The impact of gas market interventions on energy security

A report for DECC from Redpoint Energy

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1 Executive summary

Background

The increased dependence of Great Britain on gas imports, coupled with significant uncertainty as to the long term role of gas within the GB energy system, has led to an uncertain environment for new storage projects. In this context, DECC asked Ofgem to produce a report on the risks to gas security and to explore possible options for interventions to reduce these. Ofgem submitted its report in draft form to DECC in July 2012 and it was published in November 2012. The report illustrates that the current levels and diversity of supply capacity mean that interruption of supply to customers would only be expected to occur under very extreme circumstances. However, the change in supply mix does mean that a much wider range of risks become relevant than was the case historically.

Ofgem's modelling of potential interventions focused on the impact on physical security of supply, and demonstrated potential benefits in reducing the probability and expected severity of interruptions, but the scope did not include a more general assessment of the cost effectiveness of the options. DECC considered that a number of options were worthy of further investigation, including a more detailed cost-benefit analysis, to help inform a decision as to whether further intervention is warranted, and what form it should take.

DECC appointed Redpoint Energy to conduct an independent assessment of the impact of a set of potential interventions in the gas market on security of supply, considering both physical interruptions and market prices. This document sets out the assumptions that have been made for the modelling of the options and the quantitative approach undertaken to understand the potential for new storage brought forward by the market without further interventions, the impact of a set of possible interventions, and an assessment of the costs and benefits.

Modelling approach

We have undertaken both gas market modelling and storage asset modelling in this study. The gas market modelling has been primarily used to assess the impact on gas security of supply and the wholesale price of gas, whereas the storage asset modelling has been used to assess the case for investment in additional storage and the impact on profitability of existing assets.

Gas market modelling

We have deployed the same modelling framework as has been used to analyse the cash-out reforms proposed under Ofgem's Gas security of supply Significant Code Review. The methodology centres on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity, and then generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output. Flow responses to these daily variations are modelled without foresight of future variations. Model behaviour was sense-checked against historically observed data where possible. However, we note that a Gas Deficit Emergency has never occurred and relevant historic evidence, particularly with respect to supply outages, is often limited.

Storage modelling

Whilst the gas market model is effective for generating price and security of supply metrics, the 'decision rules' that drive storage operation are simplifications relative to how individual assets would in reality be optimised. A dedicated storage asset model was used to simulate in detail how Short Range Storage (SRS) and Long Range Storage (LRS) type facilities could be optimised under the simulated market conditions.

We used KyStore, a commercially available storage asset model developed by KYOS, to explore the potential value of a facility in a future spot year. The concept behind the model is to develop a rule-set for withdrawal/injection decisions that generates an optimal expected profit given a set of parameters specifying price behaviour (including the forward curve, and volatility and mean reversion parameters). We used the price simulations generated by the market model for each spot year to estimate the volatility and seasonality, and then used the storage asset model to calculate the expected profit, and associated uncertainty distribution around this.

Intervention options modelled

Three intervention options have been modelled as a part of this study. We have made assumptions on the design of each option, which is intended to be indicative at this stage. The evaluation of each of the intervention options takes place against a Baseline without an intervention. The Baseline and the intervention options are modelled primarily against a 'Stressed' scenario, similar to National Grid's Gone Green scenario but with higher (non-power generation) gas demand. Some cases have also been modelled against a Gone Green scenario.

Generic non-specific obligation

This option is modelled as the provision, most likely by the system operator, of responsive physical supply with a high ratio of deliverability to total volume, with the costs recovered through network charges. While the option design does not prescribe that the system operator's response to the obligation must be through storage, for the purposes of our modelling, we assume that this is accomplished through an additional fast cycling storage facility. This facility is assumed to operate outside of the market and does not affect the market price of gas.

Storage obligation

In our modelling of this option, an obligation is placed on suppliers to book and fill a certain amount of storage capacity over the winter period when the risk to security of supply is at its greatest. In our modelling, the maximum level of the obligation for a given year is derived based on the assumption that there must be sufficient gas in store to meet firm gas demand[1] (excluding CCGTs) during any winter day[2] under conditions where LNG is not available for an assumed number of days. Based on the resulting required storage profile produced for the winter period, the value of the obligation is set at its maximum

[1] This is derived from the National Grid Slow Progression 1-in-50 2012/13 load duration curve using an average seasonal demand shape.

[2] This is defined as the period from 1October to 31 March.

value from the start of winter though to the date when the maximum value of the profile is reached. The storage obligation is treated as a hard constraint in our model and can only be suspended to prevent, or reduce the severity of, firm gas demand interruptions. Once suspended, all storage is available to flow freely on that day subject only to technical constraints on rate of withdrawal and quantity of gas in storage.

We model two variations on the storage obligation. The primary design imposes a less onerous storage obligation in terms of volume on suppliers and is based on the assumption that LNG would not be available for 7 days from the start of an emergency. The secondary design places a higher volume obligation on suppliers and is based on the assumption that LNG would not be available for 14 days from the start of an emergency.

Supported storage

Under this option, support is provided for additional storage capacity, either 1 bcm of new SRS facilities (primary design) or 4 bcm of new LRS capacity (secondary design), in the form of a cap-and-collar regime, providing assurance on a minimum level of annual profits sufficient to achieve a required return for the investment. The additional capacity is assumed to operate normally in the market.

Modelling results

Impact on security of supply

Table 1 shows the LRS/SRS investment assumed for modelled intervention options for the Stressed scenario. In each case we estimated market investment in storage that could reasonably be expected to take place, in addition to any storage directly supported by the intervention. All the estimated market investment takes place in SRS facilities. As can be seen from Table 1, in Supported storage – primary design, we estimate that the addition of 1,000 mcm of new supported SRS capacity operating in the market would deter any additional market-based SRS investment from taking place.

Table 1 Storage investment: Baseline / intervention options – Stressed scenario

	Gas storage investment assumed in intervention options		Market investment	
	LRS	SRS	By 2020	By 2030
Baseline	0	0	400	400
Generic non-specific obligation	0	656	400	400
Storage obligation (primary design)	0	0	800	800
Storage obligation (secondary design)	0	0	800	1200
Supported storage (primary design)	0	1,000	0	0
Supported storage (secondary design)	4,000	0	300	300

Table 2 and Table 3 show the expected annual average probability of interruption for Firm Daily Metered (DM), Non-Daily Metered (NDM), Firm I&C electricity and Domestic & SME electricity customers under the Baseline and modelled intervention options for the Stressed and Gone Green scenarios respectively.

For the Stressed scenario, the results for Baseline and Generic non-specific obligation represent an average of modelled 2020, 2025 and 2030 spot years. In the case of Storage obligation and Supported storage, the results represent an average of modelled 2020 and 2030 spot years. The results represented are after assuming the market response for additional investment in gas storage. The Generic non-specific obligation is the most effective in reducing the security of supply relative to the Baseline.

Table 2 Average probability of interruption – Stressed scenario

	Firm DM gas	NDM gas	Firm I&C electricity	Domestic & SME electricity
Baseline	1 in 33	1 in 45	1 in 19	1 in 31
Generic non-specific obligation	1 in 300	1 in 450	1 in 107	1 in 281
Storage obligation (primary design)	1 in 231	1 in 273	1 in 38	1 in 79
Storage obligation (secondary design)	1 in 375	1 in 429	1 in 45	1 in 100
Supported storage (primary design)	1 in 52	1 in 65	1 in 31	1 in 58
Supported storage (secondary design)	1 in 107	1 in 143	1 in 60	1 in 150

For the Gone Green scenario, shown in Table 3, the results for Baseline and intervention options represent an average of modelled 2020 and 2030 spot years. The results represented do not assume any market response for additional investment in gas storage. Under the Gone Green scenario, the Generic non-specific obligation is again the most effective in reducing the security of supply relative to the Baseline.

Table 3 Average probability of interruption – Gone Green scenario

	Firm DM gas	NDM gas	Firm I&C electricity	Domestic & SME electricity
Baseline	1 in 333	1 in 333	1 in 115	1 in 231
Generic non-specific obligation	<1 in 1500	<1 in 1500	1 in 1500	1 in 3000
Storage obligation (primary design)	1 in 750	1 in 1000	1 in 81	1 in 200
Storage obligation (secondary design)	1 in 1000	1 in 1000	1 in 111	1 in 273
Supported storage (primary design)	1 in 375	1 in 375	1 in 150	1 in 273
Supported storage (secondary design)	1 in 600	1 in 1000	1 in 273	1 in 500

Cost benefit analysis of intervention options

The Cost Benefit Analysis (CBA) methodology is designed to assist in making a like-for-like comparison of different intervention options. All results are therefore shown as a change relative to the Baseline. The welfare changes were analysed in the downstream of the GB gas sector with a particular focus on the welfare of consumers and changes in the welfare of owners of storage capacity. Our CBA spans the period from 2020 to 2030 inclusive. Our CBA does not include an assessment of any broader impact of gas supply interruptions on the economy.

We have used a discount rate of 13% for market-based storage investment. Where storage investment takes place on a non-market basis, we have calculated the associated capital cost for a range of discount rates between 8% and 13%. This reflects the uncertainty about any reduction in the hurdle rate for storage investment associated with a cap and floor regulatory regime. It also reflects uncertainty about whether any such reduction should be treated as a net welfare gain given that the risk associated with a storage investment associated with a particular intervention would not be reduced fundamentally, but instead allocated differently between consumers and storage investors.

Table 4 to Table 6 show the impact of the intervention options under the Stressed scenario on GB consumers, suppliers and storage owners as estimated in the modelling. We assume a fully competitive supply market and hence that any change in supplier costs is passed through to consumers, leaving no change to supplier welfare throughout.

Table 4 CBA for Generic non-specific obligation – Stressed scenario

NPV (real 2012) £ million	8% hurdle rate			13% hurdle rate		
	Consumer welfare	Supplier welfare	Storage welfare	Consumer welfare	Supplier welfare	Storage welfare
Generic non-specific obligation[3]	-138.1	NA[4]	NA	-339.9	NA	NA

Table 5 CBA for Storage obligation – Stressed scenario

NPV (real 2012) £ million	Consumer welfare	Supplier welfare	Storage welfare
Storage obligation (primary design)	51.1	0	-802.3
Storage obligation (secondary design)	62.0	0	-557.5

[3] The welfare effects of the Generic non-specific obligation are limited to consumers since the supply source under the obligation is kept out of the market

[4] Not applicable

Table 6 CBA for Supported storage – Stressed scenario

NPV (real 2012) £ million	8% hurdle rate			13% hurdle rate		
	Consumer welfare	Supplier welfare	Storage welfare	Consumer welfare	Supplier welfare	Storage welfare
Supported storage (primary design)	323.7	0	-1,094.2	313.0	0	-1,391.4
Supported storage (secondary design)	986.7	0	0.3	295.0	0	-173.5

For the Supported storage – secondary design option we also conducted a CBA under the Gone Green scenario. The results are shown in Table 7.

Table 7 CBA for Supported storage – Gone Green scenario

NPV (real 2012) £ million	8% hurdle rate			13% hurdle rate		
	Consumer welfare	Supplier welfare	Storage welfare	Consumer welfare	Supplier welfare	Storage welfare
Supported storage (secondary design)	627.3	0	39.2	-91.1	0	-107.9

Conclusions

Generic non-specific obligation

The Generic non-specific obligation against the Baseline is effective in reducing security of supply, particularly as it is kept outside of the market solely for this use. This intervention results in a saving in the cost of unserved energy of £264m. However, this saving is lower than the cost of the intervention even at the lower 8% cost of capital. Because the intervention is kept outside of the market, there are no other means to recoup the cost of the intervention for consumers except for savings in unserved energy.

Storage obligation

Both designs of the Storage obligation lead to a significant improvement in security of supply for both firm DM and NDM gas customers. This improvement is greater under the secondary design, where the overall effect is comparable to that seen under the Generic non-specific obligation. This happens mainly because a storage obligation prevents storage from emptying during winter, and hence more gas in storage is likely to be available in case of a sudden supply interruption.

Both designs of the Storage obligation for Stressed scenario reduce the cost of unserved energy and increase the total cost of gas for consumers. Both of these elements are greater under the secondary design, with the overall net balance of consumer welfare being approximately the same. Both designs reduce profits from existing storage, and the magnitude of this effect is very similar. Overall net storage welfare is negative but is lower in secondary design relative to primary design. This is due to the larger gap between profits of new storage and the cost of new storage under the secondary design. This gap would suggest that market investment response in new storage capacity may be even greater than that estimated in our modelling. If that were the case, further SRS would increase the cost of new storage investment and reduce gas price volatility, driving down storage profits further. All these factors would bring storage welfare closer to that seen under the primary design of the Storage obligation.

Supported storage

In case of Supported storage, the secondary design is more effective at reducing the probability and impact of demand interruptions than the primary design, but is less effective than the Generic non-specific obligation. This is as expected given the much higher volume of gas in store under the secondary design and the less volatile behaviour of LRS relative to SRS, which means that it is more likely to be available at the time that an emergency occurs. However, given that supported storage participates in the market, there is no guarantee that it will be available to flow at times of emergency.

Supported storage – primary design appears to be beneficial to consumers but with a significant negative impact on owners of existing storage capacity for Stressed scenario. Although the security of supply benefits of additional supported SRS are estimated to be modest, there is a greater estimated benefit to consumers in terms of lower gas prices and the associated cost of support is limited.

Although the security of supply benefits of Supported storage – secondary design are estimated to be significant under the Stressed scenario, and there is a large estimated benefit to consumers in terms of lower gas prices, the associated cost of support is estimated to be large unless it is assumed that cap and floor regulation results in a better overall allocation of revenue risk from the additional LRS storage.

Given that Supported storage – secondary design is estimated to bring a net benefit to consumers under the Stressed scenario, CBA under the Gone Green scenario was also estimated. Here, the value of reduction in unserved energy relative to the Baseline is significantly lower than in the Stressed scenario. The estimated value of the reduction in the cost of gas for consumers is also somewhat lower, and the estimated cost of support is similar to that seen under the Stressed scenario. Consumers are estimated to benefit from the intervention only in the case where it is assumed that cap and floor regulation results in a significantly lower cost of capital for investors in the additional LRS storage, with no corresponding cost for GB consumers.

2 Background

2.1 Background

The Great Britain (GB) gas market is going through a significant transformation as its traditional domestic UK Continental Shelf (UKCS) supplies decline, and it becomes increasingly dependent on exports from Norway, gas through interconnectors from continental Europe, and imports of Liquefied Natural Gas (LNG). Alongside this, in recent years, summer-winter spreads have narrowed and price volatility has fallen, which, taken together with significant uncertainty as to the long term role of gas within the GB energy system, has led to a difficult environment for new storage projects.

Given the increasing dependence of GB on gas imports, the Department of Energy and Climate Change (DECC) asked Ofgem to produce a report on the risks to gas security and to explore possible options for interventions to reduce these risks and maintain secure supplies for customers. Ofgem submitted its report in draft form to DECC in July 2012 and it was published in November 2012[5]. The report illustrates that the current levels and diversity of supply capacity mean that interruption of supply to customers would only be expected to occur under very extreme circumstances. However, the change in supply mix does mean that a much wider range of risks become relevant than was the case historically.

Ofgem's modelling of potential interventions focused on the potential impact on security of supply, and demonstrated potential benefits in reducing the probability and expected severity of interruptions, but the scope did not include a more general assessment of the cost effectiveness of the options. DECC considered that a number of options were worthy of further investigation, including a more detailed cost-benefit analysis, to help inform a decision as to whether any further intervention is warranted, and what form it should take. In parallel, Ofgem is leading a Gas Security of Supply Significant Code Review with the intent of changing the cash-out arrangements, and payment for interruption, in the event of a Gas Deficit Emergency.

DECC appointed Redpoint Energy to conduct an independent assessment of the impact of a set of potential interventions in the gas market on security of supply, considering both physical interruptions and market prices. This document sets out the assumptions that have been made for the modelling of the options and the quantitative approach undertaken to understand the potential for new storage brought forward by the market without further interventions, the impact of a set of possible interventions and a quantified assessment of the costs and benefits, including unintended consequences.

2.2 Structure of the report

The sections in the report are as follows:

[5] https://www.gov.uk/government/publications/gas-security-of-supply-report

Section 3 provides an assessment of the drivers for gas storage value and an illustrative impact of gas price seasonality and volatility on gross margin of Long Range Storage and Short Range Storage.

Section 4 presents a high level overview of potential market failures in the GB markets, covering market operation and incentives to invest in gas storage.

Section 5 describes the gas market modelling and volatility modelling framework as well as the storage asset modelling approach.

Section 6 describes the intervention options and the scenarios that have been considered and modelled as a part of this study.

Section 7 states the assumptions for both the gas market modelling and the storage asset modelling.

Section 8 describes the additional specific assumptions relating to the intervention options that have been used in the modelling.

Section 9 lists the market modelling and storage modelling results for the security of supply metrics.

Section 10 describes the Cost Benefit Analysis (CBA) methodology and presents the results.

Section 11 describes the interaction between the interventions and market failures.

Section 12 describes the key conclusion of the study.

Section 13 includes additional modelling results, security of supply equivalence results and detailed results of market modelling and market iteration modelling for the Baseline and intervention options.

3 Gas storage value drivers

3.1 Types of storage

The key characteristics of a storage facility from an economic perspective are its working volume, the total volume of gas that can be stored at one time, the maximum rate at which gas can be injected into the facility, and the maximum rate at which it can be withdrawn. The main types of large scale gas storage can be categorised, from a commercial perspective, based on their typical profiles of use.

Seasonal, or long range, storage (LRS) is primarily used to inject gas during the summer, at times of lower demand, and to withdraw in winter, when demand is higher. Such facilities typically have large working volume with relatively low injection rates, suited to filling up over the summer, and higher withdrawal rates to allow flexibility on the pattern of withdrawal across the winter.

Fast cycle, or short range, storage (SRS) is primarily used to inject and withdraw in response to day-to-day market conditions. The pattern of injections and withdrawals for fast cycle will be likely to be volatile, and on aggregate will usually equate to multiple 'cycles' of storage over the year. Fast cycle facilities typically have higher withdrawal and injection rates relative to working volume that enables them to take advantage of shorter term market changes.

From a system perspective, storage could also be held purely for emergency purposes, termed strategic storage, or for use for system support from a network management perspective.

The two main types of geological storage are salt caverns and depleted gas reservoirs. Salt caverns are leached from geological salt strata. The relative costs of creating space versus adding injection and withdrawal capacity mean that these are typically developed as fast cycle facilities. Depleted gas reservoirs can provide significant volume, but higher relative costs of developing injection and additional withdrawal capacity mean that these are typically developed as seasonal facilities. They also typically require a high level of 'cushion gas' – the gas that must be present in the reservoir at all times to maintain the operability of the facility. Aquifers (and indeed undepleted gas reservoirs) can in principle also be used but present higher development risks.

Dedicated LNG storage facilities (in contrast to LNG import terminals) can also be used, with the associated liquefaction and regasification to inject and withdraw. These are relatively expensive and hence, in a GB context, have historically been developed primarily for system support reasons.

Storage also exists in the form of LNG tank facilities, where LNG is stored after unloading from ships. Pressure on the transmission network is managed within a tolerance range, which also creates effective storage termed linepack.

3.2 Drivers of gas storage value in GB

The commercial value in storage comes from the ability to buy and inject gas at times of lower price, and withdraw and sell it at times of higher price. The seasonal pattern of demand (with higher demand in winter) leads to an associated seasonal price profile, enabling storage to be used to buy at lower prices in summer and sell at higher prices in winter. Seasonality in prices, and the underlying fundamental factors behind that, is thus a key value driver.

Wholesale spot gas prices also exhibit significant movements on a day-to-day basis, and indeed within-day, and hence storage can also be used on these timescales to buy when spot prices are relatively lower, and sell when they rise. The volatility of day-ahead prices is a common metric for this element of price behaviour. Volatility is a measure of the spread in the distribution of day-to-day price movements observed over a given time period[6]. The level of volatility in the market, and the factors behind that, form the second key value driver.

Given the characteristics of LRS and SRS facilities, they have different sensitivities to these two drivers. LRS value is particularly driven by seasonality, and SRS value by volatility. To illustrate this, we show the results of modelling the potential gross margin of two representative facilities and how these vary with seasonality and volatility. The key assumptions used for both types of storage are shown in Table 8, and the results are shown for LRS in Figure 1 and SRS in Figure 2.

Table 8 Assumptions for LRS and SRS

	Capacity (mcm)	Injection rate (mcm/day)	Withdrawal rate (mcm/day)	Storage Start level (mcm)	Storage End level (mcm)
LRS	2000	10	25	0	0
SRS	500	45	45	250	250

[6] Volatility is the annualised standard deviation of daily log returns, as applied to a daily price series *P*: *day-ahead volatility = std{ ln(P(t) / P(t-1)) } * sqrt(365)* (assuming a full calendar day price series)

Figure 1 LRS Gross Margin for varying seasonality and volatility of gas prices

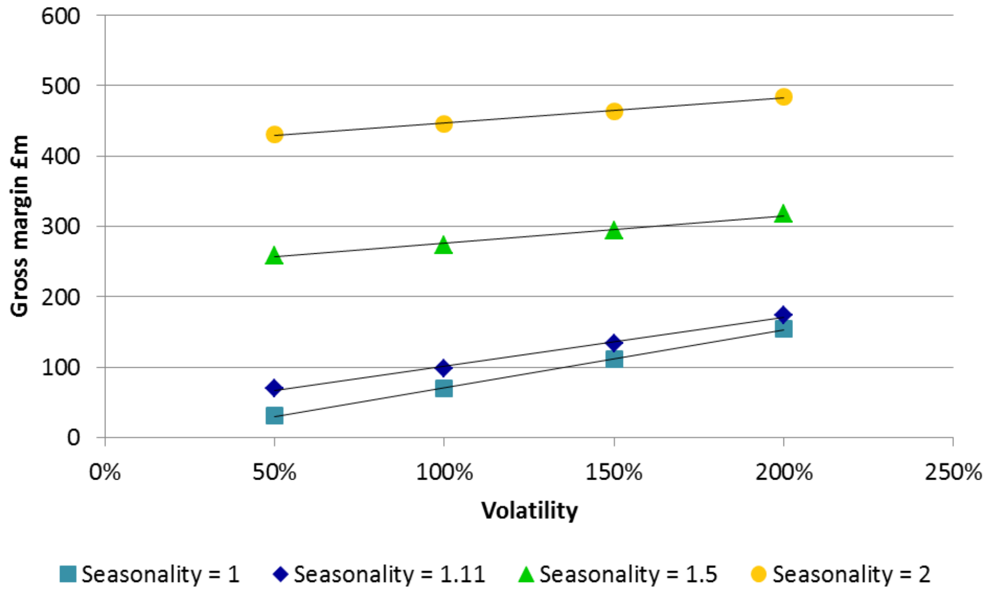
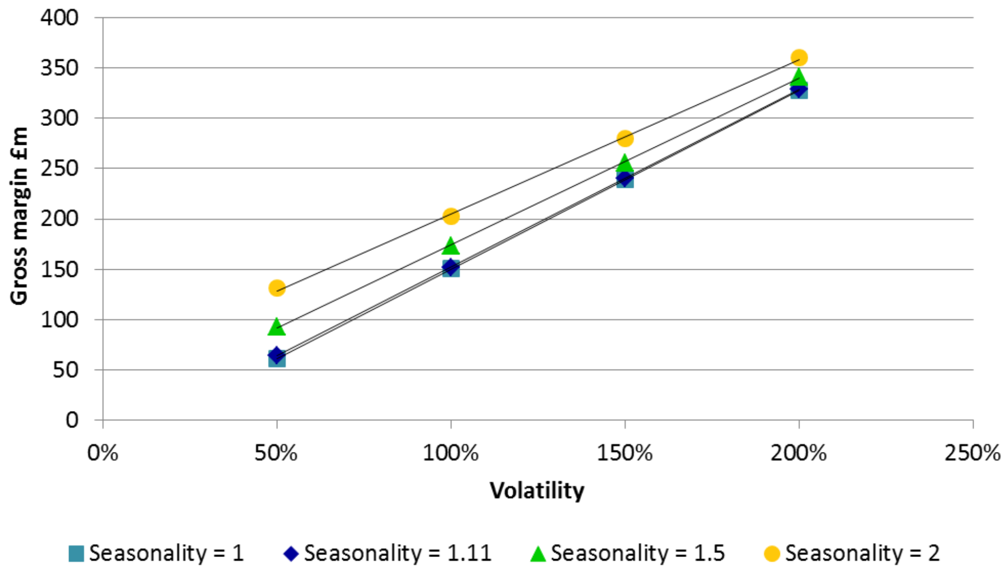


Figure 2 SRS Gross Margin for varying seasonality and volatility of gas prices



Both figures plot the expected annual gross margin (determined by the outcome of the costs of buying gas and revenues from selling it, taking into account variable costs) on the y-axis, plotted against day-ahead spot volatility on the x-axis. The different lines on the plots correspond to the results under different seasonality assumptions. The metric we have used for seasonality is the ratio of average winter to average summer price. The 1.11 value for seasonality in both figures is based on the actual forward price data that has been taken from ICE in February 2013. Comparing between the two figures, the wider spacing of the lines in Figure 1 shows the sensitivity of LRS to seasonality, and the steeper lines in Figure 2 show the greater sensitivity of SRS to volatility.

Storage strategies

Historically, storage was often viewed primarily as a means of physically balancing supply and demand, and would correspondingly be used and planned within a supplier's portfolio as a means of following customer demand. With a focus on asset optimisation, an alternative means to utilise storage is to aim to drive the greatest value through using it to buy and sell gas in the wholesale market.

The strategy deployed will in turn affect the achieved value of the facility. Considering a stand-alone asset for simplicity, value-based strategies will exhibit different levels of market risk and require different levels of trading sophistication. An example of a straightforward, low risk, strategy would be one where storage value is 'locked in' on a forward basis by buying and selling appropriate forward contracts. The expected profit from this will, however, be lower than the expected profit from a strategy involving optimal buy and sell decisions on a day-ahead basis, although this latter strategy would be more risky, with a lower potential downside outcomes. A spot-based strategy with a more sophisticated forward hedging strategy could be used to aim to capture greater upside whilst limiting downside, although this will be subject to higher transaction costs and will demand a greater level of trading capability.

Having shown the sensitivity of value to the primary drivers of seasonality and volatility, and how the strategy deployed for determining hedging and physical withdrawal and injection decisions will impact value, the next sections explore how fundamentals in the market in turn affect price behaviour and hence storage value. We review the impact both of supply and demand drivers, as well as regulatory market arrangements.

