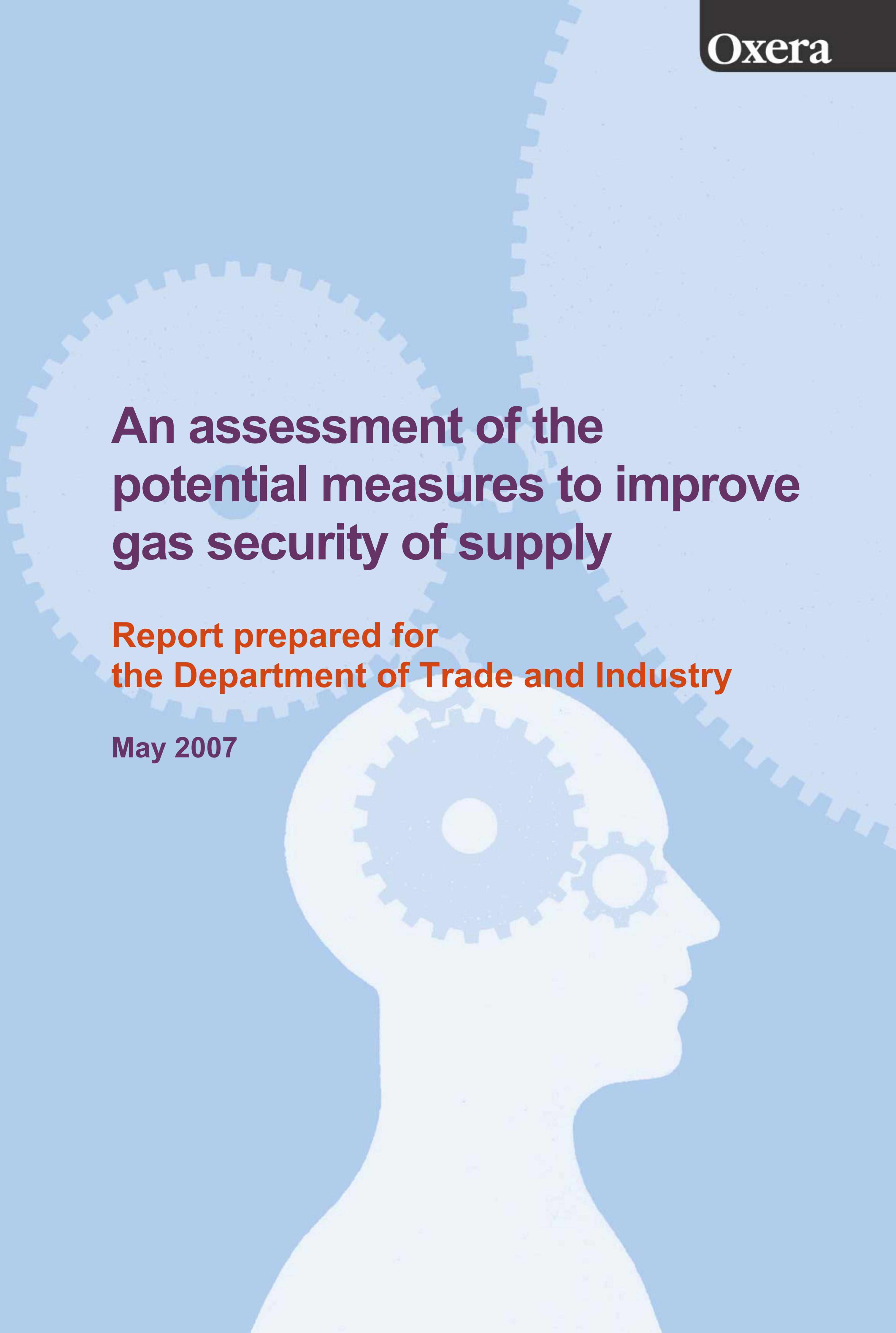
Oxera

An assessment of the potential measures to improve gas security of supply

Report prepared for the Department of Trade and Industry

May 2007



Executive summary

In October 2006, the Department of Trade and Industry (DTI) launched a consultation to assess the effectiveness of the current gas security of supply arrangements.[1] As part of this consultation process, seven measures designed to promote gas security were proposed for consideration.

Measure 1	An extension of the current supplier obligation
Measure 2	Changes to the cash-out arrangements
Measure 3	Regulation of the use of storage
Measure 4	Introduction of some form of capacity mechanism
Measure 5	Encouraging additional demand-side response from industrial and commercial (I&C) consumers
Measure 6	Encouraging the installation of back-up fuel capabilities at combined-cycle gas-turbine (CCGT) power stations
Measure 7	Smart gas metering and increased efforts on fuel efficiency

The measures aim to reduce the likelihood of forced outages (involuntary interruptions) of gas consumers by encouraging additional, or more timely, investment in infrastructure; improving the utilisation of existing assets; or providing additional demand-side flexibility to absorb supply shocks. However, the effectiveness of such measures depends not only on how successful they are in reducing exposure to outage risks, but also on the impact this has on underlying market prices, since there are economic costs associated with price changes and variability.

The aim of this study is to provide a cost–benefit assessment of the proposed policy measures over the period 2007/08 to 2020/21. Central to this is an understanding of how the measures affect the long-run pricing and investment behaviour in the gas market. To analyse this, Oxera has developed a dynamic price-security model that simulates forced outage risks and price distributions over time and integrates these with a market investment model. On this basis, the measures can be assessed relative to a Base Case in terms of three main indicators:

– the expected cost of forced outages on the system;
– the impact on wholesale and retail prices;
– the costs of implementation.

In addition, where there may be unintended consequences that the modelling approach cannot capture, these are discussed separately.

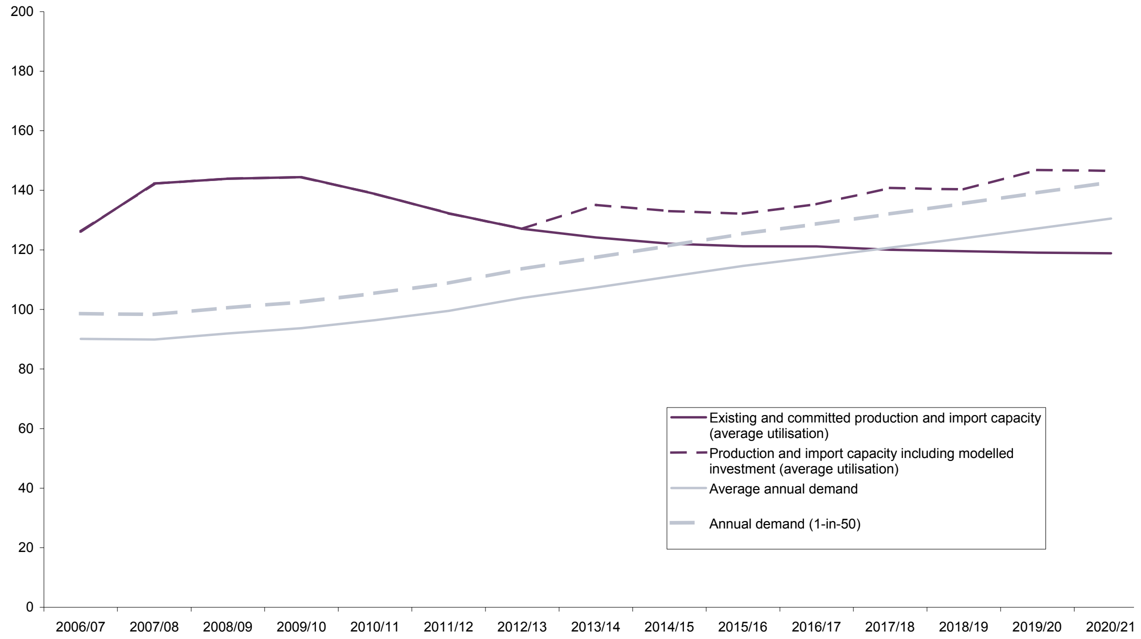
The Base Case

Oxera's Base Case takes as its starting point the existing gas delivery infrastructure and UKCS production estimates together with selected additional infrastructure indicated in the report of the Joint Energy Security of Supply (JESS) Working Group report[2] as being under

[1] DTI (2006), 'Gas Security of Supply Arrangements: The effectiveness of current gas security of supply arrangements—a consultation', October.
[2] Joint Energy Security of Supply Working Group (2006), 'JESS—Long-term Security of Energy Supply: December 2006 Report', Seventh Report, December.

construction or anticipated in the period up to 2009/10.[3] As Figures 1 and 2 illustrate, this assumed investment profile greatly improves the underlying supply–demand balance over the next five to six years; beyond that time, without further investment, however, market tightness (especially in relation to peak positions) begins to re-emerge.

Figure 1 Annual supply–demand balance (bcm)



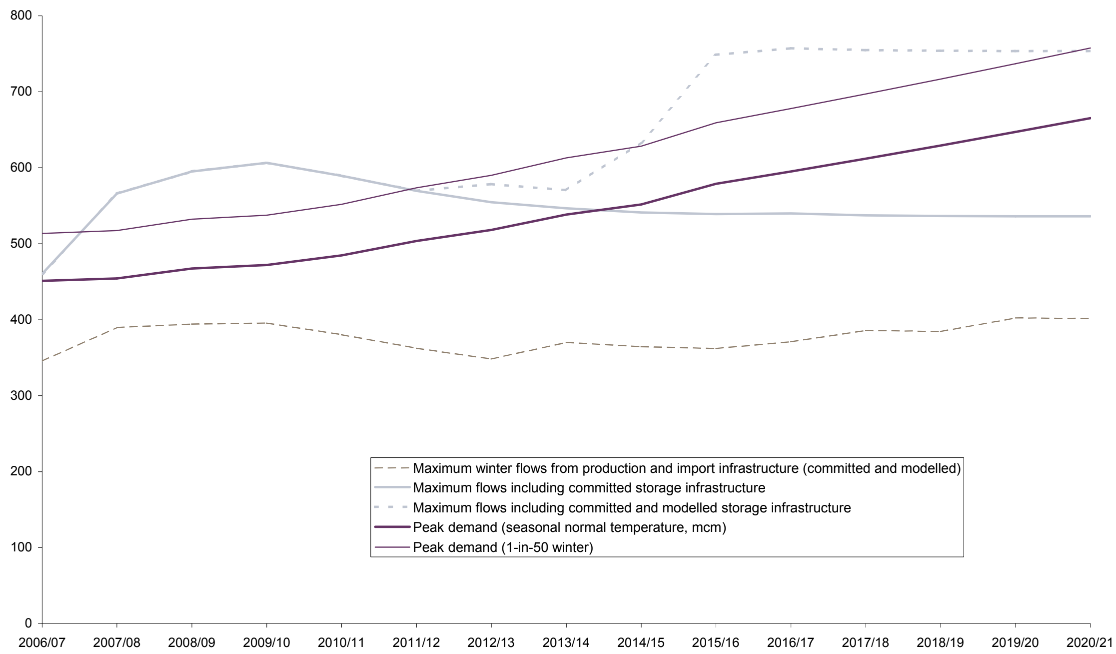
Note: The assumed supply availability de-rates maximum capacity of some delivery infrastructure elements. The de-rating factors applied are 90% (UKCS production), 75% (Continental European supplies), and 60% (LNG imports).
Source: Oxera.

The modelling of the Base Case simulates a potential new investment profile in response to expectations of future prices on the basis of the forward projections of supply and demand availability, taking into account the risk of supply and infrastructure failures and weather-related (demand) risk.[4] The impact of the new investment is also shown in Figures 1 and 2. The key features are as follows:

- an additional £5.4 billion of investment in storage and import projects, over and above that already committed, is projected over the period up to 2020/21;
- storage capacity will increase by 6.8bcm and overall deliverability will treble;
- an extra 38bcm of new import infrastructure (mainly new Norwegian gas and LNG import infrastructure) will be brought on stream to counter the decline in the UKCS and the anticipated growth in demand.

[3] This includes two new storage facilities at Aldbrough and Holford, and several import infrastructure developments, including the new LNG import terminals at Milford Haven, the upgrade to the Isle of Grain and the, now operational, Excelerate project.
[4] These results are dependent on the assumptions underlying the model. Variations in these, as illustrated by the sensitivities in the Appendices, can materially change the implications for security of supply.

Figure 2 Peak supply–demand balance (mcm)



Note: These are maximum capacities of infrastructure rather than modelled flows from the infrastructure (ie, these are indicative figures showing 100% utilisation at the peak).
Source: Oxera.

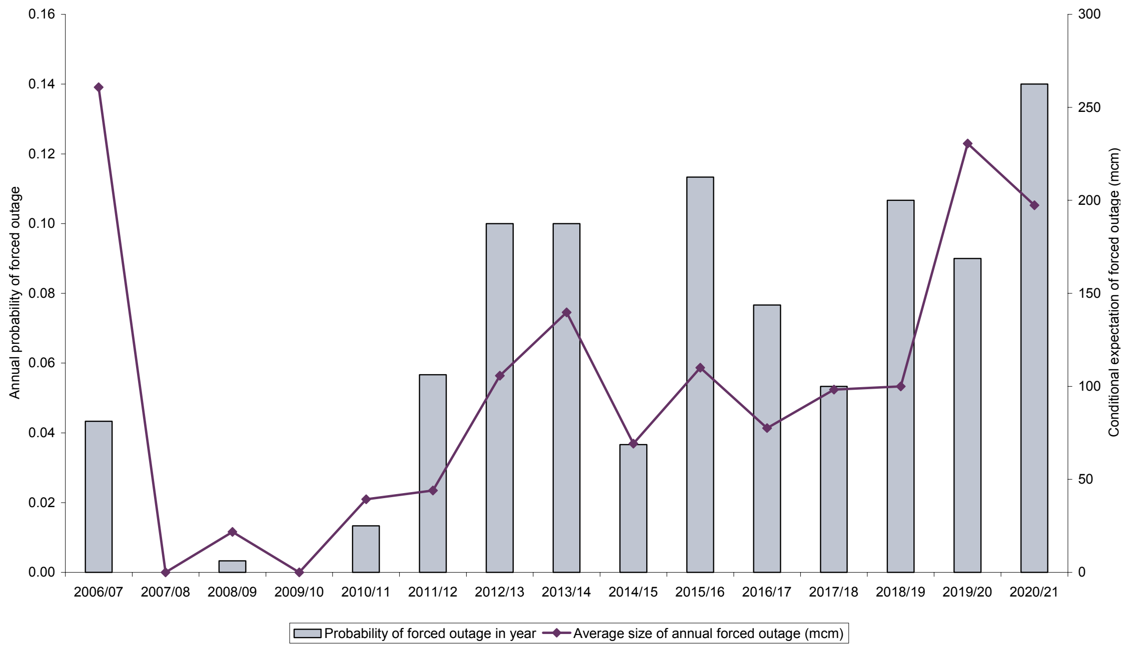
The implications of this investment for security of supply are assessed within the analysis through the modelling of forced outages (ie, interruptions to supply that cannot be met by voluntary demand-side response[5]) arising as a consequence of operational outages to delivery infrastructure[6] and demand variations. The probability of an outage occurring in a given year is shown in Figure 3 below.

In 2006/07 this probability was 0.04 (ie, there was a 1-in-25 year chance of a forced outage). The implication of the current investment round is evident in the reduction in this probability over the following four years. After 2011/12, the probability of outage is greater than in 2006/07 and shows a cyclical pattern that reflects the lumpiness of new capital investment decisions. However, though the probability of a forced outage increases, the expected size of any forced outage remains relatively low—in 2006/07 the annual expected forced outage is around 0.01% of annual demand, whereas in 2020/21, the annual expected forced outage is still only 0.02% of annual demand (see Figure 4 below). On average, outages are not expected to last for more than a day.

[5] Drawing on data in National Grid (2006), 'Winter 2006/07 Consultation Document', the Base Case assumes 16mcm/day of industrial demand-side response and 40mcm/day of CCGT response at defined price thresholds.

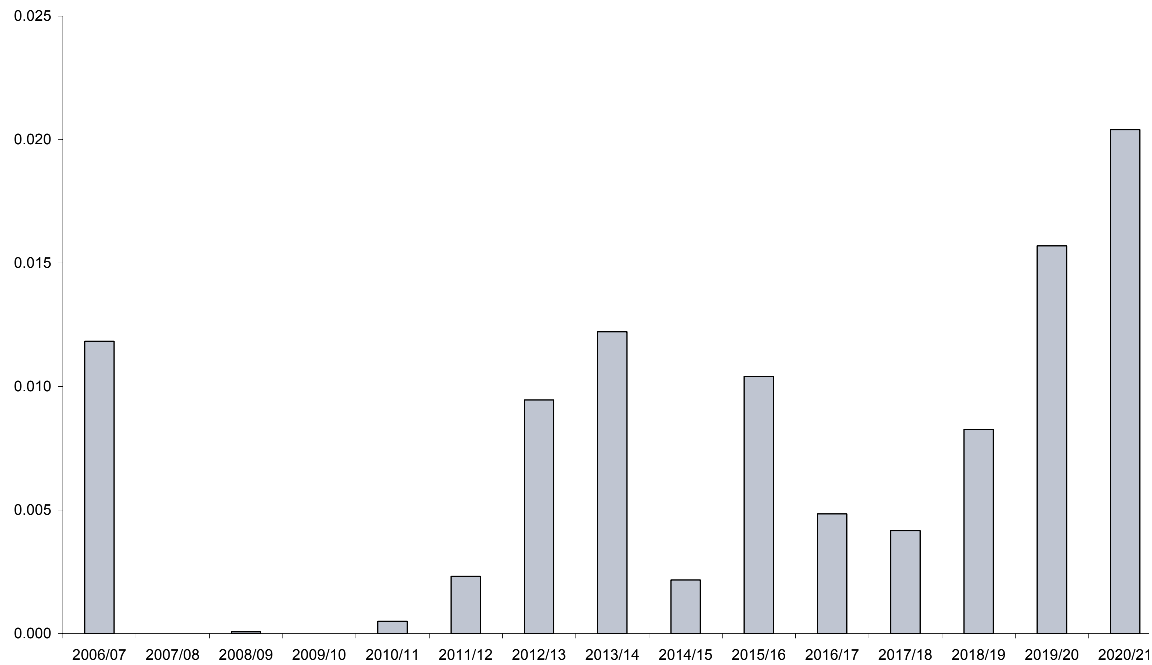
[6] The frequency and duration of operational outages used for the modelling were agreed with the DTI and are in line with previous assumptions used in analysis undertaken for the DTI. No primary empirical evidence on these risks was collated as part of this study.

Figure 3 Annual probability of a forced outage



Source: Oxera.

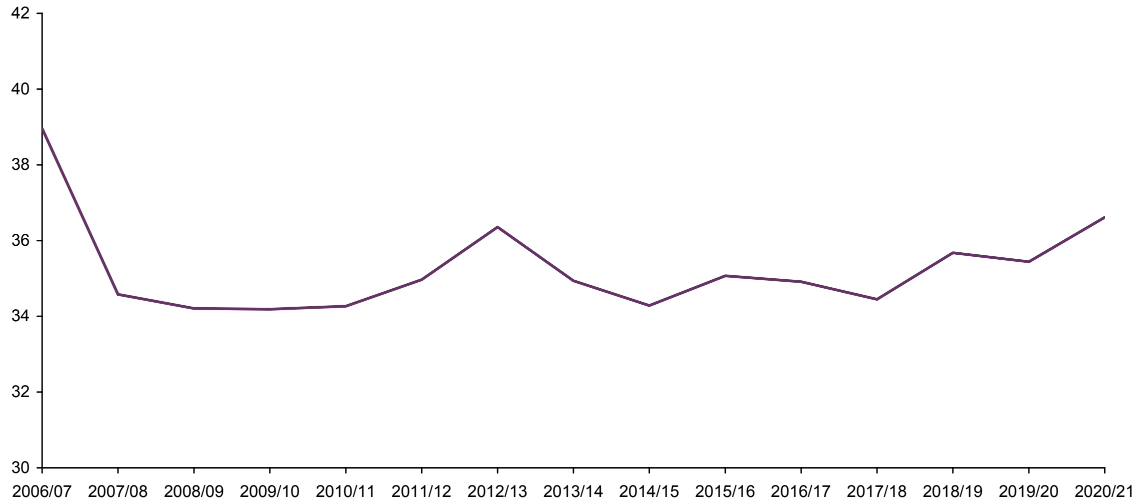
Figure 4 Annual expected outage (as % of demand)



Source: Oxera.

The introduction of new infrastructure and the changing pattern of market tightness and forced outages also have an impact on the expected spot gas prices. As Figure 5 below illustrates, the spot gas price trends down initially, driving towards the marginal cost of gas from LNG and Continental gas sources, but then a more cyclical pattern of prices emerges reflecting the lumpiness of new investment and the pattern evident in the probability of forced outages. This latter effect influences prices because, when forced outages occur, the market is assumed to face a value of lost load (VoLL) of 500p//th;[7] therefore, as the probability of an outage increases, the price distribution will reflect more periods at that price, which is more than double the highest demand-side response cost.[8] It may still be the case that average expected prices in a given year are lower than those in another year with a lower probability of outage (as is the case in 2020/21 compared with 2006/07). This is because the annual expected price reported in Figure 5 takes into account the whole distribution of price outcomes and the wholesale price when there is no market tightness may be significantly lower.

Figure 5 Annual average expected spot price (p/th)



Source: Oxera.

Quantifying the cost of interruptions

The price-security model simulates the physical outage pattern, but does not provide any indication of the cost to the economy of such an interruption. While an indicative VoLL of 500p/th has been used in the price modelling, the actual VoLL varies depending on a range of factors, including the size and duration of the outage, the sectors affected, the time of year, etc.

To capture the economic impacts of an interruption, Oxera has used Office of National Statistics (ONS) data to calculate the losses arising from a forced outage. The loss is assumed to be equivalent to the gross value added (GVA) forgone because of the lack of gas as an input to production—this follows the same methodology used by Ilex Energy in its analysis of strategic gas storage options. The estimation procedure is based on the following assumptions:

– all voluntary demand-side response is assumed to have already occurred;
– each industry has a direct GVA/mcm of gas consumption figure derived from ONS data;
– gas interruptions are assumed to fall on the industrial sector first, then the commercial sector and finally on the domestic sector;

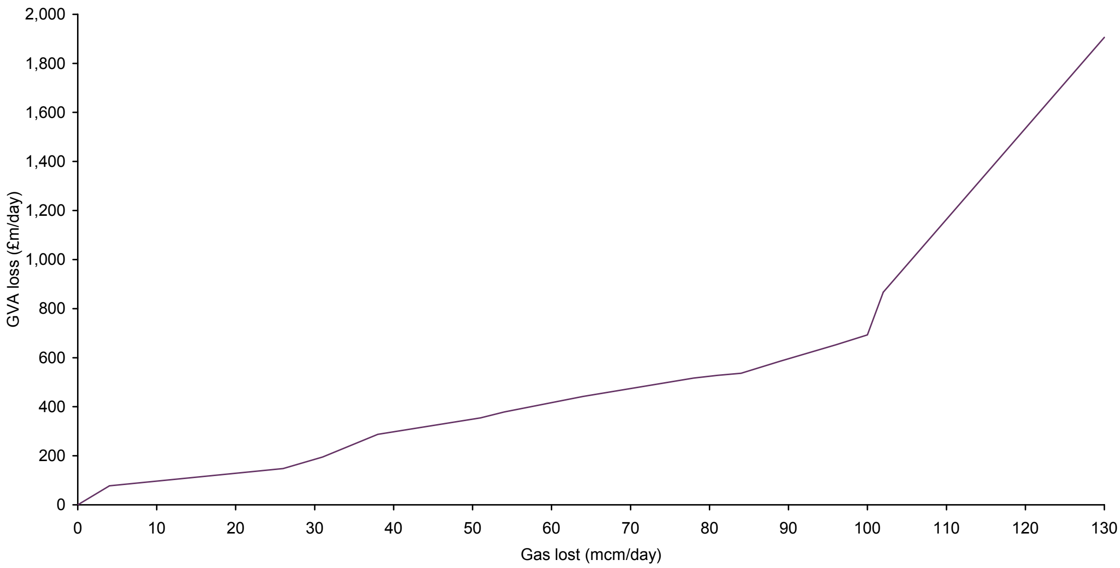
[7] See discussion in section 2.2.7.

[8] The VoLL is thus an important assumption as it has a significant impact on expected prices and hence on future investment decisions.

– within each sector, industries are interrupted according to a ranking of their direct GVA per unit of gas consumption (ie, industries with a lower marginal value of gas are shut off first);
– indirect gas consumption is also curtailed through two routes: a proportionate reduction in the electricity use required by the industry in question; a knock-on impact on upstream and downstream industries.

This provides an outage cost curve as shown in Figure 6. Applying this to the pattern of outages simulated for the Base Case yields annual expected costs of outages between £0m and £612m, as illustrated in Table 1 below.[9] Over the course of the period 2007/08 to 2020/21 the net present value of the outages (discounted at 3.5%) is £1.26 billion.

Figure 6 Estimated forced outage cost (£m/day)



Note: This figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction and miscellaneous sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; Oxera calculations.

[9] The model truncates investment decisions in 2020/21 and therefore higher costs in the final period may only be transitory.

Table 1 Annual expected forced outage levels and costs in Base Case

	Expected forced outage (mcm)	Expected outage cost (£m)
2007/08	0	0.0
2008/09	0.07	0.1
2009/10	0	0.0
2010/11	0.52	2.3
2011/12	2.49	11.8
2012/13	10.57	96.8
2013/14	13.98	214.5
2014/15	2.54	20.1
2015/16	12.47	173.4
2016/17	5.95	45.9
2017/18	5.24	110.8
2018/19	10.66	123.8
2019/20	20.75	456.1
2020/21	27.64	611.9
Net present value (NPV) (2007/08 to 2020/21)		1,262

Source: Oxera.

Impact of the proposed measures

The proposed measures were represented in the modelling through adjustments to key input assumptions that influenced the pricing signals and investment incentives.[10,] The exception to this was Measure 3 (regulating storage), where it was not feasible to operationalise the constraints on usage.[11]

Physical security

The consequences of these different investment profiles are evident in the implied physical security levels. In general:

– the size of annual expected forced outages is smaller—the measures all reduce the annual expected forced outage either by expanding the available flexible demand-side response or through enhancement of new infrastructure provision;[12]
– the probability of a forced outage is lower in all measures with the exception of Measure 7 (smart metering). Only in the low-demand situation is the probability of an outage higher than in the Base Case[13]—even here, the average size of an outage is lower than that of the Base Case;

[10] Measures 1 (supplier obligation) and 4 (capacity mechanism) were modelled in the same manner, the only difference being the severity of the winter at which the security standard was set (1-in-30 for Measure 1 and 1-in-50 for Measure 4). The modelling assumed that all measures could feasibly be implemented. It did not investigate in detail how they would be introduced, or the costs associated with their introduction.
[11] An alternative approach, focusing on the revenue implications for storage operators, was applied here. This indicated that the measure was likely to have severe adverse impacts on the viability of storage projects.
[12] There are some significant outliers in one or two years, particularly in relation to Measure 2 (cash-out pricing).
[13] This seemingly counterintuitive result arises because lower average demand dampens price signals, causing investment to be delayed and the market to become more exposed to forced outages in order to create sufficient stimulus for new investment.

– significant demand-side response is observed in all scenarios—the level of demand-side response (particularly the CCGT response) is uniformly high. It is only in Measure 4 (capacity mechanism) that demand for additional gas to meet stringent obligations is high enough to exhaust the demand-side response and push expected prices up such that the physical infrastructure investment replaces more flexible demand-side response, leading in the longer term to significant reductions in the use of CCGT response. Even in Measure 1 (supplier obligation), reductions in demand-side response relative to the Base Case are not significant and, where they arise, are identified with small differences in the timing of new infrastructure coming on line.

The different measures did produce variations in the levels and timing of investment. As Table 2 below shows, Measures 1 (supplier obligation), 2 (cash-out pricing) and 4 (capacity mechanism), which were intended to sharpen the incentives for additional infrastructure investment, led to higher levels of investment, whereas those measures (5 (industrial demand-side response, DSR), 6 (CCGT response) and 7 (smart metering)) that improved the demand-side flexibility in the system[14] reduced the need for capital investment (although the reduction was not material for the improved industrial demand-side response due to the small volumes involved).

Table 2 Comparison of investment costs (undiscounted, £m)

	Total investment cost	Incremental investment to Base Case
Base Case	**5,433.1**	
Measure 1 (supplier obligation)	5,813.2	380.0
Measure 2 (cash-out pricing)	7,008.4	1,575.2
Measure 4 (capacity mechanism)	6,979.2	1,546.1
Measure 5 (industrial DSR)	5,428.3	–4.8
Measure 6 (CCGT response)	4,042.5	–1,390.6
Measure 7 (smart metering)	5,163.8	–269.3

Source: Oxera.

The impact on forced outage costs is shown in Table 3 below. Only under Measure 2 (cash-out pricing) is there a higher cost of forced outages (largely a function of how the extreme VoLL assumption affects storage operation), with the largest reduction occurring under Measure 6 (CCGT response). The beneficial impact of the extra voluntary response is dependent on this demand flexibility being available over sustained periods of two to four weeks or more during winter periods. If this is not feasible, these measures would be significantly less effective.

[14] Technically, Measure 7 (smart metering) reduced actual demand rather than increasing available demand-side flexibility. However, the implication (a larger buffer before existing supply infrastructure is insufficient to meet demand) is the same as for the other demand-side measures.

Table 3 Comparison of outage costs (NPV, £m, 3.5% discount rate)

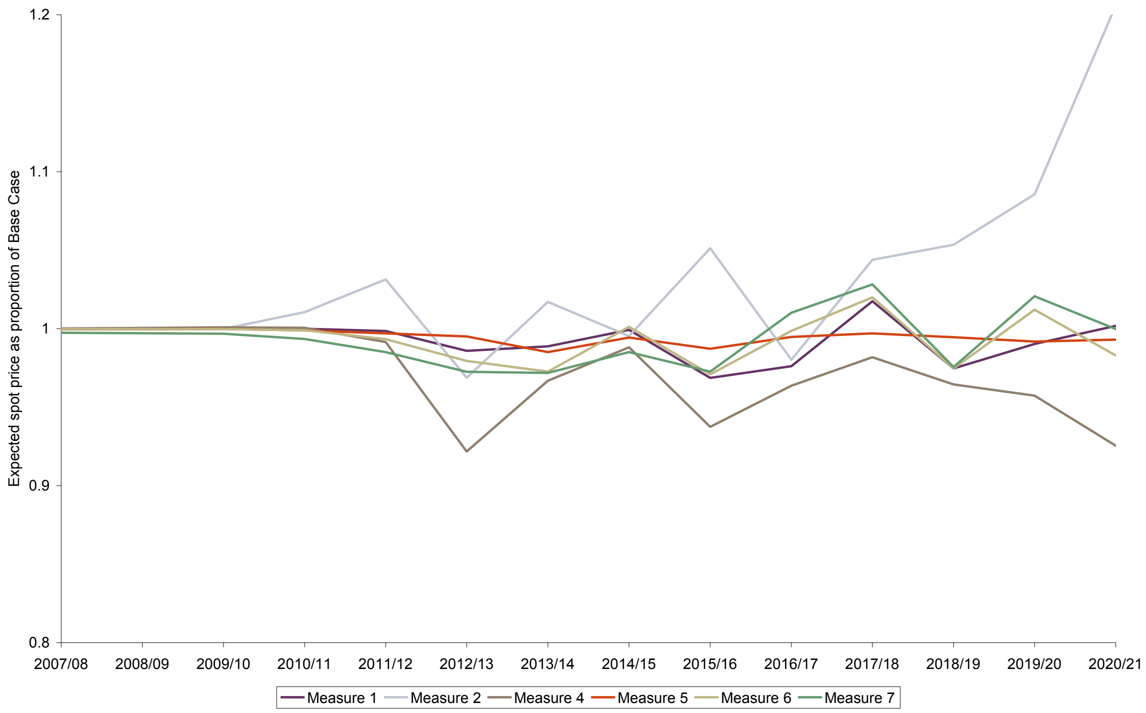
	NPV of forced outage costs	Reduction relative to Base Case
Measure 1 (supplier obligation)	808	454
Measure 2 (cash-out pricing)	1,438	–176
Measure 4 (capacity mechanism)	256	1,005
Measure 5 (industrial DSR)	589	673
Measure 6 (CCGT response)	154	1,107
Measure 7 (smart metering)	485	777

Source: Oxera.

Spot prices

The various investment profiles also affect market prices. New investment is only made if it is expected to be profitable (and hence prices enable investors to cover their capital costs).[15] Thus, the differential investment costs highlighted in Table 2 imply variations in the expected spot prices. Expected annual average spot prices show similarities with the Base Case, as illustrated in Figure 7, where the outturn prices for each measure are shown as a proportion of the Base Case price.

Figure 7 Expected spot prices relative to Base Case



Source: Oxera.

[15] Perfect foresight assumptions in the modelling remove stranded cost risk for individual investments.

Quantifying price impacts

Changes in outturn prices will have an incremental impact on welfare. These welfare effects will accrue to various market participants in the form of changes in consumer and producer surpluses.

The consumer surplus here is defined as the consumer's willingness to pay for a quantity of gas *minus* the amount they actually pay for it. The producer surplus is the price that producers receive for gas sold *minus* the production cost of gas. In general, the majority of price changes are transfers between consumers and producers and are largely offsetting (ie, the change in welfare being the deadweight loss or gain, depending on the direction of the price change).

These price effects are set out in Table 4. As can be seen, the measures where investment increased see a reduction in welfare due to higher prices, whereas those that reduced the need for physical investment led to increases in welfare. However, a proportion of UK gas consumption will be imported, and producer surplus accruing to non-UK producers supplying to the UK will reduce the welfare of the UK market participants.

Table 4 NPV of welfare changes, 2007 to 2020 (£m)

	Change in:			
	consumer surplus	producer revenue	producer revenue going overseas	aggregate welfare
Measure 1 (supplier obligation)	–907	775	523	–655
Measure 2 (cash-out pricing)	–5,062	4,248	3,466	–4,244
Measure 4 (capacity mechanism)	–4,249	3,625	2,521	–3,145
Measure 5 (industrial DSR)	857	–735	–540	661
Measure 6 (CCGT response)	1,109	–953	–676	832
Measure 7 (smart metering)	1,137	–974	–619	782

Source: Oxera.

Cost–benefit assessment

The overall cost–benefit aggregates the physical security and welfare changes and compares these to any known implementation costs. (Only for Measures 6 (CCGT response) and 7 (smart metering) were verifiable implementation costs identified, for all other Measures implementation costs have not been explicitly analysed.) The results of these are shown in Table 5 below, where, in addition to the cost elements reported in Tables 3 and 4, a net benefit is included (a reduction in the use of industrial demand-side response compared with the Base Case). While this is an order of magnitude smaller than the other effects, it is included because it is unclear whether the industrial demand-side response fully incorporates the externalities on upstream and downstream industries from a loss of production.

It should be noted that environmental impacts in terms of reductions in CO_2 emissions have not been quantified and may have an impact on the cost–benefit analysis for Measure 7 (smart metering).

Of the measures, only two show a net benefit: Measures 5 (industrial DSR) and 6 (CCGT response). However, there are caveats to this result. For both Measures 5 (industrial DSR) and 6 (CCGT response), the magnitude of the contribution they provide to gas security is dependent on three factors:

– the cost at which the voluntary response is forthcoming;
– the magnitude of the achievable response on any given day;
– the ability of the system to provide this flexibility over a prolonged period.

Table 5 Summary of cost–benefit assessment (2007/08 to 2020/21)

	Reduced interruption costs (NPV over 15 years)	Increase in welfare (NPV over 15 years)	Implementation costs (where known)	Reduced DSR cost (NPV over 15 years)	Net benefit
Measure 1 (supplier obligation)	£454m	–£655m	Licence amendment plus monitoring	£24m	–£177m
Measure 2 (cash-out pricing)	–£176m	–£4,244m	Changes to Code Contract renegotiations?	£48m	–£4,372m
Measure 4 (capacity mechanism)	£1,005m	–£3,145m		£86m	–£2,054m
Measure 5 (industrial DSR)	£673m	£661m		–£19m	£1,315m
Measure 6 (CCGT response)	£1,107m	£832m	£124m to £147m	–£1m	£1,814m to £1,791m
Measure 7 (smart metering)	£777m	£782m	£2.5 billion to £4 billion	£20m	–£2,421m to –£921m

Note: The costs and benefits presented for Measure 7 (smart metering) are derived from Oxera methodology and do not necessarily correspond with latest DTI views.
Source: Oxera.

Conclusions

In summary, the analysis shows that, under current market arrangements, while security of supply risks may be small (annual expected forced outages are in the order of 0.01–0.02% of annual demand over the period of analysis), they do exist, and there is the possibility of losing up to 3% of annual demand as a result (although with a very low probability). Measures that promote greater demand-side flexibility are largely beneficial to security of supply and should be encouraged where possible (although no clear mechanism has been identified through which such behavioural changes can be guaranteed).

Measures to increase supply-side investment impose a trade-off between higher prices and greater security. That these measures may provide additional insurance against the risk of physical outages is not in doubt; however, the cost to consumers of achieving these improvements may be prohibitive.

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1 Introduction

In October 2006, following the commitment in the Energy Review, the Department of Trade and Industry (DTI) launched a consultation to assess the effectiveness of the current arrangements for gas security of supply.[16] The consultation considered seven potential measures intended to increase physical supply or improve flexibility on the demand side, and thereby reduce the risk of involuntary supply interruptions.

Measure 1	An extension of the current supplier obligation
Measure 2	Changes to the cash-out arrangements
Measure 3	Regulation of the use of storage
Measure 4	Introduction of some form of capacity mechanism
Measure 5	Encouraging additional demand-side response from industrial and commercial (I&C) consumers
Measure 6	Encouraging the installation of back-up fuel capabilities at combined-cycle gas-turbine (CCGT) power stations
Measure 7	Smart gas metering and increased efforts on fuel efficiency

This report, commissioned from Oxera, analyses the materiality of these measures and the relative costs and benefits associated with their introduction. The report does not provide a view on the optimal level of security of supply in the gas market; rather, it considers whether the proposed measures would improve upon current market performance in respect of security of supply, and if so, whether they would do so in a cost-effective manner.

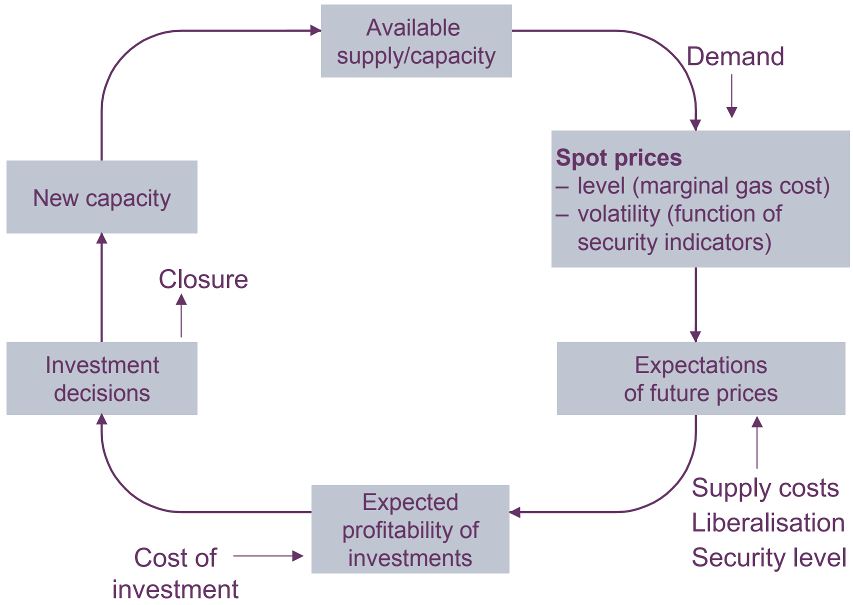
Differences in the overall security position as a result of the implementation of the proposed measures would largely stem from changes to the infrastructure investment profile that the current arrangements would be expected to deliver.[17] That is, by altering the incentives on market participants to insure against supply interruptions, the timing, level and mix of investment provided by the market will vary. These investment decisions affect not only the risk of involuntary interruptions to supply, but also the average level and volatility of prices. This is because, as the UK market has experienced in recent years, the spot and forward prices are driven by the underlying supply–demand balance in the market.

The dynamics of long-run gas market investment are set out in Figure 1.1 below. Essentially, the interactions are as follows:

– the level of security supply (present in the market or required by policy) influences current prices and the expectation of future prices;
– expectations of future prices affect future profitability associated with new investment options and hence have an impact on the investment decisions themselves;
– investment decisions affect the future level of security of supply, through alterations in potential supply options, and hence alter the determination of spot and expected future prices in subsequent periods.

[16] DTI (2006), ‘Gas Security of Supply Arrangements: The effectiveness of current gas security of supply arrangements—a consultation’, October.
[17] Regulating the operation of existing storage facilities would, however, also place restrictions on how existing infrastructure may be used and this may have additional impacts in the short run.

Figure 1.1 Dynamics of long-run investment in the gas market



Source: Oxera.

To capture this investment dynamic, Oxera has developed a price-security model that simulates both the physical outage risk associated with a given supply infrastructure and demand position, and the distribution of market prices which, given assumptions on costs of gas production and transportation, might reasonably be expected. These expectations of future prices drive the investment decisions of potential investors, affecting whether and when to invest, and in which type of infrastructure (eg, additional interconnection, storage facilities, liquefied natural gas (LNG) import terminals, etc).

In defining the investment profile, the price-security model produces, for each year, two main results that are taken to characterise the underlying security of supply in the gas system:

– the *physical outage risk*—an assessment of the risk of physical outages of different magnitudes (in mcm/day) and duration (in number of days);
– the *market price risk*—an assessment of the expected outturn price and the volatility around that mean (taking account of daily varying demand conditions and potential supply outages).

The effectiveness of the proposed measures can therefore be derived by analysing their impact on the physical outage and market price risks. These impacts need not necessarily reinforce each other. For example, a reduction in physical outage risk may correspond with significantly higher supply costs and retail market prices (reflecting the extra investment to deliver the additional security), which may offset some of the benefits of the lower outage risk.

While the price-security model should automatically account for some of the offsetting effects of measures and any inefficient distortions to the pricing signals for investment, there may be some impacts that the model does not capture adequately. Where such occasions are identified any additional impacts that may affect the quantifiable assessment are highlighted through discussion or further sensitivity analysis.[18]

[18] For example, the price-security model assumes common and correct expectations of supply availability. An ‘incorrect expectations’ sensitivity has been performed to assess the impact on model results. The results of this are presented in Appendix 2. However, due to the lumpiness of infrastructure investment and the availability of additional demand-side response, this had very little impact on the overall results.

The remainder of this report is structured as follows:

- section 2 presents the dynamic price-security model, focusing on the representation of the risks to achieving supply–demand balance at any point in time and the derivation of daily market prices;
- section 3 discusses the main investment options that are simulated in the modelling and the principal drivers affecting the investment decision;
- section 4 sets out the ‘Oxera Base Case’ investment profile and the associated physical outage and market price risks;
- section 5 presents the results from the simulations of the proposed measures, highlighting the anticipated impact of the policies, the outturn results, and any unintended consequences not fully captured in the model runs themselves;
- section 6 describes the methodology for the cost–benefit analysis of the changes in physical outage and market price risk, with particular emphasis on determining the costs to the economy of specific shocks;
- section 7 summarises the results of the cost–benefit analysis;
- section 8 provides some conclusions regarding the attractiveness of the proposed measures.

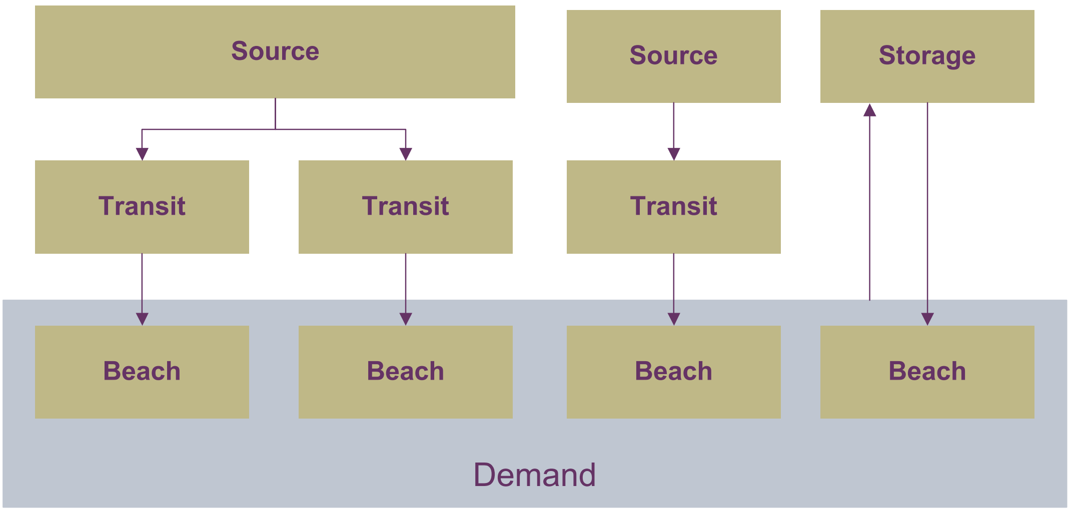
2 Modelling price and security

The price-security model can be thought of as a stylised representation of a physical gas delivery system and its associated spot gas market; the former determining what gas is available at any particular point in time (taking account of capacity constraints, reliability of infrastructure, etc) and the latter determining prices given the available supply options (taking account of production and transportation costs, the nature of competition in the market, storage arbitrage opportunities, etc) and the outturn demand conditions. In this section, the salient features of both parts of the model are described.

2.1 The physical gas system

The physical gas system in the price-security model is a stylised representation of the gas supply chain, as shown in Figure 2.1. Gas flows from one of a number of sources, along a predefined transit route and lands at a beach sub-terminal or LNG import terminal. From here, available gas is used to satisfy consumer demand (which may include demand for storage injections).

Figure 2.1 Stylised representation of the gas supply chain



Source: Oxera.

The total supply of gas available to meet demand at any point in time depends on the capacity at each point in the supply chain and the probability that this capacity will be available. Thus, gas security may be adversely affected by insufficient gas supplies or by the lack of capacity to transport the gas to the centres of demand. At any point in time, this supply shortfall may arise directly because of insufficient capacity to meet demand, or as a result of specific events that reduce the ability of one or more source or piece of delivery infrastructure to operate at full capacity.

The model represents individual points in the gas supply chain and associates with them capacity profiles that may change over time, and probabilities of exposure to specific events or outages that reduce capacity by a given percentage for a set period of time. As a result, a supply distribution is created for each day for each year of the simulation. This distribution can be compared against a similar daily demand distribution to determine the likelihood and scale of any potential shortfall.

Repeating the process across the year enables an outage distribution to be constructed, which will define the probability of an outage of a given size and duration. This outage distribution is dependent on the assumptions about demand levels and variability, and supply levels and availability. These are discussed below.

2.1.1 Gas sources

The model has four main gas sources (excluding storage, which is discussed separately):

– the UK Continental Shelf (UKCS);
– Norway;
– Continental Europe;
– the 'global LNG market'.

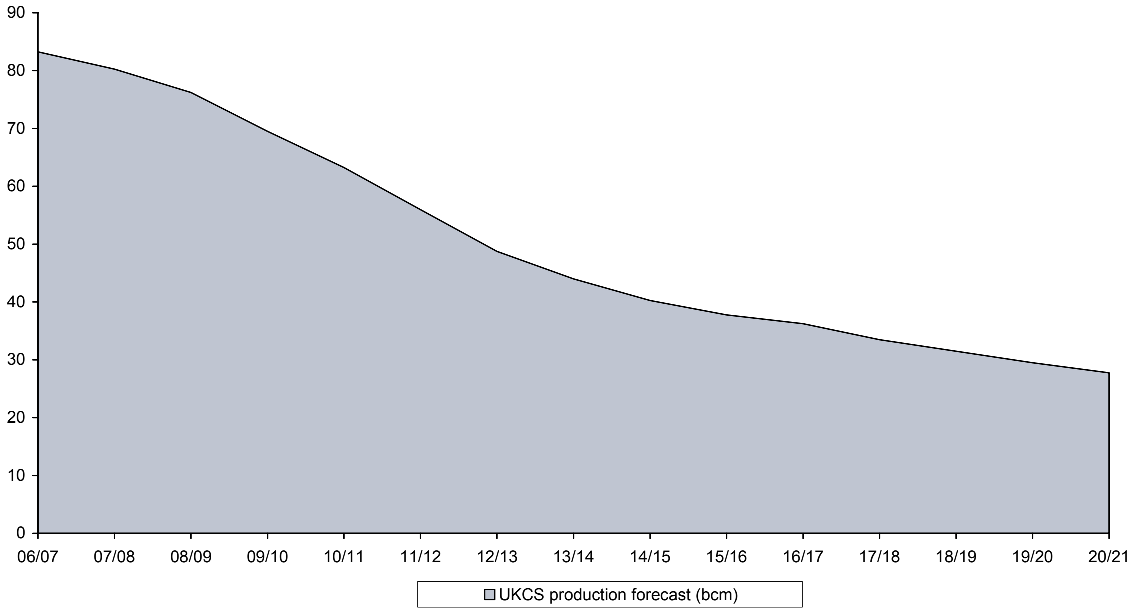
Both the UKCS and Norwegian sources are further sub-divided to reflect the broad patterns of production. There are six individual UKCS sources: one associated with each of the six main beach terminals (St Fergus, Bacton, Teesside, Easington, Theddlethorpe and Barrow). Norwegian imports are split between those accessing the UK via Easington (Langeled) and St Fergus (Vesterled and potentially the Statfjord Late Life project through FLAGS). Any additional Norwegian gas that may enter via the continent is treated as Continental Europe gas, since it is the route to market that is important, not the source.

