Gas security of supply Significant Code Review: Economic modelling for Ofgem's proposed final decision

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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) co-ordinates 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 to and during a GDE. This also implies that shippers do not face sufficient incentives to take appropriate action to prevent a GDE occurring (eg 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 help understand the extent to which the proposals could enhance security of supply, and what the costs and benefits to consumers could be.

Ofgem published a draft decision and draft impact assessment in November 2011. On the basis of the stakeholder feedback received and further analysis, Ofgem asked Redpoint to make a number of modifications to the modelling assumptions, as well as to update other assumptions on the basis of the latest view from National Grid and the market. This document describes the revised approach, assumptions and results of the 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 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 making 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 (ie 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 reduced.

As with Option 1, it is assumed that there will be an incentive for interruptible contracts to be entered into 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 shippers to make additional provisions that would reduce the probability and severity of firm customer interruptions.

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 capture 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 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. However, we note that a Gas Deficit Emergency has never occurred and relevant historic evidence, particularly with respect to supply outages, is often limited.

The methodology centres on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity, and then generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output. Flow responses to these daily variations are modelled without foresight of future variations.

Modelling assumptions are based on National Grid's Gone Green scenario and Ofgem's internal analysis. Assumptions on infrastructure availability take into account historical data where possible but also intend to reflect other risks, eg geopolitical events. Where this was not possible, assumptions were agreed with Ofgem in light of stakeholder feedback on the Draft IA and further analysis.

For the purposes of our analysis, we have assumed that only firm DM customers[1] and firm electricity customers[2] supplied by CCGTs would be interrupted at stage 2[3] of an emergency. If all DM customers and firm electricity customers supplied by CCGTs 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

[1] Note that this excludes CCGTs.

[2] This includes firm I&C, domestic and SME electricity customers.

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

network (representing stage 3 of an emergency). To reflect these assumptions, we refer to firm DM, firm electricity[4] and firm NDM customer interruptions rather than customers affected in stages 2 and 3 of an emergency.

Stakeholder feedback and model revisions

In response to publication of the Draft Impact Assessment and the Redpoint report, a number of stakeholders came forward with questions and feedback on the published findings and in certain cases offered some data to help inform some of the modelling assumptions. The most commonly raised concern was that the assumptions on infrastructure reliability were overly pessimistic and not in line with the limited historic evidence available. Section 7 reviews the key stakeholder responses, answers the key concerns that relate to our modelling and sets out alterations to the modelling assumptions in light of those responses.

In addition, Ofgem asked Redpoint to revise other model assumptions with the latest available information. This includes assumptions on fuel prices, exchange rates, electricity demand and the generation mix, non-power generation demand and annual supply from different sources. Updated assumptions were taken from National Grid's latest Ten Year Statement, updated IEA forecasts, market information and Ofgem's internal analysis.

Finally, the approach to calculating the effect of cash-out reform on the price of gas paid by GB consumers has changed. It is now assumed that any extra gas imported into GB as a result of cash-out reform is paid for at the cash-out price prevailing at the time.

All of these changes are described in Section 7. Key changes to our modelling assumptions on the basis of stakeholder feedback are as follows.

Infrastructure outages – In our revised modelling, the average magnitude and duration of most infrastructure outages are reduced. In deriving the revised assumptions, stakeholder feedback was considered alongside other information and further analysis.

Interconnector supply curves and PSO effect – Revised assumptions do not include a PSO effect (whereby gas availability to GB was reduced due to continental storage rules)[5]. We now model the supply elasticity of both IUK and BBL on the basis of historic data on price differences and flows.

Distillate backup – Distillate backup available to some existing CCGT generators now forms an additional tranche of demand side response for peak electricity demand in the revised version of the model, priced just above the level of peaking plant.

Order of interruptions – CCGTs are interrupted before other firm gas customers in the revised version of our model regardless of the relative VoLLs of gas and electricity customers concerned, in line with likely emergency procedures that National Grid would follow.

NDM minimum interruption size – Minimum constraint on the size of an NDM interruption has been removed in the revised version of the model.

Price calibration – The gas price output by the model has been calibrated to historic data spanning April 2007 to March 2010. Seasonality has also been added to the LNG price in the model and a disconnection

[4] Note that we do not model generation plant outages and hence firm electricity interruptions can only occur in our model due to gas shortages.

[5] This was previously captured in our modelling indirectly through the assumption that the price elasticity of gas imports over IUK is lower at >50% import utilisation than at lower levels of utilisation.

in the relationship between the continental gas price and the oil price is now modelled in periods of low LNG prices.

Results

Table 1 shows the likelihood of firm DM, NDM and firm electricity customer interruptions under the current arrangements and the two reform options. On average, this suggests that firm DM interruptions would occur once in 55 years and NDM interruptions to occur once in 167 years on average under the current arrangements.

Table 1 Average outage probabilities in the Base case[6]

Options	Firm DM interruptions	NDM interruptions	Firm electricity interruptions
Current arrangements (frozen cash-out)	1 in 55	1 in 167	1 in 34
Option 1: Cash-out rises to full VoLL	1 in 128	1 in 167	1 in 74
Option 2: Cash-out rises to capped VoLL	1 in 128	1 in 167	1 in 75

The security of supply results for Options 1 and 2 are not significantly different. This is due to the fact that shipper investment response in the form of building additional short-range storage capacity is estimated to be unprofitable in both cases in our modelling for a risk-neutral shipper[7]. Also, any supply that is not available in the short run at £20/th is unlikely to be available at £280/th.

Options 1 and 2 are effective at reducing the probability of firm DM and electricity customer interruption. For firm DM gas customers, the bulk of the effect is accounted for by the fact that a significant number of customers are assumed to sign commercially interruptible contracts with their suppliers and are then interrupted before firm DM customers. This has the benefit of enhancing security of supply of firm customers who might be unable or unwilling to sign such contracts. Options 1 and 2 are not effective at reducing the probability of NDM interruptions in the Base case, but they do reduce their impact, as can be seen in Table 2[8]. Further sensitivity analysis suggests that cash-out reform can reduce the probability of NDM interruptions when risks to security of supply are greater.

[6] Based on arithmetic average of probabilities of at least one event in a simulated year for spot years modelled (2012, 2016, 2020 and 2030).

[7] For the purposes of our modelling, we assume that building additional short-range storage is the only response to the increase in potential cash-out exposure as a result of cash-out reform that is available to shippers. This was shown to be profitable for a limited amount of short-range storage capacity in the modelling done for the draft impact assessment but is not profitable in our revised modelling since the probability of firm demand interruptions and hence total cash-out exposure are lower in our revised modelling results.

[8] Total amount of energy unserved shows the total impact of interruptions on customers. It incorporates information on both the probability of interruptions and the average impact of interruptions when they occur and is hence a useful measure of security of supply.

Table 2 Unserved demand in the Base case (Million therms per year)

Options	Firm DM gas	NDM gas	Firm electricity[9]
Current arrangements (frozen cash-out)	0.254	0.722	0.101
Option 1: Cash-out rises to full VoLL	0.026	0.642	0.030
Option 2: Cash-out rises to capped VoLL	0.026	0.618	0.030

Option 2 leads to the greatest improvement in net consumer welfare relative to the current arrangements. We estimate this to be £65.1m in NPV terms for Option 2 compared to £41.0m for Option 1. The difference between them is a direct consequence of our assumption that any extra gas brought into GB as a result of cash-out reform is paid for at the level of the cash-out price prevailing at the time (for modelling purposes this is £280/therm under option 1 and £20/therm under option 2 in case of NDM interruptions). Under both options for reform, a large part of the improvement in social welfare is a result of the assumption that cash-out reform incentivises an increase in interruptible contracts. Such contracts enhance social welfare by ensuring that demand with the lowest VoLL is interrupted first and thus enhancing security of supply of firm customers.

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. This can happen through more imported supplies being brought into GB in the course of an emergency or through provisions being made by shippers in order to limit their potential exposure. While provisions in the form of new SRS investment are estimated to be uneconomic on the basis of our modelling, the result may be different under a different set of circumstances. Also, other provisions, including changes in the way that gas in existing storage is managed, diversification of supplies, the use of long-term supply contracts and contracting for DSR, may prove to be welfare-enhancing for shippers facing potentially high cash-out prices.

Overall, our results indicate that allowing the cash-out price to rise to capped VoLL is the option for reform that would be likely to bring about the greatest improvement in social welfare. Under both options for cash-out reform, a large part of the improvement in social welfare seen in our modelling is a result of the assumption that the primary response of market participants to cash-out reform incentivises a significant increase in interruptible contracts. Such contracts enhance social welfare by ensuring that demand with the lowest VoLL is interrupted first. However, as noted above, there are many alternative measures that reduce the exposure of shippers to high cash-out prices and improve security of supply, including the holding of storage capacity and contractual provisions, among others. Should participant responses to heightened cash-out incentives not materialise to the extent assumed in our modelling with respect to interruptible contracts, the benefits of cash-out reform seen in our modelling would be reduced.

Capping the cash-out price reduces the possibility of unintended consequences that may occur when prices are allowed to reach uncapped VoLL, including traded market illiquidity due to credit concerns, and the risk of financial distress. However, capping the cash-out price may also leave some of the costs of a demand interruption with consumers, who might not be better placed to either handle those costs or to make provisions in order to mitigate them.

[9] Electricity demand converted into gas terms using theoretical CCGT efficiency of 51%.

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 Uniform Network Code (UNC) issues and play a lead role in facilitating code modifications. In its initial consultation[10], 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 firm 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 were designed to address concerns expressed in Project Discovery[11] 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. 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 costs to consumers would be.

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

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

Ofgem published a draft decision and draft impact assessment in November 2011. On the basis of the stakeholder feedback received and further analysis, Ofgem asked Redpoint to make a number of modifications to the modelling assumptions, as well as to update other assumptions on the basis of the latest view from National Grid and the market. All of these changes are described fully in Section 7. This document describes the revised 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 on each gas day. National Grid Gas (NGG) takes 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 3.

Table 3 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 other firm 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.

Table 4 Stages of an emergency after implementation of Exit Reform

Stage	Description
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. 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 firm gas customers are interrupted. When NDM customers are interrupted, the minimum duration of the interruption is assumed to be 14 days. This is to reflect 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.

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. Such actions include investing in storage and negotiating interruptible contracts with customers. The benefits of these measures to shippers are currently limited by the fact that they do not face the full consequences of being unable to supply the full gas demand of their customers in a GDE. 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.

Setting cash-out prices is not straightforward at this stage as outages may last for several weeks or months. For this reason, if cash-out is to reflect the full expected costs of the interruption to individual customers, it should rise to a multiple of domestic VoLL. For the purposes of modelling the impact of option 1, 14 days was chosen to represent the time that it would take to reconnect firm customers. For the purposes of our modelling, this equates to a cash-out price of £280 per therm when NDM customers are interrupted.

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[12] enter into interruptible contracts in response to Option 1[13].

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[14] and contractual provisions, amongst others. For the purposes of our quantitative estimates, we assume that investment response by shippers involves booking new 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 building that 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. Our analysis suggests that risk neutral shippers would not respond through additional investments in SRS under Option 1.

[12] See Demand side response and firm demand interruption paragraph of Section 6 for details of different demand tranches in our model.

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

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

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 given that shippers cannot influence the restoration process once parts of the network are physically isolated.

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 DM 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. Capping the cash-out price at the VoLL of domestic customers 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.

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 capture the market response to those shocks is clearly a very challenging task. We also note the difficulty of modelling low probability and potentially high impact events. This is particularly the case with respect to the calibration of supply outage assumptions, where relevant historic evidence is very limited.

Our aim was to build a model that is fit for purpose given the need to assess the risk to GB gas security of supply under the current arrangements and the effect of changes in those arrangements. 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 on stochastic modelling of the gas market using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. The model contains a full representation of the gas supply infrastructure and demand segments, together with a representation of the electricity sector. The model constructs an annual supply profile for a given demand curve at monthly granularity and generates day-by-day simulations incorporating stochastic variations in demand (gas and electricity), gas supply availability and wind output.