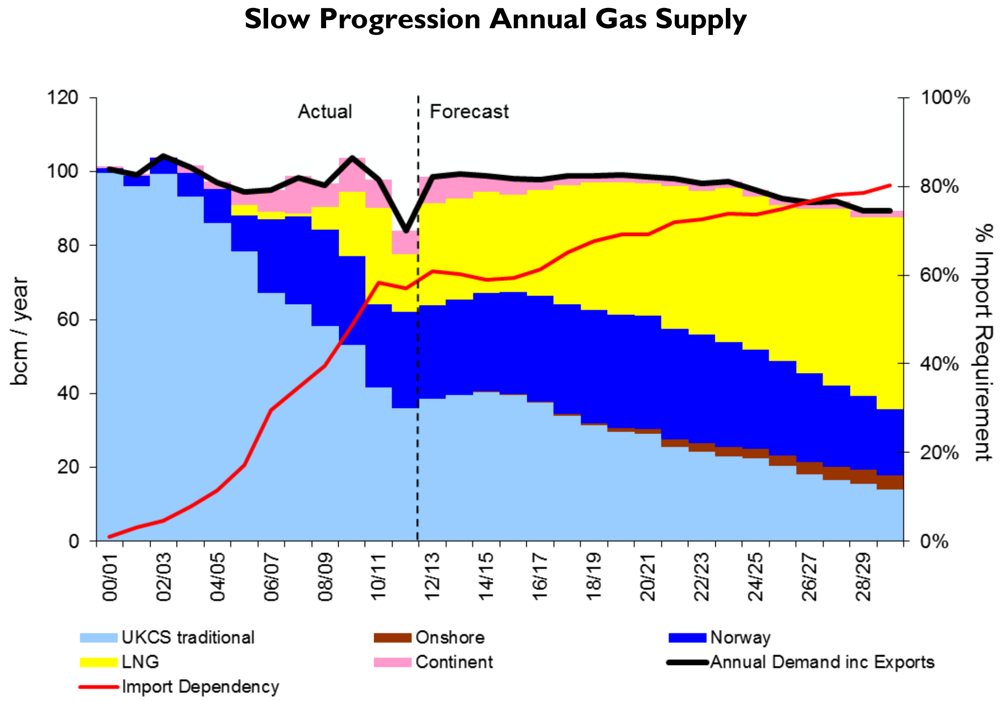
Supply drivers

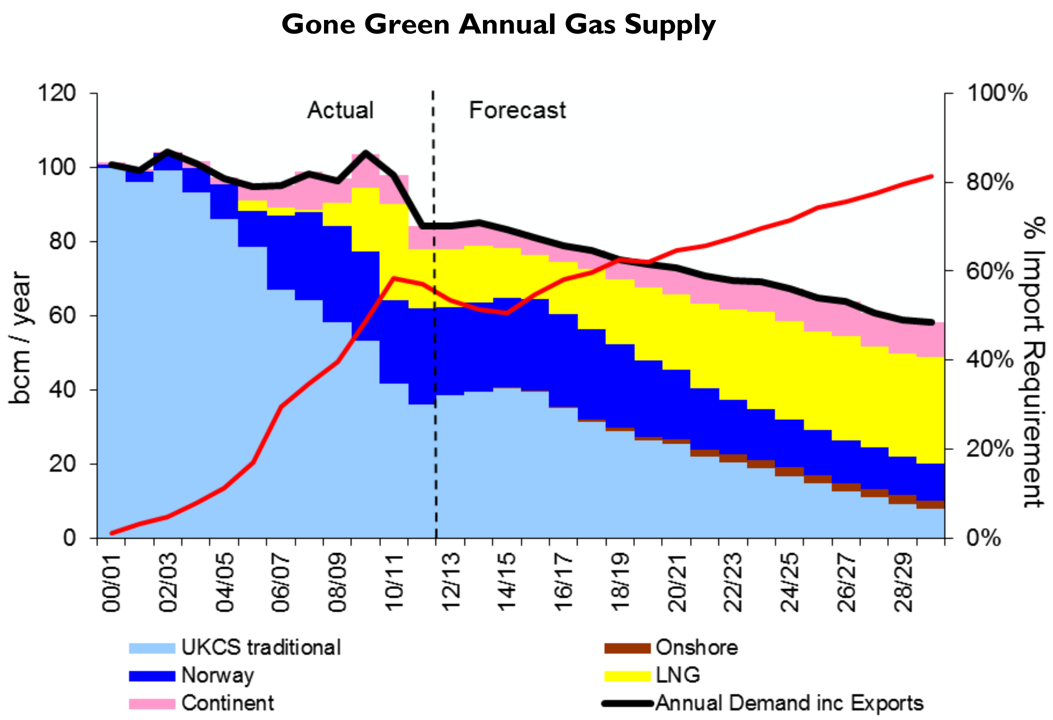
The supply mix will drive storage value in two main ways. First, variation in availability or cost of different supply sources on a seasonal basis can drive seasonality in price. Second, limited flexibility in supplies, and short term variation in availability, or cost, will impact spot price volatility.

From a GB perspective, these characteristics will vary by type of supply, which is undergoing a major transition, as imports have increased since 2003-04 with a corresponding decline in the UKCS supplies. Historically, UKCS has not only provided domestic gas but also acted as a flexible source of gas through "swing fields" which can increase production during periods of high demand or reduced gas supply. These fields are now in decline and therefore the capability to ramp up production in periods of tight supply and balance demand is decreasing.

Imports are likely to provide an increasing proportion of GB gas supply going forward. Under both National Grid's Slow Progression and Gone Green scenarios, shown in Figure 3, imports are projected to provide approximately 80-85% of the total gas supply by 2030. As seen from the figure, this is made up of gas from Norway, gas through the interconnecting pipelines with the continent, Interconnector UK (IUK) and the Bacton-Balgzand Line (BBL), and an increasing proportion of LNG imports. Norwegian production has significant flexibility, although this will to some extent be constrained by contractual commitments, and will also respond to the market situation both in GB and on the continent. The interconnectors provide a means for gas to respond to market situations on either side of the pipes where flows are efficient. The non-continuous supply chain associated with LNG creates a complex dynamic from a volatility perspective. Where LNG prices are relatively low, and terminals have a high load factor, then the 'baseload' nature of the flows will mean that there is limited flexibility. At a lower average level of flow, the tank storage at LNG terminal facilities can provide flexibility and could correspondingly reduce volatility. At lower levels still, with only intermittent flows, then the potential lag associated with LNG shipping and diversion decisions could be a driver for higher volatility. LNG is also likely to play a significant role in the seasonality of GB prices, as GB prices are affected by those in an increasingly interconnected global LNG market.

Figure 3 UK annual gas supply forecasts in the GTYS by National Grid (under the Slow Progression and Gone Green) scenarios



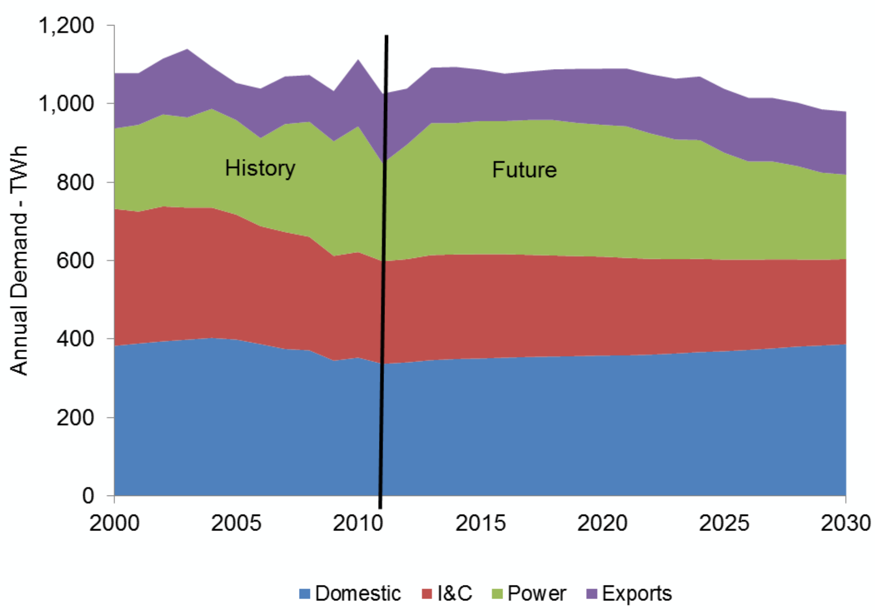


Demand drivers

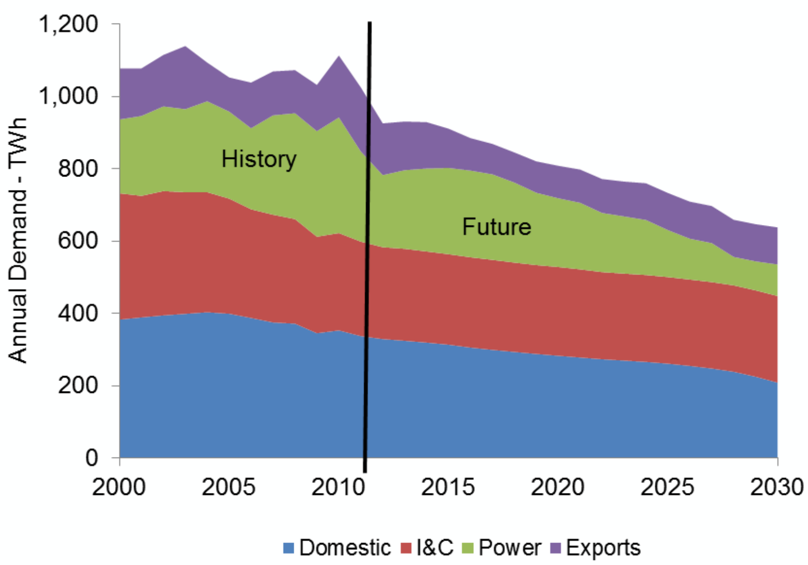
As can also be seen in Figure 4 overall gas demand is set to fall under the Slow Progression and Gone Green scenarios. The breakdown across the different sectors of demand is shown in Figure 4.

Figure 4 UK annual gas demand in the GTYS by National Grid (under the Slow Progression and Gone Green scenarios)

Slow Progression Annual Gas Demand



Gone Green Annual Gas Demand

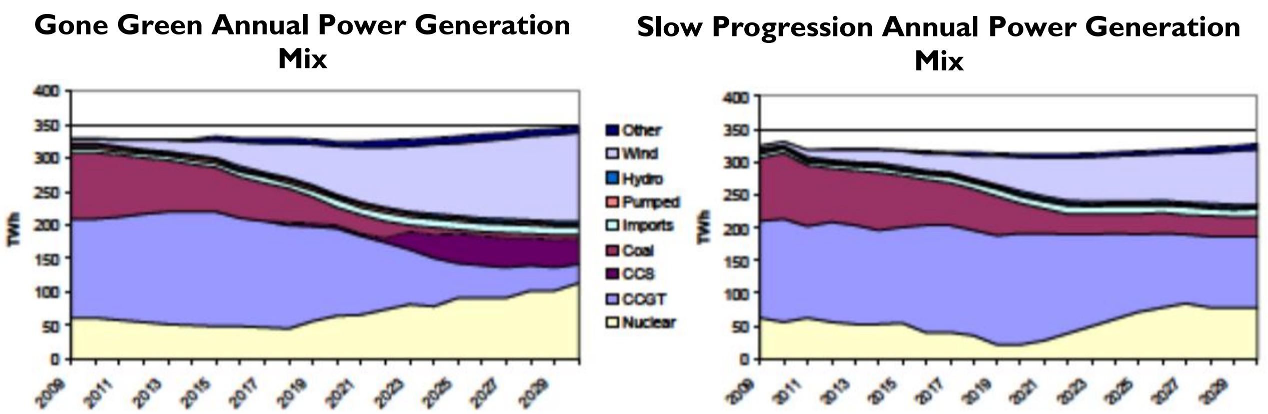


Overall, a ‘tighter’ market might be expected to lead to higher volatility, with an increased element of ‘scarcity’ pricing affecting spot price dynamics. The level of demand reduction relative to the reduction in UKCS and Norwegian supplies would influence this. However, the way in which the different supply sources interact at different levels of demand, and at different relative price levels, will also be important – for example, the way in which LNG is flowing, as mentioned above.

Currently GB demand is highly seasonal, with winter demand exceeding summer demand typically by a factor of 1.7, a key driver for corresponding seasonality in prices. This is driven particularly by the seasonal nature of heating demand.

Volatility in demand on a day-to-day basis will of course be a key factor behind spot price volatility. An important driver behind this in turn will be the way in which the electricity generation mix changes, and the corresponding demand for gas in the power sector. One of the key differences between National Grid’s Gone Green and Slow Progression scenarios, shown in Figure 5, is the different level of wind generation in the medium to long term. The intermittent nature of wind is likely in turn to drive volatility in gas generation, as CCGTs provide the flexibility needed, which in turn would be expected to drive price volatility.

Figure 5 UK annual power generation mix forecasts published in GTYS by National Grid (under Gone Green and Slow Progression scenarios)



Regulatory and market arrangements

As well as the impact of supply and demand fundamentals, the regulatory and market frameworks for GB and its neighbouring markets will impact storage value.

This can take the form of direct regulation around the use of storage. A number of European countries have security of supply requirements that put minimum constraints on the level of gas in store at different times of the year. These are generally in the form of public service obligations (PSOs) imposed on suppliers or on transmission system operators. Other things being equal, these requirements will limit the use of storage in the market, which can effectively hold back flexibility that would otherwise be available. This would tend to be an upwards driver for GB volatility, and the removal or loosening of these regulations in the future would directionally tend to decrease it.

Other types of market arrangements can also directionally affect flexibility availability and hence volatility. Balancing arrangements vary between different markets both in the granularity by which market participants’ balance positions are measured (for example, hourly or daily), and the price to which they are exposed for any imbalance. Where balancing arrangements are more 'penal' for participants, this may in turn lead to flexibility being 'held back' from the market as a risk management measure, which could drive volatility in neighbouring markets in the short run – although in the longer run this might also drive investment in further flexibility. Conversely, were these arrangements to be 'loosened' in the future, this could have a downwards impact on volatility relative to current arrangements.

Market structure, and in particular the range of participants that control flexibility, may affect the level of competition in the supply and demand of flexibility, which may also impact on volatility over time.

4 Assessment of potential market failures

4.1 Introduction

This section presents a high level overview of key potential market failures in the GB market, covering market operation and incentives to invest in gas storage. Its main purpose is to examine, from a theoretical rather than an empirical angle, if there is a potential economic case for a security of supply intervention in the GB gas market.

The study does not cover the upstream of the gas sector or the GB onshore gas pipeline network. It also does not consider potential market failures outside GB borders. Finally, it does not provide a comprehensive overview of all potential market failures but focusses on the key potential market failures that could to some extent be addressed by the interventions described in Section 6, as well as the market failures that could result from those interventions.

For the purposes of this study, we define market failure to be a failure of market operation to achieve a Pareto efficient allocation of goods such that some market participants could be made better off without making any of the other participants worse off. The specific potential causes of market failure that we consider are:

- Externalities
- Public goods
- Market power
- Moral hazard

We specifically do not consider bounded rationality as its existence is subject to a debate that we are not in a position to resolve in this short study. We also do not consider information asymmetries as our analysis does not touch on the economic decisions of small individual consumers and it would be difficult to argue that significant informational asymmetries exist between the larger market participants.

4.2 Potential market failures under current market arrangements and proposed SCR reforms

Cash-out arrangements

The main theoretical justification for Ofgem's proposed reforms of the current cash-out arrangements in the GB gas market is that the freezing of the cash-out price at times of a Gas Deficit Emergency (GDE) results in a market failure. Under these circumstances, the cash-out price does not reflect the true value of gas in times of extreme scarcity and this prevents Pareto-improving transactions from taking place in some instances. This can have two potential manifestations. The first is that gas is available to shippers at a price which is higher than the level at which the cash-out price is frozen but lower than the Value of Lost Load (VoLL) of some customers who are being interrupted and it is not in the interest of shippers to acquire that gas for their customers since they would not be fully compensated for the cost of that gas under the prevailing cash-out arrangements. The second manifestation is that the welfare of consumers could be improved by security of supply measures such as additional gas storage, demand-side response, additional supply infrastructure or more firm physical gas contracts when the full costs and benefits, measured in terms of value of unserved energy avoided, are taken into account. However, because shippers do not face the full cost of their customers being interrupted, the incentives on them to provide these security of supply measures are suboptimal.

Ofgem's proposed reform of the cash-out arrangements would cap the exposure of shippers to imbalance payments in times of emergency, hence the market failure described above would only be resolved in part, as acknowledged in Ofgem's Draft Impact Assessment[7]. The rationale for capping the potential exposure of shippers is that uncapped exposures may result in bankruptcies of some shippers. This would in turn lead to other market failures, namely increased market concentration and hence market power. It may also create a moral hazard problem with shippers not responding appropriately to the economic incentives provided by cash-out prices in the belief that they would not be allowed to go bankrupt. Hence capped cash-out represents a 'second-best' approach that is intended to strike a balance between different forms of potential market failure.

Operation of interconnectors

It has been observed that historically, gas flows on interconnectors that connect GB to mainland Europe have not necessarily followed differences in the hub prices of the markets that they connect. This can be seen in Figure 11 and Figure 12 for IUK and BBL respectively. This has in turn led to a concern that interconnectors may not be efficiently utilised in times of stress, potentially leading to higher prices and greater risk to GB consumers.

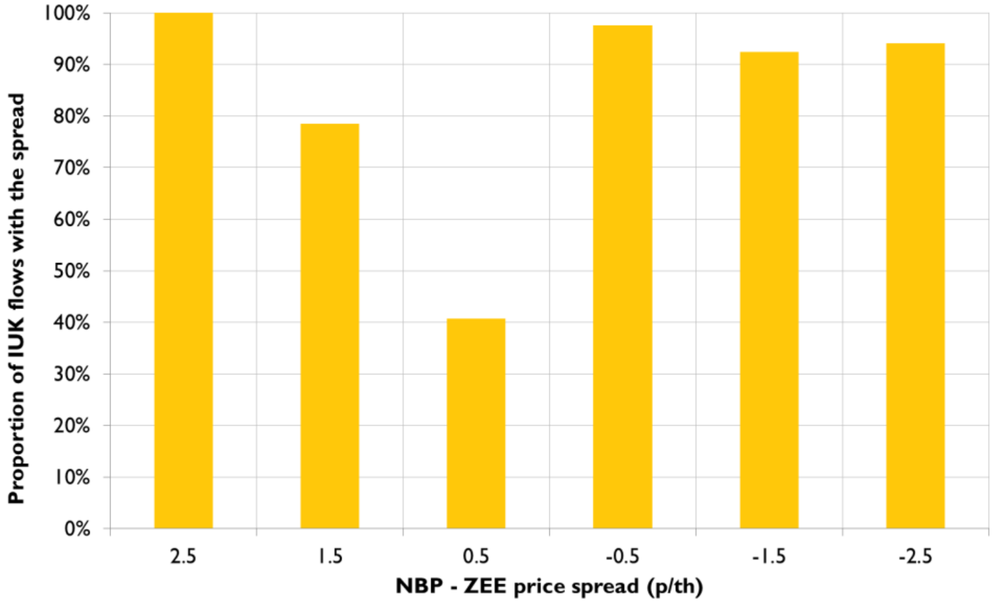
In October 2012, Ofgem, NMa and CREG published a joint call for evidence with regard to the use of the gas interconnectors on GB's borders and possible barriers to trade. Initial analysis by the regulators, the results of which are contained in the call for evidence, found some evidence of seemingly inefficient utilisation of the IUK and BBL interconnectors. Flows against the direction of the spread in spot prices or incomplete utilisation of capacity in the presence of a significant spread in spot prices were taken as a sign of potential inefficiency in interconnector utilisation.

Figure 6 shows the proportion of IUK flows that went from the higher priced market to the lower priced market at different price spreads[8]. Material inefficiency of flows can only be observed when NBP spot prices are higher than ZEE spot prices, and no counterflows are observed where the NBP-ZEE price spread is above 2 p/th. For BBL, relative efficiency of flows at different price spreads can be gauged from Figure 12. Both figures show that flows against the price spread become less likely at higher price spreads.

[7] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/Draft%20Impact%20Assessment%20Gas%20Security%20of%20Supply%20Significant%20Code%20Review.pdf

[8] The data set for this graph is the same as that used to plot Figure 11.

Figure 6 Efficiency of IUK flows



Inefficiency of operation would be apparent if all flows on the interconnectors resulted from spot trading. However, many of the flows take place on a contractual basis, and flows on the basis of contractual positions will not necessarily match observed price differences between the connected spot markets. Whilst unwinding a contractual position in a spot market may be a rational decision in those instances, it is likely to carry a certain cost, therefore flows on interconnectors against the spot market spread do not necessarily represent irrational behaviour or exercise of market power.

Inefficient operation of interconnectors is also less likely in tight market conditions as flows against the spread in the spot markets are likely to be more costly in those instances. This pattern can be observed from historic data for IUK and BBL as noted above, although note that flows do not become perfectly efficient even at relatively high price spreads. We have not carried out a specific study of interconnector efficiency, but given the facts available to us, the case for market failure in interconnector operation does not appear to be proven. Furthermore, any future move to introduce implicit auctioning of capacity to gas interconnectors is likely to improve their efficiency of operation.

Storage investment

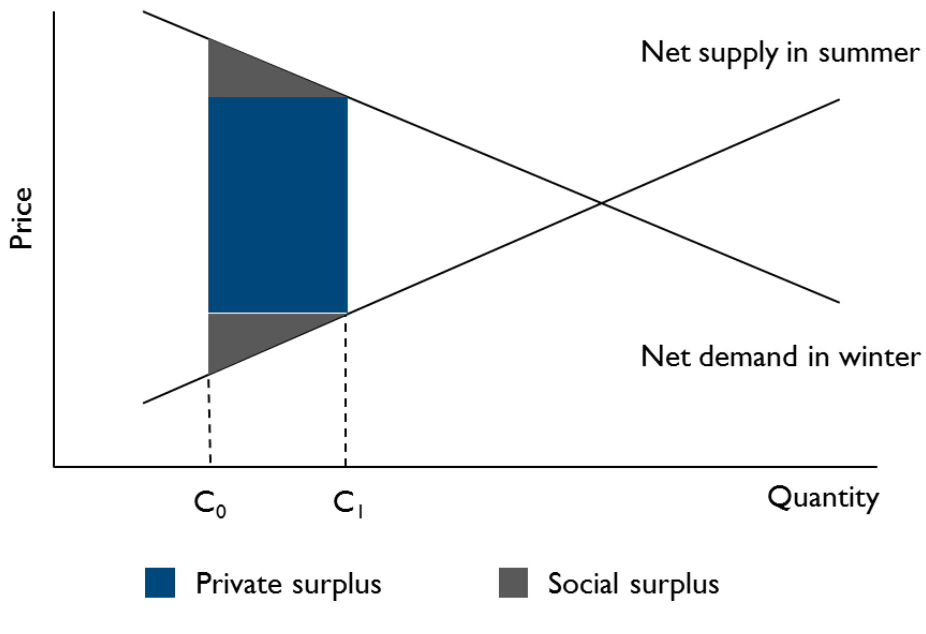
The argument that incentives to invest in storage may be suboptimal as a consequence of the cash-out arrangements has already been made above. There is a separate argument that market conditions, and more specifically seasonal spreads, are insufficient to support investment in large storage projects. This is not an argument for the existence of market failure per se, as investment in new storage capacity may be fundamentally uneconomic.

Another argument that has been made with regard to the development of storage capacity is that investment has been held back by the fact that developers are unable to lock in long-term spreads due to the lack of appropriate long-term forward products in the gas market. It is plausible that storage developers would be able to reduce their investment risk and be made better off with availability of such products. However, in order to conclude that the lack of such products represents market failure, we would have to show that there is also demand for such products from appropriate counterparties and that a Pareto welfare improving transaction could take place. In this regard, the fact that such products do not exist would imply that demand from appropriate counterparties is lacking unless there are clear barriers to mutually beneficial transactions taking place. Given the existence of other forward gas products of shorter duration, existence of barriers to mutually beneficial transactions would be difficult to prove.

There are some fundamental reasons why demand for longer term forward gas products may be lacking. Due to competition in gas supply in GB, it would be difficult for suppliers to lock their customers into very long term contracts, and hence demand from suppliers to be locked into longer term contracts with storage developers is likely to be limited. While final consumers may value price stability, or more specifically protection from price increases, they also value the flexibility of being able to switch to a better deal. It remains to be proven that final gas consumers value the former above the latter.

There is, however, a strong argument to be made that investment in seasonal storage is 'lumpy'. This means that there is a minimum threshold of seasonal storage capacity that can be built, below which investment is either uneconomic because of economies of scale or infeasible because of the physical characteristics of seasonal storage. Lumpiness of investment can lead to market failure through the existence of market power. This argument is demonstrated in Figure 7. This is a stylised representation of the operation of seasonal storage that buys gas in the summer and sells it in the winter. Increasing the amount of seasonal storage in the market from C_0 to C_1 leads to a convergence of summer and winter prices and an increase in profits that is lower than the increase in social welfare.

Figure 7 Lumpiness of seasonal storage investment



Market failure ultimately arises out of the fact that incremental storage is a price-maker rather than a price taker and thus has to take into account the effect of its investment decision on the average revenues from its capacity. If storage investment could take place in small increments, this would not be an issue since the social surplus arising from the incremental investment would converge to the private surplus and new investors would not take the effect of their investment on the profits of existing storage capacity into account. However, lumpiness of storage investment would mean that the smallest increment of additional storage investment is a price-maker.

Overall, it is likely that investment in seasonal storage is subject to some degree of market failure because of lumpiness of investment. The same cannot be said for fast cycling storage since the smallest increments of additional capacity of this type are much smaller than for seasonal storage and are unlikely to be price-makers. However, estimates of the extent to which actual investment in seasonal storage capacity is likely to be below the socially optimal level are out of the scope of this study. The true impact of the lumpiness effect on LRS investment is uncertain. Finally, this study finds no strong evidence to suggest that investment in storage is subject to market failure because of a lack of appropriate long-term risk management products.

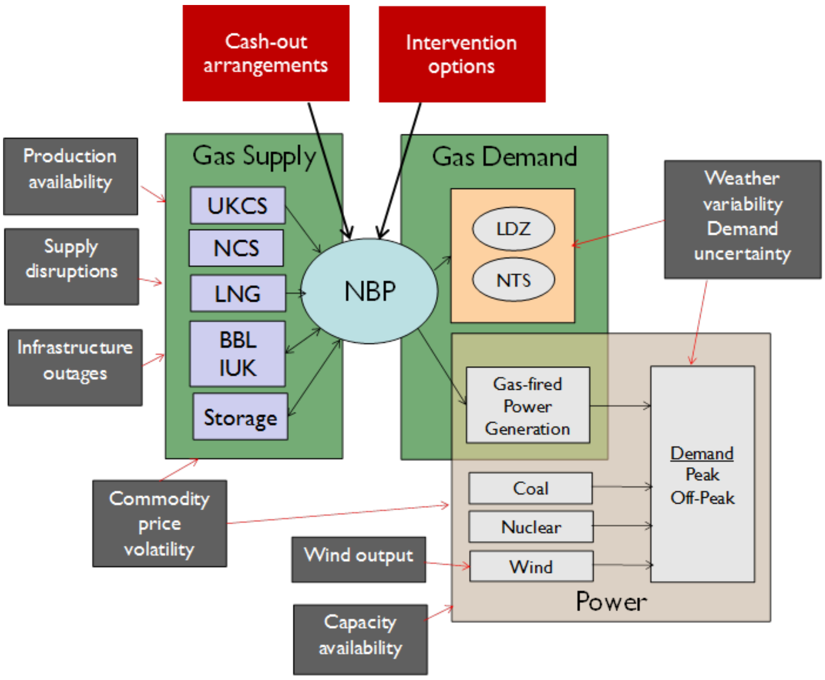
5 Modelling approach

5.1 Gas market modelling

Given the inherent trade-off between model complexity and tractability, building a model with a realistic representation of the GB gas system that is able to generate unanticipated shocks to that system and capture the market response to those shocks is clearly a very challenging task. We also note the difficulty of modelling low probability and potentially high impact events. This is particularly the case with respect to the calibration of supply outage assumptions, where relevant historic evidence is very limited.

Our aim was to build a model that is fit for purpose given the need to assess the effect of selected intervention options on GB gas security of supply and the total cost of gas for GB consumers. The model is built on the basis of daily granularity whilst fully reflecting the interdependency between consecutive days in terms of demand, storage and other factors. Simplifications to the way that the GB gas system is represented in the model were made where it was felt that such simplification would have a minimal impact on the modelling results. Model behaviour was sense-checked against historically observed data where possible. The gas market model overview is as follows:

Figure 8 Gas market modelling overview



The methodology centres on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity and generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output.

‘Decision rules’ are used to determine the associated supply flows on the day, rather than finding an optimal solution across a period, to reflect lack of perfect foresight. These are captured through the construction of ‘tranches’ of each supply source, which are defined as an available volume either at absolute price levels or at differentials to a given benchmark. Logic for liquefied natural gas (LNG) reflects the ‘lag effect’ associated with lead-times for delivery of shipments by driving supply off a rolling average price over a set number of historic days, rather than the market price on the day.

Storage is handled by using a set of calibrated withdrawal/injection rules as functions of relative spot/forward price differentials, inventory levels, and time of year. Because prices have a well-defined seasonal profile, long-run storage generally tends to be built up in advance of winter and drawn down during the winter period. The mean behaviour of long-run and short-run storage is sense-checked in relation to actual historic storage profiles. Clearly this approach greatly simplifies real decisions made by market participants. However, we believe that on an average basis over a large number of simulations, it provides a fair way to reflect typical market behaviour to a level that enables conclusions to be drawn with regard to the potential impact of alternative arrangements.

On each day, an optimisation routine is used to determine a combined gas/electricity supply match and to derive a short-run marginal price. The stochastic components in the model are driven by appropriate distribution functions. Commodity prices (feeding into the benchmark prices for continental gas and LNG, coal generation costs, and the carbon costs for CCGTs) use a correlated mean-reverting process.

The seasonal pattern of UK Continental Shelf (UKCS) gas flows is estimated from historic data provided by National Grid using monthly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean production level are drawn from a distribution fitted to the residuals of an Autoregressive Moving Average (ARMA) model and persistence of shocks estimated by that model is applied to the simulated residuals in order to model UKCS output shocks with a realistic duration. This captures variability in both upstream and terminal output.

Norwegian Continental Shelf (NCS) output is modelled as separate strategic and non-strategic components. Output from the non-strategic component is assumed to be based on long-term contractual arrangements and hence it does not vary with changes in the spot market price of gas in the GB market. Output from the strategic component is assumed to go to the market where the price of gas is highest and hence behaves in the same manner as Interconnector UK (IUK) imports. The modelling methodology for the non-strategic part of NCS supply is exactly as for UKCS above.