Source risk is reflected in two ways: profiles of maximum available volumes; operational failures (eg, field outages, instability in the producing country, etc).

Maximum available volumes

UKCS production is assumed to decline over the period of the analysis according to the profile shown in Figure 2.2, with the production associated with each terminal determined in accordance with the proportionate flows assumed in the National Grid, 'Gas Transportation Ten Year Statement 2006'.[19]

Figure 2.2 Assumed UKCS production profile (bcm)



Source: National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.; DTI assumptions.

[19] National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December. The proportion of volume allocated to each terminal is assumed to remain at that prevailing in 2015/16 for subsequent years.

Direct Norwegian gas imports are capped at a maximum of 130mcm/day,[20] which is equivalent to around 40% of potential Norwegian gas production over the period.[21]

Whereas there is a physical maximum imposed on the UKCS and Norwegian sources, the same is not true of LNG. The model assumes that there is unlimited access to LNG in a global market, the only constraint being the price at which it is available (discussed in the following section).

The maximum availability of Continental European gas may, like LNG, be unlimited, constrained only by the price it would be sold at in the market. However, the current lack of progress on effective liberalisation of the European gas markets and existing infrastructure bottlenecks around Zeebrugge suggest that volume constraints may be more appropriate in the short term to reflect the structure of trading. With the majority of European gas traded on long-term contracts, there may be limited flexibility to offer additional volumes into the UK market.

To reflect this, Oxera has used a set of assumptions provided by the DTI that restrict the volume of gas available to flow through the existing Continental pipelines, as shown in Table 2.1. The available volume increases over time due to a combination of the removal of infrastructure bottlenecks and the establishment of a more competitive European market.[22,23]

Table 2.1 Daily deliverable volumes of Continental gas (mcm/day)

Year	Volume available to the UK (mcm/day)
2006/0–2011/12	65.9
2012/13	70.7
2013/14	75.7
2014/15	80.5
2015/16	85.4
2016/17	90.3
2017/18	95.2
2018/19	100.0
2019/20	105.0
2020/21	109.8

Source: DTI assumptions.

Operational outages

In addition to restrictions on available volumes over time, at any particular point in time there may be events that disrupt supply from a given source for a period of time. These factors may include political instability in a source country or knock-on effects of disputes between producer and transit countries (such as occurred in respect of Russia and the Ukraine in 2005); however, they are more likely to reflect physical infrastructure problems. For example, the average availability of UKCS production is now assumed to be 90% of maximum

[20] Although, without additional investment in new infrastructure, the delivery capacity cannot exceed 100mcm/day (or 36.5bcm/yr).

[21] The Norwegian Petroleum Directorate 2005 forecast maximum production in 2020 of around 120bcm.

[22] For simplicity, the modelling assumes that the Balgzand–Bacton (BBL) pipeline is able to operate at capacity, with the Bacton–Zeebrugge (IUK) pipeline being constrained to the residual flows. This may lead to the value of diversity in having multiple pipelines being underestimated, as it prevents substitution of volumes through IUK if there is an operational failure on the BBL line. However, this is unlikely to have a major impact on the results of this study.

[23] A sensitivity where this short-run constraint on Continental European gas flows is removed was also investigated. The results are presented in Appendix 2.

availability, reflecting the increasing risk of outages associated with an ageing infrastructure. Similarly, over time, imported gas will be sourced from further afield, reflecting the geographic concentration of the world's known gas reserves. The implied longer transportation distances may be considered to increase the risk of a technical disruption during transportation to market.[24]

Since, for simplicity, the main import sources are an aggregation of a number of potential sources and transit routes (eg, no distinction is made as to whether LNG comes from Qatar, Algeria, Nigeria, Libya or Trinidad), no operational outage profile has been applied to these sources. Any source disruption can be considered to be captured within the outage profiles assumed for the relevant import infrastructure.

However, UKCS volumes are subject to an operational outage assumption. The daily availability of gas to each UKCS terminal is assumed to be normally distributed between 80% and 100%. Thus, on average, UKCS availability is 90% of maximum, consistent with the assumptions used by National Grid and the Joint Energy Security of Supply (JESS) Working Group, and reflective of the higher outage rates that have been observed over the last few years.[25]

2.1.2 Transit routes

Each gas source is associated with a transit route, which, as noted above, represents the last stage in the delivery infrastructure to the beach terminals—ie, the interconnectors from Continental Europe or LNG shipping. Pipelines are assumed to face the annual outage profile presented in Table 2.2, where discrete events of 1, 7, 30, 90 or 180 days are modelled. Thus, there is a 10% probability (ie, a 1-in-10-year chance) that a pipeline will have no capacity to flow for one day and a 1% chance (1-in-100-year chance) that the pipeline will have no capacity for 180 days.[26]

Table 2.2 Annual outage probabilities for pipeline infrastructure

Annual probability	Capacity lost (%)	Number of days
0.1	100	1
0.1	100	7
0.05	100	30
0.05	100	90
0.01	100	180

Source: Oxera assumptions after discussion with DTI.

2.1.3 Terminals

The final delivery point before entry into the NTS is also assumed to have an operational outage profile. However, as some beach terminals comprise two or more sub-terminals, it may be possible for a technical problem to arise at one sub-terminal and not another. Therefore, each beach sub-terminal and each LNG import terminal is assumed to have its own outage profile as presented in Table 2.3 below. In addition, there may be a catastrophic terminal failure that affects all sub-terminals entering at that point simultaneously. This is

[24] Technically, such risks are actually transit risks, but the model is simplified to consider only the last stage of transit (eg, from Zeebrugge to Bacton via the interconnector); therefore, such risks could be conceived of as being a source risk.

[25] Other infrastructure outages are assumed to affect all capacity on the installation, but the probability of events occurring vary with the potential length of the outage. There is very little empirical evidence available regarding the probability of such outages and the assumptions below are broadly in line with the high-probability DTI assumptions presented in Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', published as part of the Energy Review.

[26] The daily outage probabilities are substantially lower than these figures. For example, an annual outage probability of 0.1 is equivalent to a daily outage probability of 0.0003 (ie, the probability of one 1-day outage over ten years is (1/3,650).

modelled as a more serious, longer-term event, but with a lower probability of occurrence. The assumed outage profile is given in Table 2.4.

Table 2.3 Annual outage probabilities for sub-terminals (beach and LNG import)

Annual probability	Capacity lost (%)	Number of days
0.05	100	7
0.02	100	30
0.01	100	90
0.01	100	180

Source: Oxera assumptions after discussion with DTI.

Table 2.4 Annual outage probabilities for beach terminals

Annual probability	Capacity lost (%)	Number of days
0.01	100	30
0.01	100	90

Source: Oxera assumptions after discussion with DTI.

2.1.4 Storage

Storage enters the model as both a source of demand or supply depending on which stage of its cycle(s) the individual facility is in. Given the important role played by storage in providing flexibility and swing to the gas system, and given the high-profile incidents at the Rough storage facility in recent years, it is important to subject storage to potential outage risks. The storage outage profile is presented in Table 2.5. It is important to note that a storage outage can occur during either or both injection and withdrawal periods.[27]

Table 2.5 Annual outage probabilities for storage facilities

Annual probability	Capacity lost (%)	Number of days
0.2	100	1
0.1	100	7
0.05	100	30
0.02	100	90
0.01	100	180

Source: Oxera assumptions after discussion with DTI.

2.1.5 Demand

The demand distribution applied in this analysis captures two factors affecting outturn demand: the temperature relative to seasonal normal temperatures; the daily demand profile.

The model takes as its starting point the annual and peak gas demand consumption projections under seasonal normal temperatures, as presented by National Grid in its Gas Transportation Ten Year Statement 2006 (shown in Table 2.6 below). From historical analysis of daily gas demand data, scaling factors are applied to these central demand

[27] Outages during injection periods may limit the ability of the facility to fill all its space, and hence reduce the duration for which the facility could contribute to meeting peak demand.

assumptions to derive annual and peak demand figures for 50 assumed gas years ranging from a 1-in-50 warm to a 1-in-50 cold year.

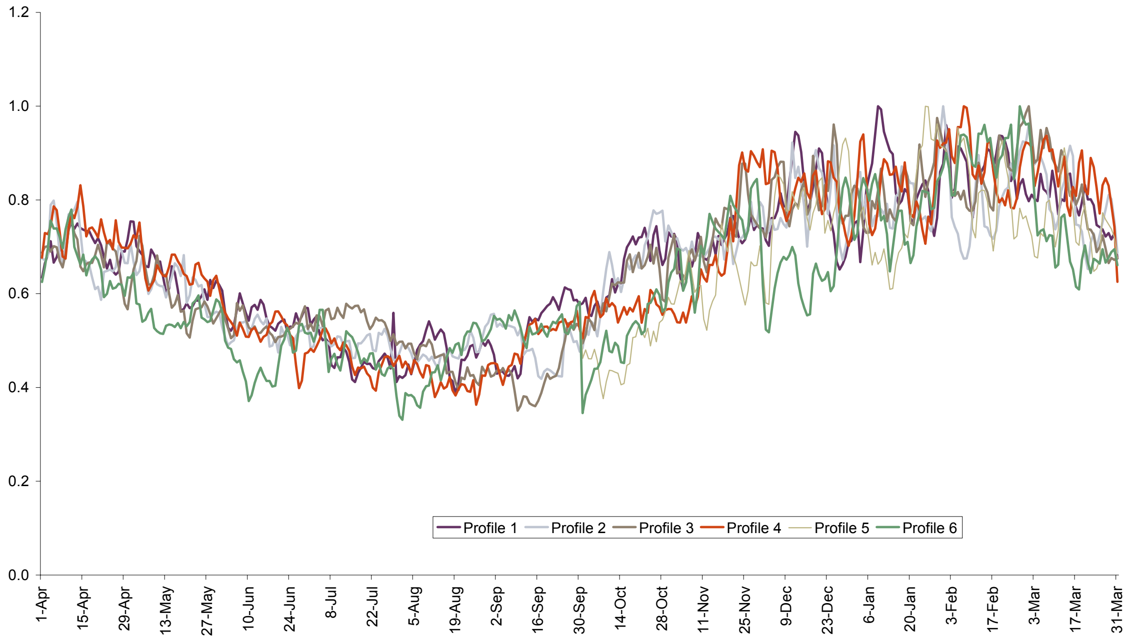
Table 2.6 Central demand assumptions

Year	Daily average demand (mcm)	Peak day demand (mcm)
2006	247.0	451.0
2007	246.3	454.3
2008	251.8	467.4
2009	256.8	472.0
2010	264.1	484.5
2011	272.6	503.7
2012	284.6	518.2
2013	294.2	538.2
2014	304.2	551.6
2015	314.1	578.9
2016	322.3	595.2
2017	330.8	612.0
2018	339.5	629.3
2019	348.4	647.1
2020	357.6	665.3

Source: National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.

In addition, the profile of gas demand is variable, and six profiles taken from National Grid analysis are used to represent the range of potential demand variability across the year. Figure 2.3 illustrates the six profiles, scaled relative to peak demand.

Figure 2.3 Demand profiles (scaled to peak demand level)



Source: National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.

The profiles provide a wide range of possible demand patterns for given annual and peak assumptions, and therefore enable the model to test for a variety of combinations of possible demand and supply outturns.[28]

2.2 Price formation

The physical security model produces a list of the volumes of gas available from different sources after accounting for any outages. Combining this with the outturn demand level is sufficient to determine any supply shortfall, but it does not enable any pricing outcomes to be assessed. For this, the raw volume data must be correctly placed in a merit stack or supply curve.

The pricing component of the security model creates daily supply curves reflecting the physical availability of gas from different sources and the price at which it is sold into the market. Comparing these with the relevant demand level then produces the outturn price.

The pricing assumptions for the different sources of gas supply take account of the possible arbitrage opportunities between different consumer markets—for example, LNG cargoes may alternatively be landed in Continental Europe or the east coast of the USA, and UKCS supplies may be sold at the National Balancing Point (NBP) or Zeebrugge—and are therefore often above the marginal cost of production.

The main assumptions employed for each of the following sources of supply:

– UKCS production;
– Norwegian gas;
– Continental European gas;
– LNG imports;
– storage (seasonal, mid-range and LNG);
– demand-side response from industrial and commercial (I&C) consumers and the power generation sector;

are described below.[29]

2.2.1 UKCS production

Although there are estimates of the cost of production from UKCS fields, the model assumes that UKCS gas is unlikely to be offered at the NBP at a cost-reflective price if the opportunity cost of selling into the UK market is high. The existence of the Zeebrugge interconnector offers two sales options for UKCS gas: sell into the NBP, or export (ie, sell into the Continental market). Exports (assuming that there are no limitations on volumes) would be sold at a Continental price; consequently, the anticipated price for UKCS gas when it is the marginal UK source would be the current Continental price less the transport cost.[30] This price formation assumption would imply full capture of the additional rent that may be earned from selling into the Continental market.[31]

[28] The implied load–duration curves have been cross-checked against National Grid Gas's most up-to-date forecasts. In the near term, differences arise solely due to changes in the National Grid Gas demand forecasts since the publication of its Ten Year Statement. In later years, the simulated load–duration curve exhibits slightly higher peak demand levels, implying some assumed long-term alteration in NGG's demand profile that is not captured in the model. The fact that the NGG forecasts are restricted for the first three years does not appear to have a material impact on the demand assumption used.

[29] These assumptions apply in all the simulations, unless otherwise stated.

[30] The transport cost is assumed to be 1p/th.

[31] In equilibrium, prices should differ only by the transport cost, but this equilibrium may entail changes in the price in both markets. For the purposes of the simulation, it is assumed that the UKCS producer is a price-taker in the Continental market and therefore that all the price adjustment would be observed in the UK NBP price.

Furthermore, the potential for importing LNG into the UK adds another possible competing source, and therefore changes the arbitrage dynamic with the Continental European market. Consequently, the UKCS price is assumed to be the minimum of the UK landed LNG cost and the Continental European gas price less the assumed transit cost.[32]

The only differentiation in the price of UKCS production arises from the inclusion of differential beach entry capacity costs. These costs, shown in Table 2.7, are the reserve prices for the main beach terminals, as published in the long-term system entry capacity auctions.[33] While this may affect the relative cost of UKCS production by terminal, it does not alter the position of UKCS volumes as baseload supply compared with competing imports.

Table 2.7 Entry capacity cost assumptions (p/th)

Terminal	Entry capacity cost (p/th)
St Fergus	0.64
Bacton	0.18
Teesside	0.06
Easington	0.05
Theddlethorpe	0.06
Barrow	0

Source: National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.

2.2.2 Norwegian gas

Norwegian gas has relatively low reported long-run production costs of 12p/th. However, as with UKCS supplies, it is assumed that these volumes would be offered to the market at a price reflecting the marginal source of supply into the UK NBP. Thus, Norwegian gas is assumed to bid into the market at a price comparable with that of UKCS gas.

2.2.3 Continental European gas

As mentioned in the discussion of volumes above, the Continental gas market is modelled as an unliberalised market in which gas is largely sold on long-term, oil-indexed contracts. The annual average price for which Continental gas is sold is set out in Table 2.8. The 2006/07 price, 40p/th, is consistent with reported prices from Zeebrugge and the Dutch Title Transfer Facility (TTF), and with border prices for Algerian and Russian gas published by the European Commission, which are in the order of 40.4p/th.[34]

Subsequent years are linked to the most recent DTI oil price assumptions used in analytical work for the 2007 Energy White Paper (with a correlation between oil and gas price movements of 0.75). These show an initial decline, before rising again slightly towards the end of the period.

[32] This effectively assumes that UKCS producers are aiming to maximise output rather than acting more strategically in their production and pricing behaviour. This is consistent with UKCS production having low marginal production costs in a competitive market setting.
[33] These costs also apply to imported gas landing at the specific terminal.
[34] DG TREN (2006), 'Quarterly Review of European Electricity and Gas Prices', September. Assuming an exchange rate of £1: €1.45.

Table 2.8 Annual average Continental gas price (p/th)

Year	Continental price (p/th)
2006/07	40.0
2007/08	37.7
2008/09	37.1
2009/10	36.5
2010/11	35.8
2011/12	35.2
2012/13	34.5
2013/14	33.8
2014/15	33.2
2015/16	32.5
2016/17	32.8
2017/18	33.0
2018/19	33.3
2019/20	33.5
2020/21	33.7

Source: European Commission; DTI; Oxera calculations.

Within a year, the Continental price is assumed to show some variation around the annual average price. An assumed profile, derived from analysis of the forward Zeebrugge prices for 2007/08, is applied to the annual average to produce monthly price variations. The adjustment factors are as shown in Table 2.9.

Table 2.9 Monthly adjustment factors to annual average prices

Month	Multiple of annual average
April	0.82
May	0.81
June	0.81
July	0.77
August	0.77
September	0.83
October	1.00
November	1.18
December	1.21
January	1.41
February	1.23
March	1.18

Source: Heren; Oxera calculations.

2.2.4 LNG imports

LNG imports are not modelled with reference to a specific source market. Rather, it is assumed that cargoes can be purchased as and when required in a liquid wholesale market. The price of LNG in this wholesale market is set with reference to the value of the cargo in competing markets.[35] Following discussion with the DTI, the base scenario LNG price has been derived using the Henry Hub forward contract price to set the initial 2006/07 price and indexing this to oil prices as per the Continental gas price.[36]

The annual average LNG price is shown in Table 2.10.

Table 2.10 Annual average LNG commodity price (p/th)

Year	LNG price (p/th)
2006/07	38.7
2007/08	36.5
2008/09	35.9
2009/10	35.3
2010/11	34.6
2011/12	34.0
2012/13	33.4
2013/14	32.7
2014/15	32.1
2015/16	31.5
2016/17	31.7
2017/18	31.9
2018/19	32.2
2019/20	32.4
2020/21	32.6

Source: Henry Hub prices; DTI assumptions; Oxera calculations.

As with Continental prices, the LNG price is not assumed constant within a year. There are two differences:

– as with Continental gas, the monthly price is profiled (see Table 2.11 below);
– on any day, given that the price in the competing market may react to shocks, it is assumed that the LNG price will be at a multiple of the average monthly price (the probability distribution of this multiple, derived from historical data, is shown in Table 2.12).

[35] These prices will be well above published LNG production and shipping costs, which, while showing some variation by source, are relatively low. (The Observatoire Méditerranéen de l'Energie reported costs in the region of 10–18p/th. See Observatoire Méditerranéen de l'Energie (2004), 'Analysis of Future Gas Supply Sources and Costs for Europe', June.)

[36] An alternative scenario, with LNG prices determined with reference to forward Henry Hub prices, was also investigated. This produced less favourable results because the average annual price of global LNG in this scenario was higher than in the Base Case (which benefited from the assumed fall in oil prices over the period). Consequently, the UK NBP price had to be higher in order to incentivise new entry, and this led to a delay in new infrastructure arriving. The results of this sensitivity are presented in Appendix 2.

Table 2.11 Monthly profile adjustment

Month	Multiple of annual average
April	0.93
May	0.92
June	0.93
July	0.94
August	0.94
September	0.95
October	0.96
November	1.01
December	1.06
January	1.13
February	1.13
March	1.1

Source: Oxera calculations.

Table 2.12 Probability distribution of daily price multiple of monthly average

Probability	Price multiple
0.123	0.72
0.762	1.00
0.102	1.20
0.010	1.50
0.002	2.00
0.001	2.90

Source: Oxera calculations.

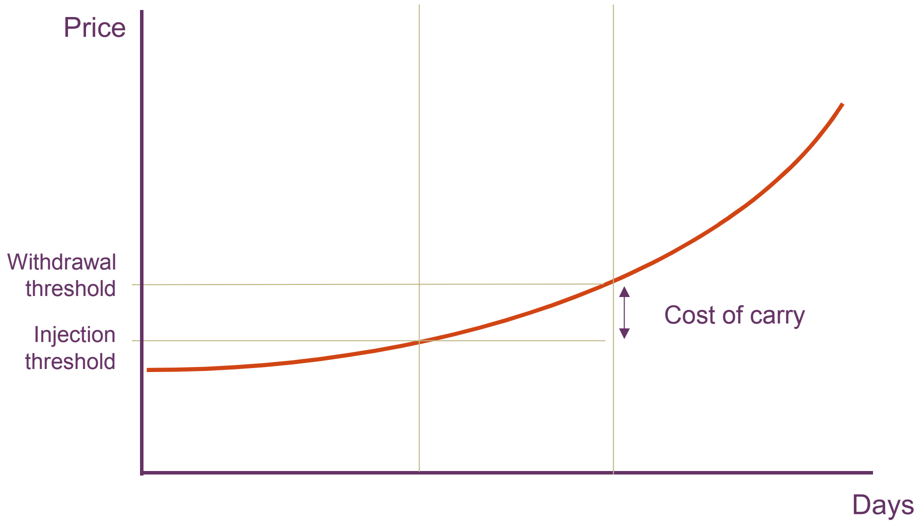
2.2.5 Storage

Unlike many gas pricing models, the operation of storage facilities (ie, the injection and withdrawal cycles and prices) is not exogenously imposed. The threshold prices at which decisions on whether to inject or withdraw from storage are determined endogenously in the model, based on an analysis of the relevant price–duration curve (annual for seasonal storage and quarterly[37] for mid-range storage), the injection and withdrawal rates, and the cost of carry (which is assumed to equal the sum of the injection and withdrawal prices for existing storage facilities).

Figure 2.4 below illustrates a price–duration curve for the relevant period. Injection will occur during low-price periods and withdrawal during high-price periods. The thresholds will be such that the difference between the two equals the cost of carry.

[37] It is recognised that the new mid-range storage facilities being constructed or currently seeking planning permission have the flexibility to operate on much shorter arbitrage periods than one quarter. However, the nature of the pricing assumptions implies optimal arbitrage, and utilisation of the fast-cycle storage facilities occurs on a quarterly basis.

Figure 2.4 Injection and withdrawal threshold prices



Source: Oxera.

2.2.6 Demand-side response

The price simulation allows for instantaneous demand-side response (voluntary outages) from two consumption groups: power generation, and large industrial customers.

Power generation

Two potential tranches of gas-fired generation demand-side response are modelled: distillate back-up and non-distillate back-up. This differentiation represents the different potential costs of interruption if the generator does or does not have a back-up fuel capability, and hence the price at which the generator would be willing to offer such flexibility.

Distillate back-up

The capacity of plant with distillate back-up is assumed to be fixed at 2.9GW, in accordance with the figures in the JESS December 2006 report.[38] The interruption of this capacity is assumed to provide 12.8mcm/day of gas release and enters the supply curve at the price in Table 2.13, which is based on a north-west Europe gas oil cargo price arbitrage, assuming 50% thermal efficiency of the station.[39] Annual changes assume that the distillate price tracks the underlying oil price, as assumed in the DTI's latest oil price projections used in its Energy White Paper analysis.

[38] There may be additional back-up capacity in generators with firm gas delivery contracts, but no estimate of that volume is provided. Thus, the figure here may be an underestimate of total distillate back-up capability. Joint Energy Security of Supply (2006), 'JESS—Long-term Security of Energy Supply: December 2006 Report', Seventh Report, December.

[39] It is also assumed that stocks can be replenished when used.

Table 2.13 Distillate back-up switching cost (p/th)

Year	Distillate back-up switching cost (p/th)
2006/07	74.0
2007/08	68.4
2008/09	66.8
2009/10	65.4
2010/11	63.8
2011/12	62.2
2012/13	60.7
2013/14	59.2
2014/15	57.6
2015/16	56.1
2016/17	56.6
2017/18	57.2
2018/19	57.7
2019/20	58.3
2020/21	58.9

Source: Datastream; Oxera calculations.

Non-distillate back-up

When there is no distillate back-up, the switching cost from gas will be related to the underlying electricity price (ie, the price of buying alternative volume on the open market). This volume is assumed to equate to the volume of CCGT response identified in the National Grid Winter 2006/07 Consultation Document.[40] This non-distillate response can be expected to occur at a range of prices reflecting the varying opportunity costs of finding alternative electricity supply. The model represents this simplistically through two separately priced tranches of CCGT response: 20mcm/day is available at a price of 40p/th[41] and 7.2mcm/day is available at a higher price of 73p/th.[42]

Large industrials

The volume of voluntary demand-side response from industry is assumed to be fixed over time and limited to large industrial customers. The prices are based on the analysis undertaken for the DTI by Global Insight in 2005,[43] whereas the volumes are set at the maximum industrial demand-side response reported for 2005/06 (around 16mcm/day) in the National Grid Winter 2006/07 Consultation Document, allocated in the same proportion as in the Global Insight 2005 study (see Table 2.14 below).

[40] National Grid (2006), 'Winter 2006/07 Consultation Document', September.

[41] This tranche is assumed to reflect the lower opportunity cost that portfolio generators may face in switching between gas- and non-gas-fired generation plant. The actual price at which fuel switching may occur will depend on the input fuel price relativities. However, within the scope of this study, concurrent modelling of the gas and electricity sector was not feasible. The price assumption used was provided by the DTI and is consistent with observed pricing thresholds for fuel switching during the winter of 2005/06.

[42] This volume is consistent with the reported capacity of gas-fired generation that is on interruptible contracts but does not have back-up fuel capability. The gas price chosen is consistent with interruption occurring at a price of £50/MWh.

[43] These prices are fixed in real terms. No adjustment has been made to these price thresholds over time. Such changes may arise if the costs of demand-side response (eg, the costs of back-up fuel) vary over time.

Table 2.14 Industrial demand-side response

Price (p/th)	Volume (mcm/day)
42	1.86
50	4.62
79	5.36
100	1.48
200	2.6

Source: Global Insight (2005); 'National Grid Winter 2006/07 Consultation Document'; Oxera calculations.

2.2.7 Value of lost load

Since there may be periods when demand exceeds supply, even after demand-side response has been taken into account, it is necessary to set a price of shortage, or a value of lost load (VoLL). The costs of interruptions are investigated in more detail in section 6. The analysis in that section suggests that, for large interruptions, the marginal VoLL may be above £30/th. However, the base assumption for VoLL used in the price modelling is to apply a figure of £5/th (500p/th).[44] This lower value may be interpreted in one of several ways:

– with different sizes of outage, the marginal VoLL will also vary and relatively low levels may be appropriate for the majority of outages;
– individuals assume that they will never be subject to a VoLL that fully reflects the cost of large interruptions, as such events will lead to a suspension of normal market operations and the imposition of emergency cash-out arrangements. Currently, these would be set in relation to the actual system buy price at the time a stage 2 emergency is declared.[45] While this may reflect a degree of shortage, it may not fully reflect actual costs.

[44] As the VoLL represents the highest 'cost' of gas in the price-security model, it is a critical assumption because it influences the shape of the price expectations against which investments are made. Unlike in the electricity sector, there is little formal analysis of customer interruption costs in gas. Voluntary demand-side response in the model is capped at £2/therm and since the VoLL figure is related to forced outages, it is anticipated that this would be above the price for voluntary interruptions. However, as section 6 illustrates, the VoLL varies depending on a range of factors, including the size of the interruption. The £5/therm figure is the average VoLL across a range of outages from 10 mcm/day to 90 mcm/day.

[45] A stage 2 emergency occurs with the suspension of the normal balancing arrangements.

3 Alternative investment options

At any particular point in time, the level of security of supply is dependent on the following characteristics of the existing gas supply chain:

– the overall capacity of the system—the volume of gas that can flow into the domestic market from potential sources;
– the diversity of the capacity—the number and type (eg, pipeline, LNG, etc) of routes to markets;
– the reliability of the capacity—ie, the likelihood of infrastructure failure, which may increase with distance transported or the age of the assets used;
– the flexibility of the capacity—the ability of the infrastructure to provide sufficient swing to match potential variations in demand or supply levels.

Over time, however, the longer-term security concern is whether investment in new infrastructure will materialise and the supply chain will evolve efficiently so as to minimise the risks faced by the gas consumers.

In the last few years, a wide variety of gas import and storage infrastructure has been, or is in the process of being, constructed (see Table 3.1). All the projects classified as 'Under construction' in Table 3.1 are treated as definite developments for the purposes of the analysis and are assumed to come on line at the operational date reported in JESS (2006).

Table 3.1 Current infrastructure projects

Project name	Project type	Capacity (mcm/day)	Operational from[1]
Operational			
Isle of Grain (Phase 1)	LNG terminal	13	Q1 2006
Zeebrugge additional compressors	Interconnector upgrade	22	Q4 2006
BBL pipeline	New interconnector	44	Q4 2006
Langeled South	Pipeline	70	Q4 2006
Under construction			
Isle of Grain (Phase 2)	LNG terminal upgrade	24	Q4 2008
South Hook (Phase 1)	LNG terminal	30	winter 2007/08
South Hook (Phase 2)	LNG terminal upgrade	30	2009
Dragon	LNG terminal	16.5–27	Q4 2007
Excelerate	LNG terminal	11.3	Q1 2007
Statfjord Late Life Project	New production	17	Q4 2007
Aldbrough	Gas storage facility	39mcm/d deliverability 420mcm space	Q3 2007
Holford	Gas storage facility	16mcm/d deliverability 170mcm space	2008

Note: [1] Assumed in the input assumptions of the model.
Source: JESS (2006).

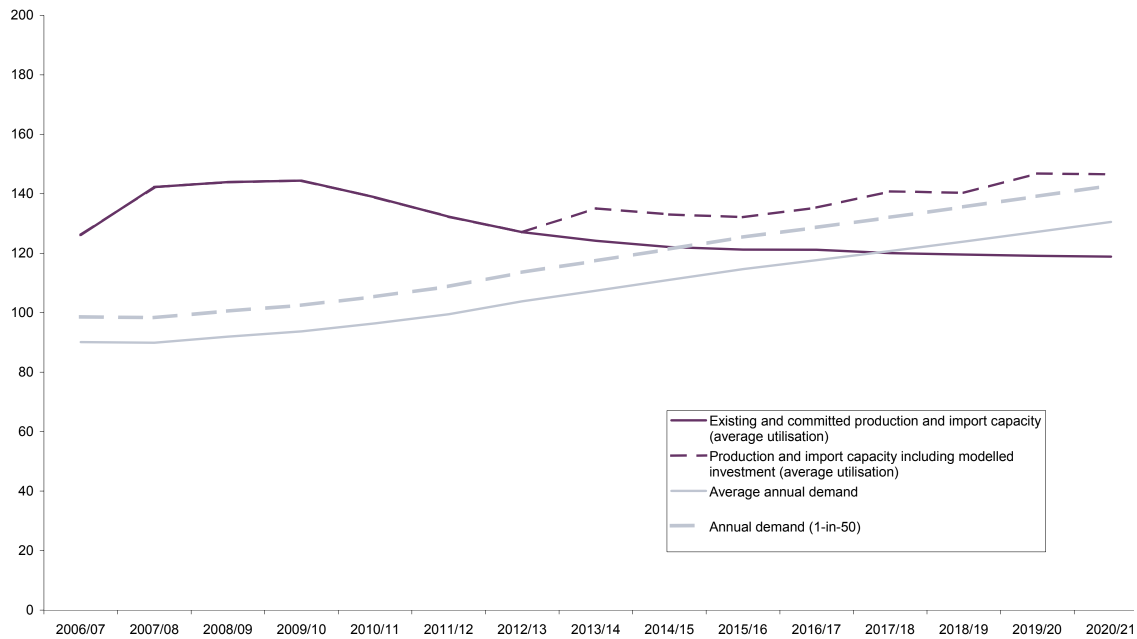
The impact of this assumed infrastructure investment on the annual and peak supply–demand balance is shown in Figures 3.1 and 3.2 below respectively.

Figure 3.1 shows the evolution of annual supply availability relative to an average and 1-in-50 cold year demand level. In the figure, annual supply capacity for some infrastructure is de-rated to reflect the fact that the availability of capacity does not guarantee that gas molecules will flow. The assumptions applied are:

– UKCS supplies (90% of maximum);
– Norwegian supplies (100%);
– Continental European supplies (75%);
– LNG supplies (60%).

If the assumptions are correct (on both the utilisation and the timing of arrival), this suggests that, in the absence of infrastructure outages,[46] the UK should have sufficient capacity (without additional investment beyond that outlined in Table 3.1) to meet demand even in the coldest years until around 2014/15, and until 2017/18 under average conditions.

Figure 3.1 Annual supply and demand projections (existing infrastructure, bcm/yr)



Note: The assumed supply availability de-rates maximum capacity of some delivery infrastructure elements. The de-rating factors applied are 90% (UKCS production), 75% (continental European supplies), and 60% (LNG imports).
Source: DTI; National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.

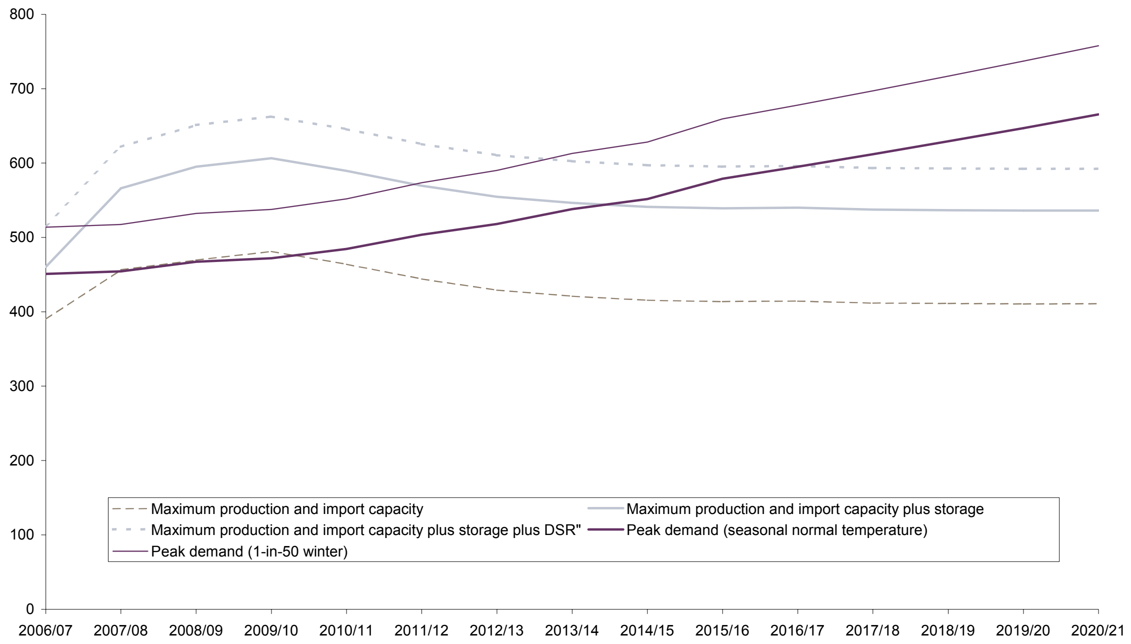
Figure 3.2 shows a slightly different picture in relation to peak demand. Assuming that all production sources are fully available (ie, 100% utilisation), with the existing storage facilities and those under construction, a peak supply deficit may arise between 2011/12 and 2013/14, depending on the demand outturn. However, if available demand-side response is taken into account, which, it may be argued, would be likely in extreme conditions, the existing infrastructure would, in the absence of outages, be able to cope with severe winters up to 2013/14.

Either way, although the assumed investment profile may alleviate current market tightness over the next five years or so, depending on demand growth and the availability of gas through the various routes, additional infrastructure will be required beyond this point. This infrastructure, unless it is already in planning or is an identified upgrade to a current facility, will probably take somewhere between three and seven years to reach commissioning (depending on the precise specifications). This means that it is important to ensure that the

[46] Infrastructure outages are those described in section 2 above.

gas security arrangements and planning regime are effective now if this infrastructure is to have the chance to address this future market tightness.

Figure 3.2 Peak supply and demand projections (existing infrastructure, mcm/day)



Note: These are maximum capacities of infrastructure rather than modelled flows from the infrastructure (ie, these are indicative figures showing 100% utilisation at the peak).
Source: DTI; National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December.

The alternative investment options are outlined below, together with the main drivers on the decision for each type of investment.

3.1 Simulating investment decisions

The infrastructure available to meet the longer-term supply–demand imbalance is drawn from the following options:

– new or upgraded interconnectors with Continental Europe (if possible);
– incremental gas from the Norwegian Continental Shelf (NCS) exploiting growing ullage in the UKCS pipelines;
– new LNG import terminals;
– upgrades to existing LNG terminals;
– seasonal storage;
– mid-range storage.

These options for new investment reflect the range of projects in JESS (2006) and the mix of projects already observed from Table 3.1. In each category of investment a series of possible projects is constructed drawing on JESS (2006), but including some additional generic projects that would be called upon if all current proposed projects had already been utilised, or, where it is possible, alternative investment options that are more attractive than current proposals may arise over the timeframe.[47]

Each potential investment project is defined by the following characteristics:

- capital cost (in £m);[48]
- operating costs (p/th);
- asset life;
- earliest commissioning date;
- capacity (bcm or mcm/day);
- injection and withdrawal rates (mcm/day)—storage only.

Applying an assumed utilisation rate (or number of cycles for storage) and an assumed cost of capital, a new entry cost, or required margin (in p/th), can be derived for each project. This new entry cost can then be compared with the expected annual margins produced as an output from the price distributions in the price-security model to determine whether, and at what time, an investment would be profitable. Where more than one investment appears profitable at one point in time, a choice is made based on a consideration of the earliest commissioning date and the highest expected margin over the period of the simulation. The process is iterated until, given the investment conditions, no further investment appears profitable.

The analysis is not intended to fully replicate the investment decisions for specific, announced, proposals, as it cannot expect to incorporate all the (sometimes confidential) parameters influencing individual commercial decisions. Instead, it should be interpreted as providing an indication of the overall level of investment which the market may support.

3.1.1 LNG import capacity

The prospective LNG import projects are identified in Table 3.2. While they refer to some announced projects, the capacities are largely arbitrary, and are more reflective of what may be required in the market, as opposed to what specific project sponsors have announced.

Table 3.2 LNG import project characteristics

Project name	Earliest commissioning date	Capacity (mcm/day)	Capital cost (£m)	Annual operating costs (p/th)	Asset life
Canvey Island	2012[1]	14.8	200	1.0[1]	20
Teesside	2013[1]	30[1]	400[1]	1.0[1]	20
Amlwch	2014[1]	30[1]	100	1.0[1]	20
Generic LNG[2]	2015[1]	16.5	259	1.0[1]	20
Generic upgrade[3]	2010[1]	16.5[1]	150	1.0[1]	20

Note: [1] Oxera assumption. [2] Assumed equal to Dragon LNG. [3] Oxera assumption based on ratio of Phase 1 to Phase 2 costs for South Hook and Isle of Grain.
Source: Capacity values are taken from JESS (2006), unless otherwise referenced. Values for initial capital costs are taken from UKOOA; company statements and the International Energy Agency (IEA), unless otherwise referenced. The values for annual operating costs and asset life are Oxera assumptions.

Applying an assumed asset life of 20 years[49] to a capital cost of £200m (for a 15mcm/day facility), and assuming an additional 1p/th operating cost, the new entry cost for an LNG terminal for a range of assumptions on utilisation and cost of capital is shown in Table 3.3.

[47] Assumptions on the availability of generic projects are open to challenge. However, the analysis can be seen as indicating investment levels that the market would support. If such projects are unavailable, then the impact will be felt across all scenarios and hence the relativities in performance would be expected to be unchanged.
[48] For storage facilities it is assumed that cushion gas forms part of the initial capital cost.

Table 3.3 Indicative LNG terminal new entry cost (p/th)

	Discount rate			
Utilisation rate	**5%**	**10%**	**15%**	**20%**
50%	2.63	3.39	4.25	5.18
75%	2.09	2.59	3.17	3.79
100%	1.82	2.20	2.63	3.09

Source: Oxera.

The relevant price differential in the market against which this new entry price should be compared is the UK NBP/global LNG price differential. If expected prices at the UK NBP are higher than the global LNG market price by the new entry cost level or more, and if these prices are expected to be sustained over the period of the investment such that the investor can recover their capital costs, then an investment should be profitable.[50]

For example, Figure 3.3 shows the simulated price differential (UK NBP minus the assumed global LNG price) in the market from 2006/07 to 2020/21, and an indicative terminal new entry cost based on a 15% discount rate and 50% utilisation (from Table 3.3 above).[51] In 2006/07, the expected differential is given by the dotted line. This suggests that no new LNG terminals would be anticipated before 2013/14, when the expected margin is greater than the new entry cost. However, other investment options may be more attractive or able to enter on a shorter timescale. The effect of this dynamic investment behaviour is partially illustrated in the dotted line which has the effect of delaying to 2015/16 the earliest date at which a new LNG terminal would be expected to recover its costs.

This investment behaviour is modelled simultaneously for all potential infrastructure options.[52]

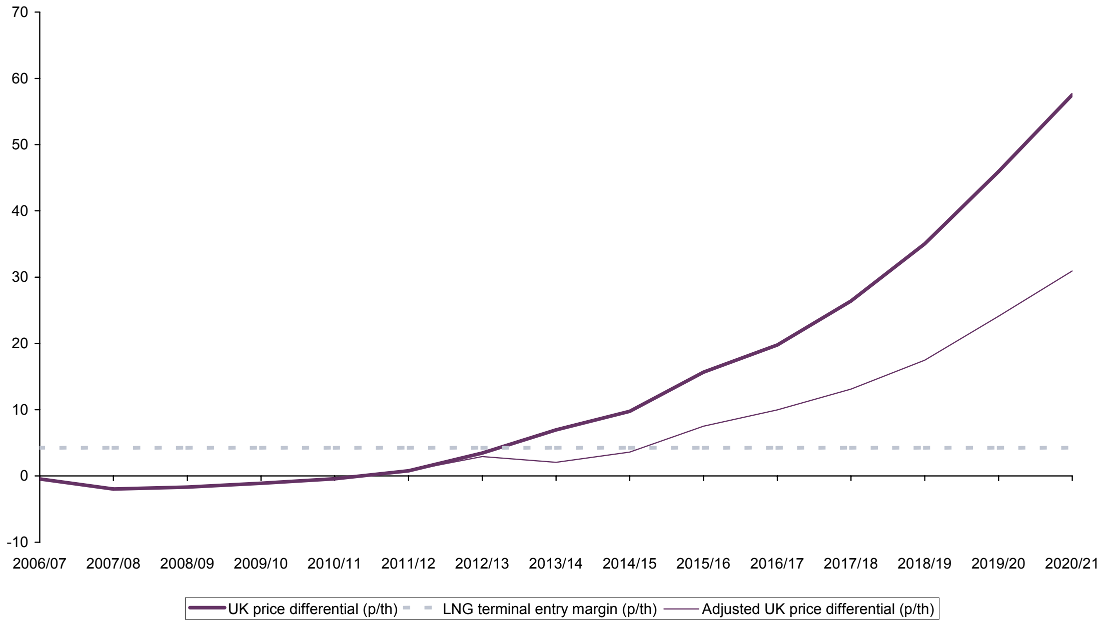
[49] Although operational life may be longer, a 20-year lifetime assumption is more appropriate from a commercial investor's perspective.

[50] It may be argued that LNG producers would expand supply to all areas provided that prices were above their long-run marginal costs. However, the model does not incorporate fully dynamic global LNG price formation or production decisions (price levels are fixed and not assumed to be based on market value rather than production costs). Therefore, the relativity between the alternative markets is used as a proxy for the geographic market choice.

[51] Sensitivity analysis on the assumed discount rate was undertaken as part of the study and is discussed in section 4.

[52] A more detailed example investment decision is provided in Appendix 3.

Figure 3.3 Market investment signal and new entry cost (p/th)



Source: Oxera analysis.

3.1.2 New pipelines

New pipeline options, detailed in Table 3.4, consist of a new pipeline and a potential upgrade to an existing pipeline. The former is understandably more expensive than the latter, and therefore the new entry cost (on the basis of the figures in Table 3.4) is correspondingly higher, as can be seen in Table 3.5 below. In the modelling, no new Continental pipelines or upgrades are allowed, reflecting both an understanding that there is no realistic scope to upgrade existing facilities and a view that there may be insufficient new gas available from Continental Europe to produce sustainable throughput rates.

As with the LNG decision, the relevant price differential would be that between the UK and the alternative market where the gas could be sold (ie, the Continent). Thus, in order for the new pipeline to be justified, the UK price must be expected to be above the Continental price by at least the new entry cost over the lifetime of the project.

Table 3.4 New pipeline infrastructure projects

Project name	Earliest commissioning date	Capacity (mcm/day)	Initial capital cost (£m)	Annual operating costs (p/th)	Asset life
Generic new project[1]	2011	44	350	1.0	20
Generic upgrade[2]	2010	44	5.2	1.0	20

Note: [1] Oxera assumption based on the Balgzand–Bacton interconnector costs.[2]Oxera assumption scaled up from compressor upgrade costs at Zeebrugge.
Source: Company websites.

Table 3.5 Indicative new entry cost (p/th)

	Discount rate							
	5%		10%		15%		20%	
Utilisation	New pipeline	Pipeline upgrade	New pipeline	Pipeline upgrade	New pipeline	Pipeline upgrade	New pipeline	Pipeline upgrade
50%	2.48	1.62	2.93	1.68	3.44	1.74	4.00	1.81
75%	2.15	1.58	2.45	1.62	2.79	1.66	3.16	1.71
100%	1.99	1.56	2.21	1.59	2.47	1.62	2.75	1.66

3.1.3 Storage facilities

The model differentiates between seasonal and mid-range storage projects, both of which are represented in the project list (see Table 3.6).

Table 3.6 Gas storage facilities

Project name	Earliest commissioning date	Capacity (mcm/day)	Withdrawal rate (mcm/day)	Injection rate (mcm/day)	Initial capital cost[6] (£m)	Annual operating costs (p/th)	Asset life
Welton	2010	437	8.2	8.65	75	1.0	20
Preesall[1]	2010	1,700	117	50	1,000	1.0	20
Caythorpe	Q2 2007	278	11.1	8.3	100	1.0	20
Portland[2]	2010–13	1,000	50	17	350	1.0	20
Generic[3]	2014	410	39	19.5	225	1.0	20
Aldbury Phase 1[4]	2009	160	2.46	1	198	1.0	20
Aldbury Phase 2[5]	2010	715	11	4.47	84	1.0	20
Bletchingly	2010	900	8	4	125	1.0	20
Saltfleetby	Q4 2008	708	7.9	4.2	100	1.0	20
Gainsborough	2010	220	16	2	100	1.0	20
Generic[7]	2014	2,760	41.5	14.5	475	1.0	20

Notes: [1] Withdrawal rate taken from Codognet, M.-K. and Glanchant, J.-M. (2006), 'Weak Investment Incentives in New Gas Storage in the UK', Paris University, June. Injection rate is an Oxera assumption used to maintain a 10:1 ratio for withdrawal to injection.[2, 4] Withdrawal rate extrapolated from a graph in Centrica Storage (2007), 'Winter Outlook Consultation Response', July. Injection rate is an Oxera assumption.[3] Oxera assumption based on Aldbrough costs.[5] Withdrawal and injection rates used to maintain the same ratio as in phase 1. [6] Excluding cushion gas costs. [7] Oxera assumption based on a Rough equivalent facility.
Source: Capacity, withdrawal and injection rates are taken from Ofgem (2006), 'Consultation on an exemption application by WINGAS Storage UK Limited for an exemption under section 19A(6)(a) of the Gas Act 1986 from section 19B of the Gas Act 1986', June, unless otherwise referenced. Values for initial capital costs are taken from the Platts UK Gas Report, Issue 290, August 2005, unless otherwise referenced. The values for annual operating costs and asset lives are Oxera assumptions.

Gas storage facilities have a more complex set of costs because the additional cost of cushion gas must be factored into the overall cost. (Cushion gas refers to the gas that must be kept in store to maintain internal pressures to a required working level.) For the purposes of this study, it is assumed that the cushion gas is purchased upfront at the current market price.[53]

[53] This is equivalent to saying that the opportunity cost is the forgone revenue from not selling the gas at this point in time. This is not strictly the case, as the cushion gas could be sold at the end of the asset's life.

Cushion gas is assumed to be a much higher proportion of seasonal storage facilities than it is of mid-range fast-cycle storage. The multiples of working volume assumed in the new entry cost calculations are three times for seasonal storage and one time for mid-range storage.

In addition, the value of storage is dependent on the number of cycles that the facility is capable of completing, as this affects the volume of gas that can be throughput over a period, the type of arbitrage opportunities open to the facility, and, consequently, the extrinsic value of the storage facility—ie, the value over and above the arbitrage value against the forward curve (the intrinsic value) from exploiting shorter-term price volatility.