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

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

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

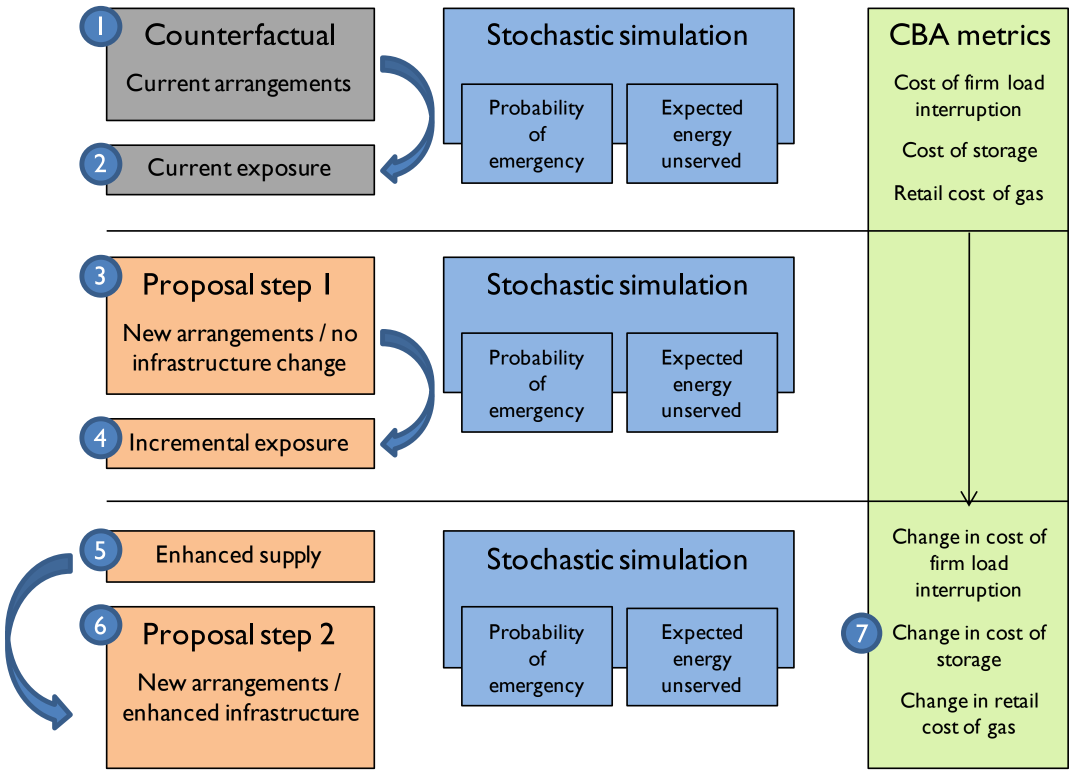
The seasonal pattern of UK Continental Shelf (UKCS) gas flows is estimated from historic data provided by National Grid using monthly dummy variables in a linear regression. Stochastic deviations from the expected seasonal mean production level are drawn from a distribution fitted to the residuals of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

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

Infrastructure outage probabilities are modelled using the Poisson distribution. Outage magnitude and duration are modelled using the lognormal distribution. Assumptions for distribution parameters were agreed jointly by Redpoint and Ofgem after accounting for stakeholder responses to the Draft Impact Assessment. In many cases, given the associated low probabilities, there is no historic dataset that can be used to derive the parameters[15].

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.



[15] 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.[16]

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.

The stochastic model is run for spot years 2012, 2016, 2020 and 2030 for the Base case. 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 20% for LRS and 50% for SRS in every simulation.

[16] We note that this is a simplified assumption which has its own limitations. First, 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. Second, 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

Overview

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 Ofgem's internal analysis and NG's Gone Green scenario under which the UK meets its decarbonisation and renewable energy targets.

This section sets out a summary of our modelling assumptions. Any changes to the modelling assumptions compared to the modelling done for the Draft Impact Assessment are specifically described in Section 7.

Commodity prices

Our commodity price assumptions rely on prices quoted in forward markets dating from April 2012 for the period up to 2015. For the period after 2015, our assumptions are based on the International Energy Agency's 2011 World Energy Outlook published in Nov 2011. For Henry Hub prices, our assumptions are based on prices quoted in forward markets dating from 25 April 2012 for the period up to 2020. After 2020, 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.

Assumptions on the average annual level of the carbon price are taken from forward markets in 2012 (as of 20/06/11), then utilise DECC's short term traded carbon values for UK public policy appraisal values to 2030[17].

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 26 April 2012 and are assumed to remain constant in real terms thereafter. The assumed £/$ exchange rate is 1.62 and the assumed £/€ exchange rate is 1.22.

Gas supply

Average daily flow in UKCS gas on an annual basis is based on data for Figure 3.3A in the National Grid Ten Year Statement (TYS2011)[18] in the Gone Green scenario[19].

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

[17] http://www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-valuation/3137-update-short-term-traded-carbon-values-uk.pdf

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

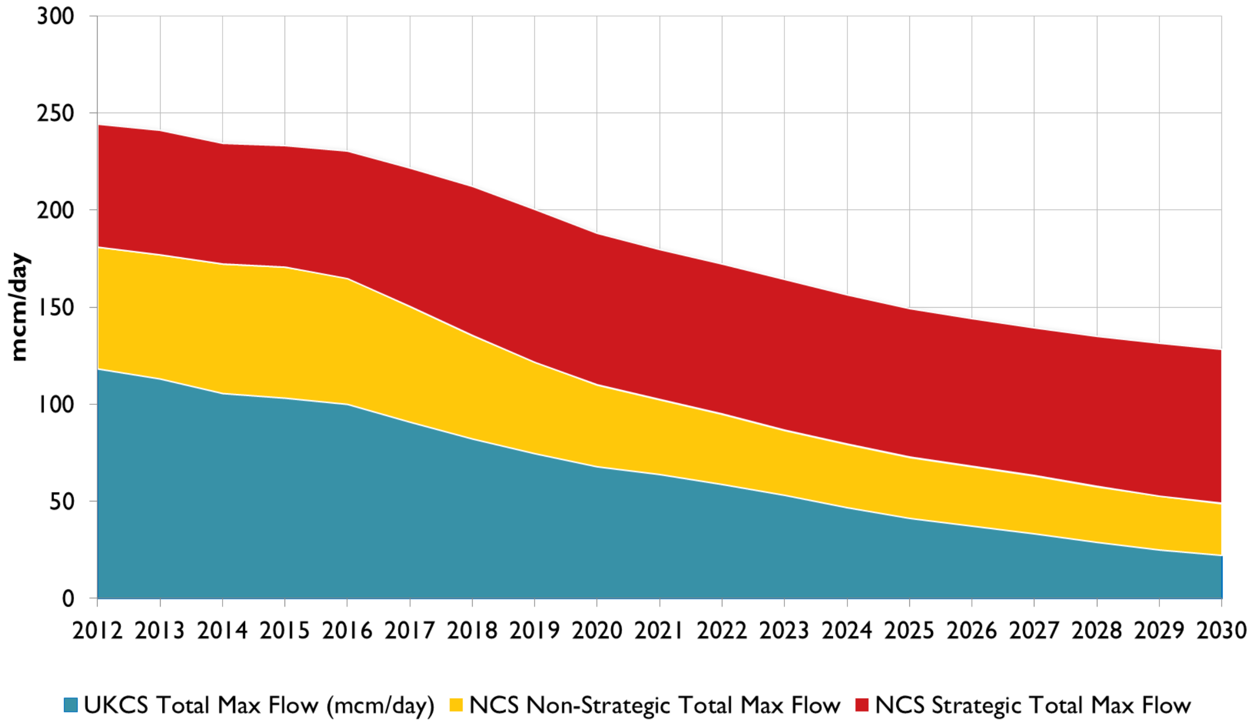
[19] Note that this does not include any projections on shale gas development in the UK, which would represent an upside risk to the projections of UKCS output.

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 IUK imports.

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

The maximum daily flow from UKCS and the strategic and non-strategic parts of NCS is shown in Figure 1.

Figure 1 Maximum daily flow from UKCS and NCS



Variability in gas supply and outages

Variability in UKCS and NCS supply is calibrated to historic data spanning ten years, as described in Section 5. 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[20];
- Mean and standard deviation of outage duration based on a lognormal distribution[21]; 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[22].

[20] This is a standard distribution for modelling binary outcomes such as outages.

[21] The lognormal distribution has a long right tail and is therefore naturally suited to modelling low probability high impact events.

It is assumed that outages are twice as likely to happen in the coldest 6 months of the year than in the warmest 6 months. This assumption applies to all sudden shocks in our modelling. Outages on different supply sources are assumed to be independent of each other. Detailed assumptions on supply outages are given in Table 5 below.

Table 5 Infrastructure outage parameters[23][24]

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

Storage outages are modelled as a multiplicative shock[25] to the maximum rate of injection and withdrawal for long and short range storage separately. Since several SRS facilities are modelled as a single block, the average impact of an outage reflects the proportion of overall SRS capacity that the average SRS facility represents. This is also the case for parameters that relate to LNG supply outages. The average impact of an outage reflects the proportion of overall LNG import capacity that the average LNG terminal represents.

For LRS in particular, we note that the Rough storage facility was completely unavailable for several months[26] in 2006 as a result of a fire, but this is the only major outage incident on that facility that we are aware of. We also note that one data point is not sufficient to define a probability distribution. Although the average outage probability for LRS in our assumptions is higher than what has been observed historically, the corresponding mean magnitude and duration are significantly lower. This is because our

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

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

[24] The average frequency of outages in winter is effectively the same as the average annual frequency of outages for the purposes of estimating the impact of firm demand interruptions since we do not observe any firm demand interruptions in the warmest 6 months of the year in our modelling results.

[25] 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.

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

assumptions represent all potential events that can affect the ability of LRS to inject gas into storage or deliver gas into the GB gas network, including problems with the gas field, rig, pipeline infrastructure (on-shore and off-shore) and problems at the Easington terminal, including all associated equipment.

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

From 2016, BBL is assumed to acquire reverse flow capability and is assumed to trade in the same way as IUK. We merge BBL capacity into IUK capacity in our model from this date and adjust IUK interruption parameters accordingly, with higher probability of outages and lower average impact of outages to reflect the fact that the combined entity represents two separate interconnectors.

Continental price shocks

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

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

Gas quality issues

Gas quality issues are assumed to impact flows over 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 in place at the moment. Although Fluxys[27] have put forward a proposal for such a treatment facility, it is not certain at this stage that construction of this facility will go ahead.

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

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

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

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

Storage

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

Detailed storage parameters used to inform our modelling are given in Table 6. These were taken from Ofgem's Pivotality model[28].

Table 6 Model storage parameters

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

Interconnectors

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

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

The annual maximum flow on the Balgzand Bacton Line (BBL) is 20 bcm on a capacity basis. No 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. From that point we assume that BBL will behave in the same way as IUK.

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

LNG

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

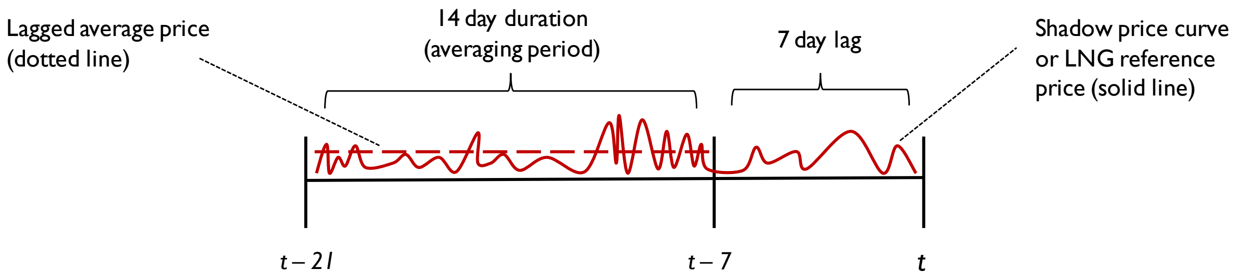
[28] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=181&refer=Markets/WhlMkts/CompandEff

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

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

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

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



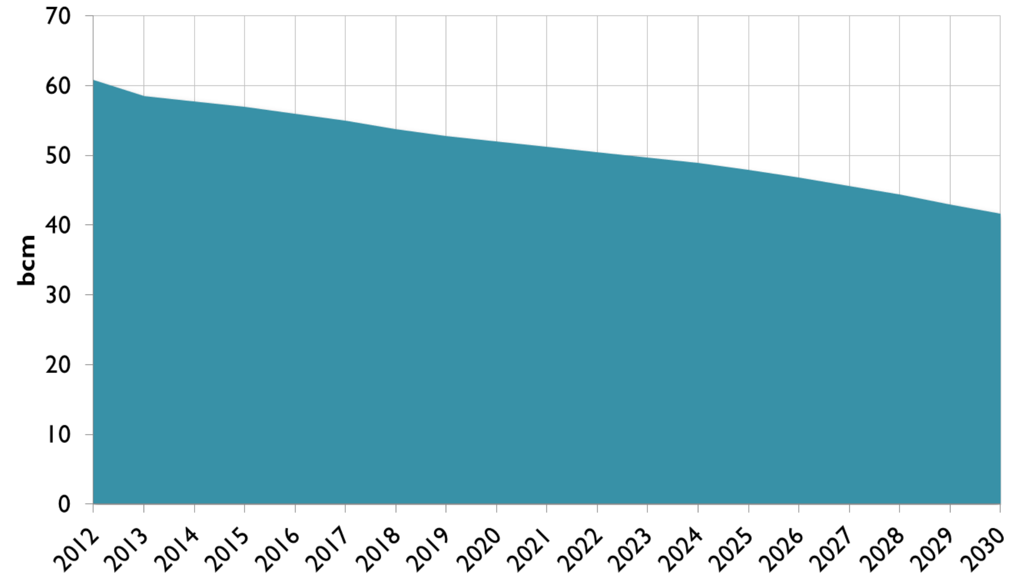
The amount of LNG gas available to flow into GB at time *t* is determined by the difference between the 14 day average system gas price, lagged by 7 days, and the LNG reference price, determined by a mixture of the Henry Hub price and the JCC price depending on the scenario and year modelled. The greater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