Infrastructure outage probabilities are modelled using the Poisson distribution. Outage magnitude and duration are modelled using the lognormal distribution. Assumptions for distribution parameters were agreed jointly by Redpoint and Ofgem after accounting for stakeholder responses to the Draft Impact Assessment as a part of the Gas Security of Supply Significant Code Review. In many cases, given the associated low probabilities, there is no historic dataset that can be used to derive the parameters.

Stochastic daily variation in Non-power generation (NPG) demand is modelled in a similar way to stochastic UKCS output. The seasonal pattern of demand is estimated from historic data provided by National Grid using monthly and weekly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean demand level are drawn from a distribution fitted to the residuals of an Autoregressive Moving Average (ARMA) model and persistence of shocks estimated by that model is applied to the simulated residuals in order to model demand shocks with a realistic duration. Gas demand from power generation is determined endogenously in the model.

We undertook a step wise approach to derive the market modelling results as a part of this study. The following approach was undertaken for the modelling purposes:

1. Define a Baseline scenario to be used as a counterfactual in assessing the costs and benefits of potential intervention options;
2. Estimate a market investment response in new storage capacity under the Baseline;
3. Define the intervention options to be modelled;
4. Estimate a market investment response in new storage capacity under each of the intervention options; and
5. Model the Baseline and intervention options with market investment response and carry out CBA of the intervention options against the Baseline.

We model a Stressed scenario and a Gone Green scenario as described in Section 6. Market investment response is only estimated in the context of the Stressed scenario. The spot years modelled under the Stressed and Gone Green demand scenarios for the Baseline and the intervention options described in this section are given in Table 9 below. A "Market model" tick indicates the gas market modelling undertaken for Baseline and the intervention options without assuming market investment in storage. A "Market iteration model" tick indicates the gas market modelling undertaken after assuming the investment response in gas storage from the market players.

Table 9 Modelled spot years under the Stressed and Gone Green demand scenarios

Intervention option	Design type	Market model	Market model iteration	Modelled spot years
Baseline (stressed)	-	√	√	2020,2025,2030
Baseline (Gone Green)	-	√	-	2020,2030
Generic non-specific obligation (stressed)	-	√	√	2020,2025,2030
Generic non-specific obligation (Gone Green)	-	√	-	2020,2030
Storage obligation (stressed)	Primary design	√	√	2020,2030
Storage obligation (stressed)	Secondary design	√	√	2020,2030
Storage obligation (Gone Green)	Primary design	√	-	2020,2030
Storage obligation (Gone Green)	Secondary design	√	-	2020,2030
Supported storage (stressed)	Primary design	√	√	2020,2030
Supported storage (stressed)	Secondary design	√	√	2020,2030
Supported storage (Gone Green)	Primary design	√	-	2020,2030
Supported storage (Gone Green)	Secondary design	√	-	2020,2030

5.2 Volatility modelling framework

A key output of the market model is the volatility of day-ahead prices, which is used as an input to the storage model. Day-ahead volatility affects the value of storage, particularly SRS, and is key to assessing the investment case for such assets. The day-ahead volatility is defined as the annualised standard deviation of daily log returns (with a full calendar day series), as applied to a daily price series *P*:

$$\textit{day-ahead volatility} = std\{ \ln(P(t) / P(t-1)) \} * sqrt(365)$$

As volatility is difficult to model, and we have used two approaches to estimate a range, using the results of the market model. These approaches give an upper and lower bound to the volatility estimate, and are used to triangulate on a suitable estimate for volatility. The steps for each approach are as follows:

1. **Lower Volatility Limits:**
   - Run the market model for a given scenario for the modelled spot years
   - Calculate the annualised price volatility for the given spot years directly from the daily price series generated for all simulations
   - Take the mean of the volatilities across all simulations

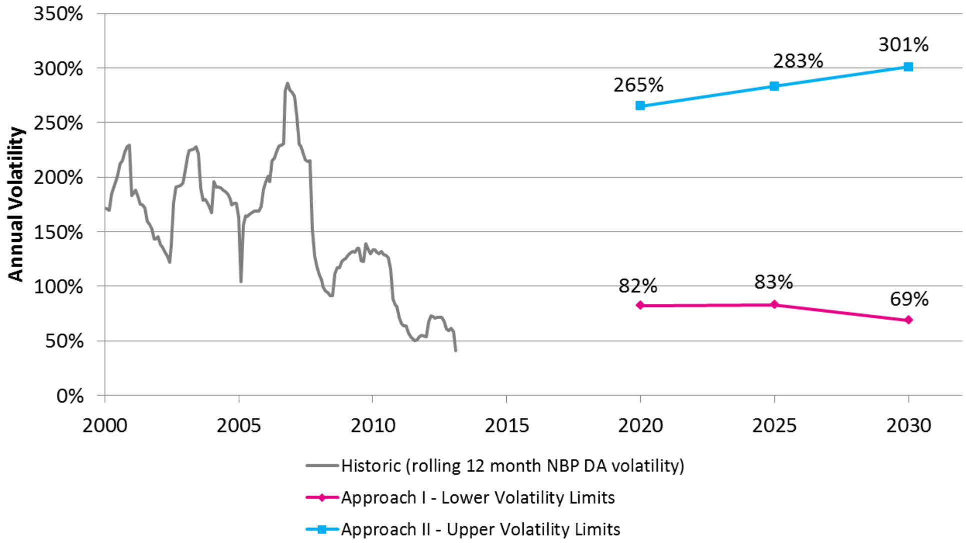
   We believe that this provides an estimate of volatility at the lower end of the range given that it does not fully account for the effect of relative scarcity of gas supply on price dynamics in the traded market.

2. **Upper Volatility Limits:**
   - Estimate a statistical relationship between volatility of actual historic prices and fundamental explanatory factors:
     - Volatility of demand (including power generation demand)
     - Capacity margin
   - Apply the estimated coefficients to equivalent explanatory factors from the market model to estimate the change in price volatility between the historic period covered and the modelled spot years

   We believe that this provides an estimate at the upper end of the range as it relies on an extrapolation of an estimated historic relationship.

Figure 9 shows recent historic volatility (rolling 12 month average of day-ahead prices) and the estimates in the Baseline Stressed scenario, using both approaches described above. It can be seen that the two approaches give an upper and lower bound that is consistent with that seen historically.

Figure 9 **Volatility estimates vs historic volatility**



For the purposes of the storage asset modelling (described in Section 5.3 below), the approaches described above were combined to give a single figure as input to the asset model in each spot year. This was calculated by adding 20% of the upper limit to the lower limit. For example, in 2020 from the graph above this would result in a final volatility figure of 135% (0.2x265% + 1x82%). The 20% scaling figure gives reasonable agreement with historic volatilities when the model is back-cast.

5.3 Storage asset modelling

Whilst the Market Model is effective for generating price and security of supply metrics, the 'decision rules' that drive storage operation are simplifications relative to how individual assets would in reality be optimised. A more detailed storage model was used to simulate in detail how SRS and LRS type facilities would operate in the simulated market conditions.

We used a commercially available economic storage model to explore the potential value of the facility in the future spot years. The model, KyStore, is developed by KYOS Energy Consulting[9], and is widely used by market participants in informing real investment decisions and market operation of assets. The concept behind the model is to develop a rule-set for withdrawal/injection decisions that generates an optimal expected profit given a set of parameters specifying price behaviour (including the forward curve, and volatility and mean reversion parameters). We used the price simulations generated by the market model for each spot year to estimate the appropriate volatility (as discussed above), and then used the storage asset model to calculate the expected profit, and associated uncertainty distribution around this. The model constructs an optimal spot trading strategy based on information about price dynamics available at a given point in time:

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[9] KYOS Energy Consulting, website: http://www.kyos.com

- current day's prices (day-ahead and forward)
- current amount of gas in storage
- statistical information about how prices may evolve in the future (volatilities and mean-reversion rates)

The model then evaluates the expected net profit generated with this strategy over time, under a set of Monte Carlo simulations of spot and forward prices. A three factor model of forward/spot price evolution is used, specifically day-ahead price movements, shifts in the overall level of the forward curve, and changes to the seasonality present in the curve.

The key inputs to model are described in Table 10 below, separated into those that describe the storage facility and those that describe the gas market.

Table 10 Key input parameters for Storage model

Storage facility	Market
Working volume of gas	Expected price trajectory (forward curve)
Start / End Volume constraints i.e. volume of gas in storage at the start and end of the year	Forward contract types
Injection/withdrawal rates of gas	Bid-offer spreads
Injection/withdraw costs of gas	Statistical properties - *Seasonality volatility, long term drift volatility, day-ahead volatility and day-ahead mean reversion*

The specific assumptions for these inputs used in this analysis are covered in Section 7.2.

The output from the storage model is an expected gross margin figure, for each year modelled. Gross margin is defined as:

Gross margin = revenue from sold gas – cost of bought gas – injection and withdrawal costs

Expected gross margin results are calculated for spot years, and gross margins for intervening years calculated by interpolating between spot year results. The resulting annual gross margin results over the lifetime of the storage facility are used in the market CBA.

In order to assess whether market investment in storage would take place or not, the project IRR is estimated for new build SRS and LRS over their economic life, under varying volatility and seasonality scenarios. The bounds of the matrix are chosen to capture the range of values seen in market model scenarios studied here. The storage model is run under each volatility/seasonality scenario for spot year 2020, to give a matrix of annual gross margin figures. Annual gross margin is assumed to remain constant after 2020, and using a simple discounted cashflow model the IRR over a 40 year economic lifetime is calculated. The capital expenditure and operating expenditure assumed is given in Table 11.

Table 11 Storage costs

Cost	units	SRS	LRS
Capital expenditure[10]	*p / th*	278	193
Fixed operating expenditure[11]	*p / th / year*	12	4.1

The IRR sensitivity matrix is developed with IRR estimated for the gas storage facilities commissioning in 2016 and 2020 under varying volatility and seasonality scenarios. Based on the volatility derived from gas market modelling for Baseline and intervention options, we have used the IRR sensitivity matrix to estimate whether additional storage investment would take place or not.

[10] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Redpoint%20further%20measures%20modelling%20report%20final.pdf

[11] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Redpoint%20further%20measures%20modelling%20report%20final.pdf

6 Modelling of intervention options

6.1 Overview

We undertook a step-wise approach to derive the market modelling results and the CBA as a part of this study. The following approach was undertaken for the modelling purposes:

1. Define a Baseline scenario for the Stressed and Gone Green scenarios;
2. Run the gas market model for Baseline scenario;
3. Estimate a market investment response in new storage capacity (as a proxy for new infrastructure investment in general) under the Baseline;
4. Run the gas market model for the intervention options under the Stressed scenario;
5. Estimate a market investment response in new storage capacity under each of the intervention options;
6. Model the Baseline and intervention options with market investment response;
7. Carry out CBA of the intervention options against the Baseline;
8. For options that appear beneficial[12], repeat for the Gone Green scenario.

The evaluation of each of the intervention options takes place against a Baseline without an intervention. The Baseline and the intervention options are modelled primarily against a 'Stressed' scenario, with additional assessment for those that appear beneficial against a 'Gone Green' scenario as a sensitivity. We assume that Ofgem's proposed SCR reforms[13] are implemented. Details of these arrangements can be found in Ofgem's impact assessment for the proposed final decision on the SCR reforms and Redpoint report on the economic modelling for Ofgem's proposed final decision[14] published on July 31, 2012.

For each intervention option, there are clearly a wide range of variants with respect to the exact design and means of implementation. For the purposes of modelling, we have made assumptions in order to model each intervention option. We describe below the certain broad level assumptions made for this purpose. The specific assumptions for modelling of each intervention option are set out in Section 8. The designs of each option are intended to be indicative at this stage.

[12] Beneficial in this context means a positive estimated impact on net consumer welfare and an impact on net storage welfare that does not significantly outweigh the impact on consumers under an assumption on the required rate of return for storage investment that falls within the modelled range.

[13] Value of Lost Load for Non-Daily Metered customers assumed at 2000 p/th as this was the latest available estimate at the time that the modelling commenced

[14] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=91&refer=Markets/WhlMkts/CompandEff/GasSCR

6.2 Generic non-specific obligation

This option is modelled as an obligation on the System Operator to provide a source of responsive physical supply with a high ratio of deliverability to total volume. While the option design does not prescribe that the System Operator's response to the obligation must be through storage, for the purposes of our modelling, we make the assumption that the System Operator's response to the exposure created by the obligation is to commission an additional fast cycling storage facility. This assumption was made because the costs of new storage can be estimated for the purposes of welfare analysis of this intervention, which was not possible with some of the alternatives to new storage that could be used to meet the obligation.

The additional storage facility under the obligation is assumed to operate outside of the market and does not affect the market price of gas[15]. The obligation should result in additional physical availability of gas and is designed to bring the probability of interruption for firm gas customers and CCGTs supplying firm electricity customers to below 1-in-50 years.

6.3 Storage obligation

In our modelling of this option, an obligation is placed on suppliers to book and fill a certain amount of storage capacity over the winter period. In our modelling, the maximum level of the obligation for a given year is derived based on the assumption that there must be sufficient gas in store to meet firm gas demand[16] (excluding CCGTs) during any winter day[17] in the event that LNG is not available for an assumed number of days. Based on the resulting required storage profile produced for the winter period, the value of the obligation is set at its maximum value from the start of winter though to the date when the maximum value of the profile is reached.

The storage obligation is treated as a hard constraint in our model and can only be suspended to prevent, or reduce the severity, of firm gas demand interruptions. Once suspended, all storage is available to flow freely on that day subject only to technical constraints on the rate of withdrawal and quantity of gas in storage. In subsequent days, the constraint of the amount of gas in storage is reset to the minimum of the baseline obligation level and the level of storage at the end of the last day in which the obligation was suspended.

Any residual storage capacity that remains after accounting for the capacity required to meet the obligation can be used for normal commercial purposes.

We model two variations on the storage obligation. The primary design imposes a less onerous storage obligation in terms of volume on suppliers and is based on the assumption that LNG would not be available for 7 days from the start of an emergency. The secondary design places a higher volume obligation on

[15] The cash-out price would have to be set at NDM VoLL when the obligation is put to use and shippers would have to be charged that marginal price in proportion to the amount of gas by which they are short relative to their supply obligations to firm customers.

[16] This is derived from the National Grid Slow Progression 1-in-50 2012/13 load duration curve using an average seasonal demand shape.

[17] This is defined as the period from 1October to 31 March.

suppliers and is based on the assumption that LNG would not be available for 14 days from the start of an emergency.

6.4 Supported storage

The design of the Supported storage option is assumed to be the same as semi-regulated option in the Ofgem Gas Security of Supply study conducted by Redpoint. Under this option, gas is available for commercial use for both NDM and DM customers and is not taken out of the market. It is assumed that sufficient support is provided in order to deliver two additional SRS facilities (primary design) or a single LRS facility (secondary design). Therefore, we model the impact of adding such additional SRS or LRS facilities under primary and secondary design respectively. The additional facility is assumed to be operational ahead of the 2020 spot year modelled[18] and operates in the same way as the existing SRS or LRS capacity on the system.

[18] Since one of the spot years modelled is 2020, it has been assumed that the additional facility is operational ahead of 2020

7 Modelling assumptions

7.1 Gas market modelling assumptions

Overview

This section sets out a summary of our gas market modelling assumptions. These assumptions include changes as a result of stakeholder feedback that Redpoint had received on the modelling done for the Gas Security of Supply Significant Code Review Draft Impact Assessment. They also include other revisions with the latest available information, including changes to commodity price assumptions, exchange rates, Non-Power Generation (NPG) demand, annual supply from different sources, distillate capacity, electricity demand and the electricity generation. The process involved discussions with DECC, Ofgem and National Grid as the assumptions were established.

Modelling is undertaken in the context of two scenarios, the Stressed scenario and the Gone Green scenario. The Stressed scenario assumes non-power generation (NPG) gas demand based on National Grid Slow Progression demand to 2025, trending with Gone Green thereafter from the level reached under Slow Progression in 2025. The Gone Green scenario assumes the National Transmission System (NTS) NPG gas demand from the 2012 National Grid Ten Year Statement. In most cases, modelling assumptions for these two scenarios are the same. Where they differ, they are presented alongside each other in this section.

Modelling low probability events for which there are no direct historic precedents requires assumptions that frequently cannot be verified using historic data. In the course of this modelling exercise, assumptions were calibrated to historically observed data where possible. Where such calibration was not possible, we have made clear and transparent assumptions which are set out in this section.

Commodity prices

Our commodity price assumptions rely on prices quoted in forward markets dating from February 2013 for the period up to 2016. For the period after 2016, our assumptions are based on the International Energy Agency's 2012 World Energy Outlook. For Henry Hub prices, our assumptions are based on prices quoted in forward markets dating from 7 March 2013 for the period up to 2021. After 2021, we assume that the Henry Hub price rises at the same rate as the crude oil price.

The market price of gas in GB is determined endogenously within the model given the total demand for gas, the supply curve of domestic and imported gas sources, available demand-side response (DSR) and the margin of available capacity over total demand. This price is calculated on a daily level.

Assumptions on the average annual level of the carbon price in GB are taken from the HMT consultation updated to be in real 01/01/2013 terms from 31/12/2009 terms using CPI figures from ONS.

Volatile daily series of coal, carbon and Henry Hub prices are simulated using a correlated, mean-reverting Brownian motion process. The input scenario commodity price is used as the mean in the calculation.

Exchange rates

Exchange rate assumptions are derived from the mid-market rate as of 8 February 2013 and are assumed to remain constant in real terms thereafter. The assumed £/$ exchange rate is 1.57 and the assumed £/€ exchange rate is 1.17.

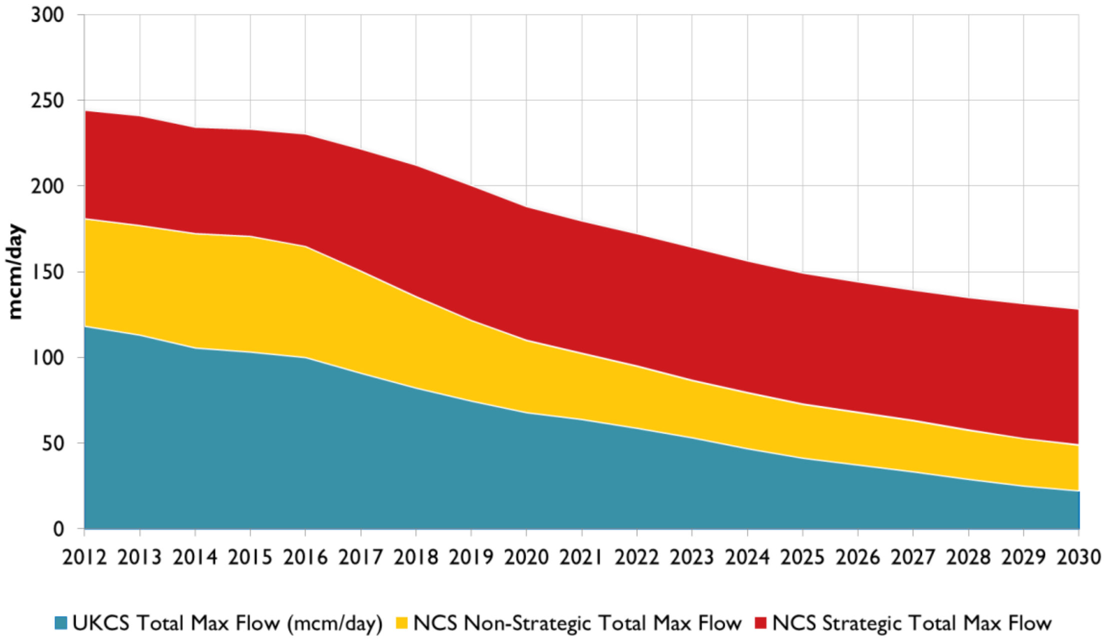
Gas supply

Average daily flow in UKCS gas on an annual basis is based on data for Figure 3.3A in the National Grid Ten Year Statement (TYS2011)[19] in the Gone Green scenario[20]. As set out previously, NCS output is modelled as separate strategic and non-strategic components.

The modelling methodology for the non-strategic part of NCS supply is exactly as for UKCS above. Predicted annual capacity and flow data is taken from TYS2011 on the basis of the Gone Green scenario. The proportion of non-strategic NCS supply is set at the ratio of forecast NCS imports into GB (Figure 3.3A of TYS 2011) and total NCS peak capacity (Figure 3.3C of TYS 2011).

The maximum daily flow from UKCS and the strategic and non-strategic parts of NCS is shown in Figure 10.

Figure 10 Maximum daily flow from UKCS and NCS



[19] http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/50703/GasTenYearStatement2011.pdf

[20] Note that this does not include any projections on shale gas development in the UK, which would represent an upside risk to the projections of UKCS output.

Variability in gas supply and outages

Variability in UKCS and NCS supply is calibrated to historic data spanning ten years. Seasonal variation in UKCS and non-strategic NCS is modelled as a proportion of total output. Hence seasonal variation in the output of these supply sources declines in proportion with the decline in annual production.

Supply outages on all gas supply sources are also modelled with a sudden component. The parameters for sudden supply shocks consist of:

- Expected frequency of occurrence in a given year, modelled using a Poisson distribution;
- Mean and standard deviation of outage duration based on a lognormal distribution; and
- Mean and standard deviation of the magnitude of the shock, as a multiplicative factor applied to full capacity and based on a lognormal distribution[21].

It is assumed that outages are twice as likely to happen in the coldest 6 months of the year than in the warmest 6 months. This assumption applies to all sudden shocks in our modelling. Outages on different supply sources are assumed to be independent of each other. Detailed assumptions on supply outages are given in Table 12 below.

[21] Multiplicative shock representation implies that a shock of 0.3 makes 70% of capacity unavailable (ie 30% would be available).

Table 12 Infrastructure outage parameters[22]

Stochastic Supply Outages								
Supply source	Average frequency (in a 6 month period)		Duration		Magnitude (proportion of capacity available after shock)			
	Summer	Winter (effective annual frequency)	Mean (days)	Standard Deviation	Mean	Standard Deviation	Min	Max
UKCS	0.03	0.07	10	2	0.80	0.20	0	1
NCS	0.03	0.07	10	2	0.60	0.20	0	1
BBL Prior to 2016	0.12	0.25	6	20	0.55	0.30	0	1
LNG	0.12	0.25	6	20	0.70	0.30	0	1
IUK Prior to 2016	0.12	0.25	6	20	0.55	0.30	0	1
BBL & IUK From 2016	0.25	0.49	6	20	0.78	0.30	0	1
LRS	0.15	0.30	10	2	0.50	0.30	0	1
SRS	0.30	0.60	10	2	0.80	0.20	0	1

Storage outages are modelled as a multiplicative shock[23] to the maximum rate of injection and withdrawal for long and short range storage separately. Since several SRS facilities are modelled as a single block, the average impact of an outage reflects the proportion of overall SRS capacity that the average SRS facility represents. This is also the case for parameters that relate to LNG supply outages. The average impact of an outage reflects the proportion of overall LNG import capacity that the average LNG terminal represents.

For LRS in particular, we note that the Rough storage facility was completely unavailable for several months[24] in 2006 as a result of a fire, but this is the only major outage incident on that facility that we are aware of. We also note that one data point is not sufficient to define a probability distribution. Although the average outage probability for LRS in our revised assumptions is higher than that observed historically, the corresponding mean magnitude and duration are significantly lower. This is because our assumptions represent all potential events that can affect the ability of LRS to inject gas into storage or deliver gas into the GB gas network, including problems with the gas field, rig, pipeline infrastructure (on-shore and off-shore) and problems at the Easington terminal, including all associated equipment.

[22] Note that for the average frequency in 6 winter months, 0.5 indicates 1 outage expected in every 2 winter 6 month periods.

[23] The impact of the shock takes the form of multiplying the maximum rate of injection and withdrawal by a number between zero and one, thus reducing the ability of the storage facility to refill or sell gas into the system for the duration of the shock.

[24] Declaration of Force Majeure was published on 16 Feb 2006 and withdrawn on 20 Nov 2006. The facility was completely unavailable for over three months during this time. Source: Howard Rogers, "The impact of import dependency and wind generation on UK gas demand and security of supply." August 2011.

For UKCS and NCS, the average frequency of sudden shocks is less than one in ten years since the continuous variation in output from these supply sources, before sudden shocks are applied, is calibrated to a ten year historic data set. For these supply sources, sudden outages represent rare events that are not present in the historic data set used for the calibration.

From 2020, BBL is assumed to acquire reverse flow capability and is assumed to trade in the same way as IUK. We merge BBL capacity into IUK capacity in our model from this date and adjust IUK interruption parameters accordingly, with higher probability of outages and lower average impact of outages to reflect the fact that the combined entity represents two separate interconnectors.

Continental price shocks

To reflect the possibility of supply and/or demand shocks in the Continental European gas market, a stochastic price shock is introduced to imports and exports over IUK as well as the 'strategic' part of NCS supply which is not covered by contractual arrangements.

Frequency of such shocks is modelled as a Poisson distribution with average frequency of shocks (in a year) set at 0.08 in the warmest six months of a given year and 0.16 in the coldest six months. Shock duration is modelled as a lognormal distribution with mean of 10 and standard deviation of 2. Shock magnitude is modelled as a multiplicative factor to the pre-shock price level with a lognormal distribution truncated at 1 and 10. The mean shock magnitude is 2 and its standard deviation is 1.

Gas quality issues

Gas quality issues are assumed to impact flows over the interconnectors in our modelling[25]. The gas flowing to GB is made up to the GB quality standard in Belgium by mixing gas sourced from Russia with gas from other sources (e.g. Norway) and there is no specific treatment facility in place at the moment. Although Fluxys[26] have put forward a proposal for such a treatment facility, it is not certain at this stage that construction of this facility will go ahead.

Without a treatment facility in place, any supply shock to Russian gas increases the probability that flows over IUK do not meet the GB gas quality standards. This risk is likely to increase over time as the average specification of gas coming from Norway is set to increase.

Since supply shocks relating to Russian gas are built into the continental price shocks functionality, capacity reductions relating to gas quality issues are assumed to be correlated with positive price shocks to the continental gas price. The relevant linear correlation coefficient is assumed to be 0.5.

Frequency of such shocks is modelled as a Poisson distribution with average frequency of shocks in a given year set at 0.07 in the coldest six months of the year and 0.03 in the warmest six months of the year. Shock duration is modelled as a lognormal distribution with mean of 10 and standard deviation of 2. Shock magnitude is modelled as a multiplicative factor to the pre-shock IUK maximum import capacity with a lognormal distribution truncated at 0 and 1. The mean shock magnitude is 0.3 and its standard deviation is 0.2.

[25] As discussed below, gas quality issues can only be expected to affect IUK, although we morel IUK and BBL as a single entity.

[26] Independent operator of the natural gas transmission system in Belgium.

Storage

Gas storage parameters are derived from information provided to Redpoint by Ofgem and National Grid. For modelling purposes, storage facilities are amalgamated into two tranches, long range and short range. We classify Rough as long range and all remaining storage facilities that are currently in operation as short range. We do not distinguish between short and medium range storage for the purposes of our modelling.

Detailed storage parameters used to inform our modelling are given in Table 13. These were taken from Ofgem's Pivotality model[27].

Table 13 Model storage parameters

Storage Type	Start Year	Capacity (GWh)	Max Injection Rate (GWh/day)	Max Withdrawal Rate (GWh/day)
Long Range	2012	36,800	238	455
Short Range		16,528	1307	1346
Long Range	After 2012	36,800	238	455
Short Range		18,028	1482	1521

Interconnectors

The IUK annual maximum import and export flows are assumed to be 25.5 bcm and 20.0 bcm respectively. The continental price in the model is represented as the German Average Import Price (GAIP). This is deterministic and based on a calibrated relationship with the crude oil price[28].

Generally, when the spot price in GB is greater than the Continental gas price, gas will flow into GB. As that price difference increases, imports into GB increase until either maximum import capacity is reached or the price difference has been eliminated.

The annual maximum flow on the Balgzand Bacton Line (BBL) is 20bcm on a capacity basis. No reverse flow is assumed to be possible on BBL before 2020, from which point the export capacity of BBL is set equal to its import capacity. From that point we assume that BBL will behave in the same way as IUK[29].

[27] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=181&refer=Markets/WhlMkts/CompandEff

[28] Note that we model a disconnection in the relationship between the continental gas price and the oil price in periods of low LNG prices. This is as a result of calibrating model price outputs to historic data.

[29] Note that BBL currently has a 'virtual' reverse flow capability, meaning that it can vary its import utilisation into GB between 0% and 100%.

