination is required before deciding whether or not markets will provide adequate security:

1. For technical reasons, supply and demand of electricity must be matched minute-by-minute, so it is important that investors build and maintain sufficient generation capacity to meet demand at all times, including times of peak demand.[29]
2. Investment in generation capacity has a long life, so investors (as well as traders and their consumers) need to consider the risks pertaining to different production methods, and to spread the associated production risks (either over diverse technologies within the electricity sector, or over investment in other sectors).
3. Physically, anyone connected to a network can take power without having a contract with a producer or supplier, so each network needs a centralised mechanism to impose a price on such "imbalances". The prices imposed by this mechanism underpin the market incentives to build and to maintain generation capacity.
4. The quality of electrical supply actually delivered to consumers has many dimensions (frequency, voltage, phase angle, etc) and depends upon a variety of services and investments arranged by the operators of each network.

The last of these items is only indirectly connected with competitive markets, since monopoly network operators play a large role in their procurement or provision.

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[29] It is often suggested that electricity "cannot be stored" but in practice hydro systems with "pondage" (ie reservoirs) perform an equivalent function. The UK has some "pumped storage" capacity in Wales and normal hydro resources in Scotland. Furthermore, the technology for storing electricity in batteries has recently made great progress, to the point where large batteries are verging on commercial viability in some uses. However, the contribution of these technologies to security of supply still relies on their *capacity* to deliver power when it is required.

Furthermore, investment and diversity depend heavily on the reaction of competing investors to the incentives provided by wholesale market prices – which depend on the prices imposed centrally on imbalances. Hence, the crucial incentives for investment in sufficient and diverse generation capacity depend upon non-market institutions. In these circumstances it may not be possible to rely for the efficient provision of security on general propositions about the properties of competitive markets.

9.2. An Electricity Market Paradigm

There exists a relatively simple market paradigm for the choices facing investors in the electricity sector. It can be compared with real market institutions in order to facilitate understanding. Originally, electricity sector planners developed it (or something like it) in order to drive central planning decisions, but the underlying economics can be adapted to include (in a simple fashion) the role of consumers and competitive markets. Appendix A describes the paradigm in some detail. The critical conclusion is that the incentive to invest in generating capacity depends crucially upon (1) the market price that prevails when some load is being lost, and (2) the expected number of hours in which load will be lost over the life of the investment. In Appendix A we explore the issues in more detail.

9.3. Real World Complications

The market paradigm described in Appendix A provides a reasonable indication of long-term trends in efficient investment and market prices, but at any one time the real world differs from it in a number of respects. These real world complications must augment any view of real electricity markets, but do not undermine the basic conclusion stated above, as the following discussion demonstrates.

9.3.1. Multiple technologies, including old plant

As mentioned in Appendix A, it is convenient to assume three sets of technologies and cost conditions in generation (base-load, mid-merit and peaking), but the real world offers a wider variety. The analysis can in principle accommodate any number of technologies but in practice only a small number will be relevant to future investment decisions. Many other technologies will be too expensive to be commercially viable investments (without subsidy), whilst some other technologies will be remnants of past investment decisions that would not now be repeated.

In the case of old plant, the market may achieve equilibrium by closing down plant when there is excess capacity. However, the cost of keeping old plant running is usually low relative to the cost of new plant, because investment costs are sunk. For this reason, it may be economic to keep old plant running, even if it uses a technology or fuel that does not now offer commercially viable investment opportunities. In these cases, the market finds equilibrium by *devaluing* existing investments, until the capital cost associated with the new asset value (as a component of annual fixed costs) is low enough to offer this technology a niche in the market. These old plants will affect electricity prices applicable to their market niche. Efficient investment in the future therefore depends in part on the legacy of investments inherited from previous years.

9.3.2. Uncertainty over availability and demand

The market paradigm assumes that generation capacity is available all year round at the same level. In practice, generation capacity will incur "forced outages" due to technical faults and may not be available to run when required to run for a least-cost despatch. Furthermore, demand in any one year is unpredictable, such that the number of hours of lost load in any one year will vary considerably. As a result of these random factors, capacity may prove sufficient to meet all load for several years, in which case prices never reach even lower values of the value of lost load (VOLL)[30] and even an efficiently built portfolio of generation will fail to cover its total annual costs. Such a period may be followed by a year in which a combination of unexpectedly high demand and simultaneous forced outages mean that capacity is insufficient – and prices hit VOLL – for long periods during that year.

9.3.3. Planned outages

Prices can also depend on the level of capacity available outside the hour of peak demand, because generators take their capacity off-line for weeks at a time, in order to carry out routine maintenance. Such planned outages normally take place in the summer, when demand is low, but may extend into the spring and autumn periods, when cold weather can raise demand unexpectedly. In these "shoulder" (mid-merit) periods, *available* capacity may sometimes be (close to) insufficient to meet demand and prices may rise accordingly. However, such price spikes signal a need to shift or curtail maintenance, rather than to build additional capacity.

9.3.4. Trading in advance

The market paradigm assumes hourly prices are set within the period concerned and does not predict the behaviour of market prices set in advance. In practice, most market prices involve contracts to deliver power in the future, so that the price is based on the buyer's and seller's expectations of the future value of electricity. All market prices for power delivered within a particular hour will tend to move in line with one another, due to arbitrage. However, since no-one can be sure when load will be lost, market prices tend to reflect a probabilistic estimate of the expected value of electricity in a future period. (Indeed, annual capacity payments may be regarded as a probabilistic assessment of the profit that generators are expected to earn from future sales at VOLL, given an average number of hours of lost load.) Expectations about future prices – and hence market prices for forward contracts – will be less volatile than the real-time value of electricity.

30 Bearing in mind that there will be different values of VOLL, depending on the customer, time of day, year etc.

9.3.5. Market dynamics close to peaks

The market paradigm assumes that prices reflect system marginal cost (variable costs) in all periods except those in which load is being lost. Theory and practice both suggest that prices may begin to rise above the system marginal cost, as demand gets close to the peak level, even though some capacity remains unused. This phenomenon can occur for a number of reasons:

- **Market abuses:** large generators may be able to exploit any market power available to them more effectively at times of high demand, because demand is less elastic then. Markets that suffer a high concentration of ownership in generation will experience such problems. However, the spread of ownership in 2002 in the UK generation sector, and the fact that much generation is covered by forward contracts means that this is not normally thought to represent a problem for competition.

- **Anticipating values:** many electricity markets (including NETA) require electricity traders to submit the prices relevant to real-time trading in advance. In a pay-as-bid system (such as NETA), generators will try to anticipate the market value of their output when setting their prices. If they foresee the *possibility* of outages, they may mark up their prices *towards* VOLL, as a way to capture the potential value of their output. Market prices will then exceed system marginal cost, even if demand does not in the event exceed capacity.

- **Non-collusive equilibria:** a number of studies[31] have shown that competing generators will mark up their prices (above variable costs) when demand nears the level of available capacity, because each generator recognises that at least *some* of its capacity may be *required* to meet demand. The potential for mark-ups depends upon the number of generators: the larger the number of generators, the less they can count on being required, and the lower the mark-up.

Each of these arguments will have more or less force in different electricity markets. They can result in pricing following a somewhat different pattern from that predicted in the market paradigm. However, the implications for investment incentives are hard to analyse without reference to the paradigm; compared with the prices predicted by the paradigm each factor may provide additional revenue (level unknown) in periods when demand is close to (but does not exceed) capacity. This additional revenue may encourage additional investment in peaking capacity, but that investment will immediately reduce the potential to earn additional revenue around peak times.

[31] The main exponents of this view in the UK are David Newbery (University of Cambridge) and Richard Green (University of Hull).

9.3.6. Market institutions

Real electricity market institutions differ from the market paradigm in a number of ways.

First and foremost, electricity markets settle trades for discrete periods – hours, half-hours, quarter-hours or five-minute periods, as the case may be. Conditions may however change more frequently, and prices for longer settlement periods may fail to capture the crucial periods when prices would otherwise be high enough to reward investment, or else they may over-compensate generators. For example, in some systems, a short-term loss of load lasting 15 minutes might set the price at VOLL for a whole hourly period, whereas the market paradigm would require different prices within and outside the period of load-shedding. Applying VOLL for a full hour, instead of 15 minutes, would overcompensate investment in capacity, by over-estimating hours of lost load. Alternatively, some markets will fail to set prices that reflect a short period of operation by a peaking generator, setting prices instead by reference to mid-merit plant that runs throughout the settlement period; such approaches would deny generators some reward for investing in capacity. The approximation inherent in using 'discrete' settlement periods means that real world pricing must be an 'inexact science'.

Second, the real-time pricing of "imbalances", which effectively determines the value of electricity in any period, may not apply the pricing rules assumed in the market paradigm. Some systems charge for imbalances according to a fixed tariff. Even where market designers tried to replicate the concepts of "system marginal cost" and VOLL, the rules may use a variety of proxies for a minute-by-minute market value, including prices set a day in advance, prices set at the start of the hourly trading period, and prices set according to an adjusted pattern of despatch, not the actual pattern. These approximations affect the level and pattern of market prices and hence the incentives to invest in capacity.

These real-world complications mean there is little purpose in insisting that electricity markets adopt every feature of the market paradigm. Instead, the market paradigm provides a framework for checking that electricity market institutions do not block the signals needed to encourage investment in generation capacity.

The characteristics of the NETA, and their implications for investment decisions, are considered in more detail below.

9.4. Effects on Incentives and Security of Supply

9.4.1. Market volatility and efficient incentives

The main implication of the market paradigm set out above is that investment incentives depend crucially upon the volatility of electricity market prices. Given that prices reflect variable costs of generation most of the time, prices must rise to very high levels during demand peaks to remunerate investments in peaking generation (and, in practice, all other kinds of generation). From the market paradigm, it can be inferred that attempts to smooth out volatility (by capping peak prices and raising off-peak prices to compensate) will distort investment incentives. Smoothing out volatility is equivalent to misleading investors into thinking that the load duration curve is somehow flatter than it really is. The result would be to encourage the construction of more base load capacity and less peaking capacity. On the other hand, demand is likely to become more "peaky" in response to smoothing prices. Hence, the matching of supply and demand is likely to become ever more inefficient. Price volatility in electricity markets therefore provides useful signals to investors and consumers.

However, there is probably a limit to the amount of electricity price volatility that is feasible, given the nature of non-market institutions in any country. During the (often short-lived) periods when load is being lost, the market price of electricity rises to VOLL. The valuation of lost load varies from one customer to another, but the need for load shedding means that at least some customers are either unaware of current price levels or face prices (such as fixed tariffs) that do not reflect the current value of electricity. VOLL is normally estimated to be a multiple of the market price applying at other times, which is determined by variable costs of generation. The old Electricity Pool, for example, used an estimate of "VOLL" of around 3 *pounds* per kWh to set prices at a time when system marginal costs were more like 2 *pence* per kWh on average. The Pool's estimate most likely reflected the cost to domestic customers of being forcibly cut off at the time of peak demand. At such times, customers would be hard hit, both by the loss of lighting (including public lighting) and by the possible loss of gas-fired central heating and other systems controlled electronically.

The Electricity Pool hid the disparity between system marginal costs and VOLL by spreading the value of lost load over many periods, through probabilistic, day-ahead pricing. Although this spreading smoothes volatility and distorts incentives compared with the market paradigm, there are good reasons to believe that attempts to impose the full degree of volatility on electricity market prices would be counter-productive, or at least highly risky for security of supply. These reasons derive from the possibility of "market failure" in the economic sense – i.e. the absence of markets that are essential for efficient production and consumption.

9.4.2. Market volatility and market failure

Some electricity markets outside the UK have already tried to apply the market paradigm without attempting to smooth the resulting volatility in pricing. Experience in these markets provides evidence that such policies are unsustainable and do not therefore provide the idealised incentives suggested by the market paradigm. Appendix C provides some useful examples of the problem and of the political or regulatory response to it. In particular, episodes in which short-term electricity market prices reach VOLL (or similarly extreme levels) provoke government or regulatory interventions to reduce prices.

The problem stems from the – inevitable and legitimate – existence of political and regulatory institutions with the power to affect electricity market prices. These institutions provide an alternative means for electricity consumers to influence the price that they pay for power – an alternative, that is, to building their own generation or freely negotiating power contracts. Consumers therefore face a choice over how they approach the possibility of generation capacity being insufficient to meet total demand, so that they face the risk of high prices and/or being cut off. They can either:

1. Pay VOLL when load is being lost; or
2. Build (or sign a contract for) a peaking generator at an annual cost of **Fp** and pay its variable costs **Vp** when it runs; or
3. Lobby politicians and regulators to cap prices when demand hits a peak and prices soar to the level of VOLL.

Note that building a plant or signing a contract may not affect the chances of an individual consumer being cut off, if network operators impose the outages. It is therefore possible to assess this choice solely in terms of the costs and the likely benefits of following each path.

Note also that shortages (episodes when prices hit VOLL) tend not to be scattered evenly through time. Because of the lumpiness of investment in generation, and because shortages tend to occur because of transitory shocks, episodes of shortage pricing tend to be concentrated within a few months and to be separate by many years.

For instance, suppose that peaking capacity has an annual capacity cost of £20/kW and that prices rise to a VOLL of £2/kWh during a shortage. This annual cost of £20/kW amounts to only £2.28/MWh *on average*.[32] In order to remunerate investment as per the market paradigm, prices would have to rise to VOLL for 10 hours per year. However, it is more likely that prices will not hit VOLL at all for several years in a row, and will have to catch up later within a short-period. For instance, suppose that prices never hit VOLL for three years, due to excess capacity; in the fourth year, the electricity market price would have to rise to VOLL often enough to provide revenue of £80/kW (i.e., four year's annual costs), which amounts to an increase in average prices of £9.13/MWh – tantamount to a 50% increase against current prices in wholesale electricity markets. Such a large increase in average wholesale prices would inevitably feed through to retail prices (or else retailers would risk bankruptcy, as in California).

Any consumer (or retailer) knowing how electricity markets work faces a choice. Option 1 exposes the customer to the risk of paying VOLL for energy at some future time. Option 2 substitutes the costs of a peaking generator (Fp, Vp), which is cheaper if the expected number of hours of lost load is high enough (as per the market paradigm). Option 3 however incurs only the cost of some lobbying, plus the cost of buying energy at whatever non-market price cap is likely to prevail.

32 £2.28/MWh = £20/kW-year divided by 8760 hours per year

In assessing Option 3, consumers will be aware that it is politically very difficult for legislators and regulators to justify generators earning VOLL for their output, and making large profits as a result, at a time when some customers are being forcibly cut off. The fact that the profits are needed to remunerate past investments in capacity is a complex argument to deploy and hard to prove. The occasional shortages required by the market paradigm are hard to distinguish from price rises due to market power or market dynamics (see section 9.3.5.). There is therefore a real risk that non-market institutions will intervene to cap market prices below the level of VOLL – and this has been borne out by experience in other markets.

The relative attractiveness to consumers of using non-market institutions to cap peak prices (rather than, say, a peaking generator) means that the peak-time markets for electricity needed to remunerate investment may simply never exist. The absence of key markets is the economic definition of “market failure” and it leads to the conclusion that market institutions by themselves will not achieve the full level of efficiency predicted by a theoretical market paradigm. This finding has important implications for policies aimed at security of supply in the electricity sector.

9.5. Implications for Policy

Given the possibility of market failure described above, there are two different paths that government policy towards the electricity sector can follow, to encourage efficient investment in security of supply:

1. **High Risk Market Paradigm** – This approach takes on board the lessons for pricing derived from the market paradigm and determines that prices will rise to VOLL when load is being lost. Government makes a commitment that it will not intervene to cap prices in a way that harms investment incentives. This policy creates the risk that the commitment is unsustainable and will be overturned whenever outages occur. To be credible, it requires strong institutional constraints on the ability of legislators and regulators to intervene in electricity pricing.
2. **Low Risk Institutional Solutions** – This approach accepts the inevitability of market failure and sets up non-market institutional solutions that avoid the conditions leading to market failure. All of these solutions work in practice by spreading the remuneration of capacity over a longer period (not just the hours of lost load), through mechanisms such as price smoothing (“LOLP.VOLL”,[33] as in the old Electricity Pool), explicit capacity payments (as found in Spain, Argentina and some other markets), or capacity obligations (a method favoured in the US that forces suppliers to invest in a certain level of capacity and prevents free-riding).

[33] ‘LOLP.VOLL’ – the multiplication of loss of load probability and the value of lost load - gave an extra payment to generators when the system supply/demand balance was approaching stress, but still contained some margin.

Governments are free to switch between these approaches at any time, but opportunistic switching will undermine investment incentives. For instance, a government that "smoothed" prices when they would otherwise be high, and then reverted to the market paradigm when they are low, would be systematically depressing power prices and undermining investment incentives. Either scheme therefore requires a degree of long-term commitment on the part of government, enforced through constitutional and procedural constraints on change.

The experience in other electricity markets suggest that it is extremely hard for regulators and politicians to resist pressure to intervene in electricity markets that suffer a rapid and large increase in prices. The potential for such intervention represents a barrier to security of supply, however, since it risks undermining long-term incentives for investment. The solution adopted elsewhere is to design market mechanisms and rules which, although they depart from the paradigm, promote more efficient investment by reducing the potential for intervention.

Below, we discuss whether NETA is subject to similar pressures, and whether the possible solutions are needed to ensure security of supply.

9.6. Evaluation of the Current Electricity Market

The old Electricity Pool represented a 'low risk institutional solution', since it adopted institutional solutions for smoothing prices through application of the "LOLP.VOLL" mechanism. The resulting distortion in incentives was one of the criticisms levelled at the Pool Rules. However, the New Electricity Trading Arrangements (NETA) are less simple to categorise.

NETA has no equivalent price smoothing formula, or capacity payments, and so it does not clearly fall into the category of institutional solution. Prices are currently settling around the level of variable costs which, given the extent of excess generation capacity, suggests that NETA functions rather like the market paradigm. However, it is difficult to say whether NETA will operate like the market paradigm if there is ever a shortage of capacity.

There are no formal rules in NETA for setting spot prices equal to VOLL (as found, for instance, in the Australian market and some others). Instead, prices for power sales will be freely negotiated in all markets, supported only by the fear of incurring a charge for imbalances. The incentives for pricing, and for building capacity, therefore depend ultimately on the pricing rules for imbalances. However, these rules are complex and there is little experience of their operation in conditions of system stress. Evaluation of NETA requires consideration of the following questions:

1. How will the prices of imbalances be determined in half-hours when demand exceeds capacity?

2. What kind of values can be expected for these prices, given the rules (which require traders to submit offers and bids at least an hour in advance, i.e. before an outage is observed)?

3. Will the resulting prices provide the sorts of incentives for investment in capacity that the market paradigm identifies as necessary?

4. Will the resulting prices be sustainable, given political and regulatory pressures?

Answers to these questions require detailed consideration of the rules of the Balancing Mechanism, its effect on contract prices and the likely behaviour of these rules and prices in times of system stress.

9.7. Contract Prices and Imbalance Prices in NETA

In a well-functioning, liquid electricity market, the competitive process of arbitrage will tend to keep the prices of all sources of electricity in line with one another. A lack of liquidity can sometimes allow price differences to open up temporarily, but systematic differences in price will attract traders, enhance liquidity and close the price gap by arbitrage.

The rules on imbalance charges play a crucial role in underpinning this process of arbitrage. A relatively small volume of energy passes through the centralised arrangements for real-time balancing and for ex-post settlement of imbalances. However, the provision of energy from centralised sources to close out imbalances represents an alternative source of physical energy. This alternative source affects the arbitrage choices available to producers, traders and consumers. If the imbalance settlement mechanism charges a high price for the electricity used to close their deficits, market participants will be prepared to pay a high price to build plant or to buy a contract, thereby reducing their imbalance. Conversely, if imbalance settlement provides a low cost source of power (e.g. because imbalance prices are capped), market participants will place a lower value on generator plants and power contracts, as alternative sources of power. These effects can impinge on investment incentives, and hence on security of supply.

9.8. Incentives for Investment in Peaking Capacity Under NETA

The market rules for imbalance settlement under NETA are particularly complex and have not yet been tested during a period of capacity shortage. It is therefore difficult to know with certainty whether imbalance prices will rise high enough during a shortage to remunerate (and hence to encourage) investment in generation capacity. The following factors (at least) will interact to determine the outcome:

1. During a shortage, many players will experience a deficit imbalance;

2. When the system is short of power, the price for deficit imbalances is the System Buy Price, which is derived primarily[34] from the prices that the system operator pays in the Balancing Mechanism for short-term purchases of power;

3. During a capacity shortage, any market participant selling power to NGC will be able to command a very high price;

4. Hence, in principle, the price for imbalances during a time of capacity shortage will rise to high levels;

5. Investors who anticipate such high prices for imbalances will be prepared to invest in generator capacity, or to pay high prices for contracts for the output from generator capacity.

However, this chain of cause-and-effect could be interrupted by a number of complicating real-world factors:

1. Players who happen to remain in surplus during the capacity shortage (because they fail to sell all their output on contract and choose to "spill" power) will receive a different, lower price,[35] and may therefore perceive a weaker incentive to add capacity. If the system operator balances the system by forcibly shedding load, some traders may find themselves with an unexpected surplus, because their demand has disappeared.[36]

2. The formula for the System Buy Price (SBP) "tags" some balancing mechanism trades as related to the transmission system, and not to a general shortage of energy or generating capacity. If the system rejects high price trades as exceptional outliers due to transmission system problems, imbalance prices may never rise high enough to remunerate and encourage investment in generation capacity. Any subjective element in the system operator's classification of trades and contracts would almost certainly undermines investors' confidence in the ability of NETA to remunerate investment through high imbalance prices.

3. Traders who sell power in the balancing mechanism must submit their prices at least one hour in advance. At that time, they may not anticipate a capacity shortage that emerges subsequently, in which case their prices will understate the value of their output. The SBP based on accepted offer prices will then under-remunerate

34 The System Buy Price also recovers costs of longer-term contracts that the system operator has incurred to manage deficit imbalances.

35 A recent modification of the Balancing and Settlement Code means that this price will in conditions of system stress be derived from indicators of current market prices. The extent to which these prices reflect the value of power in a shortage will of course depend on whether traders anticipate the shortage and the associated imbalance price for deficits.

36 The NETA rules make some allowance for lost load when calculating imbalances. However, even these rules would not deal with voluntary reductions in customer demand (eg, reductions inspired by public announcements about the likelihood of black outs).

investment in capacity. Alternatively, they may anticipate very high offer prices, because they anticipate a capacity shortage that does not materialise. These converse forecasting errors may produce occasional high prices that offset under-remuneration in other periods. However, NGC may "tag" these prices as transmission–related in order to eliminate such errors, especially if NGC fears (or reacts to) political complaints about high power prices.

4. Although capacity has a positive real-time value only when load is being lost and capacity is inadequate to meet demand, theoretical examinations of power markets suggest that prices will rise above fuel and operating costs when demand gets close to the capacity limit, because of the dynamics of power markets. (This phenomenon seems to have played a role in the California experience of 2000-2001, when prices reach relatively high levels even though capacity remained unused at the time.)

5. Even if NETA raises imbalance prices during a capacity shortage to levels that penalise traders who are short of capacity, investors may not respond if they believe that high prices were either a one-off event (now passed) or too unpredictable to be worth anticipating in future. It may take repeated capacity shortages (and outages) to motivate investors to invest in capacity.

Given the reliance of NETA on forward markets, the problems arising out of high short-term prices and the resulting short-term and long-term investment signals both deserve careful consideration, as discussed below.

9.9. NETA, Contracts and Possible Market Failures

In our electricity market paradigm, market failure arises out of the political difficulty of sustaining very high prices (equal to VOLL) at a time when the system operator is forcibly shedding customers' load. These problems create pressure for political or regulatory intervention in wholesale market pricing, if high wholesale market prices feed through to consumer prices, or if the high cost of wholesale market prices drives retail supply companies into bankruptcy.

The current electricity market in the UK possesses some, but not all, of the characteristics of a capacity obligation, such as is more directly built into some US markets (see below). NETA encourages all traders to sign contracts sufficient to cover their power sales some time into the future, in order to avoid imbalance charges. As a result, consumers' demand feeds through into a contract demand for generation capacity. Furthermore, the existence of longer term contracts protects retail supply companies from the financial burdens imposed by high imbalance prices, or by sudden price increases in other, short-term power markets.

However, the rules do not specify the reserve margin that retail suppliers must build into their contract portfolio, or how far ahead they must cover their position. As a result, they may be exposed to some price rises, particularly lasting price rises due to a change in underlying conditions.

Furthermore, the contracts between producers and retailers of electricity offer no protection to consumers, unless they also sign long-term contracts with their retailer. In practice, retail suppliers are unable to tie in small consumers for more than 28 days, due to the requirement that small consumers must be allowed to switch supplier at short notice. Consumers may therefore find that an extended period of high wholesale prices feeds through into high retail prices, even if their retail supplier is protected by long-term wholesale contracts with fixed prices, though the effect on retail prices is likely to be less than on wholesale prices as retail tariffs also reflect non-stress periods.

The introduction of retail competition (which is not so widespread in the US, for example) reduces the protection offered to consumers by contracts between electricity producers and retailers. Consequently, if NETA succeeds in raising wholesale prices during a capacity shortage, consumers may find themselves exposed unexpectedly. This exposure may prompt the kinds of regulatory intervention that creates market failure. It is not clear (due to lack of historical experience) whether political pressure to cap high wholesale prices will be a common or exceptional feature of the electricity market. If such intervention were rare (confined say to periods where Government might invoke a Fuel Security Period under sections 34 and 35 of the Electricity Act) then the risk of failure to provide sufficient investment incentives might be slight. However there is no way of currently knowing whether this will be the case, while it is clear that NETA is a market mechanism where substantial volatility of prices will be expected.

To minimise the likelihood that wholesale market prices will affect consumers, it is possible to impose a "capacity obligation" on retail supply companies, as found in many US electricity markets. In these cases, each retail supply company is obliged to sign contracts or to build generating plant sufficient to cover its customers' peak demand (plus a reserve margin) at some future date, say two years in advance. This rule has two distinct consequences. First, retail companies must build or procure generation capacity sufficient *to meet a defined level of security* – or else pay a fine for any shortfall. The level of the fine provides an incentive for investment in generation capacity (like imbalance charges). Second, the possession of real or contractual capacity *protects each retailer from the financial effects* of a rise in wholesale electricity prices. In principle, such protection can prevent high wholesale prices from bankrupting retail supply customers, or even from feeding through to consumers.

9.10. Forward Market Prices as a Signal for Investment

Although the prices for imbalances underpin every electricity market, decisions about long-term investment in generation capacity depend on investors' perception of future electricity prices. At any one time, the best indicator of these perceptions is to be found in forward and futures markets, i.e., in the markets where energy traders buy and sell contracts for power to be delivered at some future date.

Since 2000, electricity contract markets have expanded considerably, because NETA placed greater emphasis on possession of a contract than did the Electricity Pool, and because the wholesale market became much less vulnerable to the exercise of market power. At present, market reporters are able to report prices for contracts extending two or three years into the future.

9.10.1. Long-term investment signals

Provided that forward markets are reasonably liquid, the prices at which traders buy and sell forward contracts will encapsulate all the available information about the future value of electricity. If generators, consumers or traders anticipate that capacity will – or may – be short within the next two or three years, their estimate of the future value of electricity will rise. This expectation would in principle drive up the current price of forward contracts, indicating the need for investment in capacity. In recent years, it has taken about 2 years to construct and commission a new gas-fired power station, so forward markets extending two or three years into the future would indicate the value of output from a new power station at least in its first year of production.

In practice, of course, investment decisions depend upon a lot more than forward prices for the next two or three years. Any investor will expect a new generator to operate for 20 or even 40 years from its date of commissioning and there are currently no liquid electricity markets stretching that far into the future. Investors therefore have to make their own assessment of the value of the plant's output over its whole life. In doing so, they will take into account the prices at which power is likely to be available over the long-term from other sources, including other generators, other traders and (ultimately) through the settlement of imbalances. However, long-term forecasts of these factors are likely to be relatively stable, with prices being driven by the underlying costs of production. Given stable long-term price forecasts, investors are likely to place some weight on a short-term rise (or fall) in forward prices for the next two or three years, as providing a good indication that now would be a good (or bad) time to build new capacity.

This description of market incentives assumes, of course, that investors expect electricity to have a high value in the event of a shortage. If they believe that any rise in short-term prices is likely to trigger regulatory or political intervention in the market, forward market prices may not rise in anticipation of a shortage. (This problem for long-term contract prices merely follows from risks to short-term price signals, discussed elsewhere in this report.)

Even the efficient operation of forward markets does not rule out entirely the possibility of capacity shortages and outages. Indeed, an efficient market would be expected to accommodate a few hours of lost load, as per the market paradigm, in order to raise the average value of electricity sufficiently to remunerate capacity. (Only the prospect of such high values in short-term markets will raise long-term forward prices sufficiently to encourage investment.) These high price episodes will be most likely when conditions change faster than investors can react, given that it takes a minimum of two years to construct and commission a new power station.

9.10.2. Short-term price shocks

As stated above, today's forward market prices take into account the information currently available to traders. This information includes expected demand growth and other forecasts based on extrapolating recent experience into the future. However, energy markets can suffer shocks that lead to investors being caught without sufficient capacity or, equivalently, with too much capacity. For instance, suppose a commonly used type of generator experienced an unexpected "type fault", so that power station operators suddenly had to withdraw a large amount of capacity of that type. If they had not previously taken account of such a possibility, traders would suddenly perceive a much greater risk of a capacity shortage. They would increase their expectation of the future value of electricity and forward market prices would rise.

However, a "type fault" might take two years to repair. In that time, it would not be possible to construct and commission any new generation capacity. If investors did build new plant, they would most likely find it entered the market at the same time as the withdrawn capacity returned to service. Hence, it would face conditions of excess supply and low prices for the foreseeable future. Knowing that, investors would not respond to a temporary rise in forward prices by building new plant. Instead, they might only prolong the life of old plant that would otherwise have been retired, or bring back into service old plant that has recently been retired.

The flexibility offered by the timing of decisions to close existing plant provides some "cushion" against short-term price movements and helps to stabilise markets. However, a long period of low market prices would gradually eliminate capacity nearing the end of its life. Over time, plant that had already been closed would become less and less able to return to service. Hence, if a price shock occurred after a long period of low prices, the generation sector would exhibit less flexibility than it had in previous years. In these conditions, markets would be vulnerable to shortages and high prices for as long as it took to return old plant to service from a dilapidated state.

9.10.3. Foresight, mistakes and delays

Sudden shocks can hit energy markets at any time. If they occur frequently enough, they will enter investors' perceptions of future market conditions, in which case they will construct enough capacity to deal with shocks efficiently. However, if random shocks are infrequent, investors may dismiss each shock as a one-off event (like the "type fault" mentioned above) that does not affect their estimate of future market prices. Having faced a sustained period of low prices for some time, it may take a series of price shocks to convince investors that investment in additional capacity would be profitable.

A world in which investors dismissed occasional shocks and only reacted to repeated shortages might produce " boom and bust" cycles, in which prices remained low for long periods, until an unexpected change in conditions caused enough high price episodes to convince investors to act. Such cycles may appear undesirable from the point of view of security of supply, but are difficult to overcome if their cause lies in the way investors form expectations. Much depends on the frequency with which shocks (normally leading to adverse security impacts) will occur.

In all discussions of long-term investment in generation capacity, it is worth bearing in mind the irreversible nature of such investments. Option theory was developed some time ago to deal with similar cases, but took some time to become a practical analytical tool. Simply expressed, option theory says that investors will delay making an irreversible investment if they believe they can learn something about future market conditions by waiting. In the current context, investors may believe it wise to wait and see how NETA performs under conditions of capacity shortage, before committing funds to plant whose value depends upon that performance. If so, it may be inevitable that NETA has to undergo a period of *actual* high prices before the *prospect* of high prices (as reflected in forward markets) will encourage investment in generating capacity.

9.11. Possible Solutions

Trying to model investors' expectations, and the effect of different pricing schemes on the formation of expectations, is a notoriously complex problem. However, experience in other electricity markets does suggest that investors do not anticipate or avoid all capacity shortages. The market in Australia was caught out in 1998 by a sudden rise in temperatures, which increased demand for air-conditioning beyond the level that could be met. Similar factors contributed to California's problems in 2000. One can point to a number of other contributing factors (and, in California's case to a prohibition on the use of long-term contracts by incumbent supply companies) but in both cases the severity of the capacity shortage seems to have caught investors by surprise. It remains to be seen whether these transient events will foster any new investment by themselves.

There may be some merit in arranging the market and regulatory framework so that investors experience the impact of shocks more frequently and on an individually smaller scales, rather than being exposed to the full impact of shocks as they occur at relatively infrequent intervals. The grounds for this argument are that the former signals are more likely to create a stable perception of investment needs. Capacity obligations and other price-smoothing mechanisms (as discussed elsewhere) provide one means of subjecting traders to continuous pressure to maintain and to increase their capacity holdings, thereby creating a need for continued investment.

The contracting obligation encouraged by NETA, in conjunction with punitive imbalance charges, also exposes traders to a continuous stream of (relatively) small shocks. As capacity tightens, these small shocks may translate into a demand for investment. However, the creation of truly liquid markets would allow traders to avoid deficits until such time as capacity was actually insufficient to meet total demand. Hence, somewhat contrarily, the success of NETA in encouraging investment in generation capacity in the meantime may depend upon the maintenance of *illiquid* markets and frequent occurrence of deficit imbalances.