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

Gas demand

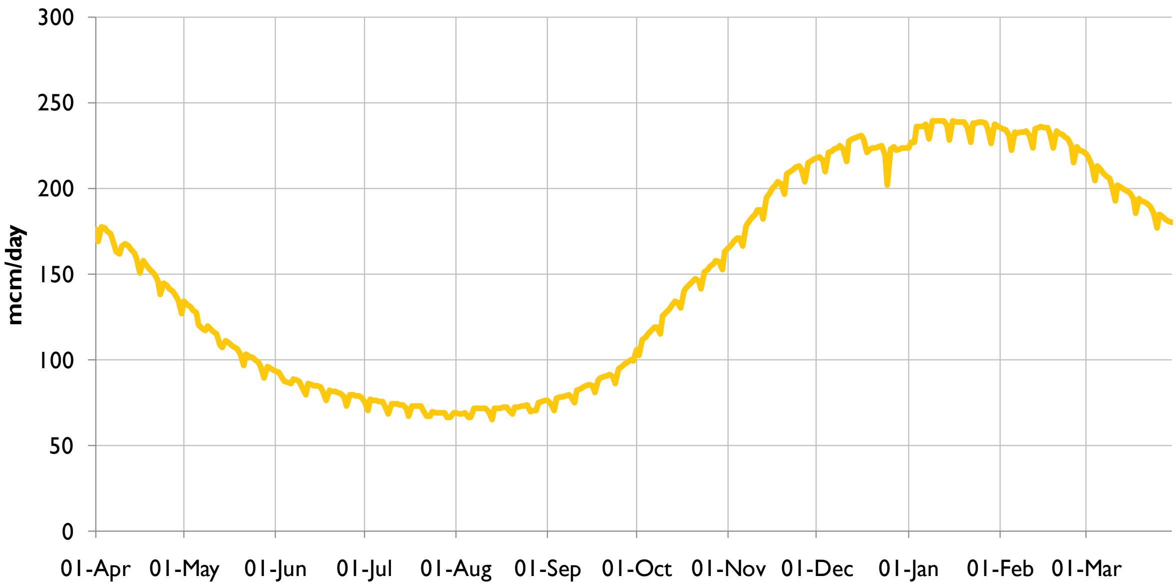
Total National Transmission System (NTS) non-power generation (NPG) gas demand is taken from the 2011 Gone Green scenario provided to us by National Grid. This includes net exports to Ireland. Total annual NTS NPG gas demand by year is given in Figure 2.

Figure 2 Total annual NTS NPG gas demand



The seasonal normal shape of demand based on 2011 annual demand is shown in Figure 3.

Figure 3 Expected demand shape



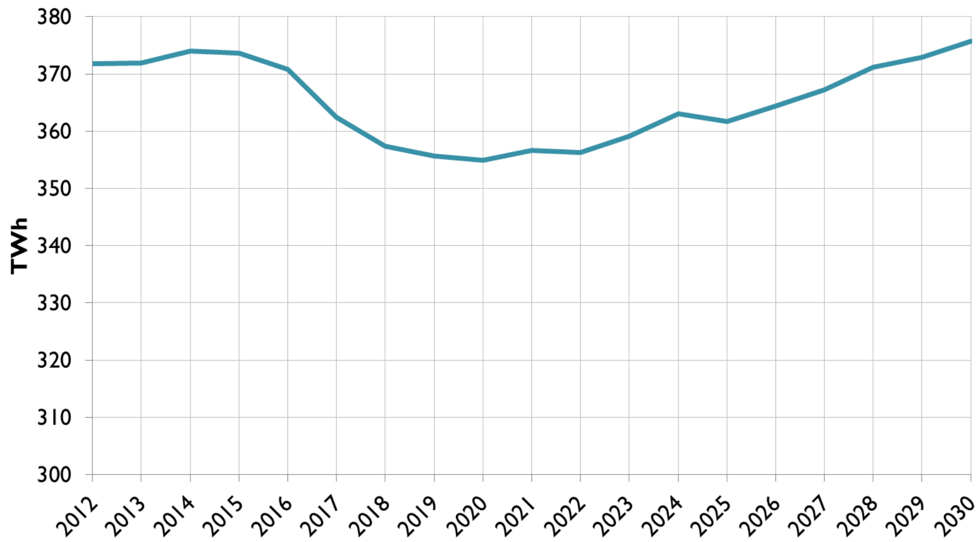
Electricity demand

Total annual demand for electricity is taken from Ofgem's November 2011 internal analysis. It is plotted in Figure 4 below. Overall demand for 2010 is taken from National Grid's 2010 Ten Year Statement.

Demand is then assumed to grow in line with economic output as well as increasing electrification of heat and transport. Energy efficiency polices are also taken into account.

Short term economic output forecasts are based on HM Treasury's comparisons of independent forecast document[29], with trend growth taken from the March 2011 OBR Economic and Fiscal Outlook[30] (energy intensity of growth is taken from Ofgem's Project Discovery). Assumptions on electrification of heat and transport are taken from Redpoint analysis based on pathway 3 of DECC's pathways analysis[31]. Energy efficiency forecasts are taken from Ofgem analysis of pathway 3 of DECC's pathways analysis.

Figure 4 Total annual electricity demand



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

Electricity generation

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

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

- Carbon Capture and Storage (CCS) coal is incorporated into high efficiency coal;

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

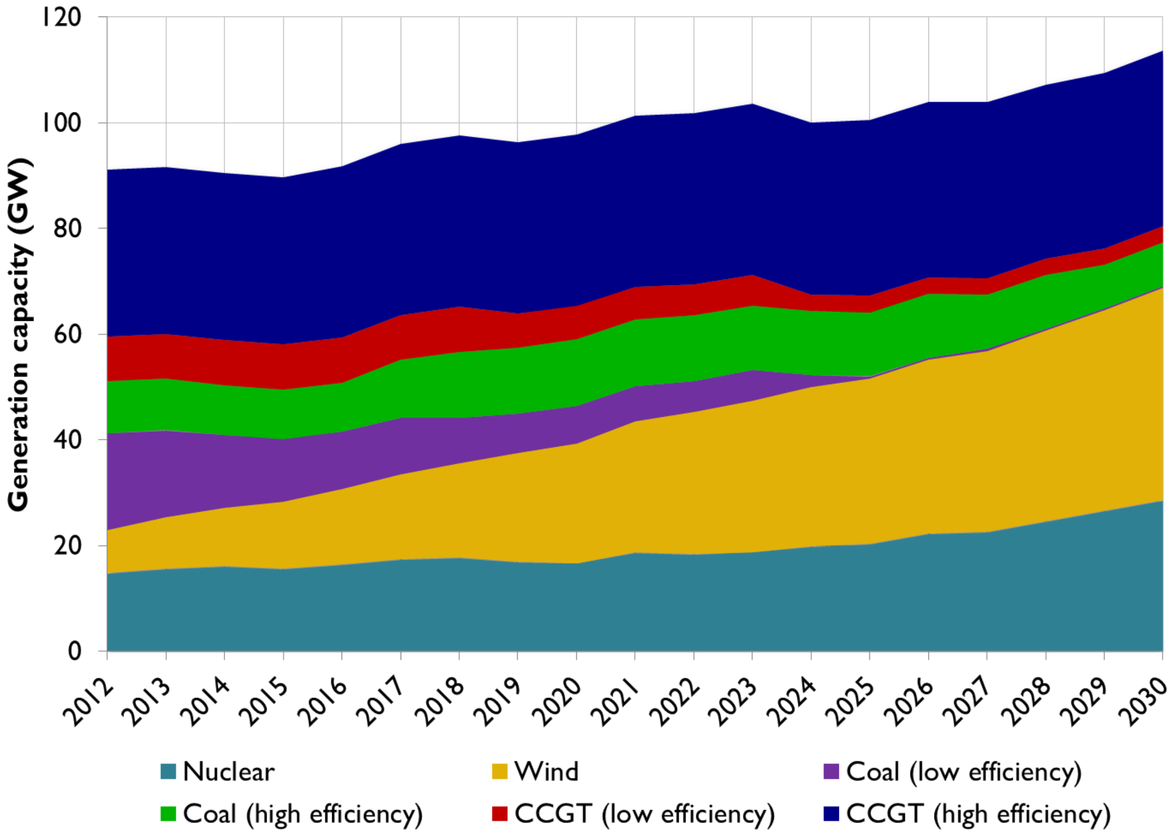
[30] Available online: http://budgetresponsibility.independent.gov.uk/economic-and-fiscal-outlook-march-2011/

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

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

Table 7 shows the generation capacity mix as represented in our model.

Table 7 Model generation capacity mix



LCPD/IED[32] plant in the model are assumed to be constrained with respect to their total annual output. The instantaneous flexibility of these plant is modelled as a tranche of DSR priced above the peaking plant tranche. Hence in the course of unusually high electricity demand or, more likely, shortage of generation from CCGTs, LCPD/IED plant are allowed to operate up to their expected technical availability. Under these circumstances, interconnectors are also assumed to be importing power into GB up to their full capacity.

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

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

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 and firm demand 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 demand used in the model, in increasing order of VoLL, are as follows:

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

The three tranches of Firm DM demand are derived by amalgamating several categories from the London Economics (LE) VoLL study[33] 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.

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

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

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

1. Interruptible I&Cs (£150/MWh VoLL – 53 GWh/week day)
2. Firm I&Cs (£4,000/MWh VoLL – 240 GWh/week day)
3. Domestic & SME (£5,000/MWh VoLL – 1,235 GWh/week day)

The corresponding VoLLs for each of these tranches are likewise taken from the Project Discovery[34][35].

When gas supply is scarce, the model will seek out all opportunities for commercial self-interruption and fuel switching away from gas generation before interrupting firm gas demand. As a general rule, firm electricity demand supplied by CCGT generation is interrupted before any firm gas demand regardless of the relative VoLLs of electricity and gas customers. This is in line with NGG's likely emergency

[33] 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.

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

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

procedures. Apart from this rule, different tranches of demand are interrupted in the order of increasing VoLL. Any NDM demand that is interrupted remains off for the subsequent 14 days.

Current arrangements

Under the current arrangements, all gas supply is assumed to be firm. When all opportunities for fuel switching and commercial self-interruption have been exhausted, the model interrupts CCGTs before interrupting any firm gas demand. It then interrupts different tranches of firm gas demand in the order of their associated VoLLs, starting with the lowest VoLL tranche. Hence, in case of a deficit of gas to supply total demand, the general order of events is as follows.

Voluntary interruption and fuel switching

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

Involuntary interruption

5. Interruption of CCGTs with corresponding interruption of Firm I&C electricity customers[36]
6. Interruption of CCGTs with corresponding interruption of Domestic & SME electricity
7. Interruption of Firm DM tranche 1 gas
8. Interruption of Firm DM tranche 2 gas
9. Interruption of Firm DM tranche 3 gas
10. Interruption of Non-Daily Metered (NDM) gas

The cash-out price is frozen when involuntary interruptions commence.

Cash-out reform

In the dynamic cash-out price scenarios, tranches 1 and 2 of DM gas demand are assumed to become interruptible. This is assumed to be prompted by the fact that the cash-out price would rise to £20/th when firm gas demand interrupted, hence shippers have a strong incentive to sign interruptible contracts with customers at a price which is lower than £20/th. It is assumed that, under the terms of the interruptible contracts, interruption takes place when the market price of gas exceeds the interruption price.

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

[36] Note the implicit assumption that some CCGT generation is required to satisfy firm electricity demand. In some cases, generation from other sources, including LCPD/IED plant and CCGTs running on distillate, is sufficient to satisfy firm electricity demand. Here, firm DM gas would be interrupted if total gas supply is still insufficient to satisfy total gas demand after all possible voluntary interruption and fuel switching has taken place.

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

Voluntary interruption and fuel switching

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

Involuntary interruption

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

7 Stakeholder feedback and model revisions

Overview

In response to publication of the Draft Impact Assessment and the Redpoint report, a number of stakeholders came forward with questions and feedback on the published findings and in certain cases offered some data to help inform some of the modelling assumptions. This section reviews the key stakeholder responses, answers the key concerns that relate to our modelling and sets out alterations to the modelling assumptions in light of those responses, as well as any other changes to our modelling since the publication of the Draft Impact Assessment.

Assumptions on infrastructure outages

Concerns were raised in the consultation responses that the assumptions on infrastructure outages were overly pessimistic and not in line with the historic evidence available. Firstly, it is important to note that historic data on many of the events modelled is very limited. Secondly, it is also important to note that outages to supply sources in the model represent both the physical outages to the infrastructure in question and problems further upstream which affect the ability of the piece of infrastructure in question to supply gas to GB. For example, outages at LNG terminals in the model are intended to capture both technical failure at a terminal, as well as disruptions (such as those due to weather or geopolitical events) to the LNG supply chain.

