Gas security of supply Significant Code Review: Economic modelling

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Background

On 11 January 2011, Ofgem launched a Gas security of supply Significant Code Review (SCR) to explore options for reforms that could reduce the probability and impact of Gas Deficit Emergencies (GDE). The current arrangements for a GDE in Great Britain (GB) were designed at a time when gas demand was met largely from domestic sources. Under these arrangements, the Network Emergency Coordinator (NEC) would co-ordinate actions of all market participants directly, rather than relying on market signals, with the cash-out price frozen when the emergency is declared. However, GB is now significantly reliant on imported gas, particularly in peak winter months, and with this comes a need also to consider the response of flows of imported gas in a GDE.

Currently, the cash-out price can be frozen at a level below the value customers place on uninterrupted gas supplies. Therefore, the price signals might not be sufficient to attract more gas immediately prior and during a GDE. This also implies that shippers do not face sufficient incentives to take appropriate action to prevent a GDE occurring (e.g. investing in storage or negotiating contracts for demand interruptibility). Furthermore, firm customers who are interrupted do not get paid for the involuntary demand side response (DSR) services they provide. This means that customers largely bear the costs and risks of a GDE.

Ofgem appointed Redpoint Energy to conduct economic modelling of the gas market under the current arrangements and under the Gas SCR draft policy proposals in order to understand the extent to which the proposals could enhance security of supply, and what the costs and benefits to consumers could be. This document describes the approach, assumptions and results of that analysis.

Options for reform

Option 1: Cash-out at the full value of lost load

The aim of Option 1 is to allow the market to play a greater role in resolving a GDE. If successful, this would be expected to address some of the main problems identified with the current arrangements. The cash-out price would not be frozen before firm load shedding but would continue to be set by balancing actions taken by NGG. Once firm load is shed (where individual large consumers are required to reduce their gas demand), shippers would still be able to carry out bilateral trades to resolve their imbalances but NGG would stop taking balancing actions on the OCM and the cash-out price would be set at the VoLL of domestic gas customers. This is intended to increase the level of commercial interruption by incentivising suppliers and larger consumers to enter into appropriate interruptible arrangements, as discussed further below. In the case of network isolation (where parts of the network stop receiving gas), the cash-out price would go to 14 times of the VoLL of domestic customers. The rationale behind this is to price in the true economic cost of physical network interruptions, which are assumed to last for a minimum 14 days for the purposes of our analysis.

This option is intended to provide a greater incentive for shippers to resolve negative imbalances by bringing in more expensive imported gas, thus reducing both the frequency of occurrence and the severity of outages. It can also be expected to incentivise the signing of interruptible contracts between suppliers and Daily Metered (DM) customers. Further, it could increase the incentive for suppliers to respond to the changed exposure by investing in additional provisions that would reduce the probability and severity of firm customer interruptions.

Option 2: Cash-out at a capped value of lost load

This option is similar to Option 1, but the cash-out price would not be increased above domestic VoLL in the event of physical network isolations (i.e. the VoLL multiple is set to 1). By capping the liability of short shippers in the event of NDM customers being interrupted, the potential problems associated with Option 1 – for example, increased financial risks for shippers and corresponding credit issues – can be minimised.

As with Option 1, it is assumed that interruptible contracts are entered into by a significant volume of DM gas users under this option. However, the lower maximum cash-out price limits the potential liability faced by short shippers in the event of network isolations, reducing the incentive for shipper investment response.

Option 3: Further interventions

There are a number of potential concerns with very high cash-out prices in an emergency, and hence reasons for considering other interventions. They include the following:

- the traded market may not operate efficiently under extreme prices (for example due to counterparty credit concerns),
- market participants cannot determine the probability of a GDE appropriately due to difficulties of assessing low probability events,
- market participants believe that they may not have to face the full consequences of a GDE because there might be a perception that some form of support would be given to ensure that the market continues to function (moral hazard),
- the extreme financial liability faced by short shippers in a GDE leads financial distress and adverse impacts on competition, or
- the potential financial liability creates a barrier to entry for new shippers by requiring them to have a sufficient credit rating to absorb the losses in the event of a GDE or to raise funds at a reasonable cost to be used as collateral for extreme negative outcomes.

For the purposes of this study, we have examined an intervention in the form of a storage obligation imposed on gas shippers. In our modelling of this option, shippers are required 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 and to hold the gas back to prevent physical network isolations (NDM customer interruptions were used as a proxy in the model). For the purposes of our modelling, the obligation level is specified for both Long-run storage (LRS) and Short-run storage (SRS) to ensure deliverability and is profiled over the winter period.

Option 4: Capped cash-out and further interventions

The rationale for combining Option 2 with Option 3 is to obtain the benefits of Option 2 in terms of bringing in additional imported gas supplies that could prevent firm customers from being interrupted as well as the benefits of an increase in interruptible contracts, while compensating for the problem of sub-optimal incentives for shippers to make provisions that could reduce the likelihood or severity of a GDE. Furthermore, the cash-out price under Options 1 and 2 might not reflect potential externalities and any social costs associated with a GDE[1]. Hence further interventions, if designed and implemented correctly, could potentially help to bring security of supply closer to the socially optimal level.

[1] Such costs could result from indirect effects on other businesses, lost tax revenue, civil unrest and dampened investor perception of the GB energy market.

Under this option, the amount of storage gas that is kept in reserve for the purposes of preventing physical network interruptions is determined administratively rather than as a result of expected profit maximisation by shippers. Hence the extent to which this option improves social welfare is at least partly determined by how close the administrated storage obligation level is to the socially optimal level of storage. For the purposes of our modelling, this option is a straightforward combination of Option 2 and Option 3.

Modelling approach

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 predict the optimal system response to those shocks is clearly a very challenging task. Our aim was to build a model that is fit for purpose given the need to assess the risk to GB gas security of supply under the current arrangements and the draft policy proposals.

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 methodology centres around 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.

Modelling assumptions are based on National Grid's Gone Green scenario and the Green Transition scenario from Ofgem's Project Discovery. Assumptions on infrastructure availability were derived from historical data where possible. Where this was not possible, assumptions were agreed with Ofgem.

For the purposes of our analysis, we have assumed that only firm DM customers would be interrupted at stage 2[2] of an emergency. If all DM customers have been interrupted and an imbalance remains, we have assumed that firm NDM customers will be interrupted through the physical isolation of parts of the network (representing stage 3 of an emergency). To reflect these assumptions, we refer to firm DM and firm NDM customer interruptions rather than customers affected in stages 2 and 3 of an emergency.

Results

Table 1 shows the likelihood of firm DM and NDM customer interruptions under the current arrangements and the four reform options. On average, we would expect firm DM interruptions to occur once in 16 years and NDM interruptions to occur once in 122 years under the current arrangements.

[2] In this section, we refer to stages of an emergency as defined after Exit Reform.

Table 1 Average outage probabilities in the base case[3]

Options	Firm DM interruptions	NDM interruptions
Current arrangements (frozen cash-out)	1 in 16	1 in 122
Option 1: Cash-out rises to full VoLL	1 in 67	1 in 303
Option 2: Cash-out rises to capped VoLL	1 in 63	1 in 182
Option 3: Further interventions (storage) with current arrangements	1 in 15	1 in 588
Option 4: Further interventions (storage) with cash-out rising to capped VoLL	1 in 175	1 in 2000

Option 1 is effective at reducing the probability of all types of firm customer interruption. For I&C gas demand, the bulk of the effect is accounted for by the fact that a significant volume of customers are assumed to sign commercially interruptible contracts with their suppliers. This has the benefit of substituting voluntary interruption for involuntary interruption. The reduction in the probability of firm I&C gas demand interruption is very similar under Option 1 and Option 2. However, Option 1 is considerably more effective in reducing the probability of NDM customer interruptions than Option 2 due to the increased provisions made by shippers.

Option 3 is effective at reducing the probability of NDM customer interruptions. The same is the case for Option 4, which is also effective at reducing the probability of firm DM customer interruptions. Under Option 3, a substantial proportion of physical gas storage capacity is reserved for the sole purpose of preventing NDM customer interruptions. As a consequence, less gas is available for other commercial purposes and to prevent curtailment of firm DM gas demand and gas demand for electricity generation.

Option 1 leads to the greatest improvement in net consumer welfare relative to the current arrangements. This is because we have assumed that the market functions efficiently in an emergency, bringing in more imported supplies when the cost of those supplies is less than the avoided VoLL.

Option 2 results in lower net consumer welfare than Option 1 because it imposes a price cap in the event of NDM customer interruptions. The mechanism which drives much of the difference in net consumer welfare between the two options is shipper investment response, which can reduce both the probability and the severity of NDM customer interruptions at lower cost than the value of unserved demand that is prevented. Since Option 2 significantly limits the potential cash-out liability of shippers, it removes the economic rationale for shipper investment in provisions such as storage.

Option 3 achieves a greater reduction in the cost of unserved demand than Option 1 and this effect is significantly enhanced when Option 2 is combined with Option 3 (i.e. as in Option 4). However, the range of uncertainty in the corresponding cost of the storage obligation (estimated to be between £255m and £3,146m) means that the impact on net welfare can only be described as a range.

[3] Based on arithmetic average of outage probabilities for spot years modelled (2012, 2016, 2020 and 2030)

Conclusion

Our analysis indicates that allowing the cash-out price of gas to rise to VoLL can reduce both the probability and impact of a GDE, assuming the market continues to operate efficiently. This happens first through more imported supplies being brought into GB in the course of an emergency, and second, if the cash-out price is set to a multiple of VoLL in the event of NDM customer interruptions, through provisions being made by shippers in order to limit their potential exposure. Further interventions can also reduce the probability and impact of a GDE. However, the design of those interventions can significantly alter their effect and an inappropriate intervention can be detrimental to social welfare.

In net welfare terms, our results indicate that allowing the cash-out price to rise to VoLL is the option for reform that would be likely to bring about the greatest improvement in social welfare. However, since our modelling assumes perfect markets, it does not account for the possibility of market failure that may occur when prices are allowed to reach extremely high levels, including traded market illiquidity due to credit concerns, and the risk of financial distress. If some kind of market failure is considered to be a likely outcome when the cash-out price is allowed to rise to VoLL, capping the cash-out price may bring about a better outcome. Finally, the impact of further interventions on net social welfare is uncertain and depends critically on the choice and design of those interventions. However, if cash-out is capped as under Option 2, there could be a case for investigating further interventions alongside Option 2 as in Option 4.

2 Background

On 11 January 2011 Ofgem launched a Gas security of supply Significant Code Review (SCR) under new powers that allow it to undertake a review of significant code-based issues and play a lead role in facilitating code modifications. In its initial consultation[4], Ofgem laid out three options for changes to the current emergency arrangements, designed to reduce the probability of an emergency occurring, the severity and duration of an emergency should one occur, and providing payment for involuntary DSR services to customers in the event of a loss of supply during a Gas Deficit Emergency (GDE). The document also discussed the potential case for enhanced obligations on shippers. The proposals are designed to address concerns expressed in Project Discovery[5] and previous modification decisions that the current arrangements may not be delivering the required level of security of supply. In particular, Ofgem highlighted that frozen cash-out prices during an emergency may not be sufficient to attract gas into the Great Britain (GB) market since prices may be higher elsewhere, and that without the possibility of cash-out prices rising to the Value of Lost Load (VoLL) for firm customers, and suitable payment for interruption, shippers may not be making sufficient provisions to cover an emergency and customers may not be receiving the level of security of supply that they would otherwise be willing to pay for.

Ofgem has been discussing its concerns with the industry on these issues for a number of years. National Grid Gas (NGG) has made several modification proposals in this area, and a number of these have been implemented. Ofgem rejected NGG's earlier proposals (UNC149) for a dynamic cash-out price during an emergency (which is a feature of some of the SCR proposals) on the grounds that prices could spiral to uneconomic levels if prices were based on shipper to shipper trades with insufficient reflection of consumers' willingness to pay.

Concerns about dynamic cash-out pricing during an emergency have been raised by some members of the shipping community. These included concerns about their potential exposures and the credit implications of extended periods of very high cash-out prices due to events beyond their control, as well as concerns that dynamic cash-out pricing would not lead to significant changes in behaviour of the relevant market players.

The Government has placed high importance on security of supply, which is also a focus of the Electricity Market Reform. The close association between security of supply in gas and electricity needs to be recognised given the proportion of gas-fired generation in the GB market.

The area is a complex one to analyse, and since a Gas Deficit Emergency has never occurred, there is limited historic evidence on which to base this analysis. There is a large range of very different events, either in isolation or in combination, which could lead to an emergency, including extreme weather conditions, major terminal outages and supply disruptions in European markets. Estimating the probability, duration and impact of these events is difficult. Also challenging is the estimation of VoLL and anticipating how players will respond to different arrangements in terms of making greater forward provisions to mitigate potential exposures to higher emergency cash-out prices, and how they would respond during an emergency.