9.12. Possible Barrier

This discussion of NETA suggests that it is probably adequate to encourage investment in advance of anticipated increases in demand, especially if all investors become aware of an approaching problem. However, NETA does not provide any obvious means of dealing with transitory shocks, which suddenly create a shortage and send prices (wholesale and retail) soaring upwards. In these cases, NETA would be vulnerable to the threat of intervention by regulatory and political authorities. The anticipation of such intervention to cap prices has a dampening effect on investment incentives.

This problem seems to be endemic to electricity markets and underlies the various capacity payments and obligations that are used around the world to smooth out rewards for building capacity and to provide a more continuous stimulus to investment. As such, it seems to be a serious barrier to security of supply and worthy of further investigation.

10. INVESTMENT IN GAS CAPACITY

10.1. Introduction

Throughout Europe, the role of markets in providing security of supply in gas is becoming almost as much a subject of debate as in the electricity market. This debate has arisen partly because of growth in the use of gas for power generation, coupled with growing concerns about increased future reliance on gas imports and the need for adequate investment in the necessary infrastructure and storage.

Competitive markets affect decisions about production and supply of gas at gas fields in the UK Continental Shelf (UKCS) and may affect decisions about contracts for gas from more distant sources (e.g. Norway, the Netherlands, Russia, Algeria or the Middle East). In both cases there will also be a requirement for substantial investment in pipelines to transport the gas to the UK transportation system and hence the retail customer. A variety of wholesale markets either well established or in the process of being established act as the main means for customers to call forth production at any point in time.

However, as for electricity, the special features of the gas sector suggest that closer attention and analysis is needed before it can be established that market provision of security will be adequate:

1. For technical reasons, supply and demand needs to be matched, though not necessarily in the precise minute-by-minute way that is required for electricity. At present gas supply and demand is matched on a daily basis in Great Britain, though there are discussions about reducing the period to a few hours or even to an hourly basis. It is important that investors build and maintain sufficient production, storage and transportation[37] capacity to meet demand at all times, including at times of peak demand. However, unlike the limited storage available to electricity, gas can be stored in a variety of ways to meet both immediate peaks (e.g. on very cold winter days) and longer seasonal peaks (e.g. the winter period).
2. Investments in production facilities, storage and transportation have long lifetimes, so investors as well as traders and their consumers need to consider the risks pertaining to different production, storage and transportation methodologies. They need to spread the associated production risks either over diverse technologies or over diverse sources of gas within the UKCS and elsewhere, or over other sectors (particularly the electricity generating sector).
3. Physically, anyone connected to a gas network can take gas without necessarily having a contact with a producer or supplier, so the gas network needs a centralised

[37] Gas can be transported by pipelines or in a ship as LNG. Here, we are referring to both kinds of transportation.

mechanism to impose prices on any "imbalances." This mechanism will impact on the investment in new facilities.

4. The quality of gas supplied generally depends on a tight specification for the gas that enables it to be burnt in gas-using appliances and equipment without further treatment, plus requirements for a minimum pressure at the customer's premises to ensure safe delivery of the gas. There is not the same multi dimensional requirement for "quality" services as in electricity.

Investment and diversity depend on the reaction of competing investors to the incentives provided by wholesale prices. Imbalance charges tend to be punitive rather than market prices because imbalances are more controllable (i.e. slower to develop) than in electricity. Hence people invest to ensure they can maintain a balance.

However there are other reasons for being concerned that competitive markets may not be sufficient to provide security of supply for gas. In particular the requirement to ensure a safe and reliable supply of gas is more onerous for gas than for electricity. This is partly because of the inherent qualities of gas (for example the need to guard against gas explosions). After a forced interruption of supply, it is costly to restore the safe supply of gas to large numbers of customers, particularly small residential consumers because it is likely that for safety reasons, each customer would need to be re-connected individually. There is therefore a need to ensure a high degree of reliability for these customers.

Most of the impact of this need is felt in the security standards imposed on the transporter (Transco) to provide sufficient transportation capacity to meet both peak days and peak seasonal loads.[38] Transco as the system operator has both to invest in sufficient transportation capacity and to have sufficient gas supplies available to meet these security standards.

10.2. A Gas Market Paradigm

We developed a relatively simple market paradigm (Appendix A) for the electricity market that sought to illustrate the choices facing investors in the electricity sector. There is a market paradigm for gas that is not precisely the same as for electricity but shares several important characteristics (Appendix B). Originally gas sector planners developed the market paradigm or something close to it in order to drive central planning decisions for investment in pipelines and for gas supply to consumers. These planners turned to a variety of companies for investment in gas production, which unlike power generation has never been a monopoly activity. As for electricity, the underlying economics of this planning model can be adapted to include the role of consumers and competitive markets.

[38] This is expressed as failing to meet a peak daily gas demand that has a probability of occurring once in twenty years (the 1 in 20 peak day) and failing to ensure sufficient supplies to meet demands in a severe winter that has a probability of occurring once in fifty years (the 1 in 50 winter).

In the case of electricity we noted that there were complications that raised the possibility of not recovering the full costs of the whole system, thus preventing efficient investment from taking place. As a result capacity payments and other schemes were designed to augment energy charges and to provide alternative ways to remunerate the necessary investment. In addition it was noted that these costs could be so high that customers would be unwilling to pay for the very highest and shortest-lived loads. This led to a security standard that permitted a limited amount of involuntary load-shedding.

In the case of gas, the situation is rather different. First, as we have noted earlier, cutting off customers who expect firm service in (nearly) all circumstances (such as residential customers using gas for heating) is very costly, in the main because of the threats to safety. The prospect of "forced outages" or forced interruptions to supply provides a real spur to investment. The security standards stem originally from the experience of outages in the last severe winter (in 1962/63), but they play relatively little role in remunerating investments, since such outages remain extremely rare.

Second, the gas industry is able to interrupt a number of very large customers who can switch to other fuels, as well as having access to gas in storage. Gas markets drive up prices and customers respond by interrupting their loads (or being interrupted) to maintain the balance of supply and demand.

The flexibility offered by interruption has a number of implications for the recovery of the full costs of the investments, particularly peaking plant and to an extent the "mid-merit" seasonal storage facilities.

The problem in electricity as we noted is that customers would not pay the very highest prices needed to recover the full cost of building plant to meet the highest level of demand, which occurs only infrequently. In the case of gas, the price of gas rises as demand increases in more severe weather. If the price rose above the cost of alternative fuels, customers with dual firing may switch to these alternative fuels, hitherto more expensive than gas. Since the later 1990s, these interruptible customers include a significant proportion of power generators that have standby fuel and can readily switch out of gas. Although electricity demands are likely to peak at the same time as those for gas, that coincidence will only affect peak hourly periods rather than the whole day.

As firm demand rises further, suppliers would call first on the mid-merit seasonal storage and then on the peaking plant. If it appeared likely that demand would exceed the system's capacity to deliver gas (from gas fields, storage facilities and interconnectors), traders would anticipate a sharp rise in the value of their gas. This anticipation would drive up the value of gas currently in storage and hence the current market price. The market would be in equilibrium when the price rose high enough for long enough:

- to reward all investments in delivery capacity (including all forms of storage); and
- to prompt enough customer interruptions to balance the supply and demand of gas.

In the electricity market, our analysis recognised demand-response in the form of involuntary load shedding. This is an alternative method for balancing supply and demand that ranks alongside the power generation technologies. Shedding electric load has no fixed cost but a very high variable cost, approximated by the value of lost load (or VOLL).

In gas, demand side response is available in the form of the system operator's ability to interrupt a number of customers, together with the possibility of customers choosing to interrupt their supplies and switch to alternative fuels. At the extremes of the system, the key issue is one of deliverability. There is a limit on the capacity to carry gas from the main beach terminals to customers at the extremes of the system.

However, limitations on deliverability drive up prices until consumers ration their own usage to fit what is available. If deliverability is tightly constrained, prices rise high enough to remunerate investment in capacity.

10.2.1. Implications for gas market pricing

The implications of this adaptation become apparent when applied to a competitive gas market, given three key assumptions about the way in which competitive gas markets work:

1. **Producers, shippers, suppliers and storage operators will select the least-cost combination of output.** Given that fixed costs are unavoidable from day to day, producers will minimise variable costs by running only base load plant when demand is low, calling on mid-merit plant only when demand rises above a certain level and using peaking plant only in the rare hours when demand approaches the maximum. Producers will continue to serve demand as long as they have capacity and deliverability. Load-shedding will only be necessary if demand would otherwise exceed the system's capacity to deliver gas. However, self-interruption may occur at lower levels of demand, when prices rise to the cost of using alternative fuels.

2. **Market prices will settle at opportunity costs** - the marginal cost of the most expensive producer or storage option or customers' willingness to pay. Competition normally drives down prices to marginal costs and the gas sector is no exception to this rule, although the marginal costs for the market (or "system") will be determined by the plant type with the highest variable cost that is called upon in the least-cost combination – or customers' willingness to pay.

3. **The existence of storage complicates the formation of prices, but does not change the fundamental principles**. Outside peak times, the *opportunity cost* of using gas is the value it might otherwise command at peak times. Arbitrage will therefore extend peak time prices into some other periods – enough periods, that is, to dampen total demand for gas sufficiently to ensure that gas remains available at the peak.

In a gas market, the incentive to invest depends crucially upon the market price that applies when load is reaching its peak, and the expected number of days in which load will be at that level over the life of the investment.

10.3. Real World Complications

The market paradigm described in Appendix B provides a reasonable indication of long-term trends in efficient investment and market prices, but the real world differs in a number of ways. These real world complications must augment any view of real gas markets, but do not undermine the basic analysis given above, as the following discussion demonstrates.

10.3.1. Multiple technologies, including old plant and facilities

As mentioned above, it is convenient to assume three sets of technologies and cost conditions in gas production and storage, but the real world offers a wider variety. The analysis can in principle accommodate any number of technologies but in practice only a small number will be relevant to future investment conditions. Unlike electricity, there are probably fewer new technologies that will be too expensive to be commercially viable (without subsidy). 'Exotic' sources of gas (e.g. speculative future developments such as hydrides or very deep accumulations) might be one example, whilst some other technologies (e.g. Rough field storage) will be remnants of past investment decisions that might or might not now be repeated.

In the case of older production and storage plant, the market may achieve equilibrium by shutting-down facilities when there is excess capacity. However, the cost of keeping plant running is usually low relative to the cost of new plant, because investment costs are sunk. For this reason, it may be economic to keep old plant running, even if it uses a technology that does not now offer commercially viable investment opportunities. In these cases, the market finds equilibrium by *devaluing* existing investments, until the capital cost associated with the new asset value (as a component of annual fixed costs) is low enough to offer this technology a niche in the market. Efficient investment in the future therefore depends in part on the legacy of investments inherited from previous years.

10.4. Uncertainty Over Availability and Demand

The market paradigm assumes that production, storage and transportation capacity is available all year round at the same level. In practice, such capacity will incur "forced outages" due to technical faults and may not be available when required. Furthermore, demand in any one year is unpredictable, such that the number of days of interruption in any one year will vary considerably. As a result of these random factors, capacity may prove sufficient to meet load for many years, in which case prices never reach the highest prices determined by the costs of LNG peaking plant and customers' willingness to pay. Even an efficiently built portfolio of production and storage will then fail to cover its total annual costs. Such a period may be followed by a year in which a combination of unexpectedly high demand and simultaneous plant or facility failures equivalent to forced outages in electricity mean that capacity is insufficient – and prices hit higher levels – for long periods.

10.4.1. Planned maintenance

Prices can also depend on the level of production storage or production capacity available outside the day of peak demand, because producers and storage operators take their capacity off-line for periods from a few days to weeks at a time, in order to carry out routine maintenance. Such planned maintenance periods normally take place in the summer, when demand is low, but may extend into the spring and autumn periods, when cold weather can raise demand unexpectedly. In these "shoulder" (mid-merit) periods, *available* capacity may sometimes be (close to) insufficient to meet demand and prices may rise accordingly. However, such price spikes usually provide an incentive to shift or curtail maintenance, rather than to build additional capacity.

10.4.2. Trading in advance

The market paradigm assumes daily prices are set within the period concerned and does not predict the behaviour of market prices set in advance. In practice, most market prices involve contracts to deliver gas in the future, so that the price is based on the buyer's and seller's expectations of the future value of gas. All market prices for gas delivered within a particular day will tend to move in line with one another, due to arbitrage. However, since no one can be sure when load will be lost, market prices reflect a probabilistic estimate of the expected value of gas in a future period.

10.5. Market Institutions

Established gas market institutions may not replicate the market paradigm for gas perfectly, but they do mirror the broad structure discussed above. For example there are well-established and reasonably liquid markets for trading gas, both at very short notice and in longer-term futures contracts. Imbalance trading through the On-the-day Commodity Market is now working reasonably well. There is a market mechanism for selling gas storage capacity as well as a mechanism for secondary trading of that capacity.

These mechanisms have so far been able to signal the need for investment in production and storage facilities[39] or for longer term supplies from outside the UKCS.

This picture of reasonably functioning market mechanisms would appear to contrast with issues arising from the working of the electricity market arrangements.

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39 Offshore gas investment has exceeded £1 bn. in every year since 1990. See JESS *First Report* June 2002, p.29.

10.6. Practical Implications for the Security of Supply

10.6.1. Investment in the UK

The main implications of the market paradigm set out above and in Appendix B is that investment incentives depend crucially upon the market price of gas that applies during the (often short-lived) periods when load is at its peak. At such times, the market prices rise to the value of the marginal source of gas at the peak, that is LNG or voluntary interruptions by customers (often driven by prices of alternative fuels). However it is also important that the price of gas signals sufficient investment in base load provision of gas supply as existing production begins to decline.

The NERA model of the gas and electricity markets showed the limits to rising gas prices at times of peak demand because of the flexibilities in the gas system. In particular, the ability to interrupt customers, or for customers to switch to alternative fuels as prices rise to levels above the cost of theses alternative fuels, limits the potential for gas prices to reach multiples of the normal level during a shortage.

This model only looks at market responsiveness in a particular year and not at longer term effects of the reductions expected in UKCS production as existing fields are depleted. However there appears to be no clear evidence that the market mechanisms lack incentives needed to encourage investment in production or storage facilities in the UKCS or onshore. There may be other barriers, such as difficulties with planning permission (Chapter 15), that may delay new storage investments but there seems little evidence to suggest that the market signals are inadequate.

As to operational security, the analysis of the market paradigm and the results of NERA's modelling work indicate a sufficient degree of flexibility for dealing with such security risks.

10.7. Conclusions: Differences Between Electricity and Gas

Although the market paradigms appear similar for electricity and gas, it is worth stressing the differences in conditions that affect their chances of success.

In electricity markets, the remuneration of investment in generator capacity hinges on the prices paid during times of capacity shortage. In most real-time electricity markets, prices rise during a shortage by one or two orders of magnitude, because of the great difference between (1) the variable (fuel and operating) costs of generation and (2) the value of lost load to consumers. Furthermore, the relative costs of generation and shedding load are such that load shedding is a normal and comparatively frequent part of electricity system operations.[40] The market paradigm therefore predicts comparatively frequent periods when customers are being cut off, whilst investors and power traders are making their largest profits. Such a combination is potentially divisive in political terms.

In the gas market, similar pressures apply, but the outcome is much less polarised. On the one hand, forced outages are so disastrous to the gas sector (i.e. it is so expensive to restore supplies safely) that they are avoided on all but the rarest occasions.[41] However, the practice of voluntary or pre-arranged customer interruption is widespread and normal, since many customers are able to switch to an alternative fuel (such as distillate or heavy fuel oil) when the cost of serving them rises above a certain level. The availability of alternative fuels puts a cap on gas market prices at such times. The availability of some gas storage also helps the overall flexibility of the market at times of system stress. Since competition keeps the prices of all hydrocarbons within a *relatively* narrow range (in terms of £ per unit of calorific value), the price cap imposed by alternative fuels is not much higher than normal gas prices (i.e. one to thee *times* higher, rather than one or two *orders of magnitude* higher as in the electricity case).

As a result, at times of peak demand, gas prices tend to rise to the level at which some customers replace their demand for gas with demand for alternative fuels. The gas system remains in balance – in that all customers willing to pay the current price are served – and the profits of gas producers – whilst higher than at other times – do not appear to be grossly out of line with costs. As a result, the potential for gas prices to invoke a political reaction is less than for electricity prices. The *mechanisms* are the same in both markets but the chances of an equivalent *degree of market failure* are much lower for gas than for electricity

[40] This statement does not mean that frequent system blackouts are normal, or that all consumers should expect to be cut off at frequent intervals. To balance supply and demand, the system operator may only have to cut off a small number of customers at any one time, and can rotate the incidence of such outages if they recur. Individual customers should therefore experience outages only infrequently. However, an efficiently planned system should expect to experience load shedding of some magnitude for a few hours per year on average.

[41] As far as we are aware, the last known incidence of large-scale forced outages due to inadequate gas supply occurred in 1963, since when planning standards have been thoroughly revised to improve security of supply.

High prices in gas and electricity markets may still provoke concerns about competition policy, because market dynamics make it hard to distinguish the effects of real capacity shortages from the exercise of market power. However, the conduct of competition policy relies on more predictable and technical appraisal processes than would apply to political interventions. Thus, although high prices may provoke an investigation by the competition authorities in either gas or electricity markets (and have done so in the past), the prospect of political intervention has more serious implications for investment, and affects electricity markets more than gas markets.

11. MARKETS AND DIVERSITY: ELECTRICITY

11.1. Diversity: a General Introduction

Diversity is a central topic in any analysis of security of energy supply. The idea of diversity is pervasive in security debates. Recent Government policy statements about security have been framed largely in terms of encouraging diversity.[42] It is based on the commonsense premise that, diversification is a good generic means of tackling risk, including risks which are difficult to anticipate in any specific way- it is a good general hedge against uncertainty. This chapter and the next two chapters consider different aspects of diversity.

Like other approaches to security, diversity is not universally beneficial for security nor does it generally come free of cost. Increased diversity could increases security risks, for instance by partially replacing a reliable technology with an unreliable technology. It will then not contribute to security. Equally if diversity involves large costs relative to reduced risk, it will also fail to contribute to adequate security levels.

While some argue that competitive markets will fail to produce ‘enough’ diversity, it is difficult to know how much diversity, and along which dimensions, is adequate. The nature of the market failure is also not always plain. Markets, it is argued, will tend to produce ‘herd’ behaviour, with all or nearly all investors choosing the same kinds of fuel for investment, or taking imports from a limited number of sources. However this is not really a market failure argument. If investors did all choose the same fuel or technology for a while, this could be rational reaction to uncertainty, or to the overwhelming economic advantage of a particular choice. Pursuit of more diversity in these circumstances could lead to very high costs and involve over-providing security. However there may be a genuine market failure argument in relation to facility dependence in gas, to which Chapter 12 returns.

Whatever the precise nature of the market failure, it is important to consider diversity arguments and the record of markets in relation to diversity. This Chapter and Chapters 12 and 13 consider different dimensions of diversity.

11.2. Types of Diversity

Much of the UK debate on diversity has focussed on electricity and on the choice of primary fuel for electricity generation. Diversity has not been a major issue in respect of transport, where oil is almost totally dominant, or domestic space heating, where gas has a dominant market share.

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42 See for instance DTI and Scottish Office *The Prospects for Nuclear Power* Cm 2860, May 1995 and DTI *Conclusions of the Government's Review of Energy Sources for Power Generation and Government Responses to the 4th and 5th reports of the Trade and Industry Committee* October 1998

However, besides fuel choice for electricity generation, diversity may be also be important in relation to:

- Fuel source (including transit routes), as different sources may carry different risks
- The number of companies in a market, given the potential for 'monopoly' decision-making under state monopoly systems
- Technology types and sources, given the possibilities of generic failure either of technology types or the specific versions of technology common to one company

All of these types of diversity are in principle important.

The existence of more players in a competitive market than under monopoly is itself an increase in diversity, and therefore liable in itself to help security

11.3. Diversity in Electricity Generation

The market paradigm of Chapter 9 suggests that the optimal portfolio of electricity generation capacity will contain a variety of technologies. However, in recent years, many commentators have noted the so-called "dash for gas", i.e. the observed tendency of private sector investors in a competitive market to favour CCGT technology over all others. Readers may therefore ask whether the diversity predicted by the market paradigm will emerge through market mechanisms, or whether private investors are more likely to "follow the herd".

In principle, investors may react in this 'herd-like' way, because they take comfort from each other's choices (even if those choices are sub-optimal). However, there are other reasons to believe that common patterns of investor behaviour are consistent with market pressures for diversity.

First, the replacement of coal-fired generators with gas-fired generators will, by many definitions of the term, have increased diversity in the stock of generation capacity in Britain. In 1990, nearly 80% of generation came from coal-fired generators, the great bulk of it supplied from British coal mines. Investment in gas-fired plant (along with an increase in coal imports) has reduced dependence on this "single" source of fuel, thereby reducing risk.

Second, although the market paradigm predicts that investors will create a diversified portfolio of generation, it says nothing about who will own what capacity. There is no reason to expect individual companies to limit themselves to one kind of plant and, indeed, they may want to diversify their own portfolio to the same extent as the whole market. As a result, if market incentives suggest that investment in gas-fired plant is required, one might expect to see all major power companies participating in this trend.

Hence, the observed tendency to invest in gas-fired plant may be a reaction by all companies to rebalance their portfolios in favour of gas and to become less dependent on generators fired by (British) coal. The result has been an increase in diversity, which should not, by and of itself, create concerns that the tendency will continue unabated, or that investors will make themselves so dependent on a few sources of gas that security of supply is compromised.

Finally, the rise of the CCGT has led to diversity in technology type as well as fuel. It has also added to diversity in technology source, as there are three major international competitor firms supplying CCGTs (or the gas turbine parts of them). This means that a type fault in one manufacturer's plant is unlikely to affect those of the other two. This kind of diversity helps security.

11.4. Storage

Because electricity is difficult to store cheaply, an important source of potential flexibility in system operation, useful for security, is not easily available. Some storage already occurs on the system through the use of pump storage. In the future, some storage could occur through flywheels, batteries etc. It is unlikely that large-scale commercial storage of electricity is likely for the foreseeable future, although recent technological developments in the UK are opening up the possibility that large batteries might supply consumers in some instances. Research work is proceeding on power storage systems, for example the Regenesys technology.[43]

Although electricity is difficult to store, storing the fuel used to produce electricity can enhance security of supply. The main fuels for electricity generation are coal, gas, and nuclear power. (Gas storage is dealt with in Chapter 12). Nuclear power can easily and cheaply store its fuel and storage of coal is also relatively cheap

Typically, each coal-fired power station will retain stocks to cover a number of days electricity production. In periods of emergency, the Government can specify stock levels through the Fuel Security Code. The ability to store coal protects against some failures in the delivery of coal to power stations, thereby also providing some security of supply in electricity. However, the level of coal stocks that generators would choose to hold on commercial grounds at power stations is unlikely to be sufficient for a prolonged interruption to coal delivery. However it is difficult to view this as a market failure.

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43 This is being developed by Innogy.

11.5. Wider Diversity Issues

However there are diversity issues connected to the interactions of gas and electricity. While the dash for gas has made the electricity market more diverse, rather than less diverse, the increasing use of gas in electricity has made the whole energy economy more dependent on gas than ever.

In 1990 gas constituted 24% of total primary energy use[44]. By 2000 this had reached 43%, mainly as a result of the increased use of gas for electricity generation. Most forecasts are for further increases in gas dependence across the economy.

The PIU Energy Review, for example, in considering a quite wide range of energy scenarios for 2020 concluded that in all scenarios gas use would probably be a higher proportion of primary energy in 2020 than in 2000.[45] This may or may not be bad for security levels – depending on the balance between the costs of diversifying into other fuels and the security benefits that would be obtained as a result. The basic question is whether or not it seems reasonable to believe that rising gas dependence leads to serious new security risks with high enough expected values to justify major new intervention and investment. This partly depends on the risks associated with future gas supply, and especially imports, which we analyse in Chapter 13. We look briefly at the issue of long-term gas dependence in the whole economy in the long term (though this is slightly beyond our terms of reference) briefly in Chapter 18.

11.6. Conclusions

Diversity is a wide-ranging issue and has many different dimensions - fuel type matters but is only one among several important dimensions. Along a range of diversity dimensions for electricity – number of companies, fuel diversity in electricity, technology diversity, technology source and sources of fuels – diversity has increased under liberalisation, and the signs are that the market is managing diversity well. However the overall diversity of fuel type in the energy economy *as a whole* has declined at the same time that diversity in electricity has increased and we return to these questions in Chapter 13 and 18.

[44] Department of Energy *Digest of UK Energy Statistics* 1991, Table 2, p. 13.

[45] Performance and Innovation Unit *The Energy Review* February 2002, Chapter 5. Cabinet Office

12. DIVERSITY AND GAS: UK ISSUES

12.1. Introduction

Gas is perhaps the focus of the greatest concerns in public debate about security and diversity. Chapter 13 considers international issues, including imports of gas, where there could be barriers to achieving adequate security due to the possible unreliability of overseas suppliers, transit routes etc. This Chapter deals with two issues connected to diversity that might appear to be barriers to adequate security. One is the issue of facility dependence (or concentration) within the UK, where a possible market barrier is explained. The other is about storage and the possible inadequate provision by markets of storage, given the potential importance of storage of gas as a way of providing a form of security analogous to diversity, especially if gas terminals were to fail.

12.2. Facility Dependence

The finite nature of delivery routes for energy products into the UK market is important for security of supply. The UK gas market, and hence much of the electricity market, relies on 6 onshore gas terminals to supply all the gas required by the UK as shown below.[46] While 6 may seem a relatively large number of terminals, some 60% of all gas landed in the UK comes through Bacton and St Fergus. Any incident, which affected the availability of a substantial proportion of these terminals' capacity for any significant period of time, particularly during the winter months, could have serious security consequences. This leads logically in to the question in the other section of this Chapter (gas storage) – if any terminals were to fail, gas storage could mitigate some of the effects.

NERA has used its model of the gas and electricity market to model the impact of a number of scenarios. We found that the gas system was flexible enough to deal with any of the eventualities we modeled *except* the cessation of inflows at Bacton. (We did not consider events involving the simultaneous loss of two separate facilities, but such events are unprecedented.) The loss of Bacton would currently make it impossible to supply all firm gas demand.

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[46] In addition to the terminals shown in the table, there is a privately owned terminal at Point of Ayr for which there is no publicly available data.

Table 12.1
UK Gas Terminals

Terminal	**Number of Sub Terminals**	**1:20 Peak Entry Capacity (GWh/d)**	**1:20 Peak Entry Capacity as a % of 1:20 peak day demand**
Bacton	3	1237	21%
Barrow	1	634	11%
Easington	2	373	6%
St Fergus	5	1385	24%
Teesside	1	432	7%
Theddlethorpe	1	409	7%
Total supplies from beach			76%
LNG			6%
Storage			18%
Total			**100%**

Source; OFGEM

What market failure might there be to suggest that the degree of concentration of terminals might be too high and lead to inadequately low security? The problem in market failure terms could be as follows. Sub-terminals are added to hubs like Bacton and St Fergus incrementally. From the perspective of the latecomer, the costs saved by locating at one of these locations rather than elsewhere are large enough to outweigh any security risk to that firm as a result of facility concentration. Earlier investments at terminals would have been undertaken at a point where facility concentration was less, and the early investors' perceptions of risk would have been equivalently less. This is a possible externality arising from the fact that decisions have been incremental, and early investors were unable to appraise the extent of risks that would eventually arise from later expansions of the terminal and the potential security vulnerability that would arise as a result.

We are not in a position to judge the significance of this externality. From an economic efficiency perspective, such concentration of terminals and sub-terminals is often seen as important, indeed critical to the development of gas "trading hubs". The fact that a number of processing, pipeline and terminal facilities are concentrated in one place means that market players can more readily trade gas and pipeline capacity and enable a deeper and more liquid market to develop. This has happened in the gas market all over the United States. In Europe such "hubs" are only gradually beginning to emerge and they are likely to be important to overall efficiency in the gas market. Such moves are generally evidence of markets working well.

These advantages would need to be set against any negative externality arising from the degree of facility concentration now apparent, but probably not considered by early terminal investors. From a security perspective, therefore, further concentration of supplies at either St Fergus or Bacton may be questionable, because of the consequences of any incident affecting a large proportion of transmission or processing capacity. This is recognized in the 2002 *Energy Review,* in its statement that: "*...the government should consider whether existing* *terminals are the right location for future developments."*[47] *If* this market failure does constitute a material market failure and barrier to the market provision of adequate security, it would seem appropriate to act on it directly using the planning system to direct new pipelines to alternative landfalls. At present, a marginal addition of a further terminal and/or pipeline connection is most likely to be granted and will be likely to be more cost efficient than a plant in another location.

The issue of facility dependence highlights the issue of how events of low probability but high consequence are handled in the liberalized system. The legal and regulatory framework in Britain lacks any specific policy or regulatory instrument, which might prevent concentration of transportation or processing infrastructure at a particular location. Planning for such low probability/high consequence events is somewhat different in nature from the generalized response planning which the UK's Gas Emergency Committee is undertaking. The Committee is putting in place plans, which set out how market players will curtail and then restore supplies to consumers in the event of an emergency:

- identify and model the impact of specific security events, e.g. the loss of a major receiving terminal such as Bacton and St Fergus for a specified period of time;
- judge the severity of the impact of these events on groups of customers and on the basis of that judgment; and
- decide what type of specific obligations needs to be placed on market players to ensure that supply curtailments arising from these events are minimized.

12.3. Possible Inadequacy in Gas Storage

Storage provides a potential substitute gas source if supply from a terminal or elsewhere were disrupted. Those who argue that markets may fail to provide 'enough' storage often point to the much larger storage facilities in major consuming countries like France, Germany and Italy

Different storage facilities provide different withdrawal rates and hence different contributions to security. LNG (liquefied natural gas) has the highest withdrawal rates and is designed to provide large volumes of gas for rapid delivery into the system, though the duration of the resulting enhanced supply levels is limited. Depleted gas fields and salt caverns also provide storage sites. In general they have a larger total volume, but slower withdrawal rates. They are more suitable for use in seasonal modulation (depleted gas fields) and management of foreseeable peaks in demand (salt caverns), rather than dealing with short shocks to the system. Storage facilities in the UK are also vulnerable to delivery route interruptions. The storage facility in the Rough gas field is located offshore and gas is

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47 Performance and Innovation Unit *The Energy Review* February 2002, the Cabinet Office, Chapter 4.

delivered from the site via the Easington terminal to the onshore network. Failure at this terminal would also interrupt withdrawals from the storage site.

Current levels of storage are designed primarily to provide sufficient levels of storage to meet fluctuations in demand (in particular, demand expected in severe winter weather) as well as more normal seasonal and daily variations in demand. There are no regulatory requirements to specifically provide storage to meet extended periods of delivery failure, though Transco is required to meet specific planning standards to deal with peak demands on particularly cold days and to meet severe winters.[48]

Contrast is sometimes drawn between the large storage capacity in some other European countries and the UK's more limited storage capacity (Table 12.2). In Europe there are wide variations in the provision of gas storage. Some of this variation can be explained by past decisions to provide for extended periods of delivery failure. Some European countries in the 1970s and 1980s constructed gas storage facilities with the specific purpose of providing gas in the event of a major delivery failure. These were constructed under state or private monopoly conditions in countries with very high gas import dependence, and partly reflected perceptions of political risks related to gas supplies from the USSR/Russia. As a result the proportion of gas consumption that can be held in store varies considerably as the Table 12.2 demonstrates.

The three major gas importing countries (France, Italy and Germany) have about 20% to 25% of annual gas consumption potentially in store compared to less than 4% in the UK. An alternative measure is the number of days of consumption that can be held in storage. A recent study showed that the "equivalent demand days of consumption" was between 80 and 95 days in Italy, France and Germany compared to 13 days in the UK[49]. In each of these countries there is a significant degree of import diversity as measured by the proportion of gas imported from different countries. The number of import entry points in each country varies but is comparable to the number of gas reception terminals in the UK (there are 6 such terminals in the UK). On the surface it is not possible to conclude that there is an obvious relationship between import dependence, the number of entry points and storage capacity. Indeed liberalisation of European gas markets could make this storage available for cross-border support.

The major continental European countries have the ability to withstand curtailment for months (and in some cases years) of any of their major supply sources, without cutting off firm customers. This is not to argue that UK gas security is *necessarily insufficient,* simply that attempting to claim that it is superior to that of major continental European countries is probably untenable. Any claim that liberalization *demonstrably* improves security of supply

48 The so-called 1-in-20 peak day and 1-in-50 severe winter period.

49 The Brattle Group "Convergence of Non-Discriminatory Tariff and Congestion Management Systems in the European Gas Sector" Report for the EU Commission September 2002.

should be made with great care, unless the particular circumstances of this improvement are carefully explained.

The fundamental principles on which liberalized and competitive markets are based are cost reduction and increased efficiency, whereas in the traditional European gas market a fundamental principle was the assurance of absolute security of supply at unknown, but probably very high, cost. The claim that a liberalized and competitive British gas market can make is not that it is *more secure* than a less liberalized continental Europe, but that it *offers acceptable and efficient levels of supply security at much lower cost* than less liberalized markets.

Storage is in any case not the only way to secure consumers against delivery risk. There is a considerable capacity for suppliers and Transco to interrupt large industrial customers who have the facility to switch to alternative fuels at short notice. More importantly, around 25% of gas-fired power stations now have distillate firing capability (see also Chapter 8). A reduction of 25% in the demand for gas for CCGTs, achieved by substituting distillate fuel (combined with increasing production from coal-fired power stations) would provide a large volume of gas for the UK market and help the system to balance in times of gas delivery failure.