For investment decisions, seasonal storage is assumed to complete a single cycle, whereas mid-range storage is assumed to work on four cycles in a year. The relevant differentials within the model are the summer/winter differential for seasonal storage,[54] and the average quarterly differential for mid-range storage.[55] A multiplier of two times is added to the quarterly differential to replicate the additional value that may exist, but which the price-security model does not capture due to limitations on the available arbitrage opportunities.[56] One important factor is that, unlike the LNG and pipeline options, the new entry cost changes over time since part of the cost reflects the cost of cushion gas. Thus, new entry costs will rise as gas prices rise; if there is not a concomitant increase in price volatility and arbitrage value, this may lower the attractiveness of storage projects.

The new entry cost for individual projects is calculated within the model. However, an indicative cost, assuming a fixed gas price of 35p/th, is shown in Table 3.7 for a £425m seasonal and a £225m mid-range storage facility. The mid-range storage is assumed to be a 400mcm, 40 mcm/d withdrawal, 20 mcm/d injection facility, and the seasonal storage is assumed to be a Rough equivalent (ie, 2760 mcm space; 41.5 mcm/d withdrawal and 14.5 mcm/d injection rate)

Table 3.7 Indicative seasonal storage new entry cost (p/therm)

	Discount rate			
Utilisation rate	**5%**	**10%**	**15%**	**20%**
£425m seasonal mid-range storage facility (1 cycle, 100%)	11.5	16.3	21.8	27.8
£225m mid-range storage facility (4 cycles, 100%)	4.7	6.4	8.4	10.5

Note: Assumes a 35p/th natural gas price.
Source: Oxera.

[54] In reality, the arbitrage value is calculated by comparing the top 90 (30) and bottom 270 (60) prices for each simulation for seasonal (mid-range) storage facilities. This roughly corresponds to the intrinsic value of the storage facility, given the assumptions imposed.

[55] While it is recognised that mid-range storage will operate against a range of shorter arbitrage opportunities, the modelling uses a quarterly arbitrage because the underlying price model has insufficient disaggregation to accurately reflect shorter arbitrage periods.

[56] This is not a precise multiplier, but is an Oxera assumption based on informal discussions with market participants.

4 The Base Case

Figures 3.1 and 3.2 illustrated the starting point for the Base Case investment scenario. The trend in the overall supply–demand balance implied by the assumed infrastructure creates forward price expectations in the price-security model that incentivise new investment to the extent that the new entry costs are likely to be achieved. This section describes the main results from the model run, focusing on the investment profile, the implied physical security of supply, and the pricing behaviour.

4.1 Investment profile

The outturn profile of investment (above that already described in Table 3.1) is shown in Table 4.1 and the implication for the indicative annual supply–demand balance and the peak supply deliverability is shown in Figures 4.1 and 4.2 below respectively. The base investment decisions are undertaken using a 15% discount rate, based on the fact that these are large infrastructure projects and that there is a high degree of uncertainty over longer-term market performance.[57]

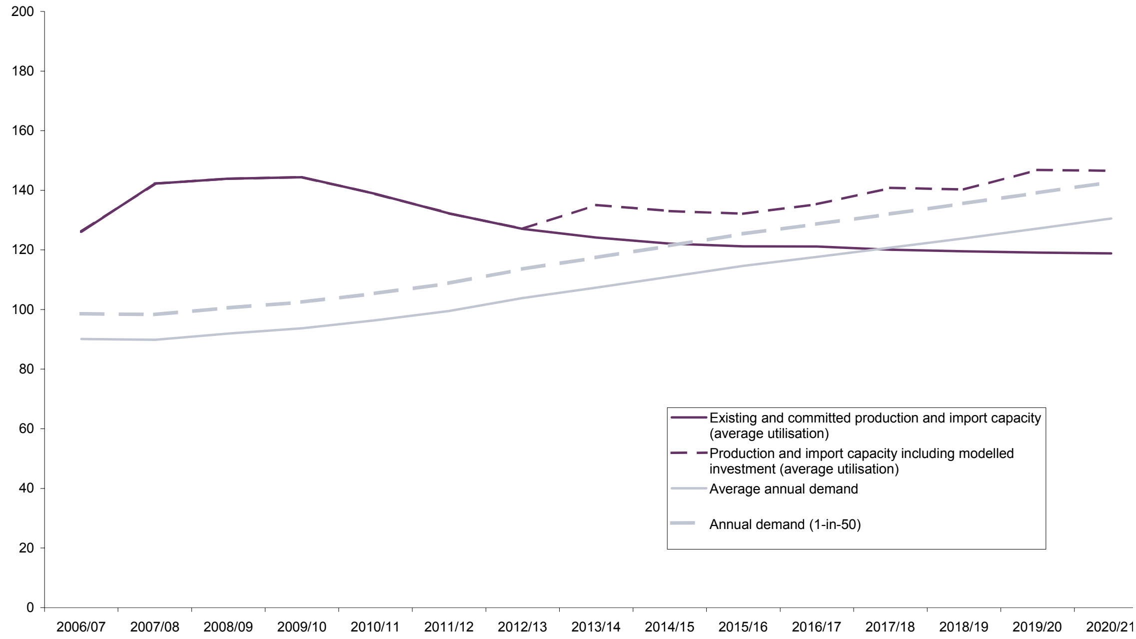
Table 4.1 Base Case modelled investment up to 2020/21

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**6,195**	**217.4**
Norwegian import capacity	10,950	30
LNG import capacity	27,925	76.5
Total import capacity	**38,875**	**106.5**

Note: Some figures may not sum due to rounding.
Source: Oxera.

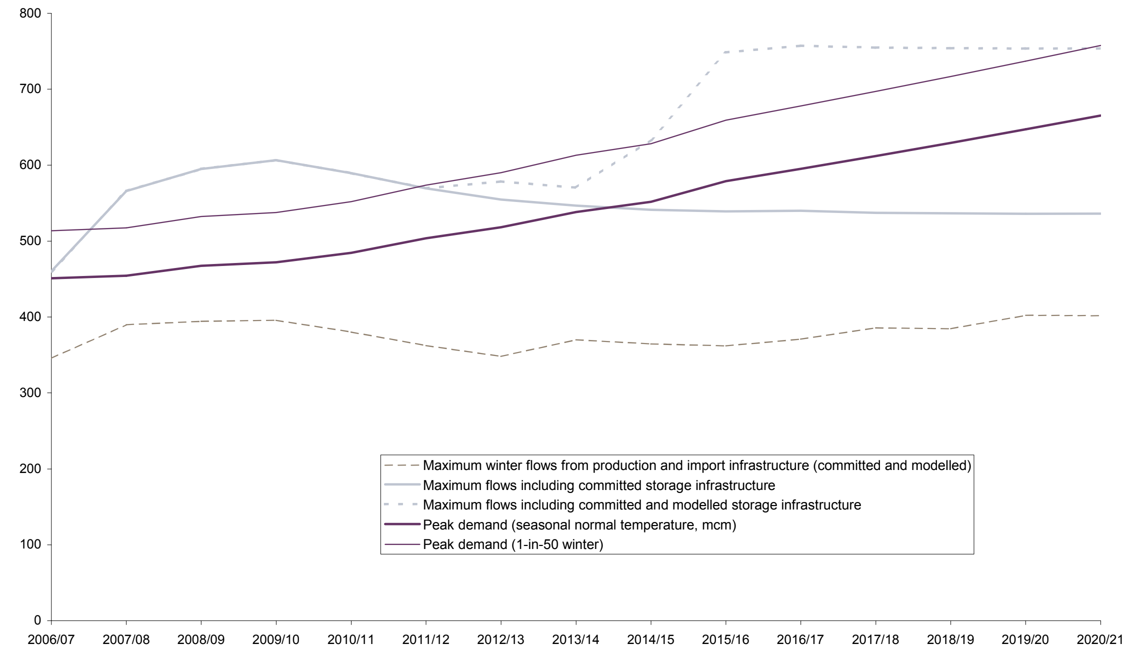
[57] A sensitivity using a lower discount rate of 10% was undertaken. As would be expected, this resulted in some infrastructure investment being brought forward since the lower entry cost requirements were realised earlier. The major differences were observed in the period between 2015/16 and 2020/21, where LNG import capacity benefited. In particular, this allowed additional facilities to come on line in 2020/21, thereby removing the large increase in outage probability and cost seen in the Base Case. The results of this sensitivity are presented in Appendix 2.

Figure 4.1 Annual supply–demand balance (bcm)



Note: The assumed supply availability de-rates maximum capacity of some delivery infrastructure elements. The de-rating factors applied are 90% (UKCS production), 75% (continental European supplies), and 60% (LNG imports).
Source: Oxera.

Figure 4.2 Peak supply–demand balance (mcm)



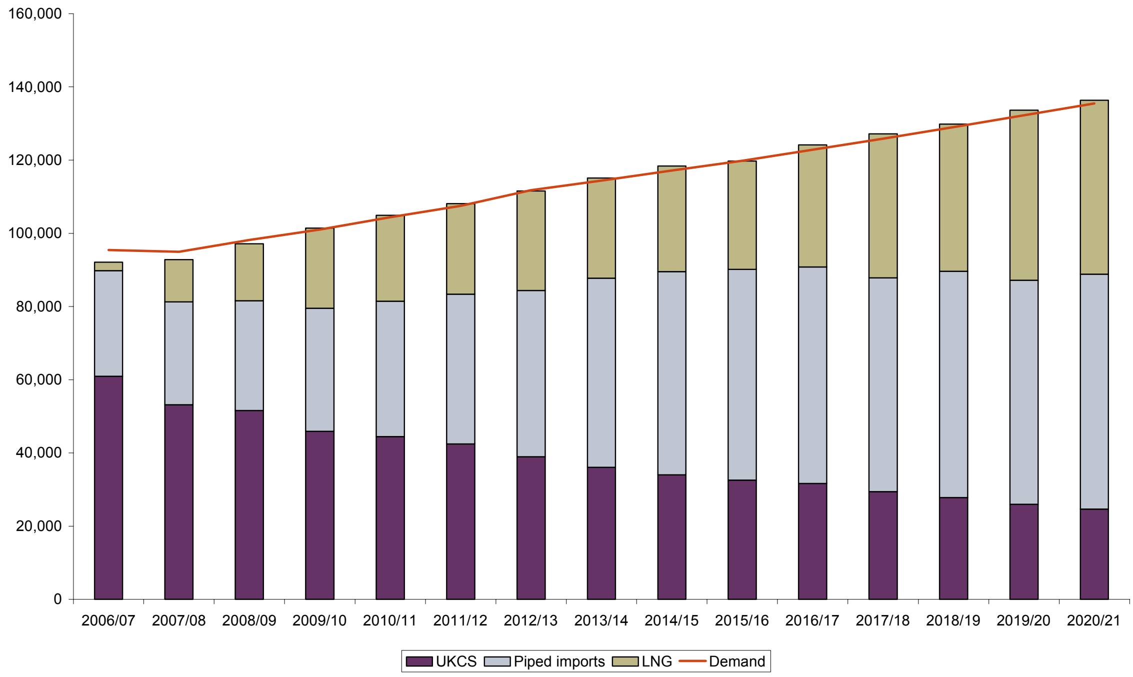
Note: These are maximum capacities of infrastructure rather than modelled flows from the infrastructure (ie, these are indicative figures showing 100% utilisation at the peak)
Source: Oxera.

As would be expected, given the significant increase in available import capacity that is currently occurring, the majority of the new investment is in storage facilities that seek to address the tighter peak supply–demand balance position. Figure 4.2 may suggest that there is a surfeit of storage capacity at the peak. However, this position is less pronounced over the course of a winter since the storage facilities are replacing lost swing from the decline in UKCS production and are therefore recovering their revenues over a longer timeframe; patterns of use will reflect this.

From 2016 onwards, the majority of new investment is in additional import facilities for LNG. The growth in LNG volumes in annual supply is illustrated in Figure 4.3, with LNG imports accounting for 35% of total demand by 2020/21.[58] [59]

The attractiveness of LNG investment is a function of the assumptions in the model regarding the availability of non-LNG sources. (It is assumed that there is a constraint on incremental volumes of gas available from Norway and that Continental gas availability will be limited to the capacity of the existing pipelines.)[60] [61]

Figure 4.3 Annual average flows by source (mcm)



Source: Oxera.

Storage also illustrates the expected behaviour given the constrained treatment within the model. For example, Figure 4.4 shows the injection and withdrawal schedule at the Rough long-range storage facility in 2007/08 for a cold winter (day 1 is April 1st 2007). As can be seen, the facility is filling up over the summer period and releasing in the winter—the majority

[58] Piped imports, from Norway and Continental Europe, make up around 42% of total demand. While the majority of new investment is in LNG terminals, these operate at lower load factors (typically around 65%), with the majority of utilisation in the winter. In the summer periods, Continental gas has a lower price than LNG (given the price profiles assumed in Table 2.9) and this, together with the assumed removal of the infrastructure bottleneck in the period from 2014/15 to 2020/21, implies greater volumes of piped imports annually.

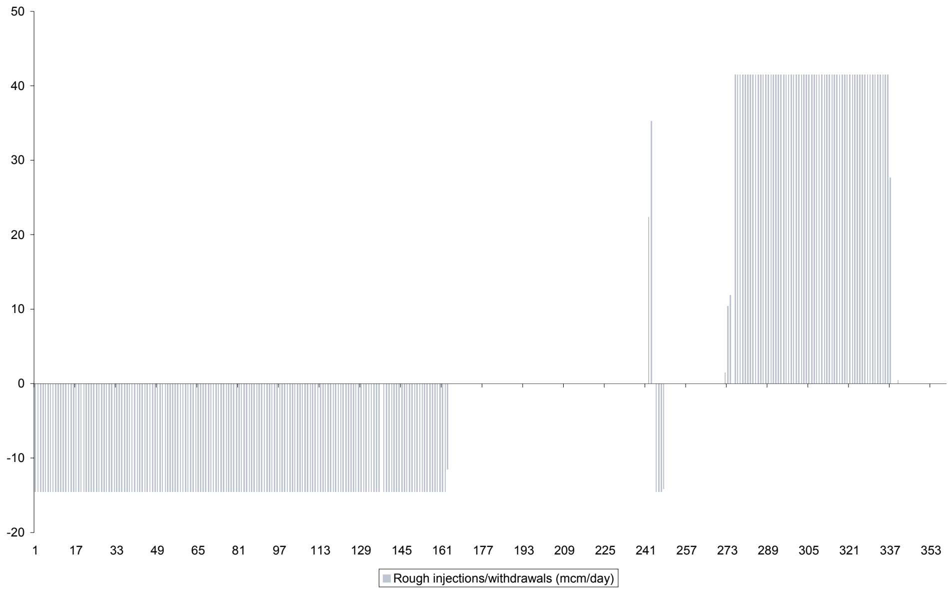
[59] Appendix 4 contains indicative daily flow positions for 2006/07, 2010/11, 2015/16 and 2020/21 resulting from the assumptions driving the Base Case.

[60] Even this availability may require additional investment in infrastructure in north-west Europe to ensure there are no bottlenecks in delivering gas to the existing interconnector pipelines to the UK.

[61] Reducing the constraint on the availability of Continental gas in the early years, although it lowers the expectation of forced outages in the near term, actually leads to higher expected outages in the longer term as the lower prices defer the LNG import investment decision, meaning that less gas is available when needed in the period from 2015 to 2020. The results of this sensitivity are shown in Appendix 2.

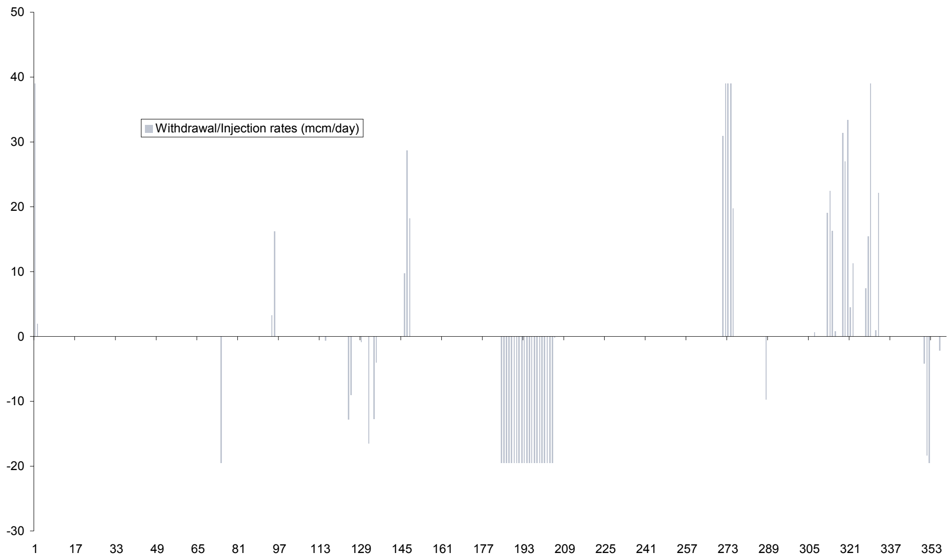
of the release occurring during Quarter 1. A different pattern is evident in the operation of a mid-range storage facility, as shown in Figure 4.5.[62]

Figure 4.4 Rough injection/withdrawal schedule, 2007/08 (mcm/d)



Source: Oxera.

Figure 4.5 Illustrative mid-range injection/withdrawal schedule 2007/08 (mcm/d)



Source: Oxera.

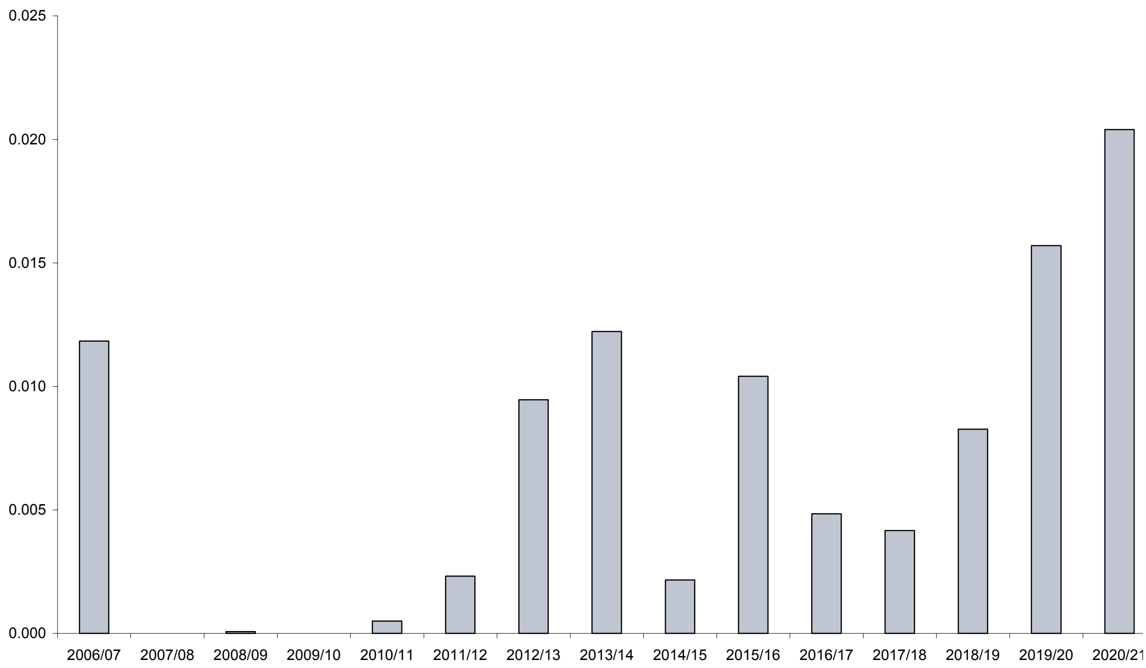
4.2 Physical security levels

The physical security level afforded by the investment profile described above is captured in a series of indicators of the likelihood and magnitude of forced outages. These are presented in Table 4.2 below. A forced outage arises when demand is greater than available supply

[62] In reality, it is anticipated that a facility such as Aldbrough would exhibit much greater short-term variation in its usage profile, but the operational constraints imposed through the model prevent this.

even after voluntary demand-side response has occurred. The expected annual forced outage volume as a percentage of annual demand is shown in Figure 4.6. As can be seen, the expected volume of forced outage is extremely low, amounting to just over 0.01% of demand in 2006/07 and rising to just over 0.02% by 2020/21.[63]

Figure 4.6 Annual expected forced outage as percentage of demand



Source: Oxera.

These low figures are due to the low probability of a forced outage occurring, as shown in Figure 4.7 and Table 4.2 below. For example, the probability of an outage occurring in 2006/07 is 0.04 (ie, equivalent to a 1-in-25 year chance of a forced outage). Thus, the expected annual forced outage is heavily weighted to the 96% of times when there is no forced outage.

Even though the probability of a forced outage is low, when they do occur they can have a substantive impact on gas availability. This is to be expected given that such interruptions are typically associated with large infrastructure events (often in conjunction with extreme weather conditions). Figure 4.7 shows the conditional expectation of the annual outage—ie, the expected annual loss from forced outages given that a forced outage event occurs.[64] In 2006/07, the size of the expected annual forced outage is 261mcm (equivalent, on average, to losing one day of gas demand). More extreme events are also possible—the maximum annual forced outage[65] in 2006/07 is 1,898mcm (see Table 4.2), or 2% of annual demand (equivalent to one week's demand)—but the probability of such an event is significantly lower.[66]

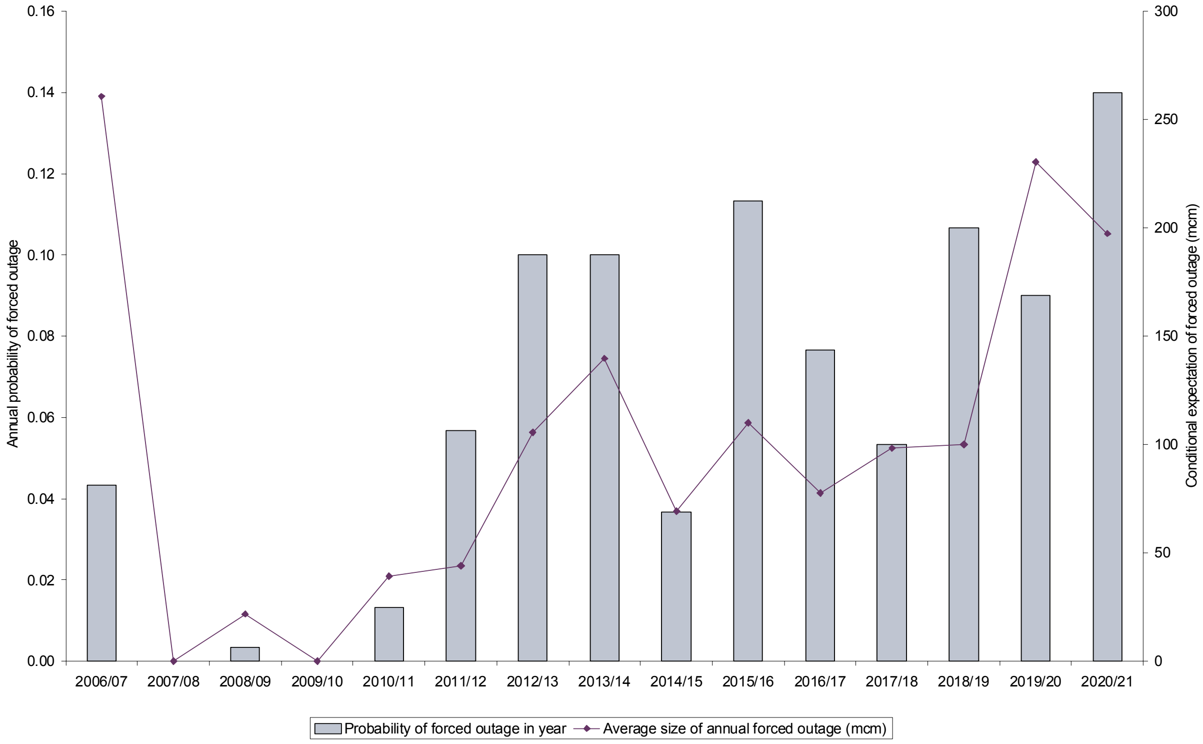
[63] Figure 4.6 shows that expected levels of outages differ between years where (as is illustrated in Figure 4.2) peak market tightness is similar. This arises for two reasons. First, in later years, although peak deliverability is comparatively similar, the duration of storage availability is lower, thereby increasing market tightness away from peak periods. Second, the mix of delivery infrastructure (and hence the exposure to outage risks) changes across time.

[64] For example, if there is a 10% chance of a 100mcm outage and a 90% chance of no outage, the expected forced outage would be 10mcm = (0.1*100)+(0.9*0), whereas the conditional expected forced outage would be 100mcm.

[65] The highest annual outage level across the 300 simulations.

[66] By definition, the probability of this occurring is 0.33%, or once every 300 years.

Figure 4.7 Annual probability of a forced outage and the conditional expectation of annual outage size (mcm)

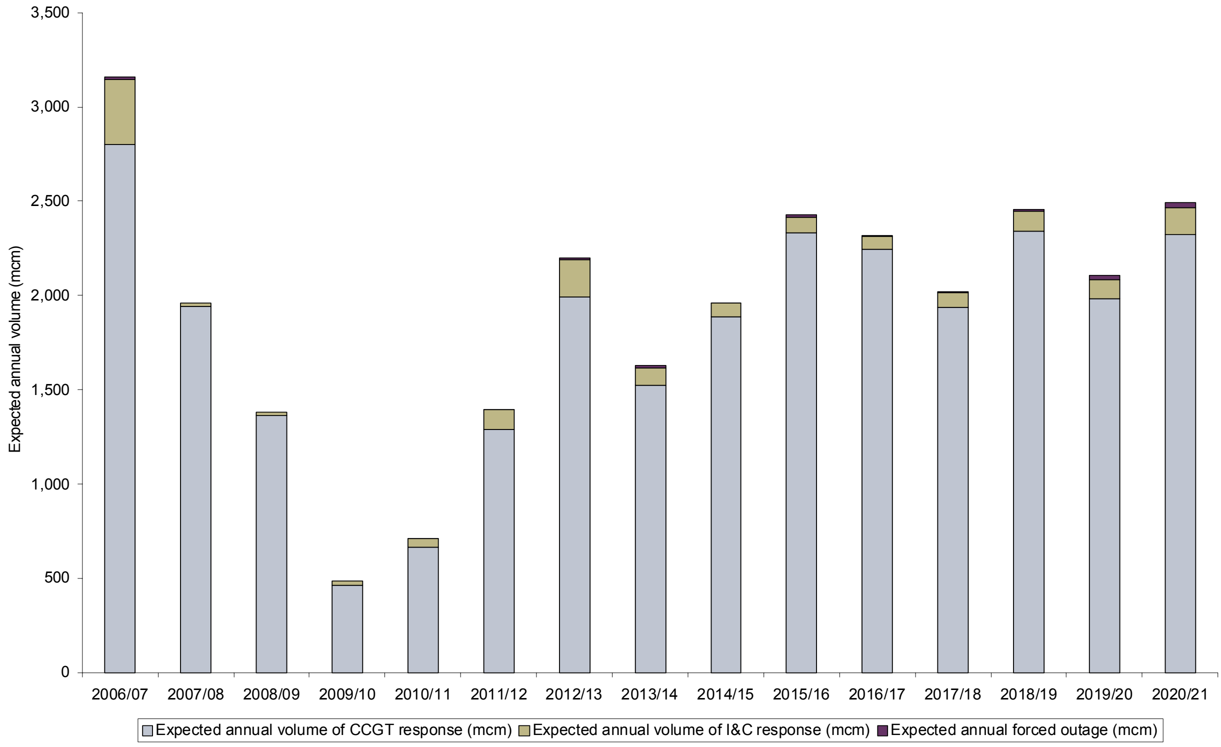


Source: Oxera.

One of the reasons for such a low probability of forced outages is that there is a large volume of voluntary demand-side response from CCGTs and large industrial consumers that provides a buffer between physical shortages and involuntary interruptions to supply. This is illustrated in Figure 4.8 below, which shows the expected annual volume of all demand-side response. The expected annual volume of all demand-side response in 2006/07 is around 3bcm (3.3% of annual restricted demand) and the majority of this is a result of economic reduction of demand by one or more groups of customers. In particular, there is a large CCGT response in most years, reflecting not only the assumed flexibility that can be provided by this particular consumption group within the model, but the potential for such behaviour to be competitive with physical supply sources at certain times of year.[67]

[67] The modelling does not look explicitly at the knock-on effects that may arise in the electricity market as a result of this reduction in gas use. In the longer term tighter environmental restrictions on coal-fired generation may become a more binding constraint on either the volume of CCGT response or, more likely, the price of accessing that flexibility by the gas market.

Figure 4.8 Composition of expected demand adjustment (forced outages and demand response, mcm)



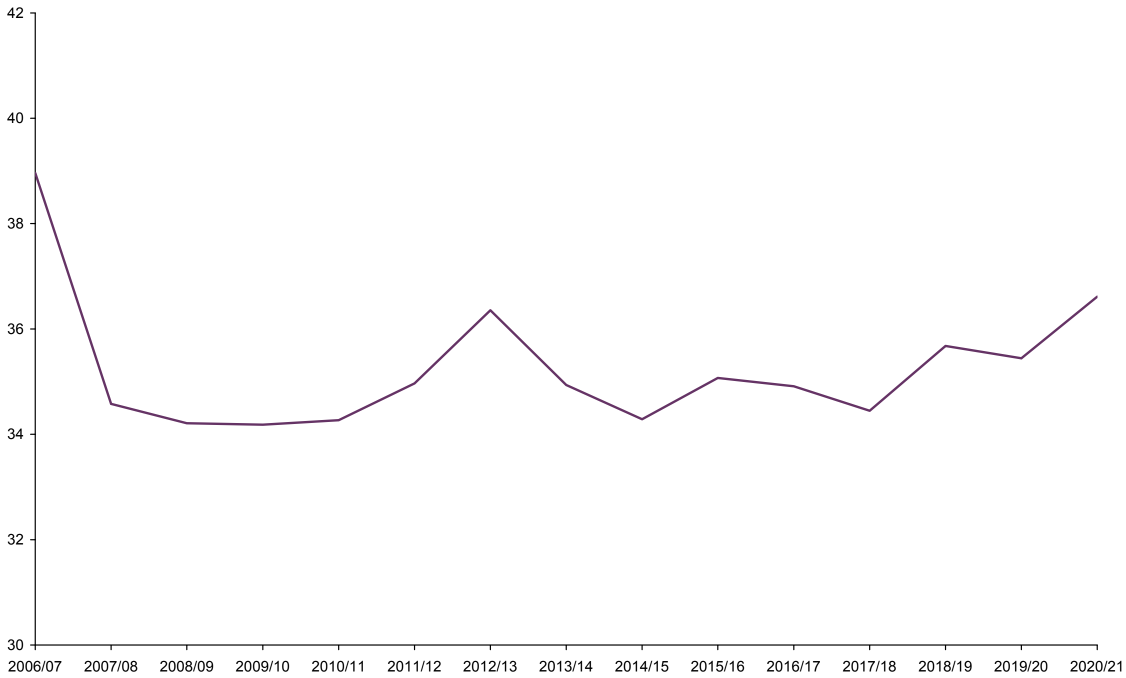
Note: Expected annual forced outage volume is significantly smaller than the scale of voluntary demand-side response in this figure.
Source: Oxera.

4.3 Pricing effects

In addition to the physical outage risk, the investment profile affects the outturn prices in the model as it effectively defines the potential sources of gas and the flexibility inherent within the delivery infrastructure. These factors are reflected in the underlying price distributions that emerge.

The average annual price over the course of the simulation is shown in Figure 4.9 below. The pattern reflects the initial reduction in price as the market moves from a position of tightness to relative abundance—prices in this period are driven down towards the assumed Continental and LNG prices. However, in the longer term the price rises, reflecting the emerging tightness in the market and the lack of capacity to respond to meet low-probability demand outcomes. This means that there is additional vulnerability to high prices when flexibility falls (ie, in high-demand periods there are more likely to be days when the demand response or even VoLL is setting the marginal price).

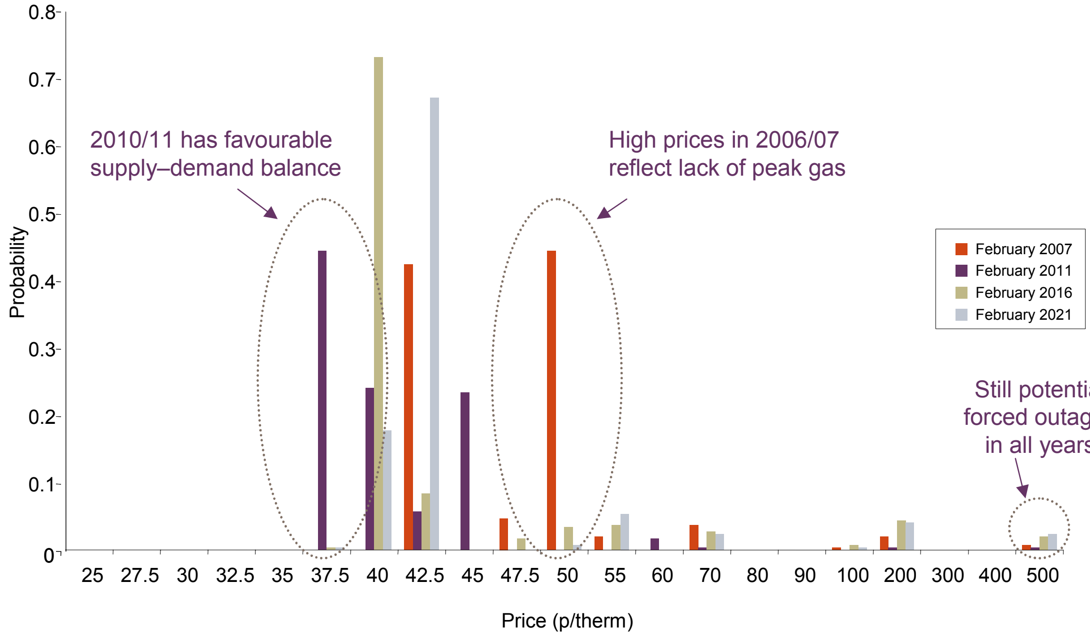
Figure 4.9 Annual average expected spot price (p/th)



Source: Oxera.

This widening of the price distribution in the longer term is illustrated in Figure 4.10, which shows the price distribution on a given February day in 2007, 2012, 2017 and 2021. The distribution originally gets narrower (implying lower price volatility) and based around a lower mean (between 2007 and 2012), reflecting the new infrastructure and potential excess supply situation; however, the price outcomes then become more extreme in 2017 and 2021, reflecting the increasing tightness in the market caused by lack of investment in new import capacity. These variations in the price distributions over time drive the relative investment incentives for types of infrastructure.

Figure 4.10 Price distribution for February 1st 2007, 2012, 2017 and 2021 (p/th)



Source: Oxera.

Table 4.2 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	11.30	0.00	0.07	0.00	0.52	2.49	10.57	13.98	2.54	12.47	5.95	5.24	10.66	20.75	27.64
Probability of a forced outage	0.04	0.00	0.00	0.00	0.01	0.06	0.10	0.10	0.04	0.11	0.08	0.05	0.11	0.09	0.14
Conditional expectation of annual forced outage (mcm)	261	0	22	0	39	44	106	140	69	110	78	98	100	231	197
Maximum annual forced outage (mcm)	1,898	0	22	0	76	187	611	1,076	288	670	374	513	567	2,442	2,674
Expected number of days with forced outages	0.75	0.00	0.01	0.00	0.04	0.33	1.08	0.92	0.28	0.91	0.55	0.48	0.75	0.83	1.20
Expected annual volume of CCGT response (mcm)	2,800	1,944	1,365	462	665	1,288	1,992	1,523	1,888	2,331	2,243	1,936	2,339	1,984	2,326
Expected annual I&C response (mcm)	346	15	17	24	47	106	196	93	72	82	71	78	107	101	138

Source: Oxera.

5 Simulating the proposed measures

The DTI consultation document describes seven potential measures for improving gas security of supply:

Measure 1	Expanding the scope of supplier obligations to include industrial customers
Measure 2	Sharpening cash-out incentives under normal arrangements[68]
Measure 3	Regulating the use of storage
Measure 4	Introducing gas capacity mechanisms
Measure 5	Encouraging demand-side response from I&C consumers
Measure 6	Encouraging the installation of back-up fuel capabilities at new CCGT power stations
Measure 7	Smart gas metering and increased efforts on fuel efficiency

In this section, the results of the simulations of the proposed measures are presented. A consistent simulation approach was applied to all measures apart from Measure 3 (regulating storage), where the effects of the proposed measure could not be effectively replicated within the modelling framework. Consequently, the analysis and discussion of Measure 3 takes a different format to that of all the other measures where the following elements are included:

– a description of the anticipated impact of the policy (in terms of changes to market signals and investment incentives) and identification of any unintended consequences that might not be captured through the price-security model;
– an outline of how the measure was represented in the modelling framework;
– summary results of forced outages and prices.

The main results presented below for each measure include:

– the optimal investment profile;
– the expected annual forced outage;
– the probability of a forced outage and the conditional expectation of the outage;
– the outturn annual average spot price;
– the outage summary statistics.

In addition, a final summary section presents a high-level comparison of these physical market results with those of the Base Case scenario. The quantification of the costs and benefits associated with any differences in performance from the Base Case is described in section 6, with further detail on the methodology applied provided in Appendix 1.

5.1 Measure 1—expanding the scope of supplier obligations to include I&C customers

5.1.1 Description of measure 1

The measure proposes to extend the current supplier obligation with respect to domestic supplies (ie, the supplier must have sufficient gas to meet domestic demand in a 1-in-50 winter) to include I&C customers.

[68] This is separate to proposed changes to the emergency cash-out regime.

Expansion of the supplier obligation in this way will increase the required volume of gas that suppliers must be able to access in the winter period relative to their expected customer demand levels. They may achieve this by putting more gas into storage, signing additional import contracts for peak delivery, adding swing options to current contracts, or purchasing demand-side response from the market.

5.1.2 Representation in model framework

The supplier obligation is represented in the model by assuming that demand for gas in any year is modelled as though the suppliers were expecting demand conditions equivalent to at least a 1-in-30 cold winter.[69] This creates a set of obligation-consistent prices in the market that reflect the expectation that a more stringent supplier obligation will be enforced, on which new investment decisions will be based. The nature of the investment modelling is such that this will allow a choice between physical gas provision and short-term demand response through their interaction in the merit order in order to determine volumes of gas purchased.

Outturn spot prices in the model are then determined using the whole of the demand distribution, thereby enabling the effect of more favourable outturn demand conditions on market prices to be illustrated.

The difference between the prices on which investment decisions are made and the outturn spot prices may lead to unintended consequences that are not captured by the modelled investment behaviour.[70] Investment decisions are based on prices that are consistently above the outturn spot price. This suggests that, without some form of forward or long-term contracting to cover the capital costs, the predicted investment may not be forthcoming and hence any reported improvement in physical security of supply may not actually materialise.

To address this, the analysis assumes that the effective price which suppliers will pass on to consumers is the obligation-consistent wholesale price encapsulated in the investment decisions. Since the investments are made only if profitable, it may be expected that suppliers will pay these prices in order to comply with their obligation, and, as such, this premium will end up being passed through to customers. Consequently, both the spot and obligation-consistent prices are reported for this measure.

5.1.3 Results

The investment profile obtained with a more stringent supplier obligation is presented in Table 5.1 below. The higher gas requirements for shippers in the winter bring forward some storage investment (reflecting the lack of existing peak gas infrastructure in the near term) and result in higher overall levels of storage capacity being built across the period. However, there is no incremental gas import capacity developed. This reflects the fact that incremental demand in this scenario occurs in the summer, as suppliers purchase additional capacity to fill the storage facilities and meet possible severe winter conditions. Summer utilisation of LNG facilities increases to meet this (utilisation is around 70% in this scenario), but storage is considered a more efficient means of meeting a possible peak requirement.

[69] This is comparable to the volumes of gas that would represent 1-in-50 cold winter conditions for domestic and I&C customers and average conditions for power generation customers.

[70] That is, there may be a free-riding problem that suppliers will not contract forward, hoping to acquire gas more cheaply on the spot markets, and hence the necessary investment will not materialise. This will only occur if the penalty for non-compliance with the obligation does not reflect the full marginal cost of the reduction in security.

Table 5.1 Investment profile over the period to 2020/21

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**6,675**	**267.4**
Norwegian import capacity	10,950	30
LNG import capacity	27,925	76.5
Total import capacity	**38,875**	**106.5**
Storage (additional to Base Case)	**480**	**50**
Imports (additional to Base Case)	**0**	**0**

Source: Oxera.

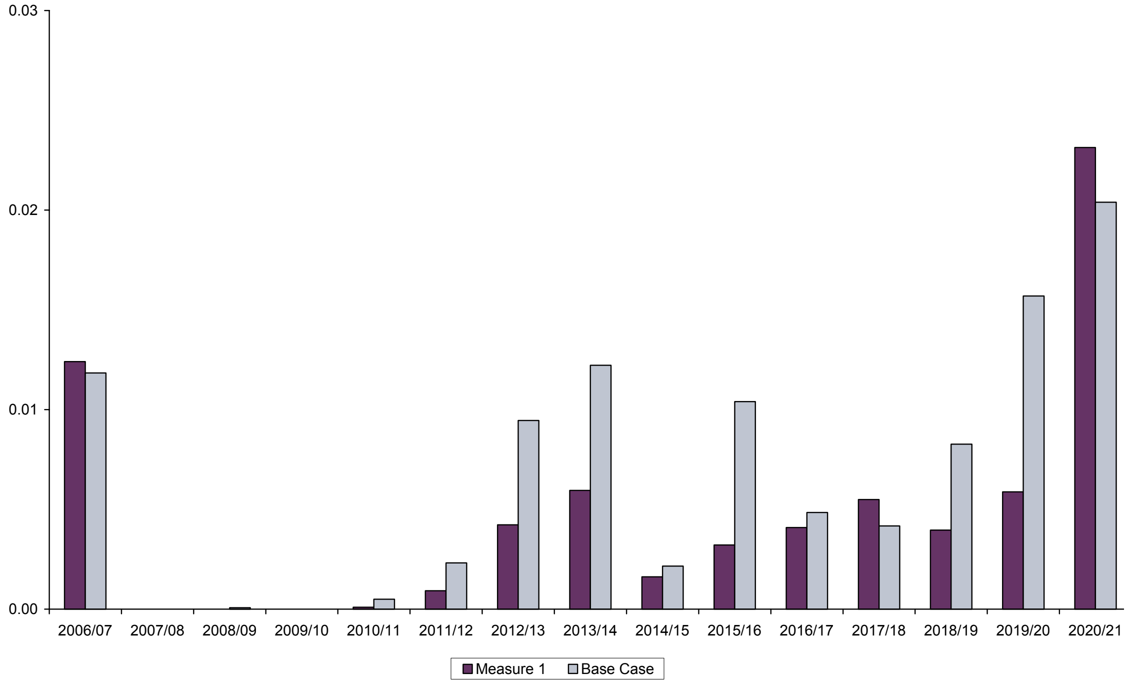
The greater volume of storage is reflected in the reduction in the expected annual forced outage volume (see Figure 5.1 below) and in the reduction in the probability of a forced outage occurring (Figure 5.3). In Figure 5.1, the annual forced outage volume is lower than the Base Case for the majority of the period under consideration. However, towards the end of the simulation there are two periods where the expected outage is slightly higher (around 31mcm compared with 26mcm in the Base Case). This is largely a consequence of the difference in the timing of new storage entry in the two models.

The earlier introduction of the facility in the Base Case produces a more resilient system to prolonged shocks than occurs under Measure 1. However, this is likely to be a transitional effect because the additional storage capacity under Measure 1 would, when fully operational, provide incremental flexibility relative to the Base Case, equivalent to the current available demand-side response.

This effect means that, when interruptions occur, they are, on average, larger than under the Base Case since the probability of an interruption is lower, as shown in Figure 5.4 below.

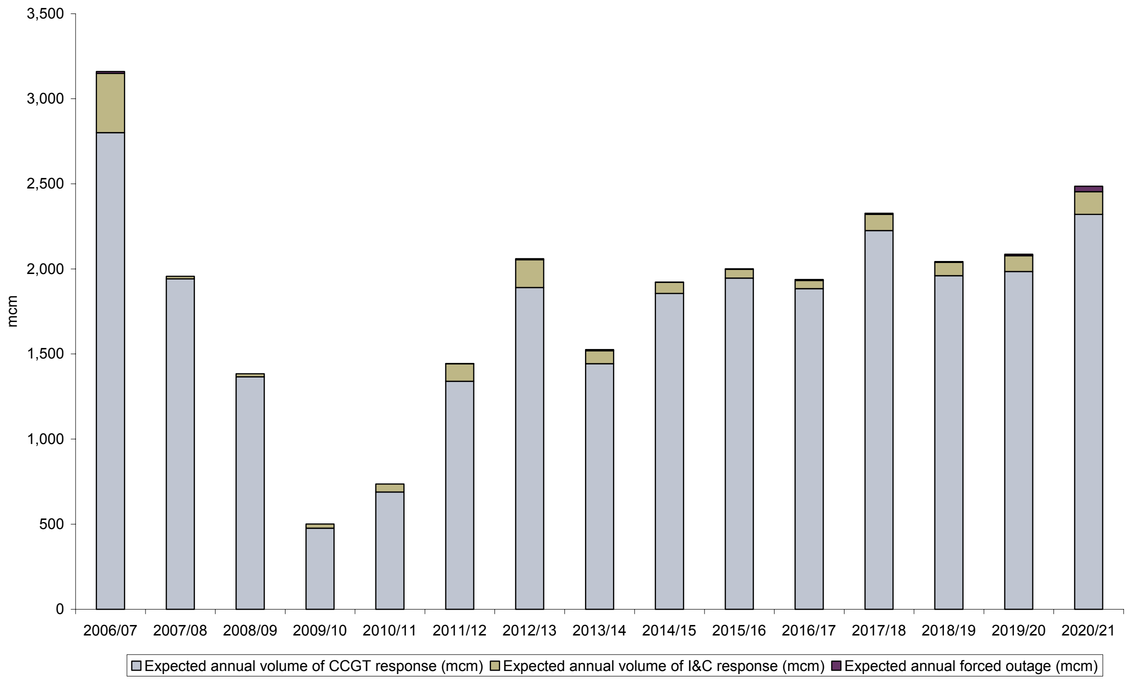
As with all the scenarios, the majority of flexibility is provided by voluntary demand-side response (Figure 5.2).

Figure 5.1 Comparison with Base Case: annual expected forced outage (% of demand)



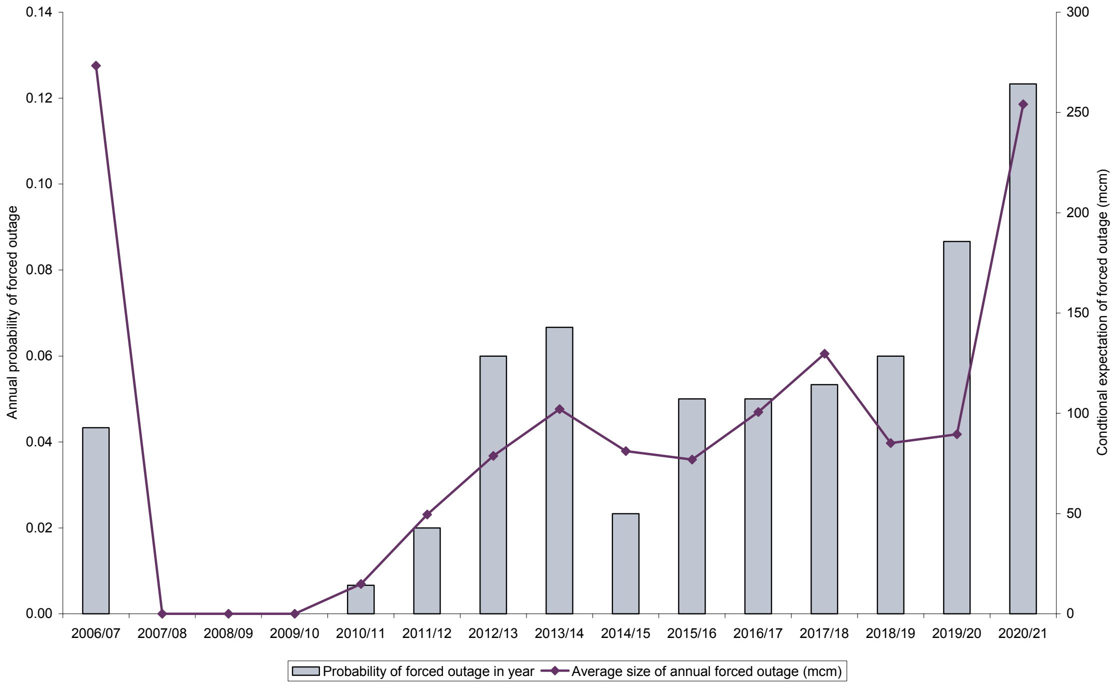
Source: Oxera.