To support its Impact Assessment of the SCR proposals, Ofgem appointed Redpoint Energy to conduct economic modelling of the gas market under the current arrangements and under the Gas SCR proposals in order to understand the extent to which the proposals could enhance security of supply, and what the

[4] Ofgem 2011, *Gas Security of Supply Significant Code Review (SCR) Initial Consultation*, 11 January.

[5] http://www.ofgem.gov.uk/Consumers/Pages/ProjectDiscovery.aspx

costs to consumers would be. This document describes the approach, assumptions and results of the analysis.

3 Current market arrangements

Gas cash-out arrangements determine charges for, or payments to, gas market participants with an imbalance between their inputs into and withdrawals from the gas network in each gas day. National Grid Gas (NGG) takes market balancing actions in the On-the-day Commodity Market (OCM) where needed to maintain a system balance (within linepack tolerances), which is also used by shippers to trade with one another. Cash-out prices, to which shippers with imbalances are exposed, are determined based on the trades carried out by NGG.

The market arrangements in the case of a Gas Deficit Emergency (GDE) are designed to keep the chance of such an emergency developing and, where one does develop, the impact on gas customers and the wider network, as small as possible without burdening consumers with excessive costs. In their current form, these arrangements are based on the presumption that an emergency that may result in firm demand having to be disconnected from the network is best resolved by a single body that takes responsibility for co-ordinating actions across the affected parts of the gas transportation system. In GB, this role is played by the Network Emergency Coordinator (NEC). The NEC can instruct NGG to take market actions and physical measures to prevent or minimise the impact of a GDE. It also has the authority to direct flows from domestic storage facilities and to instruct all domestic supply sources to flow to their maximum physical capacity to achieve these aims. Since the NEC does not have jurisdiction over imported supplies, however, the gas price will still be a key signal in determining gas flows from outside GB.

If a gas transporter deems that actions under the emergency arrangements may be required in order to prevent a GDE or to minimise the possibility of a GDE developing, that transporter will notify the NEC. NGG may then issue a Gas Balancing Alert (GBA) and take certain actions in the market to resolve the situation. If the GBA and other market actions taken by the NGG fail to resolve the situation, NGG can recommend to the NEC that an emergency is declared. If an emergency is declared, NGG may take a number of actions. The actions available depend on the stage of emergency declared. These stages need not be declared in any specific order and actions from any stage up to that most recently declared, with the exception of the restoration phase, can be taken. This is specified in Table 2.

Table 2 Stages of a GDE and actions available to NGG

Stage	Actions available to NGG
1. Potential emergency	Use emergency specification gas Maximise use of linepack Use distribution network storage Emergency interruption Issue a public appeal
2. Emergency declared	NGG's participation in the OCM is suspended Cash-out price is frozen Instruct domestic supply sources to flow Issue a public appeal
3. Firm load shedding	Curtailment of customers on a site by site basis
4. Allocation of gas and network isolation	Allocation of available gas to individual Local Distribution Zones (LDZ) and isolation of LDZs
5. Resolution	Restoration of normal market arrangements

When customers are interrupted, they are generally interrupted in the order of their size. There are some exceptions to this rule by which supply to hospitals and strategically important installations can be protected. Gas for electricity generation is generally interrupted before any NDM customers. When customers are interrupted as a consequence of the physical isolation of sections of a local distribution zone (LDZ), it is generally not possible to isolate individual customers. Therefore, a number of customers (including DM customers) within an isolated section of an LDZ are interrupted simultaneously.

From Stage 2 of a GDE, the NEC can instruct all domestic supply sources to flow to their maximum physical capacity. Shippers are obliged to comply with such instruction under the terms of their licence. NGG's activities on the OCM are suspended at this point and it is therefore not possible to set a cash-out price that is based on NGG's market actions. Shippers can continue to trade on the OCM. From this point, the cash-out price is frozen for the duration of the emergency. For shippers with a short position, the cash-out price is the price of the most expensive NGG trade conducted on the day of the Stage 2 GDE being declared.

Another administrative mechanism that is designed to incentivise shippers to maximise gas flows into the system in the event of a GDE being declared is the Post Emergency Claims (PEC) arrangement. This mechanism was introduced as part of modification UNC 0260 in 2009. It allows shippers to submit claims up to their opportunity cost of delivering imported gas to the National Transmission System (NTS) during a GDE, this being defined as the price they would have been able to obtain for that gas in a different market that they could have feasibly supplied.

However, while the PEC arrangement is likely to represent an improvement on the arrangements that were in place before it was introduced, it may not provide a strong incentive for shippers to deliver imported gas in a GDE since they have less certainty over receiving payments through this mechanism than if they sell the gas to the alternative market while the size of that payment, if a claim is successful, would be the same.

Note also that NGG is in the process of changing the stages of emergency to reflect Exit Reform implementation, expected in October 2012. The proposed reforms to the emergency arrangements are as follows.

i) NGG would continue to take market balancing actions until the first firm load disconnections occurred. These actions would set the market price. Upon disconnection of firm load, NGG would no longer take market balancing actions.

ii) The NEC would retain its ability to direct physical delivery of supply from GB sources of gas.

Different stages of emergency will be defined as follows.

Stage 1: Public appeal; use of emergency specification gas and emergency interruption (if available).

Stage 2: Maximise supplies and firm load shedding (on a site by site basis).

Stage 3: Allocation of gas between distribution networks and isolation of sections of the network.

Stage 4: Restoration.

For the remainder of this section, we refer to stages of an emergency as defined after Exit Reform.

We expect that firm DM customers would be the main group affected by a stage 2 emergency as these customers are better able to change their gas usage at short notice. However, some larger NDM customers might also be asked to reduce their gas use during stage 2 of an emergency. During stage 3, networks would be physically isolated which would affect many smaller NDM customers and potentially some DM customers. For the purposes of our analysis, we have assumed that only firm DM customers would be interrupted at stage 2 of an emergency. If all DM customers have been interrupted and an imbalance remains, we have assumed that firm NDM customers will be interrupted through the physical isolation of parts of the network (representing stage 3 of an emergency). To reflect these assumptions, we refer to firm DM and firm NDM customer interruptions rather than customers affected in stages 2 and 3 of an emergency.

For the purposes of our modelling of the current arrangements, it is assumed that normal market operations are suspended at the point at which firm gas customers must be interrupted to balance the system. Since the system is modelled to daily granularity, this is assumed to occur on a day in which the model is unable to meet total daily demand from firm gas customers with total supply available on that day.

When normal market operations are suspended, the cash-out price in the model is frozen at the price level achieved on the previous day[6]. Given this price, the model determines total supply available. If the level of supply determined by the model is insufficient to meet total demand, the model interrupts different tranches of demand in increasing order of VoLL, starting with DM customers and then going to NDM customers, until the balance between supply and demand is restored.

Gas supply for CCGT generation is curtailed before NDM customers are interrupted. When NDM customers are interrupted, the minimum size of the interruption is assumed to be 20 mcm and the minimum duration of the interruption is assumed to be 14 days. This is to reflect the limited ability of the system operator to isolate an interruption within an LDZ and the time it takes to re-connect customers safely.

Under the current arrangements the NEC can request shippers to maximise gas flows in the event of an emergency. These powers are not reflected in our modelling approach explicitly. However, domestic supplies over which the NEC has jurisdiction flow at any price if they are available, hence if the cash-out price is frozen at a low level, available flows are maximised regardless. In the case of storage, there is no explicit guarantee that it would flow if the price is frozen at a low level. It is not certain how command and control would work with respect to storage flows since orders could be made for storage to be preserved rather than flowing at maximum capacity depending on the nature of the emergency. Hence we believe that our modelling approach is an appropriate reflection of the current arrangements.

[6] This approach is subject to sensitivity analysis and is discussed in more detail in Section 8.6.

4 Options for reform

4.1 Motivation for reform

The current arrangements for a Gas Deficit Emergency (GDE) were designed at a time when GB gas demand was met largely from domestic sources. Under these arrangements, the Network Emergency Coordinator (NEC) would co-ordinate actions of all market participants. Specifically, it could maximise gas supplies administratively by requiring all domestic supply sources to flow at maximum available capacity without the distraction of having to employ market mechanisms in order to manage the emergency situation.

However, GB is now significantly reliant on imported gas, particularly in peak winter months, and with this comes a need also to consider the response of flows of imported gas in a GDE. Since NEC's jurisdiction does not extend beyond national borders, it is not possible for supply to be maximised using purely administrative means. The current arrangements may not provide shippers with sufficient incentives to attract flows of imported gas in an emergency because normal market operations are suspended in this case and the cash-out price is frozen. Hence if shippers were to pay a higher price for imported supplies than the frozen cash-out price during an emergency, they may not be able to recover the full difference. Their exposure would be limited by the PEC arrangements. However, under the PEC, shippers can only claim up to their opportunity cost of selling gas into GB, which would be the best price that they would be able to obtain by selling that gas elsewhere. It is unclear to what extent shippers would be prepared to face the uncertainty of the PEC process as compared to selling that gas to another market for a certain price that would be no less than what they would be able to obtain under the PEC arrangements.

Currently, the cash-out price can be frozen at a level below the value customers place on uninterrupted gas supplies. Therefore, the price signals might not be sufficient to attract more gas immediately prior and during a GDE. This also indicates that shippers do not face sufficient incentives to take appropriate action to prevent a GDE occurring (e.g. investing in storage, negotiating contracts for demand interruptibility). Furthermore, firm customers who are interrupted do not get paid for the involuntary demand side response (DSR) services they provide. This means that customers largely bear the costs and risks of a GDE.

Overall, the reasons for seeking reform to the current emergency arrangements are lack of incentives for shippers to make provisions that would reduce the probability and impact of emergencies or to import gas in the event of an emergency.

4.2 Option 1: Cash-out at the full value of lost load

The aim of Option 1 is to allow the market to play a greater role in resolving a GDE. If successful, this would be expected to address some of the main problems identified with the current arrangements. The cash-out price would not be frozen before firm load shedding but would continue to be set by balancing actions taken by NGG. Once firm load is shed, shippers would still be able to carry out bilateral trades to resolve their imbalances but NGG would stop taking balancing actions on the OCM and the cash-out price would be set at the VoLL of domestic gas customers. This is intended to increase the level of commercial interruption by incentivising suppliers and larger consumers to enter into appropriate interruptible arrangements, as discussed further below. In the case of network isolation, the cash-out price would go to 14 times of the VoLL of domestic customers. The rationale behind this is to price in the true economic cost of physical network interruptions, which is assumed to last for a minimum 14 days for the purposes of our analysis.[7]

Allowing the cash-out price to rise to the VoLL of domestic customers when firm load is shed is likely to provide a greater incentive for shippers to resolve negative imbalances by bringing in more expensive imported gas, thus reducing both the frequency of occurrence and the severity of outages. It can also be expected to incentivise the signing of interruptible contracts between suppliers and DM gas customers. A contract exercise price that is somewhere in the range between the VoLL of DM gas customers and the VoLL of domestic customers would benefit both parties. Alternatively, suppliers and DM customers can agree contracts that offer permanent option prices to interruptible customers (i.e. reduction on their gas bill) as well as exercise payments should they be interrupted. We account for this effect in our modelling by assuming that the two lowest VoLL tranches of firm DM gas demand enter into interruptible contracts in response to Option 1[8].

Allowing the cash-out price to rise to 14 times the VoLL of domestic customers when parts of the network are isolated may result in a further increase in imports into the GB gas market. Under current arrangements, cash-out payments would be redistributed to shippers through neutrality, thereby potentially inhibiting incentives to invest. This is addressed in option 1 by using the cash-out payments to pay firm customers that have had their gas supplies interrupted for the involuntary DSR services they provide. The potential exposure to these cash-out prices in an emergency should provide an incentive for shippers to make provisions that would reduce the probability and severity of network isolations. In light of this consideration, Ofgem asked Redpoint to make quantitative estimates of the potential investment response of shippers to proposed changes to cash-out arrangements in a GDE.

Measures that reduce the exposure of shippers to very high cash-out prices can take many forms, including the holding of storage capacity, financial insurance[9] and contractual provisions, amongst others. For the purposes of our quantitative estimates, we assume that investment response by shippers involves booking storage capacity that is only called upon in the case of NDM customers' demand being curtailed. We assume further that shippers pay both the holding cost of gas in storage and the cost associated with booking extra storage capacity. Finally, we assume that any gas that is not used to prevent NDM customers' demand from being curtailed can be sold back into the market at the same price as it was purchased.

The benefit to shippers of obtaining additional storage capacity is measured in terms of the expected avoided cash-out exposure. Shippers obtain the amount of storage capacity that maximises the surplus of avoided cash-out exposure over the cost of additional storage.

4.3 Option 2: Cash-out at a capped value of lost load

The rationale for imposing a cap on the cash-out price is to avoid some of the potential problems associated with the high cash-out liabilities that could arise under Option 1. By capping the liability of short shippers in the event of network isolation, the problems associated with potential financial distress of shippers in these circumstances, and corresponding credit issues, can be lessened.

[7] If option 1 were pursued further however, additional work would be undertaken to estimate the minimum likely duration of a NDM customer interruption.