No new interconnection capacity is assumed to be built within the model horizon.

We model the supply elasticity of both IUK and BBL on the basis of historic data on price differences and flows. The supply curve line of best fit parameters are derived from the properties of the data. The data set covered the period from 1 Oct 2009 to 31 Jan 2012. Note that since we do not model the TTF and ZEE market prices explicitly but rather have a single continental price, interconnector supply curves are formulated with respect to the difference between the model GB price and the model Continental price.

The scatter plots for the historic relationship between price differentials and utilisation for IUK and BBL respectively are given below.

Figure 11 IUK utilisation

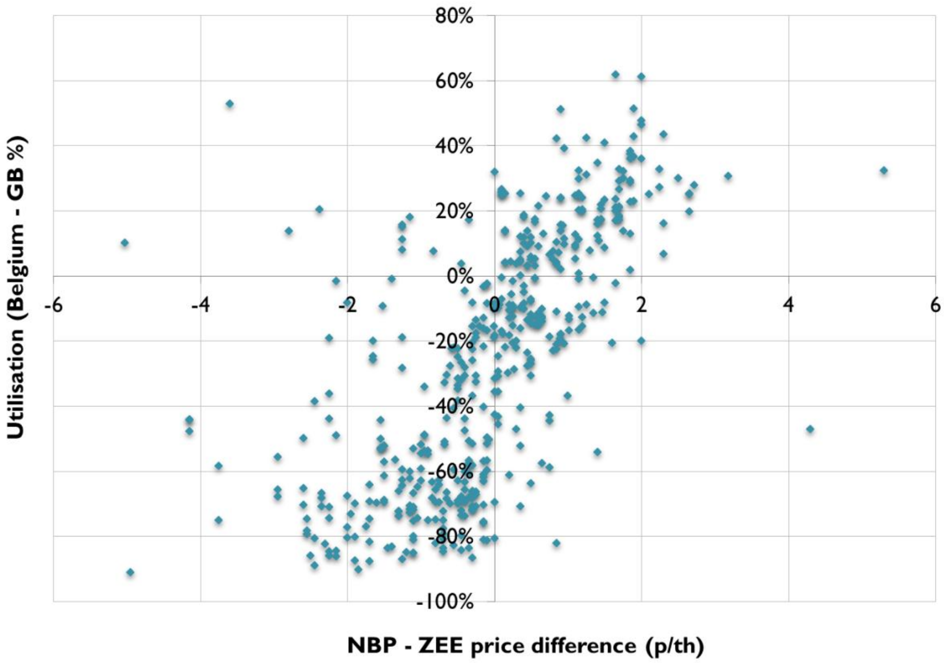
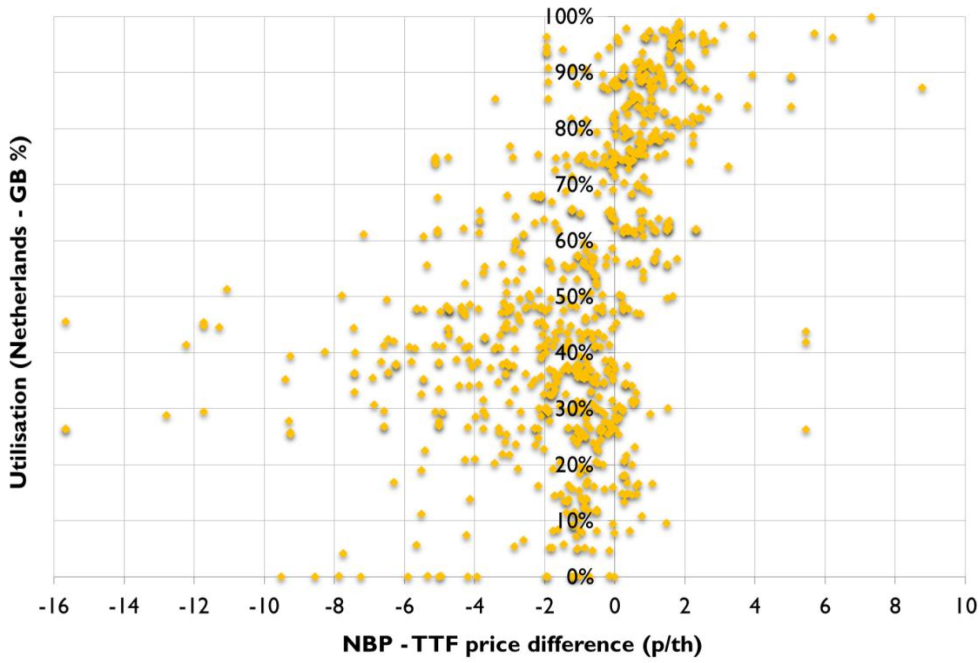


Figure 12 BBL utilisation



IUK: Proposed line of best fit is $y = 0.375x - 0.25$, where y is % utilisation with respect to imports into GB and x is the GB-Continent price difference.

BBL: Proposed line of best fit is $y = 0.2x + 0.6$, where y is % utilisation with respect to imports into GB and x is the GB-Continent price difference.

To reflect the apparent differences in the relationship between interconnector flows and price differentials between different periods, the slope of the supply curve varies stochastically around the line of best fit. In both cases, the supply curve pivots around the y intercept, -0.25 for IUK and 0.60 for BBL. The pivoting motion is driven by the outcome of a single random variable in each case. In our supply curve representation, it feeds into the price difference required to achieve a given level of utilisation of the interconnector. The effect of the random variable on a given price difference on the supply curve increases in proportion to its distance from the origin.

We use the lognormal distribution for the random variable and apply the variable multiplicatively to the price differences in the supply curve. This ensures proportionality of the effect of the variable to the distance from the origin. The choice of distribution naturally constrains that variable to values that are consistent with the model's optimisation routine.

Let the lognormally distributed random variable be denoted by L. The formula for the supply curve is then given by $y = a + bx/L$. The mean of the distribution of L is set at 1. The standard deviation of the distribution is set at 0.3 for IUK and 1 for BBL, producing the following two distributions for the random variables applied to IUK and BBL supply curves respectively.

Figure 13 IUK supply curve variability

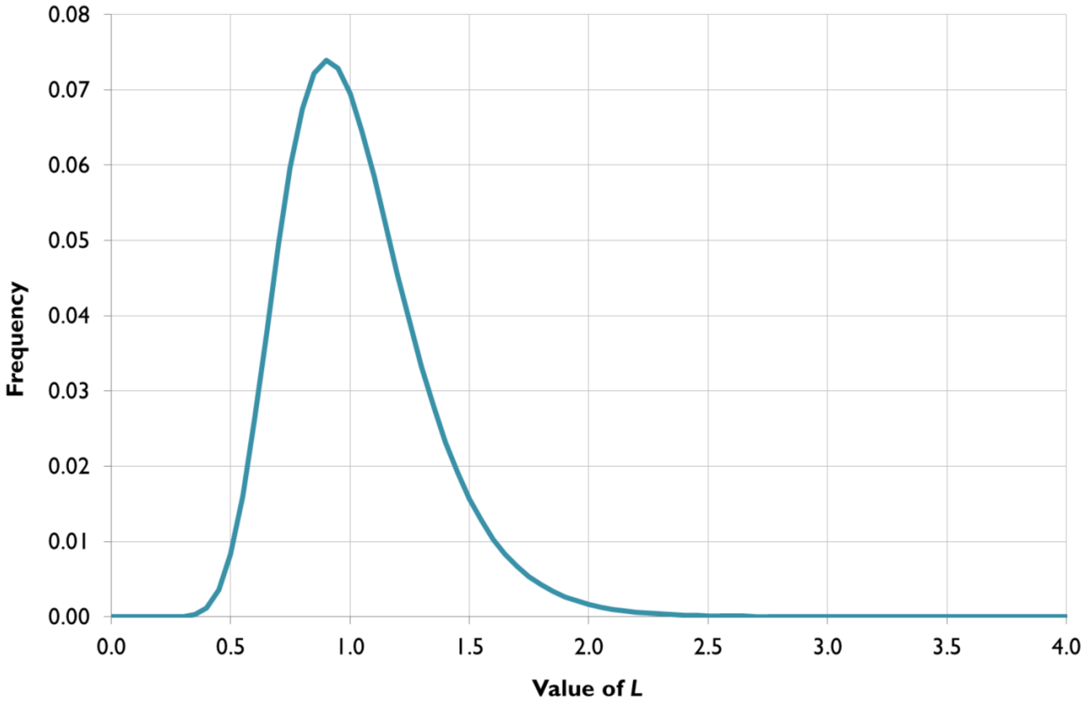
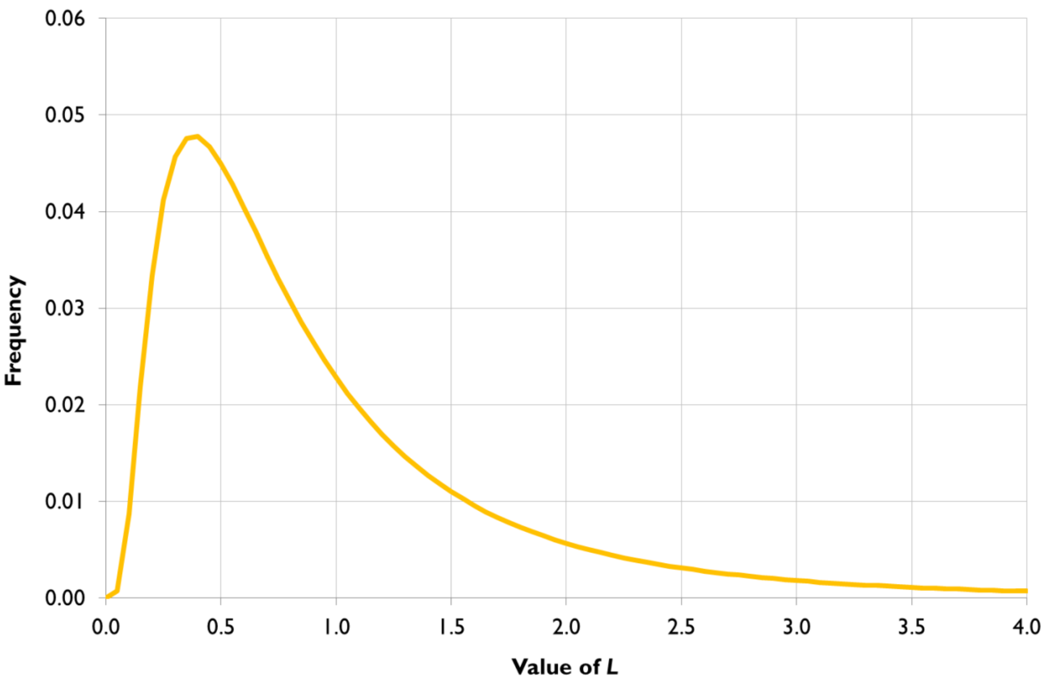


Figure 14 BBL supply curve variability



LNG

LNG maximum annual flow, i.e. the maximum amount of gas that can be sent out from all LNG terminals in a year, is assumed to be 51.5 bcm between 2011 and 2017 and 57.5 bcm thereafter. The base 2011 assumption is taken from National Grid's Ten Year Statement, with an additional 6 bcm facility assumed to come online in 2017. This equates to the construction of either a Dragon 2 or Port Meridian sized terminal. Both of these projects have planning granted but no FID has been taken.

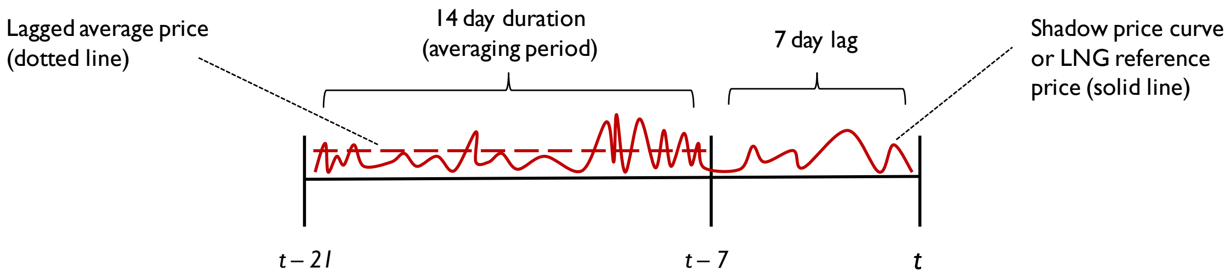
Historically, European LNG prices have been driven by the crude oil price much of the time, reflecting the prices paid for LNG by East Asian countries who lack indigenous gas resources. More recently, a rapid increase in shale gas production in the USA has changed the supply-demand balance by reducing US net gas imports and pushed LNG prices into relatively closer alignment with the Henry Hub price at some periods.

In our modelling, the LNG price can vary between the Henry Hub price and an oil-linked Japanese Crude Cocktail (JCC) price between different simulations to reflect the uncertainty about future drivers of the LNG price. The mix between the two price indices in each simulation is determined by a uniformly distributed random variable.

The LNG lag component of the model reflects the fact that LNG shippers are normally not able to make a decision to bring spot cargoes to the UK market 'on the day', given the time required to re-route ships and coordinate terminal logistics. Rather, they will make a decision in advance based on prices observed in the GB market over a prior period of days or weeks.

To reflect this in the model, we calculate a lagged average of the LNG price for the purposes of determining LNG supply. This is shown in Figure 15 below.

Figure 15 LNG supply reference price



The amount of LNG gas available to flow into GB at time *t* is determined by the difference between the 14 day average system gas price, lagged by 7 days, and the LNG reference price, determined by a mixture of the Henry Hub price and the JCC price depending on the scenario and year modelled. The greater the difference, the greater is the available LNG supply subject to the overall capacity limit. This means that there is a minimum lag of 7 days between a spike in the GB gas price and additional LNG supply becoming available to flow into GB.

We have updated the LNG modelling logic in this study to capture the storage aspect of LNG, and in particular the ability to hold back gas in tanks in expectation of higher prices later. The LNG logic has been split into separate delivery and injection decisions. The delivery decision retains similar logic to that employed previously, with availability based on a 14 day average with a 7 day lag. An additional diversion check has been added such that if NBP prices fall below a set threshold relative to LNG prices in the most recent 3 days, then delivery will not occur. The new withdrawal logic is similar to the fast cycling storage logic in the model used for the Ofgem Gas SCR study, but has been adapted for LNG. A metric has been added which is an indicator of the likelihood of upcoming LNG deliveries, based on the forward-looking view of delivery logic described above (but only given the information available as of the withdrawal date, ie still avoiding any assumption of foresight). A withdrawal price is calculated for LNG within the optimisation function on the day (similar to storage) that will reduce if further LNG deliveries are expected (tending to baseload flow where LNG prices are low, and vice versa), and will increase if the level of LNG in tanks is low (preserving optionality) and vice versa.

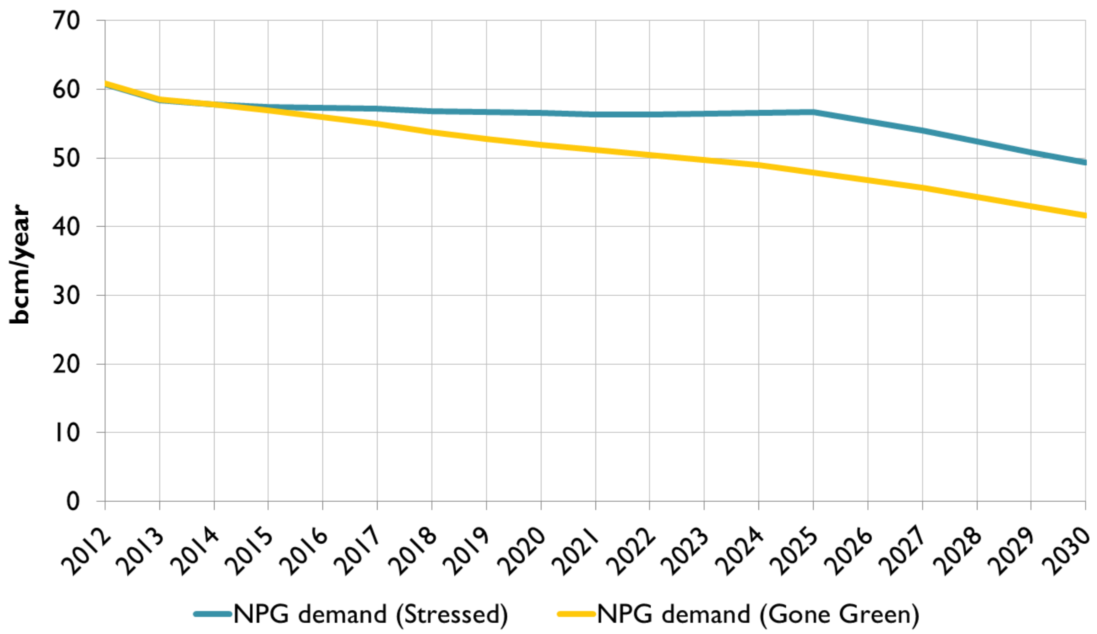
Once a decision is made to bring cargoes to the UK, the amount of LNG that is available to flow is determined. The actual flow of LNG is determined by the spot price after arrival at time *t*. This means that if a short but large price spike results in an unusually high LNG availability later, this cannot result in a surplus of supply over demand.

Gas demand

Total National Transmission System (NTS) non-power generation (NPG) gas demand for the Gone Green scenario is taken from the 2012 National Grid Ten Year Statement. Gas demand assumptions for the Stressed scenario are based on National Grid Slow Progression demand to 2025, trending with Gone Green thereafter from the level reached under Slow Progression in 2025. For this scenario, demand reductions assumed under Gone Green are achieved eventually but with a significant delay. The expectation of eventual demand reduction is assumed to make the investment case for further gas infrastructure challenging.

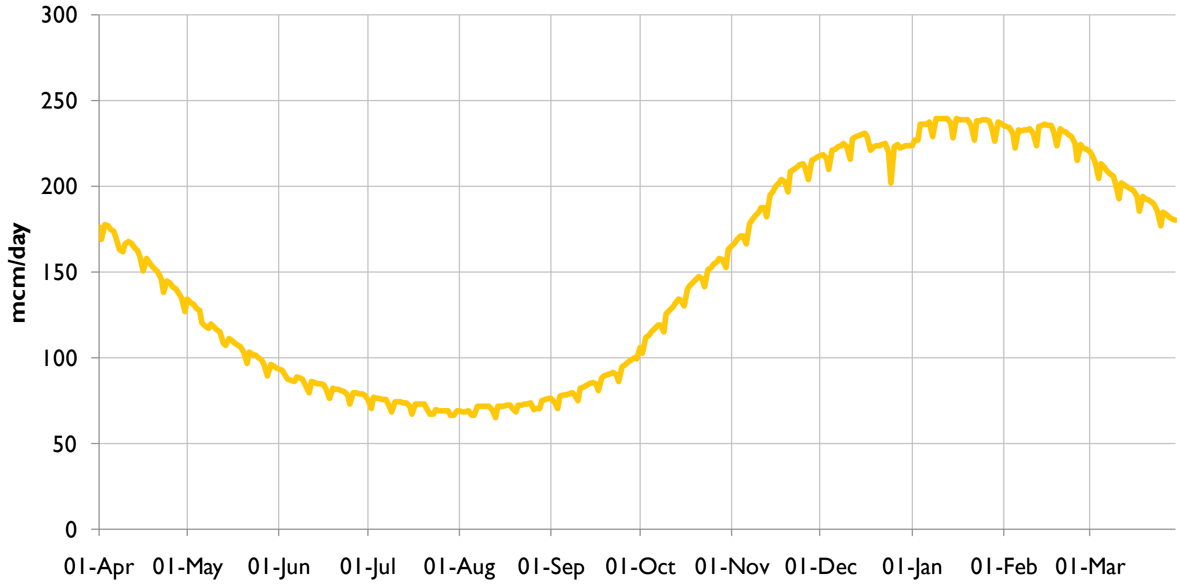
Total annual NTS NPG gas demand by year for the two modelled scenarios is given in Figure 16. This includes net exports to Ireland.

Figure 16 Total annual NTS NPG gas demand



The seasonal normal shape of demand based on 2011 annual demand is shown in Figure 17.

Figure 17 Expected demand shape



Electricity demand

Total annual demand for electricity is taken from Ofgem's November 2011 internal analysis. It is plotted in Figure 18 below. Overall demand for 2010 is taken from National Grid's 2010 Ten Year Statement[30]. Demand is then assumed to grow in line with economic output as well as increasing electrification of heat and transport. Energy efficiency polices are also taken into account.

Short term economic output forecasts are based on HM Treasury's comparisons of independent forecast document[31], with trend growth taken from the March 2011 OBR Economic and Fiscal Outlook[32] (with energy intensity of growth taken from Ofgem's Project Discovery). Assumptions on electrification of heat and transport are taken from Redpoint analysis based on pathway 3 of DECC's pathways analysis[33]. Energy efficiency forecasts are taken from Ofgem analysis of pathway 3 of DECC's pathways analysis.

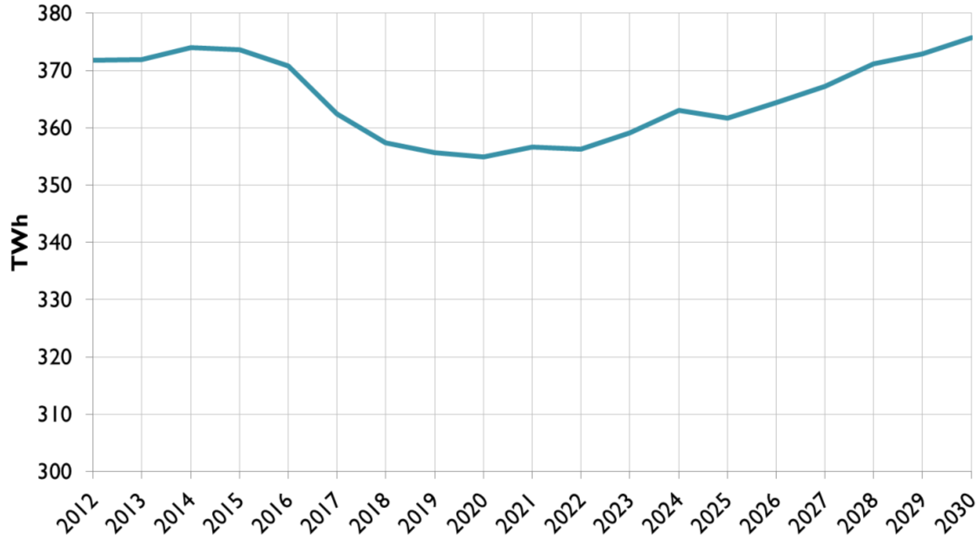
[30] The impact of the updated electricity demand assumptions as per National Grid Seven Year statement is unlikely to be significant.

[31] Available online: http://hm-treasury.gov.uk/d/201111forcomp.pdf

[32] Available online: http://budgetresponsibility.independent.gov.uk/economic-and-fiscal-outlook-march-2011/

[33] Available online: http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

Figure 18 Total annual electricity demand



Daily electricity demand in the model is subject to stochastic variation. This is modelled using a mean reverting random process. The mean reversion rate is 50 and volatility is 0.01 for both peak and off-peak demand. The minimum distance from mean is 0 for peak demand and 0.9 for off-peak demand. The maximum distance from mean is 10 for peak demand and 1.1 for off-peak demand.

Electricity generation

The model has a simplified representation of the GB electricity system and the amount of gas required for electricity generation is determined endogenously in the model. The generation mix in the model consists of nuclear, wind, CCGT and coal. The latter two technologies are split into two tranches by efficiency.

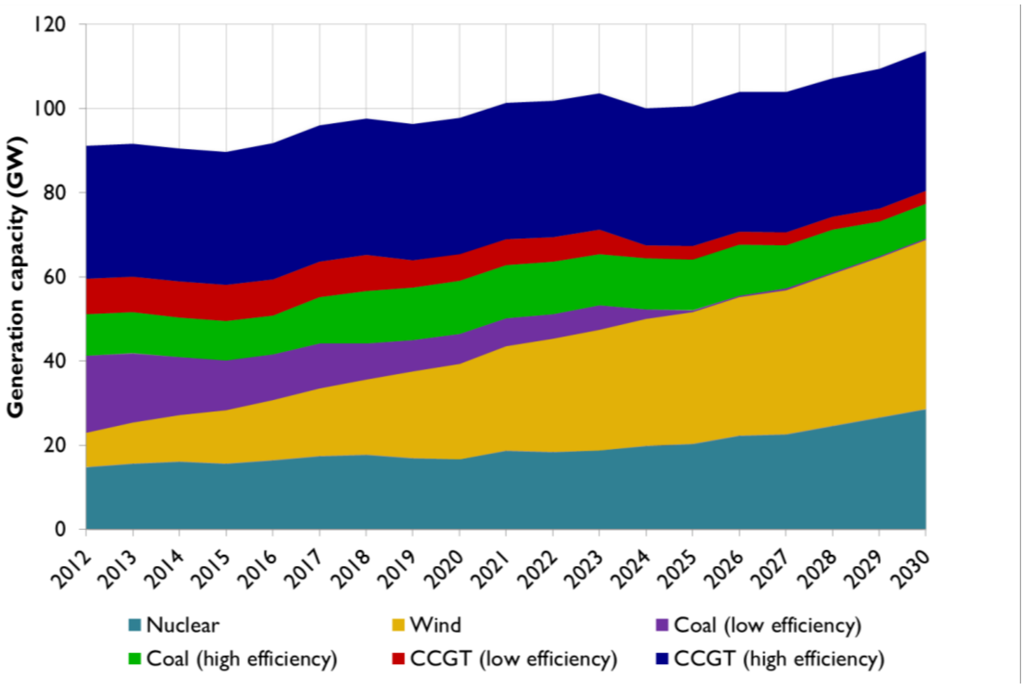
Assumptions for the generation capacity mix are taken from Ofgem's 2011 internal analysis, based on Project Discovery and updated with information from National Grid and industry[34]. Because Ofgem analysis contains a fuller representation of the generation stack, a number of assumptions are made in order to translate that representation into our model. These are as follows:

- Carbon Capture and Storage (CCS) coal is incorporated into high efficiency coal;
- Combined Heat and Power (CHP) is incorporated into low efficiency CCGT;
- Oil, Advanced Gas Turbine (AGT), pumped storage and Open Cycle Gas Turbine (OCGT) modelled as a single category of peaking plant;
- Non-intermittent renewables are incorporated into nuclear.

[34] The impact of the updated electricity generation capacity mix assumptions as per National Grid Seven Year statement is unlikely to be significant.

Figure 19 shows the generation capacity mix as represented in our model.

Figure 19 Model generation capacity mix



LCPD/IED[35] plant in the model are assumed to be constrained with respect to their total annual output. The instantaneous flexibility of these plant is modelled as a tranche of DSR priced above the peaking plant tranche. Hence in the course of unusually high electricity demand or, more likely, shortage of generation from CCGTs, LCPD/IED plant are allowed to operate up to their expected technical availability. Under these circumstances, interconnectors are also assumed to be importing power into GB up to their full capacity.

Stochastic wind output is generated by simulating a daily average load factor. Wind speeds are modelled using a Weibull distribution. To convert this into a load factor, the distribution is transformed using a turbine 'power curve'. This produces a 'U-shaped' distribution.

Given the daily granularity of our model, it is solved with respect to peak and off-peak periods for each day separately to reflect the difference between the levels of peak and off-peak electricity demand.

[35]The Large Combustion Plant Directive (LCPD) is currently applied to the power sector to limit SOx, NOx and particulate emissions. This affects the coal and oil fleet in GB. The Industrial Emissions Directive (IED) recasts seven existing Directives, including the Large Combustion Plant Directive and the Integrated Pollution Prevention and Control (IPPC) Directive, with tighter limits in particular for NOx emissions, coming into force in 2016.

Demand side response and firm demand interruption

DSR and involuntary interruption are represented jointly in the model through the definition of supply (negative demand) sources priced at the VoLL of each corresponding tranche of demand. The tranches for gas demand used in the model, in increasing order of VoLL, are as follows:

1. DM tranche 1 (318 p/th VoLL – 12.1 mcm/day in 2012)
2. DM tranche 2 (668 p/th VoLL – 14.9 mcm/day in 2012)
3. DM tranche 3 (1661 p/th VoLL – 9.6 mcm/day in 2012)
4. Non-Daily Metered (NDM) customers (2000 p/th VoLL – 113.3 mcm/day in 2012)[36]

Each of the three tranches of DM demand is derived by amalgamating several categories of I&C demand, taken from the London Economics (LE) VoLL study[37], according to similar VoLLs. The VoLL for each corresponding tranche is derived by taking an average VoLL of their constituent categories weighted by their respective gas demand in 2007 as given in the LE study.