While gas import capacity has increased dramatically in recent years, particularly with respect to LNG, it could be argued that supply sources into GB are becoming more concentrated. For example, the network of pipelines in the North Sea and the large number of fields and facilities gave GB diversity of supply channels from UKCS. However, supplies into GB are increasingly channelled through a small number of very large pipelines or terminals.

For the purposes of reviewing our modelling assumptions, stakeholder feedback was considered jointly with potential problems in the upstream part of the gas supply sector. Each set of assumptions is dealt with in turn below.

Interconnector outages

Previously it was assumed that outages on BBL and IUK will occur with an average annual frequency of 0.37 and that outages are twice as likely to occur in the coldest 6 months of the year as they are in the warmest 6 months. It was further assumed that they have a mean duration of 10 days with a standard deviation of two days. Information submitted by one of the stakeholders on unplanned outages was as follows.

Table 8 BBL outages

BBL	Hours of unplanned outage	Number of outages
2009	2	1
2010	3	1
2011	0	0

Table 9 IUK outages

IUK	Hours of unplanned outage	Number of outages
2005	10	5
2006	3	3
2007	0	0
2008	0	0
2009	0	0
2010	0	0
2011	0	0

It must also be noted that the information provided by stakeholders only covers a part of the operating life of the two interconnectors and hence omits some important pieces of information. For instance, in 2002, liquids were found in the IUK pipeline, necessitating a shutdown of some two weeks to dry out the line. Taking all this information into account, while the probability of outages previously assumed in the model is not significantly out of line with the information provided, the average duration of outages assumed is higher than the average duration observed historically.

The revised assumptions, given in Section 6, reflect the information given above. Since the daily granularity of the model does not allow for outages shorter than one day to be modelled, a closer match to historic data is achieved through a combination of assumptions on the duration and magnitude of outages. For mean outage duration, we use a high standard deviation value to reflect the high degree of uncertainty about the potential value of this parameter. Given the properties of the lognormal distribution used to model the duration of outages, this means that a large proportion of the variation would come from infrequent but large observations. This is consistent with the historic evidence quoted above and takes into account further analysis conducted to assess the risks associated with imports through interconnectors.

LNG terminal outages

One stakeholder has responded with the claim that in a recent 3 year period for which they had data for the Grain LNG terminal, the terminal had one unplanned outage lasting one day. Assuming that this is representative of all of the terminals and over a longer time period, the previous assumption of average outage frequency of once in every 3 years (approximately) is actually optimistic given that LNG is modelled as a single block. However, the previous assumption that the average outage duration is 10 days is pessimistic.

The revised assumptions, given in Section 6, reflect stakeholder feedback on LNG terminal reliability and take into account further analysis conducted to assess the risks associated with LNG imports. We note, however, that outages to LNG terminals in the model represent both physical outages and potential problems further up in the LNG supply chain.

Assumptions on continental price shocks

On continental price shocks, one response states that such shocks are rare (more so than assumed in the modelling for the Draft Impact Assessment). Such shocks were previously assumed to occur once in every two years, and were twice as likely to happen during the winter as during the summer. The mode of the increase in the continental price implied by the distributional parameters, or in other words the value that is most likely to be observed, is around 35%.

In light of the feedback to the Draft Impact assessment and further analysis, we have revised the parameters to reduce the frequency of continental price shocks. The revised parameters are given in Section 6.

Assumptions on gas quality shocks

On gas quality shocks, one of the stakeholders stated in their response that such shocks have never occurred in the past measures are planned to be put in place to prevent such shock in the future. In light of this information, the assumption that such shocks occur once in every two years and are twice as likely to happen during the winter than during the summer appears pessimistic. On the other hand, there is evidence that the quality of Norwegian gas is getting further away from UK specification over time.

In reality, much will depend on whether further measures are put in place to deal with potential gas quality issues, which is subject to some uncertainty. In light of the feedback to the Draft Impact assessment and further analysis, we have revised the parameters to significantly reduce the frequency of gas quality shocks. These parameters are given in Section 6.

Modelling of PSOs in Continental Europe

The effect of PSOs in Continental Europe was previously modelled as a significant reduction in the elasticity of the IUK import supply curve when imports exceed 50% of IUK capacity. This effect interacted with price shocks on the continent. This approach did not create a physical shortage of gas in GB due to PSOs in Continental Europe but rather raised the price at which gas can be imported from the continent. An issue with this approach was that it affected the propensity of IUK to import gas into GB at times when there was no continental price shock.

We note that since the focus of the model was on physical demand interruptions and periods of stress rather than periods of normal market operation, the previous modelling assumptions were designed to reflect expected market operation in periods of system stress. However, since it is unclear how PSOs in European countries could affect the availability of gas to the GB market should supplies of gas in parts of Europe become tight. Following further analysis, we have decided not to include a PSO effect in our revised analysis.

Interconnector supply curves

Some consultation responses have questioned the low supply elasticity attributed to Interconnector UK (IUK) in the modelling and submitted evidence of the historic relationship between the NBP/Zeebrugge price differential and IUK flows. We note that the IUK supply curve was previously intended to reflect a price differential more broadly reflecting continental contract pricing, rather than the traded prices at Zeebrugge, and that it also included an estimate of the effect of PSOs in Continental Europe. Overall it was designed to reflect the likely flow dynamics in periods of system stress, not the relationship between traded day-ahead prices between the two trading points.

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

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

Figure 5 IUK utilisation

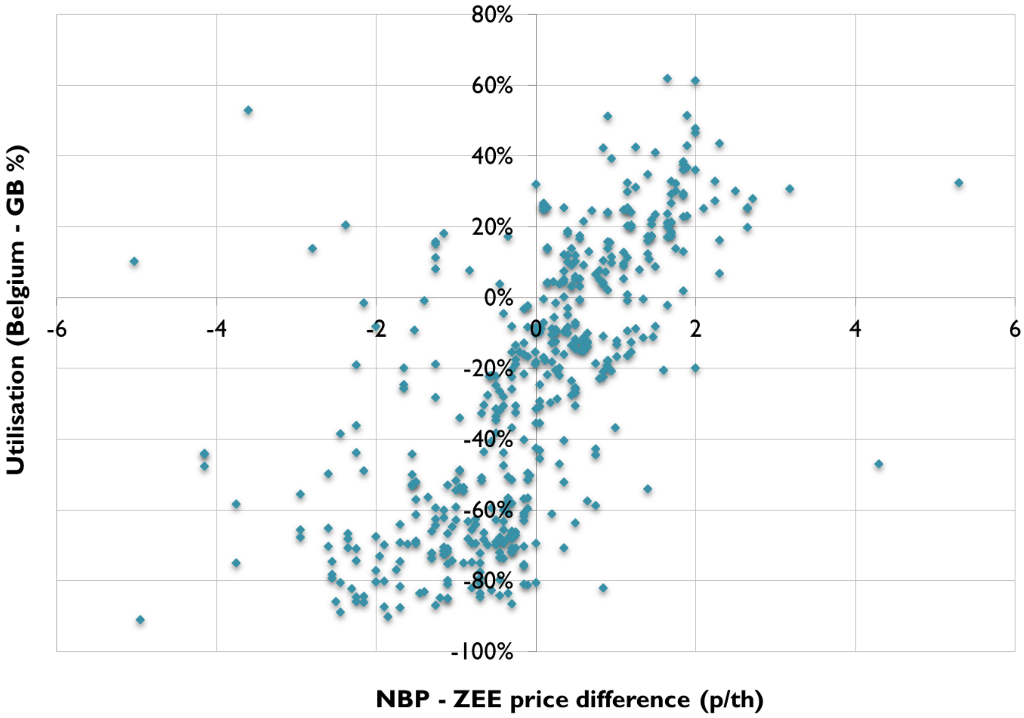
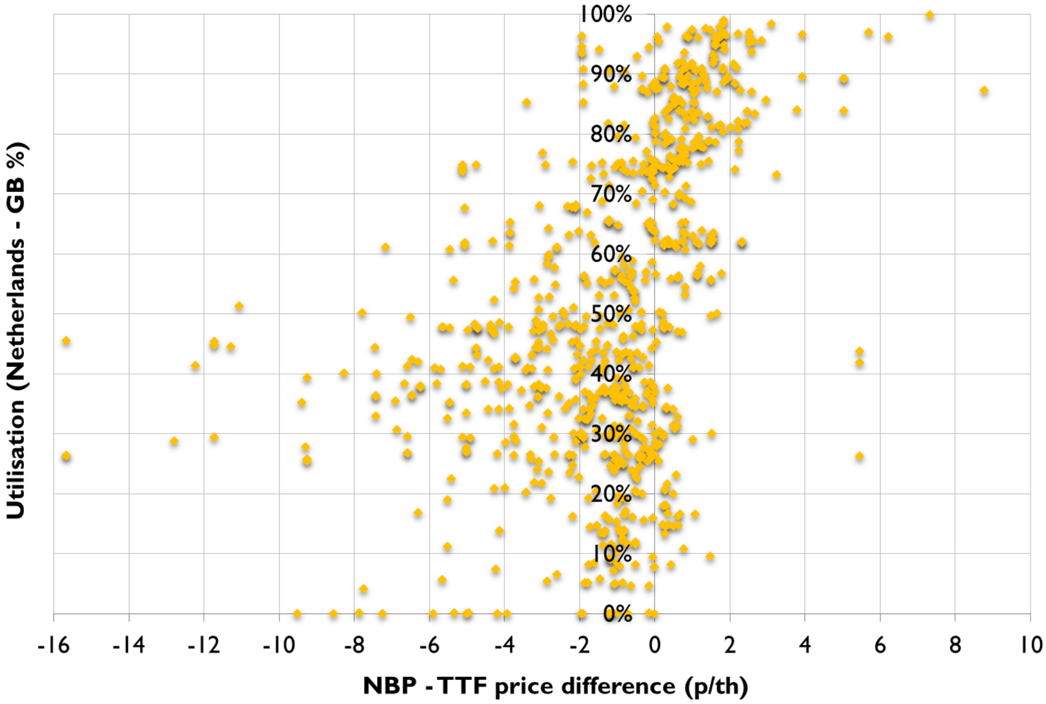