[8] However, we also test this assumption through a sensitivity analysis, discussed later.

[9] We assume for the purposes of our study that physical storage and financial insurance are equivalent in economic welfare terms.

In our modelling, this option is treated in the same manner as Option 1 in all respects with the exception of the rule on the system price when NDM customers are interrupted. Here, the cash-out price is given directly by the VoLL of domestic customers when NDM customers' demand is interrupted rather than 14 times that level.

As with Option 1, it is assumed that interruptible contracts are entered into by the two lowest VoLL tranches of Firm I&C gas demand under this option. Further, interrupted firm customers would receive a payment at the level of capped VoLL for the involuntary DSR services they provide should they be interrupted.

Since the cash-out price is capped at the VoLL of domestic customers, no extra imported supplies come forward in addition to those brought in when the cash-out price rises to the VoLL of domestic customers before parts of the network are isolated. Capping the cash-out price at the VoLL of domestic customers also limits the potential liability faced by short shippers in the event of network isolations. We apply the same methodology to estimating the profit-maximising investment response by shippers under this option as we do for Option 1. Our analysis suggests that risk neutral shippers would not respond through additional investments when a cap on the cash-out price is put in place.

4.4 Option 3: Further interventions

Interventions in the market can take many possible forms. For the purposes of assessing the potential impacts of a further intervention, we have assumed that the intervention takes the form of a storage obligation imposed on gas suppliers. A storage obligation is an administrative method intended to improve security of supply in the gas market. There are many possible reasons for imposing a storage obligation on suppliers. These can be summed into two categories, both of which are based on some form of market failure. One reason is the possibility that changes in market arrangements as outlined in Section 4.2 may not produce a socially optimal response from shippers. This may happen if shippers are systematically wrong in their assessment of the probability of a GDE (irrational response) or if there is a perception that some form of support would be given to ensure that the market continues to function (moral hazard).

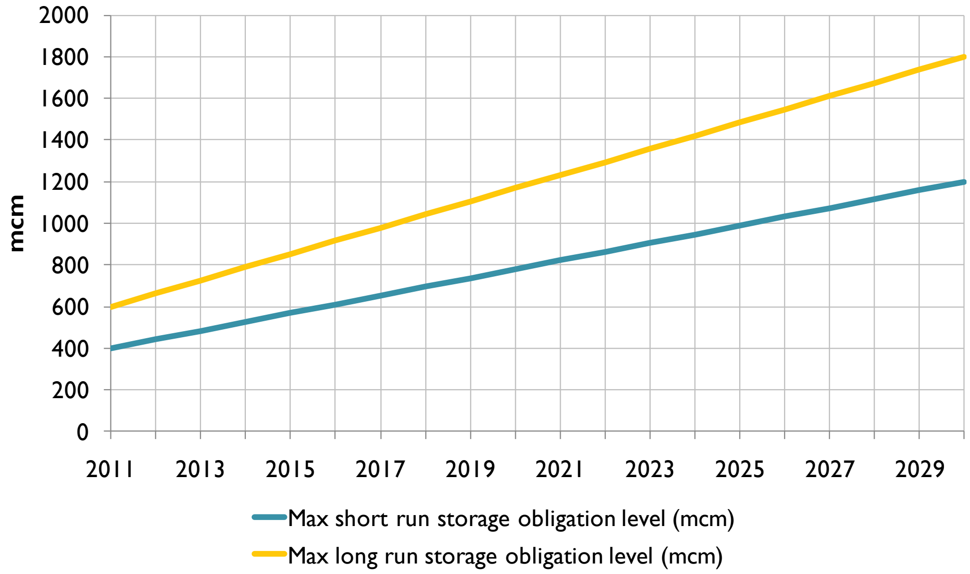
Another reason is the possibility that those changes in market arrangements may produce an adverse outcome that is detrimental to social welfare. This may happen if the extreme financial liability faced by short shippers in a GDE leads to their financial distress and the subsequent market consolidation proves to be detrimental to competition in the gas supply sector. It may also happen if that potential financial liability creates a barrier to entry for new shippers by requiring them to have a sufficient credit rating to absorb the losses in the event of a GDE or to raise funds at a reasonable cost to be used as collateral for extreme negative outcomes, which would likewise be detrimental to competition in the gas supply sector.

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. Storage can only be released for the purposes of preventing network isolation (with NDM interruptions used as a proxy in the model). The amount of storage is determined administratively rather than as a result of expected profit maximisation by shippers. Hence the extent to which this option improves social welfare is at least partly determined by how close the administrated storage obligation level is to the socially optimal level.

Time scales for the start and end of the obligation are kept the same across all years modelled, with the only change being the size of the obligation in each year. This increases on a straight line basis between 2011 and 2030 to reflect the expected increased reliance of the GB gas system on imports over that period[10]. The storage obligation level for 2011 is benchmarked to National Grid's Firm Gas Monitor[11], which reaches a maximum level of approximately 1,000 mcm as of January 2011. For the purposes of our modelling, the obligation level is specified for both Long-range storage (LRS) and Short-range storage (SRS)[12] to ensure deliverability and is profiled over the winter period.

The aggregate storage obligation level modelled for years between 2011 and 2030 is shown in Figure 1.

Figure 1 Storage obligation level



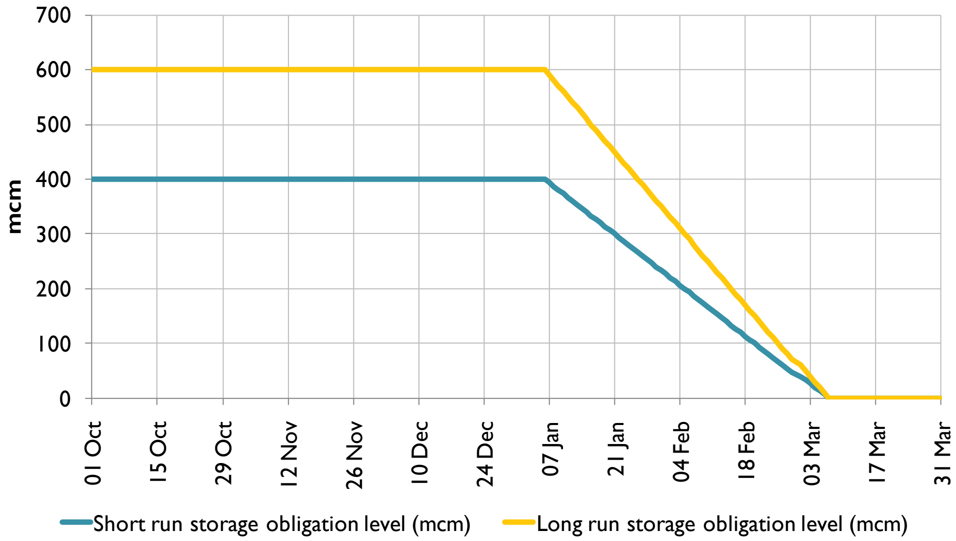
The profile of the storage obligation shown in Figure 2 is for 2011. This profile also approximately matches that of National Grid's Firm Gas Monitor.

[10] While reliance on imports is only one of many factors that determine security of supply in the GB gas system, it provides an obvious exogenous determinant on which to base our modelling.

[11] This represents the storage levels required to support all firm demand in a severe (1 in 50) winter as assessed by National Grid. More details can be found in http://www.nationalgrid.com/NR/rdonlyres/EE344897-2842-4D20-8078-872727637C02/43347/StorageMonitorsSeptember2010.pdf

[12] For simplicity we have aggregated medium-range storage (MRS) and short-range storage (SRS), and use short-range storage to refer to both.

Figure 2 2011 Storage obligation profile



Our analysis assumes that the total amount of physical storage capacity on the system does not change when a storage obligation is introduced. It could be argued that since the gas in store under the obligation cannot be used for normal price arbitrage, more investment in new storage capacity may be forthcoming. However, without knowing how the current total storage capacity compares to the profit maximising capacity level, it is not possible to know the extent of any such investment.

The storage obligation is treated as a hard constraint in our model and can only be suspended to prevent, or reduce the severity of NDM 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. Because gas stored under the obligation can only be used to prevent NDM interruptions, the model treats this gas as being effectively ring-fenced from normal trading operations.

4.5 Option 4: Capped cash-out and further interventions

The rationale for combining Option 2 with Option 3 is to obtain the benefits of Option 2 in terms of bringing in additional imported gas supplies that could prevent firm customers from being interrupted, as well as the benefits of an increase in interruptible contracts, while overcoming the problem of sub-optimal incentives for shippers to make provisions that could reduce the likelihood or severity of network isolations (with NDM customer interruptions used as a proxy for the purposes of our modelling). Furthermore, the cash-out price under options 1 and 2 may not reflect potential externalities and social costs associated with a GDE. Hence further interventions, if designed and implemented correctly, could potentially help to bring security of supply closer to the socially optimal level.

For the purposes of our modelling, this option is a straightforward combination of Option 2 and Option 3 as described in Sections 4.3 and 4.4 respectively.

5 Modelling approach

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 predict the market response to those shocks is clearly a very challenging task. Our aim was to build a model that is fit for purpose given the need to assess the risk to GB gas security of supply under the current arrangements and the effect of changes in those arrangements. Our 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 methodology centres around 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. An 'uplift' on this price is then calculated based on a function of the capacity margin on a daily basis, intended to reflect a scarcity value.

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.

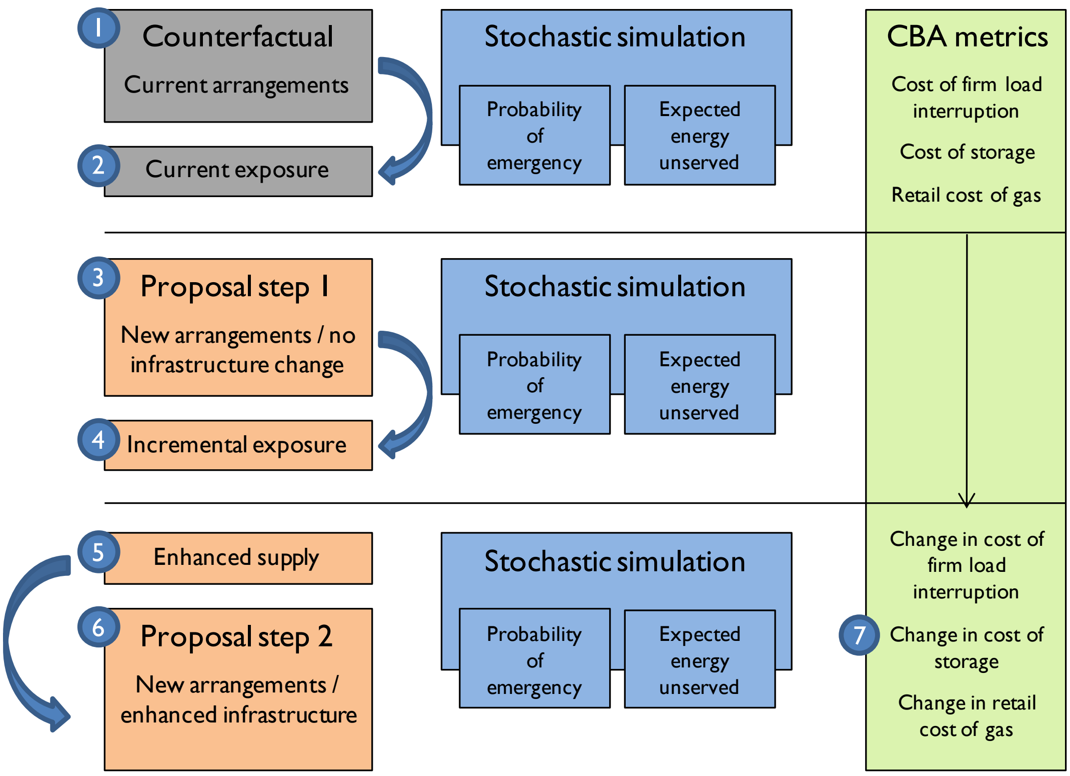
The seasonal pattern of UK Continental Shelf (UKCS) gas flows is estimated from historic data provided by National Grid using monthly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean production level are drawn from a distribution fitted to the residuals of 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 outages are modelled with Poisson distributions representing the probability of outages including a duration function. Assumptions for distribution parameters were agreed jointly by Redpoint and Ofgem. In many cases, given the associated low probabilities, there is not a historic dataset that can be used to derive the parameters[13].

Stochastic daily variation in 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.

The steps involved in modelling the counterfactual (under current arrangements) and a given proposed option are described below. Modelling is conducted using representative years to 2030.



[13] The impact of different assumptions is tested in the sensitivity analysis.

1. Estimate the probability of an emergency under current arrangements – or more generally, estimate expected unserved load – by running multiple simulations of outcomes using the GB gas market model.

2. Determine the expected 'industry exposure' associated with emergencies. Our assumption here is that shippers in aggregate are contracted to match the volume supplied prior to firm interruption, and hence that they are exposed to the volume of firm interruption at the associated cash-out price.