Figure 5.2 Composition of expected demand adjustment (forced outages and demand response, mcm)



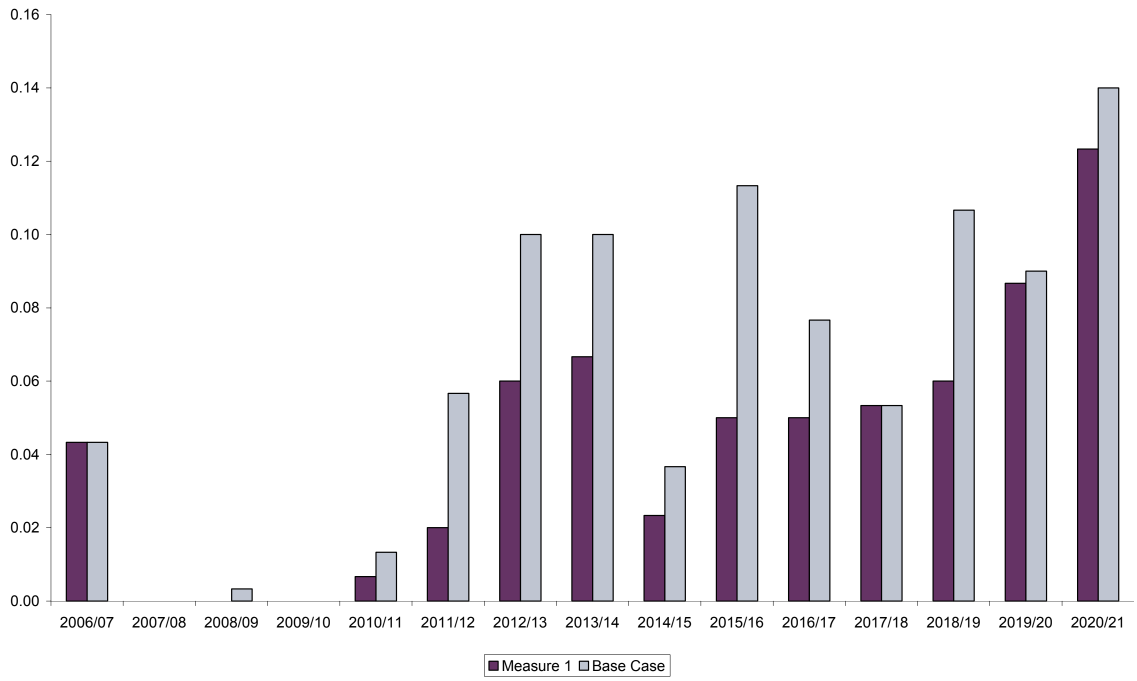
Source: Oxera.

Figure 5.3 Annual probability of a forced outage and the conditional expectation of annual forced outage size



Source: Oxera.

Figure 5.4 Comparison with Base Case: annual probability of outage

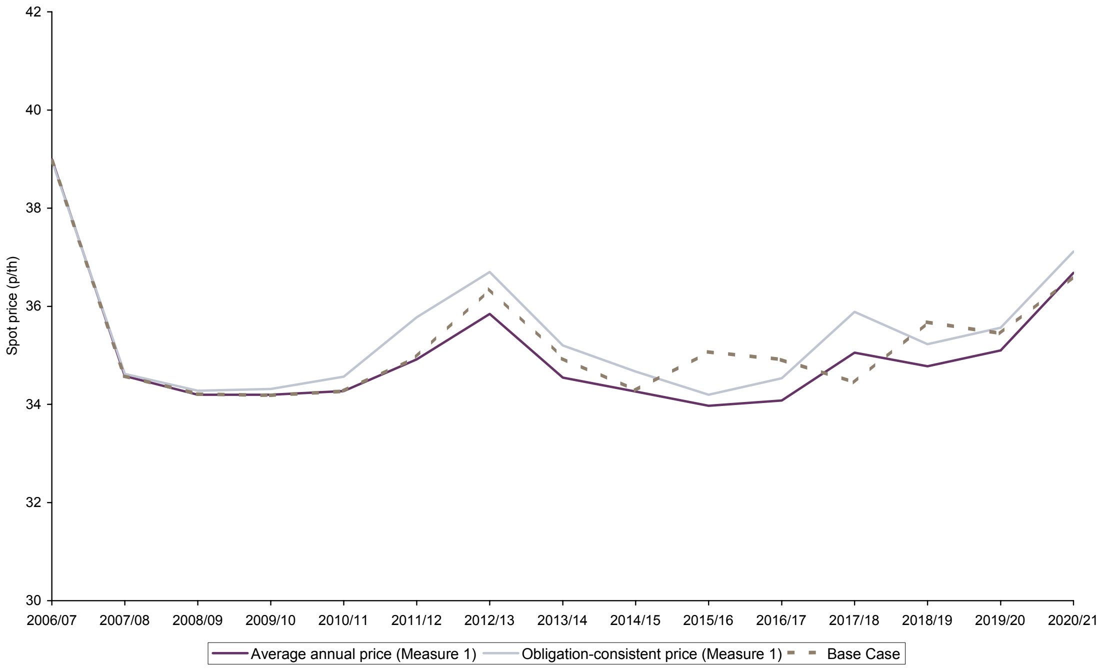


Source: Oxera.

The higher volumes of gas available to the market under normal conditions (ie, when the supplier obligation requirements are not binding) has a depressing effect on average outturn spot prices, as can be seen in Figure 5.5 below, where the Base Case expected spot price is above the expected spot price for Measure 1. These implied spot prices would result in lower actual arbitrage values from using storage and import infrastructure than investors would have factored into their investment decisions.

However, as mentioned above, it is assumed that suppliers would enter into (forward or long-term) contracts with infrastructure providers to cover their capital costs, and that the suppliers would be expected to pass these additional costs through to their customers.

Figure 5.5 Comparison with Base Case: expected spot prices (p/th)



Source: Oxera.

Table 5.2 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	11.85	0.00	0.00	0.00	0.10	0.99	4.73	6.81	1.89	3.85	5.03	6.92	5.11	7.76	31.34
Probability of a forced outage	0.04	0.00	0.00	0.00	0.01	0.02	0.06	0.07	0.02	0.05	0.05	0.05	0.06	0.09	0.12
Conditional expectation of annual forced outage (mcm)	273	0	0	0	15	50	79	102	81	77	101	130	85	90	254
Maximum annual forced outage (mcm)	1,905	0	0	0	22	151	217	473	240	231	371	485	490	642	2,642
Expected number of days with forced outage	0.73	0.00	0.00	0.00	0.02	0.28	0.61	0.59	0.24	0.36	0.33	0.58	0.41	0.50	1.24
Expected annual volume of CCGT response (mcm)	2,801	1,942	1,367	477	689	1,340	1,892	1,444	1,856	1,946	1,884	2,225	1,960	1,985	2,320
Expected annual I&C response (mcm)	347	15	17	24	47	104	163	76	64	51	49	95	78	94	134

Source: Oxera.

5.2 Measure 2—Sharpening cash-out incentives under normal arrangements

5.2.1 Description of measure

The intention of this measure is to increase the marginal cost faced by shippers when they are out of balance. Such a change would only be economically efficient if it addressed an existing market failure. There are several potential market failures that this may be intended to address:

– current cash-out arrangements mean that shippers do not face the full marginal cost of outages (ie, there is a distortion through the current set-up of trading arrangements);
– there is an additional social cost associated with outages that the cash-out prices do not capture (ie, there is an externality);
– shippers discount the cost of extreme events because they believe they will never have to face the full cost of such events (ie, security is at least a quasi-public good).

In all but the final case, sharpening the incentives may improve the efficiency of private sector investment decisions. However, if it is simply that shippers do not factor in their exposure to extreme events then sharpening the incentives may not improve the system's insurance against such events happening.

5.2.2 Representation in model framework

The model does not explicitly capture on-the-day commodity market activity and balancing prices. However, the model does assume a VoLL associated with supply outages of 500p/th. To replicate the impact of more extreme incentives, the VoLL is assumed to be 3,000p/th. The model results should therefore indicate whether, if marginal incentives are fully accounted for in the investment decision, a higher VoLL would actually lead to greater investment (since the cost of the very low probability events is more accurately reflected in the market price).

5.2.3 Results

Table 5.3 below presents the investment profile arising from the simulation of this measure. The extreme prices appear to encourage a significant additional investment in both storage and import infrastructure, implying that such an extreme VoLL does affect the marginal investment incentives. In particular, the much wider range of price outcomes (see Figure 5.8 below) encourages a higher capacity of short-term storage in the system in comparison to other scenarios because the quarterly arbitrage conditions appear more favourable.

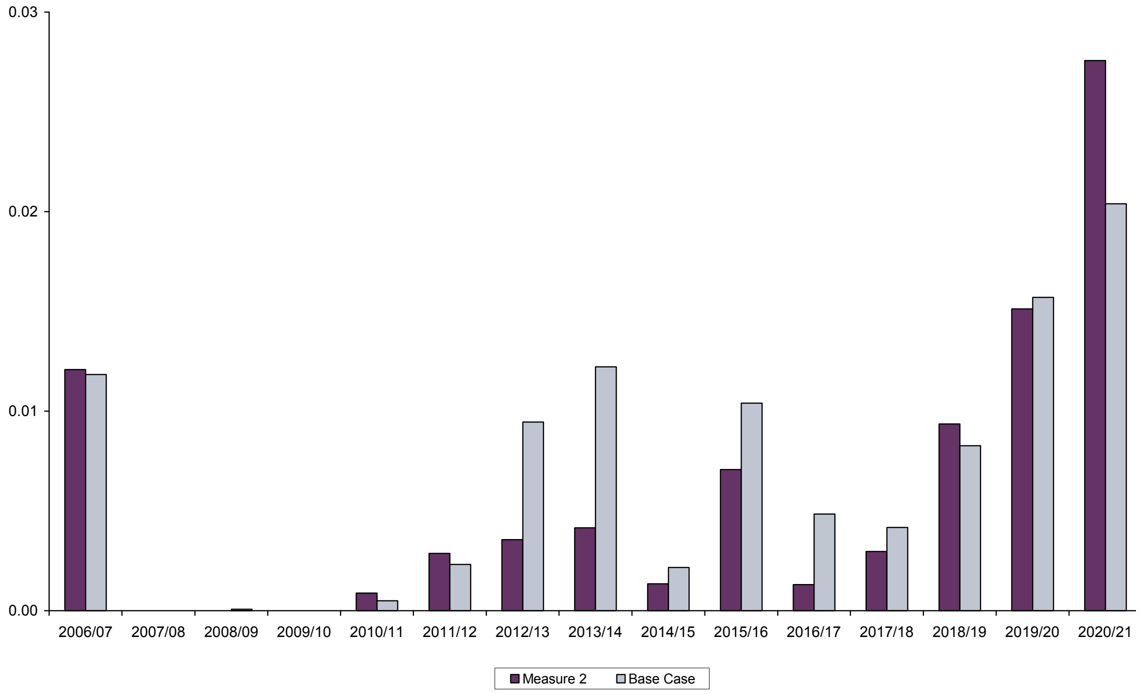
Table 5.3 Investment profile over the period to 2020/21

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**7,570**	**230.9**
Norwegian import capacity	10,950	30
LNG import capacity	33,324	91.3
Total import capacity	**44,274.5**	**121.3**
Storage (additional to Base Case)	**1375**	**13.5**
Imports (additional to Base Case)	**5399.5**	**14.8**

Source: Oxera.

This greater capacity does, as would be expected, lower the expected level of forced outages (see Figure 5.6 below) and the probability of outages (see Figure 5.9 below) over the majority of the period.

Figure 5.6   Annual expected forced outage (% of demand)

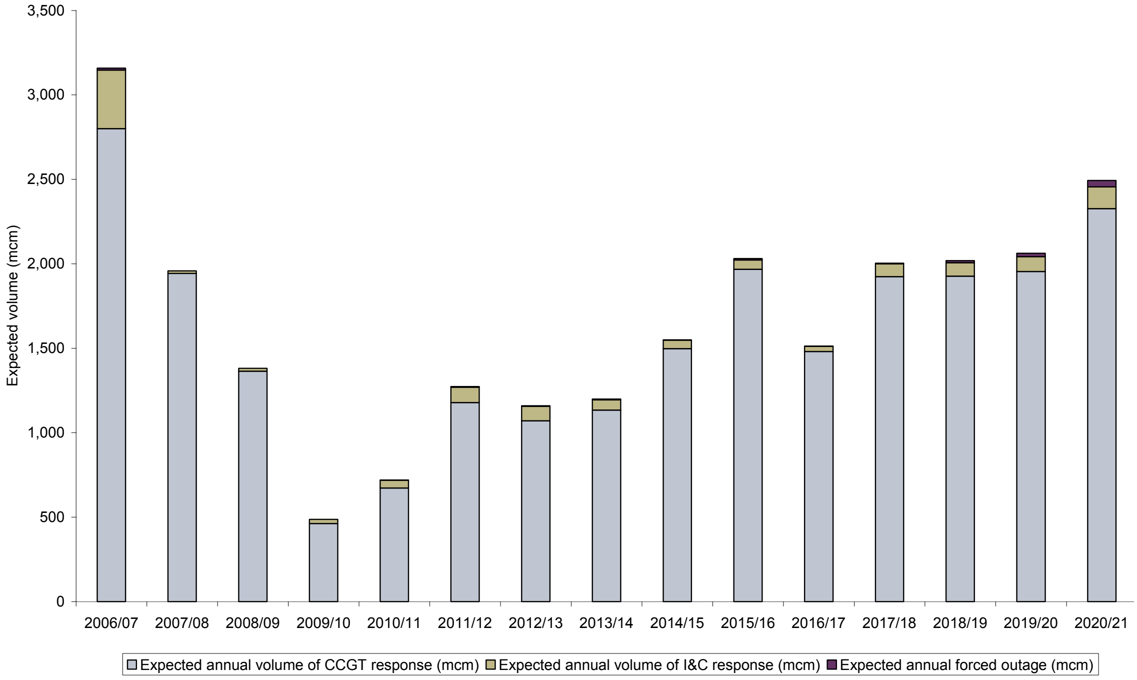


Source: Oxera.

However, in 2019/20 and 2020/21, there is a significant increase in the likelihood of interruption. This arises as a consequence of the simplified nature of the storage modelling that has been necessary in the analysis. Essentially, what is happening is that, having responded to high prices early in the winter (ie, quarter 4), mid-range storage is unable to replenish its stocks because the high prices that emerge early in quarter 1 make this uneconomic. As a consequence, when the seasonal storage has been fully depleted, there is no mid-range storage to meet potential spikes in the shoulder month of March, and hence forced outages become more likely. Thus, the simulation results may understate the contribution that effective marginal pricing makes to security.[71]

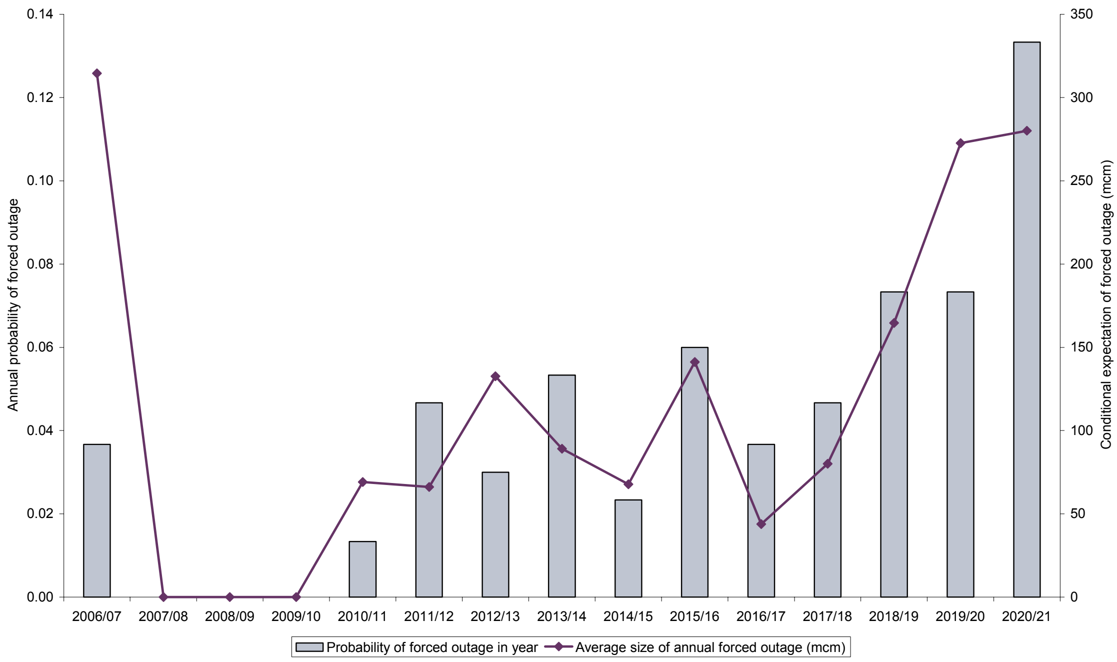
[71] This outcome is not solely related to this measure. However, the higher costs of forced outages in this scenario do make it more likely that injection thresholds will be higher during the winter periods, thereby exacerbating the effect.

Figure 5.7 Composition of expected demand adjustment (forced outages and demand response, mcm)



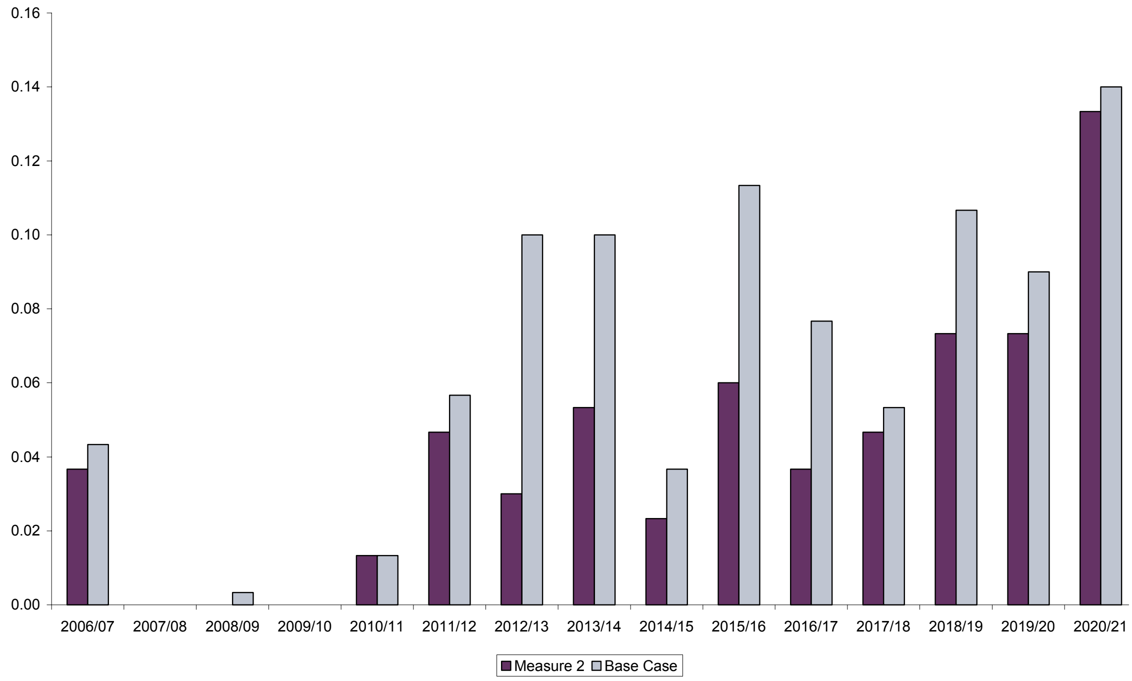
Source: Oxera.

Figure 5.8 Annual probability of a forced outage and the conditional expectation of annual outage size



Source: Oxera.

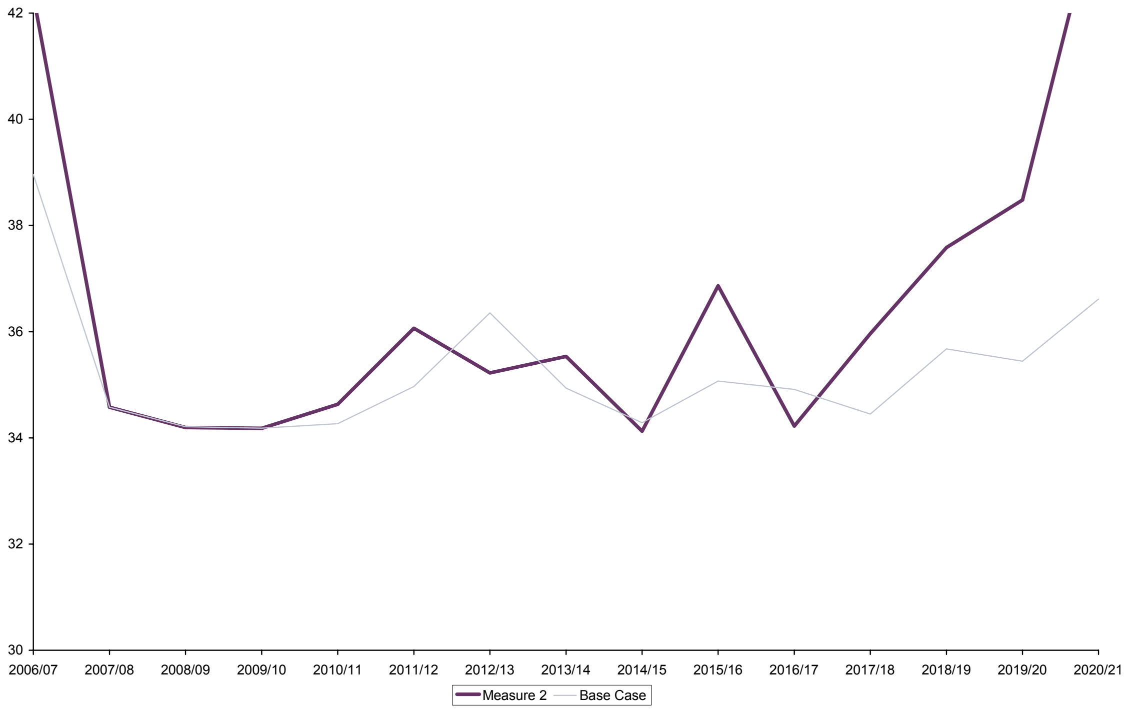
Figure 5.9 Comparison with Base Case: annual probability of outages



Source: Oxera.

The implication for prices is illustrated in Figure 5.10. In general, expected prices under Measure 2 are higher than under the Base Case, reflecting the higher assumed VoLL when forced outages occur.

Figure 5.10 Comparison with Base Case: expected annual spot market price (p/th)



Source: Oxera.

Table 5.4 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	11.53	0.00	0.00	0.00	0.92	3.09	3.98	4.75	1.58	8.48	1.61	3.74	12.08	20.00	37.35
Probability of a forced outage	0.04	0.00	0.00	0.00	0.01	0.05	0.03	0.05	0.02	0.06	0.04	0.05	0.07	0.07	0.13
Conditional expectation of annual forced outage (mcm)	315	0	0	0	69	66	133	89	68	141	44	80	165	273	280
Maximum annual forced outage (mcm)	1,905	0	0	0	168	411	282	464	214	805	185	178	2,314	2,441	2,681
Expected number of days with forced outage	0.77	0.01	0.00	0.00	0.06	0.25	0.26	0.40	0.16	0.55	0.16	0.40	0.54	0.65	1.28
Expected annual volume of CCGT response (mcm)	2,801	1,943	1,364	462	672	1,178	1,071	1,134	1,498	1,967	1,480	1,925	1,927	1,954	2,327
Expected annual I&C response (mcm)	347	15	17	24	47	92	85	61	50	56	31	75	79	88	129

Source: Oxera.

5.3 Measure 3—regulate the use of storage

5.3.1 Description of measure

This measure has been designed explicitly to prevent storage inventories being depleted in the early part of the winter and hence making them unavailable in potential cold spells during the second half of the winter. As discussion on Measure 2 has illustrated, it is possible that, in particular for mid-range storage, circumstances may arise where price differentials do not justify re-filling facilities after early winter withdrawals and hence there is a greater exposure to supply shocks in the shoulder period of March/April.

Constraining the use of existing storage facilities may serve to alleviate this problem, but may have other unintended consequences. In particular, it would prevent suppliers accessing all potentially profitable arbitrage opportunities, thereby lowering the value of storage and hence the incentive for investment. Thus, while Measure 3 may ensure a more secure use of existing storage facilities, it may result in less new investment, rendering the system more vulnerable in the longer term.

5.3.2 Representation in model framework

Storage regulation is modelled through the imposition of two conditions on storage inventories:

– storage inventories must be full at the end of quarter 3;
– storage inventories must not fall below 50% during quarter 4.

This has the effect of increasing demand, and hence price, in quarter 3, and altering the available supply curves during the two winter quarters, the combination of these effects being to lower outturn summer–winter differentials.

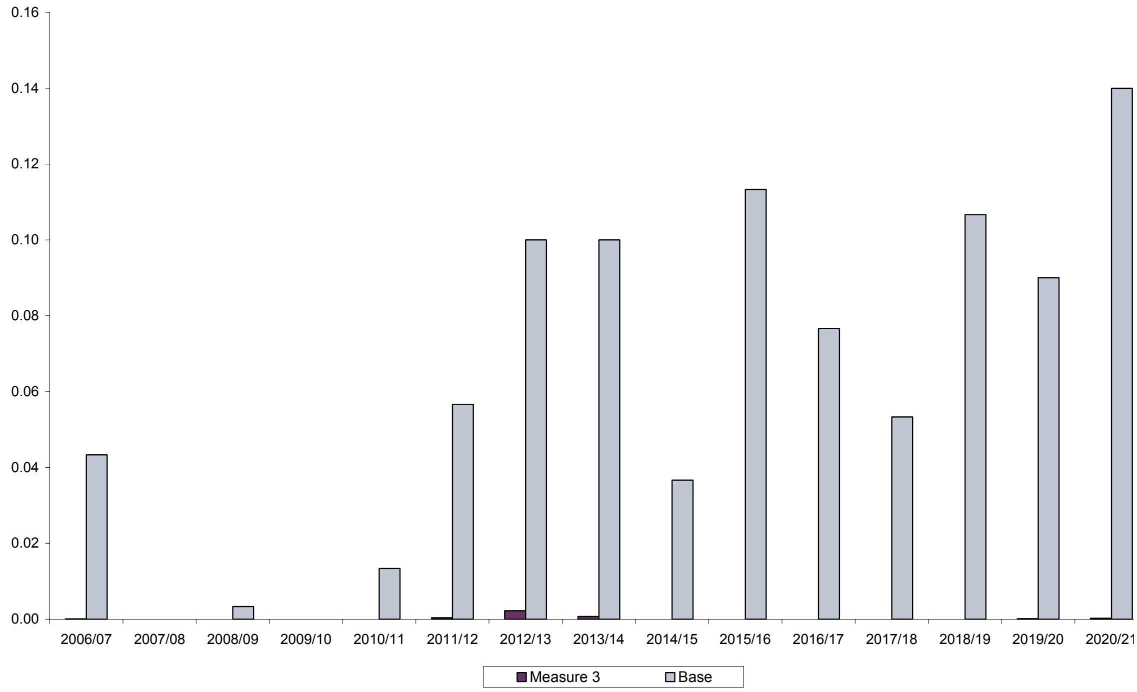
Because the storage decision is taken based on model-determined arbitrage conditions, it is difficult to find a consistent representation of the effect of this policy against which to undertake a full investment scenario. Hence, the approach taken has followed a different path. First, the Base Case investment profile is used with the new storage regulations applied to assess the impact on the main price and security indicators. Then, a comparison is undertaken of the net revenues of the storage facilities in operation under the two regimes. This latter step illustrates the extent to which the regulations may affect the ability of storage users to maximise the value of their gas, either as a consequence of the alteration in the outturn summer–winter differential, or because of the restrictions on operation during quarters 3 and 4.

5.3.3 Results

As Figure 5.11 below illustrates, by restricting the level of storage use in the early part of the winter there is a strong reduction in the expectation of forced outages relative to the Base Case. This is because the additional storage volumes in quarter 1 are sufficient to remove a number of periods of forced outage. There is no substitution of outages between quarters 1 and 4 because higher-priced demand-side response during quarter 4 offers enough flexibility to prevent forced outages.

These artificial restrictions can reduce the likelihood of forced outages so significantly because the modelling of storage inventories in the Base Case is such that shippers release when prices are above a certain threshold. For mid-range storage, in particular, this means they may release before the most extreme peaks are experienced. However, if prices stay high there may be insufficient arbitrage potential to justify re-injecting, thereby reducing flexibility later in the period. (This outcome is exacerbated if there is a high-price period stretching across the end of quarter 4 and the start of quarter 1, as this means that inventories never recover in quarter 1). By imposing a minimum inventory level on each storage facility, the risk of this outcome is significantly reduced, thereby increasing the available flexible supply in quarter 1.

Figure 5.11 Comparison with Base Case: annual expected forced outage (% of demand)



Source: Oxera.

While this constraint would imply a more optimal use of the available storage capacity, the question remains as to whether the same pattern of storage investment as observed in the Base Case would have occurred. As Figure 5.12 shows, the storage constraint has a material effect on the expected seasonal storage arbitrage, lowering the effective revenues that a storage operator has to cover their costs.

Figure 5.12 Comparison with Base Case: outturn seasonal storage arbitrage (p/th)

Source: Oxera.

The implication of this is illustrated clearly in Table 5.5, which compares the net revenues that storage facilities would have earned over the simulation period. In general, the revenues are one order of magnitude smaller under Measure 3—sufficiently different to anticipate that several of the investments would not have been profitable and thus the measure would have the significant unintended consequence of preventing investment that would otherwise have been profitable.

Table 5.5 Comparison of facility net revenue streams (£m, 2006/07 to 2020/21)

Investment type	Base Case revenues	Measure 3 revenues
Storage	6,325	733
	752	–435
	–24	–99
	3,484	130
	176	579
	587	132
	1,071	389
	68	13
	48	9
	80	–6
	324	98
	186	332
	308	71

Source: Oxera.

Table 5.6 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	0.08	0.00	0.00	0.00	0.00	0.37	2.52	0.81	0.00	0.00	0.00	0.00	0.00	0.17	0.31
Probability of a forced outage	5	0	0	0	0	22	148	49	0	0	0	0	0	10	12
Conditional expectation of annual forced outage (mcm)	5	0	0	0	0	22	76	49	0	0	0	0	0	10	9
Maximum annual forced outage (mcm)	5	0	0	0	0	22	148	49	0	0	0	0	0	10	12
Expected number of days with forced outage	0.23	0.00	0.00	0.00	0.00	0.15	0.70	0.47	0.02	0.27	0.12	0.17	0.18	0.35	0.50
Expected annual volume of CCGT response (mcm)	2,769	1,954	1,373	464	657	1,324	2,037	1,571	1,946	2,363	2,285	2,013	2,384	2,056	2,390
Expected annual I&C response (mcm)	330	12	15	23	42	101	180	87	56	62	51	69	94	96	125

Source: Oxera.

5.4 Measure 4—introduce gas capacity mechanisms

5.4.1 Description of measure

In essence, the capacity mechanism operates in a similar way as the enhanced supplier obligation, in that it requires shippers to have access to supplies of gas in excess of those that they would normally require to meet their customers' needs. The two main differences from the supplier obligation are as follows:

- the capacity mechanism would include all volumes, not just domestic and I&C volumes (ie, power generation would be included);
- the obligation may not be on suppliers but on the system operator. This may then enable greater control over how the spare capacity is used.

The impact of the first difference depends on the level at which the capacity mechanism is set. If set at a low level, the incremental demand may have very little impact on the summer–winter price differential (or at least less than the use of a supplier obligation at a 1-in-50 level).

The second difference is, however, a more fundamental issue. If there are guidelines determining the circumstances under which volumes are released onto the market (and at what price), the potential depressing effect on expectations of dumping of large excess supplies in the latter part of winter that may occur with the supplier obligation measure may be mitigated. However, there are two alternative considerations—if conditions under which the gas is released are transparent, this may:

- result in a moral hazard problem—ie, shippers do not act to minimise their risk exposure to this type of event, thereby making it more likely;
- cap expectations of prices in the market (very much like past criticism of the top-up regime), and thereby distort efficient signals for new investment (particularly of peak flexibility options such as mid-range storage and demand-side response).

Such a mechanism can look like a strategic storage option that the DTI has explicitly ruled out on the grounds of unintended consequences.

5.4.2 Representation in model framework

The capacity mechanism is assumed to require users to have sufficient supplies to meet a 1-in-50 winter demand. There is no presumption that this is the appropriate level for a system-wide capacity mechanism, but it was chosen to highlight any obvious changes in incentives and behaviour. As with the supplier obligation, the outturn prices are then simulated using the full demand distribution. The mechanism is represented in an identical manner to that of the supplier obligation in Measure 1, but with a more extreme requirement that shippers are incentivised to meet.

5.4.3 Results

As Table 5.7 below illustrates, the more extreme requirements of the capacity mechanism result in substantially greater capacity being brought to market.[72] This has the anticipated effect on the expectation of forced outages (see Figure 5.13 below), and the probability of a forced outage occurring (Figure 5.15) which, as Figure 5.16 shows, is substantially lower than that under the Base Case. In addition, the capacity mechanism appears to favour

[72] Whereas the Base Case appears to provide sufficient infrastructure to meet a 1-in-50 winter, additional infrastructure is brought forward in this scenario for two reasons: the price signals on which investors base their decisions are more extreme, being conditioned solely on the risks of outages during a 1-in-50 winter, rather than the risk of outages across the whole demand distribution; and the additional storage increases the duration of storage deliverability across the whole winter.

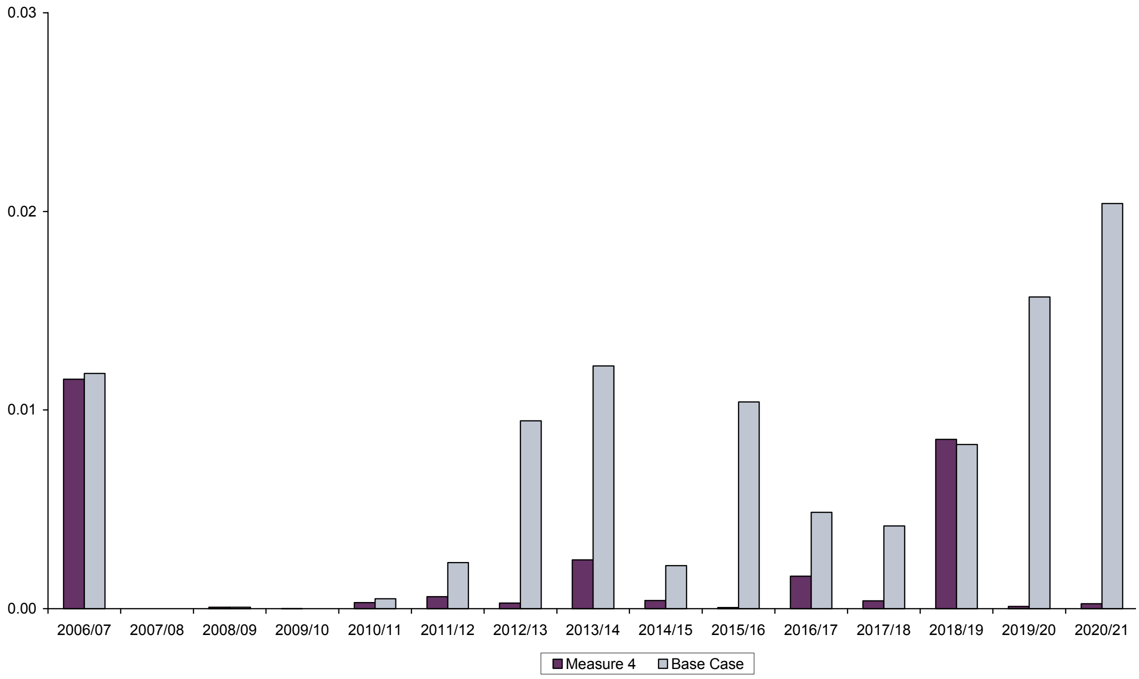
physical investment (given the strong impact on the demand-constrained prices, as illustrated in Figure 5.17) and thus there is a significant reduction in the volume of demand-side response that is required from CCGTs and the large industrial consumers (Figure 5.14).[73]

Table 5.7 Investment profile

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**8,302**	**276.4**
Norwegian import capacity	10,950	30
LNG import capacity	49,822	136.5
Total import capacity	**60,772.5**	**166.5**
Storage (additional to Base Case)	**2107**	**59**
Imports (additional to Base Case)	**21897.5**	**60**

Source: Oxera.

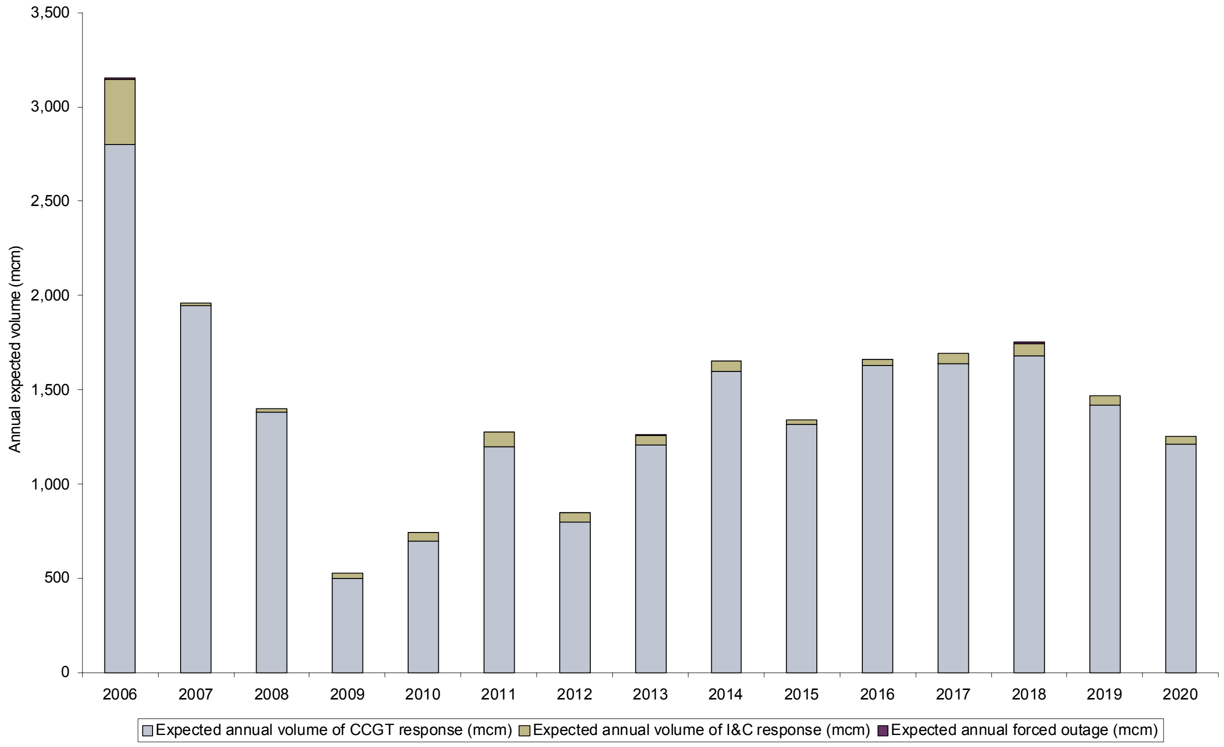
Figure 5.13 Comparison with Base Case: annual expected forced outage (% of demand)



Source: Oxera.

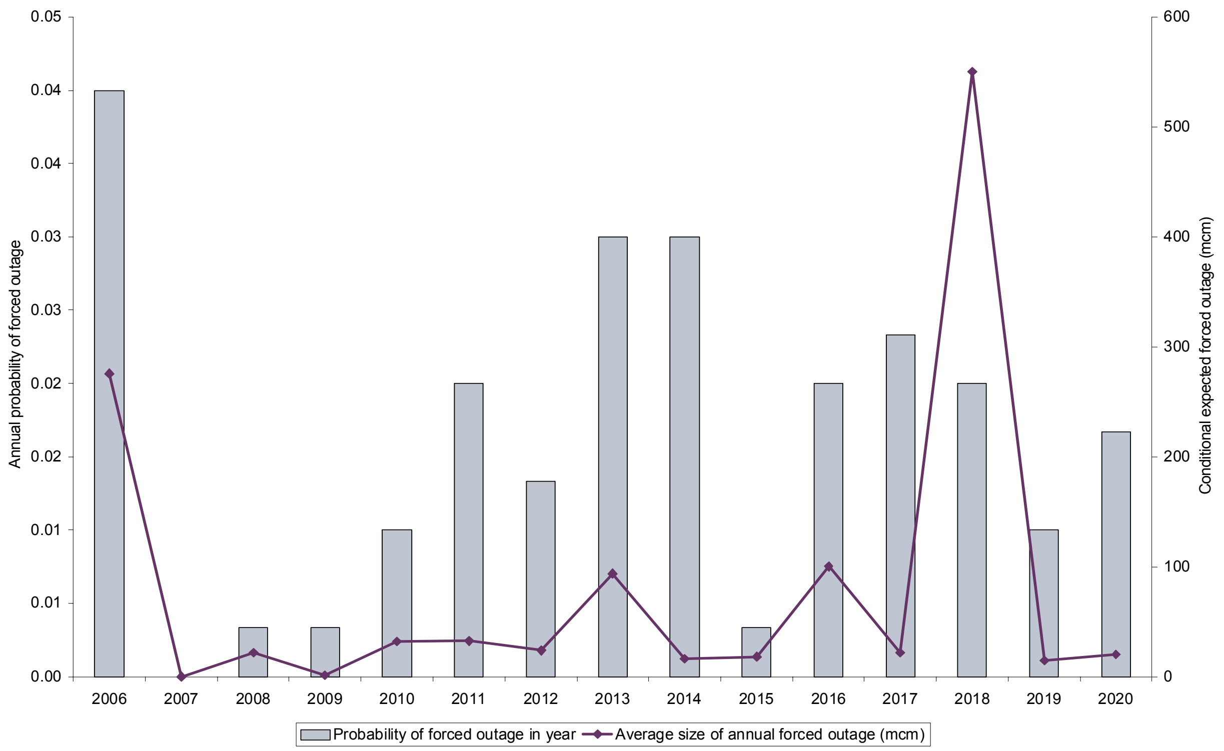
[73] The available demand-side response would be insufficient to cover the extreme capacity obligation. Since the model assumes that there is no scope for increasing the volume of daily demand-side response, this will tend to favour incremental physical investment. In reality, however, there may be options for consumers to 'opt out' of the level of security provided, thereby effectively reducing the requirement on suppliers to contract.

Figure 5.14 Composition of expected demand adjustment (forced outages and demand response, mcm)



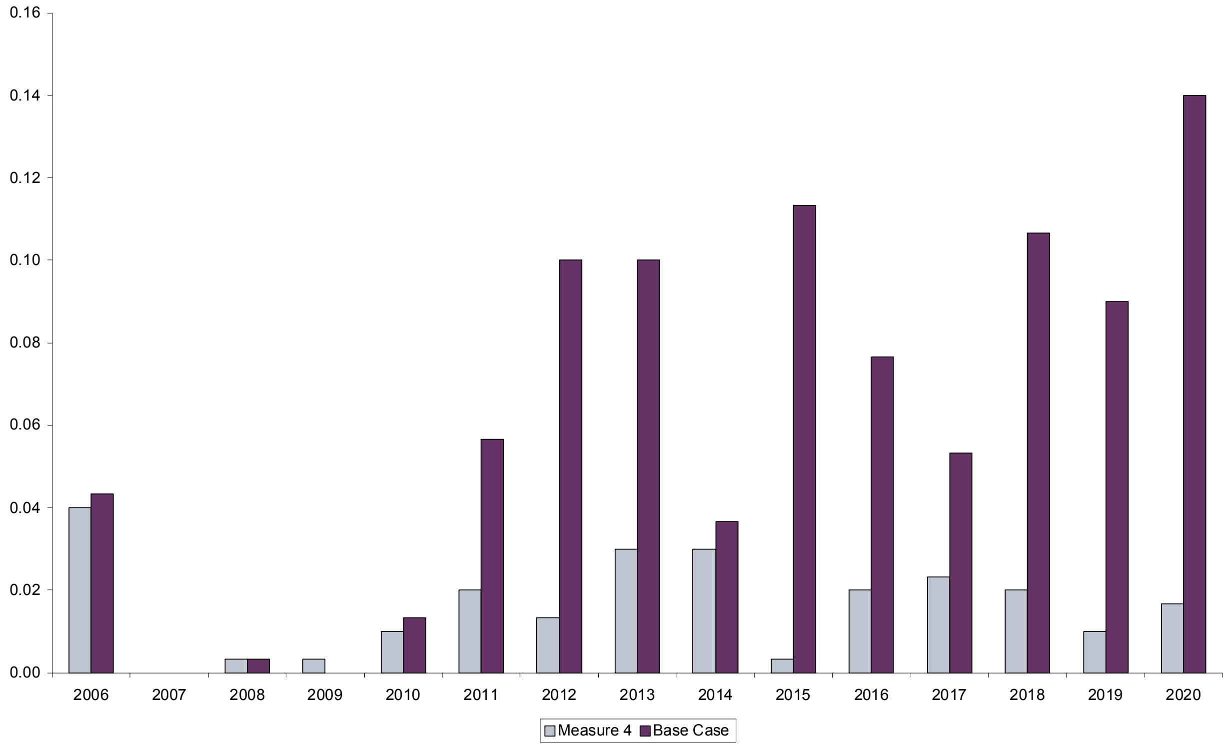
Source: Oxera.

Figure 5.15 Annual probability of a forced outage and the conditional expectation of annual outage size



Source: Oxera.

Figure 5.16 Comparison with Base Case: annual probability of outage



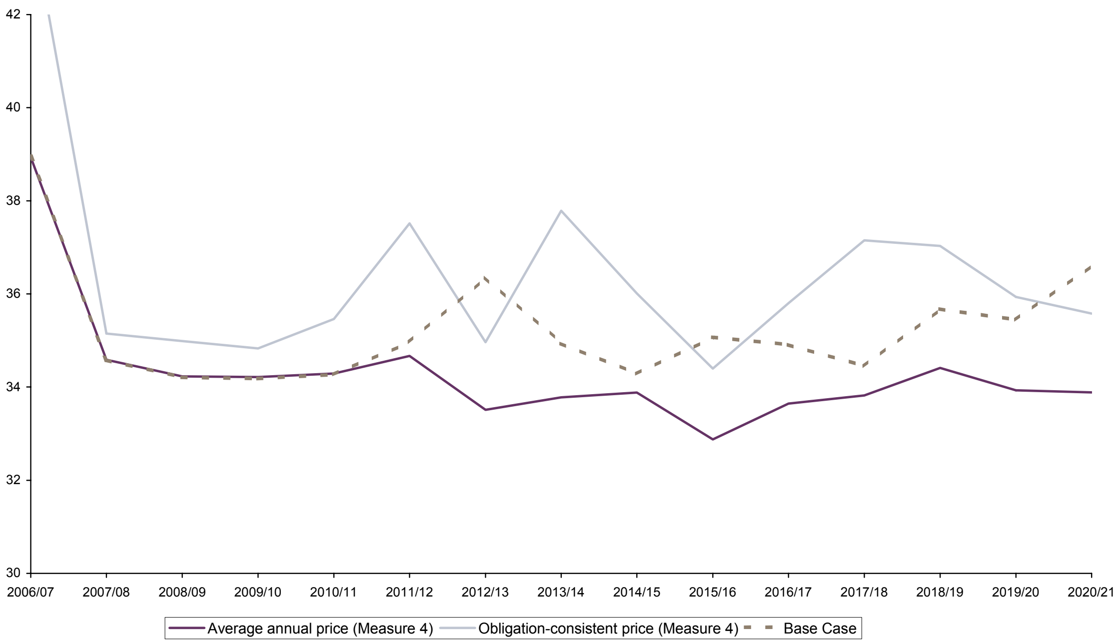
Source: Oxera.

Price movements under this measure are different than under the Base Case. Outturn spot prices are lower and more stable, reflecting the dampening effect that the higher effective supply has on the market under normal demand conditions. The obligation-consistent price passed on to end-users is generally higher than the Base Case, due to the need to encourage substantially more investment over shorter periods of time in order to ensure that the obligation is met.

This price differential may introduce unintended consequences if, anticipating lower out-turn spot prices, suppliers do not contract forward sufficiently—in effect, free-riding on others underwriting the investment. If this were to happen, the simulated investment profile (and improvement in security) would not be realised.[74]

[74] This outcome only occurs if marginal penalties for non-compliance with the capacity mechanism do not fully reflect the costs of gas security.

Figure 5.17 Comparison with Base Case: expected spot market price (p/th)



Source: Oxera.