Figure 6 BBL utilisation



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

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

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

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

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

Figure 7 IUK supply curve variability

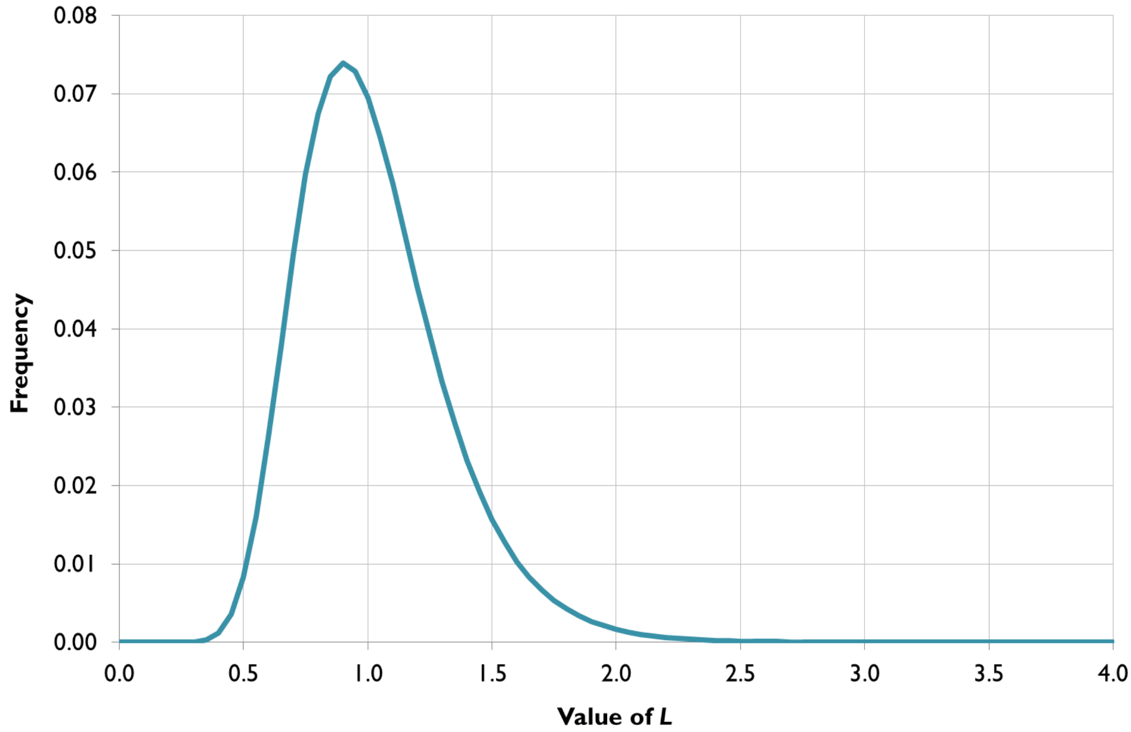
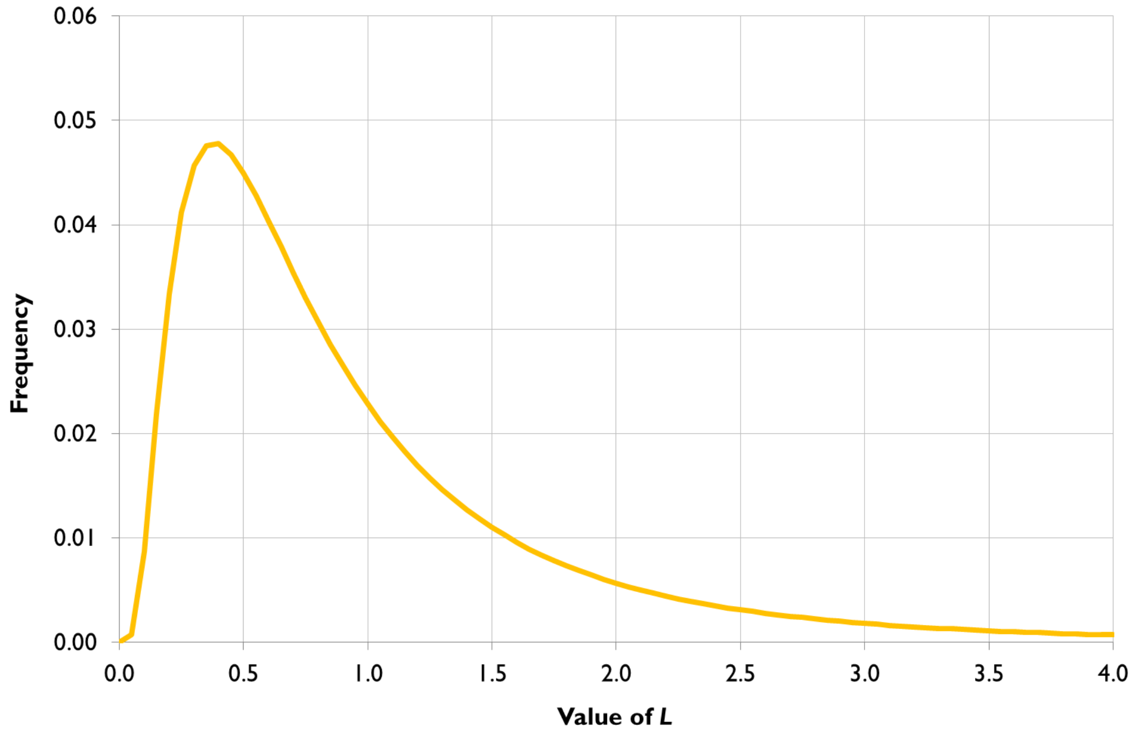


Figure 8 BBL supply curve variability



BBL capacity

For the 2012 spot year, though not the subsequent spot years in our modelling, the annual flow capacity of BBL was previously limited to 8 bcm rather than its full technical capacity of 20 bcm in order to avoid the model producing annual flows that are not consistent with historic evidence. One of the consultation responses pointed out that this could limit the ability of BBL to respond to demand in certain stressed situations, thus underestimating its contribution to gas security of supply in GB. We have removed the limit on BBL flows in the revised version of our model.

Distillate back-up

One of the consultation responses pointed out that the modelling done for the Draft IA did not account for the possibility of distillate switching available to some CCGT plant and hence would over-estimate the risks to electricity security of supply associated with gas shortages. This has been addressed in the revised modelling approach.

Data compiled by Ofgem (by means of updating the Project Discovery analysis) suggests that total CCGT capacity with distillate backup in GB falls from around 5.5 GW to around 4.7 GW between 2011 and 2025. Further, the NG Winter Outlook report 2011/2012 states that the total amount of distillate available in GB is around 100 mcm in gas equivalent terms. Using assumptions on CCGT efficiency and the split between peak and off-peak hours from our model, 100 mcm of distillate translates into 8.8 days of peak output in 2011.

Given that CCGTs are interrupted before firm DM gas demand in the revised model configuration and 8.8 days is longer than any firm DM gas demand interruption observed under the base case assumptions, distillate backup forms an additional tranche of demand side response for peak electricity demand in the revised version of the model, priced above the level of peaking plant. The instantaneous quantity of demand side response available changes in line with total capacity of plant with distillate backup.

Order of interruption

In the previous version of the model, firm gas customers and CCGTs supplying firm electricity customers were interrupted economically on the basis of the VoLL of the final customers (gas or electricity). Following stakeholder responses and further discussions with National Grid, newly available information suggests that CCGTs are likely to be interrupted before other firm gas customers due to their size (regardless of the relative VoLLs of gas and electricity customers). This assumption is incorporated into the revised version of the model.

NDM minimum interruption size

In the previous version of the model, it was assumed that the minimum size of an NDM interruption would be 20 mcm. This reflected the assumption that network isolation could only be carried out at the level of an LDZ. However, further discussions with National Grid and Distribution Network Operators indicate that this is not the case and much smaller parts of the network can be isolated. Hence the minimum constraint on the size of an NDM interruption has been removed in the revised version of the model.

Price effects and calibration

Since the focus of the modelling for the Draft IA was physical security of gas supply in GB, the model gas price was sense-checked but not calibrated and did not feed into welfare analysis of the options for reform. In light of certain stakeholder feedback and Ofgem's own view, the effect of options for reform on gas prices has acquired greater importance.

For the purposes of this study, the gas price output by the model has been calibrated to historic data spanning April 2007 to March 2010. Actual daily data on fuel prices, non-power generation gas demand and other variables were input into the model and the system gas price produced by the model was compared against the actual GB gas price for this period.

In order to improve the fit between the actual and calibrated model gas price, two changes were made to the model.

1. Seasonality was added to LNG pricing such that, at the peak of winter, the extent to which the LNG price is driven by the JCC index is double that seen at the peak of summer[37]. LNG prices in our model are higher when driven by the JCC index.

2. Disconnection in the relationship between the continental gas price and the oil price was modelled in periods of low LNG prices. This means that when the LNG price in the model is driven entirely by the Henry Hub price, the continental gas price is 20 p/th lower than that which would be suggested by the oil price relationship when the model LNG price is driven by the JCC.

Distribution of sudden shocks

One of the stakeholders questioned the use of the Poisson distribution to model sudden shocks such as infrastructure outages and suggested that the Gumbel-Jenkinson distribution would be more appropriate for this purpose.

The sudden shocks that affect supply source availability in our model have three parameters: probability of occurrence, magnitude and duration. For the occurrence or otherwise of an event, the Poisson distribution is used. This is a standard discrete distribution used to model binary outcomes. The Gumbel-Jenkinson distribution is continuous and is thus not naturally suited to modelling binary outcomes.

With regards magnitude and duration, a lognormal distribution is used. This has the benefit of always being positive (as the duration and magnitude of an outage must be) and having a long right tail, which gives it the ability to capture low-probability high impact events. A Gumbel-Jenkinson distribution restricted to positive only outcomes has a similar shape to a lognormal distribution and any differences between them are likely to have an insignificant impact on the modelling.

Statistical convergence

One stakeholder has stated that that 1,500 are insufficient to reach convergence and that modelling results based on this number of simulations cannot be relied upon. We assume that "convergence" means statistical significance of the modelling results in the context of the relevant consultation response.

The costs and benefits of each option for reform relative to the current arrangements were estimated by subjecting the model to the same set of underlying events (i.e. using the same random number seed) for the current arrangements and each of the options for reform. Hence all options were compared on a like-for-like basis.

The model is based on a daily optimisation routine. In order to keep the model computational time to a realistic level, for each simulated day, the optimisation routine does not iterate to an absolute optimum but settles for a solution that is close to the optimum. Because of the large number of simulations carried out, in a few instances, this can introduce arbitrary differences between like-for-like simulations under different sets of market arrangements that impact the results. On the whole, such differences are small and average out when simulation results are summarised.

[37] See Section 6 for an explanation of how LNG prices are derived in the model and the role of the JCC index in determining the LNG price.

The arbitrary differences described above can, on occasion, make a noticeable difference to summary results when the options being compared are very similar and few genuine differences exist or when the summary statistics being compared relate to extremely rare events. One such example is specifically discussed below and relates to the Base case results for the 2020 spot year.

In one of the simulations, small random differences in the optimisation resulted in gas prices that are slightly different under the Current arrangements and Option 2 despite them having the same demand and supply availability. This price difference caused some LNG shipments to arrive under the Current arrangements that did not arrive under Option 2. The arrival of the extra LNG under the Current arrangements coincided with events that caused an NDM interruption under Option 2 and the extra LNG available under the Current arrangements was sufficient to prevent this interruption.

We believe that this particular result is driven by small random differences in optimisation between different scenarios. Whilst the impact in absolute terms is very small, it does have the effect of increasing the probability of NDM interruptions in the summary results for Option 2 relative to Current arrangements. We therefore decided to make an adjustment on the grounds that there is a significant danger of the unadjusted results being misinterpreted. The adjustment has been made by assuming that the same amount of LNG arrives into GB under Option 2 as in the current arrangements scenario for the period of the event in question. The results for Option 2 are presented after this adjustment to the raw model outputs (with the raw results provided as a footnote).

No further similar examples of model dynamics were identified that could materially affect the summary results. However, it is not feasible to check every single simulation for such dynamics and given the very large number of simulations carried out, it is likely that some other simulations include unusual price behaviours. The effect of such occurrences would normally average out. However, because NDM interruptions are very rare events, a single outcome like this can have a material impact on the summary results.

Given the complexity of the modelling, it is not possible to formally derive confidence intervals around the modelling results. However, on a qualitative basis, large differences in results must be seen as more statistically significant than small differences. Likewise, differences that relate to more frequent events must be seen as being more statistically significant than differences that relate to rare events.

The issue of statistical significance must also be considered with respect to which aspects of the modelling results are given the greatest weighting in any assessment. In particular, the change in the probability of different types of demand interruption contains less information than the total volume of interruptions by type. This is due to the fact that interruptions are a threshold event. If a change in the market arrangement succeeds in reducing the size of certain interruptions without preventing any of them, this effect will not be visible in the probability of interruptions estimated from the modelling results. This consideration is especially important with regard to rare events like NDM customer interruptions.

Lower gas demand due to electricity interruptions

One stakeholder has argued that not all interactions between gas and electricity have been considered in the modelling done for the Draft IA. It was argued CCGT interruptions that lead to electricity outages would also lead to lower gas demand since domestic central heating would not operate.

Our modelling does not include an assumption that gas demand would be lower following the interruption of electricity customers. Rote interruptions of electricity customers allow the use of gas at times when electricity is available. During rota disconnections, it is possible that gas demand will be particularly high in periods when electricity is available, making up for reduced gas demand in periods when electricity is not available. Overall, we believe the effect is too uncertain to be included in the modelling.

LNG supply responsiveness

One stakeholder claimed that the assumption that LNG cargoes respond to an increase in the GB spot price of gas within 7 days is overly optimistic.

We firstly note that the supply of LNG into GB in our model is determined by a 14 day moving average of the GB spot price, lagged by 7 days. This means that the effect of a price spike lasting one day is smeared over a 14 day period and thus significantly diluted in the process. Secondly, it can equally be argued that a minimum 7 day delay is pessimistic with respect to future years since increasing LNG imports into Continental Europe are likely to mean that there are more LNG cargoes in the vicinity of GB on any given day.

Overall, we consider our assumptions on the responsiveness of LNG supply to changes in the GB spot price to be reasonable given the potentially wide range of future outcomes in this regard.

Oil Indexation of continental gas prices

One stakeholder argued that oil indexation as assumed for the modelled Continental European gas prices may not be the dominant price setter in the future following the introduction of the 3rd Energy Package.

It is impossible to know for sure what will drive prices in the long run. We therefore think that it is reasonable to assume that future changes in the Continental gas price reflect observed historic dynamics. These dynamics, as incorporated in our model, involve some disconnection between the oil price and the Continental gas price in periods of low LNG prices.

Model price and supply dynamics

One of the stakeholders raised concerns about the validity of quantified conclusions based on a model that was a simplified representation of reality. They also stated that it would be beneficial for interested parties to be able to analyse the daily price tracks and daily volume dispatch by supply source for the "seeds" where a failure to meet NDM demand has occurred.

While any modelling of a complex system involves a significant degree of simplification, we believe that model dynamics adequately reflect actual market dynamics for the purposes of this exercise and that quantitative estimates can complement qualitative assessment of policy design. In response to the request for detailed price and supply data in the case of NDM interruptions, we provide a case study below which demonstrates the model dynamics in the run-up and the course of an NDM outage. This is done for the corresponding period and simulation under the current arrangements and option 2 to demonstrate some of the possible effects of the change in the market arrangements on model dynamics. The point of this example is not to suggest that this exact sequence of events is how the market would react in practice, but to illustrate the directional changes that occur under different arrangements, which, when aggregated across many simulations, allow more quantitative conclusions to be drawn to support the qualitative case. In this context, the relative difference between the cases is more important than the specific absolute sequences.