3. Re-run GB model under proposed alternative arrangements, determining a revised probability of emergencies.

4. Determine the revised expected 'industry exposure' associated with emergencies (prior to the introduction of any new investment). Our assumption here is that the incremental industry exposure would be the result of firm interruptions priced at cash-out, plus any additional gas flowing relative to the counterfactual.

5. Determine the additional storage capacity that the industry would obtain to reduce its exposure to the level estimated in the counterfactual. This is estimated on the basis of the profit-maximising additional storage level where the marginal cost in terms of extra storage capacity obtained is equal to the marginal benefit in terms of reduced exposure.[14]

6. Re-run the model with this additional storage capacity and again determine the probability of an emergency and the expected unserved load.

7. Compute the change in consumer welfare relative to the counterfactual based on the additional wholesale cost of gas, the additional cost of the incremental storage capacity and the benefit of any reduction in firm interruption.

[14] We note that this is a simplified assumption which has its own limitations. Firstly, the model assumes that companies are neutral to risk. The existence of insurance markets indicates that some companies might be risk averse (wanting to avoid the biggest risks). Building risk aversion into companies' cost-benefit analysis could lead to additional investments in security of supply. Secondly, the model assumes that the only investment response available to companies is investing in storage capacity. In reality, companies might have more cost-effective instruments available to enhance security of supply, such as long-term supply contracts and diversification of imports. Therefore, companies' responses to the incentives created may be greater than suggested by the modelling.

6 Modelling assumptions

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. Broadly, the set of assumptions adopted in our modelling are designed to be consistent with Project Discovery's Green Transition and NG's Gone Green scenario under which the UK meets its decarbonisation and renewable energy targets.

Commodity prices

Our commodity price assumptions rely on prices quoted in forward markets dating from 22 March 2011 for the period up to 2015. For the period after 2015, our assumptions are based on the International Energy Agency's 2010 World Energy Outlook published in Nov 2010. For Henry Hub prices, our assumptions are based on prices quoted in forward markets dating from 22nd March for the period up to 2015. After 2015, 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 supply, the available DSR and the margin of available capacity over total demand. This price is calculated on a daily level.

Carbon price

Our assumptions on the carbon price in GB rely on prices quoted in forward markets dating from 22 March 2011 and the announced Carbon Price Support (CPS) level. For 2013, we have applied a premium of £4.94 (converted to €) to the EUA price as announced in the 2011 budget. Between 2014 and 2020, we have used the CPS level announced in the 2011 Budget directly, converted into € and adjusted to be on a 2011 real basis using cumulative Retail Price Index (RPI) between April 2009 and April 2011 (taken from the Office for National Statistics website). After 2020, the indicative CPS level from Scenario 2 of the HM Treasury Carbon price floor consultation is used after converting into € and adjusting to be on a 2011 real basis using cumulative RPI between April 2009 and April 2011.

Daily volatility in coal, carbon and Henry Hub prices is 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 21 April 2011 and are assumed to remain constant in real terms thereafter. The assumed £/$ exchange rate is 1.655 and the assumed £/€ exchange rate is 1.137.

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. Total gas storage capacity is assumed to be approximately 4.6 bcm currently and increasing to approximately 5 bcm by 2013.

Storage outages are modelled as a multiplicative shock[15] to the maximum rate of injection and withdrawal for long and short range storage separately.

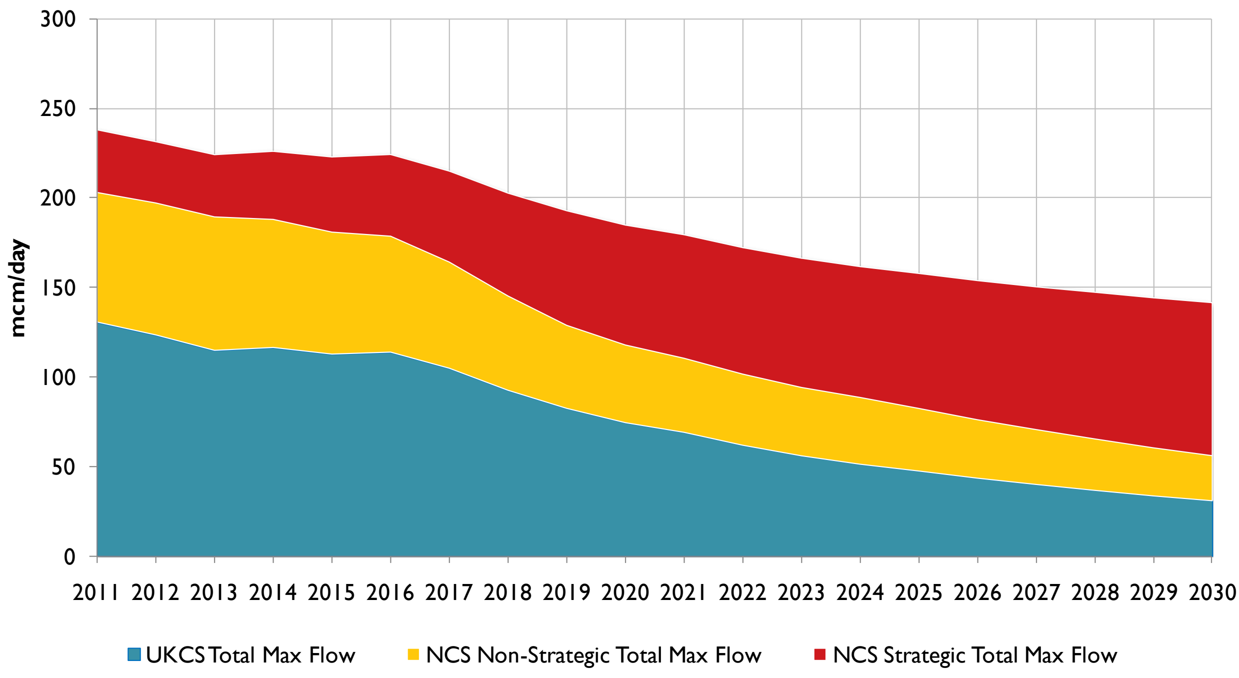
Gas supply

Average daily flow in UKCS gas on an annual basis is based on data for Figure 4.8G in the National Grid Ten Year Statement (TYS2010)[16] in the Gone Green scenario[17]. Growth/(contraction) after 2025 is extrapolated at the average growth rate between 2015 and 2025.

Predicted NCS annual capacity and flow data is taken from TYS2010 on the basis of the Gone Green scenario. The proportion of non-strategic NCS flow is set at the proportion of NCS total export capacity to UK (at 85% load factor) actually flowing to the UK as predicted in TYS2010 on the basis of the Gone Green scenario. In our modelling, flows on the Langeled pipeline are included in NCS supply.

The maximum daily flow from UKCS and the strategic and non-strategic parts of NCS[18] is shown in Figure 3.

Figure 3 Maximum daily flow from UKCS and NCS



[15] 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.

[16] http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/44779/TenYearStatement2010.pdf

[17] 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.

[18] 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.

REDPOINT

Variability in gas supply and outages

Variability in gas supply is calibrated to historic data spanning ten years. Supply outages on all gas supply sources are also modelled as 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 truncated at 1.

It is assumed that outages are twice as likely to happen in the winter 6 months than in the summer 6 months. We make the further assumption that supply outages can only lead to instances of firm demand interruptions in the winter 6 months[19]. Hence for the purposes of this modelling exercise, we assume that the frequency of occurrence is double the baseline estimate. This principle applies to all sudden shocks in our modelling.

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 expected probability of a shock in a given year set at 0.5. Shock duration is modelled as a lognormal distribution with mean of 10 days and standard deviation of 5 days. 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.

Interconnectors

The IUK annual maximum import and export flows are assumed to be 25.5bcm and 20.0bcm 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.

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 no longer supports those flows. At higher price levels, the additional price differences required to increase flows over interconnectors become asymmetric between exports and imports, making it harder to attract more imports into GB. This asymmetry is designed to reflect the effect of Public Service Obligations (PSOs) in Continental Europe as well as reduced market liquidity in periods of tight supply-demand balance.

The annual maximum flow on the Balgzand Bacton Line (BBL) is theoretically 20bcm on a capacity basis. Historically, flows have varied between 6 and 8.5bcm in the last few years. We have set BBL maximum flow as 8 to avoid the model taking an unrealistically high amount of flow.

BBL maximum flow goes to its full theoretical capacity in 2016. From that point we assume that BBL will behave in the same way as IUK (i.e. price-based flows referenced against the continental gas price). No

[19] This is backed up by simulation results, which show no instances of unserved demand in the summer 6 months, defined as the period between 1 April and 30 September inclusive.

reverse flow is assumed to be possible on BBL until 2016, from which point the export capacity of BBL is set equal to its import capacity.

No new interconnection capacity is assumed to be built within the model horizon. Interconnector import and export capacity is subject to stochastic variation. This is modelled as a multiplicative factor applied to full capacity. It is normally distributed with a mean of 0.97 and standard deviation of 0.05. The distribution is truncated at 0 and 1.

LNG

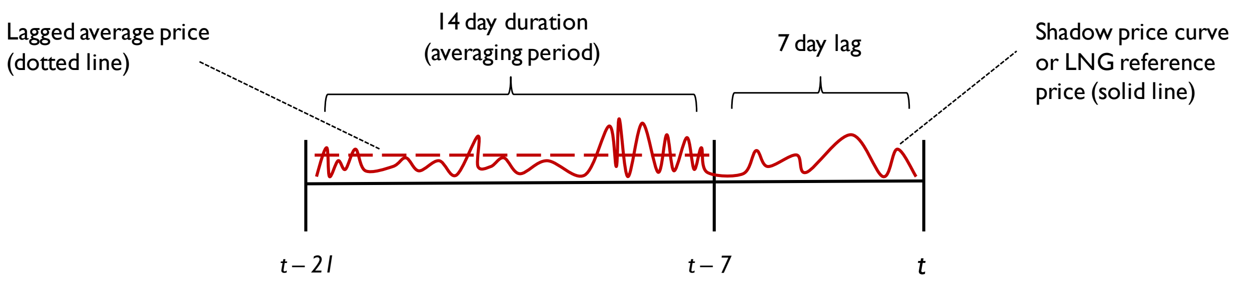
LNG maximum annual flow, i.e. the maximum amount of gas that can be sent out from all LNG terminals in a year, is assumed to be 51.5 bcm between 2011 and 2015 and 62.4 bcm thereafter. The assumption is taken from the Green Transition scenario from Project Discovery. LNG import capacity is subject to stochastic variation. This is modelled as a multiplicative factor applied to full capacity.

Historically, world 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 close alignment with the Henry Hub price.

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 the diagram below.



The supply of LNG gas at time *t* is determined by the difference between the 14 day lagged average system gas price and the LNG reference price, determined by a mixture of the lagged average 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.

Once a decision is made to bring cargoes to the UK, the LNG will then flow at whatever spot price is available in the market after arrival at time *t*. The equilibrium system price that achieves a supply-demand balance at time *t* is calculated on the basis that LNG supply is fixed.

Gas quality issues

Gas quality issues are assumed to impact flows over IUK only. 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. Hence 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.

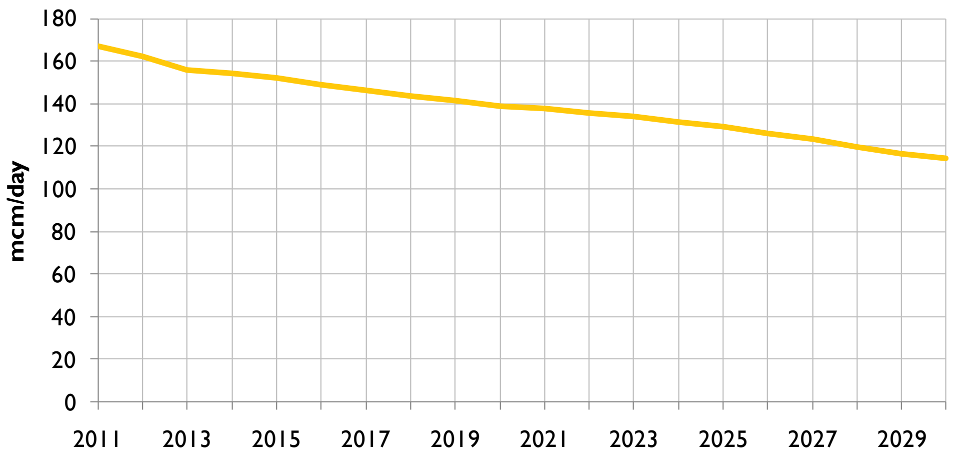
Since supply shocks relating to Russian gas are built into the continental price shocks functionality, capacity reductions relating to gas quality issues are assumed to be correlated with positive price shocks to the continental gas price. The relevant linear correlation coefficient is assumed to be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

Frequency of such shocks is modelled as a Poisson distribution with expected probability of a shock in a given year set at 0.5. Shock duration is modelled as a lognormal distribution with mean of 10 days and standard deviation of 2 days. 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.