Table 5.8 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	11.03	0.00	0.07	0.00	0.32	0.65	0.32	2.81	0.48	0.06	2.01	0.50	11.00	0.14	0.34
Probability of a forced outage	0.04	0.00	0.00	0.00	0.01	0.02	0.01	0.03	0.03	0.00	0.02	0.02	0.02	0.01	0.02
Conditional expectation of annual forced outage (mcm)	276	0	22	1	32	32	24	94	16	18	100	22	550	14	20
Maximum annual forced outage (mcm)	1,898	0	22	1	76	86	49	252	41	18	400	38	1,508	34	63
Expected number of days with forced outage	0.75	0.00	0.01	0.01	0.03	0.09	0.06	0.25	0.08	0.03	0.12	0.14	0.32	0.05	0.05
Expected annual volume of CCGT response (mcm)	2,799	1,945	1,383	499	695	1,197	797	1,207	1,597	1,318	1,628	1,639	1,682	1,419	1,212
Expected annual I&C response (mcm)	344	15	19	25	46	79	52	51	56	23	32	55	61	49	41

Source: Oxera.

5.5 Measure 5—Encourage demand-side response from I&C customers

5.5.1 Description of measure

Demand-side response provides additional flexibility in the gas system and may be cost-effective in situations where supply–demand imbalances are expected to be infrequent, short-lived and small. The consultation document suggests that further demand-side response may be elicited from the market through, for example, the provision of better information. The likely outcome would be a combination of more demand-side response being forthcoming and a reduction in the cost of provision in the market.

5.5.2 Representation in model framework

The Base Case scenario has a limited (16mcm/d) assumption of demand-side response available at a range of prices from 42p/th to 200p/th, as shown in Table 5.9. In representing Measure 5, it was assumed that the volume of demand-side response at each of the price steps would be increased as shown in Table 5.9, rather than introducing new price steps on an arbitrary basis. With no clear evidence of the additional scope for demand-side response, the overall volume of demand-side response was assumed to increase by 33%, with the majority of new volumes entering at higher prices, reflecting the likelihood that there is more scope for identifying untapped demand-side potential at higher prices.

Table 5.9 Comparison of demand-side response volumes (mcm/day)

Price (p/th)	Base Case volume	Measure 5 volume
42	1.86	2.04
50	4.62	5.09
79	5.36	8.06
100	1.48	2.22
200	2.6	3.89

Source: DTI assumptions.

5.5.3 Results

Table 5.10 shows the resulting investment profile. The relatively small incremental volumes associated with the additional demand-side response (no more than around 6mcm/day) and the high prices at which this volume is made available have a minimal effect on price expectations and outturn spot prices (see Figure 5.22) and hence have little impact on the investment behaviour, with only minor changes on the precise storage projects chosen and some slight delays to a few projects.

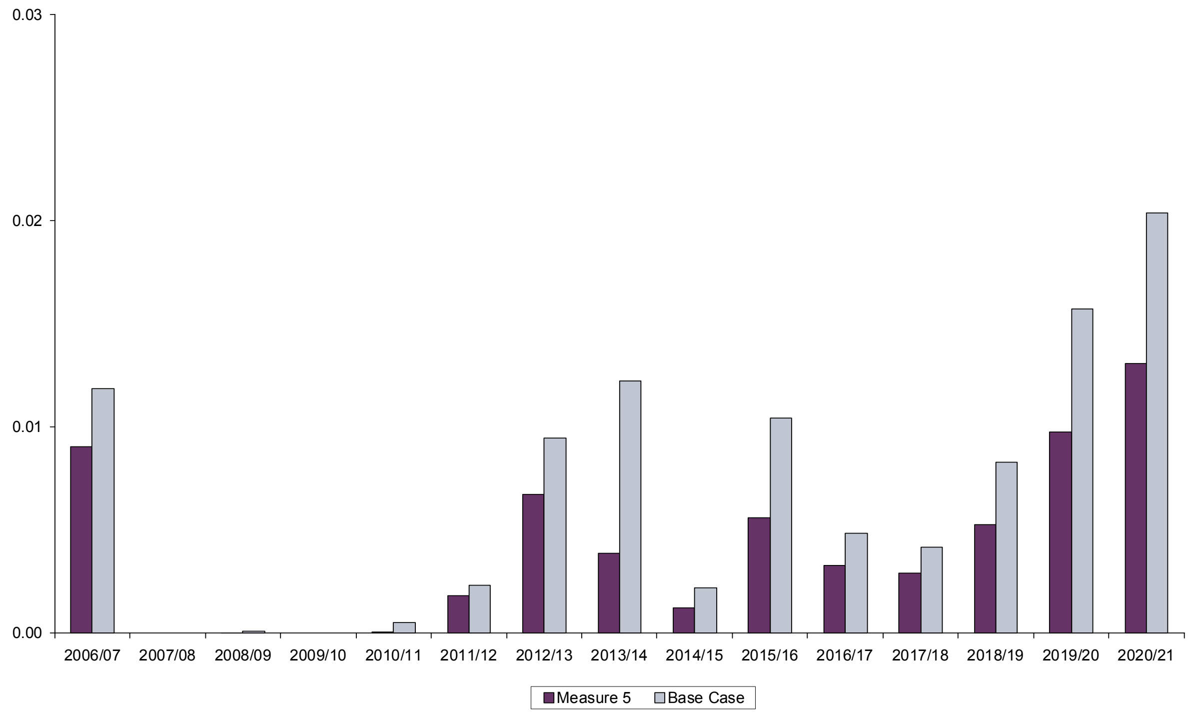
Nevertheless, expected annual forced outages are lower as a percentage of demand, primarily due to a lower average size of outage (Figure 5.20) rather than a reduction in the probability of outages occurring (see Figure 5.21). In fact, over some periods, outages are more likely (due to changes in the timing of investment), but the additional demand-side volumes reduce the size of these outages accordingly.

Table 5.10 Investment profile out to 2020/21

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**5,505**	**217.4**
Norwegian import capacity	10,950	30
LNG import capacity	27,922.5	76.5
Total import capacity	38,872.5	106.5
Storage (additional to Base Case)	**–690**	**0**
Imports (additional to Base Case)	**–2.5**	**0**

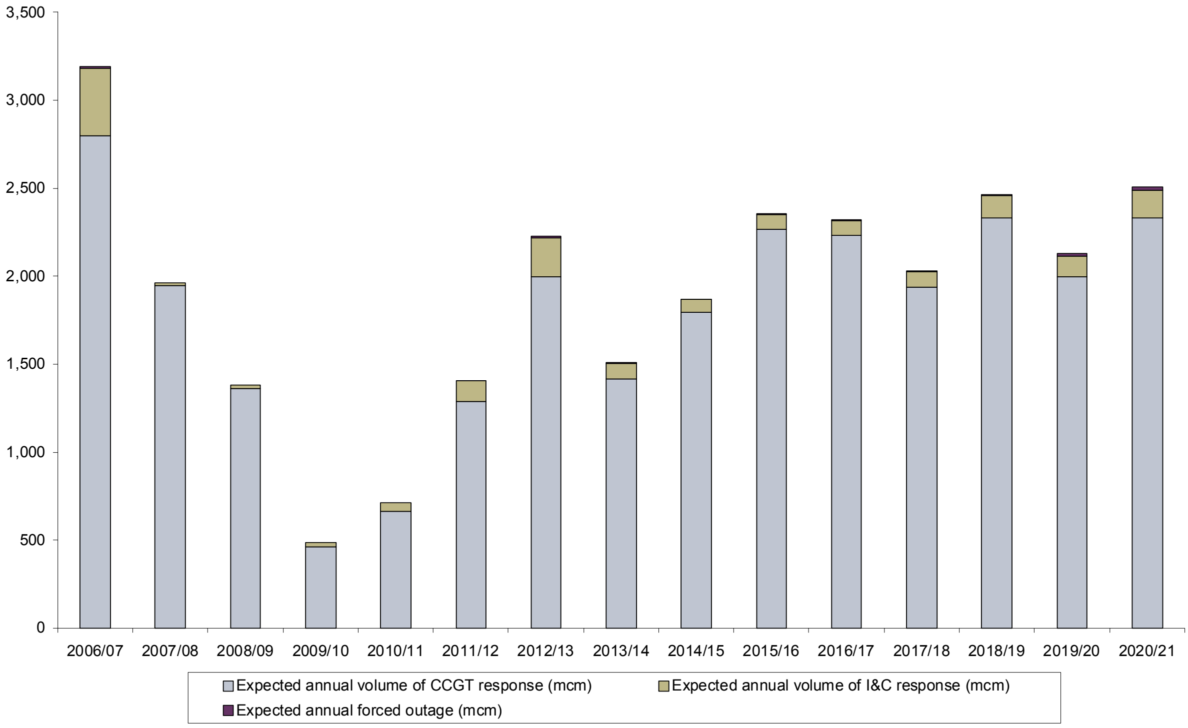
Source: Oxera.

Figure 5.18 Comparison with Base Case: annual expected forced outage (% of demand)



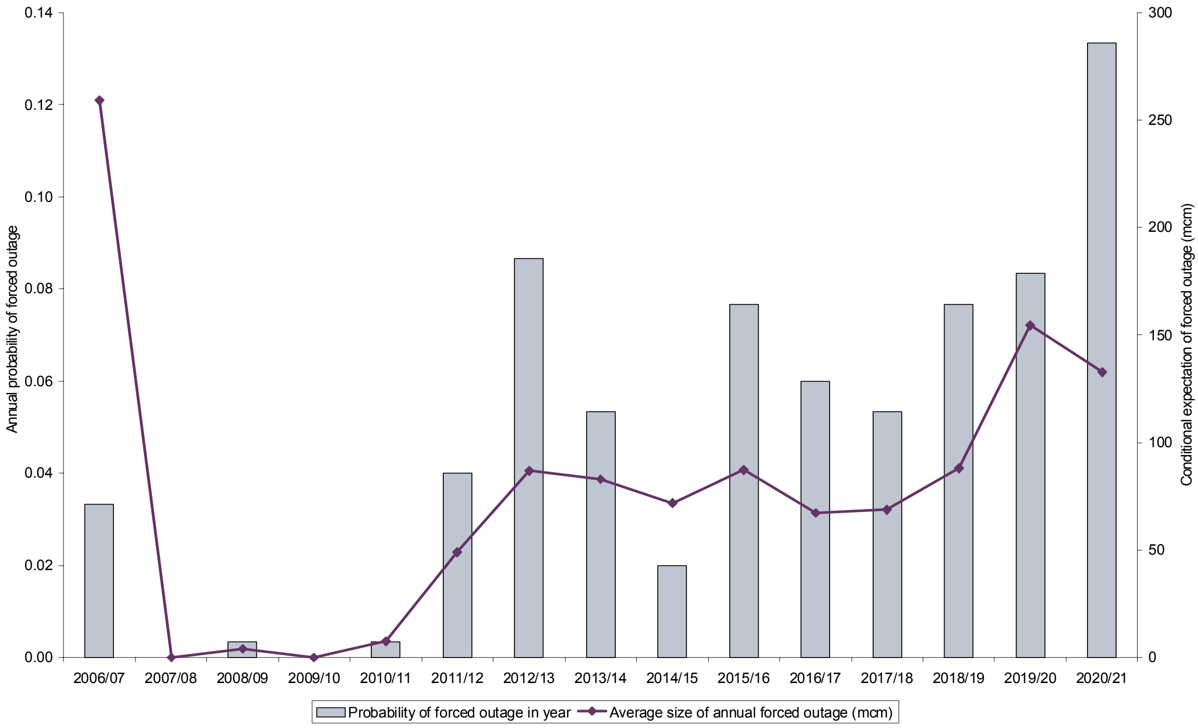
Source: Oxera.

Figure 5.19 Composition of expected demand adjustment (forced outages and demand response, mcm)



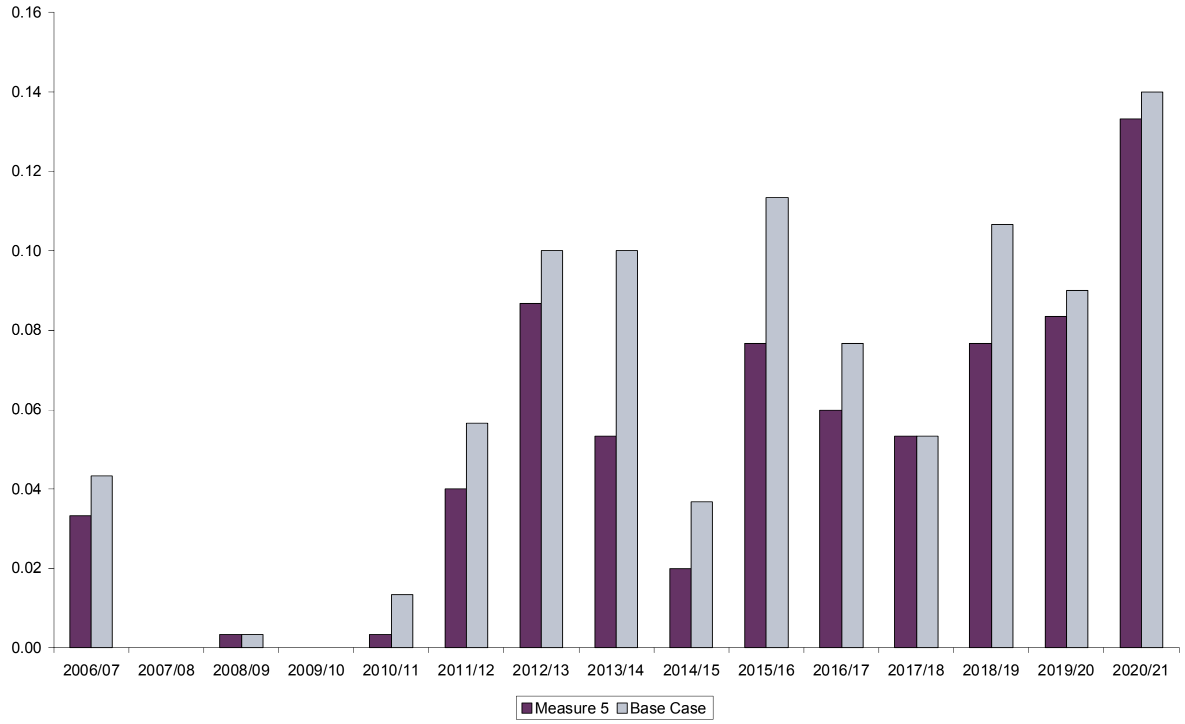
Source: Oxera.

Figure 5.20 Annual probability of a forced outage and the conditional expectation of annual outage size



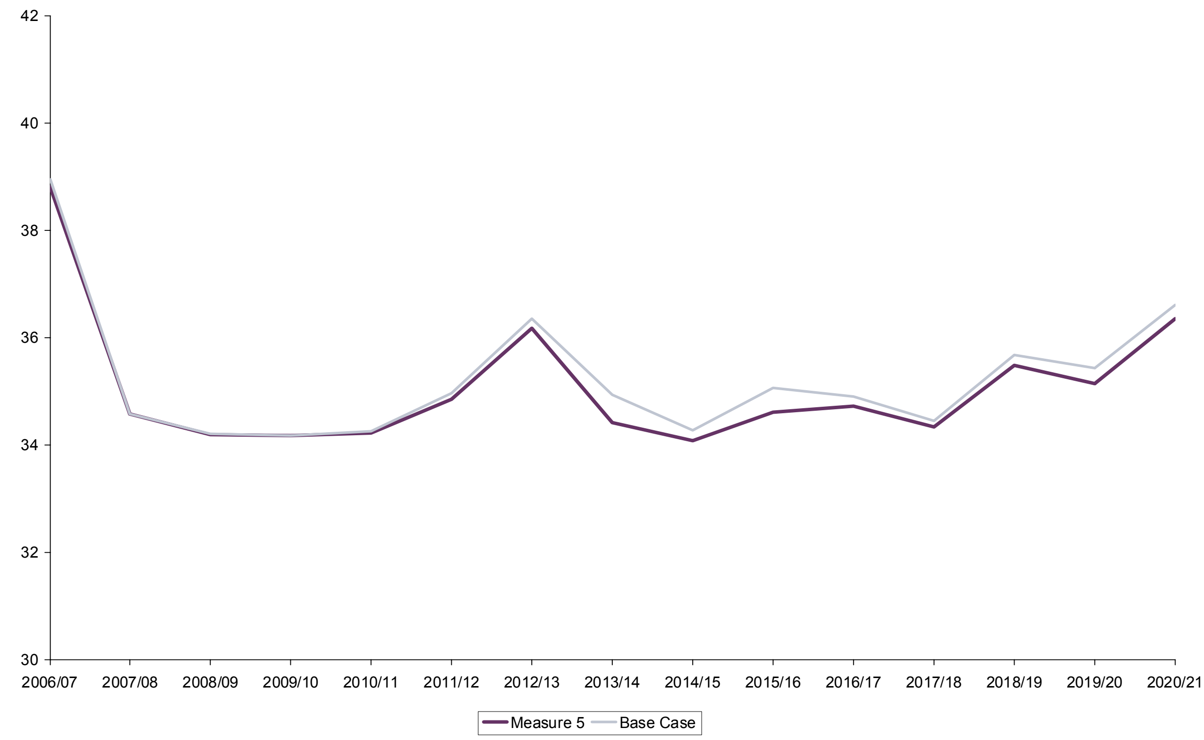
Source: Oxera.

Figure 5.21 Comparison with Base Case: annual probability of outage



Source: Oxera.

Figure 5.22 Comparison with Base Case: expected annual spot market price (p/th)



Source: Oxera.

Table 5.11 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	8.64	0.00	0.01	0.00	0.03	1.96	7.52	4.42	1.44	6.69	4.04	3.66	6.75	12.87	17.69
Probability of a forced outage	0.03	0.00	0.00	0.00	0.00	0.04	0.09	0.05	0.02	0.08	0.06	0.05	0.08	0.08	0.13
Conditional expectation of annual forced outage (mcm)	259	0	4	0	8	49	87	83	72	87	67	69	88	154	133
Maximum annual forced outage (mcm)	1,633	0	4	0	8	194	386	555	202	376	253	291	367	656	813
Expected number of days with forced outage	0.61	0.00	0.00	0.00	0.03	0.22	0.81	0.51	0.19	0.49	0.42	0.39	0.65	0.58	0.95
Expected annual volume of CCGT response (mcm)	2,798	1,945	1,363	462	662	1,287	1,998	1,415	1,797	2,266	2,234	1,935	2,329	1,997	2,328
Expected annual I&C response (mcm)	384	16	19	26	50	118	220	90	70	85	81	91	128	117	162

Source: Oxera.

5.6 Measure 6—encourage the installation of back-up fuel capability at new CCGT power stations

5.6.1 Description of measure

As with Measure 5, encouraging CCGTs to install back-up fuel capability would serve to increase the demand-side flexibility in the system. While no specific means of enforcing this mechanism has been determined, it is possible that it would be incorporated as part of the licensing procedures.

5.6.2 Representation in model framework

Existing CCGT response is modelled in three price steps, two associated with non-distillate back-up and one with distillate back-up. The Base Case demand projections, described in section 2, include assumptions on power generation consumption.[75] To simulate the measure, it is assumed that all incremental power generation consumption has associated distillate back-up capability. This leads to assumptions of available distillate back-up as presented in Table 5.12 (noting that the Base Case volumes are fixed at the 2006/07 level of 12.8mcm/day).

Table 5.12 Assumed CCGT distillate back-up response

Year	Assumed available distillate back-up (mcm/day)
2006/07	12.8
2007/08	13.1
2008/09	14.3
2009/10	19
2010/11	23.3
2011/12	26.3
2012/13	30.9
2013/14	34.1
2014/15	37.4
2015/16	41.8
2016/17	45
2017/18	48.3
2018/19	51.5
2019/20	54.7
2020/21	57.9

Source: Oxera.

In reality, the addition of extra distillate back-up will be lumpy, as and when new generating stations are commissioned. Explicit modelling of the profile of new entry into the generation market was beyond the scope of this study. The approach used will smooth some of the effects and will also overstate some flexibility that arises from higher utilisation of existing stations that would not have back-up fuel. While this may be unrealistic, the major impact of this measure will only arise when substantial new volumes of gas generation are available.

[75] The National Grid Gas Ten Year Statement 2006 has associated power generation consumption estimates that have been used out to 2015/16. The proportion of power generation to total gas use for the remainder of the period has been assumed to be as in 2015/16.

Thus, the change at the margin when there are small incremental changes will be immaterial and larger volume changes would be expected to correspond to new generation.

5.6.3 Results

The higher CCGT response has a striking impact on the investment profile, substantially lowering the investment in storage and delaying the introduction of additional import infrastructure to later in the period, as shown in Table 5.13, but it still represents a significant improvement in physical security against forced outages (as shown in Figure 5.21 and 5.23, where the expected forced outage is lower and the probability of an outage occurring is correspondingly lower). This is because the extra CCGT response substitutes for a large volume of potential storage, lowering the arbitrage opportunities that new storage infrastructure can exploit, and thereby reducing the incentive to invest.

Table 5.13 Investment profile out to 2020/21

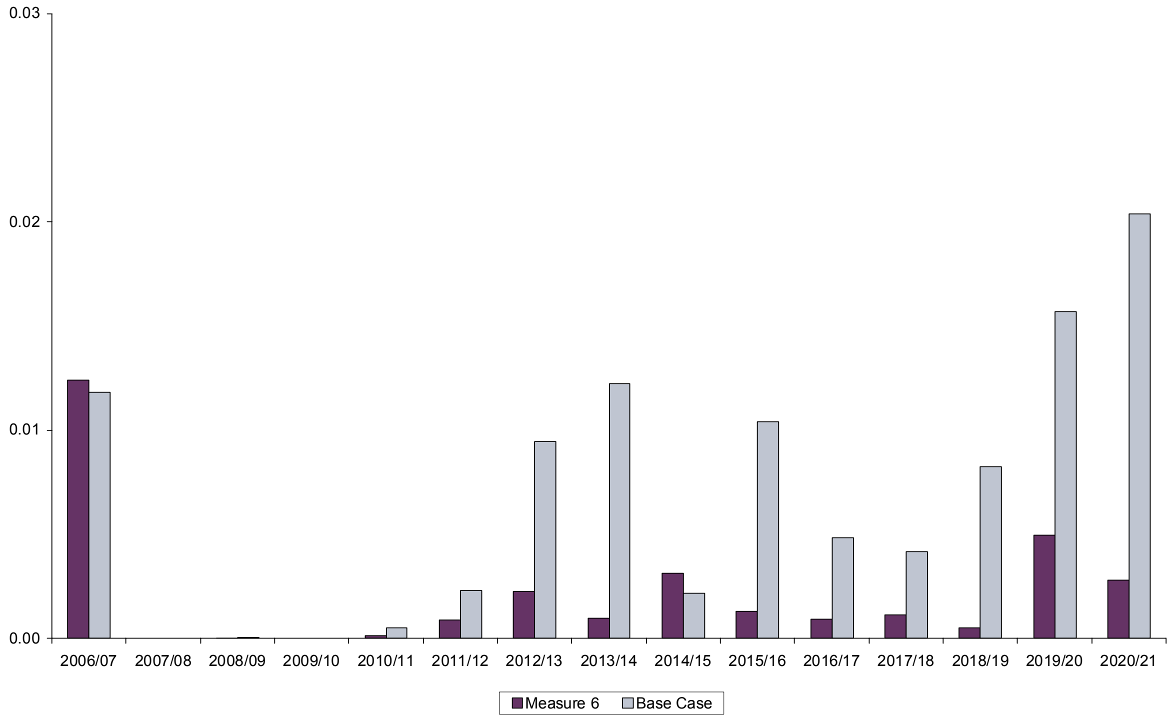
Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**5,165**	**100.4**
Norwegian import capacity	10,950	30
LNG import capacity	22,374.5	61.3
Total import capacity	**33,324.5**	**91.3**
Storage (additional to Base Case)	**–1030**	**–117**
Imports (additional to Base Case)	**–5550.5**	**–15.2**

Source: Oxera.

However, this places greater reliance on the ability of the electricity system to absorb and deal with gas supply shocks, since expected CCGT response volumes are between 10% and 20% higher than in other scenarios. This result may reflect the fact that it is more efficient to deal with gas supply shocks through adjustment in a related market where there already exists a more flexible supply infrastructure to respond to imbalance risks. However, the availability and cost-effectiveness of this alternative fuel option may alter over time as emission constraints become tighter and the generation fuel mix and capacity margins change.[76]

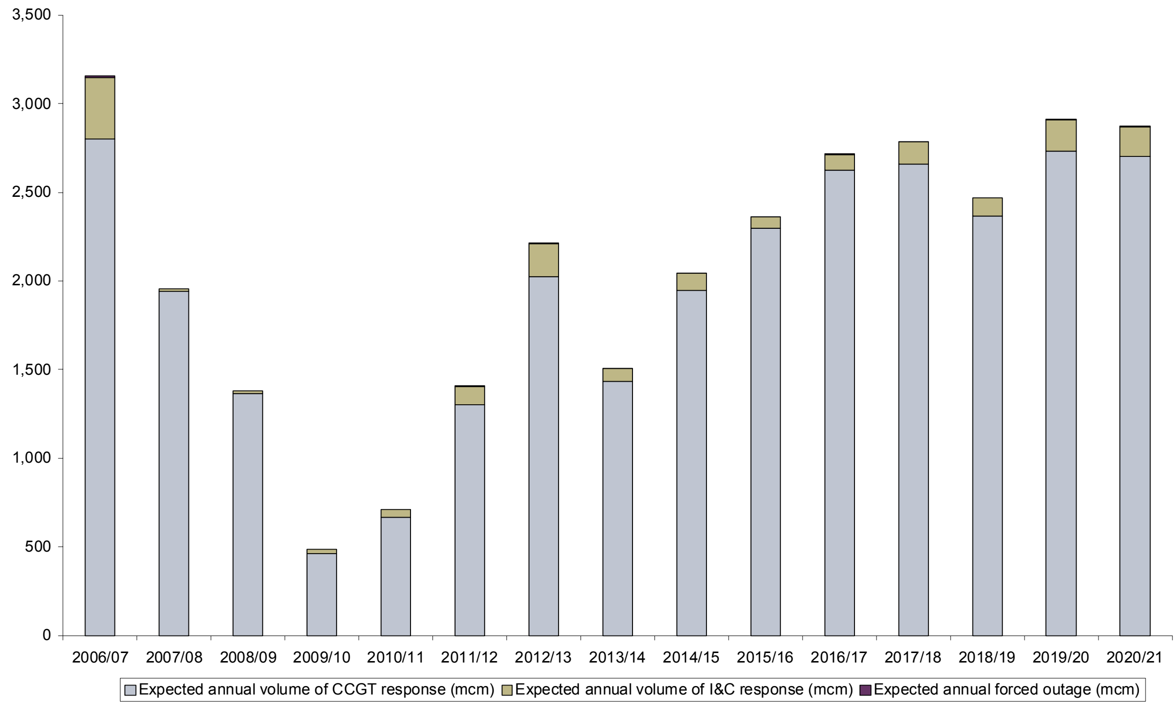
[76] The discussion in section 2.2.6 highlights the restriction of assuming fixed switching prices and volumes.

Figure 5.23 Comparison with Base Case: annual expected forced outage (% of demand)



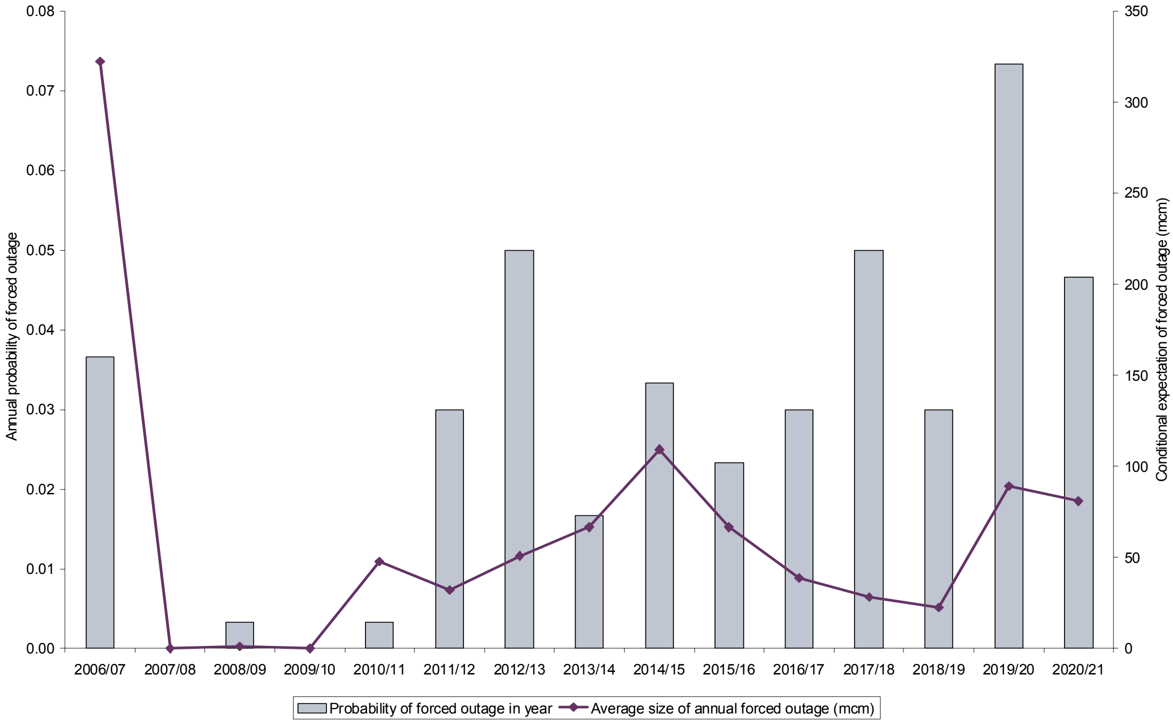
Source: Oxera.

Figure 5.24 Composition of expected demand adjustment (forced outages and demand response, mcm)



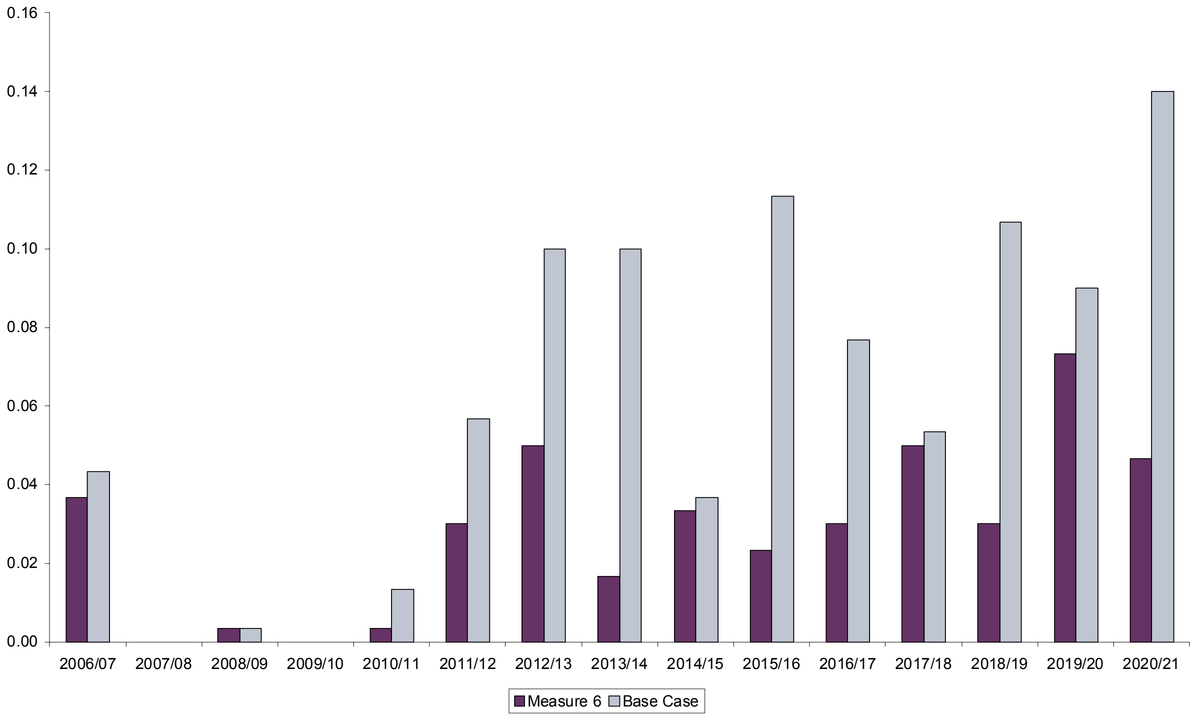
Source: Oxera.

Figure 5.25 Annual probability of a forced outage and the conditional expectation of annual outage size



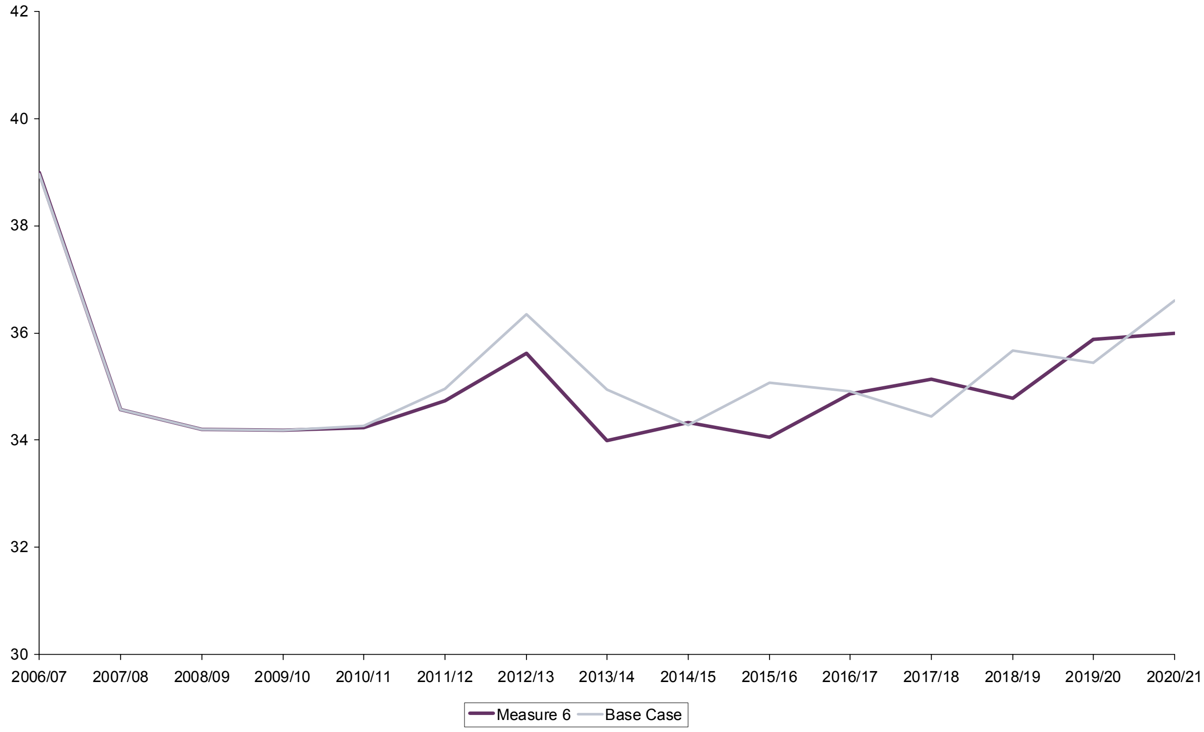
Source: Oxera.

Figure 5.26 Comparison with Base Case: annual probability of outages



Source: Oxera.

Figure 5.27 Comparison with Base Case: expected annual spot market price (p/th)



Source: Oxera.

Table 5.14 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	11.83	0.00	0.00	0.00	0.16	0.96	2.54	1.11	3.65	1.55	1.16	1.41	0.68	6.54	3.78
Probability of a forced outage	0.04	0.00	0.00	0.00	0.00	0.03	0.05	0.02	0.03	0.02	0.03	0.05	0.03	0.07	0.05
Conditional expectation of annual forced outage (mcm)	323	0	1	0	48	32	51	67	109	67	39	28	23	89	81
Maximum annual forced outage (mcm)	1,922	0	1	0	48	88	260	202	335	174	188	174	78	851	381
Expected number of days with forced outage	0.79	0.00	0.00	0.00	0.02	0.15	0.46	0.20	0.39	0.18	0.27	0.35	0.14	0.47	0.44
Expected annual volume of CCGT response (mcm)	2,800	1,942	1,364	462	665	1,304	2,025	1,434	1,945	2,299	2,625	2,658	2,365	2,732	2,702
Expected annual I&C response (mcm)	347	15	17	24	46	102	186	74	97	63	88	128	101	173	169

Source: Oxera.

5.7 Measure 7—smart gas metering

5.7.1 Description of measure

Measure 7 focuses on providing infrastructure and additional information that will enable customers to better understand their pattern of gas use and the cost implications, while also enabling suppliers to offer more efficient tariff options to reflect the variable marginal cost of gas. As a result, it may be expected that there will be a change in either or both the volume of gas consumed and the pattern of gas consumption across the year.

The major adjustments would be anticipated in the domestic sector, where gas is used mainly for space and water heating and cooking; the main change would be expected to occur in the heating load. There is scope for improvements in space heating through investment in other energy efficiency measures such as insulation, or by switching to a more efficient condensing boiler, which would create a one-off gain in absolute demand. However, it is not obvious that there are major gains to be made from changing the within-day profile of use, and the drivers of the seasonal demand patterns are not affected by this measure.[77]

5.7.2 Representation in model framework

It is assumed that the introduction of smart metering would manifest itself in a reduction in gas demand across the year and it is modelled as such in the simulation. There is little evidence available on the potential impact of smart metering in gas markets. Consequently, it has been assumed that the impact is a reduction of 5% in annual demand requirements of the domestic sector from 2010/11 (which translates to around a 1.7% reduction in total annual demand).

The reduction is not phased in during the scenario, but is assumed to have its full impact as soon as it enters. In reality, any roll-out of smart meter technology would occur over several years and the full benefit would not be felt until sufficient information had been provided on which individuals could make behavioural changes. Consequently, this measure overstates the impact of a smart metering scheme that is expected to provide around 5% reduction in domestic consumption, although it may similarly understate the magnitude of any anticipated response by the sector.

5.7.3 Results

The lower average demand results in a lower level of investment, as illustrated in Table 5.15 below. In particular, it lowers the storage investment undertaken because peak demand conditions are less extreme and hence there are fewer pricing arbitrage opportunities. The lower level of investment does result in higher probabilities of outages, particularly in later years (see Figure 5.31), but these outages are correspondingly smaller (Figure 5.30) and therefore the overall impact on expected forced outages is lower than in the Base Case (Figure 5.28).

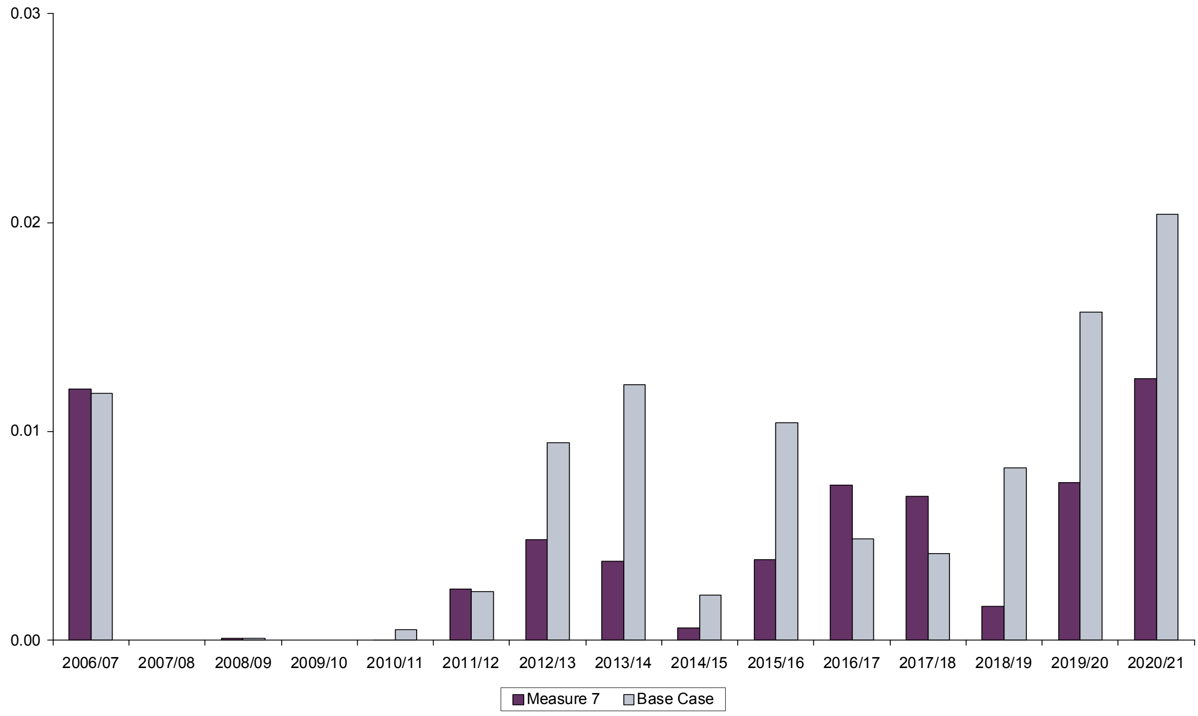
[77] Changes in load profile are more likely to arise in applications of smart metering in electricity.

Table 5.15 Investment profile out to 2020/21

Investment type	Annual capacity or space (mcm)	Maximum deliverability (mcm/day)
Total storage	**5,335**	**217.4**
Norwegian import capacity	10,950	30
LNG import capacity	21,900	60
Total import capacity	**32,850**	**90**
Storage (additional to Base Case)	**–860**	**0**
Imports (additional to Base Case)	**–6025**	**–16.5**

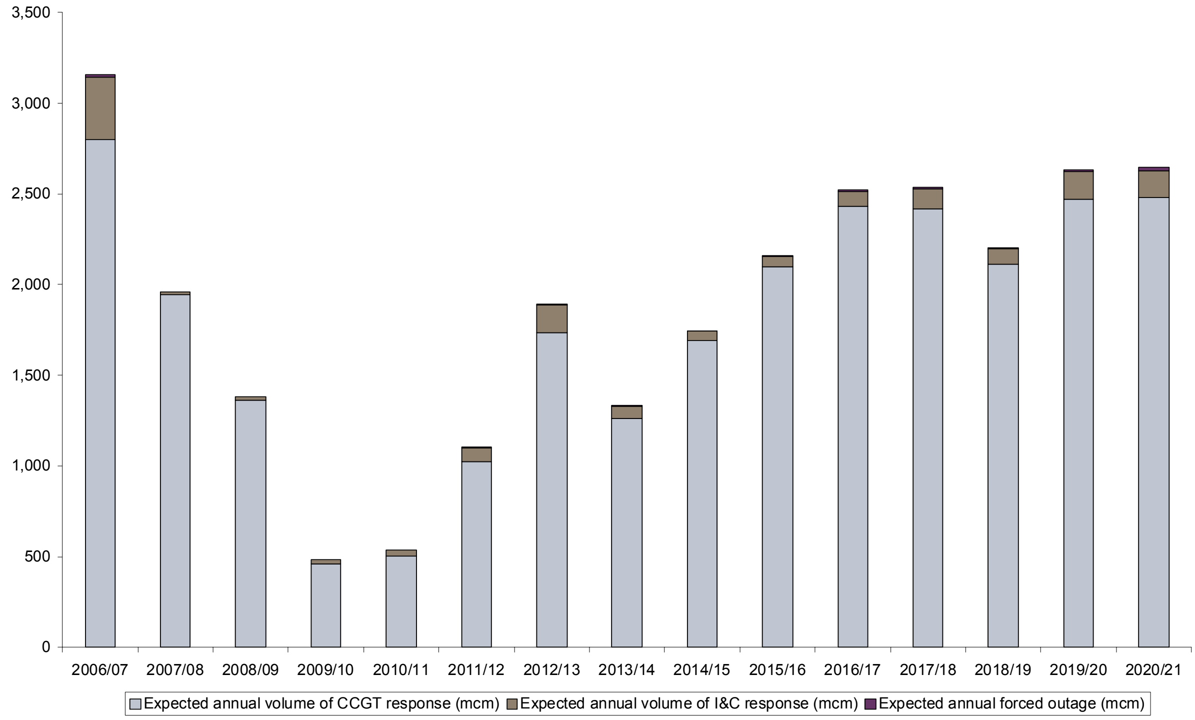
Source: Oxera.

Figure 5.28 Comparison with Base Case: annual expected forced outage (% of demand)



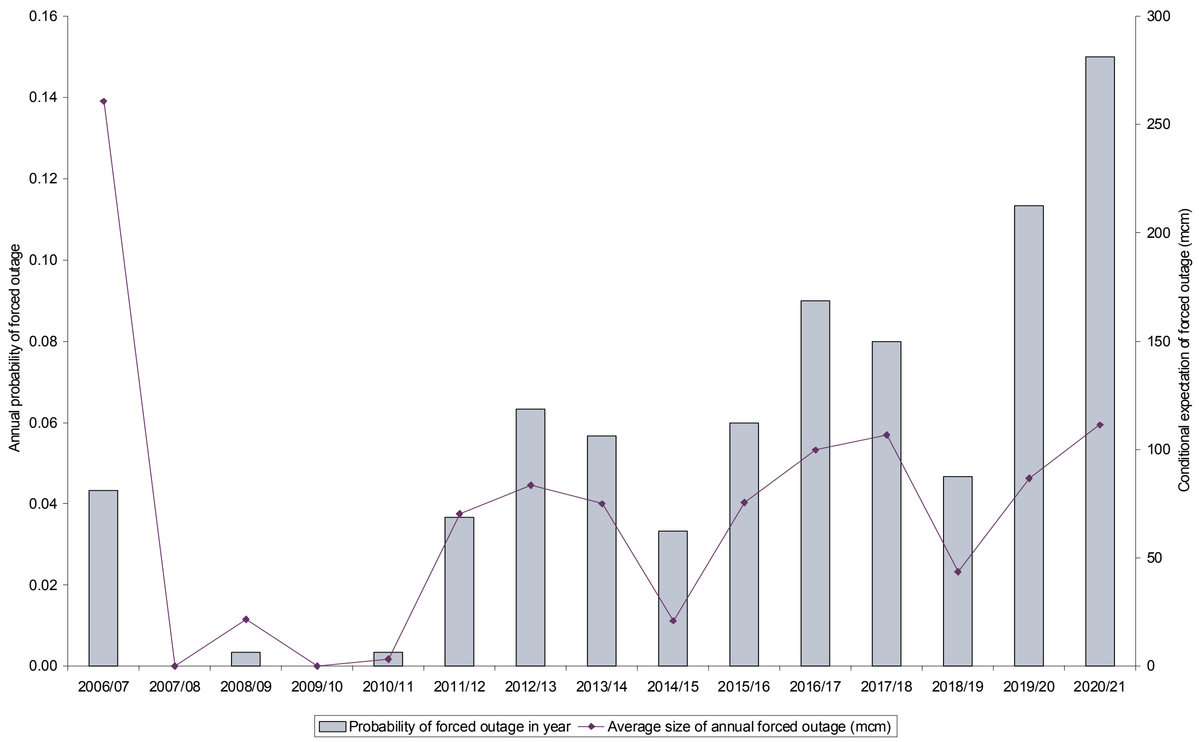
Source: Oxera.

Figure 5.29 Composition of expected demand adjustment (forced outages and demand response, mcm)



Source: Oxera.

Figure 5.30 Annual probability of a forced outage and the conditional expectation of annual outage size



Source: Oxera.