Table 12.2
Gas Storage Facilities in Europe as at 1st January 2000

	Number of storage facilities	Storage BCM	Consumption 1999 BCM	Storage/Consumption (%)	Maximum Withdrawal Capacity, million cubic metres/day
Austria	5	2.295	7,7	29.9	24
Belgium	3	0.675	15.9	4.3	appr. 19
Denmark	2	0.815	4.7	17.4	25
France	15	10.2	41.0	24.9	180
Finland	0	0.0	4.0	0.0	0
Germany	39	18.353	84.0	21.9	406
Greece	-	0.0	1.5	0.0	-
Ireland	0	0.0	3 5	0.0	0
Italy	8	15.1	66.3	22.8	265
Luxembourg		0.0	0.8	0.0	
Netherlands	3	2.0	40 3	5 0	135
Portugal		0 0	1.9	0.0	
Spain	2	1.0	16.1	6.2	8
Sweden	0	0.0	1.0	0.0	0
UK	7	3.459	93.9	3.7	134
EU-15		53.897	382.6	14.1	

Source: Eurogas (gas consumption expressed at 39 Ml/m 3 (GCV). The data refers to storage facilities used for peak shaving, seasonal variations and strategic security of supply. The storage facilities include mainly aquifer storage facilities including depleted fields and storage facilities in salt cavities but also some LNG used for peak shaving. Flexibility from production fields not included.

12.4. Conclusions

The two main issues raised in relation to possibly inadequate market provision of security in diversity and related terms for UK gas are facility dependence and possible inadequate provision of storage.

In the case of facility dependence and risks of facility failure the consequences would be large and there is a possible market failure, which could lead to excessive facility concentration of gas terminals. However the economic advantages of such concentration are probably large and it is not clear how material the externality is. It is therefore not possible to be sure whether terminal concentration does represent a material barrier to security, and the issue warrants closer study.

In the case of gas storage, the current levels of storage do not seem the result of any specific market failure, and there are alternative ways to deliver security to customers. Low levels of storage capacity relative to Germany, France and Italy does not constitute evidence that markets in the UK provide too little storage in the UK.

13. DIVERSITY AND GAS: INTERNATIONAL ISSUES

13.1. Introduction

In this section we look at the implications for security of supply of the likelihood that the UK will become increasingly dependent on the importation of natural gas in the next 10 to 20 years. Imports are themselves normally good for security. They represent, compared to self-sufficiency, *more* diversity in supply sources and will normally only be bought if cheaper than domestic sources. The background is therefore a general presumption in favour in imports for security purposes. Worries about imports therefore tend to concentrate on the idea that foreign suppliers will be less reliable than domestic suppliers and that in practice there will be few suppliers, transit routes etc. Import dependence could then reduce security. As we emphasised earlier, the growing proportion of gas used for electricity generation means that the issues we discuss below will be important for electricity as well.

The relevant question is still whether or not markets will be able to manage any such higher risks in such a way as to provide adequate security. Risks to security may rise, but this does not in itself make any case for Government intervention

The JESS report[50] indicated that by 2010 the UK could be importing between 33% and 58% of gas demand. By 2020, some estimates of import dependency rise to between 55% and 90% of gas demand[51]. This possible level of import dependency will mean that it is important to understand the possible risks to security of supply and any barriers and distortions in the gas market that could affect security. There are other commentators who see a much lower percentage dependence on imports, principally because of a much less pessimistic view concerning gas production from the UKCS.[52]

The main risks arising from this growing import dependence can be summarised as follows[53]:

- source dependence;
- transit dependence; and
- (non-UK) facility dependence.

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50 JESS (Joint Energy Security of Supply Working Group) *First Report* June 2002, p. 17..

51 DTI *Review of the Energy Sources for Power Generation* op. cit. 1998 Annex C, by Wood McKenzie, para. 1.6.

52 Professor Peter Odell, Evidence to the Select Committee on Trade and Industry, Second Report of Session 2001/2002 on *Security of Energy Supply* February 2002

53 We have drawn quite extensively in this section on Jonathon Stern "Security of European Natural Gas Supplies" Royal Institute of International Affairs July 2002

13.2. Source Dependence

It is by no means clear what the most likely sources of gas imports into the UK are likely to be. Possible sources include (1) other countries producing gas in or close to the North Sea, (2) Russia (and its wholesale customers within Europe) and (3) other producers situated outside Europe, including Algeria.

Norway's very large gas resources, plus the existing pipeline connections between gas fields in the Norwegian Continental Shelf and fields in the UKCS and with the UK onshore terminals, suggests a resumption of substantial import volumes of gas from Norway. In the 1980s and early 1990s the UK imported about 30% of its needs from Norway and so a similar proportion in the next 5 to 10 years seems highly probable. The existing import capacity[54] is about 11 bcm a year, equivalent to about half the capacity of the UK-Belgium Interconnector.

The Netherlands has large gas reserves and access to very flexible gas storage and production facilities that are relatively easy to connect to the UK pipeline system.

Further away, the next most likely long-term source, because of its very large gas reserves, is Russia. But there are other producing and exporting regions with the potential to export to the UK. For example, Exxon Mobil recently indicated that it was considering a long-term contract to bring LNG by ship from Qatar[55]. Lattice plc has announced that it is seeking planning permission to construct LNG import facilities at the Isle of Grain[56].

Geographical diversity affects the probability of delivery failure. Long delivery routes increase the chance of interruption en route either through delivery failure or due to interception of the product by intervening nations. However, there is no reason from past experience to believe that more distant sources are any less reliable than those closer to the UK. Algeria has demonstrated over nearly forty years that it is a reliable gas supplier. Russian gas has also demonstrated reliability in its exports to Western Europe. However, Russian gas is transported by pipeline through a considerable number of countries. Russia may have experienced problems of gas theft in the transit countries, and in particular the Ukraine but this has not meant reduced deliveries to importing countries such as France or Germany. Indeed the problem with Ukraine situation is more related to transit rather than import dependency.

Though the UK may grow more reliant on imports of gas, there is a reasonably diverse range of possible sources of gas, both near and further away. Early indications are that market players are seeking to diversify sources of gas without any explicit intervention. It is

54 These are the pipelines that linked the Frigg area gas fields to the UK and have recently been linked to other Norwegian fields and referred to as the Vesterled pipeline system.

55 Press release 24 June 2002

56 Press release 13 August 2002

likely that such diversification arises from a prudent commercial response to managing the risks inherent in any commercial gas contract on any large scale.

In any case, the UKCS will continue to supply an important proportion of the UK's needs into the longer term and it is far from certain that the proportion of gas demand met by imports will be as high as up to 90% by 2020[57].

Many commentators have pointed to the risks of a growing reliance on such distant sources of gas. But the prospects for such reliance in the UK need to be compared with many European countries that rely on one or two sources of imported gas and have no indigenous resources. A recent analysis concluded[58]:

- Central and south eastern Europe is highly import-dependent and poorly diversified;
- Southern Europe is highly import-dependent, with Italy the only significant producer;
- Northern Europe is completely import-dependent and poorly diversified;
- North Western Europe is the only area of Europe that has significant gas production and a diversified portfolio of imports, though it is also over 75% of the whole European market

Many of these countries are only in the early stages of market liberalisation. The lack of liberalised markets to provide cross border support may increase these countries' risks from reliance on few or even a single source of gas imports. The lack of diversity and reliance on imports has in the past led gas companies (usually in conditions of monopoly) to construct storage capable of sustaining gas supplies in the event of interruption for several months (see Chapter 12). Liberalisation of European gas markets could make this storage available for cross-border support.

Security of supply concerns have been expressed in relation to potential contractual and financing problems concerning longer term more distant supplies of gas that are raised by the transition to competitive markets. However, the experience of liberalisation in North America and the UK indicates that long-term contracts of the sort traditionally used in the gas industry are not a necessary condition for the assurance of security of supply in gas production.

Moreover the establishment of more competitive markets has not meant the disappearance of such long-term contracts; indeed it is likely they will be an important and continuing

57 Professor Peter Odell has estimated that using information on remaining discoverable gas reserves net imports could in fact be zero in 2010 and around 20 to 25% in 2020.

58 Jonathan Stern " Security of European Natural Gas Supplies" RIIA July 2002

feature in the market for many more years. However as we have seen already in liberalised markets, price and other contract terms are likely to be more flexible. Terms that are now seen as restrictive and anti-competitive are being gradually removed. In parallel new market mechanisms for trading gas (and transportation capacity) have allowed market participants to manage their risks more efficiently and for example have enabled participants more easily to manage the risks that arose in the past from take-or-pay obligations.

13.3. Transit Dependence

In the UK all gas is transported by pipeline and in Europe about 90% of gas is also delivered by pipeline. The possibility of importing gas into the UK from longer distances raises the possibility of a further layer of risk, principally commercial and political risk that may heighten security concerns.

With no specific import contract from outside the North Sea in prospect, it is difficult to be very precise about the transit risks that may arise. Looking at Europe, which imports large volumes from Russia and Algeria by pipeline, it is apparent that there are limited transit routes/countries that these pipelines pass through. In the case of Russia all gas currently transits through Ukraine or Belarus. Pipelines also cross the Czech and Slovak Republics; other pipelines cross Austria, Romania, and Bulgaria before reaching destinations in the main importing countries. For the UK, any imports from Russia by pipeline would also have to cross member states of the EU. For Algerian gas, the pipelines transit Tunisia and Morocco before reaching either Italy or Spain and Portugal.

All such transit routes have the potential for interruptions, not just for operational reasons but also because of potential conflicts within or between transit countries. However, to date there have been no reported instances of any conflicts halting the flow of gas through such pipelines (Ukraine is a special case).

13.4. Transit Dependence and European Liberalisation

The fact that the UK looks likely to import a large proportion of its gas from sources such as the Netherlands and Norway that are relatively close geographically to the UK rather than from more distant sources, will not necessarily insulate the UK from the effect of measures taken (or not taken) by EU Member States to liberalise gas markets in their own countries.

The geographical proximity of Norway and the Netherlands might serve to reduce some of the transit-dependence and source-dependence risks for UK gas imports, but there may still be risks for other importing countries that rely on more distant sources such as Russia and Algeria. Supply failures from these exporting countries could mean greater price pressures on gas supplies from other sources such as Norway and the Netherlands that could in turn affect prices and possibly availability to the UK gas market.

At present the progress of liberalisation in the EU has been varied. No country has yet achieved the degree of accessibility to competitive gas supplies and to gas transportation capacity that is available in the UK gas market. There is still a long way to go before there will be an efficient and complete internal market in gas or electricity in the EU.

It is difficult to say whether the lack of such a liberalised market is of itself a barrier to meeting the security of supply needs of the UK gas consumers as the proportion of gas imports increases. It may make the meeting of risks to gas importers and possibly to gas consumers more difficult than if the market were to be more liberalised. But importers can still seek to offset those risks as they have in the past before the liberalisation process started.

It is likely that as progress is made with liberalisation in the EU, for example, through full open access to gas transportation capacity, or to gas storage facilities and as new market mechanisms such as forward markets and trading centres are established outside the UK, then gas importers will have more opportunities to meet their market risks more readily and more efficiently.

Indeed it seems likely that, as in the UK, liberalisation may serve to reduce risks and at the same time enable the provision of secure supplies more efficiently than hitherto. A more open market will mean greater opportunities to move gas more readily across the gas network and thus help to offset the risks and effects for example, of gas supply reductions or failures from particular sources.

Barriers to third party access will apply less severely to incumbent gas companies, who may therefore facilitate the movement of gas towards the UK. This reliance on incumbents may raise prices to British consumers, but need not threaten security of supply. Incumbents will be as likely to supply gas to Britain during a shortage as any other suppliers, unless they are allowed to restrict suppliers during a shortage, in order to maximise their market power.

Nevertheless, the possibility of increased imports has led some to argue that UK security of supply depends on open access in Europe particularly in Germany, which would be the most likely transit route for Russian gas to the UK.[59]

13.5. Facility Dependence (Non-UK)

One of the highest consequence risks to the supply of gas arises from the destruction of a major production or processing facility or of a deep-water pipeline. The International Energy Agency's major study of natural gas security contains a judgment that is universally relevant:

59 Comments by OFGEM reported in The Guardian 20 September 2002.

> *Perhaps the greatest risk of prolonged interruption comes from the destruction of a major production or processing facility or a deep water pipeline whose replacement might take many months to build.*[60]

In 1998, this risk was most graphically demonstrated when an explosion at an onshore processing plant in the Australian state of Victoria caused the disruption of gas supplies to all customers throughout the entire state for a period of nearly two weeks.[61] Despite the fact that gas supplies originated from different domestic offshore fields through different pipelines, all gas production was dependent upon the availability of the plant.

European gas supplies from particular sources are vulnerable to accidents at key transmission and import facilities, some of which are remote from European territory. The most important are the Yamal—Nenets pipeline corridor, which carries nearly 90% of Russian gas production; the Ukrainian pipeline corridor, which carries around 90% of Russian gas exports; the Trans-Mediterranean and GME pipelines from Algeria to Italy, Spain and Portugal; the Troll field and associated pipeline infrastructure, which account for more than half of Norwegian production and exports.

Although it is highly unlikely that any of these facilities — particularly those involving multiple pipelines or LNG trains — would suffer a major failure for any significant period of time, such low-probability/high impact events could have a substantial impact on a particular transit route and therefore an entire gas consuming region in Europe.

It is difficult at this stage to be clear where UK gas imports will come from. As indicated earlier it is highly likely that Norway and the Netherlands will be the two most important sources in the next few years. In the longer term, it is likely that a proportion of UK gas needs will be imported from countries such as Russia, Algeria or the Middle East, though it seems equally likely that this proportion will remain quite limited for at least the present decade.

13.6. Flexibility of Import Delivery Routes

Delivery routes have different levels of flexibility in the gas market. Both LNG and pipelines can operate flexibly (i.e. by delivering variable quantities of gas), but the economics of pipelines often means that they are designed to run at full flow. Offering flexibility between different routes means either being able to adjust deliveries along different routes, or being able to substitute between different sources of gas at the entry to a delivery route. This latter kind of flexibility is enhanced by the creation of an open access regime.

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60 International Energy Agency “The IEA Natural Gas Security Study” Paris, 1995.

61 ***The Esso Longford Gas Plant Accident***, Report of the Longford Royal Commission, Government Printer for the State of Victoria, No. 61, Session l998~99, June 1999.

LNG terminals, on the other hand, are normally built in association with a single gas producer and a set of dedicated bulk LNG carriers. In principle, though, they can take LNG cargoes from any location. This allows LNG suppliers to compete to supply gas to that supply point and increases the flexible usage of that delivery route. At the present moment, the UK has no LNG import facilities. However, Lattice plc recently announced that it is applying for planning permission to construct and operate a facility at the Isle of Grain on the Thames estuary[62]. Exxon/Mobil have announced their intention to import gas as LNG from Qatar at Milford Haven, and Petroplus are also contemplating location at Milford Haven.

It is likely that these facilities, if completed, will add to the options for delivery routes into the UK. It is not clear how significant these new terminals will be in relation to supply security in the UK. Most LNG trades continue to rely on dedicated LNG liquefaction plant at the point of export and dedicated re-gasification plant at the point of import, together with LNG ships usually dedicated to the specific import contract. But there is a growing though small spot market for LNG cargoes in Europe, operating through arbitrage with North America[63] and the Middle East. However it has nowhere near the volume of liquidity or depth found in international trade in crude oil and oil products. As this trade develops, then its contribution to security may gradually increase.

In the meantime it is possible to capture some of the benefits of the small spot trade in LNG cargoes as an alternative source by using the LNG facility at Zeebrugge in Belgium, which is connected to the UK-system via the UK-Belgium interconnector.

13.7. Security Incidents

It is useful to look back over the past two decades at some specific experiences of European and other countries in respect of gas security problems. Interestingly, there are no clear examples of facility incidents.

In April 1986 a strike among Norwegian offshore workers spread to the British part of the Frigg field and the country lost around one quarter of total supplies for period of several days. Neither the fact of UK gas import dependence nor this potentially serious security event attracted any significant publicity at that time.

In November 1997, a terrorist bomb exploded in an onshore Algerian section of the Trans-Mediterranean pipeline to Italy. Supplies were maintained from storage and through

62 Press release of 21 August 2002.

63 Centrica plc reported that individual LNG cargoes are now moving in both directions between the USA gas market and Europe in response to varying gas prices in the two markets. Centrica concluded that LNG is becoming the marginal therm supplying these two markets. From Paul Massara, General Manager, Energy Management, Centrica plc "European Gas Market: too slow or coming along nicely" Amsterdam Autumn Gas Conference, November 2001

additional deliveries from alternative suppliers. There was no suggestion that the incident caused any significant inconvenience to consumers, despite fears at the time that it might herald the start of a sustained campaign of action against gas installations in Algeria's worsening civil disturbances.

The most recent example of source insecurity in natural gas trade *outside* Europe occurred in 2001 when political instability in northern Sumatra shut down the Arun liquefaction plant for several months. Indonesian LNG exports to Japanese and Korean buyers were curtailed.

The transit of natural gas exports across Ukraine in particular has encountered problems in the delivery of Russian gas to Europe in the post-Soviet era. The basis of the problem has been a lack of money in Ukraine to pay for Russian gas supplies. This has led to a decade of 'unauthorized diversions' whereby Ukrainian companies siphon off in transit to European customers. These difficulties caused the Russian company Gazprom to devise an entirely new export strategy based on avoiding transit countries wherever possible, and in particular reducing volumes in transit through Ukraine.

With very few exceptions, the transit difficulties in Ukraine have lasted only a few days, mostly outside times of peak demand in Europe, and European gas companies have managed them relatively easily. In only two cases, both in Turkey prior to the commissioning of a new LNG import facility, unauthorized diversions have caused physical shortages for end-users of gas:

- at the start of 1994 daily deliveries of Russian gas were reduced by about 50%;
- in early March 1995, one of the existing gas-fired power plants had to switch the majority of its input to fuel oil, and two fertilizer plants were put on standby.

These incidents indicate the dangers associated with dependence on a single source, not dependence on imports or Russian gas *per se*.

13.8. Conclusion

The likelihood that the UK may have to import a substantial proportion of its gas requirements in the next 10 to 20 years has caused much debate about the implications for security of supply. We conclude that:

- The UK is most likely to import much of its gas from sources relatively close to the UK namely from Norway and the Netherlands in the next few years and not from more distant sources such as Russia or Algeria. What is more there is already substantial existing (and largely empty) gas pipeline interconnections from the Norway area and any interconnection from the Netherlands will be relatively short. However, once the UK obtains imported gas in quantity from the interconnector, it is inevitably involved in wider issues in the European market and would be subject to wider risks in those markets.

- Dependence on long transit routes through EU Member States (and non EU states) is unlikely to be an important immediate issue for security of supply, though progress with gas and electricity market liberalisation in the EU will be important to enable more ready short term access to flexibility including storage and enable UK gas requirements to be more efficiently met.

- Concentration of facilities at certain landing points such as Bacton and St Fergus may pose a security threat as loss of these facilities could not readily be met by gas from other sources. Consideration may need to be given to what measures are needed to reduce the impact of low probability/high impact effects resulting from a complete facility failure.

- While imports could lead to higher risks to security, it is not clear that markets will be unable to handle these risks, or that Government should necessarily intervene.

14. UK REGULATORY RISKS

While we do not deal directly with the regulated parts of the gas and electricity industries, network regulation inevitably impacts on the competitive parts of the market. This Chapter looks at the possibility that particular regulatory positions could provide a barrier to market provision of security. The issues considered are all concerned with gas: the relation between the onshore and offshore gas networks; auctioning entry capacity; the proposed new exit regime; and the regulation of interconnectors.

14.1. Possible Barriers Due to Differences in Regulation of UK Offshore and Onshore Gas Networks

There has always been a separate legal and regulatory framework governing the offshore and onshore gas industries including the pipeline network[64]. The offshore industry has argued that the various pipeline networks constructed to connect the various offshore gas fields have been essentially an extension of the production facilities. They often carry not just natural gas but also gas liquids. This gas is then processed at the onshore terminals before delivery of a dry gas into the Transco network in accordance with the required gas specification, ensuring consistent gas quality to all consumers.

As new reserves have been discovered and developed, there have been increasing opportunities to make use of spare capacity released by depletion of old fields. Many developers installed spare capacity in the knowledge that later developments are likely to require pipeline capacity to reach the onshore terminals. The process of planning such developments and allowing access to these pipelines has been governed by the negotiation and discussion between the commercial parties involved.

DTI has a central regulatory role offshore. It licences and approves offshore exploration, development, and production of natural gas including the construction and ownership of the pipeline network required to deliver the gas to the UK gas terminals.

At the same time there is an industry Code of Practice that governs the general terms and conditions for access to pipelines. The main principles are:

- non-discrimination with regards to negotiated access to all offshore infrastructure and onshore terminals;
- terms of access will be commercially negotiated with appropriate separation of services and within a framework of transparency and standardisation between systems; and

64 The Petroleum Act 1998 consolidates the legislative framework for the exploration, development and production of natural gas from the offshore gas fields in the UK Continental Shelf ("UKCS").

- access will only be granted provided it does not jeopardise the safety and integrity of the system and does not lead to potentially unacceptable environmental damage.

There are no regulated terms for transportation tariffs; these are subject to negotiation. It is important that all these principles are applied consistently to ensure access for new production and new facilities. Appeals from parties concerning terms and conditions for access are allowed to the Secretary of State for Trade and Industry. To date no such appeals, as far as we aware, have been made.

The fact that there is a separate regulatory framework for the offshore gas pipeline network is not necessarily a barrier or distortion that might affect the security of gas supplies. Indeed the lack of any appeal to the DTI to date over terms and conditions of access to offshore pipelines indicates that few if any major concerns have led companies to take such a step.

There are indications however that may point to tensions between the regulation of the offshore and onshore regimes and in particular the incentives to invest in the two regimes.[65]

It has become increasingly clear that there is a form of "pipe-to-pipe competition" for capacity to bring gas production from offshore fields to market. The most obvious example is the decision of the field developers of the Shearwater, Elgin and Franklin fields in the Central North Sea to build the SEAL pipeline from the offshore fields directly to the Bacton terminal where it will feed gas to the UK-Belgium Interconnector.

The decision to build a longer offshore pipeline and not to land the gas at the nearest UK terminal and then to use the GB onshore network to convey the gas to Bacton was based on comparison of onshore and offshore costs. The likely costs of transportation and perceived difficulties of recovering the necessary onshore investment required to reinforce the network sufficiently to support the volume of gas flows required were evidently perceived as too high. This might imply that the offshore regime is more conducive to investment than the onshore regime.[66] Since offshore investment takes place in a context of pipe-to-pipe competition and informed negotiation by all parties, it is not possible to conclude that the offshore regime is subject to any obvious bias in favour of excessive investment. If there appears to be a bias in favour of offshore investment, the problem appears to lie onshore.

It is not clear whether taking gas reserves directly via the SEAL pipeline to the Interconnector will affect security of supply in the UK. It is important that there is sufficient incentive for developers seeking to build new infrastructure to import gas into the UK in the future. The barrier, if there is one, has more to do with doubts over cost recovery in the onshore regime than with the existence of differences between the two regimes *per se.*

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[65] Dr Nigel Evans "Gas: pricing for interconnectors and pipes" October 1998, Institute for Economic Affairs and London Business School Lectures on Regulation Series VIII.

[66] See Dr. Evans (1998)

14.2. GB Onshore Gas Network: Entry Capacity

The terms and conditions for access to the GB onshore network are based on regulated access under the Gas Act 1986 as amended by the Gas Act 1995 and the Utilities Act 2001. OFGEM acts as the independent regulator. The main concerns about actual or potential barriers or distortions are related to the incentives to invest in sufficient gas transmission capacity and in a timely and efficient manner.

The gas industry has expressed concern[67] about the adequacy of incentives to invest in sufficient capacity in the GB onshore network. It would seem that in the absence of changes there is a risk that capacity may be insufficient to meet peak and annual demands at some stage in the near future.

The debate about the adequacy of the incentives to encourage sufficient and timely investment in the GB gas transmission network was highlighted by the restrictions in capacity to carry gas away from the St. Fergus gas terminal in late 1998 and early 1999. Following investigation, OFGEM concluded that the cause was Transco's failure to invest in sufficient gas transmission capacity to carry gas away from the St. Fergus terminal.

As a result, new market arrangements were put in place in 1999 to provide clearer market signals through a system of auctions for entry capacity at gas terminals. Since 1999, the cost of entry capacity, particularly at the St Fergus terminal, has risen compared to previous charges. However, the new system has led to uncertainty over entry charges, concern at the volatility of these charges, and continuing worries about the expected availability of gas entry capacity.

These concerns have led to further consideration of the process for auctioning capacity, in particular the need to recognise that investments in the network are long-lived assets and that suppliers and shippers are investing considerable sums in upstream production facilities.

Hitherto shippers had bought capacity on annual basis. At the time the need for new long-term investment was identified through the Ten Year Statement produced by Transco every year in consultation with the all parties in the gas industry. In looking to reform the process, OFGEM has been trying to provide the necessary linkages between (1) the short term market signals in the auction process and (2) the need for Transco to invest in sufficient capacity to meet market needs in a timely and efficient manner.

This has led OFGEM to propose new arrangements for the auctioning of long-term capacity. It is difficult at this stage to judge the likely impact of these new arrangements on the availability of capacity and stability of entry capacity charges.

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67 The Gas Forum response to DTI consultation on Energy Policy 13 September 2002

Past uncertainties concerning entry capacity seem to have affected investment as evidenced by comments made by industry organisations. If this regime presents a barrier to security of supply, OFGEM will have to work to remove its cause.

14.3. Proposed Reforms to Gas Exit Regime

Proposed changes to the exit regime in gas[68], whereby all customers will receive a firm connection unless specifically negotiated as an interruptible contract with Transco, could initially drastically reduce the overall number of interruptible contracts. If implemented, this change could at least in the short term reduce the demand responsiveness of gas considerably to the extent that there is reduced interruptible capacity.

OFGEM suggest that the proposed reforms are intended to improve the mechanism for delivering an efficient amount of demand side participation to meet Transco's need that interruption terms should allow them to more efficiently manage the system. The existing system of standard 45-day interruptible contracts will be replaced by individually negotiated contracts. While underlying economic incentives will be unchanged, the transactions costs involved in negotiating more flexible contracts may mean that the long-term extent of interruptibility may be reduced.

OFGEM will thus need to monitor carefully the effect of this proposed change.

14.4. Gas Interconnectors

There are two main interconnectors linking the GB onshore network to other gas markets in Europe:

1. The UK – Belgium Interconnector was completed in October 1998 and provides some 20 bcm a year of export capacity and 8.5 bcm a year of import capacity.[69]
2. The first UK-Ireland interconnector was completed in 1992. Subsequently a link was built connecting Northern Island to the GB onshore network via the UK–Ireland interconnector. A second interconnector to Ireland is now under construction and due for completion in October 2002. In all cases links are intended only for the export of gas from the UK to Ireland and not for possible import into the UK. Ireland depends heavily on these links for its own security of supply.

At the same time there is substantial import capacity from the Norwegian gas fields in the Frigg area and there are further plans for reinforcing these links to other gas fields in the

68 OFGEM Consultation Document on changes to exit capacity rules, December 2001

69 On 1 October 2002 IUK (the inter-connector operator) announced the financing approval of new compressor capacity to upgrade import capacity from 8.5bcm to 16.5bcm.

Norwegian sector.[70] Recent announcements of gas import contracts from the Netherlands may lead to new links from the Netherlands to the UK.[71]

The terms and conditions for access that apply to these interconnectors are generally the subject of negotiation between the parties concerned. Regulation of these terms is governed only in general terms by the provisions of the EU Gas Directive (1998) and Inter-Government Treaties between the countries concerned as well as general EU competition law. In all cases it is required that third parties will in general be allowed access on reasonable terms to the interconnectors, pipelines and terminals with Belgium and Ireland.

The existence of the UK–Belgium interconnector has added to the security of gas supplies in the UK as it gives access to additional sources of gas to supply UK consumers, though it may not help in situations where there is widespread severe weather in both the UK and on the Continent (see below). There is no obvious evidence to date that there have been any major barriers to the use of these interconnectors, though an investigation by the EU Commission in 2001/2002 endorsed some changes to access arrangements that were already in hand.[72]

The interconnector can contribute to meeting peak as well as annual customer needs, for example when severe weather hits the UK, the interconnector may be an economic source of gas that helps conserve gas supplies from more expensive domestic storage. If severe weather hits North West Europe at the same time as the UK and thereby increases gas prices there as well as in the UK, there may not be sufficient gas available to supply the UK through the interconnector.[73] However the UK-Belgium interconnector allows the UK to compete for access to gas production and storage in continental Europe.

In the case of Norwegian pipelines that might serve the UK gas market in the future, Norway's position outside the EU might be a source of uncertainty. However, the provisions of the EU Gas Directive apply to Norway's through its membership of the European Economic Area ("EEA"). The Norwegian Government has therefore decided that the operation and ownership of the offshore pipeline system will be separated from the gas supply contracts. As a result a new company has been established that will operate the system on behalf of the owners (which consist essentially of the gas producers). The company is in the process of establishing terms and conditions including transportation tariffs for this major network.

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70 For example, linking the Vesterled gas field to the existing infrastructure.

71 Centrica plc has announced contracts for importing gas from Norway and the Netherlands. This followed earlier announcements from BP on importing gas from Norway.

72 There was an investigation by the EU Commission of the influence of the gas interconnector on UK gas prices in 2001/2002. The EU made some recommendations on changes to the access and trading arrangements for the interconnector, which have been implemented.

73 This conclusion is based on the NERA gas and electricity model. As such the conclusions depend on the assumptions used and it has not been possible to test this in reality

As in the case of the interconnectors, the process for access to, and new investment in, the offshore network in the North Sea, including connections to the UK onshore network will be the subject of specific negotiation. The reliance on private negotiated contracts rather than regulated access terms and tariffs may actually enhance security of supply. Investors may be more willing to fund investments covered by contract, if they provide a better prospect of cost recovery and the ability to negotiate the degree of security.

14.5. Conclusion

The purpose of this chapter has been to examine the interrelationship between the regulated and market parts of the system.

The main conclusions are:

- The differing offshore and onshore regulatory frameworks seem to result in different incentives to investors and pipeline users. It is important that there is sufficient incentive for developers seeking to build new infrastructure to import gas into the UK in the future. The barrier, if there is one, has more to do with doubts over cost recovery in the onshore regime than the existence of two different regimes *per se.*
- The new arrangements for auctioning long-term entry capacity are designed to improve the incentives to invest in onshore capacity. However, as long as some of Transco's revenues depend on regulatory decisions, incentives for onshore investment will depend on OFGEM's regulatory regime. If this regime presents a barrier to security of supply, OFGEM will have to work to remove its cause.
- Proposed changes to the exit regime in gas whereby all customers will receive a firm connection unless specifically negotiated as an interruptible contract with Transco, may reduce the overall number of interruptible contracts, even in the long-term. If implemented, this change could then reduce the demand responsiveness of gas to the extent that there is reduced interruptible capacity. OFGEM will thus need to monitor carefully the effect of this proposed change.
- While the terms of access to the UK-Belgium interconnector are subject to commercial negotiation, there are no signs yet of any difficulties for market participants to gain access to the interconnector.

15. UK POLICY RISKS

15.1. Introduction

A variety of risks to security could derive from the pursuit of other Government objectives, or from inefficiencies or failures in other parts of the public policy system. These are not market failures but they could in principle be substantial barriers. The two most frequently cited potential barriers in this category are:

- Problems arising from the application of Government's environmental policy. These mainly relate to electricity and can be sub-divided into the policies designed to encourage more efficient or low-carbon electricity generation, and the application of emission standards in electricity generation;

- Problems arising from the application of physical planning processes, so that energy investments may be subject to delays and in some cases, rejection

15.2. The Renewables Obligation

The Government has a range of policies designed to encourage more efficient and/or low-carbon generation or production, including the Climate Change Levy, the Emissions Trading Scheme, the CHP Strategy and the Renewables Obligation. Among these, the most significant in terms of possible impacts on energy security and the capacity of markets to deliver adequate security is the Renewables Obligation in the electricity industry

Here we examine the possible impacts of the Obligation, mainly but not exclusively especially on long-term investment. Currently, retail suppliers of electricity are obliged to purchase a certain percentage of their total needs from renewable sources – or else pay a fine, the proceeds of which accrue to suppliers in proportion to the extent that they meet the Obligation . The Obligation is currently 3% but will rise by 2010 to 10%.

15.2.1. Short term effects

In many markets, the impact of such a universal obligation would simply be to increase the total costs of supply. Suppose, for example, that the Renewables Obligation is required because renewable energy sources are on average 20% more expensive than non-renewable sources. An obligation to purchase 10% of demand from renewables, at 20% higher cost, translates into a 2% increase in the total cost of meeting demand for all retail suppliers, as shown by the calculation in Table 15.1.

Table 15.1
Short-term Costs of a Universal Obligation

	Volume	Unit Cost	Total Cost
Non-Renewables	90%	100	90
Renewables	10%	120	12
Total			102

Since this increase in costs affects all retail suppliers, it does not in principle affect competition between them. However, such obligations can have implications for longer term investment incentives in the generation sector.

15.2.2. Long-term effects

As a result of the Renewables Obligation, investors will have to build renewable energy sources, instead of the generator plant that they might otherwise choose to build. The displacement of other investment will have two possible effects on prices.

In the first place, if the new renewables plant displaces other capacity that would have been built, the generation portfolio will be slightly different. However, renewables plant tends to run in base load mode (or rather, whenever it is available) and so plays no role in setting short-term market prices. The effect is similar to reducing total demand by (e.g.) 10%. An optimal pattern of generation will still exist in principle and market prices can still remunerate the other kinds of capacity as per the market paradigm.