Demand

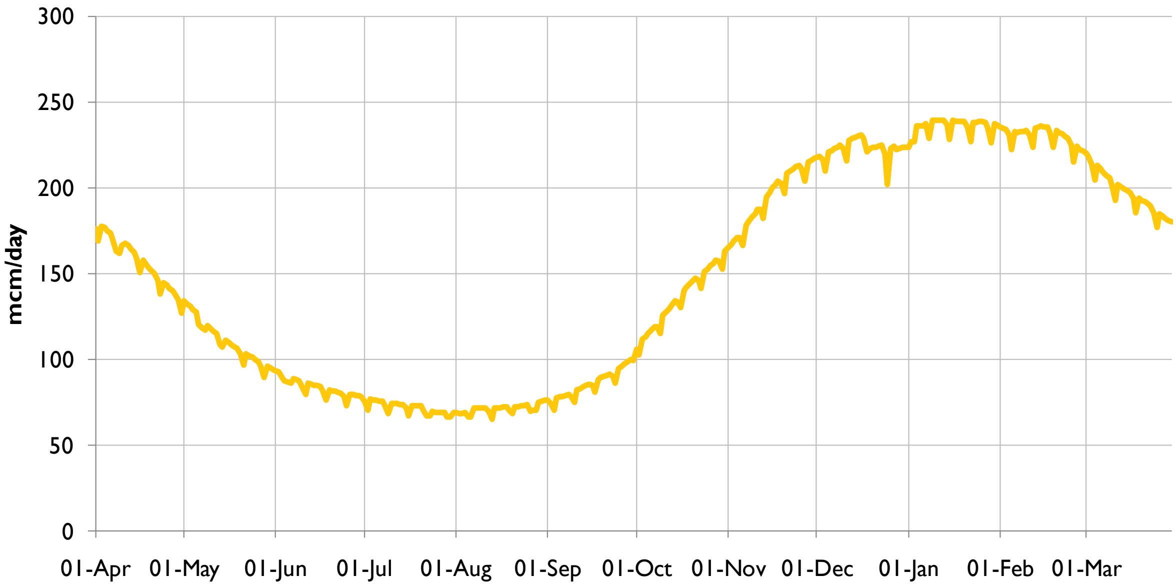
Total National Transmission System (NTS) non-power generation (NPG) gas demand is taken from the 2011 Gone Green scenario provided to us by National Grid. This includes net exports to Ireland. Average daily NTS NPG gas demand by year is given in Figure 4.

Figure 4 Average daily NTS NPG gas demand



The expected shape of demand based on 2011 annual demand is shown in Figure 5.

Figure 5 Expected demand shape



The Renewable Heat Incentive (RHI) is assumed to remain in place. Total demand for electricity is taken from the Green Transition scenario in Project Discovery.

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 the Green Transition scenario in Project Discovery.

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.

Demand side response/interruption

Demand side response (DSR) and interruption are represented jointly in the model through the definition of supply sources priced at the VoLL of each corresponding tranche of demand. As described in Section 4 above, whether the interruption of each tranche is commercial demand-side response or involuntary interruption varies with the Option being modelled. The tranches for gas DSR/interruption used in the model, in increasing order of VoLL, are as follows:

1. I&C tranche 1: includes agriculture, chemical, fertiliser, petroleum refining and construction industries;
2. I&C tranche 2: includes textile and leather, mineral, paper, printing, food and beverage industries;

3. I&C tranche 3: includes electrical engineering, non-ferrous metals, mechanical engineering, iron and steel, vehicle and other industries; and

4. Domestic and Small and Medium-sized Enterprises.

The three tranches of I&C demand are derived by amalgamating several categories from the London Economics (LE) VoLL study[20] according to similar VoLLs for those categories. 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.

Domestic and Small and Medium-sized Enterprises (SME) demand – that is, NDM customer demand - is treated as a tranche priced at the domestic gas customer VoLL. Domestic customer VoLL was selected by Ofgem from estimates of VoLL for domestic customers under various outage scenarios as calculated by LE. When this tranche is called upon, the amount of NDM customer demand that is interrupted is rounded up to the nearest 20 mcm[21]. Any NDM customer demand that is interrupted remains off for the subsequent 14 days. These figures are based on Ofgem assumptions, as discussed above.

For electricity demand, the tranches of DSR/interruption are taken from Project Discovery. They are as follows:

1. Interruptible I&Cs

2. Exporting interconnectors

3. Firm I&Cs

4. SME

5. Domestic

The corresponding VoLLs for each of these tranches are likewise taken from Project Discovery. The VoLL of different tranches of electricity demand are pertinent to this study since gas shortages can cause gas supply to CCGT generation plant to be curtailed, leading to outages on electricity demand.

The model generally calls upon different tranches of DSR/interruption to balance supply and demand on the basis of their associated VoLLs, starting with the lowest VoLL tranche, which is electricity demand from interruptible I&Cs. However, there are some significant exceptions to this rule. An example of such an exception is as follows.

For the purpose of modelling, we assumed that demand for gas from CCGT generation would be curtailed before NDM customers' demand regardless of the VoLL of electricity customers who are cut off as a consequence. The Network Emergency Coordinator (NEC) has the power to instruct domestic supply sources to flow to their maximum available capacity. While we do not model this command and control function explicitly, since United Kingdom Continental Shelf (UKCS) supplies always flow at full available capacity in our model, we believe that our modelling approach is consistent with such an arrangement.

[20] 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.

[21] National Grid has advised Ofgem that this is roughly the minimum size of an LDZ interruption in a given day.

7 Results

7.1 Probability and impact of gas shortages

7.1.1 Current arrangements

The stochastic model is run for spot years 2012, 2016, 2020 and 2030. In each case, 1,500 simulations are run, with each simulation consisting of a continuous 365 day period. Each simulation begins on 1 April. The starting level of gas storage is assumed to be zero in every simulation and the model begins to build up storage immediately according to its operating regime.

The results presented from this point onwards are averages over all the simulations and spot years for a given policy configuration. Table 3 gives the estimated average probabilities of at least one outage for four selected tranches of demand under the current arrangements.

Table 3 Average annual probability of at least one outage

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 16	1 in 67	1 in 63
NDM gas	1 in 122	1 in 303	1 in 182
Firm I&C electricity	1 in 54	1 in 105	1 in 88
Domestic electricity	1 in 154	1 in 263	1 in 303

Our analysis shows the risk of firm DM interruptions is 1 in 16 years while the risk of NDM customer interruptions is less than 1 in 120 years on average for the spot years modelled.

The corresponding figures for the expected amounts of unserved demand and cost of unserved demand as measured by VoLL are given in Appendix A.

7.1.2 Cash-out at value of lost load

Table 3 also shows the average annual probability of at least one outage on four selected tranches of demand under Option 1 and Option 2.

Our results show that Option 1 is effective at reducing the probability of all types of outages. For firm DM gas demand, the bulk of the effect is accounted for by the fact that two of the three tranches of DM gas demand are assumed to sign interruptible contracts with their suppliers. This has the benefit of substituting voluntary interruption for involuntary interruption. Interruptible contracts also play an important role in VoLL discovery and helping to make sure that customers with the highest VoLLs are cut off last in an emergency (apart from where safety considerations do not allow this). The benefit of VoLL discovery is not reflected in our results because we assume for the purposes of our modelling that the VoLL of the different tranches of demand as derived from the study by London Economics is a good proxy for actual VoLL.

The reduction in the probability of firm DM gas demand interruption is very similar under Option 1 and Option 2. This is because the assumption on interruptible contracts is the same under these two scenarios, as are all of the assumptions on the cash-out price unless NDM customers are interrupted.

Option 1, under which the cash-out price rises to 14 times domestic customer VoLL when NDM customers are interrupted, is considerably more effective in reducing the probability of NDM customer interruptions. There are two potential factors at play here. First, allowing the price to rise to 14 times domestic customer VoLL could potentially attract extra imports in a GDE that may prevent some NDM customers having to be cut off. The second factor is shipper response by which shippers book a certain amount of physical storage capacity to insure themselves against the prospect of paying out 14 times domestic customer VoLL if NDM customers are cut off[22]. This effect is not present under Option 2 as the potential payment for involuntary DSR services liability for suppliers does not justify the cost of storage that is used very rarely. (However, this is based on an assumption of risk neutrality so companies may invest more if they are risk-averse).

It is likely that any supplies that are not available at a cash-out price of one times NDM VoLL would not become available at 14 times NDM VoLL and hence the first of the two effects described in the paragraph above is likely to be insignificant. Table 4 confirms this. Results for Option 1 absent of any shipper response, particularly with respect to the probability of NDM customer interruptions, are very similar to the results for Option 2 where the cash-out price is capped at the VoLL of domestic gas customers[23].

Table 4 Effect of shipper response on outage probabilities

	Current arrangements	Option 1	Option 2	Option 1 (no investment response)
Firm DM gas	1 in 16	1 in 67	1 in 63	1 in 63
NDM gas	1 in 122	1 in 303	1 in 182	1 in 189
Firm I&C electricity	1 in 54	1 in 105	1 in 88	1 in 93
Domestic electricity	1 in 154	1 in 263	1 in 303	1 in 303

Note that the probability of domestic electricity outages is actually lower under Option 2. This seemingly anomalous result is a consequence of the assumption that a minimum of 20 mcm of NDM demand is cut off because of the difficulty of isolating individual NDM customers. In some instances, cutting off NDM customers can eliminate the need to cut off gas to CCGTs supplying electricity to domestic customers because the real shortfall in supply is only a fraction of the 20 mcm figure and the remainder of that amount can be re-routed to prevent outages elsewhere. This highlights the importance of understanding the interactions between the gas and electricity markets.

[22] The profit-maximising investment response in storage estimated in our modelling is 67 mcm in 2012, 40 mcm in 2016, 60 mcm in 2020 and 62 mcm in 2030.

[23] Table 19 shows the corresponding set of results in terms of expected unserved demand. These are consistent with the outage probability results shown in Table 4.

7.1.3 Further interventions

Table 5 shows the average annual probability of at least one outage on four selected tranches of demand under current arrangements, Option 3 and Option 4. Option 4 is very effective at reducing outages to all of the demand tranches shown in the table. Option 3 is effective at reducing the probability of NDM customer interruptions. It is much less effective at reducing probabilities of electricity outages and DM customer interruptions. For the latter, the effect of Option 3 is to slightly increase the probability of outages, though this effect does not appear to be large as borne out by our modelling results.

Table 5 Average annual probability of at least one outage

	Current arrangements	Option 3	Option 4
Firm DM gas	1 in 16	1 in 15	1 in 175
NDM gas	1 in 122	1 in 588	1 in 2000
Firm I&C electricity	1 in 54	1 in 76	1 in 263
Domestic electricity	1 in 154	1 in 208	1 in 1250

Under Option 3, a substantial proportion of physical gas storage capacity is reserved for the sole purpose of preventing physical network interruptions (with NDM customer interruptions being used as a proxy for the purposes of our modelling). As a consequence, less gas is available for other commercial purposes and to prevent load shedding (with DM customer interruptions being used as a proxy for the purposes of our modelling). An increase in the probability of NDM customer interruptions may therefore be expected. However, this effect is mitigated by two factors. One such factor is that during late winter and early spring when the storage obligation level is ramping down, more gas is available to be released into the system than would likely have been available otherwise, which reduces the probability of all types of outages in these periods. Another factor is that when the storage obligation is suspended to prevent NDM customers from being cut off, the gas in storage can be used to prevent outages on all tranches of demand in that period. Hence this particular effect of the obligation would be to prevent curtailment of I&C gas demand in the periods when the obligation is suspended.

Under Option 4, the probability of DM customer interruptions is lower than under Option 2 due to the side effects of the storage obligation as described in the paragraph above.

7.2 Cost benefit analysis

7.2.1 CBA methodology

Our CBA methodology is designed to assist in making a like-for-like comparison of different options for reform. All results are therefore shown as a change relative to the current arrangements. It is not our intention to analyse the options for reform in a general equilibrium framework where the impact of changes to market arrangements in a Gas Deficit Emergency 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.

The relationship between the downstream part of the GB gas sector and the upstream part is defined by simple assumptions based on perfect competition and perfectly elastic supply. Specifically, it is assumed that greater transfers from the downstream to the upstream in some periods do not result in a long-term increase in the average cost of gas. The gas supply sector is also assumed to be perfectly competitive, which means that any change in costs to shippers is passed on to consumers in full in the long run. This implies that net shipper welfare in our CBA is always zero and shipper revenue is equal to total shipper costs.

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. NPV is worked out on the basis of a discount rate of 3.5% in real terms. This rate is based on the HM Treasury Green Book on policy appraisal[24].

The cost of load reduction to customers is calculated on the basis of their VoLL. Payments for emergency demand side response services are worked out on the basis of applicable market rules under the corresponding policy framework. These are set out in Section 4 for each of the options modelled.