Figure 5.31 Comparison with Base Case: annual probability of outage

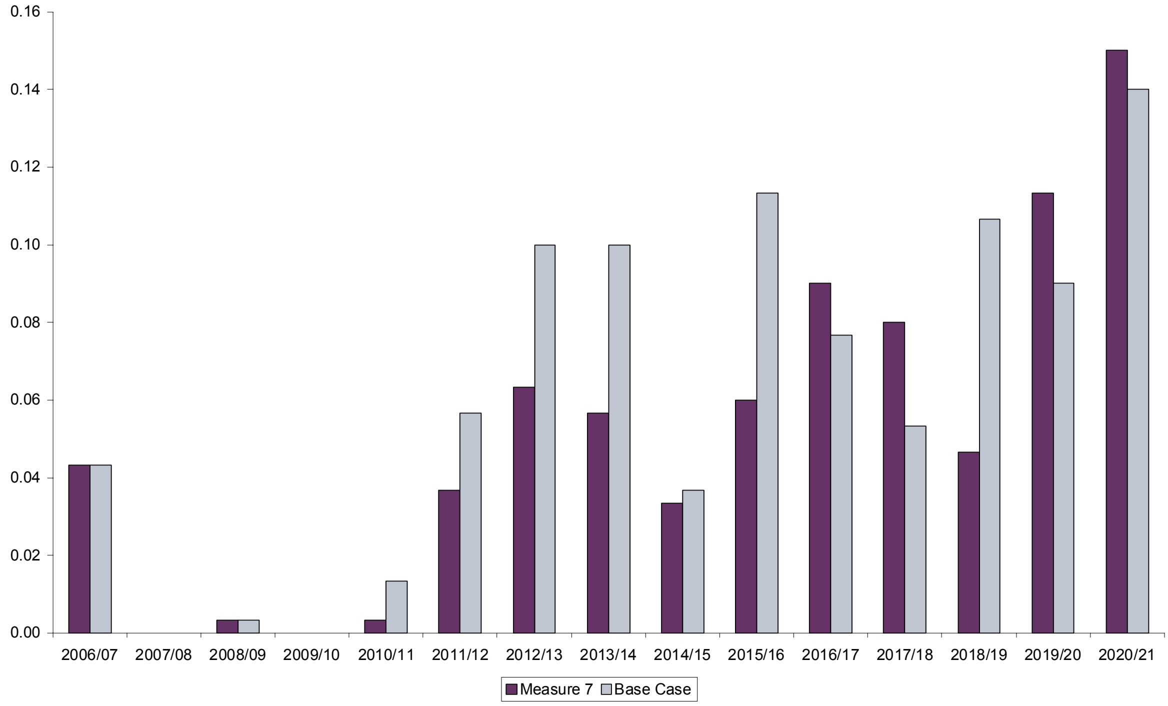
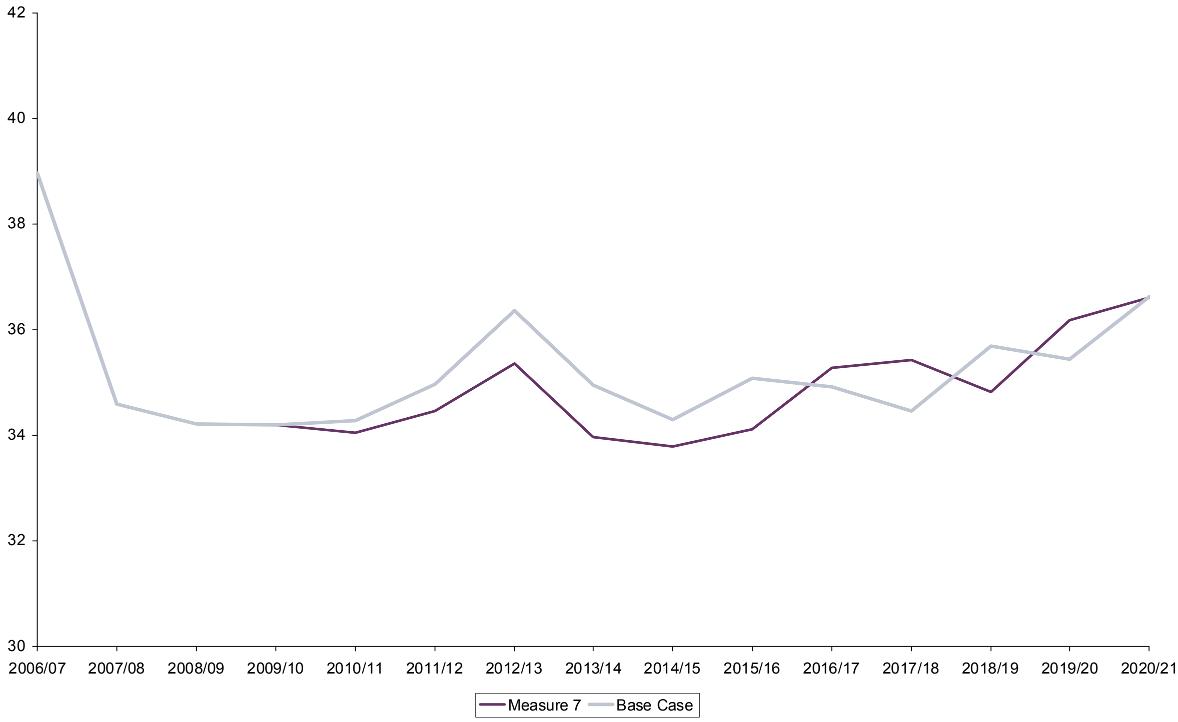


Figure 5.32 Comparison with Base Case: expected annual spot market price (p/th)



Source: Oxera.

Table 5.16 Summary supply shortfall statistics

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Expected annual forced outage (mcm)	7.59	0.00	0.00	0.00	0.01	2.58	5.29	4.25	0.70	4.53	8.98	8.53	2.04	9.82	16.70
Probability of a forced outage	0.02	0.00	0.00	0.00	0.00	0.04	0.06	0.06	0.03	0.06	0.09	0.08	0.05	0.11	0.15
Conditional expectation of annual forced outage (mcm)	325	0	0	0	3	70	83	75	21	76	100	107	44	87	111
Maximum annual forced outage (mcm)	1,763	0	0	0	3	533	383	894	121	308	625	629	153	535	551
Expected annual volume of CCGT response (mcm)	2,737	1,906	1,317	354	504	1,023	1,737	1,263	1,690	2,100	2,431	2,418	2,114	2,472	2,478
Expected annual I&C response (mcm)	307	10	12	17	33	78	149	65	54	57	82	111	85	149	152

Source: Oxera.

5.8 Summary comparison with the Base Case

The outturn physical security and prices in each scenario have been described above, together with some initial indication of their performance relative to the Base Case. In this final summary section, the main differences that arise between the Base Case and the measure scenarios are reiterated.

– The expected forced outages are generally lower—all measures lower the expected forced outage either by expanding the available flexible demand-side response or by enhancing new infrastructure provision. There are some significant outliers in one or two years, particularly in relation to measure 2.

– The probability of a forced outage is lower in all measures, with the exception of Measure 7—only in the low-demand situation is the probability of an outage higher than in the Base Case, and, even here, the average size of an outage is lower than that of the Base Case. This seemingly counterintuitive result arises because lower average demand (as seen in Measure 7) dampens price signals, causing investment to be delayed and the market to become more exposed to forced outages in order to create sufficient stimulus for new investment.

– Significant demand-side response is used in all scenarios—the level of demand-side response (particularly CCGT response) is uniformly high. It is only in Measure 4, where the guaranteed demand for additional gas to meet stringent obligations is sufficiently high to exhaust demand-side response and push expected prices up, that physical infrastructure investment replaces more flexible demand-side response, leading in the longer term to significant reductions in the use of CCGT response. Even in Measure 1, the differences that emerge are not significant and, where they arise, are identified with small differences in the timing of new infrastructure coming on line.

– Expected annual average spot prices show similarities—the patterns of prices are fairly comparable, allowing for some minor adjustments in the timing of infrastructure delivery. The exceptions are Measure 2, where the price is generally consistently above the Base Case (due to the extreme VoLL assumption that it uses), and Measures 1 and 4, where there is a discrepancy between the spot prices and the obligation-consistent prices on which investment decisions were made.

Therefore, while differences in investment and security performance across measures exist, they are often transitory timing differences. Therefore, it is necessary to quantify the effects in order to ascertain the real value of the measures considered. The background to this quantification is presented in Appendix 1, with the final cost–benefit assessment undertaken in section 6 and the conclusions from the analysis summarised in section 7.

6 Quantification of costs and benefits

The previous section described how the proposed measures altered the investment profile compared with the Base Case. For each measure, the impact of this alteration in the investment profile on expected annual forced outages and on expected annual wholesale gas prices was explained. Each of these elements imposes costs on the economy. There are costs in terms of lost output or utility when supply is interrupted, but, equally, there are costs associated with the level and uncertainty surrounding prices during the normal functioning of the market.

Whereas the simulated measures all appeared to increase gas security (using the expected annual forced outage metric), the benefit of this physical security improvement must be set against potential costs, whether they be higher prices in the market or substantial implementation costs associated with introducing the policy.

In this section, a quantification of the costs and benefits is undertaken, comparing the changes in the following elements of market performance relative to the Base Case:

– the expected cost of forced outages;
– the expected cost of industrial demand-side response;
– the change in consumer and producer surplus.

The NPV of each of these elements is calculated for each scenario using the public sector discount rate of 3.5%. The difference between the NPV of each scenario and the Base Case is then calculated and any known implementation costs are subtracted to produce the final net benefit associated with the policy.[78]

Environmental costs are not considered here. These may affect the benefit associated with Measure 6 (CCGT response)—where additional distillate operation would increase CO_2 emissions—and Measure 7 (smart metering)—where lower demand would reduce overall CO_2 emissions.

6.1 Forced outage costs

When a gas interruption occurs and consumers are involuntarily cut off, there is an associated cost that reflects the output or amenity forgone by the consumer as a consequence. The expected forced outage cost in any given year is represented as:

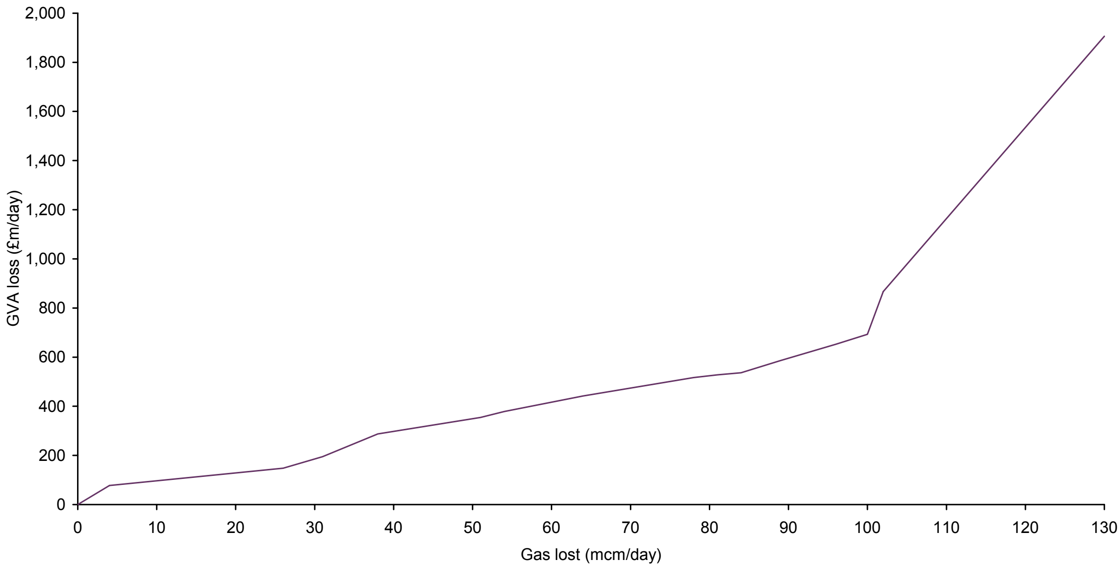
$$\text{expected forced outage cost} = \sum \text{(probability of interruption } i\text{) x (cost of interruption } i\text{)}$$

The price-security model provides probabilities of interruptions of different sizes and durations. To determine the cost of an interruption, Oxera has followed a similar methodology to that applied by Ilex Energy in its analysis of strategic storage for the 2006 Energy Review. Basically, the cost of an interruption is assumed to equal the gross value added (GVA) forgone as a consequence of lost output. Interruptions are assumed to follow a priority list of industries such that the marginal cost of interruptions increases with larger interruptions as higher value-added industries (in terms of GVA/unit of gas consumption) are affected.

[78] As discussed in section 5, Measure 3 (regulating storage) has not been analysed in the same way as the others and hence there are no comparable results. However, the analysis suggested that there may be significant detrimental impacts on investment incentives associated with the implementation of Measure 3, and thus it is not considered a viable alternative.

This is illustrated in Figure 6.1. The full analysis of the cost of interruptions is presented in Appendix 1.

Figure 6.1 Estimated forced outage cost (£m/day)



Note: This figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction and miscellaneous sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; Oxera calculations.

Table 6.1 presents the expected annual forced outage costs under each scenario. This is calculated by multiplying the cost of each outage type (ie, size and duration) as presented in Table A1.7, by the probability of that event occurring. It shows that, in the Base Case scenario, expected forced outage costs were in the order of £1.26 billion over the period from 2007/08 to 2020/21, rising significantly towards the end of the period under investigation as investment failed to match the impact of falling UKCS supply and demand growth.

Table 6.1 Expected forced outage costs by scenario (£m)

	Base Case	Measure 1 Supplier obligation	Measure 2 Cash-out pricing	Measure 4 Capacity mechanism	Measure 5 Industrial DSR	Measure 6 CCGT response	Measure 7 Smart metering
2006	137.4	148.3	148.1	133.4	100.1	149.4	95.3
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.1	0.0	0.0	0.1	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	2.3	0.2	7.0	1.6	0.1	0.7	0.0
2011	11.8	2.9	38.8	3.2	9.5	3.0	30.7
2012	96.8	29.5	33.3	1.0	43.0	10.7	32.6
2013	214.5	87.3	63.6	20.4	55.6	6.3	68.5
2014	20.1	17.5	17.6	1.2	8.7	49.3	2.3
2015	173.4	28.0	94.2	0.2	60.4	10.2	54.2
2016	45.9	77.2	5.7	21.5	25.3	5.7	95.5
2017	110.8	76.1	25.3	1.5	25.3	6.0	92.8
2018	123.8	63.4	259.9	328.4	57.9	2.5	10.2
2019	456.1	148.0	619.3	0.3	285.4	88.5	115.8
2020	611.9	704.0	1052.4	0.9	315.4	42.5	202.6
NPV (2007/08–20/21)	1,262	808	1,438	256	589	154	485

Source: Oxera.

Table 6.2 presents the NPV over the period 2007/08 to 2020/21 of the incremental benefit associated with implementing the measure compared with the baseline (ie, it is the difference between the NPV of the outage costs over the period in the Base Case and the appropriate measure). From observation of Table 6.1, it may be concluded that there is very little impact of implementing measures at this point, since differences in forced outage costs do not start to emerge until the period after 2012/13. Although this may be the case, the long lead time for investment and the importance of policy certainty credibility may imply action would still be necessary over the next few years, in order that any medium-term benefits could be realised.[79]

Table 6.2 shows that, with the exception of Measure 2, all the measures produce a benefit in terms of lower expected forced outage costs.

Table 6.2 NPV of incremental benefit of reducing forced outages (£m, 3.5% discount rate)

	NPV (£m)
Measure 1 (supplier obligation)	454
Measure 2 (cash-out pricing)	–176
Measure 4 (capacity mechanism)	1,005
Measure 5 (industrial DSR)	673
Measure 6 (CCGT response)	1,107
Measure 7 (smart metering)	777

Source: Oxera.

[79] This would be to allow sufficient time for investors to respond to the changed market incentives.

6.2 Industrial demand-side response costs

Table 6.3 shows the industrial demand-side response costs. It is assumed that these costs have not been fully captured in the price signals in the market, as has been argued for the CCGT response, since there may be additional externalities associated with the interruption of production. Without any further evidence, the industrial demand-side response is assumed to impose a cost on the economy equivalent to the offer price in the market. As can be seen, these costs are an order of magnitude lower than the forced outage benefits. As already highlighted in section 5, the use of demand-side response is similar across all scenarios with the exception of Measure 4, where the greater physical supply capacity reduces the need to rely on demand-side response.

Table 6.3 Expected demand-side response cost (£m)

	Base Case	Measure 1 Supplier obligation	Measure 2 Cash-out pricing	Measure 4 Capacity mechanism	Measure 5 Industrial DSR	Measure 6 CCGT response	Measure 7 Smart metering
2006	61.6	61.9	61.8	61.2	69.1	61.9	53.3
2007	2.5	2.5	2.5	2.5	2.7	2.4	1.6
2008	2.9	2.8	2.8	3.0	3.1	2.8	1.9
2009	3.9	3.9	3.9	4.0	4.2	3.9	2.7
2010	7.8	7.8	7.8	7.6	8.3	7.6	5.5
2011	19.3	18.6	16.5	13.4	21.6	17.7	13.7
2012	37.1	29.5	15.2	8.7	42.3	32.8	26.8
2013	19.0	14.9	11.7	9.2	18.4	13.1	12.6
2014	13.5	11.7	9.0	9.6	13.0	18.0	9.7
2015	18.3	10.6	11.7	4.0	18.8	11.6	11.8
2016	15.0	10.0	6.1	6.0	17.8	16.6	17.8
2017	14.8	18.3	14.1	9.4	17.6	22.7	21.6
2018	21.0	14.7	15.1	11.1	26.1	17.4	15.9
2019	19.5	17.3	16.6	8.1	22.7	30.2	28.5
2020	27.4	26.6	25.6	6.9	32.8	29.4	29.4
Total (NPV 2007/08–2020/21)	165	140	117	79	184	166	144

Source: Oxera.

As with the forced outage costs, the incremental benefit is calculated and shown in Table 6.4. As would be expected, Measure 5 leads to a higher cost of demand-side response, as there is more of this demand-side flexibility available and used in the scenario.

Table 6.4 NPV of incremental demand-side response benefits, 2007/08 to 2020/21 (£m, 3.5% discount rate)

	NPV (£m)
Measure 1 (supplier obligation)	24
Measure 2 (cash-out pricing)	48
Measure 4 (capacity mechanism)	86
Measure 5 (industrial DSR)	–19
Measure 6 (CCGT response)	–1
Measure 7 (smart metering)	20

Source: Oxera.

6.3 Pricing effects

In addition to influencing the likelihood of physical interruptions, the policy initiatives will affect the outturn prices in the market, and, hence, will have an incremental impact on welfare. These welfare effects will accrue to various market participants in the form of changes in consumer and producer surpluses.

For each measure the pricing impact relative to the Base Case is assumed to be as follows:

pricing impact = change in consumer surplus + change in producer surplus
– change in import costs

The *consumer surplus* here is defined as the consumer's willingness to pay for a quantity of gas *less* the amount they actually pay for it. The *producer surplus* is the price that producers receive for gas sold *less* the price at which they would have been willing to sell varying units of gas. Net import costs are included since producer surplus accruing to non-UK producers supplying to the UK will not contribute to the welfare of the UK market participants. A more complete description is included in Appendix 1.

For Measures 1 and 4, the price used to compare with the Base Case is the price assuming that the 1-in-30 and 1-in-50 demand requirements respectively are binding. That is, it reflects the costs incurred by the suppliers in meeting the security standards, rather than the outturn spot price, as these two series differ in these scenarios.[80]

The approach used to estimate the consumer and producer surpluses differs for Measure 7 (smart metering) in comparison to that used for the other policy measures, reflecting a different mechanism that leads to changes in prices and quantity demanded. Whereas price changes in the other measures are assumed to result from shifts in the supply curve, with the demand curve remaining fixed, the introduction of smart metering also leads to an inward shift of the demand curve. The interactions between demand and supply shifts then lead to an increase or a decrease in prices.

Therefore, in the case of Measure 7, changes in consumer and producer surpluses arising due to shifts in the demand curve do not reflect welfare changes. The inward shift in the demand curve may instead lead to positive income effects. Changes in consumer and producer surplus in the case of Measure 7 are estimated at the new demand curve, and may underestimate welfare changes inasmuch as these income effects are excluded.

Across all the policy measures evaluated, the change in welfare is largely reflective of the different investment profiles that arise[81] and this illustrates the trade-off present in any market decision on security of supply—greater security is usually associated with a higher cost or price for the product (effectively, a higher insurance premium).

This argument appears to be contradicted by Measures 5 to 7, all of which have shown an increase in security, but also appear to show a rise in welfare. This is largely because any benefit they provide is delivered from investment outside the gas delivery infrastructure. This investment can be estimated for Measures 6 and 7 and therefore, in these two scenarios, these external investment costs are added as implementation costs.

[80] In the other scenarios the two are equivalent, given assumptions on perfect foresight.

[81] Apart from Measure 2, where higher prices are a result of an assumed higher cost of interruption that feeds through into wholesale price expectations.

Table 6.5 NPV of welfare changes (£m)

	Change in			
	consumer surplus	producer revenue	producer revenue going overseas	aggregate welfare
Measure 1 (supplier obligation)	–907	775	523	–655
Measure 2 (cash-out pricing)	–5,062	4,248	3,466	–4,244
Measure 4 (capacity mechanism)	–4,249	3,625	2,521	–3,145
Measure 5 (industrial DSR)	857	–735	–540	661
Measure 6 (CCGT response)	1,109	–953	–676	832
Measure 7 (smart metering)	1,137	–974	–619	782

Note: NPVs are measured from 2007/08 to 2020/21.
Source: Oxera.

6.4 Implementation costs

The implementation costs of many of these measures are uncertain and further work may be required if some measures appear marginally beneficial. In only two cases has it been possible to quantify the implementation costs:

– CCGT response—the volume of incremental CCGT response equates to around 19GW of additional gas-fired plant by 2020/21. The estimated capital cost of installing back-up fuel capability is estimated at between £3.23 and £3.85m for a 390MW unit, from previous work carried out for the DTI;[82]

– smart metering—in the 2006 Energy Review, the DTI estimated a range of £5 billion to £8 billion as the cost of rolling out smart metering in the UK. Although there are less households with a gas meter than an electricity meter, studies indicate that the costs of smart gas meters are higher than those of electricity, and hence a cost of 50% of the total has been assumed to relate to the gas industry. Oxera's assumptions on the costs of smart metering may not correspond with the latest DTI views.

6.5 Summary

Table 6.6 summarises the results of the elements of cost and benefit presented above. It suggests that only the demand-side measures (5 and 6) would produce substantive benefits. The net cost associated with Measure 4 may be a function of assuming too high a level on the capacity obligation.

[82] This includes estimated capital costs for a dry-tank installation of between £3m and £3.4m and holding costs for between five and ten days of distillate stock of £0.23m to £0.45m (at a 10% discount rate and assuming a distillate price of £250/tonne).

Table 6.6 Summary of cost–benefit assessment, 2007/08 to 2020/21

	Reduced interruption costs (NPV over 15 yrs)	Increase in welfare (NPV over 15 years)	Implementation costs (where known)	Reduced demand-side response cost (NPV over 15 yrs)	Net benefit
Measure 1 (supplier obligation)	£454m	–£655m	Licence amendment plus monitoring	£24m	–£177m
Measure 2 (cash-out pricing)	–£176m	–£4,244m	Changes to Code Contract renegotiations?	£48m	–£4,372m
Measure 4 (capacity mechanism)	£1,005m	–£3,145m		£86m	–£2,054m
Measure 5 (industrial DSR)	£673m	£661m		–£19m	£1,315m
Measure 6 (CCGT response)	£1,107m	£832m	£124m to £147m	–£1m	£1,814m to £1,791m
Measure 7 (smart metering)	£777m	£782m	£2.5 billion to £4 billion	£20m	–£2,421m to –£921m

Source: Oxera.

7 Conclusions

The aim of this study has been to assess the implications of proposed policy measures for security of gas supply. Gas supply interruptions affect economic welfare not only through loss of productive capacity, but also through the impact that the perceived risk of interruptions has on market prices. Consequently, the analysis has sought to capture not only the risk of forced outages on the gas system, but also the price distributions associated with the underlying supply–demand balance.

Over time, the supply–demand balance will evolve in response to growth in gas demand and the availability of gas supply from different sources. The supply position will be linked closely to the pattern of new infrastructure commissioned in response to market signals, and capturing the underlying investment dynamic is central to the analysis. The proposed measures affect the private sector investment decision either directly or indirectly through their impact on price formation (and hence investment signals) or on the risk associated with different types of investment, and thus have an impact on the physical and pricing aspects of supply security.

Some substantive new import infrastructure has already been commissioned and the consequent relaxation of the supply–demand constraint is already evident in recent movements in the forward markets. However, the combination of growing demand and declining UKCS production means that new infrastructure will be needed from around 2013/14 and additional flexibility may be required before this (in the form of storage, since demand-side response volumes are fixed).

The Base Case scenario simulates a large infrastructure investment programme over the period from 2012 to 2020, amounting to around £5.4 billion over the period and leading to:

– a 150% increase in storage space (leaving total storage capacity at over 8% of annual demand by the end of the period);

– an additional 38bcm of import capacity, the majority of which is provided by new LNG import terminals that therefore add to the diversity of both import routes and potential suppliers.

This new investment has a material impact on the expected annual volume of forced outages on the system. In 2006/07 the expected annual forced outage was 11.3mcm, and it is broadly at or below this level up to 2018/19. This is not because the probability of a forced outage is lower, but because the severity of outages when they occur is considerably less. For example, in 2006/07, the expected size of a forced outage is 261mcm, and the maximum outage simulated is 1.9bcm. This compares with 2018/19 where there is a 1-in-9-year chance of a forced outage, but the expected size of an outage is 100mcm and the maximum outage is simulated as around 567mcm. Although outages are relatively infrequent and do not represent a sizeable proportion of annual gas demand, they are costly. The NPV of the forced outages in the Base Case is £1.26 billion.

The proposed measures are intended to improve the level of security of supply by increasing the level, or accelerating the timing, of additional investment, and therefore lead to a system where the exposure to forced outages is lower.

The analysis undertaken has been designed not only to investigate whether the proposed measures would improve security of supply, but also whether this improvement produces a net benefit to society, since the investment decisions also affect economic welfare through their impact on prices. The findings differ for each measure considered.

Measure 1—Expanding the scope of supplier obligations to include industrial and commercial customers

The impact of extending the supplier obligation is slightly negative over the period analysed. While leading to an improvement in security of supply, the pricing effects offset this benefit. With no account taken of implementation costs, the net cost is likely to be larger in reality.[83] However, this does not mean that an extension to the supplier obligation may not be a viable long-run alternative, only that it may need to have a lower required threshold.

Measure 2—Sharpening cash-out incentives under normal arrangements

An increase in the expected VoLL not only increased investment volumes, costs and prices substantially, it also did not improve security of supply. This latter effect may, in part, be a result of the modelling approach, but even removing all expected outages would not offset the observed price effects.

However, the model does show that, if market participants are credibly faced with higher costs of imbalance, then further investment may be forthcoming. There may, nevertheless, be unintended consequences from such a policy. The only reason to change the cost of imbalances is if there is an existing market failure, such that the current price does not fully reflect the cost of the imbalance. If there is no market failure, or if the extent of the market failure cannot be quantified satisfactorily, the VoLL imposed may be inefficiently high. In these circumstances, inefficient investment may be undertaken.

Furthermore, credibility of the cost is important. If market participants do not believe that they will be faced with these costs, they will discard them from their decision-making.[84]

One way of introducing more credibility and greater transparency in imbalance costs may be to guarantee the continuation of the balancing regime in all circumstances and require all demand- and supply-side participants to submit bids for every period. Even if these prices were extreme, it would signal the VoLL on both sides of the market at all points in time and would make the exposure to high imbalance charges more credible.[85]

Measure 3—Regulate the use of storage

The proposal to constrain individual shippers' use of storage facilities is interventionist and assumes that government is better able to determine the best use of a portfolio of flexibility options than individual market participants. Since there is no informational advantage, this additional distortion would appear to be detrimental to the efficient operation of the market. The initial results, however, indicated that the regime could improve security of supply, but this did not account for the distortion to the market investment signals that the measure would produce. The analysis showed clearly that the incentive to invest in new storage facilities would be compromised by this approach and therefore it is not considered a viable market-based policy instrument.

Measure 4—Introduce gas capacity mechanisms

The introduction of a capacity mechanism resulted in significant reductions in forced outages. However, this was largely due to the severity of the obligation imposed—sufficient to meet all

[83] It should be remembered that the obligation-consistent wholesale prices have been used in the welfare calculation, as it has been assumed that suppliers will pass on the costs of the forward contracts they have signed to ensure compliance with the obligation.

[84] Such a situation might arise if the high costs are only likely to be incurred when major system outages occur and these events are considered to be quasi-public goods.

[85] An additional cost–benefit assessment of such a scheme has not been undertaken and would be necessary before any firm conclusions on its attractiveness could be taken.

demands in a 1-in-50 severe winter—and the benefits in terms of improved security were more than offset by the welfare losses from the price effects.[86]

The measure was implemented in the same manner as Measure 1 (supplier obligation) and therefore could be interpreted as a sensitivity on the level of any new obligation. The negative results would suggest that, if considered, a lower obligation than that currently modelled in Measures 1 or 4 may be more appropriate.

In addition to coverage, another difference between Measure 1 and Measure 4 was the possibility for the latter to be implemented with the responsibility for delivering the obligation vested in a single body. The modelling approach has no way of effectively distinguishing these approaches. However, while the imposition of the obligation on a single entity, such as a system operator, may reduce administrative and monitoring costs, it would also run the risk of crowding out private sector investment or inducing moral hazard—ie, the private sector acts in such a way that reserves committed to the capacity mechanism are more likely to be called upon. Only if the situations where the reserved capacity would be released onto the market (and the terms on which it would be made available) are known and independent of the day-to-day operation of the market would such a mechanism not run that risk.

Measure 5—Encourage demand-side response from I&C customers

The measures that focus on improving demand-side flexibility either in the industrial sector (Measure 5) or in the power generation sector (Measure 6) appear to be the most beneficial policy options. This is because they remove the need for costly capital investment while providing a similar degree of flexibility in the marketplace.

However, these results need to be considered in their appropriate context. First, in order to be able to offer the type of flexibility required without having an adverse effect on output, firms must undertake additional investment in their manufacturing processes—this is not captured as a cost in the analysis. Second, the extent to which additional volumes are accessible to firms and to the gas market is unclear. There may be little or no additional capacity available, or at least at the prices assumed in the modelling.

Third, the ability to offer these volumes over sustained periods of time is untested. In the model, demand-side response may be required for more than two weeks continuously and there is no firm evidence that the volumes observed during winter 2005/06 (on which the volumetric assumptions were based) would be capable of providing that degree of flexibility over that time period.

Finally, regardless of whether there is substantial untapped demand-side potential in the I&C market, the effectiveness of policies to encourage this flexibility to market has not been assessed.

Measure 6—Encourage the installation of back-up fuel capability at new CCGT power stations

Encouraging back-up fuel capability on new CCGT power stations emerges as the most beneficial of the proposed policies. Once again, this is partly because the additional flexibility provided avoids major infrastructure investment in the gas chain. The capital costs of fitting back-up firing capability are a relatively small proportion (around 3%) of the total capital cost of a new CCGT, and would be unlikely to impose significant changes to electricity investment decisions.

The main reason for the strong performance of this measure is that high volumes are assumed to be available over prolonged periods—the majority of demand-side response in

[86] As for Measure 1 (supplier obligation), the obligation-consistent prices have been used in the pricing calculations.

the model is from CCGTs, and it is expected to provide volumes equivalent to over 2% of annual gas demand, with large contributions over several weeks during the peak winter periods. The practicality of such an operation may be open to challenge, particularly if developments in the electricity market mean that there is less scope for portfolio switching either due to the changing generation mix or the changing relative fuel prices.

This latter point also highlights a further issue: a substantial proportion of CCGT response is available at a relatively low price. The model has assumed a fixed, relatively low, price for non-distillate CCGT response. If relative fuel prices change, this would affect the price at which demand reduction is available, and hence have a knock-on impact across the supply curve and wholesale and retail prices.

However, allowing for these caveats, additional flexibility from the power generation source would appear to have a very strong benefit to the economy. Since the investment is a low proportion of total outlay, the main driver of the investment decision currently resides in the electricity market. Imposition of such a measure may only be necessary if the commercial incentives do not appear to be sufficient in the electricity market, and if it is thought that the additional benefit to the gas market is not fully reflected in that commercial decision.

Measure 7—Smart gas metering

Technically, Measure 7 (smart metering) reduced actual demand rather than increasing available demand-side flexibility. However, the implication (a larger buffer before existing supply infrastructure is insufficient to meet demand) is the same as for the other demand-side measures.

The major uncertainty surrounding the proposed development of smart metering technology is the effectiveness of the measure in the gas market. Whereas there have been numerous studies on the electricity market, evidence in the gas market is more sparse. If potential demand reductions are more significant, and/or the costs of the technology fall, the proposal would be more cost-effective. Furthermore, the costs and benefits presented for Measure 7 are derived from Oxera methodology and do not necessarily correspond with latest DTI views.

Summary

In summary, the analysis indicates that there is no substantial benefit from the measures designed to bring forward additional infrastructure investment at this time. However, measures designed to increase the flexibility of the demand side would seem to be cost-effective options to pursue. There is limited additional cost and even if the extent of the benefit attributed to power generation or industrial demand-side response is overstated in the analysis, the measures would still be likely to produce a net benefit to gas security of supply.

A1 Assessing the value of the proposed measures

The ultimate aim of this study is to assess how the proposed measures identified in the consultation affect underlying security of supply in terms of both physical outages and pricing behaviour.

Section 5 above describes the results from the price-security model for the measures and describes two key characteristics:

– outage distributions—the risk of there being actual physical shortages of supply of specific magnitude and duration;
– the potential behaviour of prices in the market.

These characteristics both impose costs on the economy. There are costs in terms of lost output or utility when supply is interrupted, but, equally, there are costs associated with the level and uncertainty surrounding prices during the normal functioning of the market. The primary goal of the cost–benefit framework is to provide some quantification of the net benefit associated with changes in these characteristics as a consequence of the new policies.

With this quantification and any additional implementation costs associated with policies, an NPV can be calculated over the relevant time period (and using an appropriate discount rate). To estimate this NPV, it is necessary to transform the outage and price distributions (or, more correctly, the changes in those distributions relative to the Base Case) into a quantifiable cost to the economy.

A1.1 Valuing changes in physical security of supply

When a gas interruption occurs and consumers are involuntarily cut off, there is a cost associated with this that reflects the output or amenity forgone by the consumer as a consequence. If this cost of interruption is known, the benefit associated with a policy intended to improve security of supply is:[87]

$$\text{benefit} = \text{change in probability of interruption} \times \text{cost of interruption}$$

the change in the probability of an interruption being derived from the security model.

There is, however, a wide range of interruptions of different sizes and durations that may occur, and hence the benefit is more correctly represented as:

$$\text{Benefit} = \sum \text{(change in probability of interruption } i\text{)} \times \text{(cost of interruption } i\text{)}$$

As is illustrated in many of the studies on the costs of interruption in the electricity system, the costs depend on the type of outage that occurs. Relevant dimensions include:

– size of the outage;
– duration of the outage;
– time of day/year;
– numbers and type of consumers affected;
– advance warning of the event.

[87] This formulation is not dependent on the level of risk aversion. The impact of risk aversion would be on the cost of the interruption (ie, the translation of the income loss into a welfare cost).

Measures of the VoLL in electricity are constructed as weighted averages of alternative types of events and their associated customer interruption costs. A single VoLL figure can therefore be applied to an expected energy unserved measure. With no equivalent VoLL figure existing for gas outages, the approach taken is therefore to map a cost of interruption function onto the probability distribution of outages. Thus, for an interruption of a specific size and duration, there will be an associated unique cost of that interruption.

A1.2 Calculation of the physical outage costs

When calculating the cost of any gas supply interruption, it is important to identify which customer groups are affected. In principle, there are five broad categories of consumer that differ not only in their reliance on gas (and the costs imposed by an interruption), but also in the ease with which they can be interrupted:

– power generators;
– industrial consumers;
– commercial consumers;
– public sector consumers (including schools and hospitals);
– residential consumers.

The basis of the cost of interruption calculation is the creation of a priority list of interruption across the sectors and within sectors on the basis of the associated costs of interruption for the industry/sector as appropriate. With this construct, any combination of (mcm/day, duration) interruptions can be translated into an implied cost of interruption.

It is assumed that interruptions to power generators do not impose any additional direct costs on the economy because they do not result in any curtailment of production (any interruption to power generation is on a voluntary basis); and because the pricing effect is already captured in the gas price calculation and therefore the cost is felt in changes to consumer surplus and welfare as a result of price changes.[88]

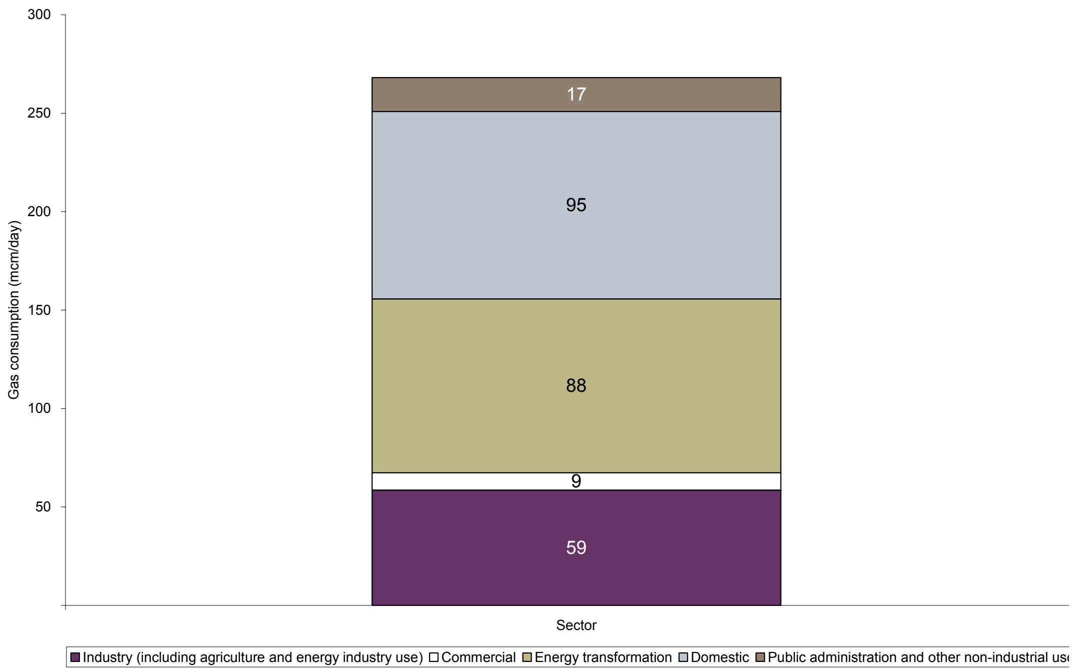
As such, the focus here is on the industrial sector interruption costs, on the assumption that:

– all daily-metered sites would be interrupted before NDM sites. Thus, despite being the largest consumers of gas (as shown in Figure A1.1), residential customers would be the last to be interrupted due to the exceedingly high costs associated with interrupting them. For different reasons, it is also assumed that public sector consumption is maintained;

– the cost to industrial customers is inferred from an analysis of the gross value added (GVA) lost due to an interruption, in a similar manner to that proposed by Ilex Energy in its earlier study (although it is recognised that GVA may both overestimate and underestimate the true cost, depending on the circumstances).

[88] The same is not considered to hold for industrial demand-side response, as the demand reduction may have implications for production decisions; and it is less obvious that the price at which interruption is offered fully reflects the costs of interrupting supply for any prolonged period of time, due to the externalities imposed upstream and downstream on firms that are involuntarily cut off.

Figure A1.1 Gas demand by different sectors, 2005



Note: The daily gas demand estimates are an annual average, with the 2004/05 peak demand of around 532mcm/day in 2004/05 being nearly twice the average annual demand of 268mcm/day. The average annual demand figures are not representative of the annual demand profile of consumers, which varies considerably across the year, particularly when winter and summer demands of residential consumers are compared.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2 and National Grid (2006), 'Gas Transportation Ten Year Statement 2006', December, Table 3.5D.
Source: Oxera.

The costs of an interruption of gas supply to the industrial sector are expected to arise due to the curtailment in production resulting from the interruption. One measure of these costs is the GVA forgone by the industry or sector in question. The withdrawal of gas supply from an industry is assumed to lead to a one-for-one loss in that industry's output and GVA. Therefore, an interruption of 10% of an industry's gas supply is considered to reduce its GVA by 10%.[89] In addition to this direct cost placed on the industry interrupted, there are two impacts, on:

– **electricity demand**—the reduced output by an industry due to an interruption in its gas supply would imply that the industry's demand for electricity would decrease to the extent that its output has been reduced, which would in turn lead to a reduction in gas demanded by gas-fired electricity generators;

– **related industries**—the ability of industries upstream and downstream of the interrupted industry to produce output will be affected.

Given a shortfall of gas supply, the optimal sequence for consumers to be interrupted would be in declining order of their gas consumption per unit of GVA, such that those consuming most gas for each unit of GVA should be interrupted first. However, it is unclear whether any scheduling of gas interruptions would automatically follow this optimal pattern. For example, it may be physically easier to interrupt the intensive gas users. As such constraints to this optimal order are imposed, an assumption is made that intensive users are likely to be interrupted before non-intensive users. Within these categories, however, the interruptions

[89] This relationship would be affected by assumptions on back-up fuel capability within the industry, which would allow production to continue and reduce the GVA loss suffered. However, it is assumed that such fuel switching would be likely to occur as part of the voluntary demand response and since this is excluded from the cost of forced interruptions, the proportionate relationship between gas use and GVA is maintained.

would take place in order of their gas consumption per unit of GVA. On the basis of physical considerations, the commercial sector is also assumed to be interrupted after the industrial sector has been.

In addition, some voluntary demand-side response will take place prior to the involuntary interruptions. As the cost of such response relative to energy used is, in general, found to be lower than the GVA lost due to involuntary interruptions, demand-side response is assumed to take place before involuntary interruptions, and the gas consumption affected by such voluntary action is removed from the calculations that follow.

The analysis begins by listing the sectors consuming gas and their levels of consumption, as published in the Digest of United Kingdom Energy Statistics.[90] The Standard Industrial Classification (SIC) codes corresponding to each of these sectors are then identified, and the GVA corresponding to these SIC codes are obtained from the Annual Business Inquiry of the ONS.[91]

Given a shortfall of gas supply, the optimal path of customer interruption according to the declining order of their gas consumption per unit of GVA is then set out (see Table A1.1).

Table A1.1 Interruption order, including direct GVA only

	GVA (£m)	Gas use (mcm)	Gas use/GVA
Electricity generation	14,301	30,371	2.124
Iron and steel	1,954	765	0.392
Oil and gas extraction	21,725	6,701	0.308
Chemicals	16,947	3,768	0.222
Non-ferrous metals	1,408	286	0.203
Public administration	22,988	4,493	0.195
Mineral products	7,526	1,171	0.156
Textiles, leather, etc	4,174	614	0.147
Food, beverages, etc	22,734	2,519	0.111
Agriculture	2,243	200	0.089
Petroleum refineries	2,431	181	0.074
Paper, printing, etc	19,228	1,189	0.062
Vehicles	18,166	900	0.050
Coal extraction	243	10	0.043
Other industries	25,055	1,051	0.042
Miscellaneous	46,508	1,829	0.039
Mechanical engineering, etc	24,096	771	0.032
Electrical engineering, etc	14,701	393	0.027
Commercial	379,444	3,180	0.008
Construction	63,531	237	0.004

Note: Gas use has been converted from GWh to mcm using a conversion factor of 1GWh=10.992mcm, as published in DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry.

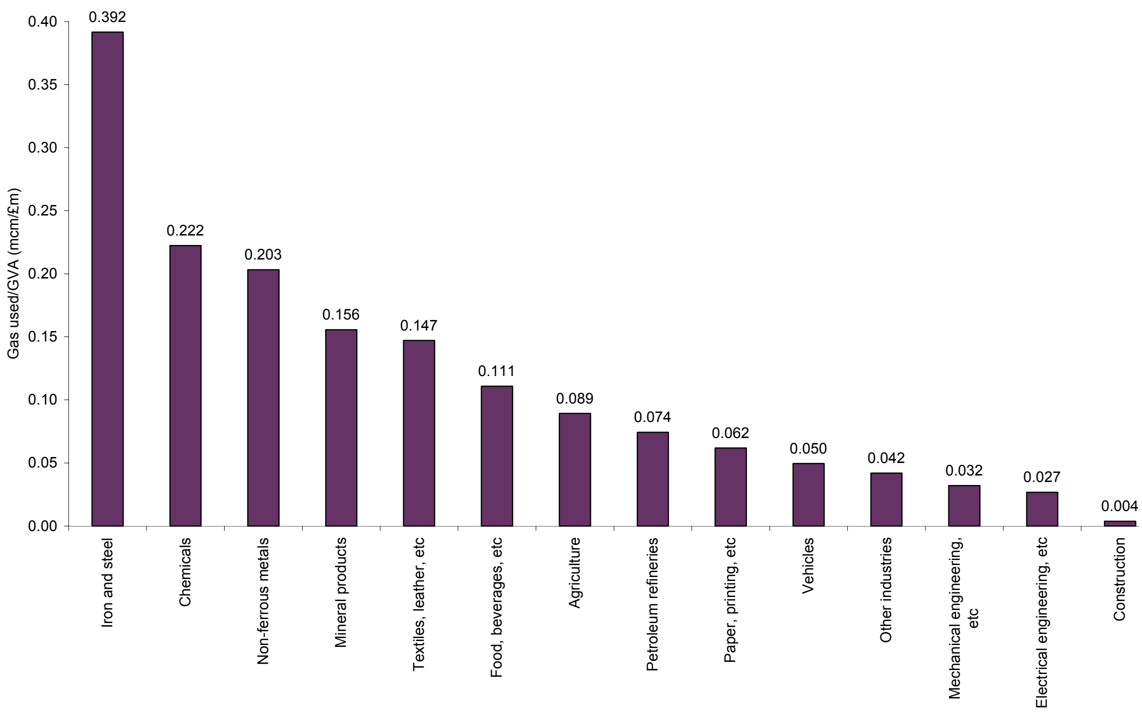
[90] DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May.

[91] Two-digit SIC codes are used in this analysis. This approach aggregates several sectors that may have substantially different energy use patterns; however, consistent data at the more detailed level was not readily available.

Even though the interruption order set out in Table A1.1 is the theoretically optimal one, certain sectors (oil and gas extraction, public administration, coal extraction, miscellaneous and commercial) may not be interrupted with the remainder of the industrial sector due to their strategic importance. Electricity generation is also not considered among the industrial sectors interrupted. Instead, reduction in gas use by electricity generation is considered a consequence of electricity demand reduction by the industrial sectors facing a gas demand interruption.

Figure A1.2 shows the theoretically optimal path of interruptions excluding the aforementioned sectors that would be interrupted only after the remainder of the industries have been. The gas use considered is the direct gas use by the sectors interrupted. Similarly, the GVA loss considered is that of the industries actually facing the gas interruption. (Figure A1.5 below considers indirect reductions in gas demand through its link with electricity demand and indirect costs of gas interruptions on related industries).

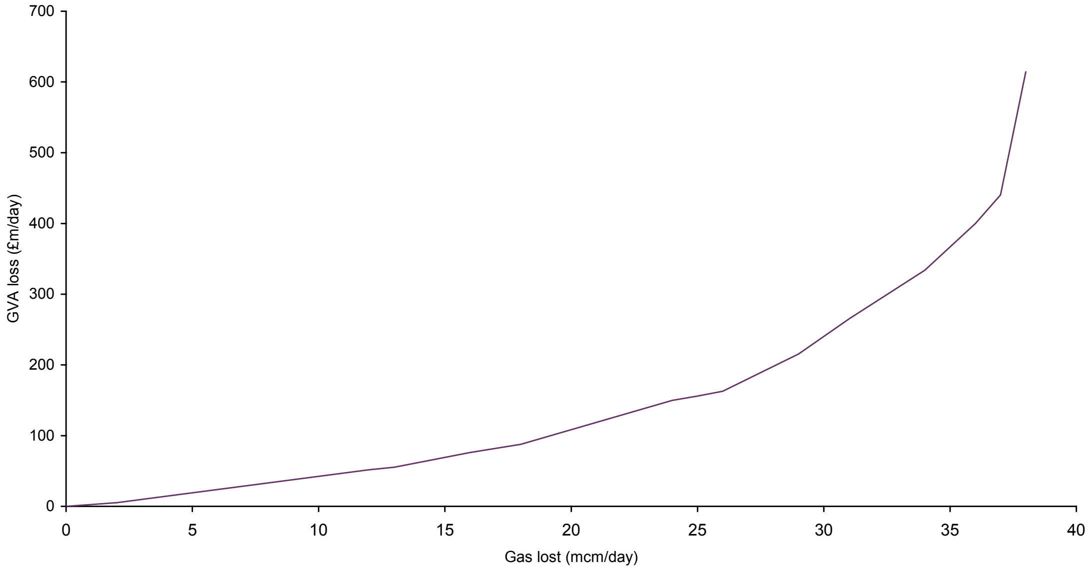
Figure A1.2 Theoretically optimum interruption order



Note: The figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction, miscellaneous and commercial sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; and Oxera calculations.

Figure A1.3 now presents the costs associated with varying levels of gas interruptions of the selected industries according to the interruption order set out in Figure A1.2. The industries identified would take the full effects of a gas supply interruption of up to 38mcm/day (about 14% of the average daily gas demand of 268mcm in 2005).