However, if the demand for new renewables plant exceeds anticipated investment needs, it will force the premature displacement and (ultimately) closure of existing plant that would otherwise have remained in remunerative service. This process will operate via excess capacity depressing market prices and reducing the reward for keeping plant available.

In practice, the costs of keeping plant available are much lower than the costs of building plant in the first place, so prices may fall below the level needed to remunerate investment without encouraging plant closure. In such conditions, excess capacity and depressed market prices may persist for many years. During this period, the main effect of the depressed market prices will be to increase the amount of subsidy that renewables need to receive (relative to market prices). However, such a policy will also affect the incentives for investment, when the time comes to close and replace existing non-renewable generating capacity.

Gradually, existing non-renewable generating capacity will reach the point where it costs too much to maintain its availability. If it costs more than can be earned at current or expected future market prices, it will be closed down. Eventually, sufficient plant will be closed down that prices will begin to rise again (as long as market prices capture the effect of capacity shortage).

However, before being prepared to invest in new plant, investors will take stock of the likely future prices. In doing so, they will (or may, at least) anticipate a repeat of the problems for cost recovery caused by the (assumed) government policy on renewables. As a result, they will (or may) only invest in new, non-renewable generation if the current market price rises high enough to offset the risk of prices being depressed in the future by policy initiatives. Hence, the attempt to foster renewables would (by driving down prices in some years) have driven up the price at which investors are prepared to enter the market with non-renewable generators

15.2.3. Possible solutions

It is possible that the only outcome of this process will be a cycle of boom and bust – periods when prices are high enough to encourage investment for short-term returns, followed by extended periods when excess capacity caused by occasional government policy interventions depresses market prices and non-subsidised investment comes to a halt. Such an outcome is not efficient.

Recognition that investment is needed, but that government policies are depressing prices, may lead to demands for governments to offer comparable subsidies to more kinds of investment in capacity. Such policies do not sit well with a commitment to competition and private sector decision-making.

To avoid such outcomes, governments would need to avoid policies that create doubt in investors' minds about the prospects for recovering the costs of investment in generating capacity. In monopoly regimes, the necessary assurance can come from provisions to allow recovery of "stranded costs", but such policies would be difficult to apply in Britain's competitive, diversified generation sector. In these conditions, the only alternative would seem to be to ensure that government-sponsored investment programmes (such as the Renewables Obligation) only displace a proportion of future investment from competitive sources, and do not lead to the creation of excess capacity and depressed market prices.

In practice the risk of stranded assets due to the Renewables Obligation may be limited over the next few years, partly because the required action on renewables builds up slowly, so that the 10% target only becomes effective eight years after the introduction of the policy. It seems probable that, provided incentives to invest in generating capacity can be made to work reasonably well, the future electricity demand/supply balance suggests significant new investment over and above the renewables capacity anticipated in the Obligation.[74]

[74] DTI Energy Paper 68 suggested a need for 13-21GW of gas-fired capacity in addition to meeting 10% of demand from renewables.

15.3. Application of Emission Limits to Power Plants

One of the principal instruments of Government policy to reduce national emissions of sulphur and nitrogen (and perhaps carbon in the future) has been to impose various emission limits on power plants. These limits have tightened over the last fifteen years or so, and are in most cases the translation into UK practice of international agreements, usually at the European Commission level. Because coal-fired power stations produce the highest levels of sulphur and nitrogen emissions per kilowatt hour of any power sources currently in use in the UK, they have been a particular focus of environmental regulation. Limits apply both to companies with generating portfolios ('bubbles') and to individual plants irrespective of ownership. Local air qualities as well as national limits are included in the regulatory process.

The first question that then arises is the extent to which application of these limits might prove a barrier to the flexible operation of the power system in the short term. For example, if gas supply to the power system were constrained at periods of high electricity demand (or nuclear power were unavailable), it would be a barrier to security if owners of coal-fired (or oil-fired) plant were prevented from responding rapidly to potential supply interruptions because their emission limits prevented them from operating their plants at full output.

All power stations receive an environmental permit from the Environment Agency under the Integrated Pollution Prevention and Control legislation. These licenses contain emission limits, partly based on overall emission standards applied nationally, but also influenced by local environmental conditions. These licences typically cover NO_x and SO_x emissions and can be specified by time periods ranging from one hour to a year. The most stringent restrictions impact on to coal-fired generation without sulphur abatement equipment such as flue gas desulphurisation, though restrictions on oil-fired stations are also significant.

Typically, the emissions constraints on coal fired generation without sulphur abatement means that the stations are unable to run all their units at full load throughout the day and/or year. The limits provide constraints on actual running patterns and so installed capacity figures may over-estimate the amount of available generation over even relatively short time periods. These limits are monitored and cannot be breached during normal operations. In principle a regime which allowed more trading of emission permits might lead to greater flexibility in times of system stress, and so avoid possible barriers to the short-term use of plant with high emissions. Moves towards such flexibility however would probably have limited impact in ameliorating any impacts of environmental restrictions, as local air quality standards would still need to be respected, and this would limit trading.

However, the practical impact of these rules on security of generation is unlikely to be significant at times of system stress, partly because the rules operate over annual periods starting each October, thus giving scope for adjustment after any unusually high winter emissions. Moreover, at times of system emergency (which can include prospective electricity supply interruptions), the Secretary of State for Trade and Industry is able to impose emergency operational rules on the electricity industry using her powers under the Electricity Act 1989 and the Fuel Security Code. Under these emergency powers, the Secretary of State is able to "require the operation or closure of a power station for a particular period".[75] In such a scenario, where power station operation might be directed by the Government and no longer the responsibility of the power station owner/operator, it would be the Government's responsibility to deal with issues of emission constraints in conjunction with the Environment Agency. In practice, Government might not take direct control of plant operation but might declare that power station operators were temporarily free (over some limited period of time) to ignore the application of normal emission limits in the interests of system security.

In relation to long-term investment, however, the operation of emission limits will have the effect of restricting the range of economic options for new power plant investment. Application of strict nitrogen and sulphur controls means that new coal-fired plants already need to incorporate flue gas desulphurisation technology, and present (Kyoto) and prospective (post-Kyoto) carbon limits mean that the prospects for investment in new coal-fired generation are remote, unless or until engineered capture and sequestration of carbon becomes economic. The impact of emission controls therefore constitutes a possible barrier to the full range of diversity that a market system might otherwise provide. However, provided that emission restrictions reflect the external costs imposed by fossil fuel combustion, the existence of restrictions will be economically efficient.

15.4. The Planning System

Many parties have cited difficulties in securing planning permission for energy investments as a major obstacle to achieving security of energy supply. The House of Commons Trade and Industry Committee for example recently stated that the 'planning system currently forms a major obstacle to the Government's achieving its energy policy in respect of both security of supply and environmental objectives'.[76] The fundamental economic problem in the securing of planning permission (where subject to local political approval) is distributional. The environmental costs are incurred by the local community, while the benefits often accrue to other communities to whom electricity or gas may be delivered. Without explicit compensation mechanisms for local communities, local planning approvals may give greater weight to local costs than to national benefits, making planning permission difficult to obtain.

The issue of whether or not such planning problems are a barrier to the market's ability to deliver adequate security is less clear cut. If it were the case that the length of planning delays was predictable and evenly distributed among different energy technologies the

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[75] The Fuel Security Code: Proposal for Interim modifications and notification of longer term review of fuel security issues, p 4. http://www.ofgem.gov.uk/elarch/retadocs/fsc_consult_2_vernon.pdf

[76] Select Committee on Trade and Industry report *Security of Energy Supply* Session 2001/02 February 2002

market might deliver security at somewhat higher cost than under a planning system that delivered approvals more rapidly. However, provided these delays occurred before the commitment of significant investment funds, few resources would be tied up in construction, and the extra costs might be modest.

More serious problems for the ability of the market to deliver security would arise if the following conditions applied:

- A significant proportion of planning applications failed completely, especially if this was the case for projects with few close or immediately available substitutes in terms of security provision (e.g. gas storage facilities)
- Where different technologies are treated differently
- There was significant uncertainty about the extent of the delay, or the length of delays was increasing over time.

Under these conditions, planning problems could affect the capacity of the market to deliver the desired levels of security, because such planning problems would mean that investors would be unable to guarantee the timeliness of investments.

The evidence about planning problems is that some elements of these conditions appear to apply in practice.

In relation to the first condition, the evidence is that relatively few projects fail completely. Even among renewable energy projects success rates are high – some 89% of renewable applications were, we understand, approved up to early 2000. However, there are some exceptions. Onshore wind and waste-burning projects have a much higher rate of failure, as do larger renewable projects. The failure rates may in any case be a poor guide to the ability of renewable developers to carry through their projects. Renewables are normally small projects, for which the costs associated with planning approval may be a high proportion of all costs, and this may discourage some potential developments from reaching planning stage. On the other hand, some projects, which have not gained approval, may have been withdrawn by developers for reasons unconnected to, planning, including poor economic prospects.

In relation to the second condition, differences between technologies, there is evidence that treatment does vary. Where planning approval powers are reserved to the Secretary of State (e.g. power stations over 50MW and offshore developments in general) approval has tended to be relatively rapid (except where other considerations intervened, such as the 'restricted consents' policy for gas-fired generation after 1998). Where planning is devolved to local level, as in the case of small projects, not only is there the distributional issue, but also rejection of the initial proposal leads to a public inquiry, which causes further delays and costs. There are clear asymmetries in the processes and time scales especially between schemes of different sizes. Large schemes generally receive speedier attention from central Government.

In relation to the third condition, uncertainty about the length of delay or a rising average length of delay, the evidence does not seem clear-cut. While 'routine' larger projects such as CCGT power stations or offshore pipelines generally proceed relatively easily, very large or relatively novel projects may run the risks of long planning delays. Large and novel projects will tend to be important for security of supply.

Examples of projects where delays have been long and unpredictable are the North Yorkshire transmission line, a proposal from Scottish Power in Cheshire for salt cavity gas storage, and (further back in time) the Sizewell B nuclear power plant. In the Sizewell case, the CEGB made initial application in 1981 but did not receive approval from the Secretary of State until 1987. It is difficult to predict the length of time a future Secretary of State would take to approve a new proposal for a nuclear power station. It may be that a proposal to build terminal and jetty facilities for receiving and storing LNG imported by ship and for re-gasification at locations such as the Isle of Grain (relatively close to London) might also run into difficulties in the future.

15.5. Conclusions

The seriousness of environmental and planning problems for the market's ability to deliver adequate security varies by specific topic.

In the case of planning, there seems to be evidence of fairly serious barriers and these barriers could worsen, especially if some kinds of large-scale energy investment were attempted. They are among the most material of all the barriers and will tend to depress security below an adequate level. The issues for electricity, while important for small-scale developers, do not at present seem to constitute a material barrier. For gas however the situation seems different. Gas projects are often large, location-specific and difficult to substitute by alternative means of providing security at short notice.

There may, for gas, be a real threat of a barrier to security-related investment and its timeliness. It is appropriate to tackle this barrier directly, and the Government is already in the process of addressing the issues raised above, in relation both to local planning, and to large-scale infrastructure projects across all sectors.

On environmental policies, the barriers are variable. In the short-term, emission limits seem unlikely to affect security significantly in the event of restrictions on the availability of generation from other, less highly regulated plants. In the long-term, emission limits constrain the range of choices for new electricity investment and thus reduce the range of potential diversity. However, there are other ways in which diversity may be achieved, and it seems highly improbable that Government would consider easing its emission limits (a cornerstone for the achievement of several international environmental commitments) in the hope of promoting more diverse, but dirtier energy sources. The impact of the Renewables Obligation on long-term investment incentives might prove to be of some materiality, though the extent of its effect will depend on the market's perception of the Government's willingness to take the necessary steps, such as advance planning and notice, to avoid or minimise the risk of stranded assets. Because the Obligation is also central to Government's overall environmental strategy, it is unlikely that Government would wish to tackle the problem directly.

16. WIDER POLITICAL RISKS

Finally a major potential problem for adequate security is that the market does not always perceive that Governments will be consistent in policy approaches. In the past, Governments have intervened in, for example, the electricity generating market, and the markets may well believe that in serious enough security events Government will intervene again, thus discouraging markets from making as full security provision as is desired.

In order to identify ways to make government commitments more credible, it is useful to review the game-theoretic mechanisms used by hypothetical negotiators to enhance the credibility of their commitments in trading partners. Essentially, game theory discusses a situation in which someone makes a commitment (i.e., a promise) now, but is tempted to break the commitment in the future. If the reward from breaking the commitment exceeds the cost of doing so, the commitment is not credible, because the negotiator will always have an incentive to break it. Hence, to make their commitments more credible, negotiators find ways to (1) reduce the reward from breaking a commitment and (2) increase the cost of doing so.

In the current context, for instance, the possibility of intervening to cap peak power prices may offer a political reward that future politicians will inevitably find hard to resist. In such conditions, general game theory suggests two possible tactics:

1. Reduce the reward for intervening, for instance by smoothing out power prices so that the remuneration of capacity is spread over more periods and the effect of a price cap in any one period is less;
2. Increase the costs of political intervention, by invoking procedural or legal hurdles to make intervention more difficult for individuals.

Examples of the kinds of procedural rules that make future interventions more costly or more difficult are to be found in any number of regulatory regimes where private investment is at stake:

- Consensual decision-making processes (such as Parliamentary legislative procedures) that mean any intervention requires the support of many individuals;
- Executive decision-making procedures that contain a number of hurdles, such as the need to undertake formal tests (like cost-benefit analysis or regulatory impact assessments), in order to prevent ill-conceived interventions;
- Legal obstacles to interventions, which prevent interventions with certain defined effects.

These obstacles are intended to delay or obstruct certain kinds of political intervention, on the assumption that it is beneficial in the long-term to avoid some interventions, even if the result is to forego some interventions that might have been desirable. Such institutions always strike a balance between short-term flexibility and long-term stability; in industries dependent upon long-term investment, the emphasis usually swings towards the latter, because the benefits of securing investment outweigh the benefits of short-term interventions. However, each regime must find its own balance.

One example of the latter kind of legal obstacle is the use of private contracts, which governments are usually loath to override. Another is the US constitutional prohibition on "regulatory taking without due process", which prevents a variety of political interventions that undermine shareholders' ability to earn a (defined) reasonable rate of return. Such restrictions underpin the success of US reliance on private sector investment and the absence (or lack of definition) of equivalent protections outside the US may ultimately constrain the potential for utility sectors to rely on private sector initiatives. However, that said, none of the US safeguards against political intervention prevented the state government of California intervening heavily in power markets during the recent crisis. And while it is not always possible to fully transfer overseas experience directly to the UK, further work might be done to explore ways of achieving the objectives in the UK context.

While very difficult to measure, the barrier represented by the market's estimation of Government willingness to 'bale market players out' in the event of serious security events may be the most important, and difficult barrier, of all to overcome.

17. INTERNATIONAL EXPERIENCE

Appendix C gives a summary of a range of security of supply experiences in other liberalised gas and electricity markets. There are a limited number of such markets, especially in gas, and the treatment is not comprehensive. Markets which are only partly liberalised are not considered because their approaches to security of supply are likely to be influenced by the continuing influence of more monopolistic or planned structures.

It is impossible to draw any direct conclusions from these experiences of markets that have been considered because national circumstances vary widely, and some of the approaches described in Appendix C may also still be influenced in part by old methods of dealing with security. (The UK is relatively more advanced in liberalisation terms than most other markets in both gas and electricity).

However it is still worth attempting a summary of experiences in dimensions of security that seem relevant to UK policy

In **electricity** markets, the main concern in security terms seems to be adequacy of generating capacity, in short-term or long-term. Some markets have no explicit mechanism for inducing investment in long-term capacity. New Zealand is a good case, where any concerns about investment adequacy are being handled by strengthening short-term market structures (e.g. development of better forward markets). California also had no explicit capacity-inducing mechanism until its power crisis of 2000/2001.

However all the other markets examined – California as of now, PJM in the USA, Australia and Norway (the latter to an as yet limited extent) all have explicit mechanisms to induce generating investment. These are varied and include reserve contracts, tax benefits, and, perhaps most interesting, capacity obligation. In this latter mechanism, present in PJM and to be generalised across the USA, retailers are required to contract for future capacity, including a specified reserve margin above expected peak demands. This is a way of intervening that interferes relatively little with normal market operation and leaves retailers free to decide on how to meet their minimum obligation. In Australia there are minimum reserve capacity levels for each region, and the option for the market operator to call on reserve contracts for capacity if needed.

In **gas** markets liberalisation is more limited and cases are fewer. In Australia there is no formal or overall approach to security, while in Spain there is a set of requirements that relate to the largest security risk that Spain perceives, that of import dependence. The Spanish approach is to set minimum storage requirements (modest by standards of storage capacity in existence in other European gas importing countries) and a ceiling on the proportion of gas imported from any one country. These provisions seem however to reflect security practices in pre-liberalised times, and may have limited applicability to the UK

18. THE PERIOD FROM 2010 TO 2020

It is difficult to say anything conclusive about the period up to nearly 20 years into the future. All kinds of currently unanticipated change may change the context in which we view security of supply. However certain kinds of development certainly seem likely even beyond the end of the current decade. Easily the most important of these is that gas will probably become even more dominant in the energy mix than in the present or in 2010. It is probably fair to say that the most often mentioned public concern about security in the longer term is the implications of higher gas dependence.

A large part of this concern seems to be about import dependence which we analysed at length in Chapter 13, and from which we concluded that gas import risks were unlikely to be as serious as many believed and that markets could probably handle those risks adequately. However there is a residual concern about diversity in a straightforward form: what might it mean, for security, to have an economy dependent on gas for perhaps 50% or 60% of all its primary energy use? We assume that the increased dependence of the UK on gas would be matched by other major economies.

Little can be said with confidence on this subject. If of course gas becomes scarcer, its price would rise, and the expected level of dependence would probably be less. But let us imagine that gas dependence does rise continuously to 2020 and that substantial imports are needed. Further developments in international traded gas would be certain with new suppliers by pipeline emerging for example from Central Asia as well as further imports from existing suppliers with large gas reserves in Russia, North Africa and the Middle East. Critically, new LNG supplies would make a substantial contribution to reducing both transit and source dependence.

Would a lower carbon economy help? (this is likely to be a major policy driver to 2020). It seems that renewables and nuclear power, both offering diversity as well as low carbon benefits, might collectively not take up a very different share in overall energy balances from today's. Nuclear power may well decline further beyond 2010 and renewables will probably grow. If on the other hand nuclear starts to grow again this might be at the expense of renewables. Large growth in combined nuclear/renewables is unlikely in the period up to 2020.

Finally many current DTI consultees on energy policy regard enhanced energy efficiency as a major key to better security, as well as a major plank in low carbon policies. Higher rates of improvement in energy efficiency are quite probable in the period to 2020 for both economic and policy-driven reasons. Will this help security much? It is difficult to be very confident that enhanced efficiency will make a large impact. In capacity terms, the supply system is likely to contract (or grow more slowly) to match demand levels, so there is no obvious security benefit there. There could be an effect of reduced gas imports. The logic would be lower gas demand and therefore lower gas imports. But it less clear that gas *dependence* would necessarily fall, and so impacts on security might be limited.

19. CONCLUSIONS

The main starting points in considering the 'right' level of security are:

- Consumers' willingness to pay for higher security levels, which tends to fall as risks to security are reduced
- The costs of providing extra security, where the costs tend to rise as risk levels are reduced.

In principle, an 'optimal' level of security can be calculated from this information, such that the value of extra security to consumers just matches the cost of providing it. In practice, exact calculation is impossible, and for most kinds of security risk there will be a 'zone of adequacy' where both the valuation of security and the extra costs of providing it will be relatively stable. An objective of policy is then to ensure that security levels are within that 'zone'.

However such a policy objective does not necessarily imply Government action. A well functioning market system could well provide adequate levels of security, and would certainly do so under the (restrictive) assumptions of perfect competition[77]. Under the former state-owned monopoly provision of gas and electricity, security levels were in some respects high, but the corresponding costs of providing such security were also substantial. The empirical record is not complete, but indicates that security is in some respects at higher levels under liberalisation than under monopoly.

At a general level, there is a widely held view that private markets tend to under-invest due ultimately to their presumed use of a higher private discount rate than the social ('correct') discount rate. This is a large subject with economy-wide implications and we did not consider it warranted a different treatment of the energy economy or energy security in comparison with the economy as a whole. It is therefore not a specific barrier to market provision of energy security.

The important practical question is whether, relative to consumers' willingness to pay (valuation of security), the current market system produces adequate security levels, or whether there are material barriers or obstacles to its ability to do so. There are two main kinds of barrier that are possible:

- Market failures, where the internal workings of the market may prevent the market from delivering adequate security (some markets will be absent)

[77] The economists' concept of Perfect Competition requires not just a good number of competing firms but also, among other things, an absence of externalities and public goods. It also takes no account of distributional issues such as fuel poverty.

- Other barriers, generally political or regulatory in origin, and sometimes potentially international, that may have the same obstructive effect.

We have examined a wide range of potential barriers, of both types, and have asked the general question whether they seem likely to provide a material obstacle to market provision of security. More specifically we have asked:

- Are there *theoretical* grounds for considering that there may be obstacles or barriers preventing consumers expressing their willingness to pay for security, or investors from responding to it?
- Are there *observable* barriers or obstacles that prevent consumers expressing their willingness to pay for security or, again, investors from responding to it, or which lead to excessively costly ways of providing security?
- Does meeting the current level of security expose consumers to risks of insecurity or actual incidents that impose a very high cost on them?
- How material do any such practical barriers appear to be, and is it likely that in trying to overcome them, can Government tackle them directly, or will some less direct method be needed to compensate for the problem to which they give rise?

The 'public goods' issue. There are limited but important 'public good' characteristics in gas and electricity supply. For small consumers, provision of service is collective among groups of consumers (all are fed by the same pipe or wire). In the absence of real time metering, it is in practice impossible to offer different levels of security to those on the same network.

The implications of these market failures for the adequacy of security are not clear. While theory suggests that the existence of public goods leads to under-provision of security by markets, it is difficult to be definitive about the real world adequacy of GB levels of security. However, there is little evidence that those who cannot make their valuations of security count in the market would systematically wish to pay for higher security levels than those who can signal their valuations to the market. A significant proportion of households suffer from fuel poverty and their willingness to pay for more security is necessarily limited. There is therefore an argument on distributional grounds for saying that wherever security levels are within the 'zone of adequacy', the preferred direction of adjustment, at least marginally, should be towards higher security levels.

Demand side participation in the market Largely because of the public goods problem, small consumers are effectively unable to make their valuation of security count in the market place. Participation by larger consumers has also, despite the intentions of NETA, been limited (though this may be largely because it has been unprofitable to do so due to excess capacity in the market). The inability of small consumers to make their valuation count in the market place is a market failure and its removal would help market participants both to understand consumer valuations of security better, and also allow a wider range of market responses to given security risks. Much of the problem can be tackled directly through encouragement of technological change, mainly better (real time) metering among small consumers. More general arguments that market failures inhibiting demand side investment do not seem effective in relation to security, as enhanced energy efficiency will probably only marginally improve security.

Possible market failures relating to short-term operations There are several related possible market failures that might arise from the existence of many firms in a market, especially where previously there was only one. Market failures here would derive from information asymmetries, or a lack of relevant information. Examples could be the lack of information about planned down-times (for maintenance) of electricity or gas plant, or a lack of information transmitted between gas and electricity market players, necessary because of increasing interdependence of the two markets. The result might be too low a level of security provision.

In practice, we found little evidence that these effects are important, and as a consequence any inability of the market to deliver adequate security for these reasons seems unlikely to be material. This is true for interactions between gas and electricity markets as well as for each market considered alone

Possible failures in long-term investment incentives There is a possible market failure, which might arise under NETA. Market mechanisms probably encourage sufficient investment in advance of anticipated demand increases. However, when there are transitory shocks, creating sudden shortages and sending prices to potentially very high levels, NETA is vulnerable to the intervention of political or regulatory authority to cap prices (thus removing the market at its peak). Anticipation of such intervention will tend to damp investment incentives because potential investors will expect that they cannot recover their full costs. The problem seems endemic to electricity markets. As such it seems a serious potential barrier to security of supply and warrants further investigation. It could be tackled directly by changing market design arrangements.

The gas market has similar characteristics to the electricity market, but market failure seems much less likely here. This is mainly because the availability of substitutes for gas for large consumers will cap peak prices at much lower levels than in electricity, and minimise the risk of an absent peak market because intervention is much less probable.

Possible inadequate provision of diversity Possible market failures here include the idea that in conditions of uncertainty about the future, market players might all choose similar investment types, fuels, technologies etc. The theoretical case here is not strong: in conditions of uncertainty, it may be rational for all players to follow similar paths – the underlying problem being uncertainty rather than market failure. Some evidence is not favourable to this 'herd instinct' idea either. The 'dash for gas' has led to much greater diversity of fuels in the electricity generating system, and other dimensions of electricity diversity have also improved.

There has been a move towards greater dependence on gas across the whole energy economy (and this will almost certainly grow) but there is little to suggest that this is an inappropriately high degree of dependence, or market failure, given that the 'right' degree of diversity also depends on the cost of its provision.

A second kind of market failure could lead to inadequate diversity in gas facilities (in particular gas reception terminals). Large gas reception terminals consist of a number of separate but spatially close sub-terminals. The sub-terminals have been added incrementally, and for the owner of the most recent sub-terminal, the risk of facility failure is a cost only in respect of his/her lost output (balanced against the economies of locating at an established 'hub'). However the loss of output if the whole terminal fails will apply to all other sub-terminal owners, and the probability of a whole terminal becoming vulnerable increases as facility dependence rises. Owners of earlier sub-terminals would therefore have faced lower risks at the time of their decisions and therefore an externality could be present.

The barrier here could be material. However the probability of such a loss of supply from such a terminal is much more difficult to ascertain from the evidence available – there are issues of protection from external threats as well as purely technical risks. The barrier could be material (subject to further work for example on the probability of failure). An obvious Government intervention here, and correction to the market failure, could be direct – for example, disallowing further sub-terminals where there is already a large concentration of sub-terminals.

Possible barriers arising from increased dependence on imported gas Imports in themselves are not evidence of market failure. Rather they are the product of a market working *well* to obtain low-cost supplies. Imports in themselves add to diversity of sources and therefore directly *contribute to* security.

There may be new security *risks* here, connected to a range of possible sources of interruption to supply: from unreliable political sources; from disruptions to transit routes and facilities; and from the possibility of stalled European energy market liberalisation. Increased but unavoidable *risks* to security are not in themselves *barriers to market provision* of adequate security, or grounds for Government intervention. Adequate levels of security may well fall over time in the face of unavoidably increased risks.

The barrier here would therefore be the inability of markets to cope with international political risk. The evidence appears to be that markets are working well to diversify and control security risks. Early import contracts are for supplies from Norway and the Netherlands, which represent low political and commercial risks, and minimise the length and complexity of transit routes. The evidence so far is that market players should handle these risks adequately.

Steady progress in European gas liberalisation would assist UK security by developing a deeper and more connected market. Slow progress might in such cases provide an extra risk to UK security, and the UK Government is already directly pursuing more rapid liberalisation across Europe. Market actors are however unlikely to rely on such progress, and will probably seek their own direct remedies to any extra risks they perceive, such as seeking contractual terms covering security issues.

Possible UK regulatory barriers Some regulatory actions will affect the competitive market and could therefore provide a barrier to the market's ability to provide adequate security. The interface between the offshore and onshore gas regimes could provide one such barrier, but there is no evidence of any significant effect.

Another barrier could be the new arrangements for auctioning long-term entry capacity. It is not clear yet whether these arrangements will constitute a materially significant barrier. It is possible that it will prove to involve mainly transitional problems of a kind that are inevitable whenever a regulatory change affects market incentives.

Possible UK policy barriers The Renewables Obligation, part of Government's pursuit of environmental objectives, probably constitutes the largest market intervention in electricity currently proposed by Government. The barrier here is that the Obligation might prove a disincentive to private investment through depressing prices in the wholesale market and leading investors to expect further commitments to renewables, compounding the difficulty of incentivising private investment. However, if only a proportion of future investment is expected to come from the Obligation, the barrier may be of limited materiality.

Environmental restrictions on electricity generation could prove a barrier to using some fuels (especially coal or oil) when markets become tight. However, to the extent that there is flexibility in the application of emission limits, the extent of any such barrier will diminish, and the current direction in environmental control is towards such flexibility. This does not seem likely to be a material barrier.

The planning system could be a major barrier to the ability of investors to implement projects expressing consumer valuations of security. This will be the case especially if planning delays (and refusals) are uncertain, and different between different projects. In the case of electricity, there are few signs that planning has provided a significant barrier to security. However, security-related projects in gas tend both to be large and location-restricted. Projects like storage sites are already showing signs of being seriously delayed by the planning system, and it seems probable that without planning reform the problem could become worse. Planning seems likely to be a serious barrier to gas security, and Government is already actively tackling the barrier directly.

Government in the UK has shown willingness to intervene in electricity and gas markets – especially electricity markets - where there have been perceived problems. Governments elsewhere, including those presiding over liberalised energy markets, have also in recent years intervened where security of supply was threatened. If markets expect Government to intervene in serious enough security events, there will be reduced private incentives for markets to provide as much security as consumers desire - markets will under-provide security. Such market expectations are probably a material barrier to adequate security provision and will lead to under-investment in security

Directly tackling this barrier is difficult. A number of indirect approaches are possible, including the use of private contracts, and reducing the rewards for intervening (for instance by designing markets to smooth power prices so that price-capping becomes less necessary). Ultimately however this may be the most difficult barrier of all to overcome.

International experience Appendix C provides some information on how other countries with liberalised systems have treated security of supply issues. The sample is limited but suggests that direct action in market design for electricity to establish an explicit mechanism to reward capacity (as a means of encouraging investment) is not uncommon. In gas, explicit security regimes are difficult to find.

The longer term It is difficult to know the kinds of energy market conditions which will face markets and Governments tackling security of supply issues in the period 2010-2020. Further increases in gas dependence seem likely, as does greater emphasis on energy efficiency. We tentatively conclude that gas and gas import dependence may be a less serious issue than often supposed, but that (oppositely) enhanced energy efficiency is not likely to be a very effective tool for promoting more adequate security.

APPENDIX A. AN ELECTRICITY MARKET PARADIGM

A.1. Generation Cost Conditions

The paradigm begins with the recognition that electricity is generated by a variety of technologies, each of which has different cost characteristics.[78] For clarity of exposition, the paradigm is normally presented in terms of three technologies as follows:

Table A.1
Cost Characteristics of Typical Production Technologies

Type	Annual Fixed Cost	Variable Cost per Unit
"Baseload"	High	Low
"Mid-Merit"	Mid	Mid
"Peaking"	Low	High

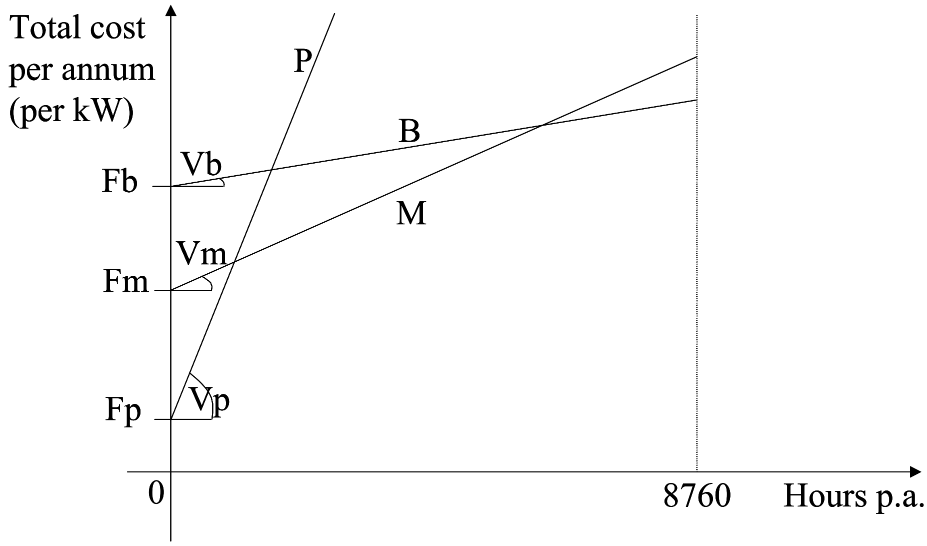
In practice, the nature of these technologies changes from time to time. In 1990, baseload generators included both "must-run" plant (run-of-river hydro and nuclear) and coal-fired generation; mid-merit plant meant oil-fired generation. By 2000, however, gas-fired generation had largely supplanted the role of coal as a baseload technology and coal-fired generation had been pushed into mid-merit. Recent rises in gas prices and the change in market arrangements have reversed this trend to some extent. These changes show the risks associated with long-term investment in generation and the associated pressures for risk management (for example, diversification of fuel sources). The paradigm takes costs as given and users must therefore make separate allowance for risk.

Figure A.1 shows the total annual costs (per kW of capacity) for the three basic types of generation: baseload (b), mid-merit (m) and peaking (p). Each type of plant is represented by an annual fixed cost per kW (F) and a variable cost per kWh (V). Total annual costs therefore vary according to the number of hours that capacity runs in a year, up to the maximum of 8760 hours (= 24 x 365). For example, a kW of baseload capacity has a relatively high annual fixed cost of **Fb**, which the plant incurs even if the plant does not run for any hours during the year. Hence, at 0 hours (on the left hand side of the figure), the annual cost per kW for baseload capacity is Fb. If the plant runs, its costs increase, at a rate equal to **Vb**, the unit cost of output from baseload capacity. The line marked **B** represents the relationship between annual hours of operation and total annual costs for baseload

78 One may ask why cost conditions should fall into this neat pattern and the answer is "by elimination". Any plant for which both costs were high, or for which one cost was high and one middling, would be uneconomic compared with at least one other technology. As a result, it would be ignored or devalued, until either its fixed or variable costs fell sufficiently to make it competitive against the technologies shown, in which case it would replace one of them. In principle, costs need not be only "high", "middling" or "low", but can take any value. As a result, it is possible for many technologies to be economic. However, in practice, it is rare for more than three technologies to achieve least-cost status at any one time. Other technologies may be left over from previous eras but must compete with those that are currently least-cost.

plant. (This report will refer to "hours" even though electricity markets may use half-hours or even shorter periods for settlement purposes. The analysis applies for different settlement periods, but the arithmetic is complicated by conversion factors.)