The cost of storage line captures the welfare cost of the storage obligation or the cost of shippers making provisions against cash-out rising to the value of lost load where this is applicable. Our CBA includes two methods for calculating the cost of storage taken up by the obligation or shipper investment response. Under the first approach, the cost of booked storage capacity is based on its Long-Run Marginal Cost (LRMC). This approach does not account for the possibility of improved utilisation of existing storage capacity and hence represents an upper bound in the possible range of costs of booked storage capacity.

Under the second approach, the cost of booking storage capacity is estimated on the basis of the loss of arbitrage profits associated with that capacity since it can only be used to prevent NDM customer outages and thus cannot be used for normal price arbitrage. Under this approach, the storage capacity required to meet the demands of the storage obligation or shipper investment response comes entirely from existing capacity, which significantly increases the utilisation of existing capacity. The details of both of these approaches are set out in Appendix B.

Since the most likely outcome is that the demands of a storage obligation or shipper investment response would be met partly through new storage capacity and partly through increased utilisation of existing capacity, the actual cost of these measures is likely to lie somewhere in the range between these estimates. Hence the difference in the cost estimates based on the LRMC and arbitrage profit methodologies provides a range for our estimates of the cost of the obligation and shipper investment response.

7.2.2 CBA results

Results of CBA analysis for Option 1 relative to the current arrangements are shown in Table 6. The cost of unserved demand is based on the VoLL of each tranche of demand. The range of values of net consumer welfare is derived by applying two alternative methodologies for evaluating the cost of reserving gas in storage as described in Section 7.2.1. The bottom of the range is derived from the LRMC method and the top of the range is derived from the arbitrage profits from storage method. This is the case for all of the CBA tables presented in this section. For Options 1 and 2, estimates of the cost of storage using the arbitrage profits method are positive values. This is because under these options, the price of gas is allowed to rise to VoLL in a GDE, increasing the arbitrage profits from storage.

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

Our analysis shows that Option 1 results in an improvement in net consumer welfare. This is due to the fact that the value of reduction in unserved demand exceeds the cost of shipper provisions regardless of the methodology used to assess the cost of the additional storage requirement. In more general terms, it shows that market failure associated with frozen cash-out has been corrected.

The analysis also shows that the retail cost of gas to consumers would be higher, but this is likely to be offset to a large extent by payment for involuntary DSR services for periods in which gas demand is curtailed.

Table 6 CBA – Option 1

£ million		NPV (real 2011)
Consumer welfare	Retail cost	-348.0 / -6.6
	Payments for involuntary DSR services	256.1
	Unserved demand by firm gas customers	347.9
	Unserved demand by firm electricity customers	12.2
	Unserved demand by interruptible customers	0.7
	Net consumer welfare	**268.9 / 610.3**
Shipper welfare	Retail revenue	348.0 / 6.6
	Cash-out liability	-256.1
	Cost of storage	-91.9 / 249.5
	Net shipper welfare	**0.0**

CBA results for Option 2 relative to the current arrangements may be seen in Table 7. Like Option 1, it also results in an improvement in net consumer welfare due to the value of reduction in unserved demand without any investment response from shippers. The retail cost of gas to consumers increases relative to current arrangements, but this is completely offset by payment for involuntary DSR services for periods in which gas demand is curtailed.

Regardless of the methodology used to assess the cost of shipper investment response, Option 1 results in a greater improvement in net consumer welfare relative to the current arrangements than Option 2. This is largely attributable to the fact that the value of reduction in unserved demand under Option 1 relative to Option 2 exceeds the relative cost of shipper investment response regardless of the methodology used to evaluate the cost of that investment. In more general terms, capping the cash-out price results in a market distortion (in comparison to Option 1)[25] that is detrimental to consumer welfare (prior to taking account of more general impacts on competition).

[25] The current arrangements arguably represent a much bigger market distortion relative to Option 1.

Table 7 CBA – Option 2

£ million		NPV (real 2011)
Consumer welfare	Retail cost	-89.3 / -11.7
	Payments for involuntary DSR services	89.3
	Unserved demand by firm gas customers	158.5
	Unserved demand by firm electricity customers	11.1
	Unserved demand by interruptible customers	0.6
	Net consumer welfare	**170.2 / 247.8**
Shipper welfare	Retail revenue	89.3 / 11.7
	Cash-out liability	-89.3
	Cost of storage	0.0 / 77.6
	Net shipper welfare	**0.0**

Table 8 shows the CBA results for Option 3 relative to current arrangements. It shows that the value of total reduction in unserved demand under Option 3 is greater than under Option 1. The estimated cost of the obligation differs very significantly depending on the methodology used to evaluate it. The range of cost estimates is such that the resulting estimates of net consumer welfare vary between -£2,706m and £185m. However, regardless of the methodology used to evaluate the cost of the obligation, the estimated change in net consumer welfare compared to the current arrangements is better under Option 1 and Option 2 than under Option 3.

Table 8 CBA – Option 3

£ million		NPV (real 2011)
Consumer welfare	Retail cost	-3,145.5 / -254.8
	Payments for involuntary DSR services	0.0
	Unserved demand by firm gas customers	438.3
	Unserved demand by firm electricity customers	5.7
	Unserved demand by interruptible customers	-4.6
	Net consumer welfare	**-2,706.1 / 184.6**
Shipper welfare	Retail revenue	3,145.5 / 254.8
	Cash-out liability	0.0
	Cost of storage	-3,145.5 / -254.8
	Net shipper welfare	**0.0**

Finally, Table 9 shows the CBA results for Option 4. Compared to Option 3, Option 4 achieves a greater reduction in the cost of unserved demand. This results in a better impact on net consumer welfare relative to current arrangements than Option 3. Compared to option 2, the impact on net consumer welfare can be better or worse depending on the modelling of storage costs.

Table 9 CBA – Option 4

£ million		NPV (real 2011)
Consumer welfare	Retail cost	-3,178.3 / -189.5
	Payments for involuntary DSR services	32.2
	Unserved demand by firm gas customers	529.7
	Unserved demand by firm electricity customers	22.6
	Unserved demand by interruptible customers	-2.0
	Net consumer welfare	**-2,595.8 / 393.0**
Shipper welfare	Retail revenue	3,178.3 / 189.5
	Cash-out liability	-32.2
	Cost of storage	-3,146.1 / -157.3
	Net shipper welfare	**0.0**

Figure 6 shows a graphical summary of the range of values of net consumer welfare for the four options for reform. In each case, the lower and upper bounds of the range of values shown are based on the LRMC and arbitrage profits methods respectively of estimating the cost of the storage obligation or the cost of shippers making provisions against cash-out rising to the value of lost load.

Figure 6 Net consumer welfare summary

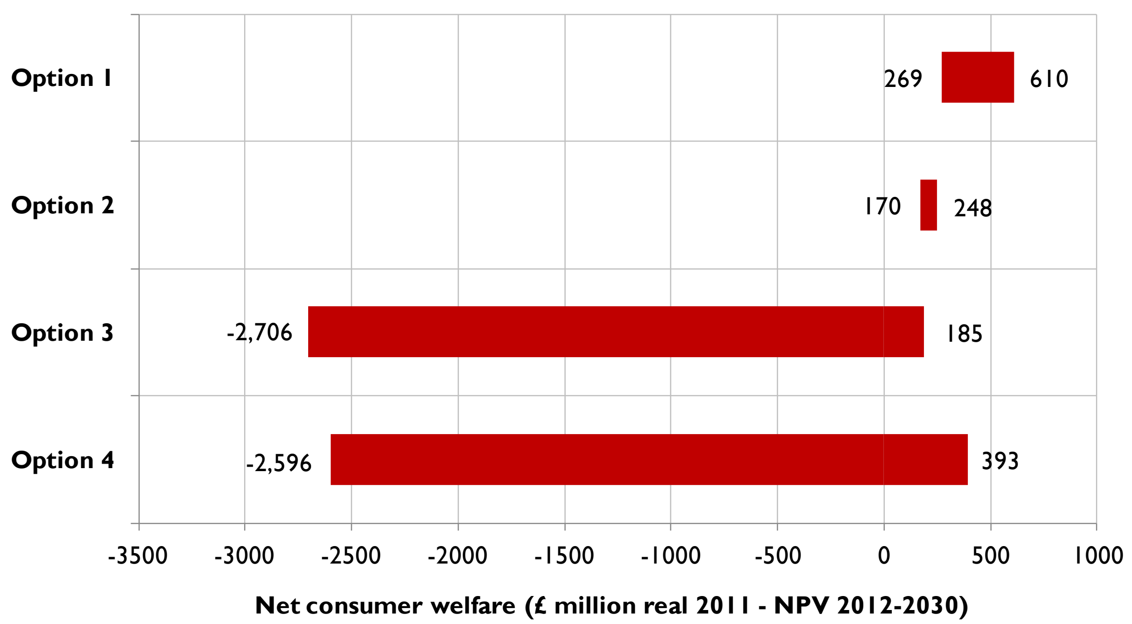
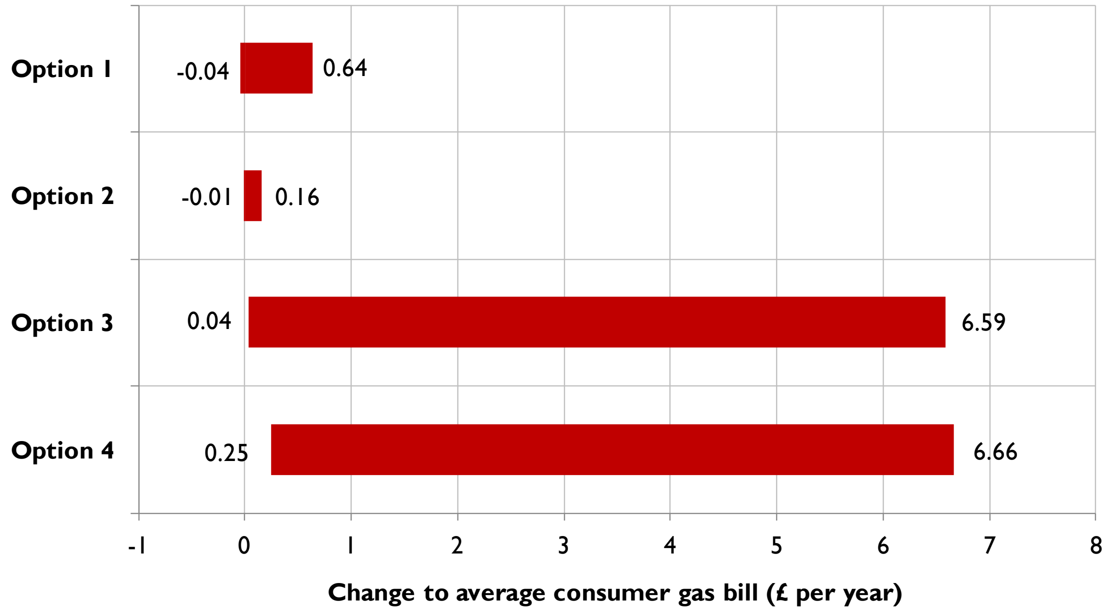


Figure 7 shows the estimated impact of each option on the average annual consumer gas bill. This is calculated based on the assumption that the average annual consumer gas demand is 16.5 MWh and the average total annual NPG gas demand is 57.9 bcm for all the spot years modelled. The figures, shown in real 2011 terms, represent an arithmetic average for the spot years modelled and reflect the Retail cost line of the CBA.

Figure 7 Consumer bills impact summary



In summary, Option 1 leads to the greatest improvement in net consumer welfare relative to the current arrangements. This appears to be a sensible result because Option 1 allows the market to function in an emergency, bringing in more imported supplies when the cost of those supplies is less that the Value of Lost Load avoided due to those supplies. The assumption that the upstream of the gas market is perfectly competitive and allowing the gas price to rise in the event of an emergency does not lead to an increase in the average price paid for gas by consumers drives this result.

Option 2 results in lower net consumer welfare than Option 1 because it imposes a price cap in the event of NDM customer interruptions and does not reflect the full costs of the outage to NDM customers that are interrupted. The mechanism which drives much of the difference in net consumer welfare between the two options is the shipper investment response[26], which can reduce both the probability and the severity of NDM customer interruptions at lower cost than the value of unserved demand prevented. Since Option 2 significantly limits the potential cash-out liability of shippers, it removes the economic rationale for shipper investment in strategic storage.

Option 3 achieves a greater reduction in the cost of unserved demand than Option 1. However, it is not clear whether this benefit justifies the cost of the storage obligation, which is estimated to be between £255m and £3,146m.

Option 4 leads to the greater reduction in unserved demand than any of the other options. The overall welfare benefit depends largely on the cost of storage and ranges between -£2,596m and £393m.

[26] Note that we have assumed a fully rational response by suppliers to the risk of large compensation payouts under Option 1.

7.2.3 Other considerations

The rationale for market interventions does not exist in a world where markets function perfectly unless restricted from doing so by regulatory barriers. However, as argued in Section 4.4, that rationale is more likely to come from the possibility of market failure, the main examples of which could include the failure of market players to form correct expectations of future events or moral hazard by which market players believe that their losses could be socialised to some extent in extreme circumstances.