NDM demand is combination of domestic and Small and Medium-sized Enterprise (SME) demand. These categories are amalgamated as it is likely to be impossible to distinguish between them for the purposes of cutting off tranches of demand. This tranche is priced at the domestic gas customer VoLL as estimated by Ofgem based on figures provided by LE.

The figures in brackets represent the estimated VoLL of each tranche (in pence per therm) and the size of the respective demand tranche (in mcm/day for 2012). After 2012, the size of each tranche of demand is assumed to change in line with general non-power generation demand assumptions.

Note that the three firm DM tranches do not include CCGTs. Since our model solves the electricity and gas markets simultaneously, we represent CCGT interruptions through interruptions of electricity customers supplied by CCGTs. These are set out below.

For electricity demand, the tranches are taken from Project Discovery. They are as follows, listed in increasing order of VoLL:

1. Interruptible Industrial and Commercial (I&C)[38] demand (£150/MWh VoLL – 53 GWh/week day)
2. Firm I&Cs (£4,000/MWh VoLL – 240 GWh/week day)
3. Domestic & SME (£5,000/MWh VoLL – 1,235 GWh/week day)

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[36] Note that a VoLL of 2000 p/th was assumed in our modelling for NDM customers as this was the latest available estimate at the time that the modelling commenced.

[37] London Economics was commissioned by Ofgem to conduct a study of Values of Lost Load for different types of GB gas consumer in support of Ofgem's Gas Significant Code Review consultation.

[38] These are assumed to be larger enterprises to differentiate them from SMEs.

The corresponding VoLLs for each of these tranches are likewise taken from the Project Discovery[39] [40]. The figures in brackets represent the estimated VoLL of each tranche (in £/MWh) and the size of the respective demand tranche (in GWh per week day for 2012). After 2012, the size of each tranche of demand is assumed to change in line with general power demand assumptions.

When gas supply is scarce, the model will seek out all opportunities for commercial self-interruption and fuel switching away from gas generation before interrupting firm gas demand. As a general rule, firm electricity demand supplied by CCGT generation is interrupted before any firm gas demand regardless of the relative VoLLs of electricity and gas customers. This is in line with NGG's likely emergency procedures. Apart from this rule, different tranches of demand are interrupted in the order of increasing VoLL. Any NDM demand that is interrupted remains off for the subsequent 14 days.

One possibility for commercial self-interruption is switching to distillate. Data compiled by DECC suggests that total CCGT capacity with distillate back up is 1.93 GW or is around 8.78 mcm/day of gas use in equivalent terms. Distillate backup forms a tranche of demand side response for peak electricity demand in the model, priced above the level of peaking plant. The instantaneous quantity of demand side response available changes in line with total capacity of plant with distillate backup.

Order of interruption

Under the Baseline in which the SCR reforms are assumed to be in place, tranches 1 and 2 of DM gas demand are assumed to be interruptible. It is assumed that, under the terms of the interruptible contracts, interruption takes place when the market price of gas exceeds the interruption price.

Although the gap between the VoLLs of the newly interruptible gas demand tranches and £20/th is relatively large, the interruption price is assumed to be competed down to the VoLLs of the two tranches of demand. This is due to the fact that at an interruption price higher than VoLL, customers would benefit from being interrupted first and would thus have a strong financial incentive to offer a lower interruption price.

Firm load shedding is deemed to set in when firm interruptions occur. At this point, the cash-out price rises to £20/th. In case of a deficit of gas to supply total demand, the general order of events is as follows.

Voluntary interruption and fuel switching

1. Electricity fuel switching from gas to coal and oil
2. LCPD/IED plant run to full technical availability
3. Fuel switching to distillate
4. DSR for Interruptible I&C electricity exercised (if supplied by CCGT generation)
5. DSR for Interruptible DM tranche 1 gas exercised

[39] Note that Project Discovery treats domestic and SME electricity demand tranches separately. However, for the purposes of our modelling, we merged SME demand into domestic demand as it would be difficult to load shed domestic and SME electricity customers separately.

[40] See http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Documents1/Discovery_Scenarios_ConDoc_FINAL.pdf

6. DSR for Interruptible DM tranche 2 gas exercised

Involuntary interruption

7. Interruption of CCGTs supplying Firm I&C electricity customers
8. Interruption of CCGTs supplying Domestic & SME electricity
9. Interruption of firm DM tranche 3 gas
10. Interruption of Non-Daily Metered (NDM) gas

7.2 Storage asset modelling assumptions

Overview

The market model contains a simple representation of SRS and LRS type facilities. To more precisely model the dispatch of such facilities in the market, a dedicated storage asset model is used, dispatching the simulated storage facilities against price simulations parameterised based on the market model results. The storage asset model is used to estimate investment decisions for new storage facilities, and to evaluate profits for such facilities in the market. In this section the key storage modelling assumptions are described.

Storage parameters

Storage facility parameters are described in Table 14, for both SRS and LRS types. These are intended to be indicative of the general 'type' (whether for current or proposed facilities). It should be noted that the "start of the year" is 1 April.

Table 14 Storage facility assumptions

Type Storage	SRS	LRS
Gas in storage as % of working gas volume at start of the year	50%	20%
Gas in storage as % of working gas volume at end of the year	50%	20%
Injection Cost (p/therm)	0.8	0.6
Withdrawal Cost (p/therm)	0.4	0.2
Injection rate, % of working volume per day	9.0%	0.8%
Withdrawal rate, % of working volume per day	9.0%	1.3%

Market parameters

The market model is used to predict daily average prices over multiple stochastic scenarios. The market model price simulations are used to calculate the expected monthly gas price used in the storage model, taken as the average monthly price across all market model simulations. Volatility of day-ahead prices is another key value driver for storage facilities, and is calculated using market model results as described in Section 5.2.

Other price simulation parameters have been calculated using historic data, from the period 1997-2012. These are as follows:

- Mean-reversion rate – 10.4%
- Long-term volatility – 22.6%
- Winter-summer volatility – 17.8%

The typical intra-day price range for forward contacts is used as a proxy for bid-offer spreads, and is based on NBP prices as reported by Platts over calendar year 2012, found to be 0.2 p/th. Monthly forward contracts are assumed to be available to storage facility operators to trade.

Table 15 shows the sources of input assumptions used for market parameters in the storage model. "Long term historics" refers to 1997-2012, "recent historics" refers to 2012 only.

Table 15 Market assumptions sources

Parameter	Source
Expected price trajectory	Market model
Forward contract types	*Assumed monthly*
Bid-offer spreads	Recent historics
Seasonality volatility	Long term historics
Long term drift volatility	Long term historics
Day-ahead volatility	Market model
Day-ahead mean reversion	Long term historics

Trading strategies

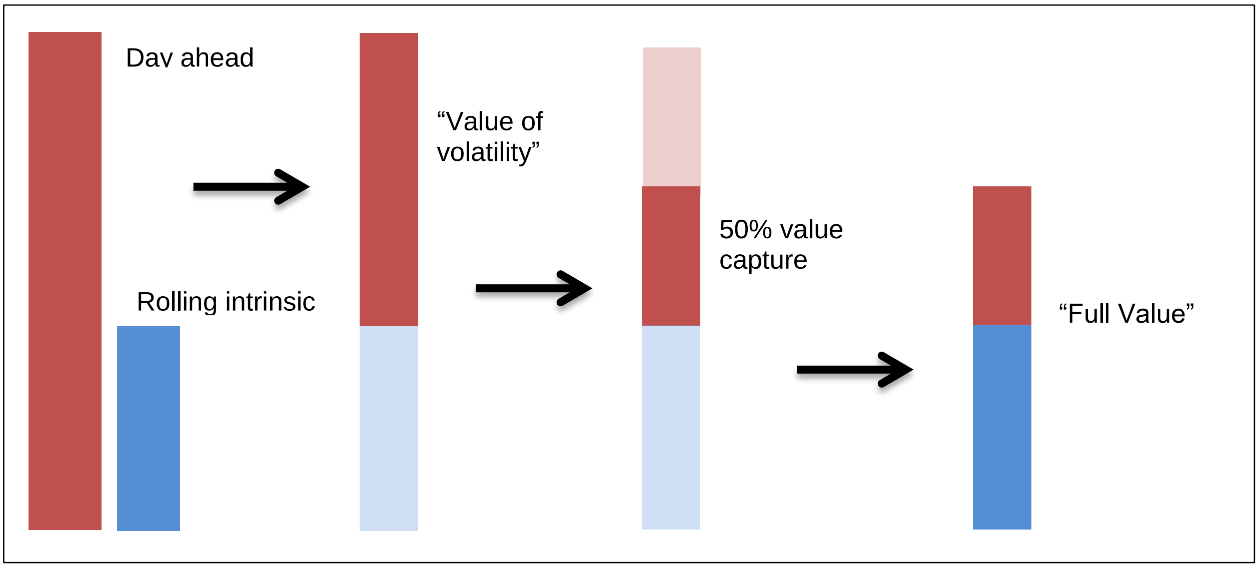
Gas storage facilities generate profits by trading natural gas to exploit spreads and volatility in gas prices over time. Trading strategies vary, and are dependent on not only the strategic goals of the owner of the capacity, but also by the specific characteristics of the storage facility, which constrain its ability to respond to price movements over various periods. In the analysis presented here two simple trading strategies have been applied:

1. ***Rolling intrinsic***: a strategy focusing on seasonal spreads in gas prices. Under this strategy the capacity owner will seek to "lock in" spreads at the start of the year by entering into forward contracts and setting an injection and withdrawal plan to deliver these contracts. This means the profits of the storage facility are fixed in advance, significantly reducing uncertainty over future cash flows for the period of the forward curve. Positions are only adjusted thereafter where it is profitable to do so (based on changes in the forward curve), providing potential upside to a pure intrinsic strategy.
2. ***Day-ahead***: a short term trading strategy aimed at exploiting changes in daily prices from demand changes (e.g. cold snaps during winter) as well as supply shocks such as production shutdowns or failures. By taking advantage of such daily price movements, expected profits can be increased (significantly for SRS facilities), but with much greater uncertainty than a rolling intrinsic strategy.

A rolling intrinsic strategy is conservative, and does not realise the full potential value of storage facilities, particularly SRS. However, a day-ahead trading strategy exposes the operator to far higher risk than many may have appetite for, or ability to trade against.

To allow the asset to be valued to reflect a trading strategy intermediate between these extremes, the difference between gross margin under day-ahead and rolling intrinsic strategies have been calculated, referred to as the "value of volatility". A 50% scalar has been applied to the value of volatility. The resulting scaled value of volatility is added to the conservative rolling intrinsic gross margin to give the "full value" gross margin, as used in the CBA. A schematic showing this process is given in Figure 20.

Figure 20 Gross margin full value capture



8 Further intervention options modelling assumptions

8.1 Generic non-specific obligation

The modelled deliverability under this option is 59 mcm/day and is designed to decrease the probability of interruption relative to the Baseline for firm gas and CCGTs supplying firm electricity customers to below 1-in-50. Any additional gas supplied under this intervention option is assumed to be kept out of the market and only used to prevent firm demand interruption.

8.2 Storage obligation

As has been described in Section 6, two design variants have been modelled for the storage obligation intervention option. Table 16 shows the assumptions for deriving the volume under the primary and secondary designs of storage obligation.

Table 16 Assumptions for estimating the storage obligation volume

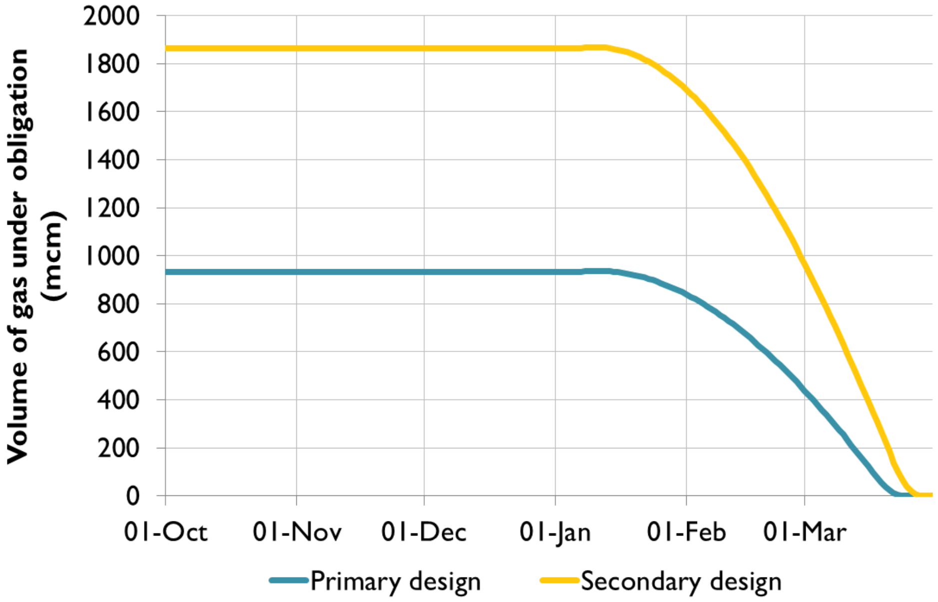
Item	Primary design	Secondary design
Type of winter demand	1 in 50	1 in 50
Demand to be protected	Firm gas demand	Firm gas demand
LNG not available	7 days	14 days

The maximum volume of the storage obligation is derived in each case to ensure that sufficient gas is available in storage to cover 1 in 50 peak winter firm gas demand given LNG being unavailable for either 7 or 14 days and all other supply sources having normal seasonal availability[41]. The derived maximum volume for storage obligation for the primary design and secondary design is estimated at 934 mcm and 1,864 mcm respectively.

The corresponding volume results are presented in Figure 21. The obligation is profiled through the winter to ensure that sufficient supplies are available at the peak of winter, and is profiled down during late winter and spring as the probability of prolonged periods of high demand decreases. The profile is broadly in line with National Grid's Firm Gas Monitor.

[41] 1 in 50 seasonal demand is derived by fitting a generic sine function to National Grid's 1 in 50 NDM demand duration curve for 2013, adjusted to include firm DM demand.

Figure 21 Derived volumes for the storage obligation



The obligation is assumed to apply to SRS and LRS storage in proportion to the total volume of those types of storage in GB. In our modelling, the constraint imposed by the storage obligation can only be violated in order to prevent a firm gas demand interruption (excluding CCGT demand).

8.3 Supported storage

Two variants of the Supported storage option have been modelled. The Primary design assumes 1 bcm of supported SRS and the Secondary design assumes 4 bcm LRS to be supported under cap and floor regulation. In each case, the withdrawal and injection rates are consistent with an average storage facility of its type in GB, although we note that for a specific storage project, both deliverability and injection rate may differ significantly from our assumptions. The modelling assumptions for supported storage are given in Table 17 below.

Table 17 Assumptions for supported storage

Item	Unit	Primary design (typical SRS)	Secondary design (typical LRS)
Maximum injection capacity	mcm/day	45	30
Maximum withdrawal capacity	mcm/day	45	50
Total volume modelled	mcm	1,000	4,000

Supported storage is assumed to operate in the market fully and its use by market participants is not restricted.

9 Security of supply results

9.1 Summary

This section presents the market modelling results for the Baseline case, which is used as a counterfactual against which the intervention options are compared, and also for the intervention options. All of the results shown in this section assume that Ofgem's SCR reform has been implemented by 2020 and that the cash-out price is capped at £20/th. For the Baseline and the two Supported storage interventions, results are shown for both the Stressed and the Gone Green scenarios since the CBA for the Secondary design of the Supported storage intervention is also evaluated under both scenarios. Results for the Storage obligation and the Non-specific obligation options are shown for the Stressed scenario only.

In each case we present three sets of results, for gas and electricity customer segments[42], that are derived statistically from the 1500 simulations run for each scenario, intervention option and spot year:

- the probability of at least one outage in a year,
- average unserved demand, and
- the cost of unserved demand, evaluated based on assumed Values of Lost Load for each customer type[43].

Note that statistics on the probability of at least one outage in a year do not contain any information on the number of outages in a given year (if more than one), the duration of those outages or their severity. Hence statistics on average unserved demand give a more accurate picture of security of supply for any given demand tranche.

The results for Baseline and Generic non-specific obligation represent an average of modelled 2020, 2025 and 2030 spot years. In case of Storage obligation and Supported storage, the results represent an average of modelled 2020 and 2030 spot years.

9.2 Baseline

This section presents the average results for the Baseline with market investment response under the Stressed and Gone Green scenarios. Based on the market model results and using the volatility modelling framework as described in Section 3 of the report, it was estimated that 400 mcm of additional market SRS investment with deliverability of 36 mcm/day would take place by 2020 under the Stressed scenario. No new market-based LRS investment takes place in our modelling and market investment response is not estimated under the Gone Green scenario.

[42] Conversion from electricity into gas terms is carried out using an assumed CCGT generation efficiency of 48.5%.

[43] VoLLs for different customer types used for CBA analysis are set out in Section 7.1.

Table 18 to Table 20 below show the average expected annual probability of interruption, and the volume and cost of the unserved demand for the Stressed and Gone Green demand scenarios. As expected, risk to security of supply as measured by the probability and impact of demand interruptions is estimated to be considerably higher under the Stressed scenario.

Firm I&C electricity has the highest probability of interruption since we assume that CCGTs are always interrupted before firm gas demand. The volume of interruption and the corresponding cost of energy unserved for NDM gas are many times greater than for firm DM gas. The main reason for this is the assumption that NDM gas interruptions last for a minimum of 14 days.

Table 18 Average annual probability of at least one outage

	Stressed	Gone Green
Firm DM gas	1 in 33	1 in 333
NDM gas	1 in 45	1 in 333
Firm I&C electricity	1 in 19	1 in 115
Domestic & SME electricity	1 in 31	1 in 231

Table 19 Unserved demand

Million therms/year	Stressed	Gone Green
Firm DM gas	0.127	0.011
NDM gas	3.036	0.380
Firm I&C electricity	0.155	0.018
Domestic & SME electricity	0.056	0.006

Table 20 Cost of unserved demand

£m (real 2012)	Stressed	Gone Green
Firm DM gas	2.1	0.2
NDM gas	60.7	7.6
Firm I&C electricity	9.2	1.1
Domestic & SME electricity	4.2	0.5

9.3 Generic non-specific obligation

This section presents the results for the generic non-specific obligation with market investment response under the Stressed scenario. These are shown alongside corresponding Baseline results for ease of comparison. It has been assumed that there is an additional deliverability of 59 mcm/day of gas under this intervention compared to the Baseline, which is kept out of the market, and used for the sole purpose of preventing firm demand interruptions.

The expected annual outage probabilities, volume and cost of unserved demand can be seen in Table 21 to Table 23. From the comparison of the results for the generic non-specific obligation against the Baseline, it can be seen that additional non-market deliverability under the intervention leads to a significant reduction in probability of outages, volume and cost of unserved demand for both firm DM and NDM gas customers. The primary reason for the strong security of supply effect of this intervention is that the additional deliverability is kept outside of the market and hence would always be available at the time that an emergency occurs.

The reduction in unserved demand for all demand tranches (gas and electricity) is by a factor of approximately ten. This is also generally the case for probability of interruption with the exception of Firm I&C electricity, for which the reduction in the probability of interruption is significantly less than the reduction in unserved demand. This shows that there are a number of interruption events for which the intervention significantly reduces the severity of Firm I&C electricity interruption without preventing it completely. This is not the case for domestic electricity since it has higher VoLL and is always interrupted after Firm I&C electricity. Hence the gas under the obligation is always used to prevent domestic electricity interruption before Firm I&C electricity interruption.

Table 21 Average annual probability of at least one outage

	Baseline	Generic non-specific obligation
Firm DM gas	1 in 33	1 in 300
NDM gas	1 in 45	1 in 450
Firm I&C electricity	1 in 19	1 in 107
Domestic & SME electricity	1 in 31	1 in 281

Table 22 Unserved demand

Million therms/year	Baseline	Generic non-specific obligation
Firm DM gas	0.127	0.010
NDM gas	3.036	0.220
Firm I&C electricity	0.155	0.015
Domestic & SME electricity	0.056	0.004

Table 23 Cost of unserved demand

£m (real 2012)	Baseline	Generic non-specific obligation
Firm DM gas	2.1	0.2
NDM gas	60.7	4.4
Firm I&C electricity	9.2	0.9
Domestic & SME electricity	4.2	0.3

9.4 Storage obligation

Table 24 to Table 26 below present the results for the Storage obligation (SO) together with the corresponding results for the Baseline. Based on the market model results and the volatility modelling framework, we estimate that a storage obligation could significantly increase the volatility of spot gas prices. This is due to the restrictions placed on the operation of storage at times when volatility of demand is at its greatest. The effect on price volatility is greater under the Secondary design of the Storage obligation, particularly in 2030, due to the greater volume of gas covered by the Secondary design.

As a consequence of increased gas price volatility under a Storage obligation, we estimate that 800 mcm of SRS investment would take place under the primary design, i.e. 400 mcm greater than in the Baseline. In case of the secondary design, which has a larger volume obligation, it was estimated that 800 mcm of SRS investment would take place in 2020 and 1,200 mcm by 2030. Thus, under the secondary design, there is an additional SRS investment of 400 mcm in 2020 and 800 mcm by 2030 relative to the Baseline. We further estimate that no additional LRS capacity would be built in this case.

From the comparison of results between the Baseline and the Storage obligation, it can be seen that both designs of the Storage obligation lead to a significant improvement in security of supply for both firm DM and NDM gas customers. This improvement is greater under the secondary design, where the overall effect is comparable to that seen under the Generic non-specific obligation.

The impact on the probability of interruption and unserved demand in electricity is directionally the same as for Firm Gas Demand but not nearly as strong. This is because the constraints on the dispatch of gas storage implied by the obligation cannot be lifted to prevent an interruption to firm electricity demand, but can be lifted to prevent non-CCGT firm gas demand interruption. Reduction in the probability and volume of firm electricity demand interruption results from the fact that a storage obligation is a barrier to the depletion of gas in storage during the early and mid-winter period, hence there is generally more gas left in store in late winter and early spring, when the level of the obligation ramps down rapidly, to prevent or mitigate potential demand interruptions.

Table 24 Average annual probability of at least one outage

	Baseline stressed	SO primary design stressed	SO secondary design stressed
Firm DM gas	1 in 33	1 in 231	1 in 375
NDM gas	1 in 45	1 in 273	1 in 429
Firm I&C electricity	1 in 19	1 in 38	1 in 45
Domestic & SME electricity	1 in 31	1 in 79	1 in 100

Table 25 Unserved demand

Million therms/year	Baseline stressed	SO primary design stressed	SO secondary design stressed
Firm DM gas	0.127	0.024	0.010
NDM gas	3.036	0.848	0.141
Firm I&C electricity	0.155	0.054	0.042
Domestic & SME electricity	0.056	0.026	0.013

Table 26 Cost of unserved demand

£m (real 2012)	Baseline stressed	SO primary design stressed	SO secondary design stressed
Firm DM gas	2.1	0.4	0.2
NDM gas	60.7	17.0	2.8
Firm I&C electricity	9.2	3.2	2.5
Domestic & SME electricity	4.2	1.9	0.9

9.5 Supported storage

This section presents the results for the two designs of the Supported storage intervention under the Stressed and Gone Green scenarios. Under the primary design, 1000 mcm of SRS capacity is assumed to be built under a cap and floor regulatory regime. The capacity is allowed to participate in the market fully and our estimates suggest that, under the Stressed scenario, no market investment response would take place under this intervention. This means that the intervention has 600 mcm more of SRS capacity overall than the Baseline.

Under the secondary design, 4000 mcm of LRS capacity is assumed to be built under a cap and floor regulatory regime. The capacity is allowed to participate in the market fully and our estimates suggest that, under the Stressed scenario, market investment response under this intervention would be 100 mcm lower than under the Baseline, but market based investment in SRS capacity would not be displaced completely. This is because our estimates suggest that the effect of the Supported LRS on gas price volatility is considerably lower than that of the Supported SRS option. Under the Gone Green scenario, no investment response is evaluated for either the Baseline or the Supported storage options.

The results show that secondary design of the Supported storage intervention is a lot more effective at reducing the probability and impact of demand interruptions than the primary design, but is less effective than the Generic non-specific obligation or the Storage obligation. This is as expected given the much higher volume of gas in store under the secondary design and the less volatile behaviour of LRS relative to SRS, which means that it is less likely to be empty at the time that an emergency occurs. However, given that supported storage participates in the market, there is no guarantee that it will be available to flow at times of emergency unlike the gas covered by a Generic non-specific obligation or a Storage obligation.

In absolute terms, both designs of this intervention are a lot less effective in reducing the probability and impact of demand interruptions under the Gone Green scenario than under the Stressed scenario. This is due to the fact that impact of interruptions is much lower under the Gone Green scenario to begin with.

Table 27 Average annual probability of at least one outage (Stressed)

	Baseline	Primary design	Secondary design
Firm DM gas	1 in 33	1 in 52	1 in 107
NDM gas	1 in 45	1 in 65	1 in 143
Firm I&C electricity	1 in 19	1 in 31	1 in 60
Domestic & SME electricity	1 in 31	1 in 58	1 in 150

Table 28 Average annual probability of at least one outage (Gone Green)

	Baseline	Primary design	Secondary design
Firm DM gas	1 in 333	1 in 375	1 in 600
NDM gas	1 in 333	1 in 375	1 in 1000
Firm I&C electricity	1 in 115	1 in 150	1 in 273
Domestic & SME electricity	1 in 231	1 in 273	1 in 500

Table 29 Unserved demand (Stressed)

Million therms/year	Baseline	Primary design	Secondary design
Firm DM gas	0.127	0.071	0.034
NDM gas	3.036	1.430	0.684
Firm I&C electricity	0.155	0.073	0.031
Domestic & SME electricity	0.056	0.024	0.008

Table 30 Unserved demand (Gone Green)

Million therms/year	Baseline	Primary design	Secondary design
Firm DM gas	0.011	0.009	0.003
NDM gas	0.380	0.368	0.227
Firm I&C electricity	0.018	0.013	0.006
Domestic & SME electricity	0.006	0.005	0.002

Table 31 Cost of unserved demand (Stressed)

£m (real 2012)	Baseline	Primary design	Secondary design
Firm DM gas	2.1	1.2	0.6
NDM gas	60.7	28.6	13.7
Firm I&C electricity	9.2	4.4	1.9
Domestic & SME electricity	4.2	1.8	0.6

Table 32 Cost of unserved demand (Gone Green)

£m (real 2012)	Baseline	Primary design	Secondary design
Firm DM gas	0.2	0.2	0.1
NDM gas	7.6	7.4	4.5
Firm I&C electricity	1.1	0.8	0.3
Domestic & SME electricity	0.5	0.4	0.2

9.6 Conclusion

As expected, the impact on security of supply for different demand tranches is estimated to be greatest for those tranches that are explicitly designed to be protected under a given intervention. These are firm gas and electricity demand under the Generic non-specific obligation and firm gas demand only under the Storage obligation. Also as expected, interventions that are kept outside of the market, i.e. Generic non-specific obligation and Storage obligation, are estimated to be more effective at preventing and/or mitigating firm demand interruption than those that operate freely in the market, i.e. Supported storage. In Section 10, we evaluate the consumer welfare impact of changes in security of supply as a result of the intervention options, as well as broader impacts of the intervention options on consumer welfare and the welfare of storage.

10 Cost benefit analysis

10.1 Methodology

Our CBA methodology is designed to assist in making a like-for-like comparison of different intervention options. Section 9 shows the cost of unserved energy estimated for the Baseline and the different modelled intervention options. However, it would not be sufficient to compare the different intervention options on that basis alone since different intervention options have different associated costs and other effects that can have a significant impact on social welfare. The CBA puts the security of supply effects and other direct welfare effects of the intervention options on the same basis to allow a more complete assessment of the different modelled options.

It is not our intention to analyse the intervention options in a general equilibrium framework where the impact of interventions feeds through to other sectors of the economy. Rather, we analyse welfare changes in the downstream of the GB gas sector with a particular focus on the welfare of consumers. We also analyse changes in the welfare of owners of storage capacity. It is likely that there are some secondary welfare effects of interventions and potential unintended consequences that are not covered by our CBA. We have sought to investigate some of these effects, with one example being the effect of supported storage on the profits of existing storage, but we recognise the possibility of other effects that are not foreseen in our analysis.

It is also worth noting that the level of confidence in the results differs between different elements of the CBA. This is addressed in more detail in Section 10.2. In summary, the level of confidence is highest in the results on physical security of supply (for the given scenario assumptions). It is lower for the estimated effect of intervention options on the weighted average price of gas as this is sensitive to a broader range of modelling assumptions, particularly around the shape of supply curves, with a higher level of uncertainty. Finally, there is material uncertainty about estimated effects of intervention options on the profits of storage assets as these estimates rely on fundamental modelling of volatility in gas prices, which is complex and subject to significant uncertainty.