Figure A.1
Annual Costs per kW for Different Types of Generation



Mid-merit plant has a slightly lower annual fixed cost per kW of **Fm**, but a slightly higher variable cost per kWh of **Vm**. The cost function of mid-merit plant is given by the line marked **M**. At zero hours of operation, the cost of mid-merit plant is lower than the cost of baseload plant, but its costs rise rapidly if it runs. Mid-merit plant is more expensive than baseload plant if running for most of the year (ie, line **M** rises above line **B**).

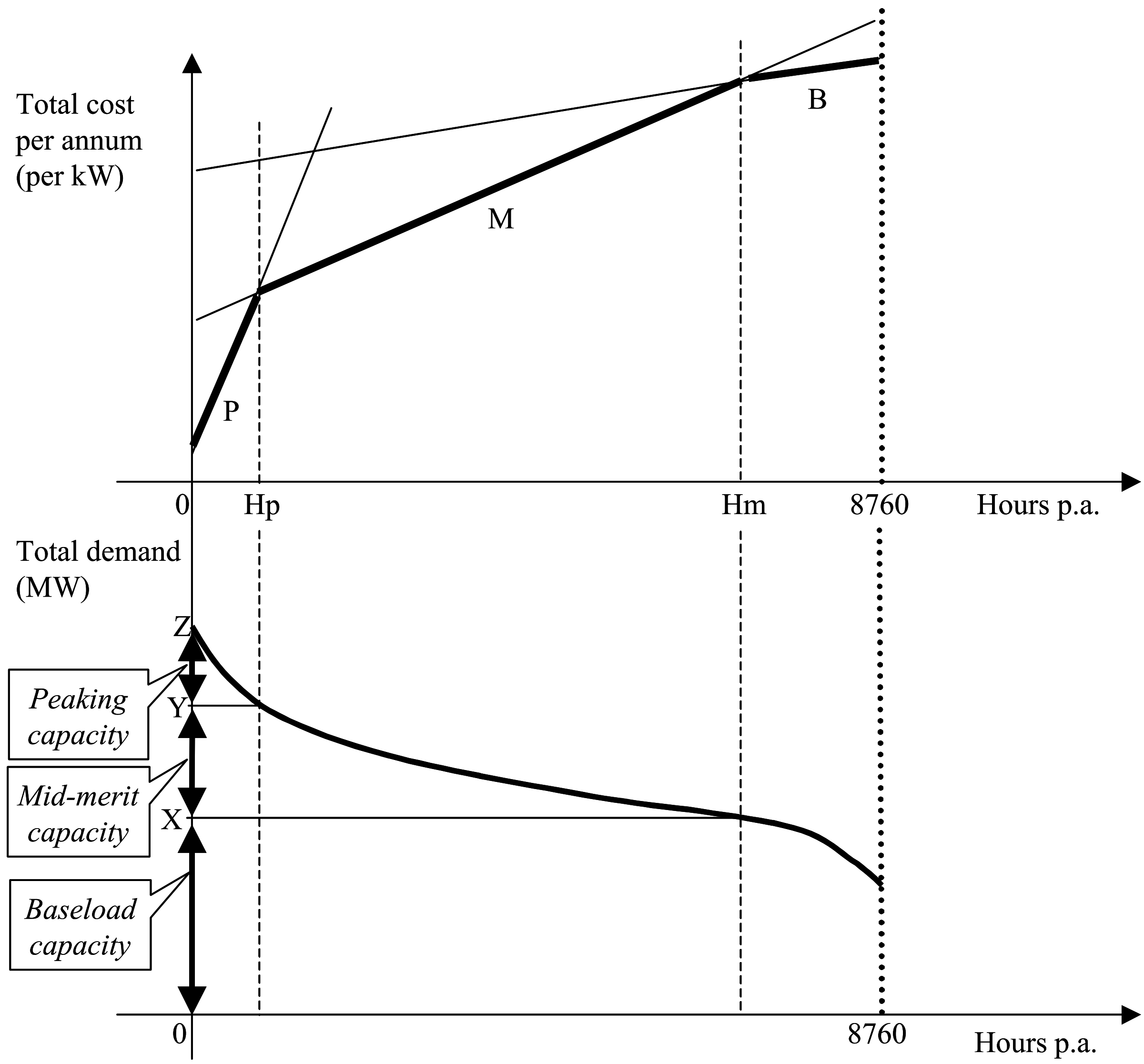
Similar, for peaking plant, the annual fixed cost per kW is very low, at **Fp**. However, its variable cost per kWh, **Vp**, is very high, so that the total annual costs of peaking plant are very high, if it runs for more than a few hours in the year.

Given these three technologies with different cost conditions, it is possible to calculate an efficient pattern of investment, sufficient to meet peak demand with the least total cost.

A.2. Efficient Least-Cost Investment

It is possible to identify an efficient portfolio of investment/by comparing the cost conditions in Figure A.1 with the demand conditions shown in Figure A.2. Here, the top half of the figure shows the same three cost functions, **B**, **M** and **P**, as in Figure A.1. The darker line indicates the least-cost technology at different levels of operation over the year. If the plant is expected to run for only a few hours (less than **Hp**), then peaking plant is the cheapest form of generation, because its low fixed costs outweigh its high running costs. For plant expected to run between **Hp** and **Hm** hours, mid-merit plant has the lowest costs overall. For any plant expected to run more than **Hm** hours per year, baseload technology is the cheapest, as its low variable costs more than compensate for its high fixed cost.

Figure A.2
Efficient Capacity Planning Model



The lower half of the figure shows a "load duration curve", a conventional presentation device in the electricity industry. On the left hand side is the hour with highest demand; on the right hand side is the hour with lowest demand. Other hours are arranged between them, in descending order of demand. Reading horizontally, one can see the number of hours ("duration") in which demand is equal to or higher than any particular level. (For planning purposes, the measure is a forecast, based on historical data.)

The figure shows the boundaries **Hp** and **Hm** transposed onto the load duration curve. The interpretation of this graph is that a least-cost portfolio of generation would include baseload capacity of OX, mid-merit capacity of XY and peaking capacity of YZ. Then if, in any hour, generation capacity operates in least-cost order *with respect to its variable costs*, each plant will run for a number of hours per year at which it represents the least-cost technology. Baseload capacity will run for long periods (greater than **Hm**), ie nearly all of the time. Mid-merit plant will run for up to **Hm** hours, but will be restricted to hours when demand is higher than OX. Peaking plant will only run when demand exceeds OY, and will not run for more than **Hp** hours.

A.3. Energy Revenues, Capacity Payments and Security Standards

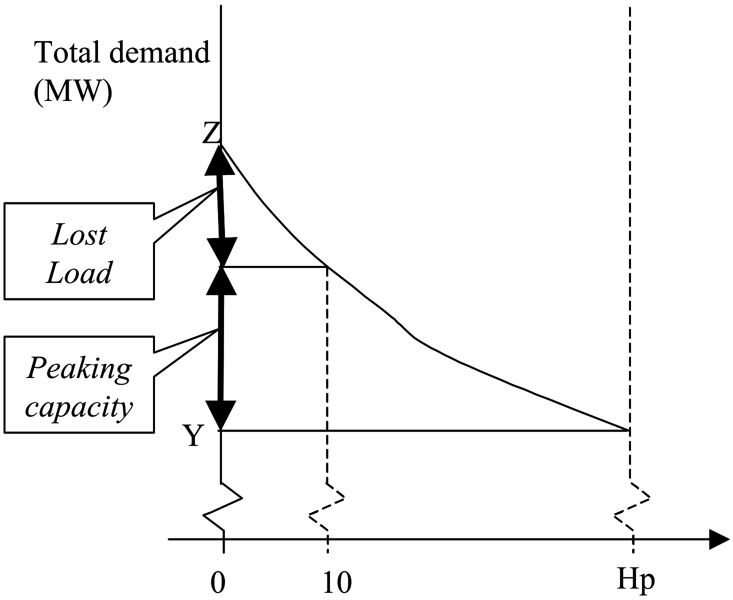
Even under monopoly systems, central planners noted the implications of this paradigm for tariffs and revenues. They assumed that the efficient (wholesale and retail) price per kWh of energy would be the "system marginal cost", ie the marginal cost of meeting an extra unit of demand. In hours to the right of **Hm**, that cost is represented by **Vb**, the variable cost of additional output from baseload capacity. In hours between **Hp** and **Hm**, system marginal cost is **Vm**, the variable cost of mid-merit capacity. For hours below **Hp**, the system marginal cost would be **Vp**, the variable cost of peaking capacity. Unfortunately, this system overlooks a number of problems and complications.

First, the planners noted that, if prices or tariffs only reflected variable costs, they would not recover the whole costs of the system – which would prevent efficient investment from taking place. Further examination of the cost structure set out above proved that the "missing" amount of revenue was equal to **Fp**, the fixed annual cost of peaking generator, multiplied by the total amount of capacity on the system. This observation led to the design of various "capacity payments" to augment energy charges.

Second, however, planners noted that building generation capacity sufficient to meet demand of OZ was inefficient, since consumers were not willing to pay as much as **Fp** for consuming energy in the hour of peak demand. They usually adopted a lower security standard, for instance a policy of anticipating 10 or 20 hours per annum of "lost load". Figure A.3 is merely a close-up of the peak demand section in Figure A.2, but shows the rationale for such standards.

In this case, the planners have decided to build total capacity that is sufficient to meet total peak in demand in all but 10 hours. In those 10 hours, demand would rise higher than the level of total capacity, so some demand must be cut-off ("lost") by the system operator. In principle, the efficient level of lost load depends on a trade-off between capacity costs (**Fp**) and the "value of lost load" (VOLL).

Figure A.3
Peak Demand Conditions



Suppose that the fixed cost of building and maintaining a kW of peaking capacity (**Fp**) is equal to £20 per year. (Assume also that variable costs, **Vp**, are relatively small and can be ignored here.) Suppose consumers are willing to pay £2/kWh to maintain supplies at times of peak demand. The planners have a choice:

1. Build one more kW of peaking capacity at a cost of £20 per year; or
2. Cut of 1 kW of load for 10 hours per year.

The second option means an extra 10 kWh of lost load per year, at a value of £2/kWh, giving a total cost of £20 per year, the same as the cost of building peaking capacity. If there were less peaking capacity, there would be more hours of lost load, and option 1 ("Build") would be cheaper than option 2 ("lose load"), so there would be a signal to invest. If there are less than 10 hours of lost load per year (on average, taking several years together), there would appear to be excess capacity, which provides a signal that it may be efficient to close plant. A similar set of comparisons between the costs of peaking, mid-merit and baseload stations will show what type of plant should be built, depending on the number of hours it is expected to run. In practice, the answer is usually a peaking plant or a baseload plant: mid-merit capacity is nearly always old plant displaced from a baseload role by newer, more efficient technologies.

In a planned system, the choice of security standard (i.e. the desired average annual number of hours of lost load) directly determines the level of investment in capacity in a planned system. This approach is not directly relevant to a market system, but it can be adapted to show what an electricity market would look like, if it offered similar incentives for efficient, least-cost investment.

A.4. Extending the Model to Cover Market Conditions

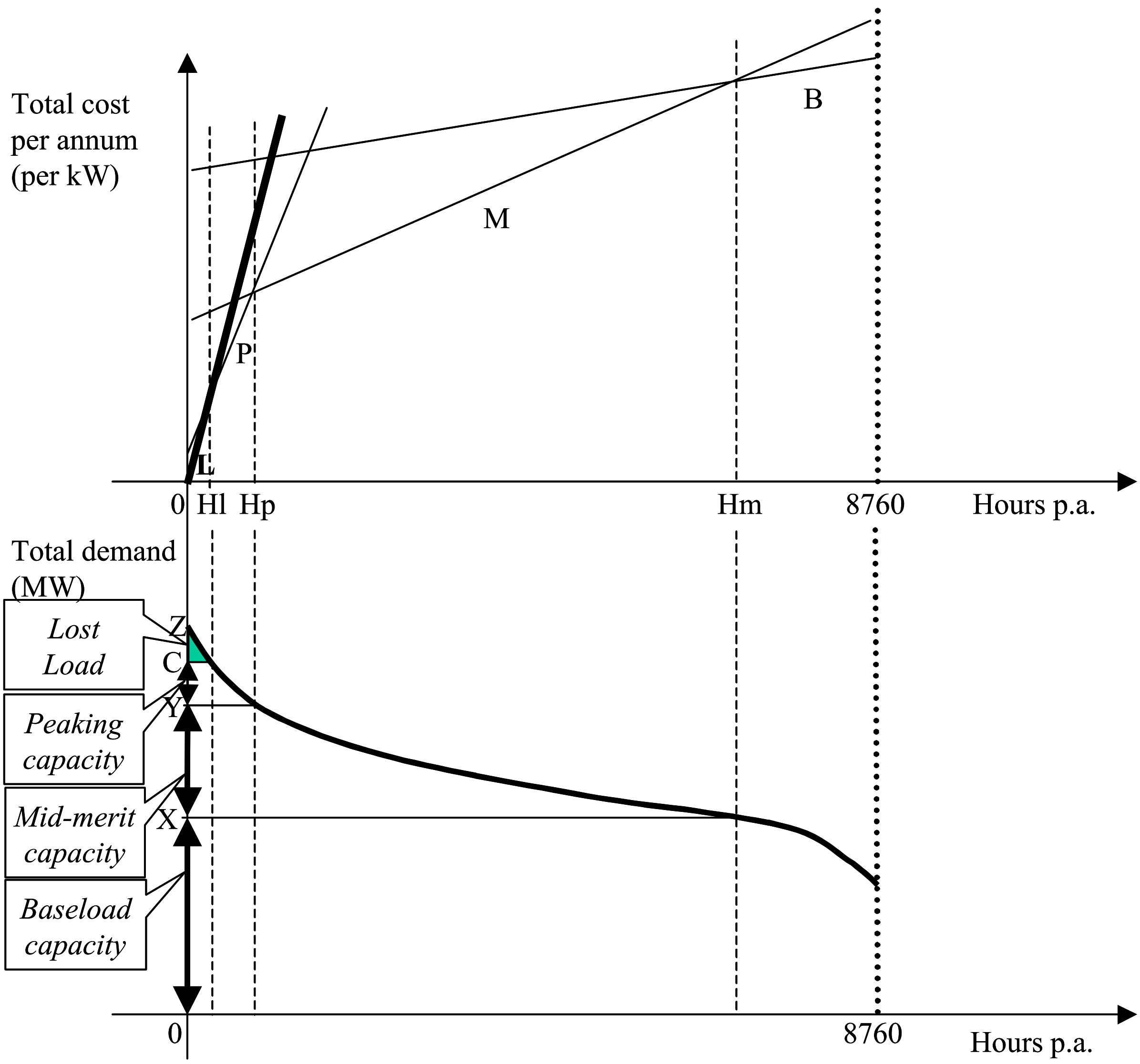
To convert the analysis above into a market paradigm, it is necessary to recognise that demand-response – in the form of load-shedding – is an alternative method of balancing supply and demand, to be placed alongside the generation technologies shown in Table A.1. For simplicity, we will examine only the possibility of losing load at peak times and will refer to a single value of lost load, meaning the value that applies at peak times when consumers are being forcibly interrupted. Table A.1 can then be extended with a "fourth technology", losing load, which has a zero annual fixed cost, but a very high variable cost per kWh of lost load, as in Table A.2.

Table A.2
Extend Table of Cost Characteristics

Type	Annual Fixed Cost	Variable Cost per Unit
"Baseload"	High	Low
"Mid-Merit"	Mid	Mid
"Peaking"	Low	High
"Lost Load"	*zero*	*VOLL*

This information can be added quite simply to the diagram of cost conditions and capacity planning, by incorporating an additional line, **L**, to represent the possibility of losing load.

Figure A.4
Market Determination of Capacity Investment



This line creates another cross-over point, Hl, below which losing load is cheaper than building and using peaking capacity. The efficient decision is therefore only to build capacity up to the level now marked as "C" and to shed load when demand exceeds that level. The volume of lost load is shown in Figure A.4 as a shaded triangle in the top left-hand corner of the load duration curve.

A.5. Implications for Electricity Market Pricing

The implications of this adaptation become apparent when applied to a competitive electricity market, given two key assumptions about the way in which competitive markets work:[79]

1. **Producers will select the least-cost combination of output.** Given that fixed costs are unavoidable from hour to hour, producers will minimise variable costs by running only baseload plant when demand is low, calling on mid-merit plant only when demand rises above OX and using peaking plant only in the rare hours when demand exceeds OY. Producers will continue to serve demand as long as they have capacity available and load-shedding will only be necessary if demand would otherwise exceed OC.

2. **Market prices will settle at the marginal cost of the most expensive producer chosen or at VOLL.** Competition normally drives down prices to marginal costs and the electricity sector is no exemption from this rule, although the marginal costs for the market (or "system") will be determined by the plant type with the highest variable cost that is called upon in the least-cost combination.

As before, this means that the price of energy will equal the "system marginal cost", but in the hours of lost load there is a new definition of this term. Instead of peak prices being set equal to the variable cost of peaking plant, **Vp**, with some capacity payment required to recover total costs, prices are now set equal to VOLL – the variable cost of shedding load – in the few hours when demand exceeds capacity.

The revenue from sales at VOLL in these hours substitutes for the capacity payment described in section A.3 and, in an efficiently built system, will equal the capacity cost of a peaking plant (as per the analysis in that section). If there are a lot of hours of lost load, these revenues (annual hours of lost load x value per kWh of lost load) will exceed the cost of adding capacity (annual cost per kW) and will encourage investment. If there are few hours of lost load, there is excess capacity and it may be efficient to close plant.

In an electricity market, therefore, the incentive to invest depends crucially upon the market price that applies when load is being lost, and the expected number of hours in which load will be lost over the life of the investment. Box A-1 provides an equivalent analysis in terms of conventional supply and demand diagrams.

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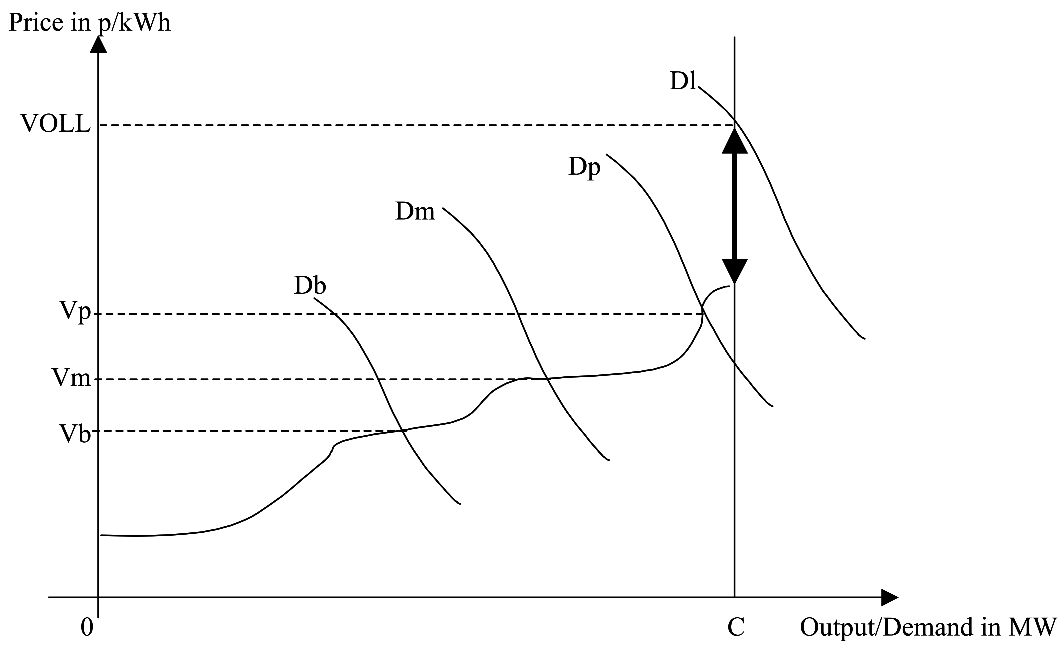
79 The decision to replace monopolies with markets rests on the belief that these conditions apply in markets or apply at least as much in markets as in monopolies, or do not apply at least as much as under a monopoly, it is open to question whether markets offer any advantage over monopolies in the electricity sector.

Supply and Demand Analysis

In the diagram below, demand can take one of four (typical levels), labelled by reference to the plant type required to operate: baseload (Db); mid-merit (Dm); peaking (Dp); or exceeding capacity (Dl). In each case, the market price is given by the variable cost of the marginal plant (Vb, Vm, Vp) or VOLL in the case where load is being shed. The incentive to invest in generation capacity depends on the frequency with which these (typical) demand conditions arise and, in particular, the frequency with which demand reaches Dl, such that load is lost, the price rises to VOLL and generation capacity receives the additional revenue needed to cover fixed costs, as marked by the double-headed arrow.



APPENDIX B. A GAS MARKET PARADIGM

B.1. Gas Production, Storage and Transportation Cost Conditions

We begin with the recognition that gas is produced and made available by a variety of technologies, each of which has different cost characteristics. In the case of gas, it is important to recognise that we have to take into consideration not only gas field production facilities (e.g. in the UKCS), but also the various means for storing gas that can meet the variations in gas demand over the day and over the year. Transportation pipeline capacity not only carries the gas but also has limited storage capabilities (i.e. line pack). The flexibility offered by LNG that is carried by ship, together with the storage, transhipment and re-gasification facilities, is also part of the cost paradigm.

Like electricity, we can present the paradigm in terms of three technologies as follows:

Table B.1
Cost Characteristics of Typical Gas Production and Storage Technologies

Type	Annual Fixed Cost	Variable Cost per Unit
"Baseload"	High	Low
"Mid-Merit"	Mid	Mid
"Peaking"	Low	High

The nature of these technologies has remained broadly the same over the years. Thus "base load[80]" is largely supplied by gas from producing gas fields in the UKCS and by supplies from further away. In the past there were substantial supplies from Norway and in the future gas might come not just from Norway but also from other gas producing basins including the Netherlands, Russia, Algeria or the Middle East. The UK–Belgium interconnector is an important part of the market paradigm for gas and acts rather like base load but is capable of flowing gas both into the UK and from the UK into Continental Europe.

The "mid-merit" supplies would come largely from storage designed principally for seasonal supplies (to help meet severe winter demands in a 1-in-50 winter) such as the depleted offshore Rough gas field and the onshore salt cavities at Hornsea and elsewhere.

Finally, strategically sited LNG storage tanks located at the geographic extremes of the gas network in Great Britain provide the "peaking" storage facilities. These are designed to

[80] The term "base load" we have used here is more commonly associated with the electricity industry, but we have kept it here in the gas industry section to better enable a comparison with the analysis in the earlier electricity section. In any case gas production does serve the same purpose as base load power generation by providing the main source of gas throughout the year.

meet the sudden demands that occur on a 1-in-20 peak day and help maintain supplies particularly to customers with high heating loads in the winter period.

In addition to these facilities, the gas industry has the ability to interrupt a large volume of load for a number of days at times of peak demand by agreement with a relatively small number of large gas customers, including power generators who can switch rapidly to alternative fuels, usually oil products such as heavy fuel oil or gas oil. For simplicity, this paradigm treats both LNG and interruptible customers as equivalent sources of gas at peak times (even though their costs differ somewhat in practice).

The pattern of costs for different types of gas production and storage facilities is broadly similar to that for electricity generation and is set out below in Figure B.1:

Figure B.1
Annual Costs per Cubic Metre per Day (m^3/d) for Different Types of Gas Supply

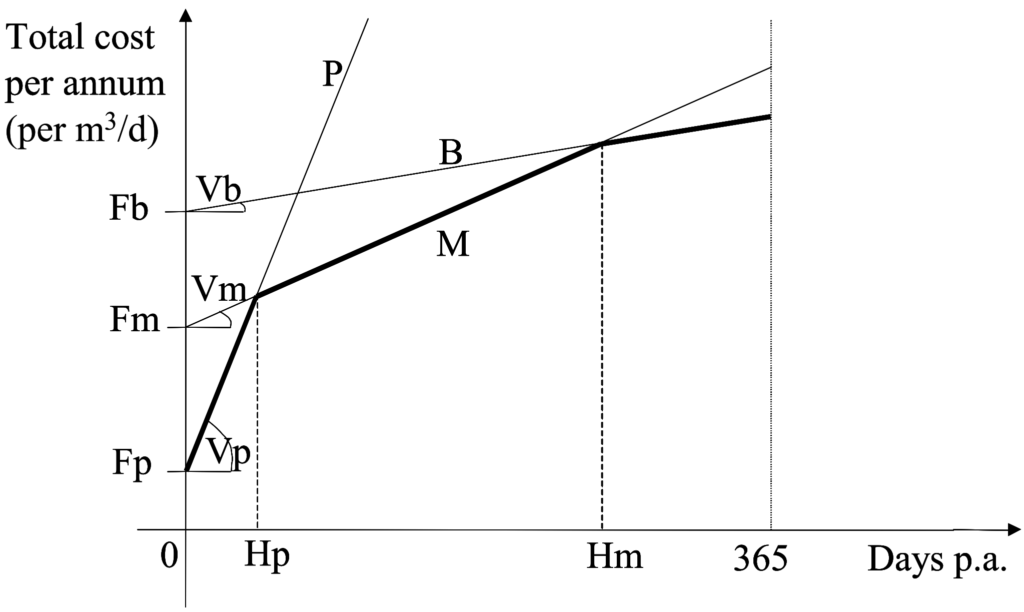


Figure B.1 shows the total annual costs per cubic meter per day or m^3/d of production capacity[81]) for the three basic types of gas production and gas storage: base load (b), mid-merit (m) and peaking (p). Each type of plant is represented by an annual fixed cost per m^3/d of demand (F) and a variable cost per m^3/d (V). Total annual costs therefore vary according to the number of days that capacity runs in a year, up to the maximum of 365 days. For example, a m^3 of base load capacity has a relatively high annual fixed cost of **Fb**, which the production plant incurs even if the plant does not run for any days during the

[81] Though not in common use to describe volume, one could use kW as the unit of measurement for capacity, because the gas industry now reports sales in kWh and it provides a useful comparison with the electricity industry. Using a volumetric measure (m^3/d) rather than an energy measure (kW) focuses attention on physical facilities.

year. Hence, at 0 days (on the left hand side of the figure), the annual cost per m^3/d for base load capacity is Fb. If the plant runs, its costs increase, at a rate equal to **Vb**, the unit cost of output from base load capacity. The line marked **B** therefore represents the relationship between annual days of operation and total annual costs for base load plant.

Mid-merit plant has a slightly lower annual fixed cost per m^3/d of **Fm**, but a slightly higher variable cost per m^3 of **Vm**. The cost function of mid-merit plant is given by the line marked **M**. At zero days of operation, the cost of mid-merit plant is lower than the cost of base load plant, but its costs rise rapidly if it runs. Mid-merit plant is more expensive than base load plant if running for most of the year (i.e., line **M** rises above line **B**).

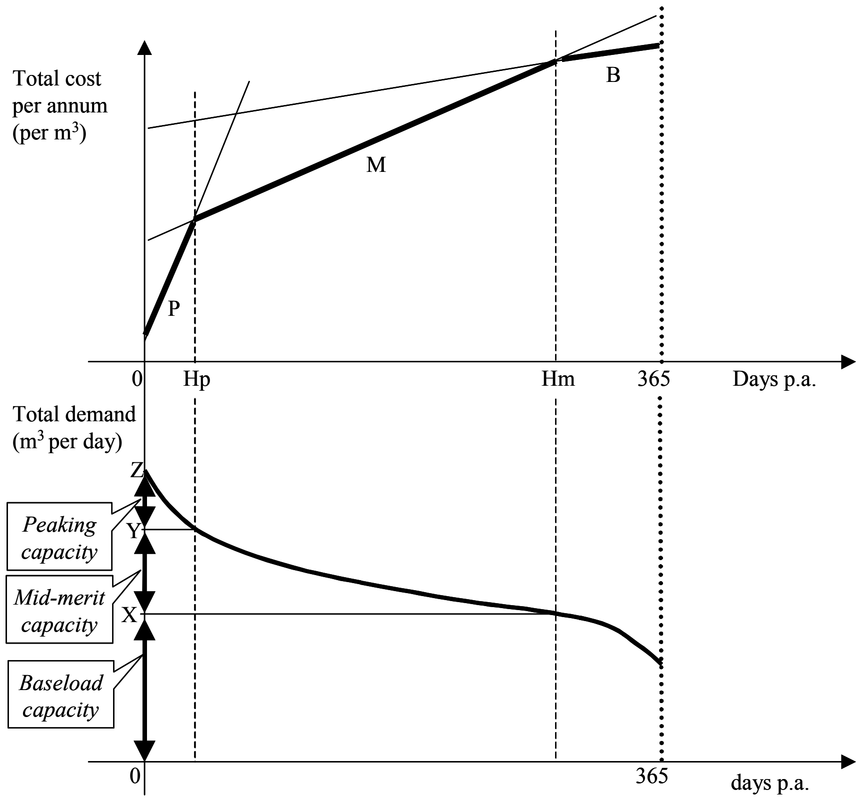
Similarly, for peaking plant, the annual fixed costs per m^3/d is very low, at **Fp**. However, its variable cost per m^3, **Vp**, is very high, so that the total annual costs of peaking plant are very high, if it runs for a lot of days in the year.

Given these three technologies with different cost conditions, it is possible to calculate an efficient pattern of investment in each one, sufficient to meet peak demand with the least total cost.

B.2. Efficient Least-Cost Investment

It is possible to identify an efficient portfolio of investment, by comparing the cost conditions in Figure B.1 above with the demand conditions shown in Figure B.2 below. Here, the top half of the figure shows the same three cost functions, **B**, **M** and **P**, as in Figure B.1 above. The darker line indicates the least-cost technology at different levels of operation over the year. If the plant is expected to run for only a few days (**Hp or less**), then peaking plant is the cheapest form of production, because its low fixed costs outweigh its high running costs. For plant expected to run between **Hp** and **Hm** days, mid-merit plant has the lowest costs overall. For any plant expected to run more than **Hm** days per year, baseload technology is the cheapest, as its low variable costs more than compensate for its high fixed cost.

Figure B.2
Efficient Gas Capacity Planning Model



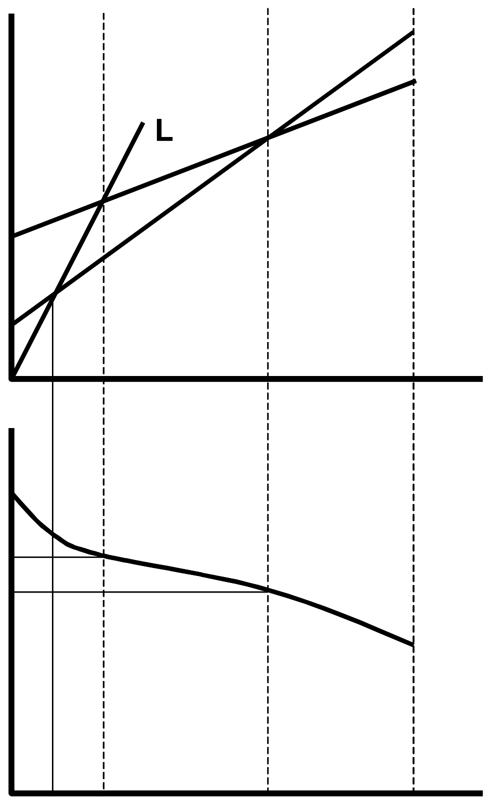
The lower half of the figure shows a "load duration curve," a conventional presentation device in the gas industry. On the left hand side is the day with the highest demand; on the right hand side is the day with lowest demand. Other days are arranged between them in descending order of demand. Reading horizontally, one can see the number of days ("duration") in which demand is equal to or higher than any particular level. (For planning purposes, the measure is a forecast, based on historical data.)

The figure shows the boundaries **Hp** and **Hm** transposed onto the load duration curve. The interpretation of this graph is that a least-cost portfolio of production from gas fields and gas storage facilities would include baseload capacity of OX, mid-merit capacity of XY and peaking capacity of YZ. Then if, in any day, production capacity operates in least-cost order *with respect to its variable costs*, each plant will run for a number of days per year at which it represents the least-cost technology. Baseload capacity will run for long periods (greater than **Hm**), i.e. nearly all of the time. Mid-merit plant will run for up to **Hm** days, but will be restricted to days when demand is higher than OX. Peaking plant will only run when demand exceeds OY, and will not run for more than **Hp** days in practice, about 45 days, that being the standard for interruptible contracts.