If market interventions can be rationalised on the grounds of possible market failure, the rules according to which it is implemented and the level of the intervention would have to be considered very carefully. Given the operating rules assumed for the purposes of our analysis, where the storage obligation can only be violated to prevent NDM interruptions, the large difference between the average level of the obligation and the average estimated profit-maximising shipper investment response would suggest that the socially optimal level of any storage obligation is likely to be considerably lower than the level considered in our modelling.

A cap on the cash-out price in an emergency is also difficult to rationalise in a world of perfectly functioning markets characterised by perfect competition and lacking any credit constraints. However, in reality, the gas supply market is not perfect and may not be resilient to extreme events. The purpose of a cap on the cash-out price would be to prevent certain instances of market failure by limiting the exposure of shippers in the event of physical network isolations. Specifically, an appropriate cap on cash-out in case of firm customers being interrupted due to physical network isolations would significantly reduce the possibility of financial distress of shippers in these circumstances, removing the danger of increases in market concentration and the resulting negative consequences for consumers. It would also mitigate the moral hazard problem by capping the potential losses faced by shippers in emergency situations.

The potential exposure of the shipper community to high cash-out prices under Option 1 is very large. From our modelling results, we estimate that the average maximum annual exposure of the shipper community to high cash-out prices is approximately £8bn under Option 1 and £1.2bn under Option 2. The maximum is calculated over 1,500 years simulated for each of the spot years modelled[27] and then an average is taken over the maxima calculated for the four spot years.

The positive features of Option 2 would also come with certain negative consequences. Firstly, under some extreme and unlikely circumstances, the price may not reach a high enough level to reduce the impact of physical network isolations even though allowing it to reach that level would have resulted in an improvement in net social welfare. A potentially more significant effect is that the cap on the cash-out price removes the incentive for shippers to book additional storage as provision to reduce the risk of NDM outages, thus increasing both the probability and the impact of such outages. This is indeed predicted by our model. Furthermore, the cash-out price under options 1 and 2 does not reflect potential externalities and social costs associated with a GDE[28]. This means that Option 2 in combination with some form of market intervention may be a better policy in consumer welfare terms than Option 2 on its own. However, any intervention carries the risk of unintended consequences that could be detrimental to social welfare. This is why careful analysis would need to be undertaken to understand the likely effects, costs and benefits of any further interventions.

[27] Note that total exposure within a given year can be due to more than a single outage event.

[28] Such costs could result from indirect effects on other businesses, lost tax revenue, civil unrest and dampened investor perception of the GB energy market.

8 Sensitivity analysis

8.1 Overview

To determine the importance of certain assumptions in driving the modelling results set out in Section 7, Ofgem asked Redpoint to carry out sensitivity analysis based on alternative sets of assumptions. These sensitivities were as follows:

1. **Energy scenario**: This sensitivity is based on assumptions consistent with the Dash for Energy scenario in Project Discovery. This scenario represents a view of the world in which fossil fuel prices, and particularly those of oil and gas, are persistently very low. This leads to significantly higher demand for gas as well as electricity generated from gas compared to the base case but is not matched by corresponding investment in diversifying gas supply sources.

2. **Infrastructure outages**: Under this sensitivity, the mean duration and probability of occurrence of outages on key gas supply and storage infrastructure are double the level assumed in the base case model. This applies to UKCS supply, NCS supply, IUK, BBL, LNG terminals and storage facilities. This sensitivity tests how the probability and impact of outages on key supply infrastructure feeds through into the probability and impact of gas shortages.

3. **LNG price**: This sensitivity tests the effect of a change in LNG prices on the key model outputs. In particular, here the LNG price is assumed to be driven purely by the price of crude oil, which results in a higher LNG price on average than under the base case.

4. **Demand side response**: This sensitivity tests the impact of interruptible contracts signed by certain tranches of I&C gas demand under Options 1, 2 and 4. In this sensitivity, no new interruptible contracts are signed under these options.

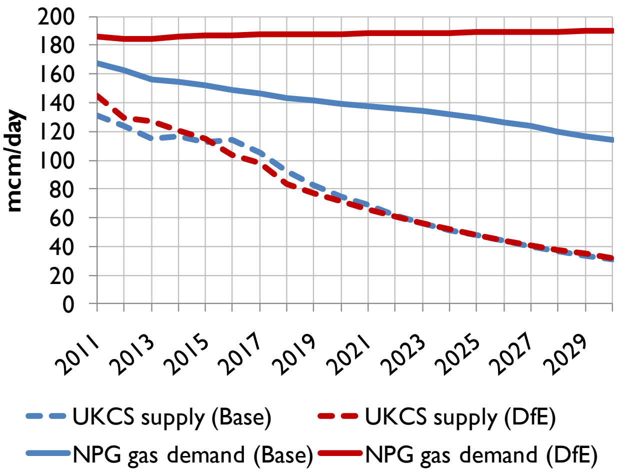
5. **Frozen cash-out**: This sensitivity tries to reflect the possibility of the cash-out price rising in a slow onset of an emergency before being frozen and the possibility of post-emergency claims from shippers. In particular, the cash-out price for the duration of a GDE in this sensitivity is frozen at a level calculated based on an 80% weighting of the price prevailing on the day before the onset of the GDE and a 20% weighting of the price that would prevail under Option 2 on the first day of the GDE.

Note that numerical results for the sensitivities presented in this section and the appendices refer to 2020 only with the exception of the DSR and Frozen cash-out sensitivities, for which the results refer to an average for all of the spot years modelled.

8.2 Energy scenario

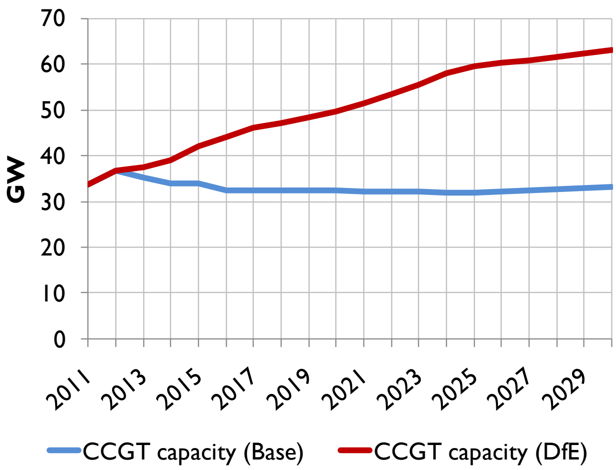
Based on Project Discovery's Dash for Energy scenario, this sensitivity assumes that the prices of fossil fuels are persistently low as compared to the base case. This results in considerably higher gas demand, which remains high until 2030. Higher demand is not matched by a significant increase in the supply of gas. The profile of UKCS output and non-power generation (NPG) gas demand is shown in Figure 8.

Figure 8 NPG demand and UKCS supply



Low gas prices also result in a substantial increase in CCGT generation capacity, driving up the demand for gas. This is shown in Figure 9.

Figure 9 CCGT installed capacity in GB



Running the model using the Energy scenario assumptions under the current arrangements results in a large increase in the probability of outages on all tranches of demand compared to the Base case.

Table 10 shows the effect of allowing the cash-out price to rise in an emergency under Options 1 and 2 when the underlying risk of outages is very high. The change to cash-out arrangements reduces the probability of Firm DM and NDM outages[29]. However, this still leaves a significant probability of outages on all tranches of demand since the outage probability decreases from a very high level.

[29] Based on an arithmetic average for all of the spot years modelled.

Table 10 Probability of at least one outage in a given year

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 1 (81%)	1 in 1 (69%)	1 in 1 (69%)
NDM gas	1 in 9	1 in 22	1 in 16
Firm I&C electricity	1 in 2 (57%)	1 in 2 (59%)	1 in 2 (59%)
Domestic electricity	1 in 3	1 in 3	1 in 3

Table 11 shows that Option 4 is the most effective policy configuration in reducing the probability of all types of outages within the model. This is consistent with the Base case results.

Table 11 Probability of at least one outage in a given year

	Current arrangements	Option 3	Option 4
Firm DM gas	1 in 1 (81%)	1 in 1 (76%)	1 in 2 (56%)
NDM gas	1 in 9	1 in 19	1 in 93
Firm I&C electricity	1 in 2 (57%)	1 in 2 (51%)	1 in 2 (47%)
Domestic electricity	1 in 3	1 in 3	1 in 5

Overall, the Energy sensitivity represents a world in which the annual probability of at least one instance of unserved gas demand due to a shortage of gas is high. Our understanding is that this scenario was originally meant to demonstrate what investment would be required to ensure security of supply in a world of unanticipated high energy demand. Given that under this scenario demand is consistently and significantly higher than its expected level beyond this decade without significant extra investment in supply infrastructure, this may be considered a more extreme scenario.

8.3 Infrastructure outages

This sensitivity represents a test of the way that changes in the probability and duration of some of the underlying shocks that can cause a GDE feed through into the actual probability of a GDE occurring. It concentrates on supply shocks, doubling the mean duration and probability of outages on all supply infrastructure in the model.

Table 12 shows the average probability of outages on different tranches of demand modelled under this sensitivity. While the probability of instances of unserved demand is generally higher than in the Base case, this probability is not doubled when the probability and duration of infrastructure outages are doubled. This highlights the fact that GDEs are often caused by combinations of events in our model and the role of demand spikes that this sensitivity does not address. Note also that the assumption on the average impact of an infrastructure outage is unchanged in this sensitivity.

Table 12 also shows the effect of changing the cash-out price arrangements in an emergency under Options 1 and 2. The change to cash-out arrangements reduces the probability of firm DM and NDM customer interruptions, with Option 1 being more effective at reducing the probability of NDM customer interruptions. The overall effect appears to be similar as under the Base case assumptions.

Table 12 Probability of at least one outage in a given year

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 12	1 in 88	1 in 88
NDM gas	1 in 83	1 in 769	1 in 500
Firm I&C electricity	1 in 36	1 in 125	1 in 125
Domestic electricity	1 in 100	1 in 370	1 in 303

Table 13 shows that Option 4 is the most effective policy configuration in reducing the probability of all types of outages. This is consistent with the Base case results. Both Options 3 and 4 are characterised by no occurrences of NDM customer interruptions in any of the 1,500 simulations runs in each case[30].

Table 13 Probability of at least one outage in a given year

	Current arrangements	Option 3	Option 4
Firm DM gas	1 in 12	1 in 28	1 in 167
NDM gas	1 in 83	Less than 1 in 1500	Less than 1 in 1500
Firm I&C electricity	1 in 36	1 in 167	1 in 250
Domestic electricity	1 in 100	1 in 370	1 in 500

8.4 LNG price

As described in Section 6, the Base case assumption for the LNG price in our model is that it is driven by a mixture of the Henry Hub price and the oil linked JCC price 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 price tends to be much higher when it is linked to the JCC price.

[30] The same is not true of the Base case, which is not based on the same combination of outages as this sensitivity because the parameters of the random number functions used in the two sets of simulations are different.

Figure 10 shows a plot of the total number of interruption days in each simulation against the value of the LNG price variable in each corresponding simulation. Interruption days are summed across all tranches of electricity and gas demand, hence interruption of two tranches of demand in a single day would represent two interruption days. When the LNG price variable is equal to 0, the LNG price is driven entirely by the Henry Hub price. When it is equal to 1, the LNG price is driven entirely by the JCC price.

Figure 10 LNG price and outage days

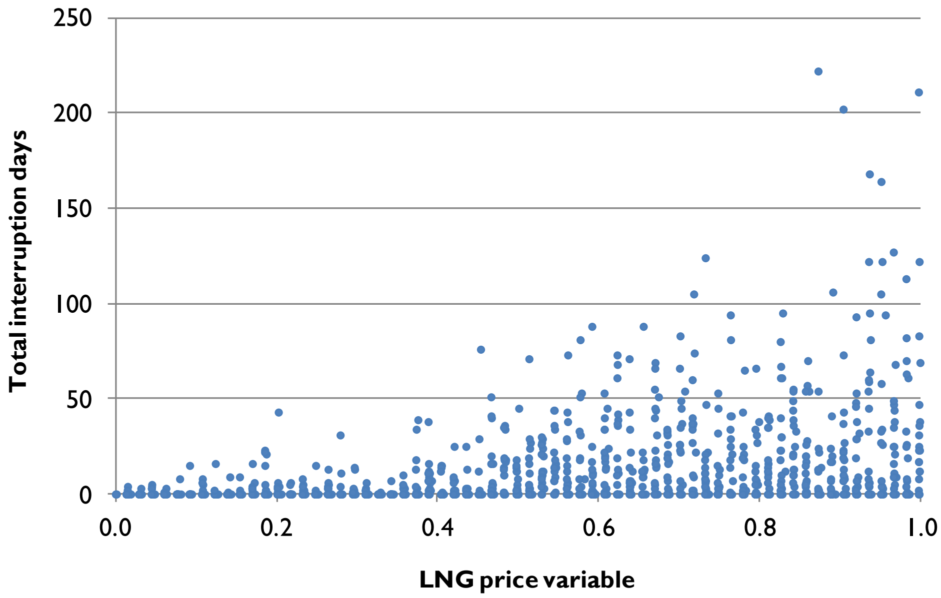


Figure 10[31] demonstrates that the risk to GB security of gas supply is generally higher when LNG price is high and driven by the JCC price[32]. The reason for this is that a low LNG price and thus high LNG imports into GB leave IUK and BBL to respond to shocks by bringing extra supplies into GB when necessary. When the LNG price is very low, GB tends to act as an LNG import hub, exporting surplus gas into the continent via the interconnectors, increasing the potential contribution of the interconnectors in averting a GDE. However, when the LNG price is high and LNG imports into GB are low, the GB system is more vulnerable to negative shocks since BBL and IUK are generally already bringing gas into GB at near full capacity and LNG supplies are not able to respond to a sudden shock quickly enough because of the time it takes to re-route shipments of LNG.