Our CBA spans the period from 2020 to 2030 inclusive. Since we model selected spot years, in order to find the Net Present Value (NPV) of the key CBA metrics, values for the years not modelled are interpolated from the values for the years that are modelled. All our modelling is carried out in January 2013 real terms using a long-term inflation assumption of 2% per annum. NPV is worked out on the basis of a real terms discount rate of 3.5%, with all future values being discounted to January 2013. This rate is based on the HM Treasury Green Book on policy appraisal[44].

All results are shown as a change relative to the Baseline. The cost of load reduction to customers is calculated directly on the basis of their Value of Lost Load. Our analysis does not include an assessment of any broader impact of gas supply interruptions on the economy. Change in net supplier welfare as a result of reform is assumed to be zero by definition, driven by the underlying assumption that gas suppliers are competitive and only make a 'normal' profit. The result of this assumption is that any changes in the costs

[44] http://www.hm-treasury.gov.uk/d/green_book_complete.pdf

faced by suppliers are passed on to consumers in the long run. In our CBA, this is done through the Retail revenue line item, which is a sum of changes in Cash-out liability, Payments to interruptible customers and Change in total cost of gas.

The cost of new storage is calculated on an annuitised basis to ensure that costs of any additional gas storage infrastructure are reflected on a like-for-like basis with the associated benefits in our CBA analysis. We have used a hurdle rate of 13% for market-based storage investment. Where storage investment takes place on a non-market basis, we have calculated the associated capital cost for a range of hurdle rates between 8% and 13%. This reflects the uncertainty about any reduction in the hurdle rate for storage investment associated with a cap and floor regulatory regime, or as in the case of the Generic non-specific obligation, with additional infrastructure being procured by the System Operator and the associated cost being passed through to consumers.

It is likely that revenue stabilisation would decrease investment risk for storage developers and lower their hurdle rate for investment. More fundamentally though, the range of hurdle rates also reflects uncertainty about whether any such reduction should be treated as a net welfare gain. Revenue risk of storage (or risk associated with extent of reduction in the cost of unserved energy in the case of the Generic non-specific obligation) would not be reduced fundamentally under cap and floor regulation or SO procurement and operation respectively but would instead be passed to consumers to some degree. Hence, if it is assumed that consumers are better able to handle revenue risk associated with storage, or in the case of the non-specific obligation, the risk associated with its contribution to security of supply, a lower hurdle rate assumption is appropriate. Otherwise, if it is assumed that consumers are in no better position to manage this risk than storage investors, a higher hurdle rate assumption is more appropriate.

10.2 Results

Generic non-specific obligation

The welfare effects of the non-specific obligation are limited to consumers since the supply source under the obligation, which is in addition to any storage that exists in the Baseline after market investment response, is kept out of the market. Table 33 shows the impact of this intervention on GB consumers as estimated in our modelling. The cost of the infrastructure, assumed to be fast cycling storage, is estimated for a range of required rates of return on investment.

Table 33 CBA– Generic non-specific obligation

£ million		NPV (real 2012)	
		13% hurdle rate	8% hurdle rate
Consumer welfare	Retail cost	0.0	0.0
	Cost of additional storage	-603.9	-402.1
	Payments for involuntary DSR services	0.0	0.0
	Payments for voluntary DSR services	0.0	0.0
	Load reduction to firm gas customers	229.3	229.3
	Load reduction to firm electricity customers	38.6	38.6
	Load reduction to interruptible customers	-3.9	-3.9
	Net consumer welfare	**-339.9**	**-138.1**

The Retail cost line shows the change in the total cost of gas for consumers under the intervention option relative to the Baseline. This is zero as the intervention is assumed to operate outside of the market. The cost of additional storage is the cost of the physical infrastructure required to meet the obligation, which we assume takes the form of SRS[45]. Change in value of load reduction to different types of customers is estimated at their respective VoLLs as set out in Section 7.1. Payments for voluntary DSR services represent the change in exercise payments to interruptible customers under their DSR contracts, estimated at the VoLL of those customers. Payments for involuntary DSR services represent the change in compensation payments to interruptible customers, estimated at capped VoLL of firm customers. These are assumed to be zero under this intervention as the intervention is kept out of the market.

Although this intervention option is kept out of the market, it is not entirely neutral to the operation of the market in our modelling. This is due to the assumption that NDM interruptions last for a minimum of 14 days. If the intervention prevents an NDM interruption, total NDM demand is higher for the remainder of the 14 day period than if the interruption had taken place. Since NDM demand has the highest VoLL, the model will always seek to meet it before other demands, and hence higher NDM demand will have knock-on effects on the ability of the model to meet other demands given available supply. In the modelling results, we see this as an increase in load reduction to interruptible customers. Compared to other CBA line items, this is a very minor effect on overall consumer welfare.

The intervention has a significant positive effect on security of supply and results in a saving in the cost of unserved energy of £264m. However, this saving is lower than the cost of the intervention even at the lower 8% cost of capital[46]. If the obligation is placed on the System Operator, the associated cost would eventually be passed through to consumers, hence savings in the cost of unserved energy would have to

[45] We assume a capex cost of new SRS investment of £1.01m per mcm of capacity and estimated the annual capital cost on an annuitized basis for the range of the required rate of return.

[46] Note that the cost of additional storage in the CBA table represents the sum of discounted annuitized costs for the period between 2020 and 2030 inclusive.

exceed the cost of the intervention for the overall impact of the intervention on consumer welfare to be positive.

Storage obligation (Primary design)

The Storage obligation has an effect on the operation of gas storage facilities in GB and hence the welfare effects of intervention go beyond consumers. The storage obligation is effective at reducing the probability and impact of demand interruptions, and the cost of unserved energy is reduced by £160m. Restrictions on the booking and operation of storage mean that storage is not always available to flow when the market price of gas increases, especially in early winter when the volume of gas under the obligation is at its greatest. This results in an increase in the total cost of gas for consumers of £78m, leaving an overall net welfare benefit for consumers of £51m.

Restrictions on the booking and operation of storage capacity result in greater gas price volatility, which increases the economic incentives to invest in additional fast cycling storage capacity. Under our modelling approach, an additional 400 mcm SRS facility is built under this option relative to the Baseline (800 mcm more than under Baseline before market investment response). The cost of this additional storage is less than the corresponding profits generated in the model. Restrictions of storage operation lead to a significant reduction in the profits of existing storage, more than offsetting the effect of higher volatility. This is estimated to be £912m.

Table 34 CBA– Storage obligation (Primary design)

£ million		NPV (real 2012)
Consumer welfare	Retail cost	-78.4
	Cost of price volatility	3.5
	Payments for involuntary DSR services	-18.8
	Payments for voluntary DSR services	-15.4
	Load reduction to firm gas customers	136.2
	Load reduction to firm electricity customers	8.7
	Load reduction to interruptible customers	15.4
	Net consumer welfare	**51.1**
Supplier welfare	Retail revenue	78.4
	Total cost of gas	-112.6
	Cashout liability	18.8
	DSR liability	15.4
	Net supplier welfare	**0.0**
Storage welfare	Profits of existing storage	-911.8
	Profits of additional market storage	478.0
	Profits of additional supported storage	0.0
	Cost of additional market storage	-368.4
	Cost of additional supported storage	0.0
	Net storage welfare	**-802.3**

In addition to the consumer welfare lines that have already been defined in the context of the Generic non-specific obligation, the CBA for the storage obligation has several elements to account for the estimated effects of a storage obligation on the market. Under consumer welfare, we have incorporated an estimate of the cost of price volatility, which is assumed to be passed on by suppliers to consumers. We have estimated this as the change in the requirement of suppliers to hold capital against the risk associated with the cost of meeting demand variations under volatile spot prices[47]. This is a positive number in the context of both designs of the storage obligation since greatest imbalance exposures tend to occur in the event of demand interruption, and the probability of such events is reduced by a storage obligation in our modelling.

[47] This is estimated as the change in the cost of holding capital against the 95th percentile imbalance exposure, assuming an 8% real cost of capital.

Welfare of suppliers is modelled under the assumption that they are perfectly competitive and pass on any changes in their net welfare to consumers through the retail cost of gas. The change in the retail revenue of suppliers corresponds to the change in the retail cost of gas for consumers. It is the sum of the change in the total cost of gas, which is estimated from the model price results, change in cash out liability, which is equivalent to compensation payments for interruption to firm customers, and change in DSR liability, which is equivalent to exercise payments to interruptible customers under their DSR contracts.

Finally, we also estimate the welfare of storage, both for storage that exists under the Baseline as well as the intervention option, and new storage that is either a direct or an indirect consequence of an intervention. The profits of existing storage line estimates the effect of the intervention on the profits of LRS and SRS that is present in both the Baseline and the intervention option. The Profits of additional market storage line estimates the profits of market-based storage that is built under the intervention option but not under the Baseline. It is positive under this intervention since the amount of market-based storage under the intervention is greater than under the Baseline. If an intervention prevents some storage from being built, the entry for this line is negative. The corresponding cost of the additional market-based storage, evaluated on an annuitized basis and assuming a 13% required rate of return, is shown in the Cost of additional market storage line. Profits and costs of additional supported storage relate to any supported storage built under the corresponding intervention. Costs are evaluated on an annuitized basis for a range of possible required rates of return.

An initial reading of the results may indicate that consumers are likely to benefit from this intervention and owners of existing storage capacity are likely to lose out, with the losses to owners of existing storage being significantly greater than the net benefit to consumers. However, it is important to note that we do not model all of the interactions between different economic agents. In particular, in our modelling, the storage obligation is imposed on existing and new storage directly. In reality, the obligation is likely to be imposed on suppliers, who would in turn have to book storage capacity. This would have important implications for the distribution of the benefits and costs associated with this intervention.

When restrictions are placed on the operation of storage directly, as in our modelling, the reduction in profits associated with loss of flexibility is suffered by the owners of gas storage. However, if an obligation is placed on suppliers to book and hold a certain amount of storage capacity, owners of that capacity would still have the option to sell that capacity to traders wishing to take advantage of trading on price volatility and seasonal spreads. If this enabled them to achieve the same value for the capacity as they could have without the constraint, then any loss may be suffered by suppliers as they would have an obligation to book storage capacity that cannot be used for trading on price volatility and seasonal spreads in most periods. Given that suppliers are assumed to be perfectly competitive in our CBA modelling, such losses would be passed on directly to consumers.

Overall, given likely mechanics of the storage obligation and our modelling results for direct impacts of intervention on consumer welfare and storage welfare, our modelling suggests that consumer welfare is likely to be reduced by the storage obligation.

Storage obligation (Secondary design)

The secondary design of the Storage obligation intervention option places a more onerous requirement for the booking and holding of storage capacity than the primary design. In our modelling, we estimate that an additional 400 mcm of SRS capacity would be built under this option by 2020 and 800 mcm by 2030 relative to the Baseline. The cost of this additional storage is significantly less than the corresponding profits generated, which would suggest that market investment response in new storage capacity may be even greater.

As with the primary design, the effect of the obligation is to reduce the cost of unserved energy and increase the total cost of gas for consumers. Both of these elements are greater under the secondary design, with the overall net balance of consumer welfare being approximately the same.

Also as with the primary design, the obligation reduces profits from existing storage, and the magnitude of this effect is very similar. Overall net storage welfare is negative but better than under the primary design. This is due to the larger gap between profits of new storage and the cost of new storage under the secondary design. As stated above, this gap would suggest that market investment response in new storage capacity may be even greater than that estimated in our modelling. If that were the case, further SRS would increase the cost of new storage investment and reduce gas price volatility, driving down storage profits further. All these factors would bring storage welfare closer to that seen under the primary design of the Storage obligation.

Given likely mechanics of the storage obligation, our modelling suggests that, as with the primary design, consumer welfare is also likely to be reduced by the secondary design of the storage obligation.

Table 35 CBA– Storage obligation (Secondary design)

£ million		NPV (real 2012)
Consumer welfare	Retail cost	-160.4
	Cost of price volatility	4.5
	Payments for involuntary DSR services	-30.4
	Payments for voluntary DSR services	-19.0
	Load reduction to firm gas customers	228.6
	Load reduction to firm electricity customers	19.7
	Load reduction to interruptible customers	19.0
	Net consumer welfare	**62.0**
Supplier welfare	Retail revenue	160.4
	Total cost of gas	-209.8
	Cashout liability	30.4
	DSR liability	19.0
	Net supplier welfare	**0.0**
Storage welfare	Profits of existing storage	-961.2
	Profits of additional market storage	943.8
	Profits of additional supported storage	0.0
	Cost of additional market storage	-540.0
	Cost of additional supported storage	0.0
	Net storage welfare	**-557.5**

Supported storage (Primary design)

Under the primary design of the Supported storage intervention, 1000 mcm of new SRS capacity is assumed to be built under a cap and floor regime. Since the details of any potential support regime have not been worked out at the time of writing, we model the revenue support as a simple 'top-up' regime, noting that there are other possible support mechanism designs. If in any given year, profits of supported storage fall below the required hurdle rate for investment, a top-up payment is made to the owners of that storage to cover the difference. Any such payments appear as a cost of supported storage under consumer welfare and are added to profits of additional supported storage. Hence if the rate of return on supported storage is below the hurdle rate for supported storage investment in every year between 2020 and 2030, profits of additional supported storage and cost of additional supported storage will sum to zero.

We estimate that an addition of 1000 mcm of new supported SRS capacity that operates in the market would deter any additional market-based SRS investment from taking place. Hence, because 400 mcm less of market-based SRS capacity is built under this intervention option than under the Baseline, profits of additional market-based storage are negative and the cost of additional market storage is positive[48].

This intervention option is not as effective at reducing the probability and impact of demand interruptions as either the Non-specific obligation or the Storage obligation and the gain for consumers in terms of reduction in the value of unserved energy is just £57m. However, because the additional storage capacity is able to buy energy from the market during periods of low prices and sell it back into the market when high prices prevail, it is estimated to reduce the demand weighted price of gas for GB consumers. The value of this reduction for the period between 2020 and 2030 is estimated in our modelling to be £263m.

The additional supported SRS capacity is estimated to be relatively profitable and, even applying a high discount rate of 13% for storage investment, only requires limited support in the early years around 2020 and no support thereafter. However, the additional SRS capacity, which participates in the market fully, is estimated to significantly reduce gas price volatility and thus has a significant negative impact on the profits of existing storage. Profits of existing storage are estimated to be reduced by £1300m in NPV terms for the period between 2020 and 2030.

The estimated reduction in the profits of existing storage as a result of this intervention is large. Given the inherent complexity and uncertainty involved in the modelling of gas price volatility, discussed in detail in Section 5, the level of confidence in estimates of changes in storage arbitrage revenues as a result of intervention is lower than in associated changes in security of supply and, to a lesser degree, the total cost of gas for consumers.

One consideration could be whether the reductions seen in our modelling of this intervention option could be large enough to result in negative unintended consequences such as existing storage operators exiting the market. Whilst it is not in the remit of this study to consider that question directly, we note that new SRS investment is estimated to require little or no support despite significant reductions in gas price volatility. Further, we note that the investment made by existing storage investors is a sunk cost, hence exit from the market would only be rational if on-going revenues are insufficient to cover on-going fixed and variable costs plus any maintenance costs. This is less likely than revenues on any new investment being insufficient to cover the associates fixed, variable and investment costs.

[48] In simpler terms, since there is less market-based storage under the intervention than in the baseline, market-based storage profits are lower and the cost of market-based storage is lower.

Table 36 CBA– Supported storage (Primary design – Stressed scenario)

£ million		NPV (real 2012)	
		13% hurdle rate	8% hurdle rate
Consumer welfare	Retail cost	262.7	262.7
	Cost of supported storage	-10.7	0.0
	Cost of price volatility	13.6	13.6
	Payments for involuntary DSR services	-4.0	-4.0
	Payments for voluntary DSR services	-5.7	-5.7
	Load reduction to firm gas customers	50.4	50.4
	Load reduction to firm electricity customers	1.1	1.1
	Load reduction to interruptible customers	5.7	5.7
	Net consumer welfare	**313.0**	**323.7**
Supplier welfare	Retail revenue	-262.7	-262.7
	Total cost of gas	252.9	252.9
	Cashout liability	4.0	4.0
	DSR liability	5.7	5.7
	Net supplier welfare	**0.0**	**0.0**
Storage welfare	Profits of existing storage	-1,300.5	-1,300.5
	Profits of additional market storage	-624.2	-624.2
	Profits of additional supported storage	1,086.0	1,075.3
	Cost of additional market storage	368.4	368.4
	Cost of additional supported storage	-921.1	-613.3
	Net storage welfare	**-1,391.4**	**-1,094.2**

Overall, from an initial reading of the results, this intervention appears to be beneficial to consumers in the context of the Stressed scenario. Although the security of supply benefits of additional supported SRS are estimated to be modest, there is a greater estimated benefit to consumers in terms of lower gas prices and the associated cost of support is limited. However, the negative effect of intervention on net storage welfare is estimated to be much greater in magnitude than the positive impact on net consumer welfare and it is worth noting that the distribution of costs and benefits between consumers and storage owners under this option depends on the design of the support mechanism for storage (e.g. whether it is available to existing as well as new storage). Under some designs, consumers may end up underwriting the loss in the value of existing storage as a result of competition from new supported storage, in which case the overall effect of this intervention option is likely to be negative.

Supported storage (Secondary design)

Under the secondary design of the Supported storage intervention, 4000 mcm of new LRS capacity is assumed to be built under a cap and floor regime. We estimate that this additional LRS capacity, which operates in the market, would prevent 100 mcm of additional market-based SRS investment from taking place.

This intervention option is significantly more effective at reducing the probability and impact of demand interruptions than the primary design and the gain for consumers in terms of reduction in the value of unserved energy is £211m. Because the additional storage capacity is able to buy energy from the market during periods of low prices and sell it back into the market when high prices prevail, it is estimated to reduce the demand weighted price of gas for GB consumers. The value of this reduction for the period between 2020 and 2030 is estimated in our modelling to be £842m.

The additional supported LRS capacity is estimated to be relatively unprofitable compared to supported SRS under the primary design and, applying a high hurdle rate of 13% for storage investment, requires support to the value of £727m in NPV terms between 2020 and 2030. In this case the profits and costs of additional supported storage shown in the CBA are the same in absolute terms. This is because the exact details of the support regime are unknown at the time of writing, and hence it is modelled as an annual floor on revenues equal to the annuitized cost of the additional supported storage, noting that there are other possible support mechanism designs. If the annuitized cost of additional supported storage exceeds the revenue of that storage in every year between 2020 and 2030, as is the case with supported LRS under the assumption of 13% hurdle rate for storage investment, the profits of additional supported storage are made up to the annuitized cost of storage in every one of those years.

The additional LRS capacity, which participates in the market fully, is estimated not to reduce average gas price volatility in a significant way and thus has only a small negative impact on the profits of existing storage, most of this pertaining to existing LRS. Profits of existing storage are estimated to be reduced by £110m in NPV terms for the period between 2020 and 2030.

Given that this intervention option is estimated to bring a net benefit to consumers under the Stressed scenario, we also estimate the CBA under the Gone Green scenario, shown in Table 38. Here, the value of reduction in unserved energy relative to the Baseline is significantly lower than in the Stressed scenario. The estimated value of the reduction in the cost of gas for consumers is also somewhat lower, and the estimated cost of support is similar to that seen under the Stressed scenario. Consumers are estimated to benefit from the intervention only in the case where we assume that cap and floor regulation results in a significantly lower cost of capital for investors in the additional LRS storage, with no corresponding cost for GB consumers.

Table 37 CBA– Supported storage (Secondary design – Stressed scenario)

£ million		NPV (real 2012)	
		13% hurdle rate	8% hurdle rate
Consumer welfare	Retail cost	842.1	842.1
	Cost of supported storage	-727.0	-35.3
	Cost of price volatility	24.7	24.7
	Payments for involuntary DSR services	-24.1	-24.1
	Payments for voluntary DSR services	-31.6	-31.6
	Load reduction to firm gas customers	153.1	153.1
	Load reduction to firm electricity customers	26.2	26.2
	Load reduction to interruptible customers	31.6	31.6
	Net consumer welfare	**295.0**	**986.7**
Supplier welfare	Retail revenue	-842.1	-842.1
	Total cost of gas	786.4	786.4
	Cashout liability	24.1	24.1
	DSR liability	31.6	31.6
	Net supplier welfare	**0.0**	**0.0**
Storage welfare	Profits of existing storage	-109.6	-109.6
	Profits of additional market storage	-156.0	-156.0
	Profits of additional supported storage	2,590.0	1,898.3
	Cost of additional market storage	92.1	92.1
	Cost of additional supported storage	-2,590.0	-1,724.5
	Net storage welfare	**-173.5**	**0.3**

Table 38 CBA– Supported storage (Secondary design – Gone Green scenario)

£ million		NPV (real 2012)	
		13% hurdle rate	8% hurdle rate
Consumer welfare	Retail cost	622.1	622.1
	Cost of supported storage	-749.4	-31.0
	Cost of price volatility	11.6	11.6
	Payments for involuntary DSR services	-4.8	-4.8
	Payments for voluntary DSR services	-12.0	-12.0
	Load reduction to firm gas customers	22.2	22.2
	Load reduction to firm electricity customers	7.3	7.3
	Load reduction to interruptible customers	12.0	12.0
	Net consumer welfare	**-91.1**	**627.3**
Supplier welfare	Retail revenue	-622.1	-622.1
	Total cost of gas	605.3	605.3
	Cashout liability	4.8	4.8
	DSR liability	12.0	12.0
	Net supplier welfare	**0.0**	**0.0**
Storage welfare	Profits of existing storage	-107.9	-107.9
	Profits of additional market storage	0.0	0.0
	Profits of additional supported storage	2,590.0	1,871.6
	Cost of additional market storage	0.0	0.0
	Cost of additional supported storage	-2,590.0	-1,724.5
	Net storage welfare	**-107.9**	**39.2**

Although the security of supply benefits of additional supported LRS are estimated to be significant under the Stressed scenario, and there is a large estimated benefit to consumers in terms of lower gas prices, the associated cost of support is estimated to be large unless it is assumed that cap and floor regulation results in a better overall allocation of revenue risk from the additional LRS storage. These conclusions are sensitive to changes in assumptions on Non Power Generation (NPG) demand. If it is assumed that no overall risk reduction is achieved as the result of the way that the additional LRS capacity is regulated, and the Gone Green NPG demand scenario is assumed to prevail, intervention results in a loss of net welfare for consumers. Under the Stressed scenario, intervention results in a gain to net consumer welfare even if no overall risk reduction is assumed to be achieved as a result of the way that the additional LRS capacity is regulated.

It is also worth noting that the distribution of costs and benefits between consumers and storage owners under this option depends on the design of the support mechanism for storage (e.g. whether it is available to existing as well as new storage). Under some potential designs, consumers may end up underwriting the loss in the value of existing storage as a result of competition from new supported storage.

The modelled result on the change in the profits of existing storage as a result of this intervention is markedly different from the corresponding result under the primary design. The main driver of this result is that, while seasonal spreads are estimated to be reduced under the Supported LRS option relative to the Baseline in both of the spot years modelled, the modelled change in volatility in the price of gas are relatively low, with a small increase in 2020 and a small decrease in 2030. Hence, while profits of existing LRS are estimated to decrease under this intervention in both of the modelled spot years, profits of existing SRS are estimated to increase in 2020. The very different impact on volatility compared to the Supported SRS option is due to a range of factors in the model. First, the additional injection and withdrawal capacity is subject to different 'decision rules' for LRS, which changes its impact in the market and reduces its effect on volatility. In the summer, for example, there is limited flexibility associated with the additional LRS injection profile, which could be expected to have a directionally upward impact on volatility. Second, the seasonality associated with the LRS has a material impact on the supply mix in summer and winter (as shown by the results presented in Section 3), in contrast to the additional SRS, which has no significant impact on the average mix of supplies. This change in supply mix can in turn be expected to impact on volatility. In particular, changing the average levels of LNG flows could have a significant effect, given the dynamics between price and flow that we describe in 7.1. Finally, there is a somewhat reduced level of SRS storage relative to the Baseline due to the assumed displacement of market investment.

Table 39 Modelled effect of Supported LRS on profits of existing storage[49]

£ million per year	2020	2030
Existing SRS	23	-16
Existing LRS	-11	-33

Given the inherent complexity and uncertainty involved in the modelling of gas price volatility, the level of confidence in estimates of changes in storage arbitrage revenues as a result of intervention is a lot lower than in associated changes in security of supply (for our given set of assumptions) and, to a lesser degree, the total cost of gas for consumers. We therefore carry out a simple sensitivity on the effect of the Supported LRS intervention option on gas price volatility and profits of existing storage.

From Table 39 and Figure 1, we know that a decrease in price volatility of 100 percentage points is estimated to reduce the gross annual profits of a 4 bcm LRS facility by around £67m and the gross profits of a 1 bcm SRS facility by around £333m[50]. The relationship between gross profits of storage and price volatility is estimated to be roughly linear for the range of volatilities between 50% and 200%. For existing SRS and LRS, with capacities of 1630 mcm and 3327 mcm respectively under our modelling assumptions, a decrease in price volatility of 100 percentage points would therefore imply a reduction in gross annual profits of around £543m and £55m respectively.

[49] Values in this table are undiscounted and given in Jan 2013 real terms.

[50] This assumes price seasonality of around 1.5.

We also know that the Supported SRS intervention option is estimated to reduce gas price volatility by 21 percentage points in 2020 and 26 percentage points in 2030 whereas the Supported LRS intervention option is estimated to increase gas price volatility by 10 percentage points in 2020 and reduce it by 4 percentage points in 2030. The Supported SRS option has 600 mcm more SRS capacity than the Baseline, whereas the Supported LRS option has 100 mcm less SRS capacity and 4 bcm more LRS capacity than the Baseline. If we take the volatility results under the Supported SRS option and the relationship between price volatility and gross profits of different types of storage as given, and then assume that the effect of different types of additional storage on price volatility should be proportional to their average injection and withdrawal rates, the effect of the Supported LRS option on profits of existing storage would be as in Table 40[51].

Table 40 Effect of Supported LRS on profits of existing storage[52]

£ million per year	2020	2030
Existing SRS	-302	-335
Existing LRS	-44	-66

This is a much larger effect than that seen in our direct modelling of the Supported LRS option and demonstrates the range of uncertainty about the feedback of further storage investment into price volatility and the profits of existing storage.

[51] Average of injection and withdrawal rates for 1 bcm of SRS capacity and 4 bcm of LRS capacity are 90 mcm/day and 35 mcm/day respectively.

[52] Values in this table are undiscounted and given in Jan 2013 real terms.

11 Interaction between interventions and market failures

Generic non-specific obligation

This particular intervention is kept out of the market and used only to prevent demand interruptions. Hence, in theory, it can correct any market failure arising from insufficient incentives being placed on suppliers to prevent demand interruptions. Numerical estimates of the security of supply benefits and the costs of this particular intervention can be a guide in this context. A reduction in the value of unserved demand that is greater than the cost of the intervention would suggest that the market failure has been mitigated to some extent for a given set of assumptions that define the model used to derive these estimates.

In the context of the CBA result for the Non-specific intervention presented in Section 10.2, it can be concluded that, given the modelling assumptions used to derive these estimates, the size of the intervention modelled is likely to be above that which is socially optimal. This conclusion applies for both the real investment hurdle rates we modelled, 8% and 13%.

Storage obligation

As seen in our modelling results, both of the modelled storage obligation options result in a significant improvement in GB gas security of supply. Hence, as discussed in relation to gas cash-out prices in Section 4, if the planned cash-out arrangements result in security of gas supply being undervalued by market participants relative to its true social value, a storage obligation may help to mitigate this instance of potential market failure.

The existence of a storage obligation is also likely to lead to market failure, the impact of which on social welfare may be greater than the impact of any failure in the gas cash-out regime to incentivise provision of security of supply. This is relatively straightforward to demonstrate since a storage obligation puts an obligation on a market participant to hold a certain quantity of gas in store at times when demand for gas is likely to be at its greatest. Hence there are likely to be instances in which a Pareto improving transaction between holders of gas under the obligation and potential buyers of gas could take place, but it is precluded by the storage obligation.

In this section, we do not explicitly consider the relative impacts of the two forms of market failure discussed above. However, we note from our CBA modelling results that, once the welfare of consumers and storage profits are taken into account, the overall net welfare impact for those two groups is estimated to be negative for both designs of the storage obligation.

Supported storage

Aside from the question of whether some of the risk faced by private storage developers would be best allocated to consumers, which has been discussed above, any kind of support for storage as a direct subsidy or a risk transfer would create market failure if applied in the context of a perfectly functioning market. However, where market failure exists before the introduction of a support mechanism, correctly targeted support can mitigate that market failure in theory.