B.3. Revenues and Security Standards

Even under monopoly systems, central planners noted the implications of this paradigm for tariffs and revenues. They assumed that the efficient (wholesale and retail) price per m^3 (or per kWh of energy) would be the "system marginal cost," i.e. the marginal cost of meeting an extra unit of demand. In days to the right of **Hm**, that cost is represented by **Vb**, the variable cost of additional output from baseload capacity. In hours between **Hp** and **Hm**, system marginal cost is **Vm**, the variable cost of mid-merit capacity. For days below **Hp**, the system marginal cost would be **Vp**, the variable cost of peaking capacity. However, as in the electricity sector, such prices would fail to cover the costs of peaking capacity (Fp), or indeed the total costs of other capacity. As in electricity, the costs of peaking capacity are covered by gas market prices rising about Vp, due to the influence of customer demand. Customers are not willing to pay any price for gas and many customers who are not formally identified as 'interruptible' will nevertheless reduce their consumption of gas (either by reducing their total energy use or by switching to alternative fuels) when the gas price rises above a certain level. Figure B.3 shows the curtailment of demand that occurs when the gas price rises above WTP, the customers' willingness-to-pay.

Figure B.3
Gas Demand Reduction Due to Customer Action



As in Figure A.3 for the electricity sector, the line marked L shows the value of load reduction, or customers' willingness-to-pay for gas at peak times, and the shaded area shows the volume of gas demand reduction at high prices. However, this gas paradigm differs in two key respects from the analysis of lost load that applies to the electricity market:

At peak times, customers have more opportunities voluntarily to take action to reduce their demand for gas in response to high prices without the need for the system operator to impose involuntarily load shedding;

Because customers reduce their demand for gas at relatively low gas prices (e.g., prices comparable with the cost of using other fuels), production technologies can only cover their costs if customer-driven prices apply for relatively long periods, e.g. 10 or 20 *days* per year on average. (In the electricity paradigm, customers set prices at VOLL for only 10 or 20 *hours* per year on average.)

Remuneration of investments in the gas sector does not rely on involuntary load shedding by the system operator (as distinct from agreed interruptions), because supplies to a gas network cannot be easily or cheaply restored at the end of such an outage. When the gas supply is cut off, the pressure in the network drops to the point where air from the atmosphere may actually be sucked into the pipes at the burner tip, creating a potentially explosive mixture of gas and air. To minimise the risk to safety, supplies can only be restored after labour-intensive and expensive scrutiny of each customer's connection. An efficiently designed gas system will avoid such catastrophic outages in all but the most extreme conditions. Instead, peak gas prices reflect the price at which (certain) customers voluntarily close off their gas supply.

APPENDIX C. INTERNATIONAL EXPERIENCE OF SECURITY OF SUPPLY

C.1. Introduction

The focus of NERA's work for DTI on security of energy supply is the provision of security in competitive electricity and gas markets. These are the markets for production of gas and electricity and for their retail sale. Both electricity and gas also require transport (transmission and distribution), and responsibility for security in these parts of the system rests with regulated monopoly companies and with OFGEM. Because our primary interest is in the provision of adequate security in competitive markets, the potentially relevant parts of overseas experience is confined to those countries where substantially liberalisation has taken place. In other countries, which have liberalised less, approaches and interventions are likely to be very different from those relevant to the UK because they need to take less account of the impact of possible measures on the operation of competitive markets.

However in describing below security issues in the USA, Australia, New Zealand, Norway and Spain, some attention is given to security issues which are primarily concerned with the transportation system for gas and electricity, because security issues are system-wide and security problems that show up in the competitive parts of the market may have connections to monopoly segments. It may therefore be of interest to record the balance – both in terms of security problems and in policy attention – between competitive and non-competitive market segments.

C.2. Security of Supply in the USA: PJM

C.2.1. Background

The Pennsylvania-New Jersey-Maryland Interconnection L.L.C. (PJM) is in charge of the operation and control of the bulk electric power system throughout major portions of five Mid-Atlantic states and the District of Columbia. PJM has to maintain the safety, adequacy of supply, reliability, and security of the regional power system and create and operate robust, competitive, and non-discriminatory electric power markets. The region has a population of 25 million, peak load of 62,500 MW, and the PJM market has two hundred participants.

PJM considers the system as having adequate supply when there is sufficient capacity online (i.e. available in the short term) to meet load and operating reserve requirements, and there is sufficient installed capacity (i.e. available in the long term) to meet its installed capacity requirement. PJM defines an installed capacity requirement of about 120% of peak load – i.e. 20% reserve. (For 2000/01 PJM approved a 119.5% installed capacity requirement; for the 2001/02 planning period it was 119%.)

C.2.2. Security of supply

To ensure security of supply PJM takes several measures. It:

- Requires Load Serving Entities (LSEs) – companies with responsibility to distribute or retail electricity to customers - to take responsibility for meeting the installed capacity obligation, and polices their compliance with this. PJM also facilitates and administers a market for capacity (an "ICAP market") so that LSEs and generators can buy and sell capacity.
- Monitors, evaluates and coordinates the operation of the high-voltage transmission lines to maintain a reliable and secure electric system.
- Coordinates changes and additions to the grid by forecasting future needs to ensure reliability in the long-run through PJM's Regional Transmission Expansion Planning process.[82]
- Complies with the principles and standards established by the national reliability council (North American Electric Reliability Council – NERC) and regional equivalent (the Mid Atlantic Area Council – MAAC). These standards define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability.

A system is considered secure if it complies with the technical reliability criteria set by MAAC:

- Installation of generation and transmission facilities shall be coordinated to ensure that in each year for each member system the probability of occurrence of load exceeding the available capacity resources shall not be greater, on the average, than one day in ten years. (The 20% installed reserve margin has been calculated as being consistent with this one-in-ten-year criterion.)
- The system must be able to withstand a single contingency (i.e. the loss of any single transmission line, generating unit or transformer in addition to normal scheduled outages). After the contingency, the system must be capable of readjustment to normal.
- After occurrence of the outage and the readjustment of the system, the system must be able to withstand the subsequent outage of any remaining generator or line without exceeding the short time emergency rating. After this outage, the system must be capable of readjustment so that all remaining equipment will be loaded

[82] To determine cost responsibility for expansion facilities, PJM performs a "baseline" analysis of system adequacy and security. The purpose of this analysis is to identify areas where the system is not reliable; to develop and recommend facility expansion plans, and to establish what will be included as baseline costs in the allocation of the costs of expansion for those projects proposing to connect to the PJM system.

within applicable emergency ratings and voltage criteria for the probable duration of the outage.

- The system must be able to withstand the loss of any double circuit line, bipolar DC line, faulted circuit breaker or the combination of facilities resulting from a line fault coupled with a stuck breaker in addition to normal scheduled generator outages without exceeding the short-time emergency rating of any facility or applicable voltage criteria. After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

C.2.3. Installed capacity obligation

The installed capacity obligation is a key component of these security measures which has been in place from the beginning of liberalisation. It is an extension of the regulated method of installed reserve obligations that existed under vertical integration, before a competitive market was implemented in PJM. PJM has existed to pool utility resources in the Mid Atlantic region for 75 years, with a variety of sharing arrangements being in place over that time. Historically, there was a rule requiring vertically integrated utilities to meet an "Accounted-For Obligation" – meaning, to have capacity resources that exceed their peak demands by a predetermined percentage. Prior to 1997, the PJM pooling arrangements were based on reserve sharing and splitting the savings of a joint dispatch – and utilities could arrange capacity contracts between themselves to fine tune their compliance with the accounted-for obligation. In 1997, the energy pool was established, energy was traded at a market price (rather than by splitting the savings of re-dispatch cost), and a market-based mechanism of trading capacity was established by PJM. Other changes were made to the capacity rules as well, but essentially the CO is an outgrowth of the old accounted-for obligation. The modifications were designed to accommodate the restructuring that followed 1997, and in particular, the new role of "Load Serving Entities" (LSEs), who would not necessarily have physical capacity to match their customers' load.

The capacity obligation works as follows:

- Each LSE is obliged to ensure it holds enough capacity "tickets", representing physical generating capacity available to PJM, so that the LSE is able to cover its contribution to PJM peak load, plus the installed reserve (of approximately 20%). Because several states within the PJM territory have retail competition, the peak load of an LSE is a function of its success attracting retail customers. The LSE's peak load is a sum of the peak loads from a year earlier of its individual customers, although the load of most customers – who are not metered hourly – it is determined on an estimated basis. The peak in year n-1, used for estimating the peak in year n, is calculated in November of year n-1 as the average load on the five peak system hours of the previous summer.

- Generators selling capacity tickets can only sell them to one LSE, and they can only sell them for one system. (The New York system, bordering on PJM, also has a capacity obligation.) Most tickets are sold under long-term contracts. However there are also centralized ICAP auctions for contracts of shorter duration – one to three months. These auctions are run by PJM and used by LSEs to match their holdings of capacity tickets with their current portfolio of retail customers. Generators also use them to adjust their contract positions for temporary plant closures. Until 2001, the ICAP requirement was evaluated on a daily basis and PJM ran daily ICAP markets. The requirement is now measured over a longer time horizon, so the daily market has ceased.

- Generators selling capacity tickets must demonstrate to PJM that they have physical plant that is operable. They must also agree to coordinate maintenance scheduling with PJM (although they are not prohibited from declaring forced outages when necessary), and they must agree to make their units available to sell energy in PJM at the market price and curtail any exports in the event of a system critical or emergency condition within PJM.

- Generators outside of PJM can sell capacity into PJM, but they must show that it is deliverable to PJM in the event that PJM calls upon it. They must hold adequate transmission rights in the external system. PJM downgrades the capacity credited to external generators by a factor called a "capacity benefit margin", reflecting the lower value of this capacity in solving system problems.

- PJM operates a capacity register and monitors the compliance of LSEs with their capacity obligations. Any LSE that does not comply is penalized at a price based on the rate of cost recovery required by a new provider of capacity (i.e. a peaker). The penalty increases if the system as a whole is short of capacity.

Different plant types are given differing capacity values, depending on their rate of forced outage, so a 1 MW wind unit would be assigned a lower "unforced capacity" than a coal unit. (The term "unforced capacity" refers to the capacity of a unit after taking into account the effect of forced outages.) The Equivalent demand Forced Outage Rate (EFORd) rates are calculated for each individual unit on a rolling 12-month average basis.

The capacity obligation method provides revenues to generators that run very infrequently and might otherwise have closed down. It also increases the revenues to all other generators, so that these generators don't rely on market energy prices alone for viability.

The current duration of monitoring is effectively an "Interval". "Intervals" are the four-month period commencing June 1, the three-month period commencing October 1, and the five-month period commencing January 1. Changes to the customer base of a load-serving entity during an interval will not necessarily affect its CO during that interval, however unforced capacity can still change on a daily basis, depending on the status of individual units. If an LSE is non-compliant at any time during an interval, it is deemed to be non-compliant for that interval. The deficiency charge is paid only once during an interval and is based on the largest amount of megawatts a party is deficient in any one instance during the interval.

Due to the inelastic nature of the administratively determined demand for capacity, short-term ICAP market prices are volatile. They have been zero for periods of time when PJM had excess capacity; they have risen to the cost of keeping infrequently-run units open at times; and at times when the installed reserve margin has fallen below the target level (notably in early 2001) they have risen to the cost of entry. The daily ICAP market and daily penalty stopped because a majority of the members of PJM who were eligible to vote on such a rule change felt that – although daily MW volumes were low – prices in the daily ICAP market were too volatile.

Prices in the daily markets were capped at the cost of entry (or twice the cost of entry if the pool in total was deficient) because these were the penalties for a non-compliant LSE. A non-compliance LSE would not pay more for capacity than it would be penalized for being deficient. Penalties continue to be based on the cost of entry (about $58/kW-year plus forced outage adjustments).

Capacity prices and energy prices are tightly related. In the long-term, it is expected that total revenues to a generator in a competitive market will equal the cost of entry. Setting aside ancillary services, in an energy-only market, all revenue will come from energy, but in a capacity and energy market, revenues should come from both sources, unless the CO constraint is not binding. If an energy-only market would have induced a 20% installed reserve, and the installed capacity obligation is, say, 19%, then capacity tickets will have zero value. However, if an energy-only market would have induced, say, a 10% installed reserve, but a reliability standard consistent with a 19% installed reserve is demanded by politicians/ regulators, then capacity will have a value.

The potential reasons for the difference between what the energy-only market would induce and what politicians/regulators demand are numerous. In the U.S., at least, the role of demand response and price caps has been widely discussed in this respect.

Overall, the capacity obligation method appears to have met its objectives in PJM, which has not been subject to supply adequacy problems recently.

C.2.4. Future developments

On 31 July 2002 FERC (the Federal Energy Regulatory Commission) announced a Standard Market Design (SMD) to apply to all electricity traded in the U.S.[83] In this SMD, FERC has announced a new capacity adequacy requirement method, based loosely on PJM's, that will apply to the whole country.[84] The main reason given for the provision is that spot market prices alone are not expected to signal the need to begin development of new resources in time to avert a shortage, particularly since spot market prices are subject to market power mitigation measures and might not produce prices high enough when situations of scarcity arise. However the proposed new methodologies appear to suffer from a number of problems, and it is not clear that they offer any improvement on the current installed capacity (ICAP) methods used in the PJM and New York.

For example, the reason for an LSE to comply with its resource obligation is the threat of a penalty if it does not. The proposed penalty is added to the spot market price for the capacity-short LSEs when the system cannot meet the required level of operating reserves. But if LSEs are free to contract at any time to avoid exposure to the spot market, it is difficult to see how the proposed mechanism could have its desired effect. It appears that capacity-short LSEs could avoid the penalty by making sure they have energy contract cover at peak times. It is also difficult to see how the size of the penalty could be commensurate with the value of capacity. FERC suggests penalties of the order of $500/MWh when operating reserves are violated. This seems too low.[85]

Furthermore, the method proposes that spot market service to a capacity-short LSE should be curtailed first, when a shortage is severe enough to require the shedding of some consumers. It is not clear that this rule is workable with existing technology, particularly in a region with retail competition where a retailer's customers may be widely distributed within several distribution networks.

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83 The announcement was long anticipated, and preceded by a number of workshops around the country with industry representatives. The regulatory procedure regarding a NOPR is that the industry and interested parties will now make submissions to FERC, after which FERC will issue a final rulemaking. The SMD NOPR is attracting significant opposition from other regulatory and government agencies, mainly because of the new jurisdictional authority FERC intends to assert. State Public Utility Commissions, in particular, are concerned that they are losing jurisdiction regarding transmission prices to default service customers. Federal politicians are concerned about industry reform, following the California debacle. FERC, however, has significant power, and it remains to be seen how many, if any, of the major proposals in the NOPR will be modified or removed. There are large numbers of utilities both broadly for the reforms and large numbers broadly against.

84 FERC has not recently issued any comparable NOPR in the gas industry.

85 Refer, for example, to *The Adequacy of Prospective Returns on Generation Investment Under Price Control Mechanisms*, Dr. Alfred Kahn, Electricity Journal, March 2002

C.3. Security of Supply in the USA: The Californian Energy Sector

C.3.1. Institutions

The California Energy Commission (CEC) is the primary energy planning agency. Based on a model that forecasts demand under different conditions, the CEC monitors if the expected generating capacity will provide for expected demand, scheduled maintenance, emergency outages, system operating requirements, and unforeseen electricity demand. An important measure taken to ensure security of supply was to facilitate the siting process in 2001. On February 8, 2001, Governor Gray Davis signed six Executive Orders to expedite the review and permitting process of power generating facilities in California. The Energy Commission was directed by these orders to expedite licensing of power plant applications via 21-day emergency peaker projects and four-month and six-month expedited projects.[86]

A new institution, the California Consumer Power and Conservation Financing Authority (Authority) was created last year. The Authority is responsible for ensuring that electricity supply is sufficient so that Californians do not face electricity shortages or very high prices. The Authority is taking action to restore the 15% reserves that have historically been available. It has the power to determine an appropriate level of peak load plant to place under its control, and finances renewable power plants and energy efficiency programs. In a deliberate attempt (after the California power crisis of 2000/2001) to avoid over-reliance on the market, the Authority has a substantial portfolio under its control (A portfolio combining 1,000 MW of renewable energy with about 2,000 MW of peaking units and load management which the Authority can dispatch at a moments notice). This is intended to assure California of a steady stream of uninterrupted power at cost-of-service rates.

The Authority has contracts with customers to provide reserves by reducing their demand a maximum of 24 hours a month for a reservation fee payment. The Authority has accepted every customer that wants to join the program and has not set a limit for the future.

Regarding reserve plants, the Authority was going to control some peaking units. However, contract development for financing peaking units was suspended given the CPUC's decision related to the Department of Water Resources (DWR) revenue rate agreement. A small number of contracts may be negotiated only in areas where local reliability problems exist. At the moment there are not detailed plans on this respect.

The Western Electricity Coordinating Council (WECC) is a voluntary organization that develops the planning and operating reliability criteria and policies, and the facilitation of a regional transmission planning process.[87] WECC does not have an underlying definition of

[86] See Governor's Executive Order D-26-01

[87] A nation-wide institution, the North American Electric Reliability Council (NERC) is a voluntary organization that promotes bulk electric system reliability and security. NERC's enforcement is based on reciprocity, peer pressure, and the mutual self-interest of all those involved. WECC follows NERC's rules.

an adequate level of security of supply. As to assessment of security risks (capacity adequacy), WECC reviews the reported projected reserve margins and questions those that are below roughly 12%. This number reflects WECC's operating reserve requirement (up to 7%) plus not less than 5% to cover forced outages and demand variance from forecast.

The California Independent System Operator follows WECC's policies and ensures that the State's demand for electricity is covered in the short-run. When reserves fall below certain thresholds, the ISO aims to maintain reliability by keeping the operating reserves above 7%.

Natural gas regulatory reforms over the past two decades have created a situation where market forces can generally be relied on to provide additional capacity when needed. Indeed, several proposals to add about 2300mcfd of interstate capacity and 700 intrastate capacity in the next 2 years are being pursued.[88]

The CEC recommends that 15-20% excess interstate and intrastate pipeline capacity be maintained to mitigate price volatility in the gas market.

The CPUC has adopted broad, general criteria for new pipeline capacity. Following the curtailments in the late 1980s, the CPUC concluded that "slack capacity" of 10% in the near-term and up to 20% in the long-term (based on cold-year throughput forecasts) would "support the unbundled gas service structure, foster competition (gas-on-gas and pipeline-to-pipeline), and achieve a higher level of reliability of gas service in California."[89] These criteria required new pipelines to be economically justifiable.

C.3.2. Current security concerns

According to the CEC, the electricity outlook for the next several years should provide reliability and moderate prices. In the electricity market, capacity is expected to meet total demand since there is more than 11,000MW of power under construction[90] and new trading arrangements will be in place. Additionally, transmission lines under construction will relieve the most congested path in California (Path 15).

However, there are important concerns in the gas market that affect the electricity market since most of the new capacity comes from gas plants. Gas demand in California is expected to grow from 6.5mmcfd to 7.5mmcfd in the next decade. This will require more pipelines coming from the Rocky Mountains, Canada and the South West. Some of the additional capacity needed is under construction or planned, but there is still concern about part of the

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88 For more details see California Energy Commission, Natural Gas Status Report, 7/1/02

89 See D.90-02-016.

90 Mainly private generators like Calpine, Intergen, Duke and Mirant are building and planning to build power plants in California. The owners are paying for their investments, although most have long-term contracts with DWR.

needed capacity. The main drive for demand increase is the construction of new gas power plants.

Regarding state pipelines and storage, the CPUC believes that California's natural gas transportation and storage system is adequate to provide seasonally reliable amounts of competitively priced natural gas and recommends that the Power Authority should not finance any new natural gas projects.[91]

C.3.3. Important security incidents in the last 20 years

C.3.3.1. The power crisis of 2000/2001

The most important incident was the recent California power crisis. Despite the ISO's confidence that there was enough electricity available to ensure reliability during the summer of 2000, two weeks after the forecast was issued, the state was hit with warm weather and an outage of nearly 6000 MW of capacity. In 2001, there were five episodes of rolling blackouts. These episodes however, do not give a true picture of the problems that the ISO was confronting. A more revealing indicator is the number of ISO System Emergency declarations.

When the ISO forecasts a shortfall in Operating Reserves it issues "Alerts" to stimulate the market to respond to these forecasts and prevent the actual shortfalls. If the grid is in danger of instability the ISO declares a "System Emergency" and generators are obligated to respond immediately. There are 3 stages of emergency: [92]

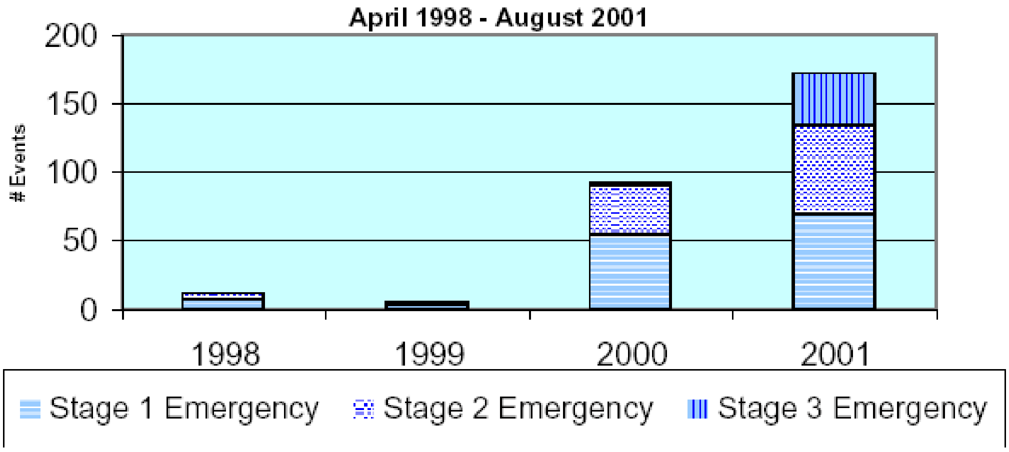
- Stage 1 Emergency is declared when an operating reserve shortfall is unavoidable or forecasted to occur within the next two hours;
- Stage 2 Emergency is declared when operating reserves fall below five percent or are expected to within the next two hours,
- The most severe stage of emergency (Stage 3 Emergency) is declared when a critical reserves fall (to below 1.5%) is unavoidable or forecasted to occur within the next 2 hours.

In 2000 and 2001 the number of Emergency Declarations increased considerably:

[91] CPUC, California Natural Gas Infrastructure Outlook 2002 – 2006

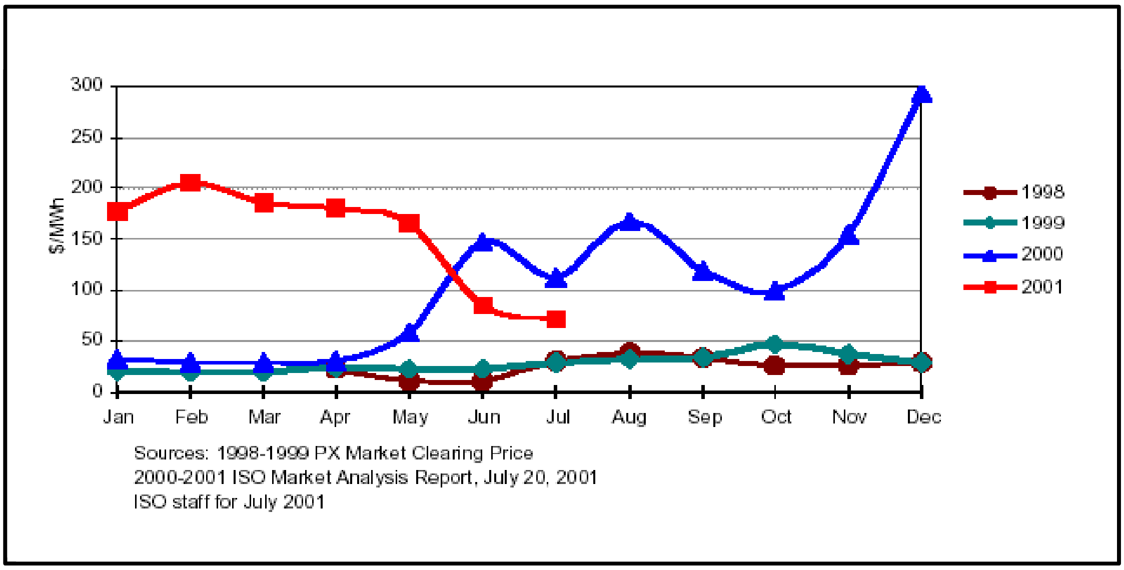
[92] CAISO, Emergency Operations Procedures

Figure C.1
ISO Emergency Declaration



As shown in the graph, reliability was considerably compromised in 2000 and 2001. Prices for electricity also reached very high levels by historic standards from May 2000 until early in 2001. Wholesale costs in 2000 (US$27 billion) more than tripled compared to 1999 ($US 7.4 billion).

Figure C.2
California ISO Average Monthly Wholesale Electricity Costs
April 1998-July 2001



The emergency declarations and increases in prices can be attributed in part to fundamental supply and demand factors, as well as to weather-related and a number of other factors:[93]

- No new significant generation had been built in California for over 10 years, increasing the state's dependence on energy imports. Imports accounted for 18% of the total GWh consumed in 1999 and 15.5% in 2001.

- It was hot all across the West in the summer of 2000 reducing available imports. Additionally, work was being done on the British Columbia transmission line.

- California had planned to have price responsive demand in the market, but this was lost when the Public Utilities Commission decided to freeze the retail rates at 1996 levels and these fixed prices did not reflect high wholesale market prices. Moreover, even in the one case, San Diego Gas and Electric, where market prices did flow through to customers, there was no mechanism to allow customers to be aware of and respond to those prices except after the fact

- Poor market rules exacerbated price volatility by artificially separating energy and ancillary services markets, failing to allow smooth integration between day-ahead and spot market, and containing congestion management provisions that were inefficient and led to a further lack of transparency/ inefficiency. Prior to 2000, the California wholesale electricity market did not have any explicit or separate capacity obligation, or payment. Generators were supposed to recover their capacity costs when their marginal cost was below the market price (system MC) so there were no explicit capacity payments.

- California's power market was not fully competitive. Some of the high prices were related to a poor market design, especially, the fragmentation of the electricity into many independently priced products in a series of auctions administered by the Power Exchange (PX) and ISO. This fragmentation could have provided gaming opportunities for market participants, although this has not been established. There have been many allegations of abuse of market power in California in the period concerned, but nothing has been categorically proved

- The utilities were not allowed to contract/hedge, and had to buy all their power through the Power Exchange (PX) and ISO. This lack of contracts meant that the utilities were highly exposed to any price volatility, and generators had maximum incentive, and received maximum benefit, from engaging in any price manipulation that was possible.

- The price of natural gas approximately doubled in the US during the year 2000 (see 3.2.2. below). This made gas-fired electricity generation more expensive. Also, as hydroelectric energy was not available, the gas-fired power plants in California had

[93] In 2000 parts of California experienced the hottest summer in over 100 years

to operate at higher-than-normal levels. Many of these plants reached their maximum emissions limit[94] and had to pay high penalties to continue generating, which flowed through to the wholesale cost of electricity.

By the end of the year 2000, PG&E and SCE had accumulated over $12 billion in obligations to the market since they had to pay the increased market wholesale price but could only charge the fixed retail rates. The possibility of bankruptcy was now real. Generators were reluctant to sell energy into the California market to protect themselves against risk of non-payment. This caused further deterioration in the supply demand balance and forced the federal government to intervene and require generators to supply energy to California. On January 17, 2001, the governor of California issued an emergency order allowing the Department of Water Resources (DWR) to buy electricity on behalf of the utilities for 12 days. Two weeks later the California Power Exchange suspended trading in its markets and closed its doors. In February 2001, the Governor signed AB1X, authorizing DWR to enter into long-term contracts to buy and sell electricity. The State spent about $2 million per hour, and planned to issue $10 billion in bonds– the largest municipal bond ever issued. Retail access was suspended to assist in providing DWR with a stable customer base from which to recover its costs and permit issuing the bonds at investment grade.

The supply demand balance was expected to improve as the peak demand summer months concluded and the moderate fall and winter demand arrived. Unfortunately, this did not happen. In the winter of 2001, natural gas prices surged nationwide, hydro resources were much less abundant than expected and generators that had been running full out over the summer had to come down for maintenance. There was a continued lack of supply and the ISO instituted rolling blackouts for two days in January and March, increasing concern of more lengthy and widespread blackouts in the spring and summer months.

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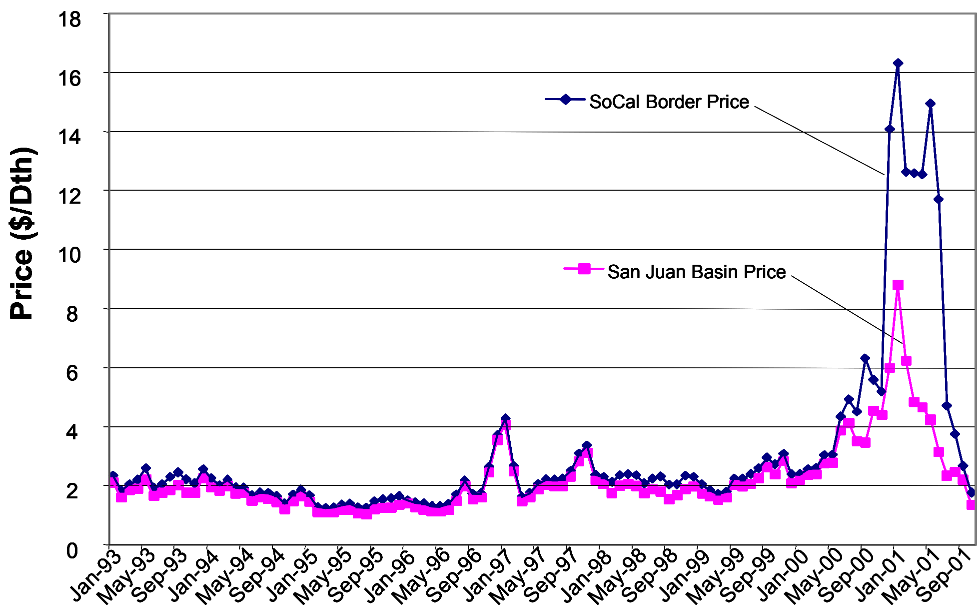
94 California has stringent air quality regulations. Regulation on emissions in the Los Angeles area is controlled by the Regional Clean Air Incentives Market (Reclaim) program. Reclaim was designed to foster reductions in NOx. Each facility that participates in Reclaim has a yearly allocation of NOx Reclaim Trading Credits (RTCs) that declines each year. A facility whose emissions exceed its annual allocation may comply by installing emissions control equipment, curtailing production or acquiring excess RTCs. A facility that exceeds its allocation without acquiring the correspondent RTCs is subject to civil penalties and administrative sanctions.

In response to a number of factors, prices for NOx RTCs in 1999-2000 ranged up to $50 per pound ($100,000 per ton) and many facilities (specially old gas and coal plants) found that they could not acquire sufficient RTCs to cover exceeded allocations so they had to curtail production.

C.3.3.2. Gas prices

In 2000 and 2001, a combination of factors drove gas prices to very high levels and threatened the reliability of the gas infrastructure.

Figure C.3
Basin and Southern California Border Prices – Low and Stable Throughout the 90s, but Volatile in 2000 - 2001



Source: CPUC, California Natural Gas Infrastructure Outlook 2002 – 2006, November 2001

Consumers were exposed to the high spot gas prices of 2000/01 to a limited extent only. When deregulation started the three utilities (San Diego Gas and Electric, Pacific Gas and Electric and Southern California Edison) were allowed to recover their stranded costs by freezing their rates at the 1996 level[95]. All customers were free to change retailers. Customers that did not switch retailers were never exposed to the market prices, instead they paid the frozen rate. An exception was San Diego Gas and Electric. During the summer of 2000 it completed its recovery of stranded costs and was thus allowed to start passing through wholesale prices to retail consumers. Due to the public outrage caused by the price increases, this policy was immediately reversed and caps were again placed on retail rates.

Large customers that switch retailers could have been exposed to the market price or could have a fixed contract with a retailer that then faced the market price. Small customers that switched retailers were mostly under fixed contracts, but most retailers went bankrupt as the market prices were considerably above their contracted prices. The retail access program was suspended on September 2001.

95 Market price (plus transmission, distribution, etc.) was thought to be below the frozen rate.

As we can see on the following table only a small percentage of the total load was not served by the utility and therefore perhaps exposed to the market price.