The following case study refers to a simulation for spot year 2030. Under the current arrangements, two NDM outages occur within the period shown, separated by just a few days. Under option 2, price dynamics during the first NDM outage change subsequent gas flows and prevent the second NDM outage from occurring. Note that in the context of the summary results, the second NDM outage, which is prevented under option 2, will only show up in the statistics on total volume of interruption and not outage probability since outage probabilities are worked out on the basis of there being at least one outage in a simulated year. The calculation of outage probability statistics is explained in Section 8.1.

Figure 9 shows model gas market dynamics for the selected period under the current arrangements and Figure 10 shows power generation by source for the corresponding period[38]. Within the time horizon shown, interconnector imports and NCS supply account for the bulk of total gas supply into GB. No LNG arrives into GB within the period shown as the gas price in GB is not sufficiently high to attract LNG shipments.

In Figure 9, where the red line showing Non Power Generation (NPG) demand rises above the stack of supply sources, firm gas demand is interrupted. NPG demand reaches a peak of 317 mcm/day on 19 Dec[39]. This, combined with a severe reduction in the ability of LRS to deliver gas, no LNG shipments being delivered into GB and lack of gas in SRS, results in firm DM gas being interrupted on 18 Dec and NDM gas demand being interrupted on 19 Dec[40]. No CCGTs are subject to involuntary interruption throughout this episode since other electricity supply sources, including wind, coal, interconnectors and CCGTs running on distillate, are sufficient to meet electricity demand. On 18 Dec, the cash-out price is frozen at the level prevailing on 17 Dec.

Gas in SRS runs out on 8 Dec and is not replenished until after 19 Dec. This is because no LNG arrives into GB during the period shown and periods of low NPG gas demand coincide with periods of relatively moderate or low wind, as can be seen in Figure 10[41], which means that gas demand for power generation is relatively high. Available supply sources are only just sufficient to meet total demand that includes demand from CCGT generators[42].

[38] Note that power generation by peaking plant, interconnector imports, LCPD/IED plant exceeding their average running hours constraints and CCGT plant running on distillate are not shown in this graph.

[39] 317 mcm/day represents approximately a 98.6th percentile of annual maximum demand figures in all the simulations for 2030 carried out in our study. In other words, out of the 1,500 simulations carried out for 2030, less than 21 will see an absolute annual peak demand of above 317 mcm/day.

[40] Since an NDM interruption lasts for a minimum of 14 days under our modelling assumptions, the NDM customers interrupted on 19 Dec are off for the subsequent 13 days, which can be seen in the persistent gap between total demand and total supply during that period.

[41] In Figure 9, gas demand including power generation differs from total demand when gas is being injected into storage and/or when interconnectors are exporting gas from GB. This can be seen to happen between 1 Jan and 4 Jan. Gas demand including power generation is the same as NPG demand either when there is sufficient wind and nuclear generation to satisfy all electricity demand, as happens on 3 Jan, or when there is insufficient gas to meet NPG demand, as happens from 18 Dec and then again from 7 Jan.

[42] Note that model dynamics of SRS injection and withdrawal work through the level of the current price of gas relative to the expected future price of gas as determined by the model.

Figure 9 Example of modelled gas market dynamics under current arrangements

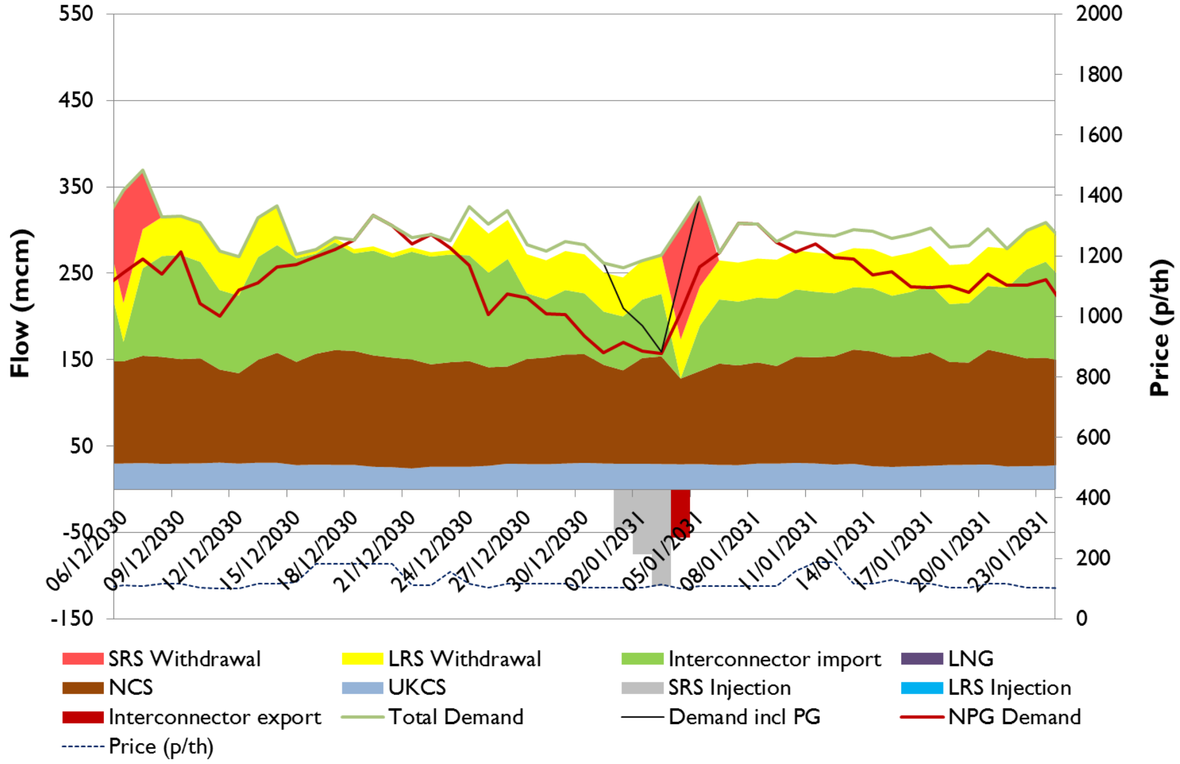
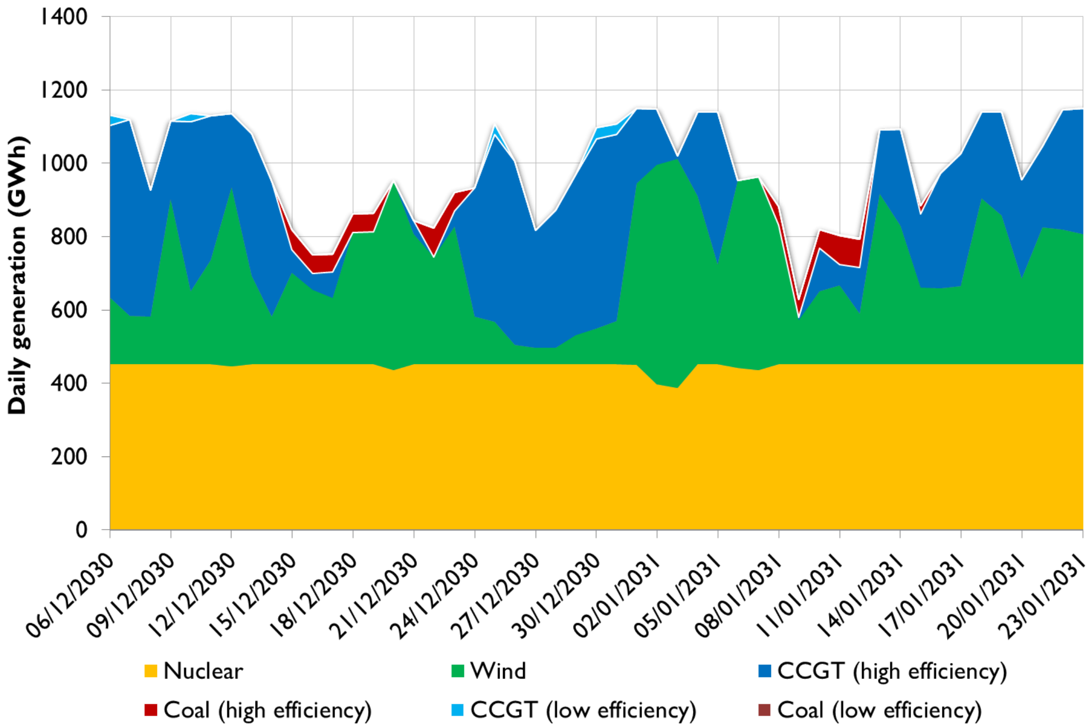


Figure 10 Example of modelled power generation under current arrangements



In Figure 11, we see the model gas market dynamics for the corresponding period under option 2 and in Figure 12 we see the corresponding modelled power generation. Although the cash-out price is allowed to increase on 18 Dec and reaches £20/th on 19 Dec, no extra gas supply is available to prevent or mitigate the NDM interruption.

Demand falls rapidly in the next few days and the supply shortage is resolved both under option 2 and the current arrangements. However, shortly after LRS is restored to its full withdrawal capacity, a negative shock to interconnector capacity occurs. From 3 Jan, demand starts rising rapidly and, under the current arrangements, the gas injected into SRS since the last interruption is not sufficient to prevent the second NDM interruption on 7 Jan.

Under option 2, the spike in prices that occurs during the first NDM interruption increases LNG shipments into GB since availability of LNG to flow into GB is determined by a 2 week moving average of the GB price lagged by 7 days. This is the proxy used in the model to reflect the lag involved in LNG responses to market events given shipping schedules, implying in this case an increased expectation of prices following the event that leads to decisions by market participants to send cargoes to GB. The increase in available LNG allows for an increase in the volume of gas injected into SRS in the days after the price spike. When the subsequent demand spike and interconnector outage come around, there is ample supply to meet demand and no demand interruptions occur.

Figure 11 Example of modelled gas market dynamics under option 2

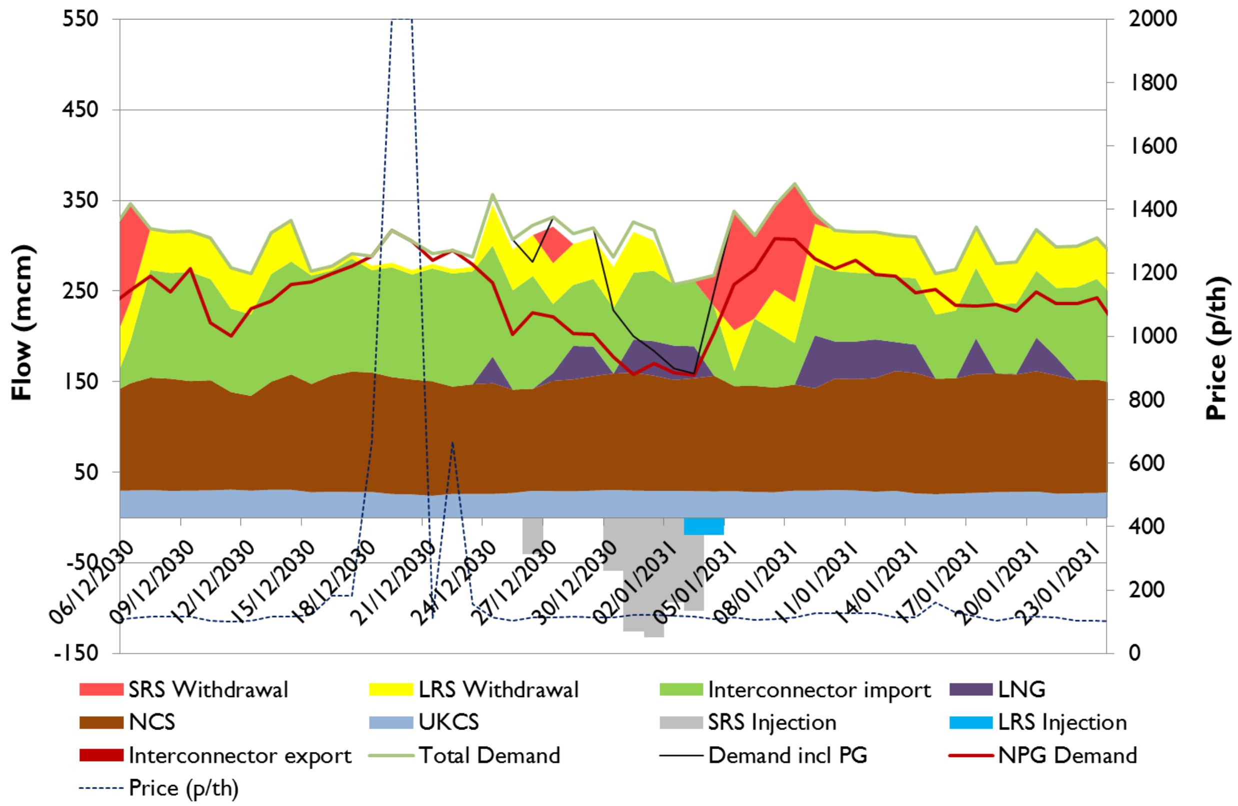
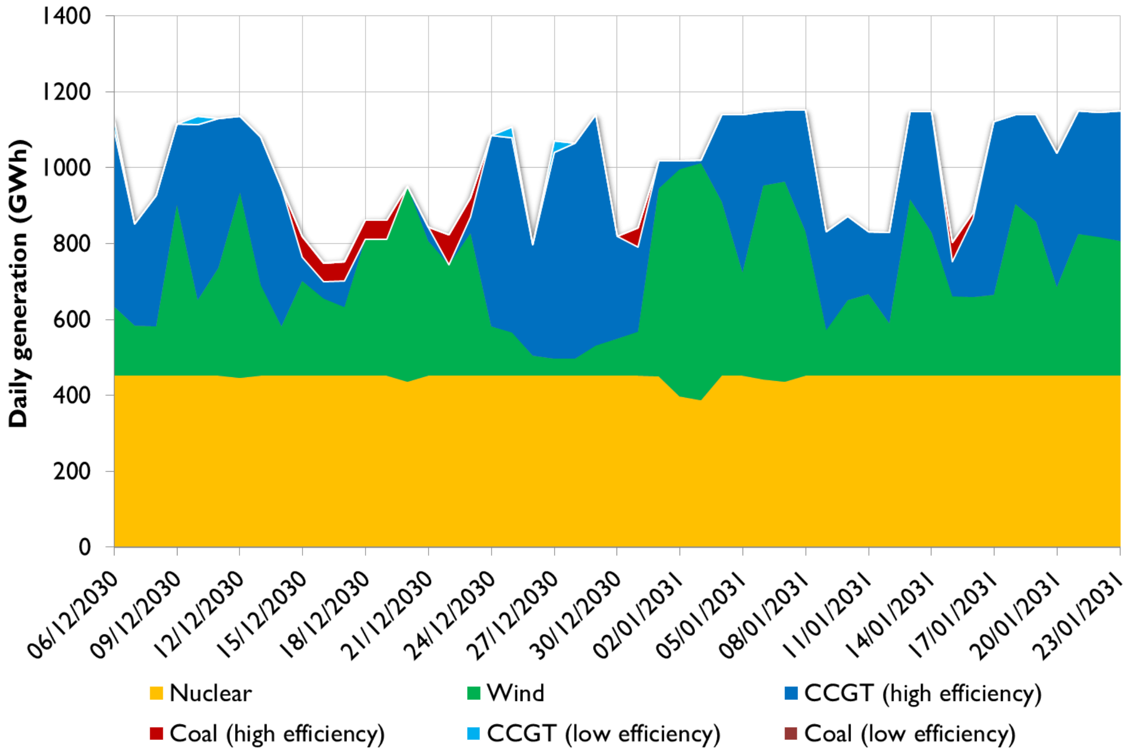