Figure A1.3 Cost of a gas interruption on selected industrial consumers, with direct gas use and direct costs only

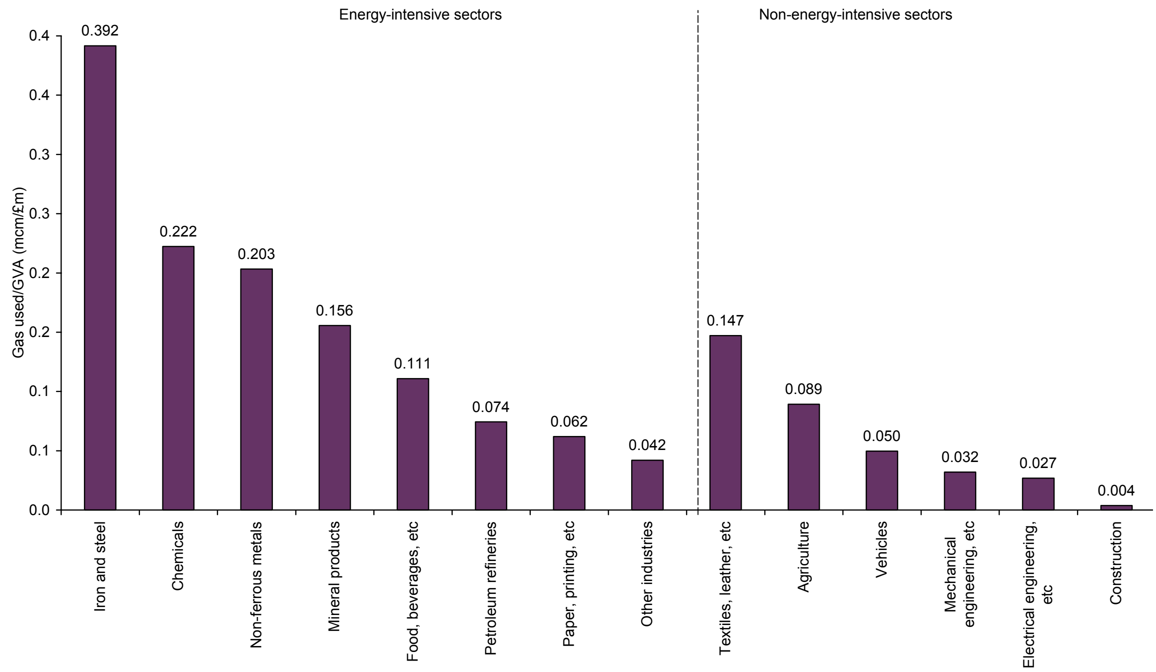


Note: The figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction, miscellaneous and commercial sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; and Oxera calculations.

Taking into account the physical constraints of interrupting gas users across the economy, the energy-intensive users[92] (as identified by Global Insight[93]) may be interrupted before the non-energy-intensive users, to deliver an alternative interruption order. Among the energy-intensive and non-energy-intensive users, an order of interruption will be determined according to their gas use per unit of GVA (see Figure A1.4).

[92] As gas consumption data is available for Digest of United Kingdom Energy Statistics sectors rather than the narrower energy-intensive sectors, the former, which encompass the identified energy-intensive sectors, have been used.
[93] Global Insight (2005), 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices', May.

Figure A1.4 Interruption order assuming that energy-intensive sectors are interrupted before other sectors



Note: The figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction, miscellaneous and commercial sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; and Oxera calculations.

This alternative order of interruptions is used to determine the GVA loss associated with varying levels of gas interruptions, as shown in Figure A1.5. The amount of gas loss included here is the sum of the gas lost directly due to the interruption of the selected industrial sectors and that lost indirectly due to the reduction in electricity demand by industries that have curtailed production due to the gas interruption. For the purposes of this study, a linear relationship is assumed between industry output and electricity demand. Therefore, the reduction in electricity demand will be in proportion to the reduction in output.[94]

Also, it is assumed that gas is the marginal generating technology, and therefore CCGT plants will face the entire electricity demand reduction. This will in turn lead to a reduction in gas demand equivalent to that shown in Table A1.2.

[94] This assumption implies that all electricity use in a sector is variable. Additional sensitivities on the proportion of electricity use that may be considered fixed are reported later in this section.

Table A1.2 Conversion of electricity consumption to gas consumption, selected sectors

	Electricity use (GWh)	Gas use (mcm)
Petroleum refineries	5,624	1,023.3
Iron and steel	5,019	913.2
Non-ferrous metals	7,693	1,399.7
Mineral products	7,965	1,449.2
Chemicals	23,162	4,214.3
Mechanical engineering, etc	8,695	1,582.1
Electrical engineering, etc	7,427	1,351.3
Vehicles	5,859	1,066.0
Food, beverages, etc	12,593	2,291.3
Textiles, leather, etc	3,477	632.6
Paper, printing, etc	13,050	2,374.5
Construction	1,929	351.0
Other industries	21,962	3,996.0
Agriculture	4,152	755.5
Commercial[1]	75,294	13,699.8

Note: Electricity consumption is converted to gas consumption assuming a gas-fired power station efficiency factor of 50%. [1] The total electricity use (75,294GWh) converted to gas use by the commercial sector equals 13,699.8mcm. If the 13,699.8mcm figure had been used, total electricity use converted to gas used by the selected industries would sum to 37,099mcm, which is higher than the actual gas used for energy transformation purposes by electricity generators (30,371mcm). It is therefore assumed that only a portion of the reduction in electricity demand by the commercial sector (6,970.5mcm) comes from gas-fired generation. Furthermore, when demand-side response from CCGTs is added into the analysis, this figure falls to 4,004.9mcm.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 5.2; ONS (2006), Annual Business Inquiry; and Oxera calculations.

The costs of the interruption considered here include both direct GVA lost due to the reduction in production by the industries facing the gas interruption and the effects on the GVA by industries downstream and upstream of these directly interrupted industries[95] (see Tables A1.3 and A1.4).

It is assumed that the output and GVA lost by the downstream industries is in proportion to the output and GVA reduction of the industries directly affected by the interruption. Due to the complexity in determining the links across industries, only industries one step away from the interrupted industries have been considered. In addition, the analysis is based on the assumption that the downstream industries do not hold stocks of inputs and are unable to produce if industries upstream to them do not produce. Thus, the GVA loss measured here is necessarily an upper bound on the effects on downstream industries one step away from the interrupted industries. However, as the analysis does not include links further downstream of the interruption, all the relevant GVA losses have not been included.

[95] The relevant downstream sectors have been identified through interviews with large energy-intensive users. See Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April.

Table A1.3 Loss in GVA by downstream industries

Upstream industry	Downstream industries	GVA lost by downstream industries (£m/day)
Chemicals	Packaging (plastics), silicon chips, shoes, water	15.4
Iron and steel	Vehicles, metal products, wires, construction	70.4
Mineral products	Construction, concrete, glass containers	66.9
Non-ferrous metals	Construction, aviation	41.1
Paper, printing, etc	Packaging	3.2

Source: Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April, Table 13; and ONS, 'Annual Business Inquiry'.

To estimate the upstream effects, the five largest upstream industries affected by an interruption of each of the energy-intensive sectors are identified from the Leontief Inverse table published by the ONS. The GVA by these upstream industries is obtained from the ONS Annual Business Inquiry. As some of the sectors are upstream of more than one of the energy-intensive industries, the GVA by the upstream industries due to demand from the energy-intensive industries is divided equally across the relevant energy-intensive industries. The Leontief multiples are then used to determine the impact of a 1% change in GVA by the energy-intensive industry on the GVA by the upstream industries. Table A1.4 sets out the wider Digest of UK Energy Statistics industries that encompass the energy-intensive industries along with the GVA lost by upstream industries if each of the energy-intensive industries were to stop production entirely.

Table A1.4 Loss in GVA by upstream industries

Gas consumers	GVA lost by upstream industries (£m/day)
Agriculture	2.3
Mineral products	5.1
Chemicals	8.2
Petroleum refineries	17.4
Food, beverages, etc	4.8
Paper, printing, etc	7.5
Non-ferrous metals	2.2
Iron and steel	2.0
Other industries	6.0
Total	**55.4**

Source: ONS, 'Annual Business Inquiry'; and Oxera calculations.

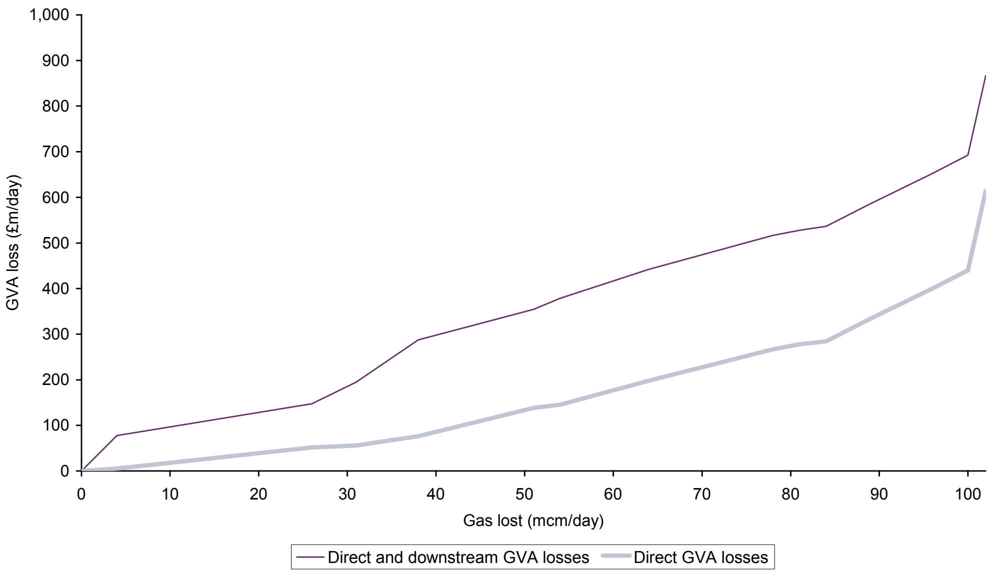
The inclusion of GVA lost by upstream and downstream sectors due to a gas interruption may lead to double-counting of the costs arising due to the interruption of the relevant sectors. For instance, the interruption of the iron and steel sector potentially leads to a loss in GVA by its downstream sectors (vehicles, metal products, wires and construction). However, these downstream sectors are themselves also gas users. A large enough gas interruption may directly lead to a loss in their output and GVA. Their inclusion within the GVA lost indirectly as a result of an interruption of the iron and steel sector and directly as the GVA lost due to their interruption leads to double-counting of costs. Consequently, the GVA lost measure used may be an overestimate of the costs of an interruption.

Figure A1.5 below shows that with the inclusion of direct and indirect GVA losses, if the industrial sector alone is interrupted, the total gas saved will equal 102.6mcm/day, of which

38.5mcm/day will come from the industries interrupted, and 64.1mcm/day will come from the consequent indirect loss of gas demand by CCGTs. Through its indirect effects on lower gas demand by the power generation sector, an interruption of the industrial sector will therefore lead to a gas saving of up to 38% of total daily gas demand.

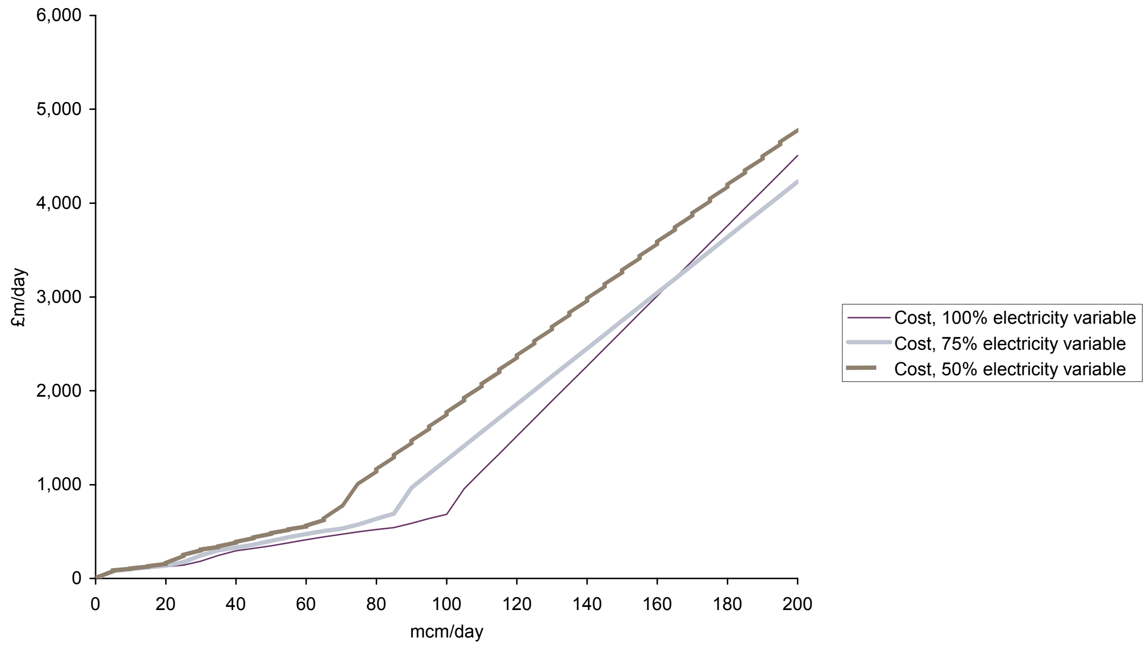
This figure appears high; however, it is consistent with the ONS data and the assumption that all electricity use is variable. If lower volumes of electricity use were assumed variable, this would lead to an increase in the unit cost of interruption, as shown in Figure 6.6 below. The interruption costs when losses are less than 60mcm/d are not significantly different and the majority of the interruptions observed fall in this region.

Figure A1.5 Cost of a gas interruption on selected industrial consumers, gas use through electricity use included, direct and indirect costs included



Note: This figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction, miscellaneous and commercial sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; and Oxera calculations.

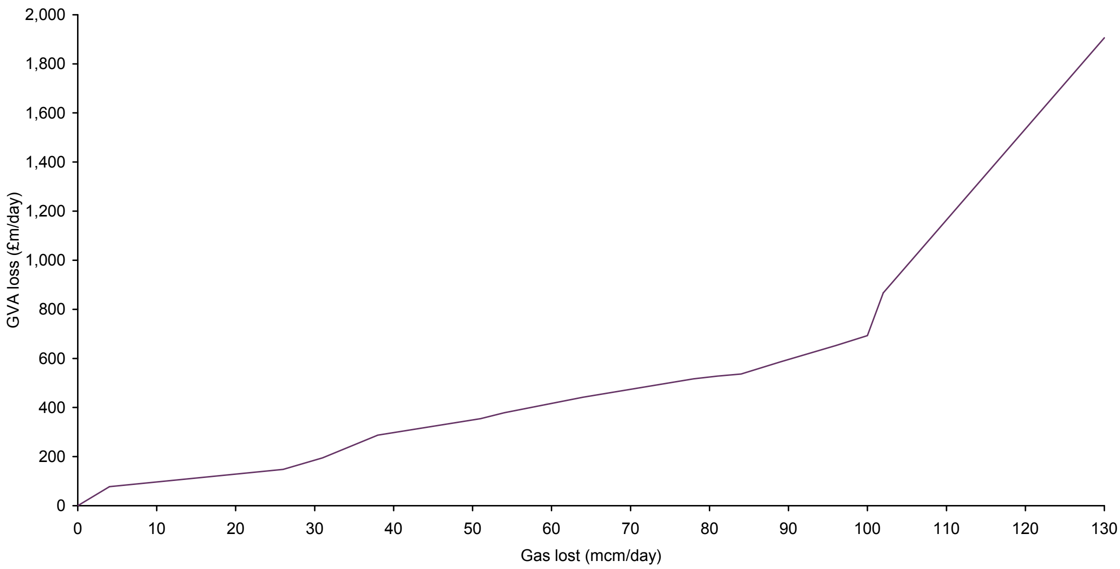
Figure A1.6 Impact of different assumptions on variable electricity consumption



Source: Oxera.

In a situation of a more extreme interruption, however, other sectors will have to be interrupted. Figure A1.7 and Table A1.5 below study the impact of an interruption of gas supplies to the commercial sector. Such an interruption will come in after the selected industries in the industrial sector have been interrupted. It would lead to a total gas saving of 130.4mcm/day at a cost of around £1,906m in terms of total GVA lost per day.

Figure A1.7 Cost of a gas interruption on selected industrial and commercial consumers, gas use through electricity use included, direct and indirect costs included, demand-side response excluded



Note: This figure assumes that the electricity generation, oil and gas extraction, public administration, coal extraction and miscellaneous sectors are not interrupted.
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; and Oxera calculations.

Table A1.5 Costs of gas interruption, excluding demand-side response (£m/day)

Interruption size (mcm/day)	Cost (£m/day)
10	95
20	127
30	184
40	296
50	347
60	413
70	472
80	522
90	589
100	684
110	1,143
120	1,517
130	1,891
130.4[1]	1,906

Note: This table assumes that the electricity generation, oil and gas extraction, public administration, coal extraction and miscellaneous sectors are not interrupted. [1] 130.4mcm/day is the largest possible gas interruption that can be placed on the industrial and commercial sectors (including indirect reduction in gas demand through its use in the electricity sector).
Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; and Oxera calculations.

Treatment of voluntary demand-side response

The above analysis focuses on the cost of involuntary interruptions. The model already assumes that several intensive industrial users provide voluntary demand-side response at a range of prices, as reproduced in Table A1.6 below. The per-unit cost of demand-side response is the price at which gas users sell gas back into the market, either stopping production or switching to back-up fuels.

Table A1.6 Industrial demand-side response

Price (p/therm)	Demand-side response (mcm/day)	Cost (£m/day)
42.0	1.9	0.29
50.0	4.6	0.87
79.0	5.4	1.59
100.0	1.5	0.56
200.0	2.6	1.94

Source: Global Insight (2005), 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices', May; JESS (2006); Datastream; and Oxera.

The costs of a voluntary gas interruption are substantially lower than the GVA losses taking place in the case of an involuntary interruption (see Figure A1.7 above and Table A1.7 below). Voluntary demand-side response is recorded separately in the modelling, and is assumed to 'cost' the economy the price at which it is bid into the market.

When industries that engage in voluntary demand-side response are affected by forced outages, it is assumed that their affected gas consumption is their total gas consumption minus their contribution to voluntary demand-side response.

Cost of interruption and duration of outage

The above data can be used to estimate the costs associated with different levels of forced outages of varying durations, as show in Table A1.7 below. The costs of interruptions to domestic and public sector consumers have been assumed at 3,000p/therm. These figures are used in section 7 to calculate the expected costs of forced outages.

Table A1.7 Costs of forced gas outages (£m)

	Interruption duration (days)			
	1	5	30	90
Interruption size (mcm/day)				
10	32	112	1,662	5,700
20	83	290	2,223	7,620
30	137	480	3,215	11,023
40	192	671	5,184	17,775
50	289	1,012	6,075	20,828
60	765	2,676	7,222	24,762
70	1,293	4,524	8,253	28,297
80	1,821	6,373	9,138	31,330
90	2,349	8,221	10,302	35,320
100	2,877	10,069	11,973	41,051
110	3,405	11,917	20,009	68,601
120	3,933	13,766	26,550	91,029
130	4,461	15,614	33,092	113,457
140	4,989	17,462	39,633	135,885
150	5,517	19,310	46,174	158,313
160	6,045	21,159	52,716	180,740
170	6,573	23,007	59,257	203,168
180	7,102	24,855	65,799	225,596
190	7,630	26,704	72,340	248,024
200	8,158	28,552	78,882	270,452

Source: DTI (2006), 'Digest of United Kingdom Energy Statistics 2006', May, Table 4.2; ONS (2006), Annual Business Inquiry; Ilex Energy (2006), 'Strategic Storage and Other Options to Ensure Long-term Gas Security', April; Global Insight (2005), 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices, May; JESS (2006); and Oxera calculations.

The relative costs of outages of different sizes and durations depend on a number of factors, including the marginal industry being interrupted on each of the days of the interruption. If a smaller interruption for a longer duration implies that industries with higher gas use relative to their GVA will be interrupted than in the case of a larger interruption over a short duration, the interruption costs will be lower in the former case.

Ordering industries on the basis of declining gas consumption per unit of GVA should, in theory, lead to a rise in GVA lost per unit of gas interrupted as the size of the interruptions is increased. The data suggests, however, that this is not always the case in practice. When, for instance, the size of a 30-day gas interruption increases from 10mcm to 20mcm, the total GVA loss increases, counter-intuitively, from £1,662m to £2,222m, implying a GVA loss per unit of gas use falling from £166/cubic metre to £111/cubic metre. Such an outcome arises due to the following reasons.

– *The ordering of intensive and non-intensive sectors*—the interruption order is not the declining order of gas use per unit of GVA across all industries considered; rather, it assumes that energy-intensive industries are interrupted prior to non-energy-intensive industries, with industries within these categories being interrupted according to the declining order of their gas use per unit of GVA. Furthermore, taking the physical aspects of the ease of interruption into account, despite having a higher gas use per unit of GVA than the construction industry, the commercial sector is assumed to be interrupted after the industrial sector as a whole. This reordering of intensive and non-intensive users and the commercial sector in the interruption order means that a lower-GVA sector may be hit at the margin.

– *Large difference between direct gas consumption and total gas consumption*—while, in most industries, indirect gas use is approximately equal to direct gas use, in sectors such as non-ferrous metals, petroleum refineries and paper, it is a much higher multiple of direct gas use. Due to the large level of indirect gas use in these industries, the marginal GVA becomes lower.

– *Large difference between direct GVA and total GVA*—the addition of indirect costs to the direct costs of an interruption has similar effects to the addition of indirect gas consumption to overall gas use levels. For instance, considering a 30-day interruption, the GVA loss due to the first 10mcm of involuntary gas interruptions is very high. This is because, although the iron and steel industry (the first to be interrupted) has low gas consumption (4.6mcm/day of direct and indirect consumption), its GVA is extremely high (£72.3m/day of indirect GVA in addition to its direct GVA of £5.4m/day).[96]

Despite these seemingly counterintuitive results, the existing interruption order based on direct gas usage and direct GVA is considered appropriate, even though the theoretically optimal order would additionally include indirect gas use and the indirect effects on GVA.

– *Direct gas usage*—the inclusion of indirect gas use will require the system operator to be aware of the electricity usage of the gas users and the impact of the reduction in electricity demand on gas use. This may in turn require the system operator to be aware of the nature of electricity contracts of the gas users. Given the costs of these informational requirements, the system operator may be expected to consider direct gas usage alone when interrupting gas consumers.

– *Direct GVA*—given the complexities in measuring indirect GVA effects and the potential for GVA to under- or overestimate the actual effects of an interruption—particularly when it is being extended to upstream and downstream industries—direct GVA alone is expected to be used in determining the interruption order.

Issues with the GVA measure of the costs of interruptions

While measures of GVA provide a means of quantifying the costs of a gas interruption, there are situations where the GVA may over- or underestimate the costs of an interruption. One factor underlying these discrepancies is the duration of the interruption. An interruption lasting a day, for instance, would lead to a reduction in the output of the industry interrupted. Even if this industry does not hold stocks of its output and cannot provide necessary inputs to the downstream industry, the downstream industry may still be able to produce if it holds input stocks. The costs on the downstream industry will therefore be lower than the GVA. If, however, the gas interruption lasts for one week or one month, the downstream industries will not be able to produce and will face a near-complete loss of GVA to the extent that their production is limited. A longer-term interruption of, say, six months would provide the downstream industries the opportunity to contract with foreign industries for inputs, thereby allowing them to continue production. Once again, GVA will overestimate the actual costs of the gas interruption for downstream industries. Furthermore, if there is excess capacity in the downstream industry, it would be able to produce lost output at another point in time once gas supply, and consequently its input supply, are restored. The costs incurred in such a case would not be the GVA loss; rather, they would equal any overtime wages paid to workers for shifting production to another time.

[96] The GVA effects have been estimated assuming no demand-side response.

Not only is it possible for GVA to overestimate the costs of a gas interruption, it may also underestimate them under certain conditions. For instance, the curtailment of production may have additional costs associated with, say, closing down and restarting production.

As discussed above, the inclusion of the upstream and downstream effects of an interruption in addition to its direct effects leads to double counting of the costs of some industries. The GVA measure, as estimated above, may therefore be an overestimate of the costs of an interruption.

A1.3 Pricing effects

In addition to influencing the likelihood of physical interruptions, the policy initiatives will affect the outturn prices in the market, and, hence, will have an incremental impact on welfare. These welfare effects will accrue to various market participants in the form of changes in consumer and producer surpluses.

The *consumer surplus* here is defined as the consumer's willingness to pay for a quantity of gas *less* the amount they actually pay for it. As the demand curve represents the marginal willingness to pay, the consumer surplus is measured as the area lying between the demand curve and the price level. The *producer surplus* is the price that producers receive for gas sold *less* the price at which they would have been willing to sell varying units of gas. The latter equals the marginal cost of gas production. As the marginal costs of production form the supply curve, the producer surplus is measured as the area above the supply curve and below the price level.[97]

Given that a proportion of UK gas consumption will be imported, surplus accruing to non-UK producers supplying to the UK will not contribute to the welfare of the UK market participants. Exports from the UK will, by contrast, add to the welfare accruing to gas producers in the UK.

These components of economic welfare are set out in Table A1.8.

Table A1.8 Components of economic welfare

Consumer surplus	Producer surplus	Import costs	Net welfare
∑ Marginal willingness to pay	Annual supply[1] x wholesale price	(Imports/annual demand) x producer surplus	Consumer surplus
– Annual demand x retail price	– ∑ Supply costs of different gas sources	– Exports x wholesale price	+ Producer surplus
			– Net import costs

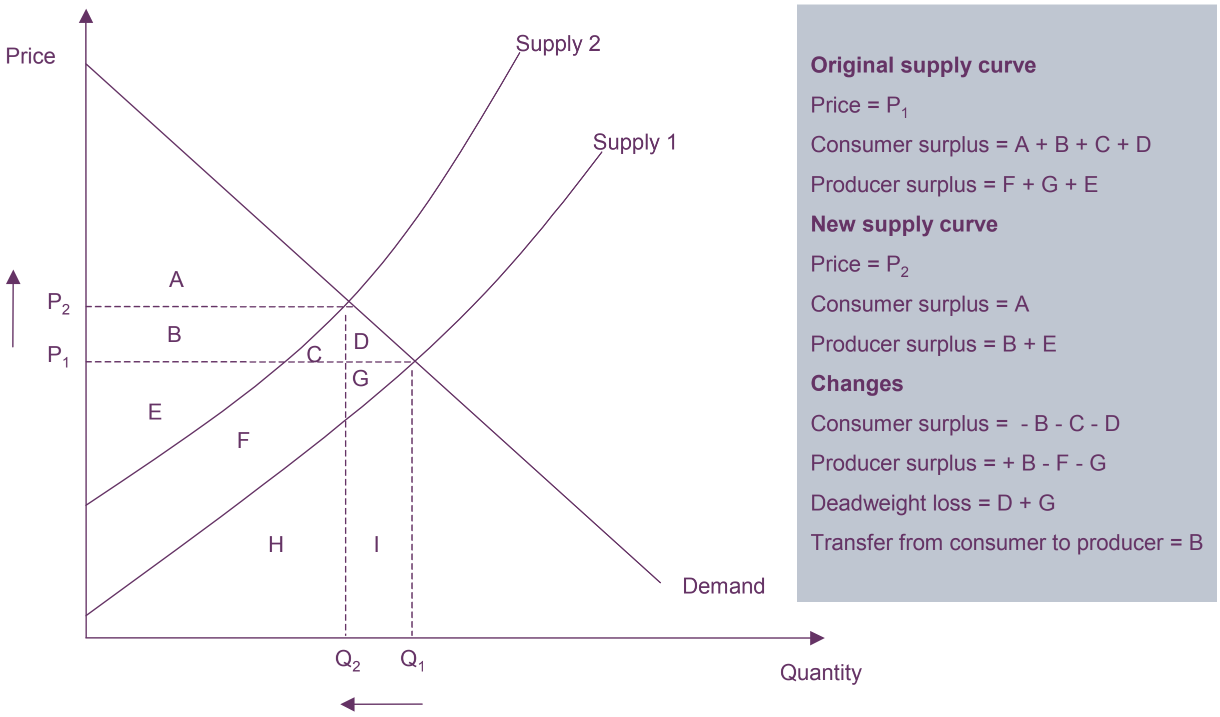
Note: [1] Annual supply equals annual demand in equilibrium.
Source: Oxera.

Now Figure A1.8 below illustrates the welfare impact of a policy that shifts the supply curve up from Supply 1 in the Base Case to Supply 2, resulting in an increase in prices from P_1 to P_2. According to the welfare concepts discussed above, consumer surplus in the Base Case equals A+B+C+D, and is reduced to A with the upward shift of the supply curve. Similarly, producer surplus changes from F+G+E in the Base Case to B+E after the upward shift of the supply curve.

Areas D and G represent the deadweight losses that have been incurred by the economy due to the imposition of the policy that has led to consumers purchasing less gas than they would have in the Base Case.

[97] While this holds in theory, it should be noted that, in the actual model, the supply curve is derived on an opportunity cost basis.

Figure A1.8 Welfare effects of a price change



Source: Oxera.

This theoretical framework is now applied to the policy options proposed for improving the security of gas supply. The costs and benefits of these policies can be measured in terms of the changes in producer surplus received by gas producers and the changes in consumer surplus received by final consumers.[98]

The first stage of the welfare analysis involves measuring the welfare impact of changes in price levels on gas producers. As the supply modelling has been done on a value rather than a cost basis, it does not provide a long-run marginal cost curve that may be used to determine producer surplus. Inasmuch as the marginal costs of gas production are not expected to change over time, changes in producer revenue is the measure used as a relatively close proxy to changes in producer surplus. Producer revenue here is calculated as the product of wholesale gas prices and demand estimated by the modelling.

In the second stage of the welfare estimation, the impact of changes in price levels on final gas consumers are considered. This impact is estimated as the full consumer surplus lost or gained. In order to make this estimation, changes in outturn wholesale price levels are translated into changes in the retail price levels (with appropriate weighting of the proportion of wholesale price in the retail price), allowing the retail supply curve to be determined. The following assumptions are made regarding this curve.

– Retail tariffs are composed of wholesale costs, transmission costs and supply margins. In estimating the consumer surplus, Oxera assumes that the transmission costs and supply margins remain fixed, with wholesale costs being the only variable component of retail prices. As wholesale costs are around 50% of the retail price, the fixed component of retail tariffs is assumed to equal the wholesale price in the Base Case in 2006

[98] In addition to gas producers and final consumers, the other key participants in the gas market are shippers/suppliers. To understand their role in determining the overall economic welfare, the gas market may be divided into a wholesale component and a retail component, with shippers/suppliers playing the role of consumers in the wholesale market and that of suppliers in the retail market. Assuming full wholesale cost pass-through by shippers/suppliers into the retail market, any surplus transferred from consumers to shippers/suppliers in the retail market would in turn be transferred to gas producers in the wholesale market.

(38.96p/therm), with the variable component equalling the wholesale costs in each year under each of the policy measures.

– Changes in the wholesale prices are passed through in full to retail prices. In estimating changes to the consumer surplus, changes in the wholesale prices are therefore added on to the base retail price (corresponding to price P_1 in Figure A1.8) to determine the new retail price, which corresponds to price P_2 in the figure.

– It has not proved possible to robustly quantify the impact of changes in the price-duration curves on wholesale contract premia. As such, contract premia are assumed to be constant across scenarios.

– In calculating the welfare loss or gain, an assumption on the price elasticity of demand must also be made. A review of the literature shows that a range of demand elasticity estimates is available covering different timeframes and categories of consumers (see Table A1.9). Oxera has chosen a figure of –0.3, which is the upper bound of the range used by the Competition Commission in the Centrica/Dynegy merger.[99]

Table A1.9 Review of demand elasticity estimates

	Elasticity	Data	Source
Long-run estimates (gas)			
LR demand elasticity for households (OLS)	–0.133 (not significantly different from 0)	1978 to 2002	Nilsen et al (2005)
LR demand elasticity for households (heterogeneous GLA-AR1)	–0.133 (not significantly different from 0)	1978 to 2002	Nilsen et al (2005)
LR demand elasticity for households (heterogeneous shrinkage (OLS))	–0.099	1978 to 2002	Nilsen et al (2005)
LR demand elasticity for households (heterogeneous shrinkage (GLS-AR1))	–0.181	1978 to 2002	Nilsen et al (2005)
LR household elasticity	–0.317	1978 to 1997	Asche et al. (2002)
LR demand elasticity of UK manufacturing industry	–1.4839		Oxford Institute for Energy Studies (1985)
Long-run estimates (energy)			
LR elasticity of energy demand for all industry	–0.5		Cambridge Econometrics Multisectoral Dynamic Model, quoted in Department of Trade and Industry (1998)
LR elasticity of energy demand for all industry	–0.4		DTI (1995)
LR elasticity of energy demand for all industry	–0.3 (excludes iron and steel)		DTI modelling in 1998, quoted in DTI (1998)
Short-run estimates			
SR demand elasticity for households (OLS)	–0.056 (not significantly different from 0)	1978 to 2002	Nilsen et al. (2005)
SR demand elasticity for households (heterogeneous GLS-AR1)	–0.048 (not significantly different from 0)	1978 to 2002	Nilsen et al. (2005)
SR demand elasticity for households (heterogeneous shrinkage (OLS))	–0.048	1978 to 2002	Nilsen et al. (2005)
SR demand elasticity for households (heterogeneous shrinkage (GLS-AR1))	–0.086	1978 to 2002	Nilsen et al. (2005)
SR household elasticity	–0.223	1978 to 1997	Asche et al. (2002)
Price elasticity of gas demand (for households)	–0.34		Baker et al. (1989)

[99] Competition Commission (2003), 'Centrica plc and Dynegy Storage Limited and Dynegy Onshore Processing UK Ltd. A Report on the Merger Situation', August, p. 264.

	Elasticity	Data	Source
Price elasticity of gas demand in the UK and Ireland market	0 to –0.3	Based on the 2002/2003 year with data from July 1st 2002 to March 5th 2003.	Competition Commission's Inquiry into the Centrica/Dynegy merger, Lexecon's analysis.
SR demand elasticity of UK manufacturing industry	–0.69		Oxford Institute for Energy Studies (1985)
Other			
Elasticity (multinomial logit model)	–1.34		Wigley and Vernon (1982)
Price elasticity of fuel demand	–0.22		Hunt et al. (2003)
Ratio of LR gas price elasticity to SR gas price elasticity for industrial demand	4–5		Al-Sahlawi (1989)
Ratio of LR gas price elasticity to SR gas price elasticity for residential and commercial demand	5–10		Al-Sahlawi (1989)

Source: Nilsen, O.B., Asche, F. and Tveteras, R. (2005), 'Natural Gas Demand in the European Household Sector', August. Asche, F., Osmundsen, P. and Tvetaras, R. (2002), 'Tax shifting in long-term gas sales contracts', Table 2, Guest Lecturers, Department of Economics, University of Calgary, http://econ.ucalgary.ca/Guest-Lecturers/energytaxincidence23doc.pdf. Oxford Institute for Energy Studies (1985), 'The Demand for Energy by UK Manufacturing Industry', Table 2, http://www.oxfordenergy.org/pdfs/EE1.pdf. Cambridge Econometrics Multisectoral Dynamic Model, quoted in DTI (1998), 'Economic instruments and the business use of energy', November, Table F.1. DTI (1995), 'Energy Projections for the UK', EP65, March. Baker, P., Blundell, R. and Micklewright, J. (1989), 'Modelling household energy expenditure using micro-data', *Economic Journal*, **99**:397, September, 720–38. Wigley, K.J. and Vernon, K. (1982), 'Methods of Projecting U.K. Energy Demands Used in the Department of Energy', paper presented to the International Association of Energy Economists and British Institute of Energy Economics Conference. Hunt et al. (2003) quoted in Communities and Local Government (2006), 'Review of the Sustainability of Buildings', November, p.16. Al-Sahlawi, M.A. (1989), 'The Demand for Natural Gas: A Survey of Price and Income Elasticities', *Energy Journal*, **10**:1, 77–90.

A2 Results of sensitivity runs

As part of the analysis, Oxera undertook a range of sensitivities on the core assumptions underlying the Base Case:

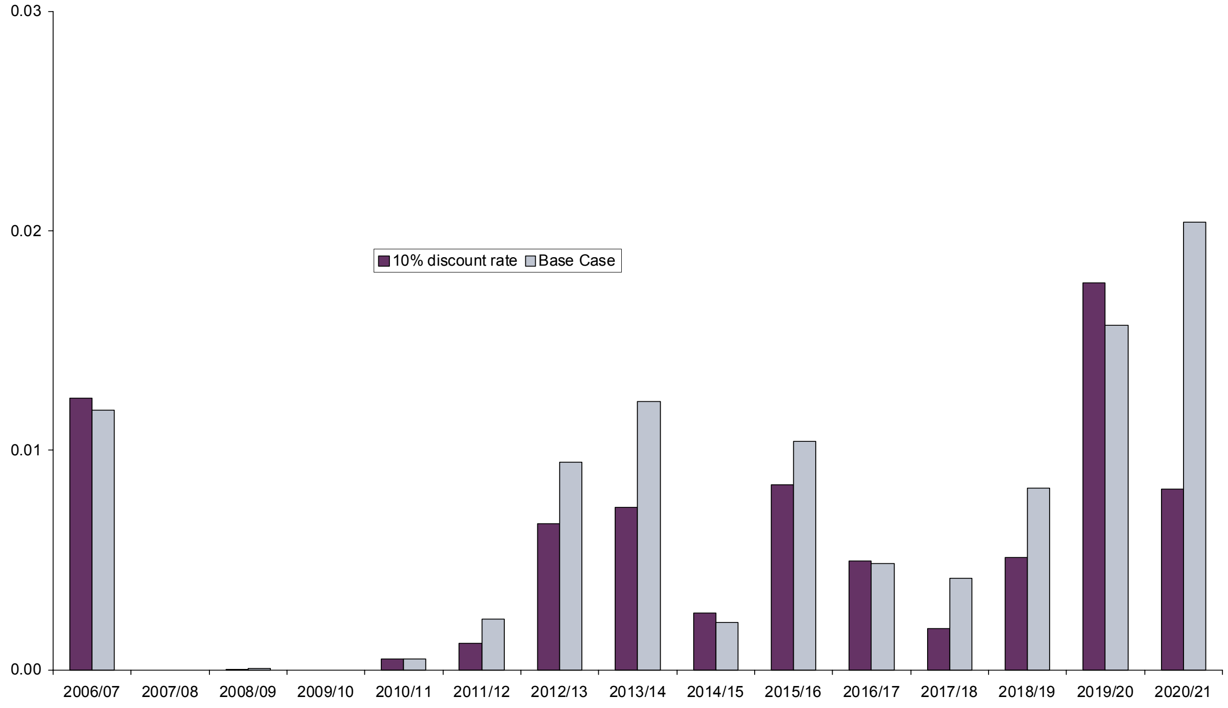
1) the assumed discount rate;
2) the availability of additional Continental European supplies;
3) the price of LNG;
4) the outage probabilities;
5) the existence of correct expectations (or perfect foresight).

Each of these has been referred to in the text, where relevant. This Appendix compares the results for each sensitivity with the Base Case.

A2.1 Lower discount rate

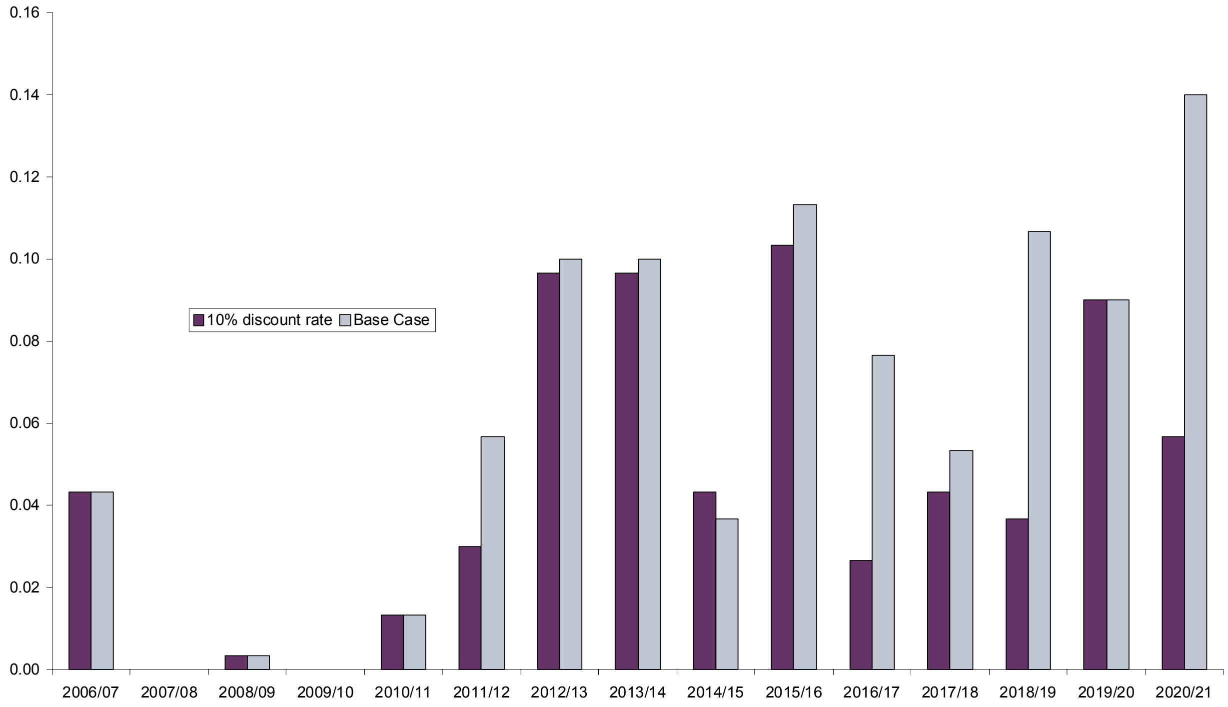
The Base Case assumes a 15% discount rate for all infrastructure projects. Lowering the required return to 10% reduces the margin required by any investor to incentivise additional investment (as is clear from the illustrative calculations in section 3). The lower discount rate does indeed accelerate some investment and consequently lowers the expected annual outage size and probability of an outage, as shown in Figures A2.1 and A2.2 respectively. The major difference between the two occurs in the final period of the simulation (2020/21), where the lower discount rate makes new infrastructure viable that would not have occurred in the Base Case until a later date.

Figure A2.1 Comparison with Base Case: expected annual outage (as % of demand)



Source: Oxera.

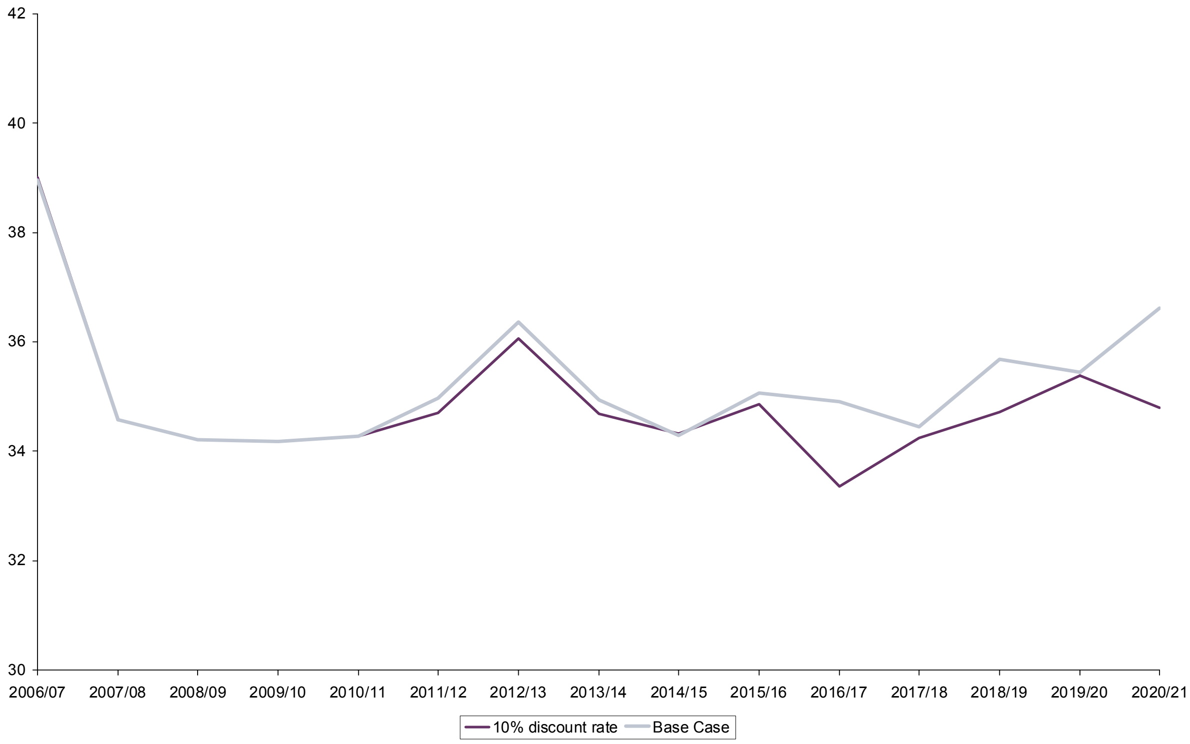
Figure A2.2 Comparison with Base Case: annual probability of outage



Source: Oxera.

The differences in the new entry cost require the spot prices to be higher in the Base Case in order to attract new investment, as illustrated in Figure A2.3. However, these differences are not significant or particularly persistent. This is largely because, in the model, a tightening supply–demand balance changes prices to a greater extent than the difference in the new entry cost for projects in this sensitivity. Even when investment decisions are lagged in the Base Case, the price response is still such as to ensure this is not a long-lived differential.

Figure A2.3 Comparison with Base Case: expected spot price (p/th)



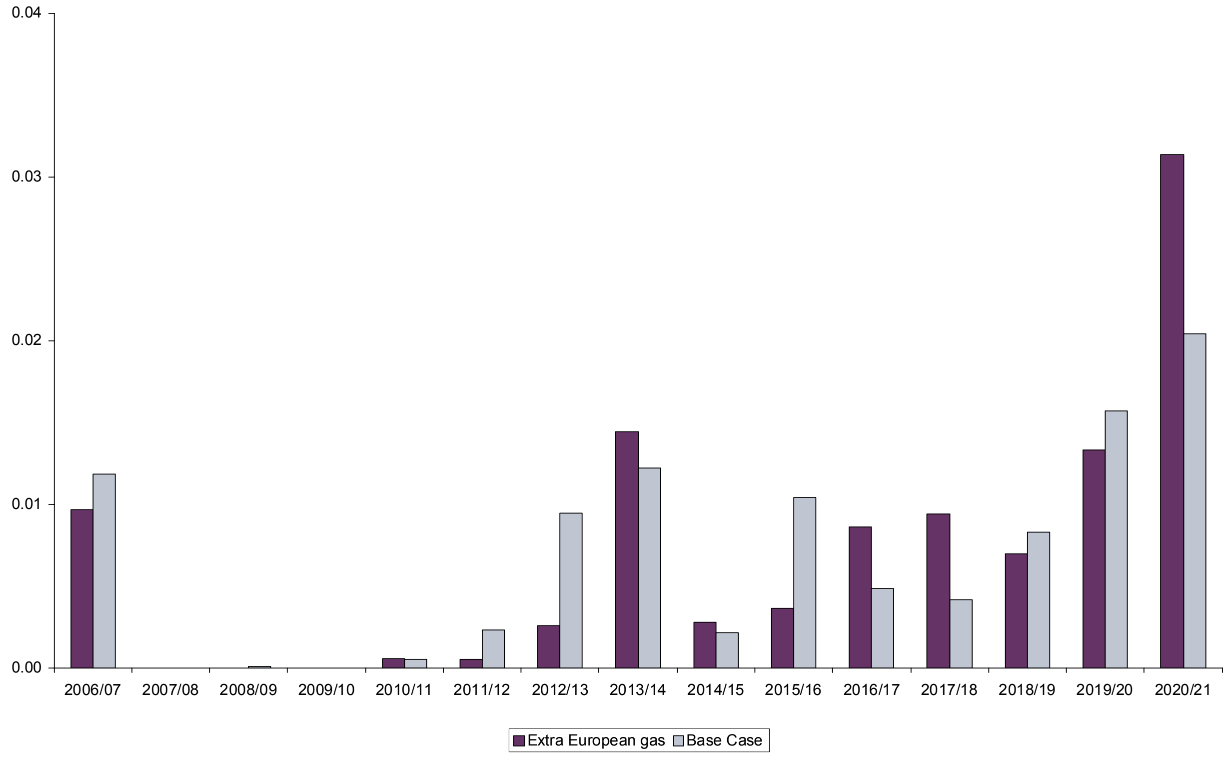
Source: Oxera.

A2.2 Extra European gas

The Base Case assumes that there are bottlenecks in the Continental European system that prevent the current import infrastructure from being fully utilised across the year. This places greater pressure on the supply–demand balance, as the existing infrastructure is unable to operate to capacity. Allowing extra European gas to be available in the early period of the simulation (availability is assumed to start at 80% of capacity) lowers the expected outage and probability of outage in the period up to 2012/13.