Table C.1
California Statewide Summary

Date	Residential	Commercial <20 kW	Commercial 20 – 500 kW	Industrial > 500 kW	Agricultural	Total	Total customers
Oct-99	1.77%	3.90%	13.86%	31.37%	9.27%	13.27%	178,701
Dec-99	2.12%	4.43%	14.57%	31.70%	9.57%	13.82%	209,752
Feb-00	2.25%	4.74%	14.84%	33.33%	9.87%	14.48%	219,023
Apr-00	2.25%	9.79%	15.02%	36.00%	9.92%	16.04%	222,649
Jun-00	2.07%	5.30%	14.78%	31.66%	7.68%	14.03%	208,711
Aug-00	2.06%	3.94%	12.95%	27.46%	6.03%	12.20%	188,834
Oct-00	2.02%	3.67%	12.36%	27.37%	6.86%	11.94%	187,017
Dec-00	2.03%	3.10%	12.43%	24.89%	6.01%	11.20%	185,754
Feb-01	1.50%	1.80%	5.40%	6.30%	0.90%	3.90%	172,565
Apr-01	1.20%	1.40%	2.70%	3.30%	0.90%	2.20%	99,157
Jun-01	1.10%	0.50%	2.70%	3.50%	1.00%	2.10%	82,705
Aug-01	0.90%	0.80%	5.00%	4.90%	0.50%	3.10%	84,833

Derived from CPUC data

California gas prices have fluctuated considerably as a result of several factors:

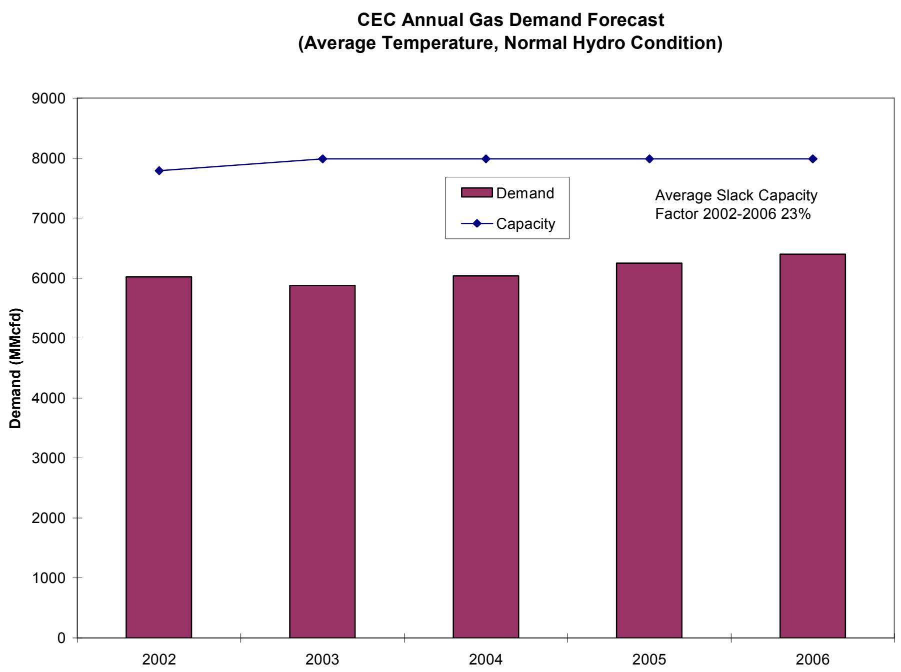
1. Natural gas prices over the past decade were low and did not provide incentives to drill enough wells. Since 1999 average US wellhead prices rose and drilling activity followed.
2. In California, strict environmental regulations restrict many fuels. For example, burning oil for power generation is restricted to a few plants.
3. Low excess pipeline capacity also affects price volatility:

Early in the year 2000, El Paso Natural Gas Company, which owns one of the two main pipelines bringing gas into California, awarded a 15 month contract for about 40 percent of the pipeline’s capacity (about one-sixth of California's daily demand) to an affiliate. While the cost of 1,000 cubic feet of gas typically is less than $1 higher at the California end of the pipeline, spot prices in the state rose to almost $50 more than the Texas-New Mexico price in December. The CPUC filed a complaint with the FERC challenging anticompetitive contracts between El Paso and its affiliate. According to the CPUC, El Paso and its affiliate withheld substantial amounts of interstate pipeline capacity to California, causing $3.2 billion of excessive natural gas costs to California consumers during the 15-month term of the contracts. The issues in the CPUC v. El Paso complaint proceeding still are being litigated before the FERC.[96]

In August 2000, an explosion on one of the pipelines delivering natural gas from the Southwest at a time when supplies where already tight caused another price jump.

In November 2001, extreme cold weather increased gas demand in Southern California. The lack of transportation capacity forced power plants to shift to fuel oil.

Figure C.4
CEC Annual Gas Demand Forecast



C.3.4. Sources of security risks

The main concern in California concerning security risk is the high import dependence in both gas and electricity.

California produces only 15% of its gas requirements. Most of the interstate pipelines in California cross various states, creating competition for gas along them. While there is enough pipeline capacity to satisfy California's demand, demand is expected to grow at a fast rate and therefore considerable additional capacity will be needed in the next 10 years.

Regarding electricity, California would be unable to meet summer demand peak for electricity without imports. The availability of imports depends on the supply-demand

[96] FERC Docket No. RP00-241-000.

balances in the Pacific Northwest and Desert Southwest. Surplus (excess of contracted amounts) in the Northwest depends on hydrological conditions.

C.3.5. Policies or risks affecting/ targeting especially domestic or industrial customers?

Both gas and electricity small customers are at lower risk than large customers. Electric utilities have the obligation to serve small customers at the rates set in 2001. The state through DWR signed long-term contracts to guarantee supply. The state is buying wholesale power at high costs and selling at lower, capped rates. As a result, the state is currently negotiating to rewrite billions of dollars in long-term contracts signed during the height of the state's power crisis of 2000-01.

Another policy specifically directed to small customers is the "20/20 Rebate Program" started by Governor Davis in May 2001. The program rewards residential, business, and agricultural customers that conserve substantial amounts of energy from June through September. The 20/20 program offers a 20% reduction in electricity bills for customers who reduce use from June through September 2002 by 20% when compared to energy use during the same months in 2000.

C.4. Security of Supply in the Spanish Electricity Sector

Spain liberalised the wholesale electricity market in January 1998. The previous regulatory regime had led to a situation of such overcapacity that the system was able to meet rapid demand growth for three years (up to December 2001) without supply being threatened in spite of the fact that very little capacity was being added to the system.

C.4.1. Important security incidents in the last 20 years

In December 2001, the combined effect of dry hydrological conditions and a cold winter meant that supply had to be interrupted forcibly for a few hours (interruptible customers were called to reduce their consumption a number of times).

There are indications that the events of December 2001 (low rain, and cold weather) would have been substantial enough to cause security problems under pre-liberalisation arrangements as well. The 12-month demand growth up to December 2001 was 14%. If liberalisation had not occurred and the government had maintained a security margin of 10%, supply would still have been insufficient to meet demand. In addition, other countries in Europe experienced similar supply difficulties around the same time, suggesting that the problem was not specific to the Spanish electric model.

C.4.2. Price fluctuations

Consumers have been protected from wholesale price increases due to the way in which stranded costs are paid annually (the payment is reduced if the price increases), and the continued existence of a regulated tariff defined by the government and which has been falling in spite of increases in the costs of supply.

The final (regulated) tariffs have been falling while the wholesale (free market) price has been increasing because the capacity payment has been reduced and, more importantly, because the annual payment for stranded cost compensation has been declining to offset the increase in the wholesale price.

In fact, it is very likely that in 2002 the "payment" for stranded cost compensation will be negative and generators will have to give back some of the money received in previous years as stranded cost compensation. In other words, the continuous reductions in tariffs in spite of cost increases led to the 2002 tariffs being at a level lower than the cost of supply.

This situation is clearly unsustainable. Currently the government and the electricity companies are negotiating the methodology for setting tariffs until 2010, with a view to allowing companies to recover costs without effecting a big tariff increase in the short term that might exert inflationary pressures.

C.4.3. Sources of security risks

Diversification in fuel sources and excess capacity has meant that there have been no serious concerns about security of supply at the national level until recently. With the fall in the capacity margin since the introduction of competition, the energy sector regulatory authority (CNE) has expressed concerns about dependence on oil of the Spanish electricity system. However, the CNE considers that the planned building of CCGT plants in Spain will contribute to the diversification of fuel sources.

Concerns over security of supply at the local level have existed for a number of years, as a result of the impact of tourism (which means that load moves to the coast), the increased use of air conditioning units (which generate reactive power and reduce transmission capacity) and insufficient investment in power lines.

C.4.4. Current security concerns

The lack of sufficient investment is often blamed on the administrative complexity associated with having to obtain permits from various levels of bureaucracy. Environmental impact permits, for example, may take up to two years to obtain. For new generation capacity investments, the time to obtain a licence to build, for example, a CCGT plant is estimated to be in excess of 2 years. For transmission and distribution, some lines require permits for the Ministry for Economics, Ministry for the Environment, and all of the regional and local governments that the line crosses, and some of the local regulations may be inconsistent. This is seen as the main cause of delays. The CNE has warned that this situation may threaten supply.

Companies have also recently been arguing that the level of tariffs is too low for them to be able to recover the cost of investments, and there is a concern that, for this reason, companies may not be investing as much as would be required.

Since the introduction of wholesale competition, the capacity margin has been falling. This has been due to the slow development of new plants, due to administrative requirements (mainly the environmental impact analyses). Now that new plants are coming on-stream, the concern is shifting towards the security of the gas supply.

C.4.5. Measures to address security concerns

There are various measures which are aimed, at least partly, at ensuring the security of supply. These include:

- Capacity payments for generators
- Promotion of interruptible demand
- Promotion of renewables, cogeneration and residues-based generators
- Increase in interconnection capacity
- Speeding of administrative procedures for permits

Capacity payments for generators: In the wholesale market, a payment to generators exists called "payment for capacity guarantee". The calculation behind the level of this payment has never been made public. Its level seems to be roughly related to the annuity costs of investing in a peaking plant (so that reserve plant would be built even if it had low expectations of being dispatched), but its level has been reduced by the government over the years from the equivalent of about 1.3 Ptas/kWh down to 0.80 Ptas/kWh of final demand (the payment to generators is based on their installed capacity) even though the capacity margin was falling. There has never been any clear explanation of the rationale for these numbers, and its true origins are unclear especially as its level has fallen while plant margins have been getting tighter. Investors may largely see this as a political payment and ignore it in their investment decisions, simply hoping that if there is demand the plants will sell at a price that will allow them to recover costs.

The capacity payment mechanism has unclear effects on company revenues. To the extent that the capacity payment encourages additional entry, the capacity payment would depress the market price and reduce the revenues obtained by generators from wholesale market sales. However, this reduction in revenues would be compensated by the revenues provided by the capacity payment. In the short term, a capacity payment may provide generators with additional revenues. However, over the medium term, a capacity payment would not normally represent an additional source of revenue for generators, since it would depress the market price. Only to the extent that the capacity payment would encourage the building of new plant would costs for customers increase. That increase in costs represents the cost of maintaining a reserve margin.

The level of the capacity payment is modified by the government at its entire discretion. It is not announced for future years, nor is there any announcement about the length of time during which the level will be maintained. It is not clear whether there is actually a methodology for setting the capacity payment in Spain. Since the liberalisation of the market, the payment has been reduced even as the capacity margin was falling. This means that the capacity payment is highly unpredictable and suggests that it is subject to being used politically, to achieve short-term reductions in the tariffs. Thus, it is doubtful that generators take account of the capacity payment when making investment decisions for generation assets whose lives may extend 30-40 years.

If the capacity payment was working properly one would expect that peaking plant (the most economic plant to provide the reserve margin) would be built. In fact almost all the new plant build in Spain is for CCGTs operating in base-load. It is too early to say whether the lack of peaking plant build is due to the fact that (a) as CCGTs are built the plants that currently function as peaking plants are becoming the reserve plants, which means that there is no need for new peaking plants, or whether (b) the lack of a methodology for determining the capacity payment means that it is being heavily discounted by generators when taking their investment decisions and that the capacity payment is therefore ineffective.

For the capacity payment to be usable by the government to stabilise the reserve margin around the desired 10% level over the medium term (rather than simply preventing old peaking plants from closing), the methodology for setting the capacity payment will have to be defined in a way consistent with that objective. In addition, the methodology has to be protected, to the extent possible, from the risk of political interference. As it currently stands, all the capacity payment will achieve is to prevent the closing of old peaking units that are displaced by new entry.

Promotion of interruptible demand: Following the forced supply interruptions in December 2001, the government considered introducing rules allowing it a degree of control over the use of reservoir hydro, and the possibility of disallowing exports. These rules were not, however, implemented.

The regulated tariff includes a cost item called "diversification and security of supply costs" which represented in 2001 4.6% of the tariff.[97] These costs include the costs of the basic uranium stock, the costs of the back end of the nuclear fuel cycle, interruptibility discounts and Special Regime costs (see below: these include renewables, cogeneration and residues-

[97] See Real Decreto 1164/2001, de 26 de octubre.

based generation). The government sees nuclear generation, demand interruptibility and, especially, special regime generation, as contributing to security of supply.

The government is trying to introduce additional flexibility in the use of interruptible demand from tariff customers. Interruptible customers served under the full-service regulated tariff receive discounts for being interruptible. However, the excess capacity meant for many years that it was extremely rare for them to be asked to reduce their demand. Following the repeated requests for them to reduce their demand during the last winter, interruptible customers complained they were being asked to reduce their demand too frequently.

The level of interruptibility discounts are determined by direct negotiation between the system operator and each individual customer, rather than regulatory or market-based mechanisms. Under the old framework, where the government determined the investments in generation, the only problems that were expected to arise occasionally were problems with the local grid. This meant that market processes would likely be inadequate (there would not be sufficient competition to supply those services because of the local nature of the service required). The process for determining the discounts has not changed since the introduction of competition. The underlying logic is that, if the wholesale market is designed properly, retailers will naturally offer discounts to customers for providing interruptibility services in case of insufficient generation.

Promotion of renewables, cogeneration and residues-based generators: The government is also trying to encourage Special Regime generators to participate actively in the market.[98] Special Regime generators have a choice between being remunerated on the basis of regulated tariff, or participating in the wholesale market and receiving a regulated premium. The vast majority of Special Regime plants choose not to participate in the competitive market and receive a regulated tariff payment which is directly linked to final consumer tariffs. This means that Special Regime generators do not respond to market price signals of scarcity. In fact, the combination of rising gas prices and falling final tariffs, means that it became increasingly uneconomic for some gas-fired Special Regime generators to generate. Consequently, even as demand grew, the generation from gas-fired Special Regime generators fell, contributing to the supply difficulties.

[98] Two types of plants can be distinguished. "Ordinary regime" plants, which participate in the competitive wholesale market includes fuel-oil, imported coal, domestic coal, nuclear, and hydroelectric plants. Imports also participate in the competitive wholesale market. "Special regime" plants, which do not have to participate in the competitive market for their remuneration, include renewable, cogeneration, and residue-based plants.

Speeding of administrative procedures for permits: The government is also trying to simplify the administrative procedures, especially as they relate to line building. However, given the lattice of overlapping regulations, the government seems to have opted to instead promote some basic criteria and encourage cooperation between the various entities.[99]

Increase in interconnection capacity: Finally, the Spanish government has sought to increase the level of interconnection capacity with neighbouring countries. An agreement was reached with the Portuguese government to increase interconnection capacity as part of the agreement to create an Iberian electricity market. A commitment was also obtained from the French authorities to increase interconnection capacity in exchange for allowing state-owned EdF to buy a stake in Hidroeléctrica del Cantábrico through EnBW.

C.4.6. Definition of an adequate level of security and the underlying approach to the assessment of security risks

The wholesale market is competitive and nothing in its design suggests that a certain level of security of supply is targeted. The CNE defines *security margin* in the electricity sector on the basis of the ratio between available capacity and peak demand. The CNE states that, following the criteria used by the System Operator, it is desirable that the ratio should be 1.1 or higher.[100] Available capacity is calculated taking into account planned and forced outages, and assuming a dry year (the lower the level of the reservoirs the lower their generation capacity).

Neither the CNE nor the system operator have any way of attracting capacity to ensure that the security margin reaches the "desired" level. The government has the ability of attracting capacity to ensure that the security margin reaches the "desired" level, through the definition of the level of the capacity payment. Higher levels of capacity payment will tend to attract more capacity build than lower levels. By increasing the capacity payment when the margin falls below 10% and reducing it when that margin is exceeded, the government should be able to stabilise the margin around that level.

In addition, according to the CNE, Royal Decree 1955/2000 defines some basic representative parameters of levels of quality that can be used to set incentives and penalties.[101]

The global level of quality of transmission will be defined by a connection point. In the transmission grid it may be referring to a connection between:

- A generator and the transmission grid

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99 See La Gaceta del Lunes, 19 August 2002.

100 See Framework Report on Electricity and Gas Demand, and its Coverage", published in December 2001, page 182.

101 See Planning and Development of the Electricity and Gas Transmission Networks 2002-2011, June 2002, page 132.

- The transmission grid and the distribution grid
- Two HV grids owned by different companies
- Interconnections.

The indicators are the energy not supplied (ENS, in MWh), average interruption time (TIM, in minutes), and the time the grid was unavailable due to preventive maintenance, unforeseen unavailabilities, or causes unrelated to maintenance (as a percentage).

The measuring of zonal quality is based on the time of interruption equivalent to installed capacity (TIEPI), the TIEPI percentile (value of TIEPI that is not exceeded by 80% of the municipalities), and the number of interruptions equivalent to installed capacity (NIEPI). TIEPI is the 'time of interruption equivalent to the power' - a weighted average of the duration of interruptions, where the weights are defined by the percentage of power that is affected by the interruption. NIEPI instead measures the times that an interruption occurred, adjusted by the power being affected.

C.5. Security of Supply in the Spanish Gas Sector

C.5.1. Key features of the Spanish gas system

There are several physical and economic features of the gas system that influence the approach taken by the Spanish government to security of supply in the gas sector.

Spanish gas market liberalisation started in 1998 with the Law 34/1998, known as Hydrocarbons Law. Royal Decree-Law 6/2000 sets out the following calendar for market opening (in terms of gas volumes):

- **June 2000:** Users with annual demand in excess of 3 mcm (70% of the market).
- **January 2002:** Users with annual demand in excess of 1 mcm (90% of the market).
- **January 2003:** All industrial, commercial and residential users (100% of the market).

The Spanish gas market will be fully liberalized in 2003, but regulated end-user tariffs will continue to be in force. Since 2003 all end-users will be able to choose supplier.

All users can choose to stay in the regulated market or switch to the liberalised market. Maximum regulated tariffs are published by the Ministry of Economy and apply to the regulated market only. This means that distribution companies supplying gas to captive customers cannot charge prices above published maximum tariffs. They might charge prices below maximum tariffs to customers, but might do so only on a transparent basis and must apply the same tariffs to all customers in the same category.

In the liberalised market suppliers face no constraints to their pricing policies: prices could be higher or lower than maximum regulated tariffs, and depend just on the bilateral contract between each supplier and each customer. Currently there are no plans to end the tariff market for any user category. Thus, no user is forced to switch to the liberalised market.

C.5.1.1. Dependence on imports

Because domestic natural gas reserves are extremely scarce (national production accounts for less than 5% of total consumption), Spain is heavily dependant on gas imports. Half of the total natural gas supply to Spain arrives in liquefied form on LNG carriers to three different regasification plants. The remaining natural gas is imported via two international connections, with Europe (the Lacq-Calahorra pipeline) and with Algeria (the Maghreb-Europe pipeline).

Additionally, wellhead and transportation costs from Algeria are relatively low compared to other gas sources that can potentially supply the Spanish market. This explains why traditionally most gas has been imported from Algeria.

C.5.1.2. Contract price structure

Natural gas imports to Spain have historically been carried on the basis of long-term (usually 20 years) gas supply agreements containing "take-or-pay" clauses and price indexation to the quoted price for oil and its derivatives on the global markets (as expressed in US Dollars). Therefore, the supply price structure in Spain is such that gas prices at the Spanish border do not reflect occasional gas supply restrictions.[102]

Transportation costs in Spain from the border to burner tip are currently regulated through uniform national charges for each type of facility (high pressure transport network, regasification plants, distribution facilities and storage sites). Therefore third-party-access costs do not fluctuate according to short-term restrictions in the use of the facilities.

As a result, end-user prices are fairly stable and tend to fluctuate only in response to international oil price market events.

C.5.2. Security of supply policies

The issue of security of supply has been approached in the Spanish gas sector from two different perspectives.

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[102] In the past few years, however, short-term LNG supply contracts have made increasing use of terms shorter than two years.

C.5.2.1. Continuity of gas supplies

The measures adopted to guarantee continuity of gas as a commodity relate to strategic storage requirements and diversification of supply sources.

C.5.2.1.1. Storage requirements

First, the Hydrocarbons Law establishes that transporters that inject gas into the system, suppliers and eligible customers that make use of their right of access and are not supplied by a licensed supplier, are required to maintain in storage, for security purposes, a minimum volume of gas equivalent to 35 days of their firm sales or firm consumption. Depending on the system's available capacities, the Ministry of Economy could raise the number of days up to 60. Further legislation is needed to make effective the implementation of this measure; to date, due to the lack of clear legislation, no player in the gas market has met this 35 day requirement.[103]

The government has never made public any information concerning methodologies used to set the storage requirement. We understand that the 35-day requirement was established *ad hoc*, not following any visible analytical process. Broadly the 35-days number corresponds with the estimated number of days that the system allowed, when the Hydrocarbons Law was passed in 1998 (the calculation probably took into account data from 1997). However no storage facilities have been built since 1998; nowadays, according to the Planning document the system allows just for, approximately 22 days.

According to the Hydrocarbons Law, <u>depending on the system's available capacities</u>, the Ministry of Economy could raise the number of days up to 60. We understand that the 60-days figure is a long-term target. If current plans for new storage facilities were built the availability of storage for strategic use would increase to approximately 57 days in 2010, according to the Ministry Planning document.

To our knowledge, Enagás is the only company building and studying the construction of new underground storage facilities as a consequence of the 35 day rule. If all planned storage facilities are developed, according to the Ministry of Economy, the 35-day strategic storage security requirement will be met in 2005, and there will be excess capacity from 2005.

The decision to build a new storage facility is not market-driven in the sense that storage prices do not fluctuate in response to capacity shortages/surpluses. The remuneration of each storage facility is regulated and is determined on a case-by-case basis (while standard costs for regasification and pipelines opex and capex exist, no such standard costs are specified for storage facilities).

103 According to recent press reports (Expansión, 31/07/2002) the Ministry of Economy is already drafting a regulation to implement this measure.

C.5.2.1.2. Diversification of sources of supply

Second, the Hydrocarbons Law sets a limit of 60% to the volume of gas that transporters and suppliers can import from a single country. Consumers with guaranteed alternative sources of energy are exempt from fulfilling this requirement. The Government retains the right to impose the same limitation to eligible customers for the volumes of gas not acquired through a licensed supplier, if the size and origin of its imports may have an effect over the national balance. Although the Hydrocarbons Law states that the Ministry of Economy must establish the conditions to meet this obligation, the relevant legal provisions have not been developed yet.

There are two mechanisms available to enforce a given proportion of LNG/pipeline import capacity. First, the new planning framework establishes that the planned total regasification capacity is mandatory. If there are no private plans for construction, the Ministry can open a tender process and, in case there are no bids, the Ministry can command Enagás (as TSO) to build the required capacity. Second, each gas infrastructure facility requires an administrative authorisation granted by the Ministry. Article 67.1 of the Hydrocarbons Law establishes that the authorisations for construction of gas infrastructures covered by mandatory planning must be granted by means of a competitive procedure that must be handled and resolved by the competent authority. In practice, we understand the Ministry would check consistency of LNG project proposals with mandatory planning requirements prior to the granting of any authorisation to construct.

C.5.2.2. Appropriate transmission infrastructure

C.5.2.2.1. Definition of security of supply

In this area, there is an underlying definition of an adequate level of security of supply, although it is not contained in legislation. The CNE (National Energy Commission), in its "Framework Report on Electricity and Gas Demand, and its Coverage", published in December 2001, defines *security margin* in the gas sector as the relationship between the "peak daily emission capacity" (peak daily sent-out capacity) and the forecast "peak daily demand", and considers that the adequate security margin level must be 1.1 or higher. The Ministry of Economy makes reference to the same desirable security margin level in its last planning report[104] when it set the criteria for the development of new gas facilities.

C.5.2.2.2. LNG/pipeline mix

The Ministry of Economy has expressed the desirability[105] of maintaining a 50/50 mix of pipeline and LNG imports, highlighting that it would not be desirable to let any of them to

[104] Planning and Development of the Electricity and Gas Transmission Networks 2002-2011, June 2002, chapter 11.

[105] Planning and Development of the Electricity and Gas Transmission Networks 2002-2011, June 2002, chapter 10.

fall below a third of total supply, given the advantages in terms of security of supply that the mix implies:

- Swing provisions (variations in contractual commitment on the buyer side at the border) make supplies via pipeline more appropriate to deal with seasonal demand. Moreover, these imports are not subject to supply interruptions caused by weather conditions

- LNG supplies are the cheapest way of dealing with winter peak daily demands. Additionally, while imports via pipeline are limited to those from Algeria and Norway, there are numerous areas of the world that are within a reasonable distance from Spain and have the appropriate infrastructure and reserves to serve as sources of LNG to the Spanish market. This increases supply competition and minimizes the exposure to pricing policies from the small number of producers supplying the European market.

C.5.3. Security of supply levels

C.5.3.1. Security of supply track record

There has never been any important security incident in Spain. Although a large part of gas is imported from countries with a high country-risk index, such as Algeria,[106] Nigeria or Libya, this has not raised serious concerns about security of supply. (No major disruption to gas supply of a political or technical nature has ever been experienced in any OECD country.)[107]

C.5.3.2. Current situation

C.5.3.2.1. Indicators

Strategic storage requirements

According to the Ministry of Economy,[108] current underground storage facilities provide only for around 22 days of storage for security purposes, but the development of new underground storage facilities will provide for more than 35 days in 2005.

Diversification of supply sources

We understand that the 60% limit was established *ad hoc*, not following any visible analytical process. The limit corresponded almost exactly to the percentage of gas imports from

106 Additionally, gas imported from Algeria via the Maghreb-Europe pipeline, which in 2001 represented a 30.6% of total imports, is transported through Morocco.

107 OECD/IEA (1998): Natural Gas Pricing in Competitive Markets, p. 45.

108 Planning and Development of the Electricity and Gas Transmission Networks 2002-2011, June 2002, chapter 12.

Algeria when the Hydrocarbons Law was passed in 1998 and, given Spain's geographic proximity to Algeria and the competitiveness of Algerian natural gas prices, it is likely to remain around that level in the next decade.

Security margin

According to NERA estimates, the security margin of the Spanish gas system has diminished over the last decade from around 1.5 in 1991 to less than 1.2 in 2001.[109] Taking into account transport and LNG storage constraints within the system, the security margin was around 1.05,[110] below the underlying definition of security of supply. There is growing concern that gas infrastructures may be inadequate to meet expected gas demand in the short run.

LNG/pipeline mix

The 50/50 objective in the relative import capacity available through LNG regasification facilities and pipeline facilities was practically achieved in 2000 and the expansion plan recently published by the Ministry expects to approximately keep meeting this target as new facilities are built or existing facilities are expanded. The 50/50 import capacity available through LNG regasification facilities and pipeline facilities is just a desirable ratio for Spain according to the Ministry of Economics' opinion, but the development of existing and new gas entry points in Spain is not required to reach that ratio.

C.5.3.2.2. Reasons for the currently tight security margin

Poor regulation in a context of uncertain gas demand has led to lack of investment. In summary, the current tight security margin is due to an inadequate planning infrastructure, a lack of appropriate revenue incentives for regulated infrastructure investment, exacerbated by the instability of the tariff framework. In the past, the Spanish energy sector was characterized by inadequate planning infrastructure, a lack of appropriate revenue incentives for regulated infrastructure investment and instability of the tariff framework. This poor energy regulation in a context of uncertain gas demand led to lack of investment in this sector and it is responsible for the currently tight security margin. and a context of highly unpredictable gas demand caused by the proliferation of plans to build new gas fired power station. The translation of plans into plants is uncertain because public announcement of plans to build new gas fired power stations is not binding. Electricity companies can later decide to go on with their projects, delay them or not to build the plants.

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109 These estimates take into account nominal entry capacity into the system, but do not take into account transport constraints within the system.

110 This figure results from the observed daily peak demand in 2001 and peak daily emission capacity figures published by the CNE in chapter 7 of the "Framework Report on Electricity and Gas Demand, and its Coverage". According to this report, the security margin could be lower than 1 in 2002. The CNE in the "Framework Report on Electricity and Gas Demand, and its Coverage" is not considering the linepack[110] in the transmission pipelines. That means that a security margin lowers than 1 does not directly imply supply interruptions.

Reforms in 2002 were aimed at removing bottlenecks in the system:

- A new tariff and remuneration framework was passed in September 2001[111] and completed in February 2002.[112] Until then, legislation had not specified in detail how to remunerate investments - legislation regarding LNG regasification plants was specially unclear.. This meant that incentives to build new gas infrastructure were weak . New legislation introduces an integrated economic cost-based. system for setting allowed revenues, end-user tariffs, TPA charges and a revenue compensation system.. End-users tariffs are uniform in Spain and (more or less) cost-reflective. End-users tariffs and TPA tariffs are established to cover the overall costs of the Spanish gas system. The Ministerial Order 301/2002, passed in February 2002, establishing the remuneration framework for the regulated activities in the gas sector, establishes an accredited cost for each company developing regasification, transmission, storage and distribution activities. The revenue compensation system compensates each company for any difference between the accredited cost and revenues collected. Tariffs are now (more or less) cost-reflective and there is consistency between regulated end-user and TPA tariffs.

- Regarding energy planning, the former mandatory global energy planning system, where targets, in practice, were never achieved and did not clearly define planning responsibilities, has been replaced by a new system. Planning is now mandatory (but at minimum levels) for pipeline, strategic storage and total regasification capacity. Companies submit their infrastructure plans to the Ministry of Economy, which approves or rejects those plans. In the event that the Ministry of Economy considers that certain infrastructure (related to pipelines, strategic storages facilities and total regasification capacity) is needed but no company has submitted a plan to undertake it, the Ministry of Economy will set up a tender. If no company is interested in taking part in the process, the Ministry of Economy will appoint the System Operator as responsible for the development of that particular infrastructure and indicative for other infrastructures (including individual regasification plants).

  The new system has led to the elaboration of a planning report by the Ministry of Economy,[113] that includes forecasts of future supply and demand over a ten-year period and identifies the main security of supply dangers and gas infrastructure needs. According to this report, infrastructures currently under construction (new LNG regasification plants and increase in capacity of existing LNG plants and international pipelines) will be sufficient to cover forecast gas demand increases. However, any delays could give rise to supply restrictions in 2003, 2004 and even in 2005.New entrant suppliers have already expressed their concern that they will not

111 Royal Decree 949/2001.

112 Ministerial Orders ECO 301/2002, ECO 302/2002 and ECO 303/2002.

113 Planning and Development of the Electricity and Gas Transmission Networks 2002-2011, June 2002. This plan is already in a draft form and the Congress will approve a final version later this year.

be able to meet their customers' demand levels after 2003. They fear that ENAGAS will not allow them access to the regasification plants due to congestion problems.[114] Access problems are also exacerbated by the lack of operation rules.[115] More alarming is that, according to a recent CNE report,[116] many facilities now under construction are suffering significant delays,[117] mainly because companies are finding it hard to fulfil onerous bureaucratic procedures for plant approvals.

The Ministry of Economy's report on energy planning also highlights the importance of reinforcing international interconnections, especially with Portugal and France, as a way to enhancing security of supply in the Iberian Peninsula.

Although these reforms have improved the previous situation important uncertainties remain, potentially leading to inefficient capacity additions:

- Planning is mandatory only as a minimum for pipelines, strategic storage and total regasification capacity, but the treatment of investments above the minimum is unclear. Current legislation establishes infrastructure construction targets but it does not set any clear rules to convert the costs of achieving the security and diversification aims into access tariffs. Specifically, there are no clear methodologies that establish how the costs incurred as a result of a tender process will be translated into third-party-access tariffs. Neither there are explicit constraints on the costs that the TSO would be allowed to recover in case it is asked to build the required infrastructure.
- Planning remains indicative for other infrastructures and criteria for project selection are unclear. The Ministry of Economy tries to prevent companies from building inefficient infrastructures, since accredited costs of new infrastructure investments are included in gas tariffs. That's why the infrastructure plans need Government approval. However the criteria for infrastructure plans approval are not detailed in legislation. The remuneration framework for regulated activities does not clarify issues such as the remuneration of investments in underground storage facilities, remuneration of investments in capacity expansion of existing facilities, the calculation and updating of efficiency factors, etc.

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114 Cinco Días, 11/07/2002.

115 The Network Code is still under discussion and will be probably passed some time this year. We believe that under its current form it does not guarantee access on transparent grounds.

116 The CNE is required to publish in a bimonthly basis a follow-up document to the "Framework Report on Electricity and Gas Demand, and its Coverage", published by the CNE in December 2001. The first follow-up document was published in May 2002. Here we refer to the second one, published in July 2002.

117 These include the increase in capacity of Barcelona's regasification plant (805 days), Cartagena's regasification plant (181 days) and Huelva's regasification plant (181 days).

C.6. Security of Supply in New Zealand: The Auckland Power Supply Failure (1998)

C.6.1. Background[118]

On 20 February 1998 Mercury Energy (Distribution business covering the Auckland area) issued a press release that it could no longer supply electricity to the city of Auckland. It was not until 27 March 1998 that full supply was generally available, and additional cable failures and system outages continued to occur until May.

Auckland Central Business District (CBD) network is connected to the transmission system via six Mercury Energy 110 KV cables. The inner city load was usually supplied by four 110 kV cables. However, by the evening of the 20 February 1998 four of the six 110 kV cables had failed, leaving Auckland CBD with only enough capacity to supply emergency services.

In response to this failure the Minister of Energy instigated an inquiry into the cause of the cable failures and the factors contributing to the failure of power supply.

C.6.2. Findings of the Government Inquiry

There were a number of causes for the failure of the cables including unstable ground, road and rail vibration, and installation shortcomings.

The Inquiry found that the level of network distribution planning which incorporated an 'n-2' standard for redundancy was appropriate for the CBD load. Although the Inquiry found that the n-2 criteria had been followed with respect to the 110 kV transmission network Mercury had not consistently applied it to the whole CBD area.

The Inquiry noted that Mercury Energy's risk management and contingency planning did not include contingency plans for the failure of four 110 kV transmission cables. However, they believed that it would have been unusual for Mercury to have such a contingency. They did note that due to the poor reliability of the electricity cables, Mercury should not have regarded the electricity cables as stable or reliable elements of the system.