In the context of SRS, the only potentially relevant market failure identified in Section 4 is the suboptimal incentives on market participants to ensure security of gas supply to firm customers. Some kind of support for SRS could therefore help to mitigate market failure in theory. However, there are two considerations which would suggest that the socially optimal level of support should probably be limited. First, our modelling suggests that the security of supply benefits of additional SRS capacity that operates in the market are likely to be modest. Second, Ofgem's proposed reforms to the gas cash-out arrangements could be expected to remove much of the market failure that exists under the current arrangements, and hence the benefit of further intervention could be swamped by unintended consequences of intervention.

In the context of LRS, there are two relevant potential market failures identified in Section 4. The first of these relates to the cash-out arrangements as with SRS above. The second relates to the lumpiness of LRS investment. Both of these are likely to lead to under-provision of LRS capacity by the market, hence some kind of support for LRS could help to mitigate these market failures. Estimating the optimal level of support for LRS is very difficult and out of the scope of this study. However, that level is likely to be larger than the level which is optimal for SRS given the greater security of supply benefits of LRS estimated in our modelling and the consideration of lumpiness in LRS investment.

Finally, while the details of any potential support mechanism for storage are unknown, this section has referred to support provided in a generic fashion, noting that there are many possible support mechanism designs. However, details of that potential support mechanism can have a significant influence on whether an intervention is successful or if there is a significant chance that any unintended consequences override the intended effects. For example, one of the possible unintended consequences of rate of return regulation, if applied to actual outturn capex costs of a project, is that it reduces appropriate incentives for the developer to control the costs of the project. Whilst an examination of such details is out of the scope of the project, we would emphasise their importance in the broader context of potential intervention options.

Conclusion

In this section, we have sought to identify the key interactions between market failures and the intervention options. However, it is likely that there are some further interactions that are not covered by our analysis, some of which could potentially have a material impact on either the rationale for or the welfare impact of the intervention options.

12 Conclusions

Generic non-specific obligation

The Generic non-specific obligation against the Baseline is effective in reducing security of supply, particularly as it is kept outside of the market solely for this use. This intervention results in a saving in the cost of unserved energy of £264m. However, this saving is lower than the cost of the intervention even at the lower 8% cost of capital. Because the intervention is kept outside of the market, there are no other means to recoup the cost of the intervention for consumers except for savings in unserved energy.

Storage obligation

Both designs of the Storage obligation lead to a significant improvement in security of supply for both firm DM and NDM gas customers. This improvement is greater under the secondary design, where the overall effect is comparable to that seen under the Generic non-specific obligation. This happens mainly because a storage obligation prevents storage from emptying during winter, and hence more gas in storage is likely to be available in case of a sudden supply interruption.

Both designs of the Storage obligation reduce the cost of unserved energy and increase the total cost of gas for consumers. Both of these elements are greater under the secondary design, with the overall net balance of consumer welfare being approximately the same. Both designs reduce profits from existing storage, and the magnitude of this effect is very similar. Overall net storage welfare is negative but is lower in secondary design relative to primary design. This is due to the larger gap between profits of new storage and the cost of new storage under the secondary design. This gap would suggest that market investment response in new storage capacity may be even greater than that estimated in our modelling. If that were the case, further SRS would increase the cost of new storage investment and reduce gas price volatility, driving down storage profits further. All these factors would bring storage welfare closer to that seen under the primary design of the Storage obligation.

Supported storage

In case of Supported storage, secondary design is more effective at reducing the probability and impact of demand interruptions than the primary design, but is less effective than the Generic non-specific obligation. This is as expected given the much higher volume of gas in store under the secondary design and the less volatile behaviour of LRS relative to SRS, which means that it is likely to be available at the time that an emergency occurs. However, given that supported storage participates in the market, there is no guarantee that it will be available to flow at times of emergency.

Supported storage – primary design appears to be beneficial to consumers but not for the market as a whole in Stressed scenario. Although the security of supply benefits of additional supported SRS are estimated to be modest, there is a greater estimated benefit to consumers in terms of lower gas prices and the associated cost of support is limited.

Although the security of supply benefits of Supported storage – secondary design are estimated to be significant under the Stressed scenario, and there is a large estimated benefit to consumers in terms of lower gas prices, the associated cost of support is estimated to be large unless it is assumed that cap and floor regulation results in a better overall allocation of revenue risk from the additional LRS storage.

Given that Supported storage – secondary design is estimated to bring a net benefit to consumers under the Stressed scenario, CBA under the Gone Green scenario was also estimated. Here, the value of reduction in unserved energy relative to the Baseline is significantly lower than in the Stressed scenario. The estimated value of the reduction in the cost of gas for consumers is also somewhat lower, and the estimated cost of support is similar to that seen under the Stressed scenario. Consumers are estimated to benefit from the intervention only in the case where it is assumed that cap and floor regulation results in a significantly lower cost of capital for investors in the additional LRS storage, with no corresponding cost for GB consumers.

13 Annexures

13.1 Additional modelling results

In this section we present some additional results on the effect of the different intervention options on selected model dynamics. No results are presented for the Generic non-specific obligation since this intervention takes place outside of the market and does not affect the model dynamics considered here.

LNG imports to GB

Figure 22 and Figure 23 show the average seasonal pattern of LNG imports into GB under the Baseline and the two Supported storage interventions for 2020 and 2030 respectively across the modelled 1500 simulations. LNG imports tend to be higher in the summer due to the greater average seasonality of LNG prices than continental gas prices, which means that reliance on interconnector imports to supply demand is greater in the winter. The spike in imports at the start of the model period (like the similar features on subsequent graphs) is a modelling boundary effect explained by the tendency of storage to inject gas at that time to reach an equilibrium level of stock and can therefore be disregarded.

In both of the modelled spot years, the Supported SRS option makes no significant difference to average seasonal LNG flows. This is due to the fact that injection and withdrawal behaviour of SRS tends to be volatile with a weak seasonal component, hence the effect of cycling of SRS on LNG imports averages out across the 1500 simulations. The supported LRS option causes LNG imports to increase in the summer and reduce in the winter in line with the seasonal cycling pattern of LRS.

Figure 22 LNG imports to GB – Supported storage (2020)

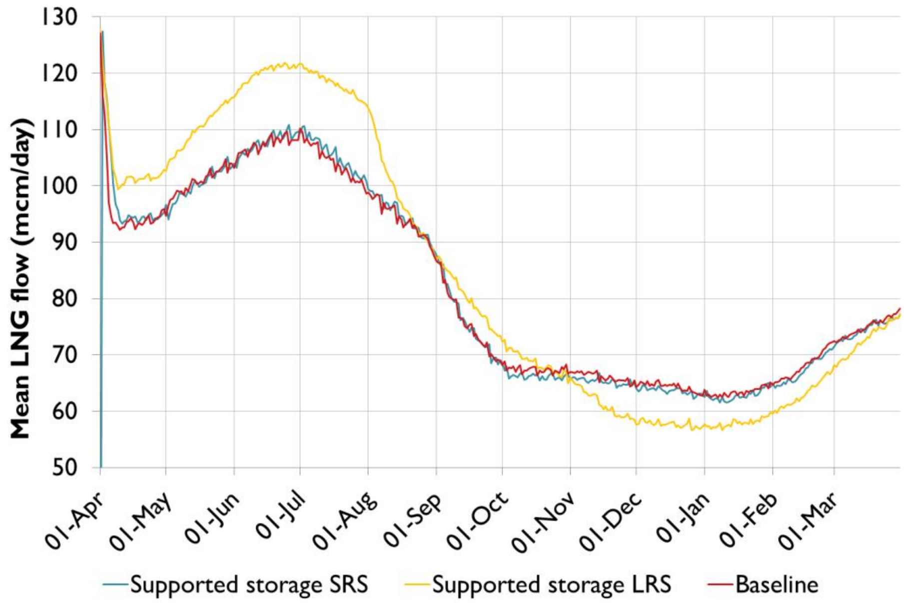


Figure 23 LNG imports to GB – Supported storage (2030)

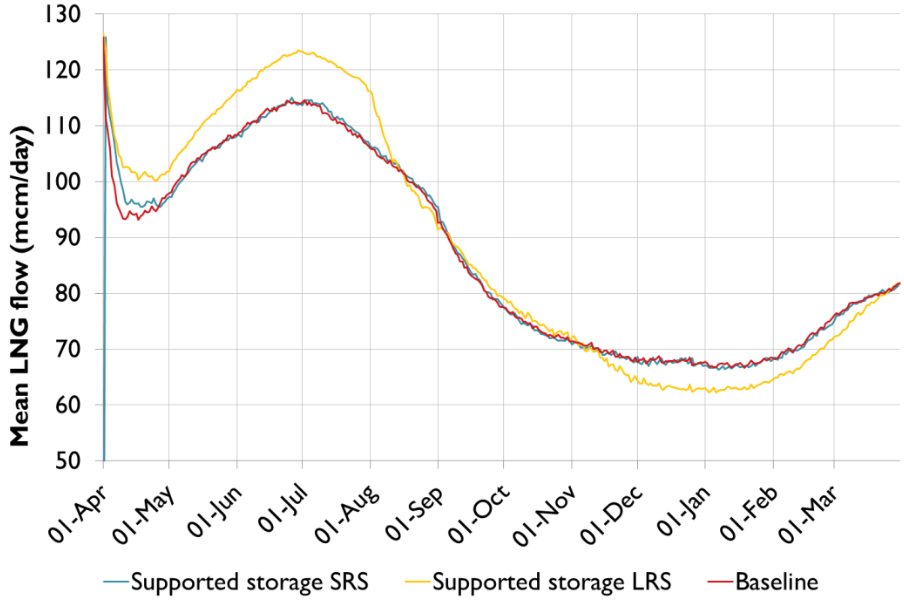


Figure 24 and Figure 25 show the average seasonal pattern of LNG imports into GB under the Baseline and the two Storage obligation intervention options for 2020 and 2030 respectively. The effect of a storage obligation on LNG imports into GB appears to be ambiguous and weak relative to the Supported LRS intervention option. LNG flows tend to be higher in the summer months as the obligation implies greater injection of gas into storage before the start of winter. They can, however, be lower in late autumn when the level of the obligation is stable and in late winter when the declining level of the obligation means that more gas can be released from storage into the market.

Figure 24 LNG imports to GB – Storage obligation (2020)

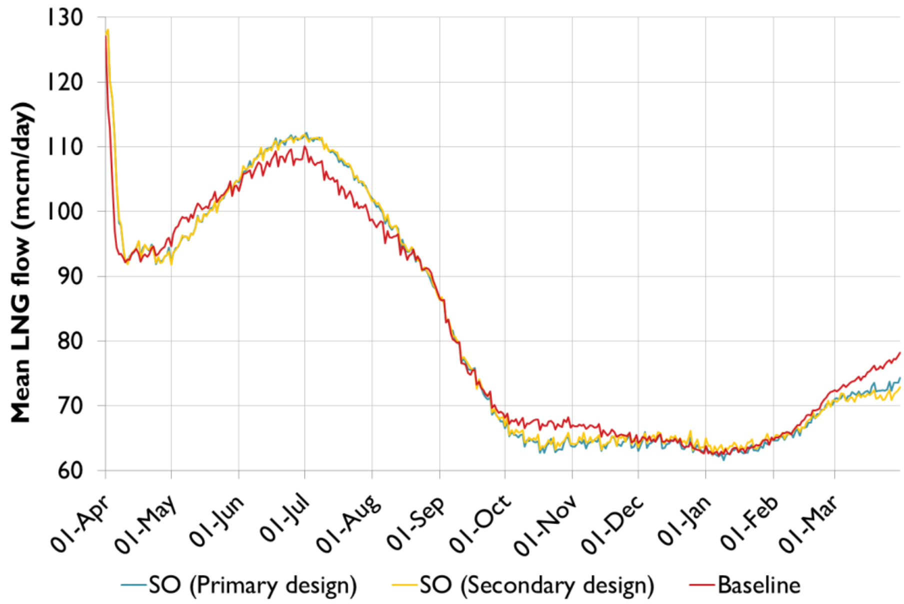
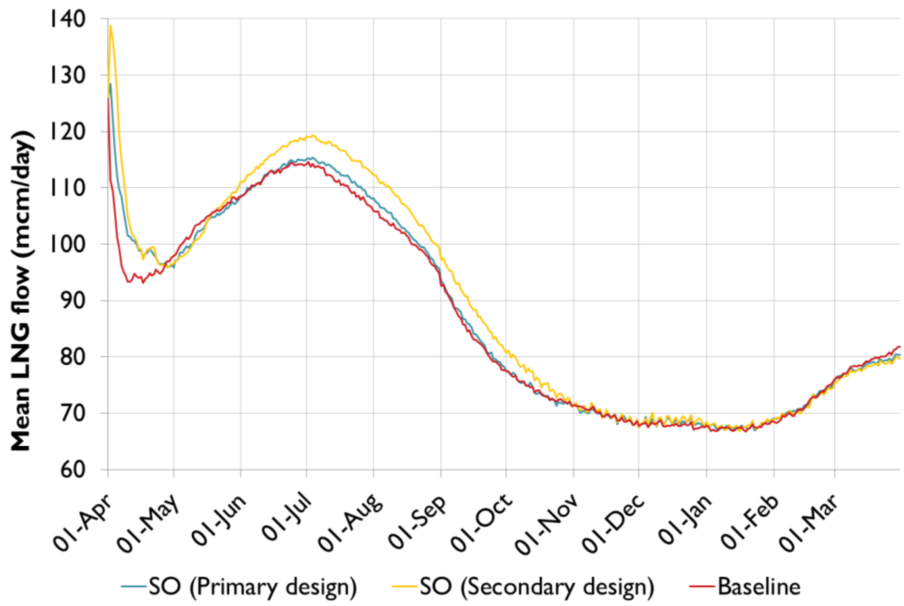


Figure 25 LNG imports to GB – Storage obligation (2030)



Interconnector imports to GB

Figure 26 and Figure 27 show the average seasonal pattern of net imports over the IUK and BBL interconnectors into GB under the Baseline and the two Supported storage interventions for 2020 and 2030 respectively. Net interconnector imports follow the same seasonal pattern as GB demand. In both of the modelled spot years, GB is a net importer over interconnectors in the winter and a net exporter in the summer, acting as a hub for LNG imports, which tend to be higher in the summer. The spike in imports at the start of the model period is explained by the tendency of storage to inject gas at that time to reach an equilibrium level of stock.

In both of the modelled spot years, the Supported SRS option makes no significant difference to average seasonal interconnector flows. As with LNG flows, this is due to the fact that injection and withdrawal behaviour of SRS tends to be volatile with a weak seasonal component, hence the effect of cycling of SRS on LNG imports averages out across the 1500 simulations. The supported LRS option causes interconnector exports to fall in the summer and imports to decrease in the winter in line with the seasonal cycling pattern of LRS. This effect is stronger in 2030 than in 2020 due to the greater import dependency of GB by 2030. The jump in interconnector flows at the beginning of September under the Supported LRS option relates to the injection profile of the additional LRS storage in our model, which has generally filled up by that date.

Figure 26 Interconnector imports to GB – Supported storage (2020)

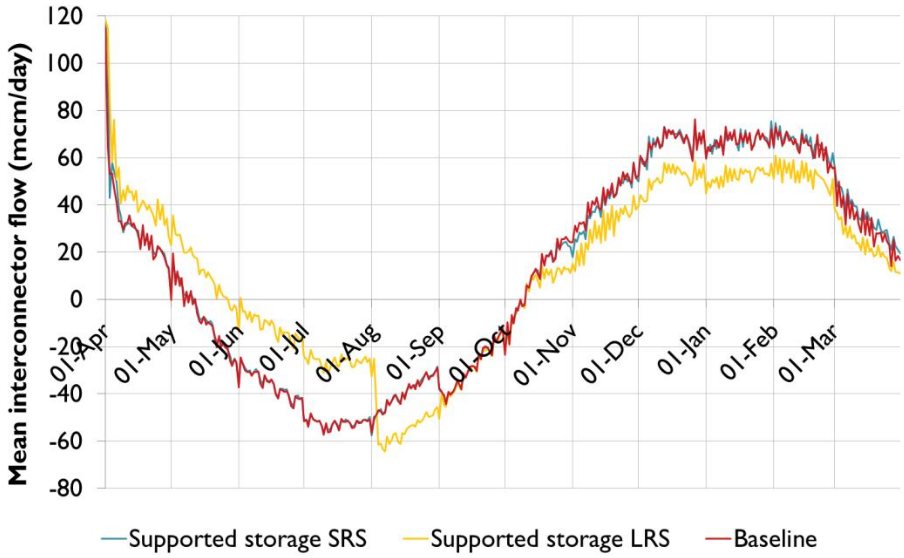


Figure 27 Interconnector imports to GB – Supported storage (2030)

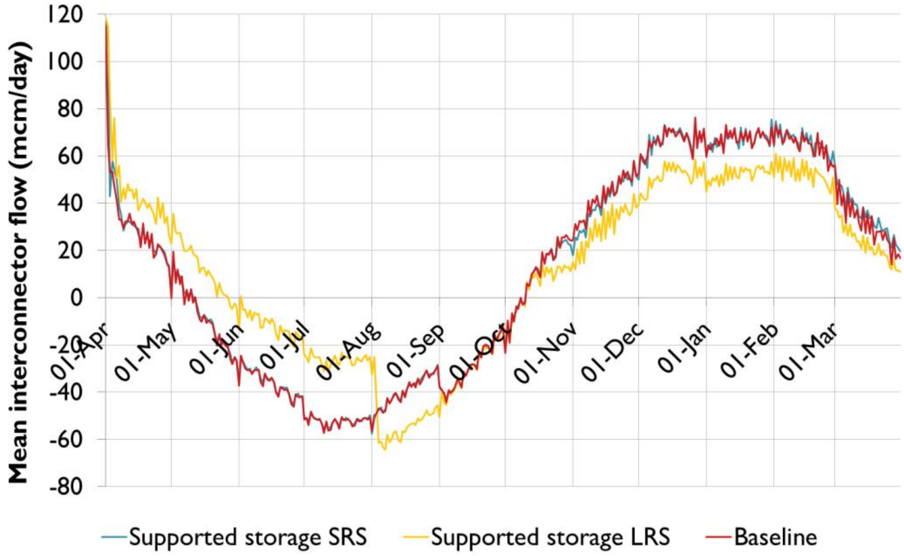


Figure 28 and Figure 29 show the average seasonal pattern of interconnector imports into GB under the Baseline and the two Storage obligation intervention options for 2020 and 2030 respectively. The effect of a storage obligation on interconnector imports into GB appears to be insignificant for both of the options and modelled spot years.

Figure 28 Interconnector imports to GB – Storage obligation (2020)

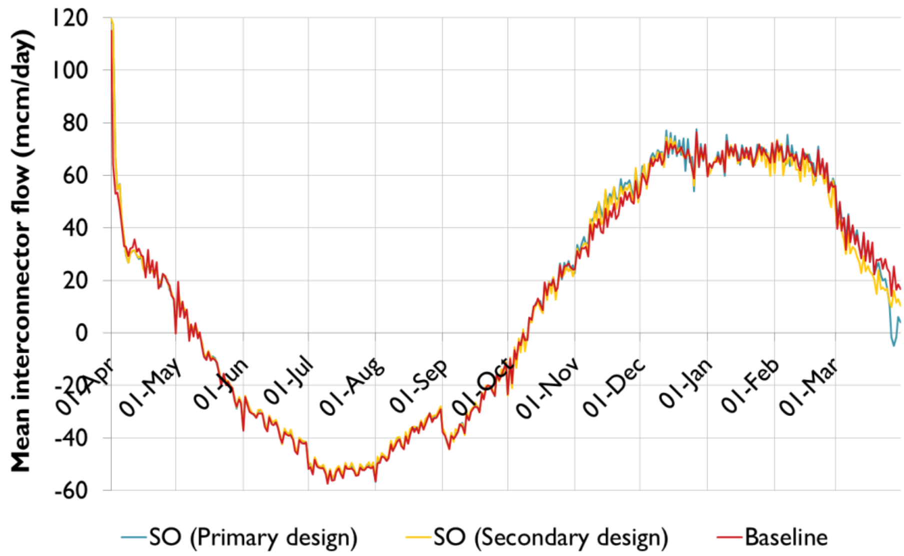
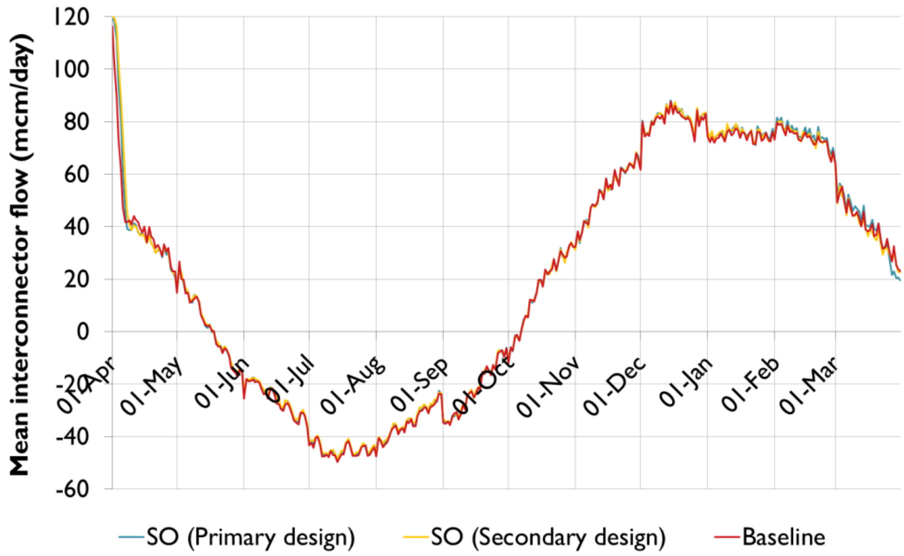


Figure 29 Interconnector imports to GB – Storage obligation (2030)



UKCS revenue

Figure 30 and Figure 31 show the average seasonal pattern of UKCS revenues under the Baseline and the two Supported storage interventions for 2020 and 2030 respectively. The seasonal pattern of UKCS revenues is a result of seasonality in both GB gas prices and UKCS flows. Since we model UKCS as a price taker, UKCS flows are an exogenous input in our modelling and do not differ between the Baseline and the different intervention options. Hence any differences between the Baseline and the intervention options are a direct result of corresponding differences in gas spot prices.

In both of the modelled spot years, the Supported SRS option makes no significant difference to average seasonal UKCS revenues. The supported LRS option causes UKCS revenues to increase in the summer and fall in the winter due to the effect of the additional LRS on gas price seasonality. For both spot years, the effect of the Supported LRS option on average daily UKCS revenue is no greater than 1%.

Figure 30 Daily UKCS revenue – Supported storage (2020)

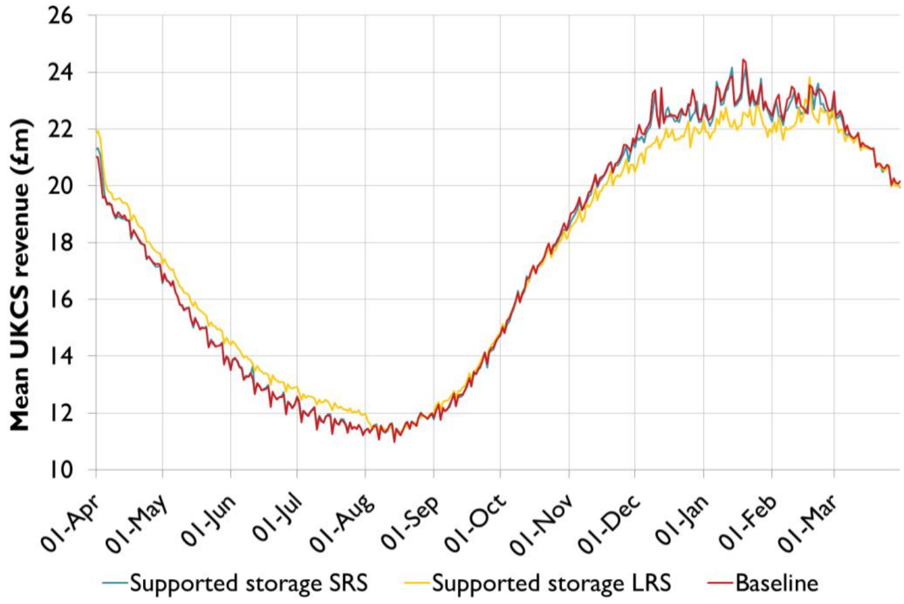


Figure 31 Daily UKCS revenue – Supported storage (2030)

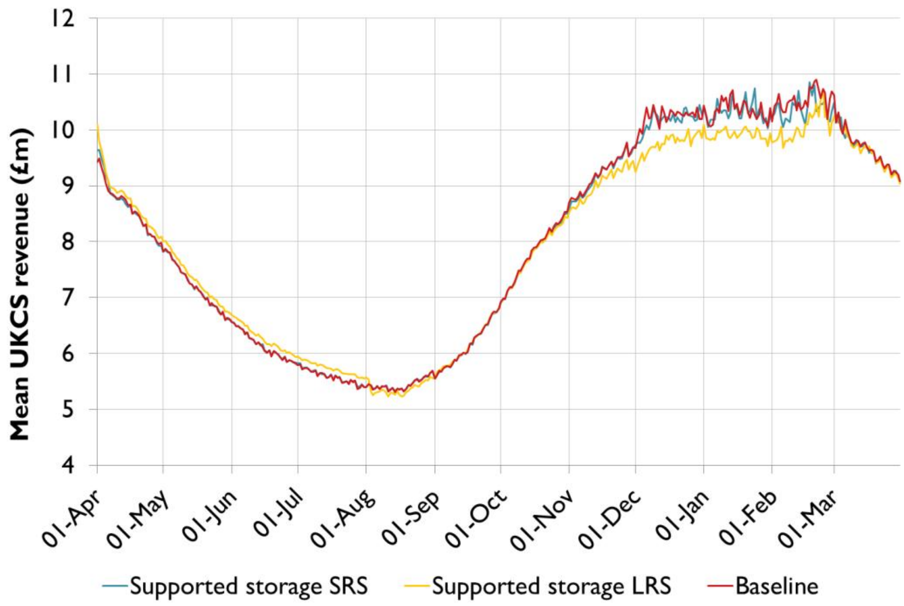


Figure 32 and Figure 33 show the average seasonal pattern of UKCS revenues under the Baseline and the two Storage obligation intervention options for 2020 and 2030 respectively. The effect of a storage obligation on UKCS revenues appears to be insignificant for both of the options and modelled spot years.

Figure 32 Daily UKCS revenue – Storage obligation (2020)

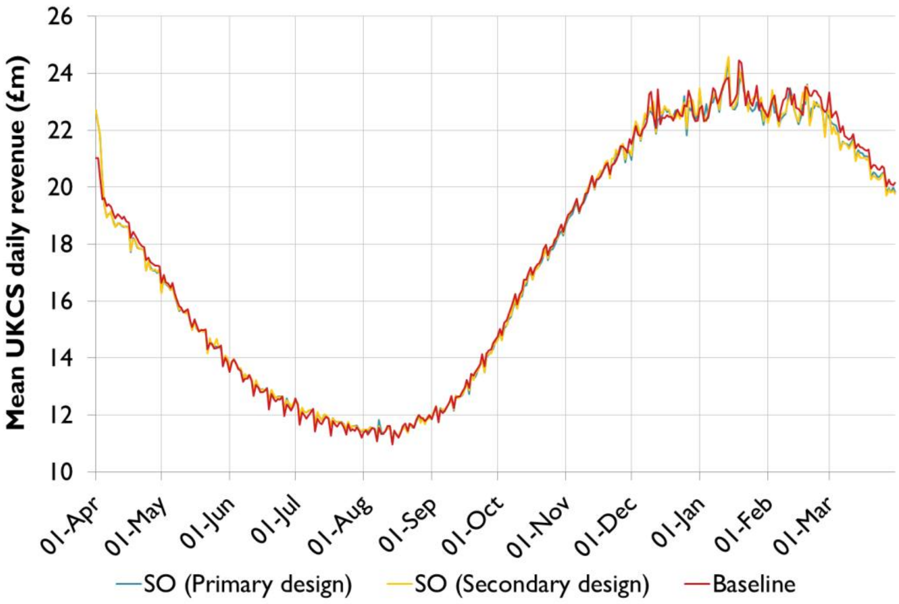
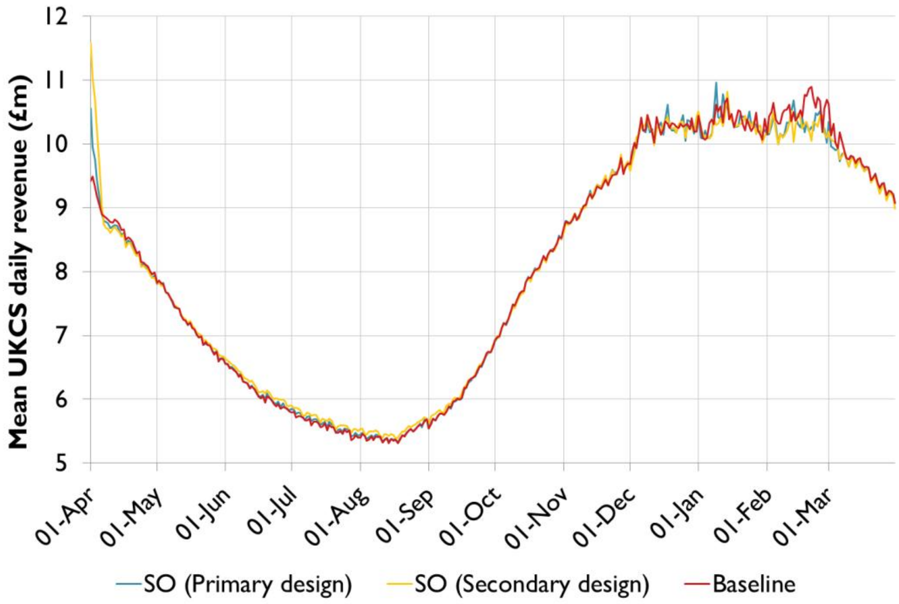


Figure 33 Daily UKCS revenue – Storage obligation (2030)



Exports of supply security

We examine the potential tendency of intervention options to export security of supply to Continental Europe via interconnectors and diverted supplies from Norway. In the context of our modelling, the proxy is the change in net interconnector flows between GB and Continental Europe and NCS flows to GB under a given intervention option relative to the Baseline in times of stress in Continental Europe. We define times of stress as periods in which the Continental gas price is above 200 p/th. With regard to NCS flows, the working assumption is that any flows that do not go to GB in times of stress in Continental Europe end up in Continental Europe.