Figure 12 Example of modelled power generation under option 2



Update to assumptions

In addition to the model revisions carried out in response to stakeholder feedback on the Draft Impact Assessment, Ofgem asked Redpoint to revise other model assumptions with the latest available information. As part of this exercise, fuel price assumptions were revised given changes to forward prices, IEA long-term forecasts and latest assumptions from Ofgem's internal analysis. Exchange rates were revised with latest spot market rates. Assumptions on NPG demand and annual supply from different sources were taken from National Grid's latest Ten Year Statement. Finally, assumptions on electricity demand and the generation mix were taken from Ofgem's internal analysis.

We have carried out a sensitivity on the revised Base case model where the assumptions described in the paragraph above were taken from the modelling done for the Draft Impact Assessment. This is described in Section 8.4.5.

CBA methodology

In the modelling for the draft impact assessment, it was assumed that reform of the cash-out arrangements would not lead to any change in the average cost of gas paid by GB consumers. This assumption was made on the basis of the further assumption of perfect competition in the gas market and a perfectly elastic long-run supply curve of gas.

The calibration of prices estimated by our model has enabled Ofgem and Redpoint to reassess the original assumptions on the long-term price effects of cash-out reform. It was decided that a more prudent assumption is that any extra gas imported into GB as a result of cash-out reform is paid for at the cash-out price prevailing at the time. This change in assumptions reflects the likelihood that the costs to the upstream of the gas sector would increase when extra gas is imported into GB, but this increase would not apply to all gas supplied into GB.

8 Results

8.1 Probability and impact of gas shortages

The results presented from this point onwards are averages over all the simulations and spot years for a given policy configuration. Table 10 gives the estimated average probabilities of at least one outage in a simulated year for four selected tranches of demand under the current arrangements and the two options for reform[43].

Table 10 Average annual probability of at least one outage

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 55	1 in 128	1 in 128
NDM gas	1 in 167	1 in 167	1 in 167
Firm I&C electricity	1 in 34	1 in 74	1 in 75
Domestic & SME electricity	1 in 91	1 in 333	1 in 333

Our analysis shows that, under the current arrangements, the risk of firm DM interruptions is 1 in 55 years while the risk of NDM customer interruptions is 1 in 167 years on average for the spot years modelled. Our results show that Option 1 is effective at reducing the probability of all types of outages except for NDM gas. 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. There is likewise a significant reduction in the probability of interruption of firm electricity customers supplied by CCGTs. DSR plays a significant role in this respect since, under cash-out reform, the DM gas demand tranches that become interruptible are interrupted before CCGTs.

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). Another benefit of interruptible contracts is that they allow DSR to be substituted for more expensive supply when the market price of gas is high. Under current arrangements, unless DM customers are on a spot price contracts, this would not happen and the economic cost of this would ultimately be borne by the customers themselves.

The reduction in the probability of firm DM gas demand interruption is the same under Option 1 and Option 2 save for one small difference in the probability of Firm I&C electricity interruption. 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. In addition, shipper response by which shippers book a certain amount of new physical storage capacity to insure themselves against the prospect of paying out 14 times domestic customer VoLL if NDM customers are cut off, is estimated to be

[43] Note that the results presented in this section are after the adjustment to the results for Option 2 discussed in detail in the "Statistical convergence" paragraph of Section 7. Before the adjustment , the average annual probability of at least one NDM outage under Option 2 is 1 in 162 (0.62%) rather than 1 in 167 (0.60%). The expected annual level of unserved NDM demand is 621,000 therms before the adjustment compared to 618,000 therms after the adjustment. This compares to 722,000 therms under the current arrangements.

unprofitable for shippers based on our modelling results due to the very low probability of firm demand interruptions [44].

Table 11 Unserved demand

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	0.254	0.026	0.026
NDM gas	0.722	0.642	0.618
Firm I&C electricity	0.088	0.027	0.027
Domestic & SME electricity	0.014	0.003	0.003

Table 11 shows the expected annual quantity of unserved demand for the same demand tranches. This gives a more accurate picture of the change in security of supply as a result of cash-out reform since it captures all changes in unserved demand due to reform. This is not the case for probabilities of interruptions since only changes that are large enough to prevent all interruptions of a given type in at least one simulated year are captured. The table shows that the total volume of NDM gas interrupted is lower under Option 1 than under the current arrangements. This means that the severity of certain NDM interruptions is reduced under Option 2 compared to the current arrangements even though the total number of simulated years with interruptions is unchanged[45].

Table 11 also shows that the expected annual quantity of unserved demand for NDM customers is actually marginally lower under Option 2 than under Option 1. For other types of customers, the total cost of unserved energy is the same or very similar. 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 similarity in the results. Having examined the individual simulations where differences between Option 1 and Option 2 arise, we are satisfied that these result from minor imperfections in the optimisation.

8.2 Cost benefit analysis

8.2.1 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.

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

[44] See Section 4.2 for a description of the methodology to estimate optimal shipper response to high cash-out exposure.

[45] Note that this is also true before the adjustment to the Base case results under Option 2 described above.

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[46].

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.

Change in net supplier welfare as a result of reform is assumed to be zero by definition, driven by the underlying assumption that gas suppliers are competitive and only make a 'normal' profit. The result of this assumption is that any changes in the costs faced by suppliers are passed on to consumers in the long run. In our CBA, this is done through the Retail revenue line item, which is a sum of changes in Cash-out liability, Payments to interruptible customers and Change in total cost of gas.

Change in the total cost of gas to suppliers as a result of cash-out reform consists of two elements. Firstly, in periods when the cash-out price is allowed to rise to VoLL and extra gas is imported into GB as a result, the cost of the extra imported gas is reflected in the total cost of gas line as quantity of extra gas imported times the cash-out price. Secondly, in periods when the cash-out price rises above the interruption price of the DM gas demand tranches that become interruptible under the reform options and there is no underlying gas shortage, those tranches are interrupted under cash-out reform but not under the current arrangements. The reduction in the total cost of gas purchased by suppliers as a result of cash-out reform is reflected in the total cost of gas line as quantity of gas interrupted times the cash-out price under the current arrangements.

8.2.2 CBA results

Results of CBA analysis for the two options for reform relative to the current arrangements are shown in Table 12. The cost of unserved demand is based on the VoLL of each tranche of demand.

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

Table 12 CBA (NPV - £ million real 2012)

		Option 1	Option 2
Supplier welfare	Cash-out liability	-181.0	-26.7
	Payments to interruptible customers	-51.1	-51.3
	Change in total cost of gas	4.8	23.1
	Retail revenue	227.3	54.8
	Net supplier welfare	**0.0**	**0.0**
Consumer welfare	Retail costs	-227.3	-54.8
	Payments for involuntary DSR services	181.0	26.7
	Payments to interruptible customers	51.1	51.3
	Load reduction to firm gas customers	33.1	39.2
	Load reduction to firm electricity customers	54.2	54.1
	Load reduction to interruptible customers	-51.1	-51.3
	Net consumer welfare	**41.0**	**65.1**

Our analysis shows that the retail cost of gas to consumers would be higher under both of the options for reform. The estimated impact of the options on average annual consumer bills is an increase of £0.46 for option 1 and an increase of £0.11 for option 2[47]. This reflects the increase in total costs of suppliers under the reform options. From the perspective of consumers, the increase in the average consumer bills is compensated by an increase in payments to interruptible customers and payments to firm customers for involuntary DSR services.

Our analysis also shows that both options for reform result in an improvement in net consumer welfare. This is due to the fact that the sum of the value of the change in unserved demand, change in payments to interrupted customers and change in the retail cost of gas is positive in both cases. In more general terms, it shows that the distortion of incentives associated with frozen cash-out has been mitigated.

There are two reasons for the lower net consumer welfare increase under Option1 than under Option 2. The biggest difference is due to the change in the total cost of gas. In our CBA methodology, it is assumed that when the cash-out price is allowed to rise under the reform options, any additional gas brought in as a result of cash-out reform is paid for at the level of the cash-out price prevailing at the time. Under Option1, the amount of extra gas imported into GB in times of emergencies as a result of cash-out reform is not significantly greater than under Option 2. However, the cost of that gas is significantly greater under Option 1 since during an NDM interruption, the cash-out price would rise to £280/th under Option 1 and £20/th under Option 2.

A much smaller difference between Options 1 and 2 is in the cost of load reduction to firm customers, which is higher under Option 1. Having examined the individual simulations where differences between Option 1 and Option 2 arise in this respect, we are satisfied that these result from minor imperfections in the optimisation.

The change in the total cost of gas for suppliers is a positive number for both options, which indicates a reduction in the total cost of gas compared to the current arrangements. This is because the reduction in

[47] Calculated from the retail cost line of the CBA assuming annual NPG gas demand of 57.9 bcm and average annual consumer gas demand of 16.5 MWh.

the cost of gas[48] consumed by DM gas tranches that become interruptible with cash-out reform outweighs the cost of extra gas imported as a result of cash-out reform.

Estimated reduction in firm NDM unserved demand contributes to improvement in social welfare under both options for reform[49]. However, a greater part of the estimated improvement in social welfare as a result of cash-out reform stems from the increase in interruptible contracts that is assumed to accompany cash-out reform in our modelling. In the context of the model, interruptible contract improve social welfare in two ways. Such contracts enhance social welfare by ensuring that demand with the lowest VoLL is interrupted first, thus enhancing security of supply of firm customers (including electricity customers supplied by CCGTs) who are unable or unwilling to sign interruptible contracts. Secondly, they substitute DSR for more expensive gas supply in some instances when the gas price exceeds the VoLL of customers with interruptible contracts.

There are many alternative measures that reduce the exposure of shippers to high cash-out prices and improve security of supply, including the holding of storage capacity and contractual provisions, among others. Should participant responses to heightened cash-out incentives not materialise to the extent assumed in our modelling with respect to interruptible contracts, the benefits of cash-out reform seen in our modelling would be reduced.