118 Ministry of Economic Development: Inquiry into the Auckland Power Supply Failure 1998, http://www.med.govt.nz/inquiry/final_report/index.html

C.6.3. 2001 Winter inquiry

The Post Winter Electricity Review[119] by the Office of the Minister of Energy was in response to the high prices experienced during the 2001 winter, due to the tight supply situation and record demand.

These demand and supply side conditions occurred due to the dry cold weather conditions experienced at the time, which led to additional electricity demands and low hydro generation due to low water levels.

C.6.3.1. Characteristics of the New Zealand electricity market include:

- Heavy reliance on hydro which accounts for 64 per cent of total generation;
- Retail market had six participants of which four also owned generation assets. Due to the lack of an adequate hedging strategy, one independent retailer collapsed as a result of the higher spot market prices experienced in the 2001 winter;
- The largest load centres are in the North Island while most hydro generation is in the South Island, so that electricity is transported on a long thin transmission grid where losses and constraints are considerable;
- The combination of dependence on hydro with limited storage means that the impact of a 'dry year' on electricity supply can be severe; and
- Limited backup generation was held for dry years so that the spot market had to rise sharply to induce additional supply from diesel generators and open cycle cogeneration.

C.6.3.2. Recommendations of the Inquiry

The Inquiry recommended that:

- There was no fundamental flaw in the wholesale electricity market. However the market would have performed better if the market improvements specified in the Government Policy Statements[120] had been implemented including:
  - projections of system adequacy;
  - disclosure of forward hedge prices;

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119 Ministry of Energy, *Post-Winter Electricity Review¸ October 2001,* http://www.winterreview.govt.nz/media/index.html

120 Relevant Government Policy Statements were delivered in December 2000 and February 2002. Please refer to http://www.med.govt.nz/ers/electric/package2000/gps/index.html and http://www.med.govt.nz/ers/electric/gps2002/index.html for more details.

- disclosure of generator offer prices into the market;
- development of real time spot market pricing and promotion of demand-side participation;
- arrangements for setting agreed transmission prices;
- arrangements for agreeing on and paying for new transmission investments to relieve constraints; and
- development of financial instruments to manage transmission risk.

The recommendations of the inquiry focused mainly on measures to promote market transparency and liquidity. One cannot, however, conclude that spot prices were accepted ex post as broadly reasonable is. What happened is that the Minister for Energy stated that it was clear from the review that the wholesale electricity market would have worked better if the changes specified in the Government Policy Statement of December 2000 had been fully implemented by the industry. (Recommendations in the Policy Statement are very broad including further evolution of self-regulatory arrangements and the establishment of an Electricity Governance Board that would develop rules and principles for the various parts of the electricity chain among other issues.) The Minister further stated that although the industry had made progress towards the changes required by government in the Policy Statement it is necessary to set milestones for market improvements. (those are the ones we refer to above)

Furthermore, in light of concerns about high spot prices, the Minister amended the Government Policy Statement and required public disclosure of generator offers into the wholesale market after 2 weeks instead of 3 months. That gives consumers and other interested parties an early opportunity to seek explanations from generators if questions arise about offer behaviour and prices.

C.6.3.3. Further reforms

Submissions to the Winter Review claimed that one of the contributing factors was insufficient liquidity in the hedging market. The Minister for Energy responded to these claims by commissioning a report on hedging markets in New Zealand.[121] The report proposed mandatory hedging requirements on generators, as a way of curbing their incentive to increase spot prices. The Government called for submissions on this report, but has not yet issued any further recommendations.

121 Small, John, *Hedge Markets for Electricity Power in New Zealand,* A Report to the Ministry of Economic Development, March 2002.

C.7. Security of Supply in the Australian Electricity Sector

Security of supply is consistently addressed by all regions in the National Electricity Market (NEM).[122] This is done through the National Electricity Code (Code) through a hybrid of both market based and centrally planned mechanisms. By contrast the gas sector in Australia does not specifically address the issue of security of supply.

C.7.1. Generation

C.7.1.1. Adequate supply

The Code in Australia establishes a Reliability Panel, whose function is to determine the appropriate reliability criteria for the NEM.

The Reliability Panel has determined that the minimum reliability standard should be set at a maximum unserved energy of 0.002% in its 1998 determination The intervention threshold capacity reserve triggers within each region are therefore set at the greater of:

- the size of the largest contingency within the region; and
- the level calculated to achieve the maximum unserved energy of 0.002%.

The Reliability Panel has recently noted NEMMCO's recommendation that the minimum reserve margin should be set to the size of the largest generator in each region, as this is now sufficient to cover the unserved energy criterion. The recent NEMMCO 2002 Statement of Opportunity[123] (SOO) sets the following minimum reserve margins:

- 420 MW in Queensland increasing to 450MW by 2003;
- 660 MW in NSW increasing to 700MW from 2003/04;
- 540 MW in Victoria increasing to 570 MW in mid-2003; and
- 260 MW in South Australia.

In NEMMCO's annual SOO, reserve margins are calculated by the following formula:

Reserve Margin = Generating Capacity + Optimised Interconnection Import Capacity – Peak Demand + Demand Side Participation

[122] The NEM currently comprises of five regions including South Australia, Victoria, NSW, Queensland and the Snowy Region (The Snowy Region is a generating region only)

[123] NEMMCO, 2002 Statement of Opportunity, July 2002, p 7-3.

Where:

Generating Capacity:	Is estimated for both summer and winter capacity;
Optimised Interconnection Import Capacity:	Is calculated based on physical interconnection capacity but assumes that there is no diversity between regional peak demands;[124]
Peak Demand:	Is calculated as the level of maximum demand expected for a "one in ten year" hot summer.
Demand Side Participation:	Likely DSP contributions have been included in regions with tighter supply conditions and recent evidence of a significant response during high price/peak demand periods.

There are no rules that would allow NEMMCO to sell contracted reserve capacity to third parties.

C.7.1.2. Mechanisms employed to ensure an adequate levels of security

The NEM is an 'energy only' market. Generators receive their total revenue via the spot price. There are no separate capacity payments as in some other electricity markets. Under this approach, investment in new capacity is driven by the spot price being high enough at peak times in the year to provide sufficient remuneration for peaking generation plant to enter the market (ie, to cover both their investment costs and capital costs).

There is a cap on the spot price in $/MWh, known as Value of Lost Load (VoLL). In April 2002 VoLL was increased from $5,000/MWh to $10,000/MWh to ensure that there is sufficient market generation. The level of VOLL is prescribed in the National Electricity Code. The National Electricity Code Administrator (NECA) Reliability Panel was required to review the level of VOLL annually. The Panel recommended an increase in VOLL from A$5000 in 2000, to A$10,000/MWh on 1 September 2001 and to A$20,000/MWh by April 2002. The timing of the proposed increases was intended to reflect the time required to allow the market to develop appropriate risk management and insurance mechanisms, and to allow scope for enhanced demand-side management participation and increased

124 The Reserve Level Working Group has yet to complete the necessary studies to confirm that the current levels will satisfy the unserved energy criteria if the reserve margin is calculated making the less restrictive assumption of diversity between regional peak demands and would be based on historically recorded levels of diversity.

incentives to peaking plant investment. However, on 20 December 2000, the ACCC issued a determination acknowledging that the proposed increase in VoLL provides public benefit, as it encourages investment in peaking capacity in circumstances where demand peaks occur for only a few hours a year. However, the Commission did not consider that VoLL provides the incentive for reliability of supply through improved demand side response. Consequently, the Commission did not believe that an increase in VoLL to $20,000/MWh delivers sufficient public benefit to outweigh the anti-competitive detriments of such an increase. The Commission therefore proposed to limit the increase in VoLL by 1 April 2002 to $10,000/MWh. The Commission stated that this will provide an additional incentive to promote investment in peaking plant whilst capping risk in the market at a level lower than that proposed.

NEMMCO is given powers under the National Electricity Code to intervene in the market either by dispatching plant provided under a reserve contract or by issuing directions to market participants in accordance with the policies & guidelines for market intervention set down by the Reliability Panel.

To date, NEMMCO has <u>not</u> determined that the reserve requirements are likely to be breached, and had not activated its reserve trader powers (prior to establishing the NEM, VPX in Victoria did activate its reserve trader contracts in the summer of 1997/98.) Reserve trader contracts can be for either additional peaking generation or additional demand side participation programs. The Code provisions in relation to reserve contracts are stated in Appendix A.

In addition NEMMCO has the power of direction, separate from its Reserve Trader function. It can direct generators in relation to scheduled generating units, network service providers in relation to scheduled network services and market customers in relation scheduled loads (s4.8.5c). Section 4.8.5(e) states that NEMMCO's right to issue directions will cease when its right to enter into reserve contracts in accordance with clause 3.12 ceases. This is currently prior to 1 July 2003. The ACCC Determination on VOLL from December 2000 extended NEMMCO's reserve trading powers to the 1 July 2003. At the present the Reliability Panel has not recommended to extend NEMMCO's powers.

For each dispatch interval where NEMMCO intervenes (declared by NEMMCO as an intervention price dispatch interval), the dispatch price must be determined in accordance with an intervention pricing methodology.

Pricing calculation is based on the "what if" scenario. The Intervention Price or "What If" dispatch price shall be 'the value which NEMMCO, in its reasonable opinion, considers would have applied as the dispatch price for that dispatch interval had the plant provided under a reserve contract not been dispatched'.

The Intervention Price preserves the market signals that would have existed had the intervention action not been taken and it is used as the dispatch price for the purpose of spot price determination and settlements.

C.7.2. Transmission planning

Under the National Electricity Code[125], Network Service Providers (NSPs) are free to agree acceptable reliability criteria with affected Code Participants.[126] However, the Code provides guidance on what, in general, should be considered the minimum acceptable reliability standard.

Specifically, Schedule 5.1 of the Code sets out network performance standards to be provided or co-ordinated by NSPs. Schedule 5.1.2.2 sets out the "minimum reliability standard" for certain network services to be provided by NSPs within a region. Schedule 5.1.2.2(a) requires that the network must be able to withstand credible contingency events. Schedule 5.1.2.1 in turn sets out the credible contingency events and practices that must be used by NSPs for network planning purposes.

These contingency events essentially define the minimum reliability standard to be provided by NSPs as an (n-1) reliability standard, with varying levels of transfer capacity ranging from zero up to full system capability, depending on network topology and network user requirements. Although the Code refers to this standard as being the "minimum reliability standard", it allows for NSPs to agree with a Code Participant to adopt reliability criteria (defined via a set of credible contingency events) differing from those set out in Schedule 5.1.2.1.[127] This has been done in the recent network augmentation of the Sydney CBD where a 'n-2' standard was agreed.

C.7.2.1. Disruptions

In the 2001/02 summer both Victoria and South Australia experienced both blackouts and brownouts. The overriding contributing factor was the extreme temperature conditions especially in South Australia which experienced the hottest summer ever recorded. Since then significant new generation has come online (ie, Pelican Point).

C.8. Security of Supply in the Australian Gas Markets

C.8.1. Historic background

Australia is lacking a national policy on 'security of gas supply'. This is caused by the multilevel political structures (federal, state and territory) that govern the gas industry in Australia. Historically Australia's natural gas industry developed as a number of separate, State-based markets with legislative and regulatory barriers restricting trade between States. The supply chains in each market were highly integrated, with monopolies operating at the production, distribution and retailing stages.

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125 http://www.neca.com.au/files/necacode/

126 Code Participants include NSPs, generators and customers who are registered with NEMMCO.

127 National Electricity Code, Schedule 5.1.2.1, second paragraph.

Exploration and processing was carried out by a small number of companies under long-term leases granted by State and Territory Governments. In most jurisdictions a single transmission pipeline connected a single basin to the major population centre and regional markets. Producers sold gas to public and private distribution monopolies under long-term, restrictive sales contracts, often underpinned by State or Territory legislation.

While these arrangements have underpinned the industry's development from the mid-1960s, they have also left consumers exposed to monopoly power. And, as was learned during the 1998 Victorian gas crisis ('Longford incident'), they also exposed consumers to the risk of loss of supply in the event of a single industrial disaster.

Both market power and security of supply issues encouraged subsequently governments at federal/state/territory level to pursue reform and restructuring of the gas industry.

C.8.2. Reform and restructuring

In 1994 the Council of Australian Governments (COAG)[128] decided to address the problems of gas industry fragmentation, security of supply and monopoly power by aiming for the development of nationally integrated and competitive markets. This involved a series of complementary reforms that were supported by the various States and Territories, including

- to remove all legislative and regulatory barriers to free and fair trade in gas;[129]
- to restructure the gas utilities by separating transmission and distribution from the publicly-owned utilities, and to require ring-fencing arrangements in the privately-owned retail utilities. Public utility businesses were corporatised. Retail franchise arrangements were also reformed to allow the phased introduction of competition.
- to establish the National Third Party Access Code for Natural Gas Pipelines Systems (The National Gas Code). The code sets out a consistent procedure for the ACCC and State/Territory regulators to assess proposed arrangements for pipeline operators to sell transmission and distribution services to gas producers, retailers and users.

Those reform and restructuring measures were the basis for the introduction of competition and encouraged the development of pipeline network in Australia. Both competition and new pipeline development had positive effects on security of supply.

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128 COAG is a body that comprises federal, state and territory governments in Australia and develops policy guidelines.

129 A number of initiatives followed. South Australia, for example, introduced legislation in 1998 liberalising access to gas fields by new explorers and producers. Victoria amended its *Petroleum Act 1958* to allow interconnection between Gippsland Basin gas reserves and the NSW gas pipeline system, and to allow Victorian gas to be sold in NSW. These reforms were aimed at increasing competition between producers in different gas basins and increase security of supply.

Australia has been gradually introducing competition in the gas market. Whereas most states allow for large and medium sized customers to choose their own gas supplier only New South Wales has introduced full retail competition. Victoria is planning to open the gas market later this year. There has also been significant investment, expansion and integration of the gas transmission and distribution network in recent years, particularly in south eastern Australia (South Australia, Victoria, and New South Wales) that has enabled competition and increased security of supply.[130]

C.8.3. The Longford incident

Victoria experienced the largest gas incident in the history of the Australian gas sector.[131] On Friday 25th October 1998 there was a massive explosion at Esso's Longford gas plant in rural Victoria that jeopardized gas supply of the whole state. The Government of Victoria reacted swiftly and issued a Directive that protected gas supplies for essential services by giving the Victorian Energy Network Corporation (VENCorp)[132] – the gas system security agency – the power to instruct households and businesses to stop using gas appliances.[133] The powers had been provided to VENCorp under the Gas Industry Act that allows directions to be made on gas use to protect supplies. [134] Within days Victoria's entire gas supply was shut down and customers remained without gas for weeks causing substantial damage to the Victorian economy and major inconveniences for smaller household consumers.

A Royal Commission was subsequently established to investigate the incident and found in July 1999 that Esso, a subsidiary of Exxon, was responsible for the disaster that killed two workers, injured eight and cut gas supplies to the entire state for two weeks. The Commission's findings state that the major cause of the accident was "the failure of Esso to

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130 However, the Australian gas market continues to be fragmented. The location of Australia's natural gas reserves and the large distances between the load centres has created two main transmission networks not linked to each other, one in the eastern states (New South Wales, Queensland and Victoria) and South Australia, and the other serving only Western Australia.[130] The eastern states network is a loose network with limited interconnection among the states. The majority of natural gas provided to the east coast market is from only two basins, the Cooper and the Gippsland.

131 In NSW, the only significant disruption occurred in 1983 when a section of the MSP near Moomba exploded. This resulted in a disruption to the gas supplies due to the significant volumes of gas carried along the length of the pipeline.

132 Victoria has a unique system where the ownership (plus maintenance) and operational responsibilities for the state's transmissions system are split between GasNet and VENCorp respectively.

133 The emergency measures were kept in place until August 3, 1999 to protect emergency supplies in the event of any problems with rectification works at Longford. The measures were only lifted following the successful completion of a 30 day operational trial of the Longford plant.

134 The conditions of Part 6A of the Gas Industry Act are invoked when it appears the available supply of gas is or is likely to become less than sufficient for the reasonable requirements of the community. The Act allows for any directions to be made to ensure the protection of the security of the system in areas including supply, transmission, distribution The Act provides for penalties where customers ignore those instructions and sanctions can also be applied for companies.

equip its employees with appropriate knowledge to deal with the events which occurred"[135]. In doing so, Esso failed to provide safe working environment for its employees in breach of the state's Occupational Health and Safety Act.

Following the incident and the high dependency on a single pipeline, the Victorian government announced on 16 October 1998 to proceed with an upgrade of the interconnector with New South Wales from 15 tj per day to around 80 tj per day. In addition, the government initiated to bring forward to 1999 the construction of the South West Pipeline[136] and aspects of the underground storage project.[137] In addition, on November 17, 1998 the Victorian government announced that it plans to proceed with the privatisation of Victoria's gas industry. The Victorian Premier stated that "the lessons clearly learned from the Longford gas explosion is that the current producer monopoly leaves the State vulnerable to supply interruptions" and "private ownership is the only way to encourage exploration and development of alternative sources of gas supply".[138] It was the position of the government that privatisation of the Victorian gas industry would provide strong impetus to an integrated national pipeline system and improve diversity of supply.

C.8.4. Security of supply

Australia does not have an explicit national policy that addresses the issue of security of natural gas supply. The gas sector in Australia is a shared responsibility between the Commonwealth, State and Territory Governments and security of supply is being dealt with by each State and Territory.

Sates and territories acknowledged that in order to increase security of supply greater competition in the gas production/exploration has to be achieved. The removal of barriers to interstate trade in gas and retail franchises, and the implementation of the national gas access code enabled producers and consumers to obtain access to gas transmission and distribution pipelines to ship their gas to market. This had significant impact on attracting new entrants to potential new gas fields and encouraging new gas pipeline development that subsequently diversified gas supply sources.

135 The explosion occurred when hot lean oil came into contact with equipment that had been operating well below normal temperatures. This caused the brittle metal to fracture and release massive amounts of hydrocarbon gas, which came into contact with an ignition source, causing a violent explosion. The equipment had reached such low temperatures because the supply of lean oil had ceased for over three hours due to the failure of two pumps. Because of Esso's lack of training, none of the supervisors and plant operators knew that this could occur.

136 The Victorian government contributed Australian $ 7.3 million to the construction of the South West Pipeline.

137 News Release, From the Office of the Premier, Government to pursue gas supply alternatives, Friday 16 October 1998

138 News Release, From the Office of the Premier, State moves to increase gas competition, November 17, 1998

C.9. Security of Supply in the Norwegian Electricity Sector

C.9.1. Background information

Norway, Finland, Sweden and Denmark operate a single electricity market for wholesale electricity trading, known as the Nordpool. Nordpool was established in 1993, but Denmark was only incorporated in 2000. Each country retains the rights to regulate and set the market rules and each country had different reasons and timetables for liberalization of their markets. The Nordpool operates two separate markets: the physical market and the financial market. Elspot (and Elbus in Sweden and Finland) is the physical commodity market traded for the following 24 hours only and is used to manage transmission and delivery constraints on the network. Elspot provides the system electricity prices for each zone on the network. The total network across the Nordic region is split by transmission constraints and an electricity price is derived for each of these zones. This zonal pricing structure is known as system splitting. System operators in each country are responsible for real time balancing on their network. The financial markets cover both futures and options. Contracts can be traded from blocks of days to up to 4 years in advance, whilst financial derivatives products, such as options and volatility products, are also available. Any company (provided they are credit worthy) can participate in the Nordpool markets regardless of whether they own physical assets in the region.

C.9.2. The Norwegian market

The Norwegian market was the first market to open to liberalization and is the model for all the Nordic countries. Norway started the liberalization process in 1990 with the Energy Act. The Energy Act removed the monopoly supply rights of distribution companies, allowing retail competition. It opened up access to the transmission and distribution networks and the wholesale market. Furthermore, the Act required the total separation of transmission and accounting separation for distribution companies. The electricity industry is regulated by the Royal Ministry for Petroleum and Energy.

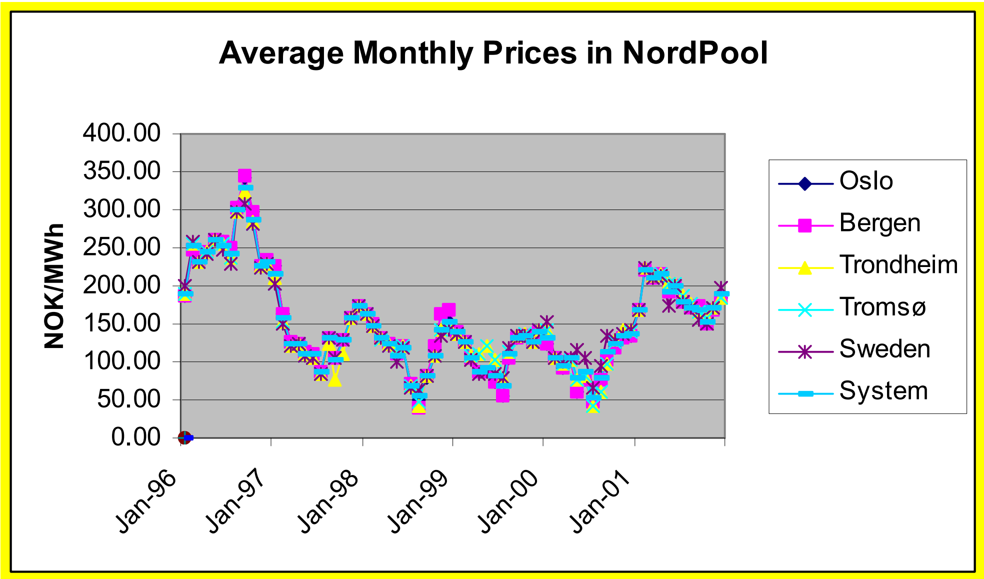
Norway's generation portfolio is 99 percent hydro generation. Generation volumes fluctuate with rainfall, but in an average year equate to 120TWh. In addition, Norway exports about 9 TWh and imports about 8 TWh from neighbouring countries. The largest generator is state-owned Statkraft, which generates approximately 30 percent of all electricity. The next largest generator has a market share of 6 percent. Overall, ownership is a mixture of state and private ownership.

C.9.3. Security of supply issues in Norway

The Norwegian market is dominated by hydro generation for its domestic generation portfolio. A predominantly hydro based system has different security of supply issues to a thermal generation based system. In a thermal system, the main consideration is sufficient generating ***capacity*** compared to projected demand. In a hydro based system, it is sufficient ***fuel*** in the form of water as well as sufficient capacity for the projected demand. For hydro system, the generators can build sufficient capacity on the network, but if there is insufficient rainfall then the capacity cannot be utilised and electricity shortfalls can occur.

The following graph of electricity prices demonstrates considerable variability over the period from 1996 to 2001. Prices in Nordpool are dependent on the overall levels of rainfall. In periods of low rainfall prices are high, whilst in years of high rainfall electricity prices are comparatively low.

Figure C.5
Average Monthly Prices in NordPool



Hydro capacity exhibits another difficulty not faced by thermal based systems. The number of sites for hydro capacity are finite, once utilised, the total generation on the system cannot be expanded unless another type of generation is built. In mature markets such as Norway, it is difficult to expand capacity to meet growing demand without either building thermal generation or increasing imports.

Thermal generation has a different cost characteristic than a hydro based system. Under the thermal system, the production costs are fixed based on the cost of fuel and generators bid prices at which they are willing to generate power. Under a hydro based system, the value of generation is the opportunity cost of using the water. In a high rainfall period, the opportunity cost is low and the overall prices are low. In low rainfall periods, the opportunity cost is high and the overall prices are high. This fundamental difference in prices means that it is very difficult for thermal plant to recover its costs (including variable costs of generation) in a predominantly hydro system without some government or pricing intervention to support the thermal plant.

C.9.4. Government response to security of supply

The Norwegian government has responded in a number of ways to the perceived shortage of capacity in Norway.

1. The market has a capacity market for the 6 month winter hydro season to meet the peak demand on the system. The capacity market is based on uniform price auctions (or SMP auctions). It has two quarterly auctions as well as monthly auctions for supply increase or demand reduction in three regions: Southern Norway, Oslo Zone, and Northern Norway. Contracts awarded in the auctions can run for a year, a quarter or a month. If the plant is called during under the contract, it is also paid for the energy it generates (or foregoes) according to the price in the balancing market.

2. The Government has encouraged, though not only for security reasons, a number of international interconnections. Not only is the network linked to Sweden, Norway has two further interconnectors under construction: the NorNed link to the Netherlands and the Viking Cable to Germany. In addition, a connection to the British market is also a future possibility.

   Interconnectors enable Norway to export electricity during peak demand (when prices are high) and import baseload electricity during off peak periods. Interconnectors help to level out the electricity prices from year to year as in high rainfall years, exports increase and in low rainfall years, imports increase.

3. In May 2000, the Government exempted new hydro schemes from a 3 percent investment tax to promote further hydro projects in the face of public opposition to new hydro projects.

C.9.5. Conclusions

The Norwegian market exhibits some fundamental differences to the British market. The market is dependent on rainfall levels rather than on actual capacity built. As such parallels from this market are difficult to draw. The government is concerned about security of supply in the face of increasing local demand for electricity and the limited options for new hydro sites. It has encouraged security of supply by (1) encouraging a capacity market for generation and demand reduction; (2) exempting new projects from a 3 percent tax; and (3) the most important influence is the development of interconnectors with other countries to provide geographical diversity to the rainfall risk and to allow interconnection to thermal and nuclear based systems providing diversity to the Norwegian system. However, the extent of intervention by the Government in Norway in relation to security of supply is quite limited to date.

C.10. Annex Code Provisions for Reserve Contracts in Australia

Code provisions in relation to Reserve Contracts:

- NEMMCO can enter into reserve contracts with market participants in accordance with the relevant guidelines and procedures developed by the Reliability Panel (Reliability Panel Determination on Reserve Trader and Direction Guidelines, June 1998). NEMMCO must enter into contracts prior to 1 July 2003 (3.12.1).
- Section 2.4.1 of the Code defines a market participant to be any person registered with NEMMCO as any one or more of the following categories:
  - Market customer
  - Market generator
  - Market Network Service Provider
- Prior to 1 July 2003, as part of the Reliability Panel's review of VoLL, the Reliability Panel must also consider whether NEMMCO's power to enter into reserve contracts (as a safety net) can be removed (3.12.1).
- NEMMCO has the power to enter into reserve contracts to ensure the reliability of supply (3.12.1c). These contracts may relate only to particular trading intervals: 3.12.1(f)
- NEMMCO is not able to contract for reserves that are likely to be submitted or available for dispatch in the trading interval that the contract relates to (3.12.1f)
- NEMMCO must seek a market response to low reserve levels if there is sufficient time (3.12.3 and 3.12.4).
- Plant capacity that is subject to a reserve contract by NEMMCO can only be submitted by NEMMCO and NEMMCO is entitled to any resulting spot market revenue (3.12.6a). Capacity for the *trading intervals* covered by the reserve contract is only available to be bid by NEMMCO.
- Clauses 8.8.1 and 8.8.3 required the Reliability Panel to determine guidelines governing the issuing of directions and entering into reserve contracts. The determination of guidelines issued by the Reliability Panel in 1998 prevent NEMMCO from entering into reserve contracts earlier than six months from the projected shortfall. NECA has proposed that this safety net timeframe be extended to a rolling three year period. As far as we are aware, this change has not yet been implemented.
- NEMMCO must call for tenders whenever possible. The Reliability Panel Determination on Reserve Trader and Direction guidelines details the requirements of the tender process. Payment should be through a fully open, competitive tender

process. There are no predetermined limits, however if mutually acceptable terms and conditions cannot be agreed, there is provision for independent arbitration (principally, but not soled in regard to price). Either party can initiate arbitration, but the outcome is not binding. NEMMCO is unable to reject a tender solely on price in circumstances where it would have to resort to direction, unless first offering to go to arbitration. The arbitrator can be selected from a panel established by NECA, but this is not required. Any arbitrator agreed to by both parties may be appointed.

C.10.1.1.1. Operation of Reserve Contracts

- NEMMCO must aim to submit bids and offers under a reserve contract to minimise distortions to the spot market (3.12.6e)
- NEMMCO's bids only cover the quantities, not price bands (3.12.6a)
- NEMMCO must not dispatch plant subject to a reserve contract until all valid dispatch bids or offers (including those priced at VoLL) have been dispatched and there would otherwise be insufficient supply to meet the load in any region (3.12.7a). If there will still be insufficient supply, NEMMCO may make changes to the pre-dispatch schedule or to central dispatch to dispatch plant under the reserve contract (3.12.7b).
- NEMMCO's bid for reserve capacity is only for a quantity (no price bid)
- Pricing of bids from reserve contracts: Under section 3.9.3, in the event of market intervention, NEMMCO is required to price according to its published methodology (required under 3.9.3b). 'What if' pricing is used – ie what would have happened if the reserve trader dispatch not occurred? For further detail, see "Intervention Pricing Methodology in the National Electricity Market, Final Report".

APPENDIX D. TERMS OF REFERENCE FOR STUDY ON SECURITY IN GAS AND ELECTRICITY MARKETS

1. Objectives and Scope.

1.1 The study is to assess (a) whether there currently exist factors that give rise to barriers or distortions that can be expected to affect the operation of both the gas and electricity markets in Great Britain in ways that might impede the ability of those markets to achieve efficiently an adequate level of security of supply for energy customers in Great Britain, and (b), if any such factors are identified, their materiality and significance, both in absolute terms and relative to one another. Depending on the outcome of the analysis, the consultants may be asked to carry out further work, for example, either to consider the possible development of monitoring arrangements that could signal, in a timely way, the potential emergence of any such barriers or distortions in the future, or to consider whether there are specific measures that could be taken to improve the efficient achievement of security of supply. The focus of analysis should be on the next 10 years, but with consideration of potential issues up to 2020.

1.2 For the purposes of this study, the consultants should consider barriers or distortions which affect not just the ultimate physical achievement of security of supply but also those barriers or distortions that may affect the efficient achievement of security of supply, i.e. achieving security of supply at lowest cost.

1.3 The principal focus of the study is the *competitive* parts of the gas and electricity markets, including interconnectors, gas storage and gas terminals. Although it is recognised that the owners and operators of monopoly transmission and distribution networks have a crucial role to play in providing security of supply to consumers, the study does not need to consider their role in detail except to the extent that these networks might constitute barriers to entry or exit from the Great Britain market. The study should take account of developments of the role of the transmission and system operators that are being taken forward, particularly by OFGEM. The study should take account of the implications for security provision of a range of outcomes for the development of the European gas market and of the interactions between gas and electricity markets.

1.4 The task can be broken down into the following three stages:

- What is the appropriate definition of security of supply, and therefore what is meant by an "adequate" level of security provision?
- To identify any barriers or distortions affecting the efficient operation of the gas and electricity markets, which may mean that security provision for gas or electricity or both is inadequate or excessively costly; and

- Consider the practical effect of any such barriers or distortions and whether their impact is likely to be material on achieving adequate security.

1.5 The consultants will report to a Project Steering Group comprising representatives of DTI, HM Treasury and OFGEM.

2. Defining "Adequate" Provision of Security.

2.1 The first task is to define what should be understood by an "adequate" level of security provision. This should take into account the following:

- The assumption that electricity generation and supply, and gas shipping, supply and the provision of gas to the Great Britain market, will continue to be activities open to competitive provision;
- All markets exhibit imperfections of one kind or another;
- Government or regulatory activity intended to improve market operation can sometimes be counterproductive; and
- Any other relevant considerations.

2.2 For the purposes of this study, the term "adequate" in relation to security or investment should be taken to encompass all points in time, peak and off-peak, short term and long term. Adequate provision therefore covers not just the quantity provided but the timing of that provision. Timely provision is important for the electricity sector since electricity as such cannot be stored and for the gas sector as cutting off supply to smaller customers has important safety implications.

2.3 The consultants should also consider the extent to which the prospect of erratic or sharply fluctuating gas and electricity prices to final consumers, especially domestic consumers, is consistent with adequate levels of security[139].

3. Will Market Provision be Adequate.

3.1 A number of arguments have been put forward why market provision of security of electricity and gas supply might be inadequate. For example, some of these are discussed in Chapter 4 of the PIU Energy Review, particularly Paragraphs 4.9 – 4.12[140]. The likelihood of increasing future reliance on imported gas and uncertainties over the development of the European gas market and over the means

139 Prices in wholesale markets could be more volatile than those to final consumers.

140 Other sources include the February 2002 House of Commons Trade and Industry Committee Report on Security of Energy Supply and the February 2002 House of Lords European Union Committee Report, Energy Supply – How Secure Are We?

whereby imported gas would be delivered to the Great Britain market could also have implications for the ability of gas suppliers in Great Britain to deliver adequate security to their customers.

3.2 The study should assess whether there currently exist barriers or distortions to the efficient operation of the gas and electricity markets that may impede the provision of adequate levels of security of supply, and if so, the materiality and significance of those barriers or distortions. In doing so, the consultants should consider and assess the various views of interested parties that have been put forward on these issues, but they should reach their own, independent conclusions. The reasoning leading to those conclusions should be clearly and comprehensively explained.

3.3 The study should consider whether evidence from other countries with liberalised gas and electricity markets provides indications of the success or otherwise of gas and electricity markets in providing adequate security.

4. Practical Extent of Possible Inadequate Market Provision.

4.1 This part of the study should assess the materiality for achieving adequate security of supply of any barriers or distortions to the efficient operation of the market identified in Section 3 leading to inadequate provision of energy security where the effect is thought to be significant.

4.2 Taking each reason in turn, the study would attempt to consider the practical importance of that reason, including an assessment of the extent to which the barrier or distortion will affect achieving physical security of supply, lead to additional costs in achieving security of supply, or lead to excessive fluctuations in prices to consumers. The consultants should attempt to rank any barriers or distortions identified, based on their relative importance for achieving security of supply.