Table 41 shows the change in average annual net interconnector flows between GB and Continental Europe and NCS flows to GB under a given intervention option relative to the Baseline in times of stress in Continental Europe. Negative numbers indicate a decrease in net flows from Continental Europe and Norway to GB. Our results indicate that, within the context of our modelling, both the storage obligation and supported storage intervention options generally tend to decrease net flows to GB on interconnectors and from Norway at times of stress in Continental Europe. That tendency is greatest for the Supported LRS intervention. However, even under this option, the expected size of this effect for an average modelled spot year is less than 43 mcm/year. This is less than 0.1% of average annual GB non-power generation gas demand between 2020 and 2030 in the Stressed scenario.

Table 41 Change in stressed flows to Continental Europe

Change in annual stressed flows (mcm)	2020	2030
Storage obligation (primary)	-4	-8
Storage obligation (secondary)	3	-18
Supported Storage SRS	-12	-30
Supported Storage LRS	-30	-55

13.2 Security of supply equivalence

In addition to the core modelling and CBA of the intervention options carried out for this report, DECC also requested that Redpoint attempt to put different intervention options (Generic non-specific obligation, Storage obligation and Supported LRS) on the same security of supply basis to the extent allowed by the differing designs of these intervention options and to carry out CBA analysis on the results. The idea behind this exercise is to estimate the economic cost of a given improvement in security of supply across the different intervention options analysed.

The key assumptions and the results of the analysis are given below.

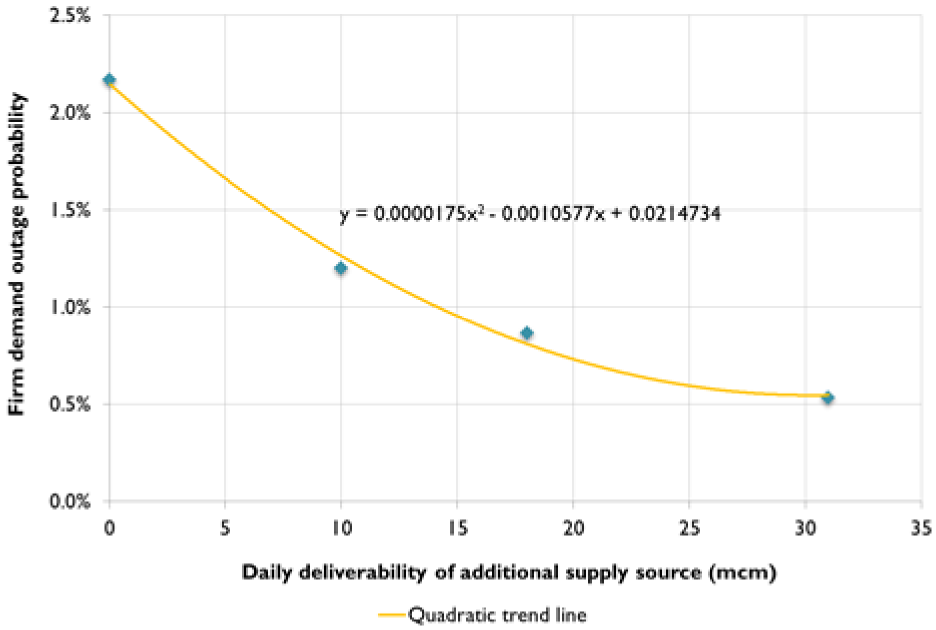
Assumptions

- Security of supply metric targeted across the different intervention options is the probability of firm gas demand interruption under the Supported LRS intervention option (0.93%);
- Generic non-specific obligation re-designed to protect firm gas customers (excluding CCGTs) to put it on the same basis as the Storage obligation; and
- Market investment response under the Storage obligation is scaled proportionately with the size of the obligation relative to the primary design.

Results

For the Generic non-specific obligation, three additional model runs were performed for spot years 2020 and 2030. Figure 34 plots the target security of supply metric (firm demand outage probability averaged between 2020 and 2030) against the daily deliverability of the additional supply source implied by the intervention in each model run. Results for the Baseline model run form an additional point on the graph, implying zero additional deliverability. Results from the original Generic non-specific obligation runs are not included in this graph since they were carried out on a different basis (also protecting CCGT gas demand).

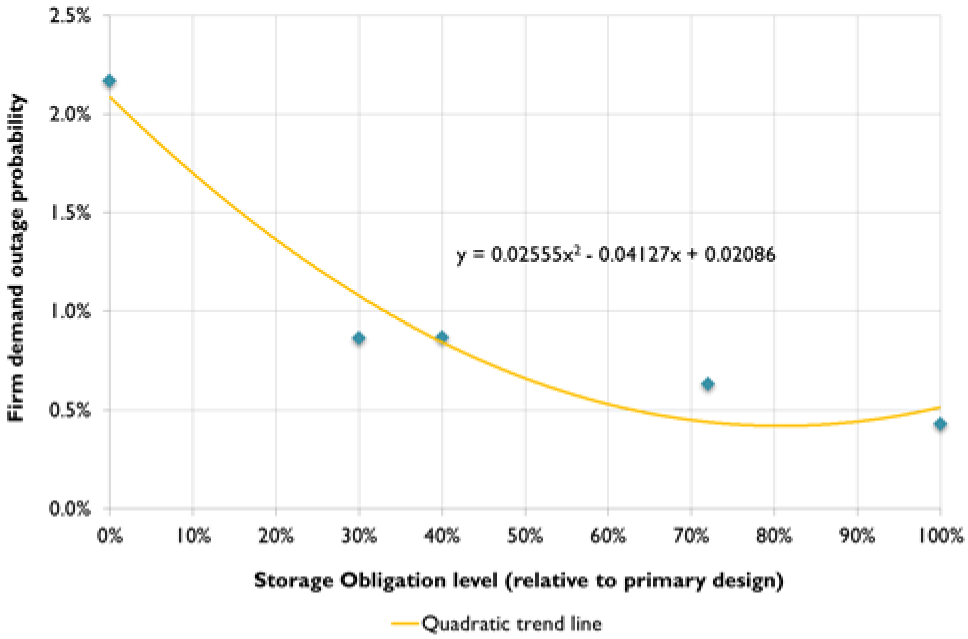
Figure 34 Targeted security of supply – Generic non-specific obligation



The results show that increasing daily deliverability of the additional supply source under the obligation leads to reductions in the probability of firm demand interruption that are diminishing on the margin. Plotting a quadratic line of best fit through the points on the graph allows us to estimate the size of the obligation that is consistent with the same firm demand outage probability as the Supported LRS intervention. This is 15.4 mcm/day.

A similar process is used to derive the level of the Storage obligation (relative to the primary design) that yields the same firm demand outage probability as the Supported LRS intervention option. The graph that plots results for the three additional model runs together with the Baseline (0% SO level) and the Storage obligation primary design (100% SO level) can be seen below.

Figure 35 Targeted security of supply – Storage obligation



Similarly to the Generic non-specific obligation, the results show that increasing the level of the Storage obligation generally leads to reductions in the probability of firm demand interruption that are diminishing on the margin, though this relationship is less stable than for the Generic non-specific obligation. Plotting a quadratic line of best fit through the points on the graph allows us to estimate the size of the obligation that is consistent with the same firm demand outage probability as the Supported LRS intervention. This is estimated to be 36%, implying that the maximum level of gas under the obligation would be 336 mcm and the level of market investment response in new SRS capacity would be 144 mcm more than that seen under the Baseline.

Note that a quadratic line of best fit is not universally decreasing, and in the case of Figure 35, is not always decreasing for the full range of the Storage obligation level modelled (0-100% relative to the Primary design of the storage obligation). We have experimented with other functional forms for the line of best fit, including exponential decay, but found that the quadratic representation provided the best fit to the data overall, and especially locally to where the targeted security of supply level is found on the graph.

The CBA for the targeted Generic non-specific obligation is given in Table 42. Values for load reduction to different types of customers are derived through the same kind of interpolation as that used to derive the targeted obligation level. The cost of additional storage is calculated directly on the basis of the same assumptions as those used to calculate the cost of storage in original modelling of the Generic non-specific obligation.

Table 42 CBA – Targeted Generic non-specific obligation

£ million		NPV (real 2012)	
		8% hurdle rate	13% hurdle rate
Consumer welfare	Retail cost	0.0	0.0
	Cost of additional storage	-105.0	-157.6
	Payments for involuntary DSR services	0.0	0.0
	Payments for voluntary DSR services	0.0	0.0
	Load reduction to firm gas customers	154.2	154.2
	Load reduction to firm electricity customers	-5.4	-5.4
	Load reduction to interruptible customers	-1.1	-1.1
	Net consumer welfare	**42.7**	**-10.0**

The results suggest that the targeted Generic non-specific obligation would improve net consumer welfare assuming an 8% real hurdle rate on the investment in additional SRS storage capacity under the obligation but would reduce it slightly under the assumption of a 13% real hurdle rate.

The CBA for the targeted Storage obligation is given in Table 43. Values for load reduction to different types of customers and the cash-out liability of suppliers are derived through the same kind of interpolation as that used to derive the targeted obligation level. The cost of additional market storage is calculated directly on the basis of the same assumptions as those used to calculate the equivalent cost in original modelling of the Storage obligation. All other values, including retail cost of gas, cost of price volatility and profits of existing and additional market storage, are calculated directly from an additional model run of the targeted (36%) Storage obligation level.

Table 43 CBA – Targeted Storage obligation

£ million		NPV (real 2012)
Consumer welfare	Retail cost	-186.9
	Cost of price volatility	0.0
	Payments for involuntary DSR services	-15.5
	Payments for voluntary DSR services	2.6
	Load reduction to firm gas customers	147.0
	Load reduction to firm electricity customers	-5.2
	Load reduction to interruptible customers	-2.6
	Net consumer welfare	**-58.1**
Supplier welfare	Retail revenue	186.9
	Total cost of gas	-207.7
	Cashout liability	15.5
	DSR liability	5.2
	Net supplier welfare	**0.0**
Storage welfare	Profits of existing storage	26.7
	Profits of additional market storage	226.8
	Profits of additional supported storage	0.0
	Cost of additional market storage	-132.6
	Cost of additional supported storage	0.0
	Net storage welfare	**120.9**

The results suggest that the targeted Storage obligation would be slightly detrimental to net consumer welfare. The also suggest that, given the assumption that 144 mcm of additional SRS capacity would be built in response to this level of the Storage obligation, the profits from that additional storage would significantly exceed the costs (assuming a 13% hurdle rate for investment).

13.3 Annual results

a) Probability of interruption

Table 44 Probability of at least one outage in a given year (baseline market model: stressed with SCR)

	2020	2025	2030	Mean
Firm DM gas	1 in 88	1 in 23	1 in 33	1 in 35
NDM gas	1 in 100	1 in 29	1 in 58	1 in 48
Firm I&C electricity	1 in 33	1 in 12	1 in 22	1 in 19
Domestic & SME electricity	1 in 58	1 in 17	1 in 37	1 in 29

Table 45 Probability of at least one outage in a given year (baseline market model: Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	1 in 375	1 in 300	1 in 333
NDM gas	1 in 375	1 in 300	1 in 333
Firm I&C electricity	1 in 88	1 in 167	1 in 115
Domestic & SME electricity	1 in 188	1 in 300	1 in 231

Table 46 Probability of at least one outage in a given year (baseline market model iteration: stressed with SCR)

	2020	2025	2030	Mean
Firm DM gas	1 in 75	1 in 21	1 in 33	1 in 33
NDM gas	1 in 107	1 in 25	1 in 60	1 in 45
Firm I&C electricity	1 in 33	1 in 11	1 in 25	1 in 19
Domestic & SME electricity	1 in 63	1 in 17	1 in 47	1 in 31

Table 47 Probability of at least one outage in a given year (generic non-specific obligation market model: stressed with SCR)

	2020	2025	2030	Mean
Firm DM gas	1 in 1500	1 in 107	1 in 375	1 in 237
NDM gas	1 in 1500	1 in 136	1 in 375	1 in 281
Firm I&C electricity	1 in 250	1 in 50	1 in 188	1 in 102
Domestic & SME electricity	1 in 500	1 in 167	1 in 750	1 in 321

Table 48 Probability of at least one outage in a given year (generic non-specific obligation market model: Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	<1 in 1500	<1 in 1500	<1 in 1500
NDM gas	<1 in 1500	<1 in 1500	<1 in 1500
Firm I&C electricity	1 in 750	<1 in 1500	1 in 1500
Domestic & SME electricity	1 in 1500	<1 in 1500	1 in 3000

Table 49 Probability of at least one outage in a given year (generic non-specific obligation market model iteration: stressed with SCR)

	2020	2025	2030	Mean
Firm DM gas	1 in 750	1 in 150	1 in 500	1 in 300
NDM gas	1 in 1500	1 in 188	1 in 1500	1 in 450
Firm I&C electricity	1 in 214	1 in 54	1 in 214	1 in 107
Domestic & SME electricity	1 in 375	1 in 167	1 in 500	1 in 281

Table 50 Probability of at least one outage in a given year (storage obligation market model: primary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 500	1 in 79	1 in 136
NDM gas	1 in 500	1 in 83	1 in 143
Firm I&C electricity	1 in 32	1 in 15	1 in 20
Domestic & SME electricity	1 in 63	1 in 38	1 in 47

Table 51 Probability of at least one outage in a given year (storage obligation market model: secondary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 1500	1 in 188	1 in 333
NDM gas	1 in 1500	1 in 188	1 in 333
Firm I&C electricity	1 in 37	1 in 20	1 in 26
Domestic & SME electricity	1 in 136	1 in 48	1 in 71

Table 52 Probability of at least one outage in a given year (storage obligation market model: primary design Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	1 in 1500	1 in 500	1 in 750
NDM gas	<1 in 1500	1 in 500	1 in 1000
Firm I&C electricity	1 in 79	1 in 83	1 in 81
Domestic & SME electricity	1 in 214	1 in 188	1 in 200

Table 53 Probability of at least one outage in a given year (storage obligation market model: secondary design Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	1 in 1500	1 in 750	1 in 1000
NDM gas	1 in 1500	1 in 750	1 in 1000
Firm I&C electricity	1 in 107	1 in 115	1 in 111
Domestic & SME electricity	1 in 250	1 in 300	1 in 273

Table 54 Probability of at least one outage in a given year (storage obligation market model iteration: primary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 750	1 in 136	1 in 231
NDM gas	1 in 750	1 in 167	1 in 273
Firm I&C electricity	1 in 44	1 in 33	1 in 38
Domestic & SME electricity	1 in 100	1 in 65	1 in 79

Table 55 Probability of at least one outage in a given year (storage obligation market model iteration: secondary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 750	1 in 136	1 in 375
NDM gas	1 in 750	1 in 167	1 in 429
Firm I&C electricity	1 in 44	1 in 33	1 in 45
Domestic & SME electricity	1 in 100	1 in 65	1 in 100

Table 56 Probability of at least one outage in a given year (supported storage market model: primary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 94	1 in 52	1 in 67
NDM gas	1 in 136	1 in 65	1 in 88
Firm I&C electricity	1 in 44	1 in 30	1 in 36
Domestic & SME electricity	1 in 75	1 in 60	1 in 67

Table 57 Probability of at least one outage in a given year (supported storage market model: secondary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 375	1 in 125	1 in 188
NDM gas	1 in 500	1 in 188	1 in 273
Firm I&C electricity	1 in 150	1 in 107	1 in 125
Domestic & SME electricity	1 in 250	1 in 375	1 in 300

Table 58 Probability of at least one outage in a given year (supported storage market model: primary design Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	1 in 375	1 in 375	1 in 375
NDM gas	1 in 375	1 in 375	1 in 375
Firm I&C electricity	1 in 125	1 in 188	1 in 150
Domestic & SME electricity	1 in 250	1 in 300	1 in 273

Table 59 Probability of at least one outage in a given year (supported storage market model: secondary design Gone Green with SCR)

	2020	2030	Mean
Firm DM gas	1 in 750	1 in 500	1 in 600
NDM gas	1 in 1500	1 in 750	1 in 1000
Firm I&C electricity	1 in 188	1 in 500	1 in 273
Domestic & SME electricity	1 in 375	1 in 750	1 in 500

Table 60 Probability of at least one outage in a given year (supported storage market model iteration: primary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 68	1 in 42	1 in 52
NDM gas	1 in 88	1 in 52	1 in 65
Firm I&C electricity	1 in 41	1 in 25	1 in 31
Domestic & SME electricity	1 in 68	1 in 50	1 in 58

Table 61 Probability of at least one outage in a given year (supported storage market model iteration: secondary design stressed with SCR)

	2020	2030	Mean
Firm DM gas	1 in 214	1 in 71	1 in 107
NDM gas	1 in 300	1 in 94	1 in 143
Firm I&C electricity	1 in 68	1 in 54	1 in 60
Domestic & SME electricity	1 in 188	1 in 125	1 in 150

b) Unserved energy

Table 62 Unserved energy (baseline market model: stressed with SCR)

Million therms/year	2020	2025	2030	Mean
Firm DM gas	0.038	0.217	0.109	0.121
NDM gas	0.945	6.237	2.868	3.350
Firm I&C electricity	0.064	0.294	0.114	0.157
Domestic & SME electricity	0.021	0.104	0.036	0.054

Table 63 Unserved energy (baseline market model: Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.010	0.012	0.011
NDM gas	0.319	0.442	0.380
Firm I&C electricity	0.023	0.013	0.018
Domestic & SME electricity	0.008	0.005	0.006

Table 64 Unserved energy (baseline market model iteration: stressed with SCR)

Million therms/year	2020	2025	2030	Mean
Firm DM gas	0.049	0.235	0.097	0.127
NDM gas	1.013	5.488	2.606	3.036
Firm I&C electricity	0.062	0.313	0.088	0.155
Domestic & SME electricity	0.026	0.119	0.023	0.056

Table 65 Unserved energy (generic non-specific obligation market model: stressed with SCR)

Million therms/year	2020	2025	2030	Mean
Firm DM gas	0.002	0.035	0.010	0.016
NDM gas	0.068	0.635	0.204	0.302
Firm I&C electricity	0.005	0.038	0.012	0.018
Domestic & SME electricity	0.001	0.012	0.003	0.005

Table 66 Unserved energy (generic non-specific obligation market model: Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.000	0.000	0.000
NDM gas	0.000	0.000	0.000
Firm I&C electricity	0.003	0.000	0.001
Domestic & SME electricity	0.000	0.000	0.000

Table 67 Unserved energy (generic non-specific obligation market model iteration: stressed with SCR)

Million therms/year	2020	2025	2030	Mean
Firm DM gas	0.004	0.022	0.003	0.010
NDM gas	0.068	0.452	0.140	0.220
Firm I&C electricity	0.009	0.028	0.008	0.015
Domestic & SME electricity	0.002	0.009	0.002	0.004

Table 68 Unserved energy (storage obligation market model: primary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.006	0.057	0.031
NDM gas	0.022	0.797	0.410
Firm I&C electricity	0.053	0.128	0.090
Domestic & SME electricity	0.013	0.027	0.020

Table 69 Unserved energy (storage obligation market model: secondary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.002	0.028	0.015
NDM gas	0.105	0.403	0.254
Firm I&C electricity	0.036	0.095	0.065
Domestic & SME electricity	0.005	0.025	0.015

Table 70 Unserved energy (storage obligation market model: primary design Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.002	0.008	0.005
NDM gas	0.000	0.047	0.024
Firm I&C electricity	0.018	0.017	0.018
Domestic & SME electricity	0.005	0.005	0.005

Table 71 Unserved energy (storage obligation market model: secondary design Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.002	0.006	0.004
NDM gas	0.022	0.058	0.040
Firm I&C electricity	0.012	0.016	0.014
Domestic & SME electricity	0.004	0.003	0.003

Table 72 Unserved energy (storage obligation market model iteration: primary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.006	0.042	0.024
NDM gas	0.125	1.571	0.848
Firm I&C electricity	0.035	0.073	0.054
Domestic & SME electricity	0.011	0.040	0.026

Table 73 Unserved energy (storage obligation market model iteration: secondary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.005	0.015	0.010
NDM gas	0.037	0.244	0.141
Firm I&C electricity	0.035	0.049	0.042
Domestic & SME electricity	0.012	0.014	0.013

Table 74 Unserved energy (supported storage market model: primary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.036	0.085	0.060
NDM gas	0.616	1.958	1.287
Firm I&C electricity	0.050	0.083	0.067
Domestic & SME electricity	0.020	0.023	0.021

Table 75 Unserved energy (supported storage market model: secondary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.008	0.025	0.017
NDM gas	0.320	0.793	0.556
Firm I&C electricity	0.016	0.013	0.015
Domestic & SME electricity	0.006	0.003	0.004

Table 76 Unserved energy (supported storage market model: primary design Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.009	0.009	0.009
NDM gas	0.163	0.572	0.368
Firm I&C electricity	0.016	0.009	0.013
Domestic & SME electricity	0.007	0.003	0.005

Table 77 Unserved energy (supported storage market model: secondary design Gone Green with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.003	0.004	0.003
NDM gas	0.116	0.338	0.227
Firm I&C electricity	0.008	0.003	0.006
Domestic & SME electricity	0.002	0.002	0.002

Table 78 Unserved energy (supported storage market model iteration: primary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.053	0.090	0.071
NDM gas	0.798	2.063	1.430
Firm I&C electricity	0.060	0.086	0.073
Domestic & SME electricity	0.027	0.021	0.024

Table 79 Unserved energy (supported storage market model iteration: secondary design stressed with SCR)

Million therms/year	2020	2030	Mean
Firm DM gas	0.014	0.054	0.034
NDM gas	0.434	0.933	0.684
Firm I&C electricity	0.028	0.034	0.031
Domestic & SME electricity	0.007	0.010	0.008

a) Cost of unserved energy

Table 80 Cost of unserved energy (baseline market model: stressed with SCR)

£m (real 2012)	2020	2025	2030	Mean
Firm DM gas	0.6	3.6	1.8	2.0
NDM gas	18.9	124.7	57.4	67.0
Firm I&C electricity	3.8	17.6	6.8	9.4
Domestic & SME electricity	1.6	7.8	2.7	4.0

Table 81 Cost of unserved energy (baseline market model: Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.2	0.2	0.2
NDM gas	6.4	8.8	7.6
Firm I&C electricity	1.4	0.8	1.1
Domestic & SME electricity	0.6	0.4	0.5

Table 82 Cost of unserved energy (baseline market model iteration: stressed with SCR)

£m (real 2012)	2020	2025	2030	Mean
Firm DM gas	0.8	3.9	1.6	2.1
NDM gas	20.3	109.8	52.1	60.7
Firm I&C electricity	3.7	18.7	5.3	9.2
Domestic & SME electricity	1.9	8.9	1.7	4.2

Table 83 Cost of unserved energy (generic non-specific obligation market model: stressed with SCR)

£m (real 2012)	2020	2025	2030	Mean
Firm DM gas	0.0	0.6	0.2	0.3
NDM gas	1.4	12.7	4.1	6.0
Firm I&C electricity	0.3	2.3	0.7	1.1
Domestic & SME electricity	0.1	0.9	0.2	0.4

Table 84 Cost of unserved energy (generic non-specific obligation market model: Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.0	0.0	0.0
NDM gas	0.0	0.0	0.0
Firm I&C electricity	0.2	0.0	0.1
Domestic & SME electricity	0.0	0.0	0.0

Table 85 Cost of unserved energy (generic non-specific obligation market model iteration: stressed with SCR)

£m (real 2012)	2020	2025	2030	Mean
Firm DM gas	0.1	0.4	0.0	0.2
NDM gas	1.4	9.0	2.8	4.4
Firm I&C electricity	0.5	1.7	0.5	0.9
Domestic & SME electricity	0.2	0.7	0.1	0.3

Table 86 Cost of unserved energy (storage obligation market model: primary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.1	0.9	0.5
NDM gas	0.4	15.9	8.2
Firm I&C electricity	3.2	7.7	5.4
Domestic & SME electricity	0.9	2.0	1.5

Table 87 Cost of unserved energy (storage obligation market model: secondary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.0	0.5	0.2
NDM gas	2.1	8.1	5.1
Firm I&C electricity	2.1	5.7	3.9
Domestic & SME electricity	0.4	1.8	1.1

Table 88 Cost of unserved energy (storage obligation market model: primary design Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.0	0.1	0.1
NDM gas	0.0	0.9	0.5
Firm I&C electricity	1.1	1.0	1.1
Domestic & SME electricity	0.4	0.4	0.4

Table 89 Cost of unserved energy (storage obligation market model: secondary design Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.0	0.1	0.1
NDM gas	0.4	1.2	0.8
Firm I&C electricity	0.7	0.9	0.8
Domestic & SME electricity	0.3	0.2	0.2

Table 90 Cost of unserved energy (storage obligation market model iteration: primary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.1	0.7	0.4
NDM gas	2.5	31.4	17.0
Firm I&C electricity	2.1	4.4	3.2
Domestic & SME electricity	0.8	3.0	1.9

Table 91 Cost of unserved energy (storage obligation market model iteration: secondary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.1	0.3	0.2
NDM gas	0.7	4.9	2.8
Firm I&C electricity	2.1	2.9	2.5
Domestic & SME electricity	0.9	1.0	0.9

Table 92 Cost of unserved energy (supported storage market model: primary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.6	1.4	1.0
NDM gas	12.3	39.2	25.7
Firm I&C electricity	3.0	4.9	4.0
Domestic & SME electricity	1.5	1.7	1.6

Table 93 Cost of unserved energy (supported storage market model: secondary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.1	0.4	0.3
NDM gas	6.4	15.9	11.1
Firm I&C electricity	1.0	0.8	0.9
Domestic & SME electricity	0.4	0.2	0.3

Table 94 Cost of unserved energy (supported storage market model: primary design Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.2	0.2	0.2
NDM gas	3.3	11.4	7.4
Firm I&C electricity	0.9	0.6	0.8
Domestic & SME electricity	0.6	0.2	0.4

Table 95 Cost of unserved energy (supported storage market model: secondary design Gone Green with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.1	0.1	0.1
NDM gas	2.3	6.8	4.5
Firm I&C electricity	0.5	0.2	0.3
Domestic & SME electricity	0.2	0.2	0.2

Table 96 Cost of unserved energy (supported storage market model iteration: primary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.9	1.5	1.2
NDM gas	16.0	41.3	28.6
Firm I&C electricity	3.6	5.1	4.4
Domestic & SME electricity	2.0	1.6	1.8

Table 97 Cost of unserved energy (supported storage market model iteration: secondary design stressed with SCR)

£m (real 2012)	2020	2030	Mean
Firm DM gas	0.2	0.9	0.6
NDM gas	8.7	18.7	13.7
Firm I&C electricity	1.7	2.0	1.9
Domestic & SME electricity	0.5	0.7	0.6

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