Under this sensitivity, the LNG price is permanently driven by the JCC price. Under this assumption, the probability of outages on all tranches of gas and electricity years is considerably higher than under Base case assumptions. Table 14 shows that the probability of instances of unserved demand for gas and electricity is significantly lower under Options 1 and 2, which is consistent with results under Base case assumptions.

[31] Data is based on simulations under Base case assumptions and current market arrangements for 2012.

[32] The linear correlation coefficient between the two variables plotted in Figure 10 is 0.4.

Table 14 Probability of at least one outage in a given year

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 6	1 in 27	1 in 28
NDM gas	1 in 45	1 in 75	1 in 71
Firm I&C electricity	1 in 19	1 in 38	1 in 40
Domestic electricity	1 in 53	1 in 149	1 in 149

Table 15 shows that Option 4 is the most effective policy configuration in reducing the probability of all types of outages. This is consistent with the Base case results. Both Options 3 and 4 are characterised by no occurrences of NDM customer interruptions in any of the 1,500 simulations runs in each case.

Table 15 Probability of at least one outage in a given year

	Current arrangements	Option 3	Option 4
Firm DM gas	1 in 6	1 in 15	1 in 100
NDM gas	1 in 45	Less than 1 in 1500	Less than 1 in 1500
Firm I&C electricity	1 in 19	1 in 100	1 in 149
Domestic electricity	1 in 53	1 in 250	1 in 500

8.5 Demand side response

Under Base case assumptions, the arrangements in Options 1 and 2 are such that the cash-out price rises to the VoLL of domestic gas customers when firm gas customers are interrupted. This is assumed to prompt tranches 1 and 2 of DM gas demand to sign interruptible contracts with their suppliers. Under this sensitivity, it is assumed that no new interruptible contracts are signed under Options 1 and 2.

Table 16 shows that while the probability of NDM customer interruptions is not affected by the assumption on interruptible contracts, the probability of firm DM customer interruptions is significantly higher in this sensitivity than under Base case assumption.

Table 16 Probability of at least one outage in a given year

	Current arrangements	Option 1	Option 2	Option 4
Firm DM gas	1 in 16	1 in 17	1 in 16	1 in 27
NDM gas	1 in 122	1 in 303	1 in 189	1 in 1000
Firm I&C electricity	1 in 54	1 in 93	1 in 83	1 in 222
Domestic electricity	1 in 154	1 in 238	1 in 286	1 in 1200

The benefit of interruptible contracts is that they reduce the risk of firm demand interruptions by substituting voluntary interruption for involuntary interruption. Under voluntary interruption, demand with the lowest VoLL is generally interrupted first since interruptible contracts assist the process of VoLL discovery. This would bring a net welfare advantage in comparison to a world where demand is interrupted involuntarily and there is no reliable way of making sure that demand with the lowest VoLL is interrupted first.

Another consideration is that under the market arrangements for Options 1 and 2, the cash-out price rises to the VoLL of domestic gas customers when firm gas demand is interrupted. Hence shippers are incentivised to bring in imported supplies priced up to the VoLL of domestic gas customers in order to prevent firm gas customers from being interrupted. When there are no interruptible contracts, many of those firm gas customers will have VoLL which is lower than the VoLL of domestic gas customers. Hence an increase in interruptible contracts would bring the net social welfare benefit of substituting some voluntary interruption for more expensive imported supplies.

8.6 Frozen cash-out

This sensitivity tests the Base case assumption on the way that frozen cash-out works under the current arrangements. Here, when firm gas customers are interrupted, the cash-out price for the duration of a GDE in this sensitivity is frozen at a level calculated based on an 80% weighting of the price prevailing on the day before the onset of the GDE and a 20% weighting of domestic customer VoLL. **Table 17** shows average probabilities of interruptions of different tranches of demand. Broadly, after adjusting for the effect of interruptible contracts under Option 2, these probabilities are similar to those under Option 2 and lower than under the Base case. This demonstrates that the gas price often does not have to rise to a very high level to attract additional supplies of imported gas. It also implies that the way that the current arrangements are implemented can have a significant effect on the course of an emergency. If NGG carries on taking balancing actions in the market for longer and allows the cash-out price to rise to a high level before being frozen, this increases the chances that additional imported supplies can be brought in to help to avert or mitigate the effects of a GDE.

Table 17 Probability of at least one outage in a given year (current arrangements)

Firm DM gas	1 in 16
NDM gas	1 in 188
Firm I&C electricity	1 in 81
Domestic electricity	1 in 252

9 Conclusion

Overall, our analysis suggests that we would expect firm DM interruptions to occur once in 16 years and NDM interruptions to occur once in 122 years under the current arrangements. Our results also show that security of gas supplies is sensitive to the overall level of demand. Base case demand assumptions in our modelling are consistent with National Grid's Gone Green scenario and falling demand beyond 2012. If the actual rate of decline in gas demand is significantly lower than that assumed in our modelling, the probability of a GDE may be higher than we estimate.

An interesting finding from our analysis is that the price of LNG gas relative to gas supplies from Continental Europe can have a significant effect on the probability of a GDE, with lower LNG prices being associated with better security of supply. Our modelling approach on LNG prices has been to assume that their level is uncertain going into each gas year, but within each year, their starting level is highly persistent within a certain band of variation. In reality, LNG prices display a high level of persistence from one year to the next and their near term level can be anticipated with more certainty than in the medium and long term. Given the average price of LNG cargoes being brought into GB around the time of writing, it is unlikely, though far from impossible, that the near term will see high LNG prices. However, in the longer term, LNG prices are less certain.

Several options for reform are considered in this report. Our analysis indicates that allowing the cash-out price of gas to rise to VoLL can reduce both the probability and impact of a GDE. This happens firstly through more imported supplies being brought into GB in the course of an emergency regardless of whether the cash-out price is capped, and secondly through provisions being made by shippers in order to limit their exposure to very high cash-out prices but only if the cash-out price in not capped. Further interventions can also reduce the probability and impact of a GDE. However, the design of those interventions can significantly alter their effect. If those interventions are designed solely to prevent NDM outages, their knock-on effects could be such as to increase the probability of outages on other tranches of firm gas demand.

In net welfare terms, it appears that allowing the cash-out price to rise to VoLL is the option for reform that would be likely to bring about the greatest improvement in social welfare. However, since our modelling assumes perfect markets, it does not account for the possibility of market failure that may occur when prices are allowed to reach extremely high levels, potentially causing financial distress. If some kind of market failure is considered to be a likely outcome when the cash-out price is allowed to rise to VoLL, capping the cash-out price may bring about a better outcome. Capping the cash-out price at a level below that which consumers are theoretically willing to pay may leave some of the costs of a GDE with consumers, who are not best placed to either handle those costs or to make provisions in order to mitigate them. This suggests that investigation of further interventions to enhance security of supply may be worthwhile. However, the impact of further interventions on net social welfare is highly uncertain and depends critically on the design of those interventions. Unsuccessful interventions can have a significant detrimental effect on net social welfare even despite reducing the probability of a GDE.

A Modelling results

A.1 Summary

The results contained in this appendix supplement the results contained in Section 7. They represent averages across all simulations and all spot years modelled. Unserved demand represents the total expected impact of outages in a year. For electricity demand, quantity of unserved electricity demand is converted into gas terms at the efficiency rate of a new existing CCGT plant, which is assumed to be 51%. Cost of unserved demand is calculated on the basis of the VoLL for each tranche of demand as estimated in the LE VoLL study. Average outage size is calculated conditional on an outage on I&C Tranche 1. Average outage size is calculated conditional on an outage on I&C Tranche 1. The cost of unserved demand and the cost of average outage is calculated as an arithmetic average for the spot years modelled.

A.2 Cash-out at value of lost load

Table 18 Unserved demand

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	1.310	0.072	0.085
NDM gas	2.243	0.876	1.573
Firm I&C electricity	0.032	0.017	0.019
Domestic electricity	0.006	0.004	0.003

Table 19 Effect of shipper response on unserved demand

Million therms/year	Current arrangements	Option 1	Option 2	Option 1 (no shipper response)
Firm DM gas	1.310	0.072	0.085	0.085
NDM gas	2.243	0.876	1.573	1.440
Firm I&C electricity	0.032	0.017	0.019	0.019
Domestic electricity	0.006	0.004	0.003	0.003

Table 20 Cost of unserved demand

£m (real 2011)	Current arrangements	Option 1	Option 2
Firm DM gas	7.3	1.2	1.4
NDM gas	44.9	17.5	31.5
Firm I&C electricity	1.9	1.0	1.1
Domestic electricity	0.4	0.3	0.2

Table 21 Average outage size

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	20.4	1.2	1.5
NDM gas	34.8	12.9	27.1
Firm I&C electricity	0.6	0.3	0.4
Domestic electricity	0.1	0.1	0.1

A.3 Further interventions

Table 22 Unserved demand

Million therms/year	Current arrangements	Option 3	Option 4
Firm DM gas	1.310	1.325	0.026
NDM gas	2.243	0.352	0.143
Firm I&C electricity	0.032	0.023	0.005
Domestic electricity	0.006	0.005	0.001

Table 23 Cost of unserved demand

£m (real 2011)	Current arrangements	Option 3	Option 4
Firm DM gas	7.3	6.6	0.4
NDM gas	44.9	7.0	2.9
Firm I&C electricity	1.9	1.4	0.3
Domestic electricity	0.4	0.3	0.0

Table 24 Average outage size

Million therms	Current arrangements	Option 3	Option 4
Firm DM gas	20.4	20.9	0.8
NDM gas	34.8	6.4	5.7
Firm I&C electricity	0.6	0.5	0.2
Domestic electricity	0.1	0.1	0.0

A.4 Other results

Table 25 Cost of an average outage (average for all years modelled)

£m (real 2011)	Current arrangements	Option 1	Option 2	Option 3	Option 4
Firm DM gas	114.2	20.4	24.4	115.6	13.7
NDM gas	696.8	257.3	542.2	128.7	114.5
Firm I&C electricity	35.1	19.3	22.8	30.5	10.6
Domestic electricity	10.5	6.8	5.1	9.1	1.1

B Evaluating the cost of keeping gas in reserve

LRMC: Under this methodology, the cost of keeping gas in reserve is estimated on the basis of the LRMC of physical storage. The capex cost of physical storage capacity is assumed to be £800m/bcm. The real rate of return required on gas storage is assumed to be 12%. One implicit assumption under this methodology is that the owners of physical storage capacity reserved to prevent NDM outages are fully remunerated for their investment and other costs by shippers who book that capacity. Since the total amount of physical capacity in our modelling is the same under all options for reform as under the current arrangements, the other implicit assumption is that the value of storage capacity that is not covered by the reserve does not change when a significant proportion of that capacity is taken up by that reserve.

Lost arbitrage profits: Under this methodology, the cost of keeping gas in reserve is estimated on the basis of the loss of arbitrage profits associated with the obligation. This approach involves estimating changes in storage arbitrage profits on the basis of the weighted average cost of injection into storage and the weighted average withdrawal revenue. The holding cost of gas in store is calculated on the basis of a 12% real required rate of return. It is also assumed that any gas remaining in store at the end of the gas year is sold at the same price as the price at which it is purchased. The implicit assumption here is that is that no new storage capacity is built when a storage obligation is imposed on suppliers.

The LRMC approach may overestimate the cost of keeping gas in reserve because it implicitly assumes that the obligation is met using only new storage capacity. This does not take into account the benefits of improved utilisation of existing storage capacity.

The lost arbitrage profits approach may underestimate the cost of the obligation because no new storage capacity is built in the model under Options 3 and 4 relative to the current arrangements, resulting in an increase in arbitrage profits (i.e. scarcity rent) of the storage capacity that is not used to store gas under the obligation, which offsets the costs of the storage obligation. In reality, an increase in the scarcity value of storage is likely to attract new investment in storage capacity, which would be priced at the LRMC on new capacity and would reduce the scarcity rent to existing storage.

Finally, the variance of the estimates of the cost of keeping gas in reserve obtained by this approach is also likely to be considerably greater than for other items in the CBA since arbitrage profits are estimated over all periods regardless of whether there is any unserved energy in those periods, whereas the other items in the CBA only pertain to periods in which there is unserved energy, which occur relatively infrequently.