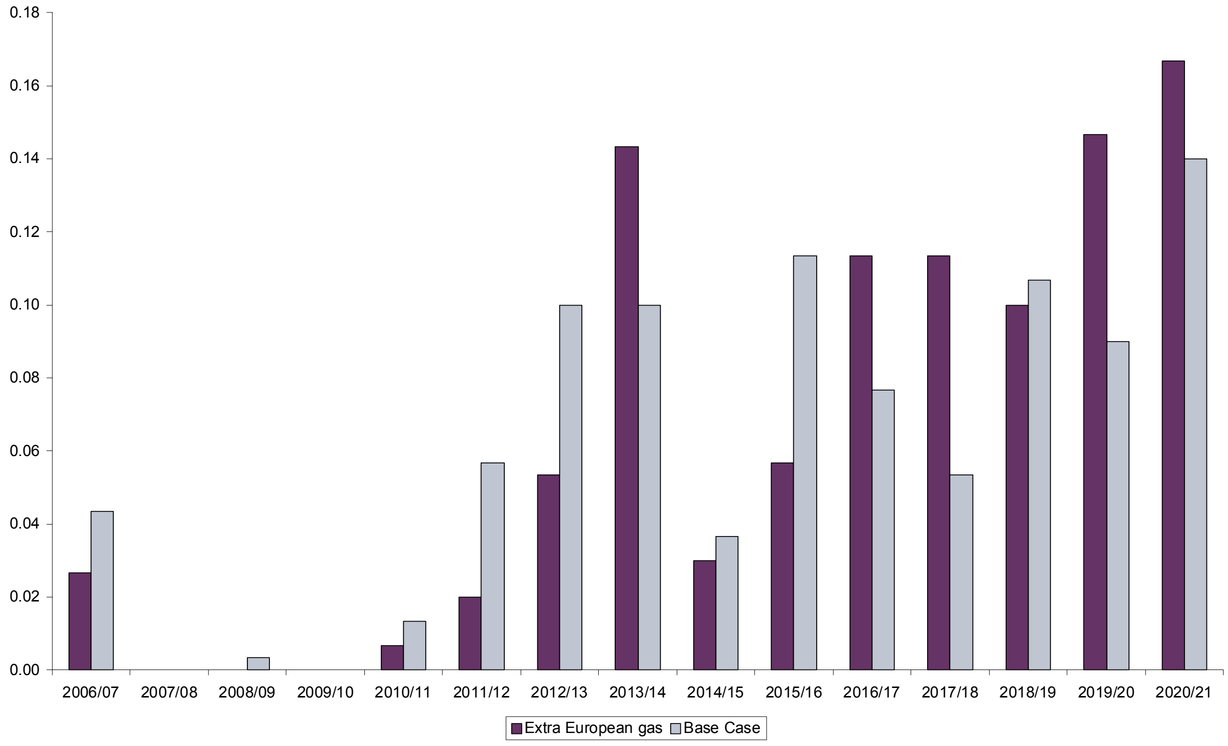
After this period, however, when the constraint on European volumes is lifted in the Base Case, the situation is generally worsened. This is because the extra European gas available in the early period lowers prices (see Figure A2.6) and therefore delays new infrastructure investment, which continues to lag in the medium term. It would be expected that this would be transitory, as the market would remove this asymmetry in the medium term.

Figure A2.4 Comparison with Base Case: expected annual outage (as % of demand)



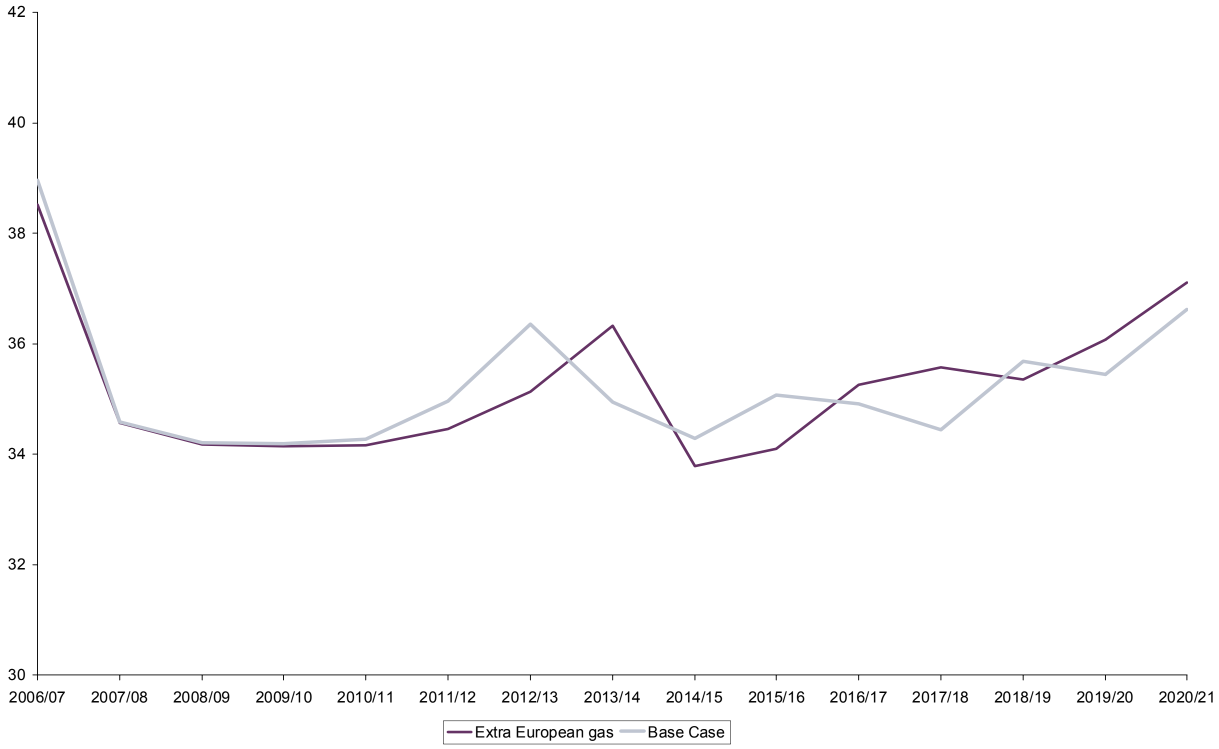
Source: Oxera.

Figure A2.5 Comparison with Base Case: annual probability of outage



Source: Oxera.

Figure A2.6 Comparison with Base Case: expected spot price (p/th)



Source: Oxera.

A2.3 Non-oil-indexed LNG price

The Base Case assumes that LNG prices are oil-indexed. Since LNG is often the marginal source and the majority of new infrastructure options available are LNG import terminals (whose viability depends on the differential between global LNG prices and the UK NBP price), this assumption may have important impacts on the security level.

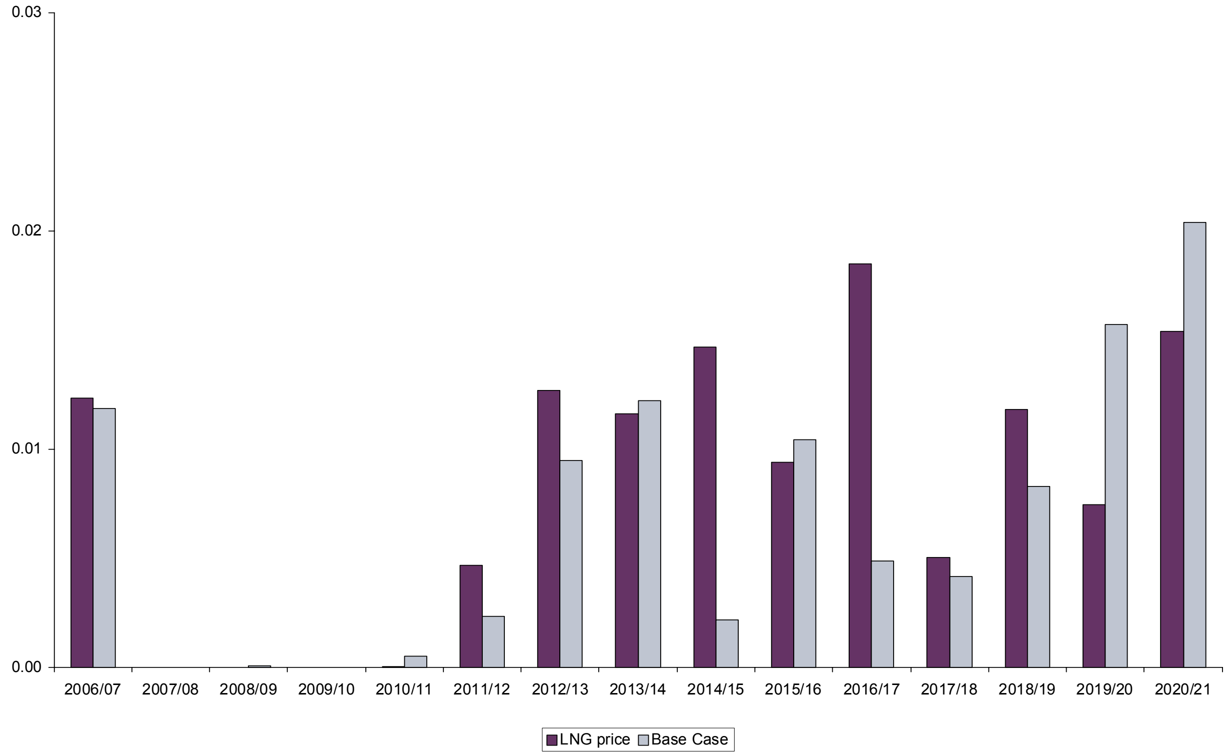
Table A2.1 shows the two price series, with the sensitivity run assumptions derived from the Henry Hub forward curve out to 2012/13 and assumed to be constant thereafter. These prices are higher than those in the Base Case, leading to a higher average spot price (Figure A2.9), but this is not always sufficient to encourage new LNG import investment on the same timeframe as the Base Case, hence the higher probabilities of outage (particularly around the period 2014/15 to 2016/17, when the first new LNG import terminals are modelled as entering the market in the Base Case).

Table A2.1 Annual average LNG commodity price (p/th)

Year	Base Case (p/th)	Sensitivity (p/th)
2006/07	38.7	38.7
2007/08	36.5	36.61
2008/09	35.9	41.13
2009/10	35.3	40.21
2010/11	34.6	38.36
2011/12	34.0	36.6
2012/13	33.4	34.94
2013/14	32.7	34.94
2014/15	32.1	34.94
2015/16	31.5	34.94
2016/17	31.7	34.94
2017/18	31.9	34.94
2018/19	32.2	34.94
2019/20	32.4	34.94
2020/21	32.6	34.94

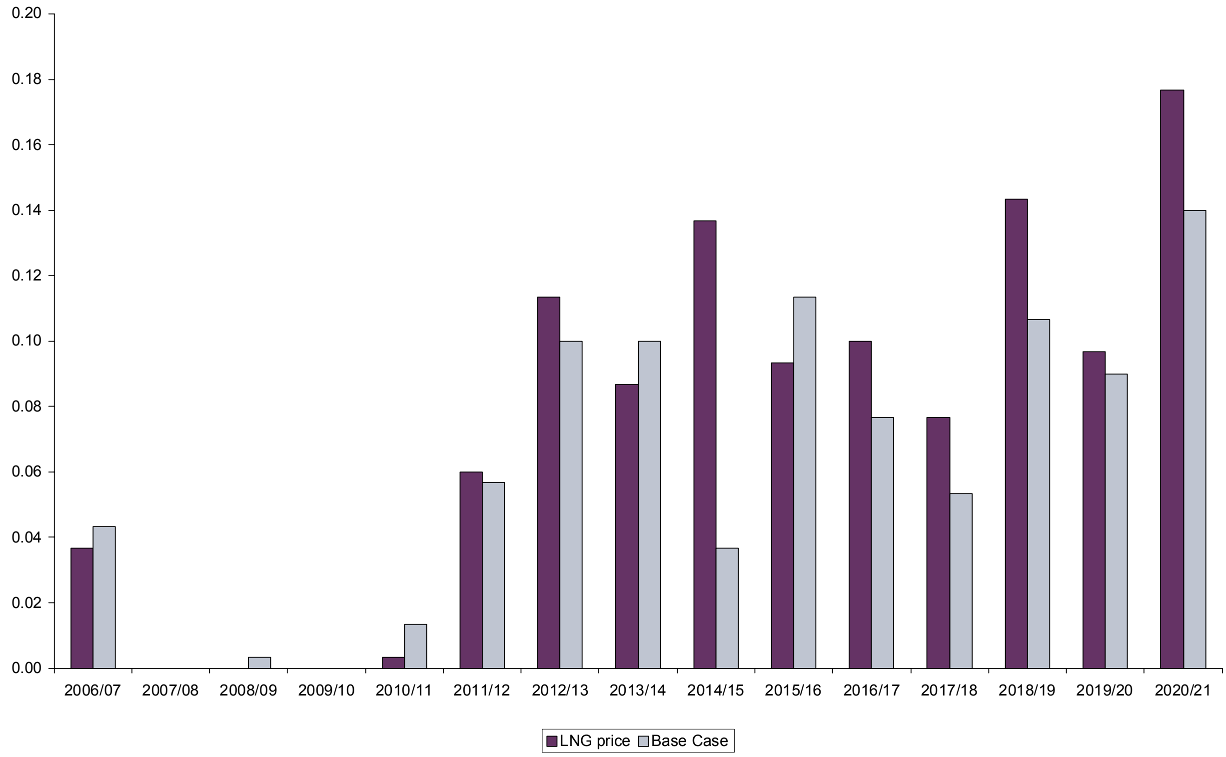
Source: Henry Hub prices; DTI assumptions; Oxera calculations.

Figure A2.7 Comparison with Base Case: expected annual outage (as % of demand)



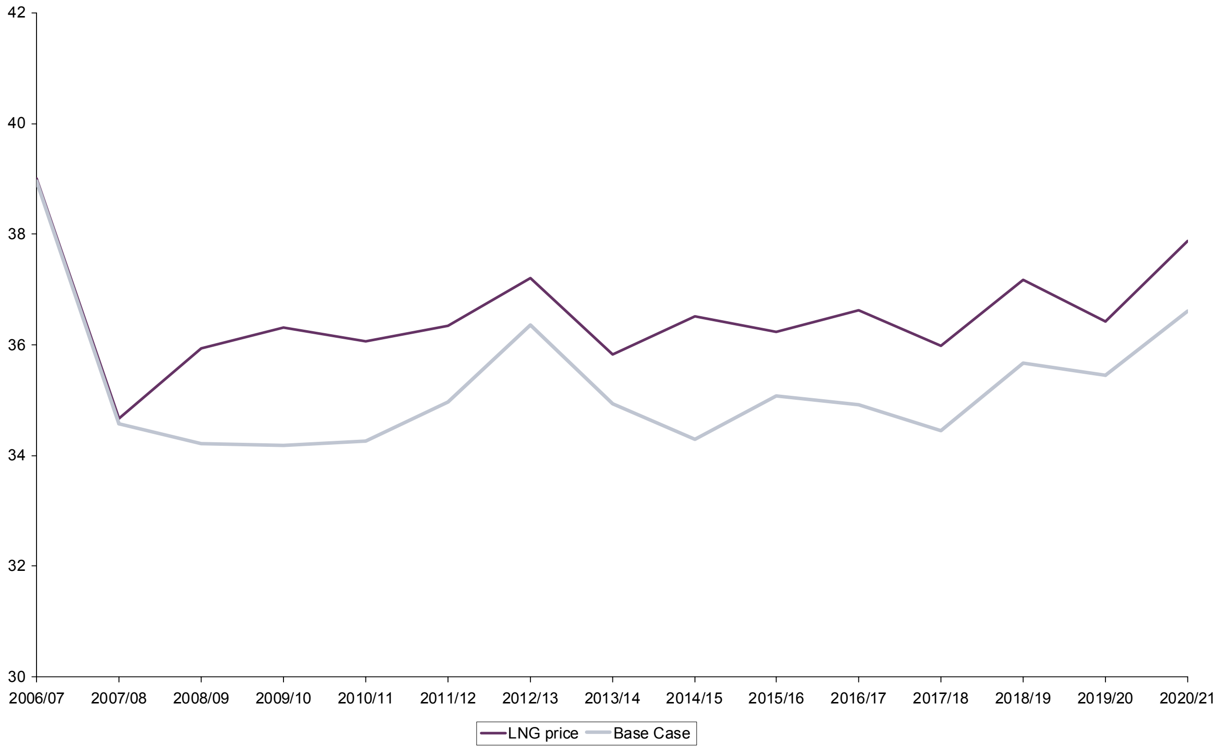
Source: Oxera.

Figure A2.8 Comparison with Base Case: annual probability of outage



Source: Oxera.

Figure A2.9 Comparison with Base Case: expected spot price (p/th)



Source: Oxera.

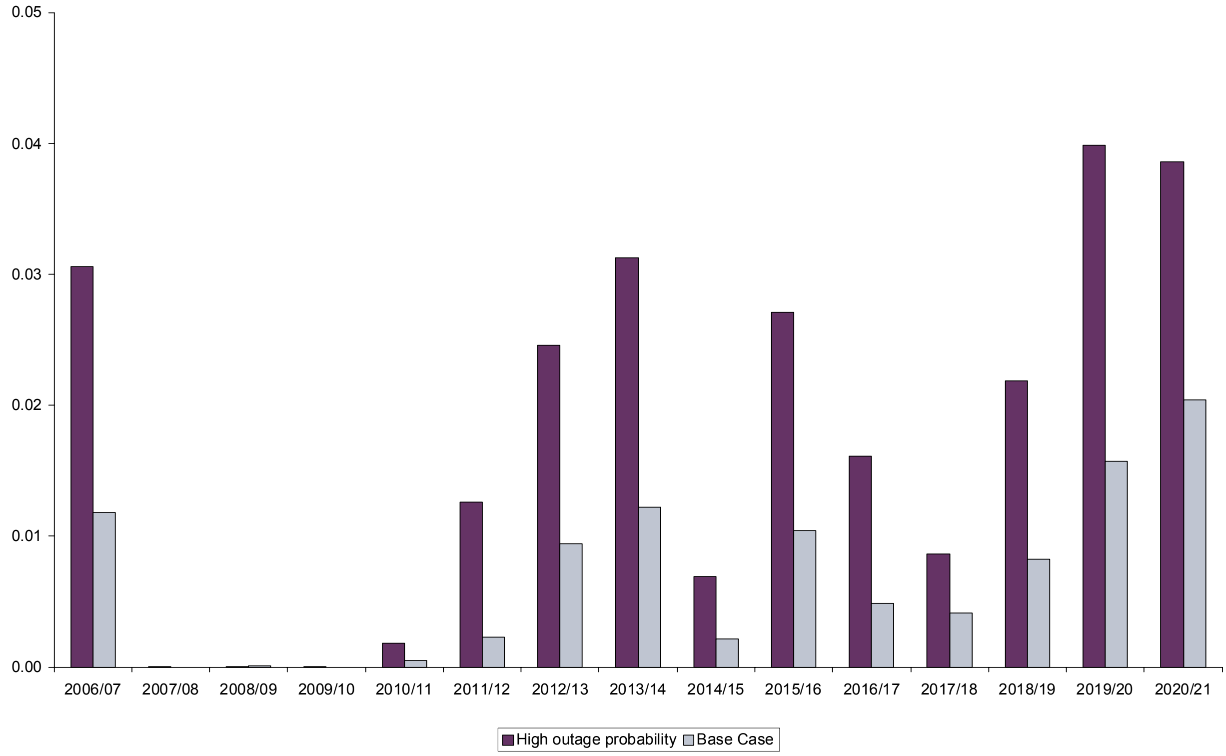
A2.4 Higher outage probabilities

The sensitivity on higher outage probabilities was not a full investment run. Instead, the Base Case investment profile was assumed and the impact of an increase in the outage risk for infrastructure was assessed. For longer-duration events, a tenfold increase was assumed (ie, a 1-in-100-year probability became a 1-in-10-year probability). For the shorter-duration outages, the risk was doubled (ie, a storage outage probability of 1-in-5 years became 1-in 2.5 years).

As Figure A2.10 shows, the expected size of annual outages rises quite significantly. However, the probability of an interruption does not change as markedly (Figure A2.11). This suggests that the higher risk to infrastructure means there are more concurrent outages that therefore reduce the ability of the system to respond. However, the outages themselves are still relatively small in size.

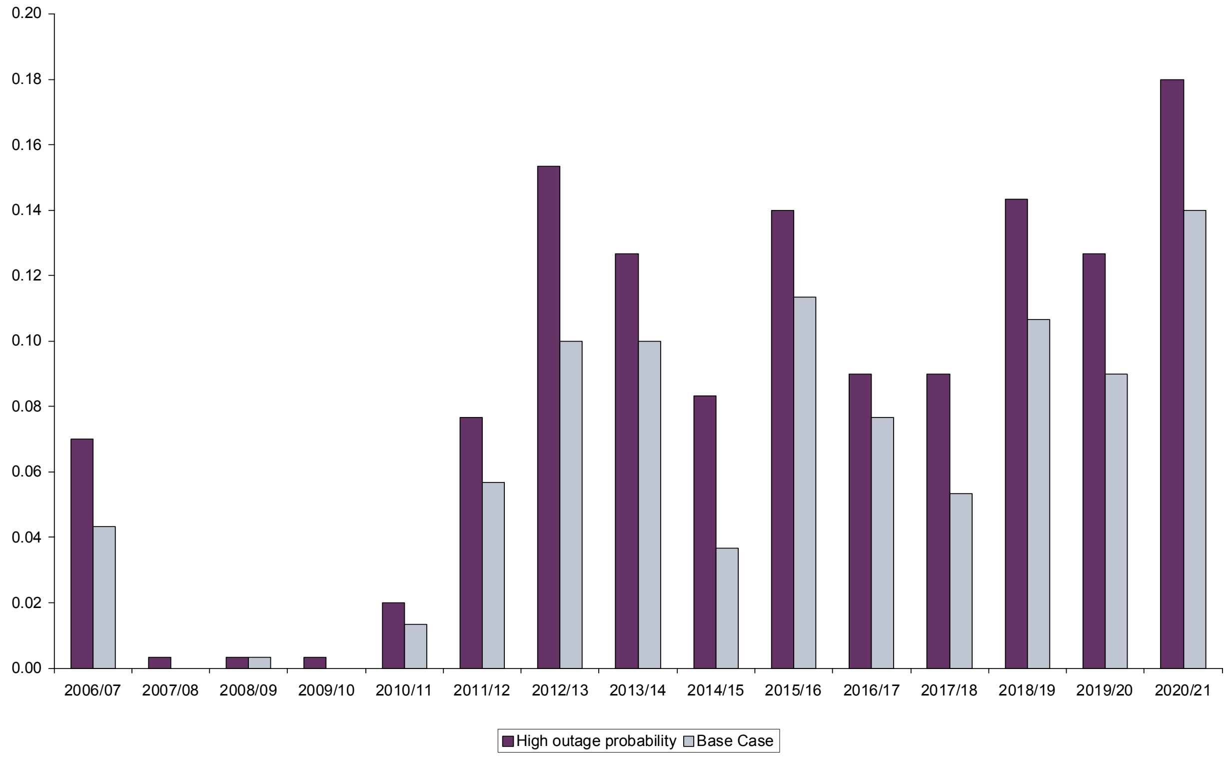
It is only in the last two years, 2019/20 and 2020/21, that the outage size (and hence cost) increases significantly. This is illustrated by the difference in the NPV of the cost of outages over the period 2007/08 to 2020/21 compared with the Base Case. In the Base Case, this amounts to £1.26 billion; in the high outage case, it is around £4.65 billion. However, it is likely that such large anticipated costs would have led to further investment at an earlier stage, thereby reducing the likelihood of the high cost outages.

Figure A2.10 Comparison with Base Case: expected annual outage (as % of demand)



Source: Oxera.

Figure A2.11 Comparison with Base Case: annual probability of outage



Source: Oxera.

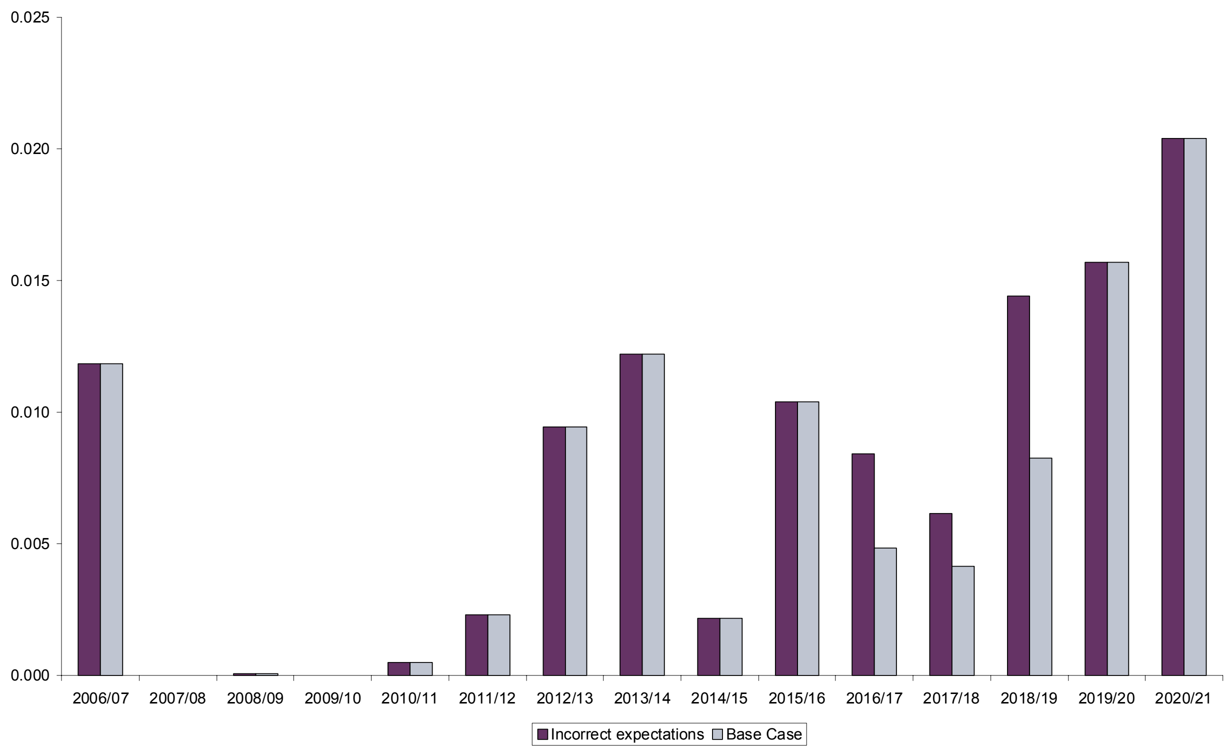
A2.5 Incorrect expectations

Although there is uncertainty regarding the availability of gas in the model, the distribution of outages is common knowledge—ie, everyone has the same expectations and they are, on average, correct. This sensitivity has investigated the scenario where expectations of the speed of decline of the UKCS are incorrect. Specifically, at any point in time, suppliers expect future UKCS supplies to be more abundant than they are in the model. Current-year production is known, but future supplies are always expected to be 5% above the model assumption.

This may be expected to lead to a delay in investment decisions because investors believe that supply and future prices will be such that no new investment is needed. Figures A2.12 to A2.14 show the results of the analysis. They illustrate that incorrect expectations can lead to a delay in investment. In this case, a piece of storage infrastructure that arrives in 2016/17 in the Base Case is delayed until 2019/20 with imperfect expectations.

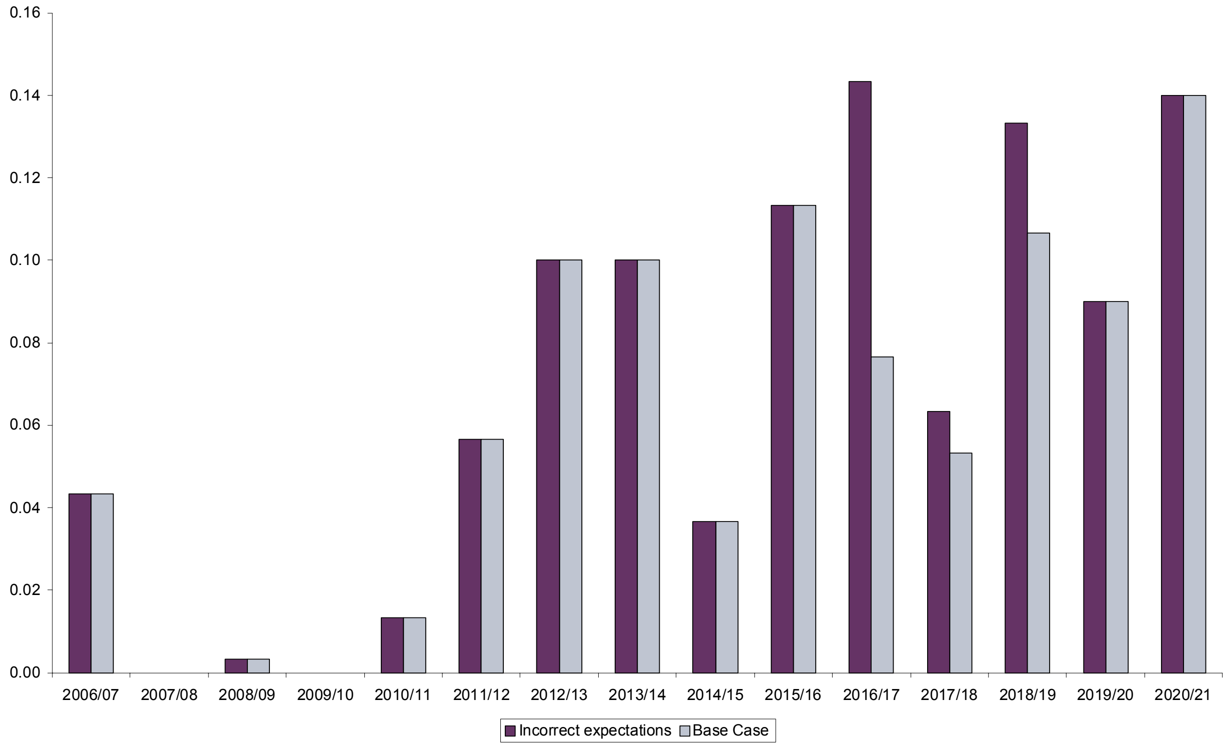
The lack of significant shifts in the pattern of infrastructure investment is explained by a combination of factors. Significantly, only one component of expectations has been altered (the UKCS volumes), and this by a relatively small volume at any point in time. Therefore, the degree to which price expectations will differ from actual outturns is very small (between 2016/17 and 2018/19, expected prices in the incorrect expectations scenario are, on average, 0.34p/th lower than those in the Base Case). In these circumstances, only investment decisions that are truly marginal are likely to be affected—all other projects will continue to be profitable or unprofitable. Consequently, there is very little change.

Figure A2.12 Comparison with Base Case: expected annual outage (as % of demand)



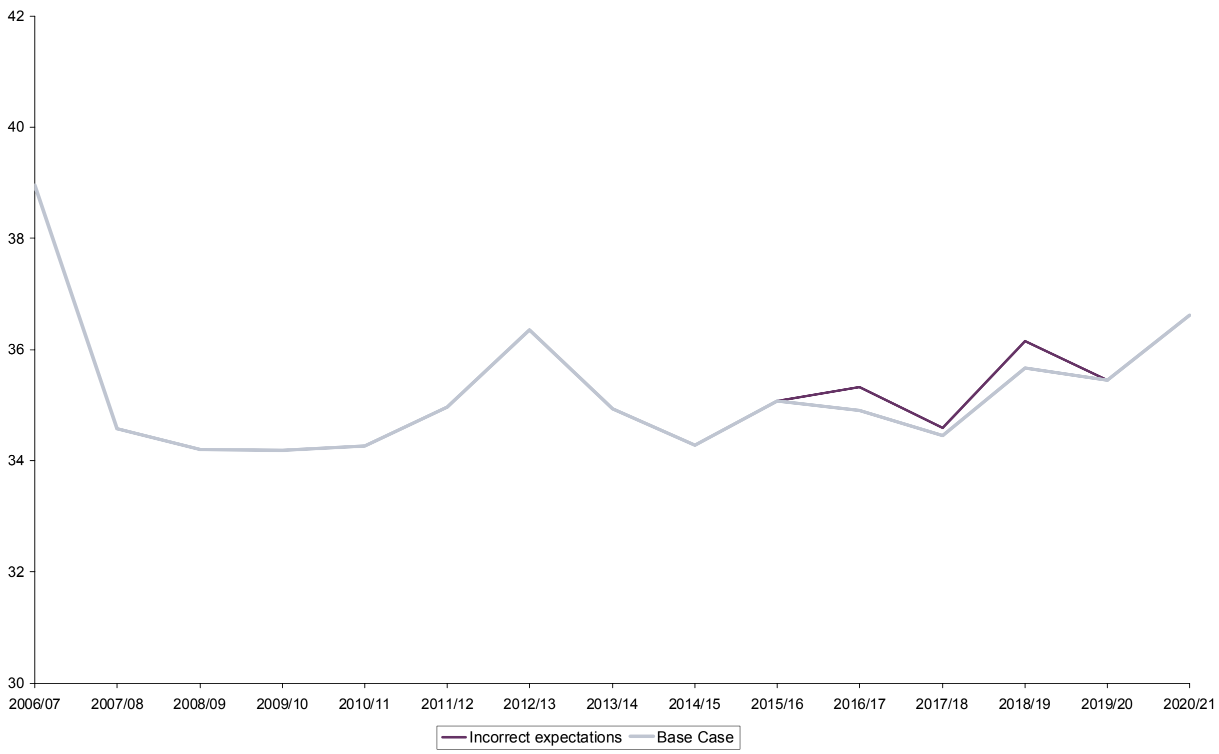
Source: Oxera.

Figure A2.13 Comparison with Base Case: annual probability of outage



Source: Oxera.

Figure A2.14 Comparison with Base Case: expected spot price (p/th)



Source: Oxera.

Furthermore, it is unlikely that shippers will not update their initial expectations over time to remove the forecast bias. If this does occur, the extent to which security will be adversely affected will diminish.

A3 Example investment decision

The investment model has a database of potential projects from which to choose. The decision is affected by forward price expectations and earliest commissioning dates—the former affecting the viability of a project and the latter limiting the potential choices available in a given year.

Initially, expectations of future prices are conditioned solely on the basis of the committed infrastructure projects contained in Table 3.1, the gas cost assumptions and outage risks. The price-security model derives the expected NBP price (allowing the NBP/global LNG price differential to be calculated) and the expected storage arbitrage opportunities. These spreads are then compared with the new entry costs for the database of potential projects and investment decisions taken.

For example, take a generic storage facility with the characteristics as set out below.

Key characteristics (Generic Storage 1)

Space (mcm)	900
Deliverability/injectability (mcm/d)	8/4
Earliest commissioning date	2010/11
Cushion gas requirement (mcm)	2250
Capital cost (£m)	125
Annual operating cost (p/th)	1.0
Asset life (yrs)	20

Source: Oxera.

The new entry cost for this facility varies over time depending on the expected cost of the cushion gas (which is assumed to be capitalised at the time of construction). As an indicative example, if the cost of cushion gas was 35p/th, the required summer–winter differential would be 21p/th, at a 15% discount rate. This consists of the annual operating cost (1p/th) and an annuitised capital and cushion gas cost (20p/th).

The price-security model produces an initial set of price expectations (and associated seasonal arbitrage) based on the supply capacity that is already operational or is under construction (shown in Figure A3.1 below as the red line). This would initially indicate that the storage facility would be viable from 2012/13. However, at this point in time, there are also several other projects that are viable. Moreover, they have lower new entry thresholds (reflecting different technical specifications and cost assumptions), which means that they have a higher profitability. All five profitable storage options are listed below (the facility under discussion is Generic 1).

Potential storage options

	Incremental return above new entry cost in 2012/13 (p/th)	Earliest commissioning date
Generic 1	2.12	2010/11
Generic 2	7.05	2009/10
Generic 3	10.46	2010/11
Generic 4	7.00	2014/15
Generic 5	1.27	2010/11

Source: Oxera.

Generic 4 is ruled out because it is unable to enter the market until 2014/15. The model then chooses Generic 3 as the first investment. This is on the basis that investors will expect the most profitable projects to have the greatest incentive to enter early. Updating price expectations leads to a change in the seasonal arbitrage value (shown by the green line) that affects the incremental return for the projects, as shown below.[100] This illustrates that Generic 3 is still able to make at least a normal return and that Generic 1 is unable to make a normal return if Generic 3 is built.

Impact of updating expectations

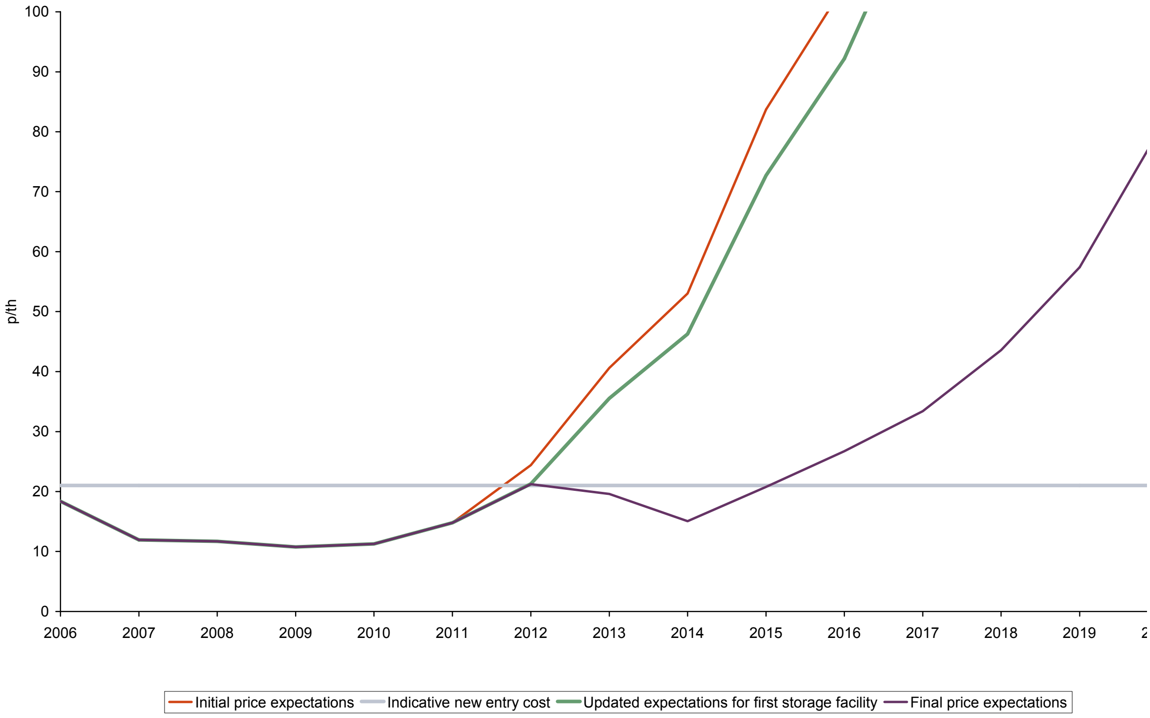
	Incremental return above new entry cost in 2012/13 (p/th)	
	Initial	After new storage facility entry
Generic 1	2.12	–0.8
Generic 2	7.05	4.08
Generic 3	10.46	7.40
Generic 5	1.27	–1.82

Source: Oxera.

This process is repeated for all storage and import infrastructure projects—from the table above it can be seen that Generic 2 would still be developed in 2012/13—and price expectations will change accordingly. This eventually changes expectations (before an investment in Generic 1 has been made) to those shown as the purple line in Figure A3.1 below. This finally leads to the investment in Generic 1 being committed for entry in 2016/17.

[100] The 21p/th line is indicative and will be affected by the relative changes in the expected cost of cushion gas.

Figure A3.1 Updated price expectations (p/therm)

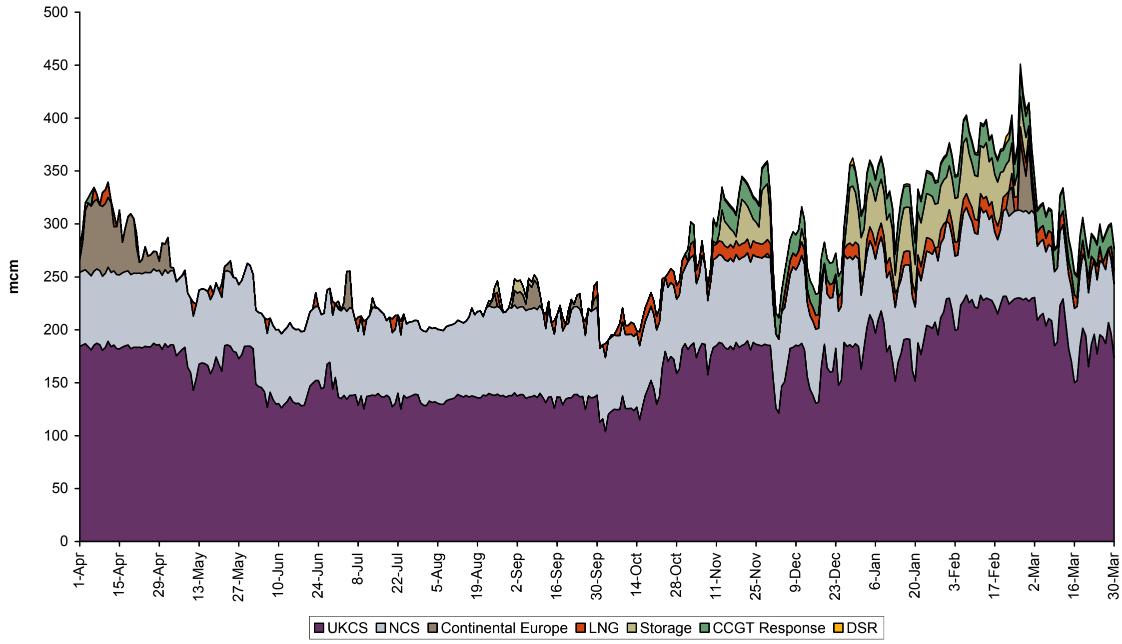


Source: Oxera.

A4 Base Case daily flow charts

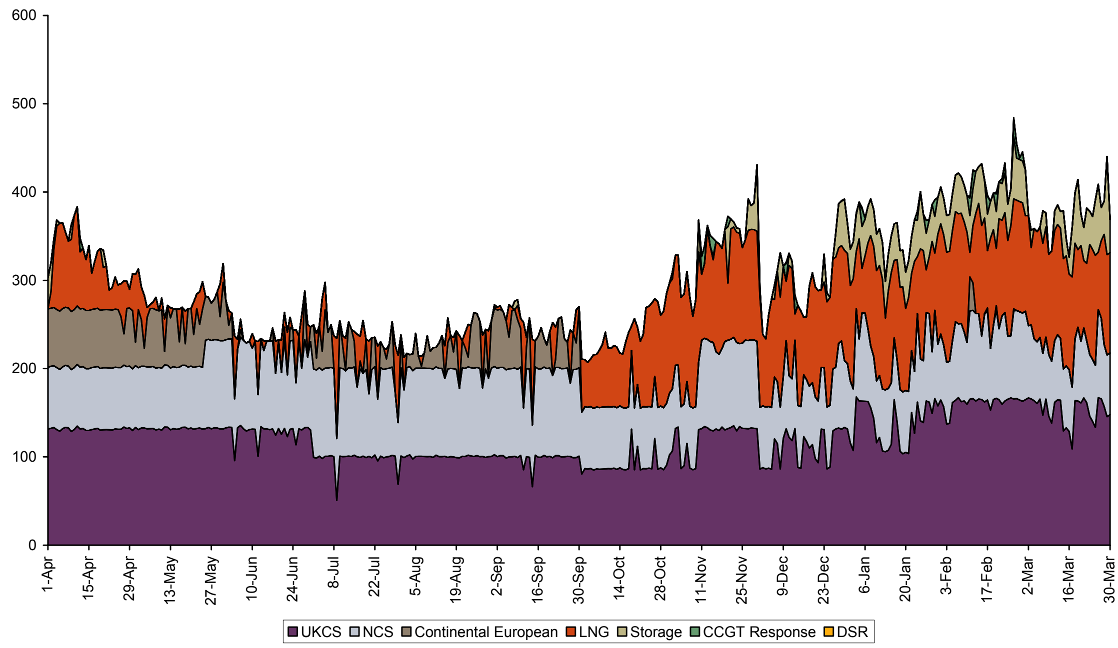
The following charts show how the composition of supply changes over the period of the analysis.

Figure A4.1 Daily flows, 2006/07 (mcm)



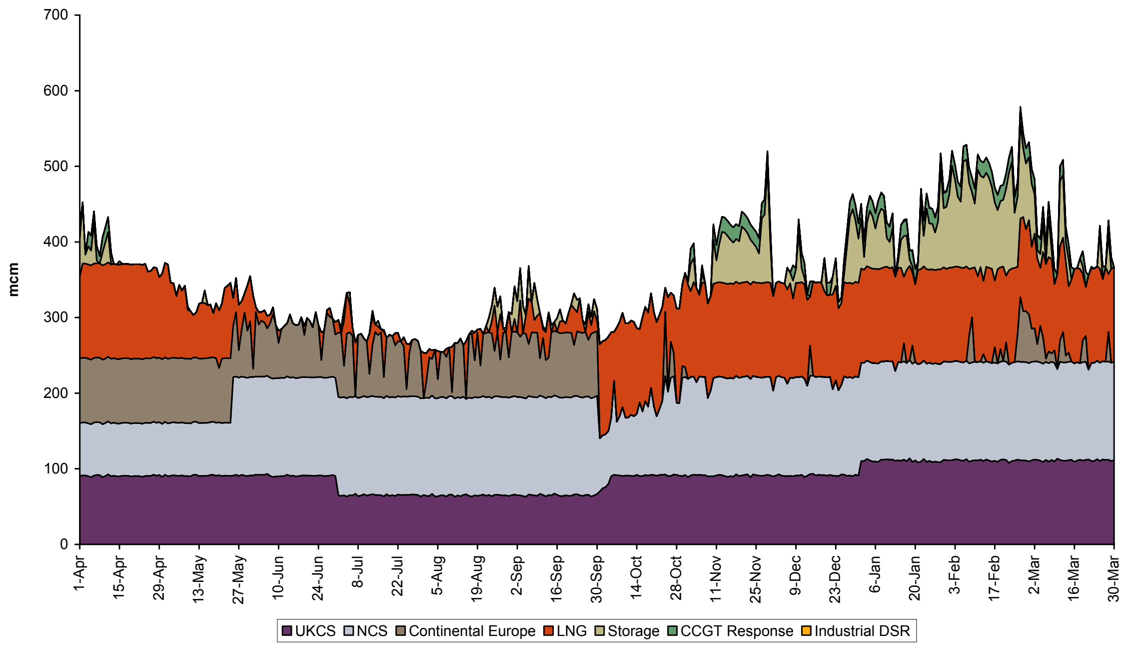
Source: Oxera.

Figure A4.2 Daily flows, 2010/11 (mcm)



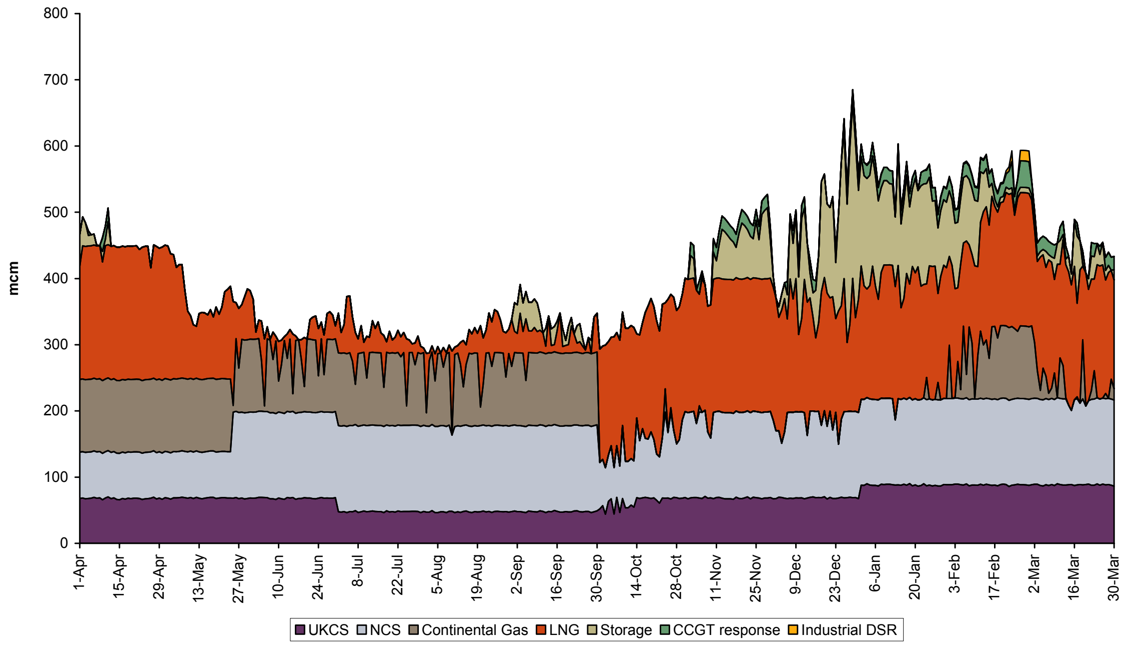
Source: Oxera.

Figure A4.3 Daily flows, 2015/16 (mcm)



Source: Oxera.

Figure A4.4 Daily flows, 2020/21 (mcm)



Source: Oxera.

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