8.3 Other considerations

A cap on the cash-out price in an emergency is difficult to rationalise in a world of perfectly functioning markets characterised by perfect competition and lacking any credit constraints. The fact that our modelling results suggest that Option2 is better for social welfare than Option 1 is a direct consequence of assumptions on the price paid for any extra gas imported in the course of an emergency as a result of cash-out reform, as well as assumptions on the nature of shipper response to potentially very high cash-out prices. With respect to shipper response, there may be cheaper options besides new SRS investments, one example being changes in the way that existing storage capacity is utilised, which are extremely difficult to estimate within a formal modelling framework.

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 unintended consequences by limiting the exposure of shippers in the event of physical network isolations. Specifically, an appropriate cap on the cash-out price could significantly reduce the possibility of financial distress of shippers, removing the danger of increases in market concentration and the resulting negative consequences for consumers.

The potential exposure of the shipper community to cash-out prices during a gas deficit emergency is larger under Option 1 than under Option 2. From our modelling results, we estimate that, in gas deficit emergencies, the average maximum annual exposure of the shipper community to high cash-out prices is approximately £5,675m under Option 1 and £976m under Option 2. The maximum is calculated over 1,500 years simulated for each of the spot years modelled[50] and then an average is taken over the maxima calculated for the four spot years. The average annual cash-out exposure, if firm customers are interrupted, evaluated over all simulations in which firm interruptions occur, is £1,120m under Option 1 and £267m under option 2. The biggest annual cash-out exposure, when firm demand interruptions

[48] This is calculated as the volume of interruption of these tranches under cash-out reform that does not occur under the current arrangements times the cash-out price under the current arrangements.

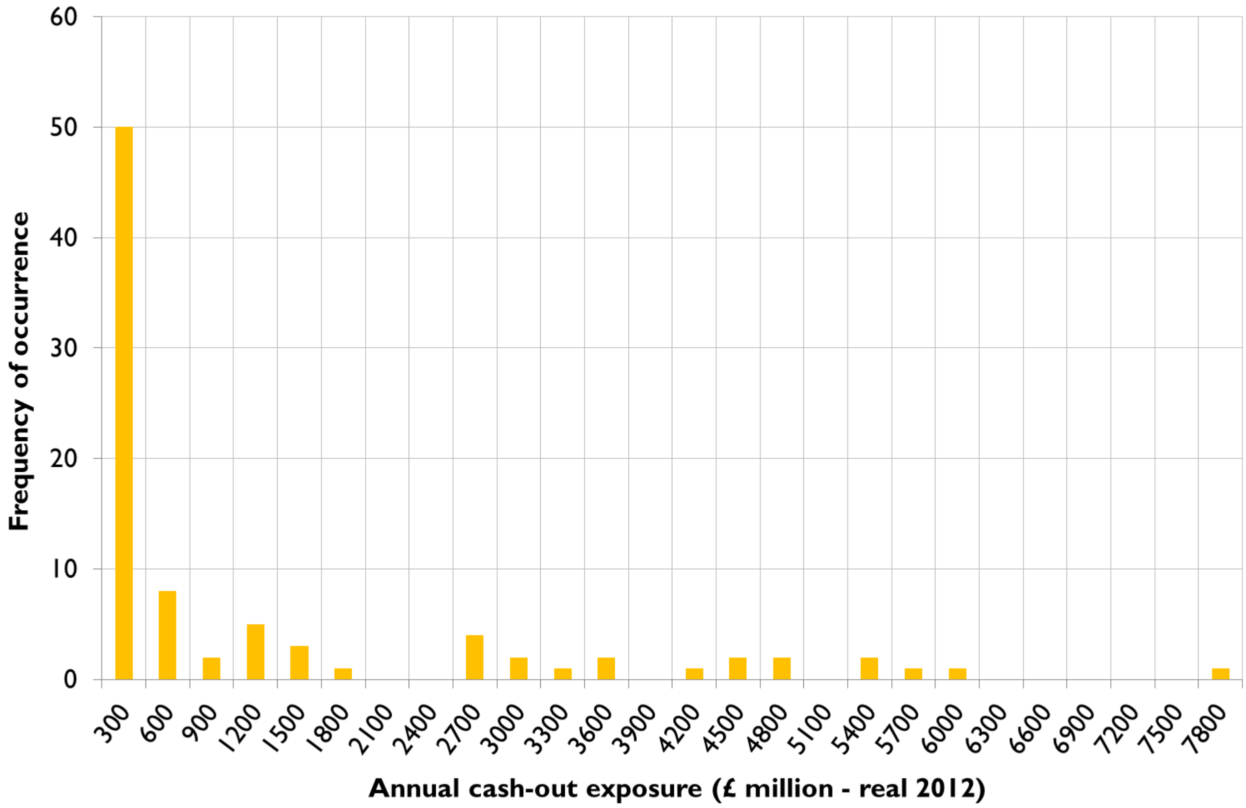
[49] This is particularly the case under Option 2, where, under our assumptions, the cost of extra imported gas attracted into GB to offset NDM interruptions is always much lower than the value of the reduction in unserved NDM demand.

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

occurred in our simulations and evaluated over all simulated years, is £7,606m under Option 1 and £1,390m under option 2.

Full distributions of annual cash-out exposures for the shipper community as a whole, for simulations where firm demand interruptions occurred, can be seen in Figure 13 and Figure 14[51] for Option 1 and Option 2 respectively. These numbers represent the cost of firm demand interruptions to the supplier community in years in which such interruptions occur. In other words, they represent payments to firm customers in years in which such payments are made.

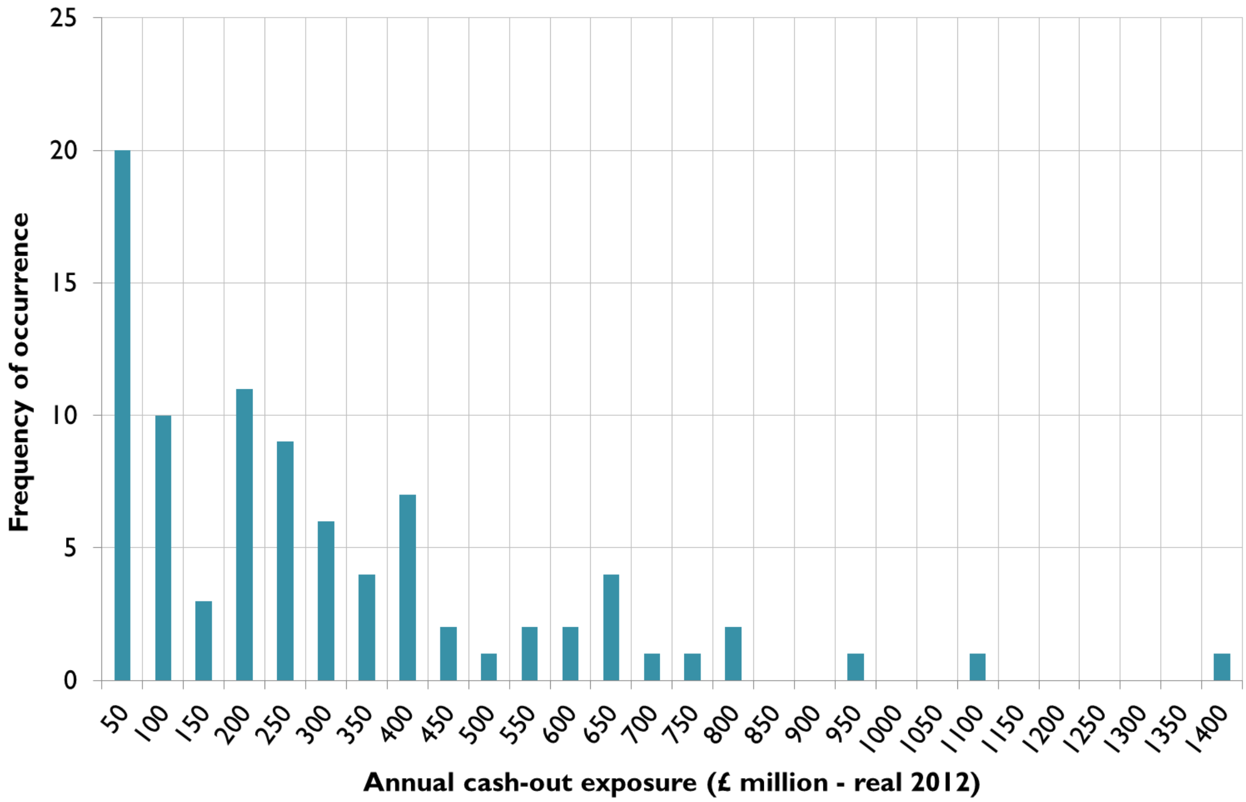
Figure 13 Distribution of annual cash-out exposures (Option 1)[54]



[51] Exposures are extracted from a total of 6,000 simulated years (over four spot years) for each of the options for reform. Exposures of below £1m are excluded from the relevant distributions for computational convenience. Our model produces minor variations in the sizes of all variables between different simulations because the optimisation process does not iterate to an absolute optimum but settles on a solution arbitrarily close to an optimum. This is done in order to keep the computation time of the model manageable. One of the implications of this is that, for simulated years where there are no interruptions, the total annual amount of unserved energy in the summary model results is never zero but arbitrarily close to zero. In order to exclude these observations from the distribution of cash-out exposures, a threshold is set at £1m below which an estimated annual exposure is excluded from the summary distribution. This threshold level is an arbitrary but small number on a system-wide level.

[54] The number on the y-axis indicates the number of times that a certain level of annual exposure is seen out of a total of 6,000 simulations. The label of 300 on the x-axis indicates exposures of above £1m and less than or equal to £300m. The label of 600 on the x-axis indicates exposures of above £300m and less than or equal to £600m.

Figure 14 Distribution of annual cash-out exposures (Option 2)



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 take measures to reduce the risk of NDM outages, thus increasing both the probability and the impact of such outages. This is not predicted by our model since we limit potential shipper response to new SRS investment.

Furthermore, the cash-out price under options 1 and 2 does not reflect potential externalities and social costs associated with a GDE[55].

8.4 Sensitivity analysis

8.4.1 Overview

To determine the importance of certain assumptions in driving the modelling results set out in Section 8.1, Ofgem asked Redpoint to carry out sensitivity analysis based on alternative sets of assumptions. The sensitivities were run for selected spot years, the majority being run for 2020 only. Where appropriate, we provide references to sections of this document where the corresponding Base case results for the same spot years can be found. The sensitivities are as follows:

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

1. **Infrastructure outages**: Under this sensitivity, the mean duration, magnitude 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 supply 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.

2. **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 JCC index, which results in a higher LNG price on average than under the base case.

3. **Demand side response**: This sensitivity tests the impact of interruptible contracts signed by certain tranches of DM gas demand under both options for reform. In this sensitivity, no new interruptible contracts are signed under these options.

4. **Old assumptions sensitivity:** This sensitivity tests the impact of rolling back all assumptions on fuel prices, as well as assumptions on demand, supply availability and power market parameters, taken from either NGG or Ofgem's internal analysis, to those used for modelling done for the Draft IA.

8.4.2 Infrastructure outages

This sensitivity represents a test of the way that changes in the probability, magnitude 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, magnitude and probability of outages on all supply infrastructure in the model.

Table 13 shows the average probability of outages on different tranches of demand modelled under this sensitivity. Section A.2.2 shows the corresponding probabilities under the Base case. The probability of instances of unserved demand is generally higher than in the Base case and is more than doubled when the probability, magnitude and duration of infrastructure outages are doubled.

Table 13 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 both options being equally effective in this regard. The overall effect appears to be broadly similar as under the Base case assumptions.

Unlike in the Base case, in this sensitivity, the probability of NDM interruptions is lower under both options relative to the current arrangements. Since there are many more NDM interruptions in this sensitivity than in the Base case, the likelihood of cash-out reform making a large enough difference to prevent NDM interruptions in at least one of the simulated years is greater.

Option 2 sees a slightly lower probability of Firm DM gas interruption than Option 1. Having checked the relevant simulation, we are satisfied that the difference results from small and random differences in optimisation results and is thus not statistically significant.

Table 13 Probability of at least one outage in a given year (Sensitivity 2020)

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 21	1 in 47	1 in 48
NDM gas	1 in 54	1 in 63	1 in 60
Firm I&C electricity	1 in 13	1 in 28	1 in 28
Domestic & SME electricity	1 in 38	1 in 125	1 in 125

Table 14 shows the corresponding expected unserved demand figures under the sensitivity. Section A.2.2 shows the corresponding results under the Base case. The impact of interruptions is more than doubled in the sensitivity relative to the Base case. Cash-out reform significantly reduces the impact of all types of demand interruption in this sensitivity. Option 1 is more effective at reducing the impact of NDM interruptions than Option 2. Overall, it appears that the effectiveness of cash-out reform in reducing the impact of demand interruptions is increasing in the underlying probability and magnitude of interruptions.

Table 14 Unserved demand (Sensitivity 2020)

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	1.059	0.101	0.107
NDM gas	2.546	1.286	1.438
Firm I&C electricity	0.296	0.085	0.084
Domestic & SME electricity	0.030	0.005	0.005

8.4.3 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.

Figure 15 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 15 LNG price and outage days

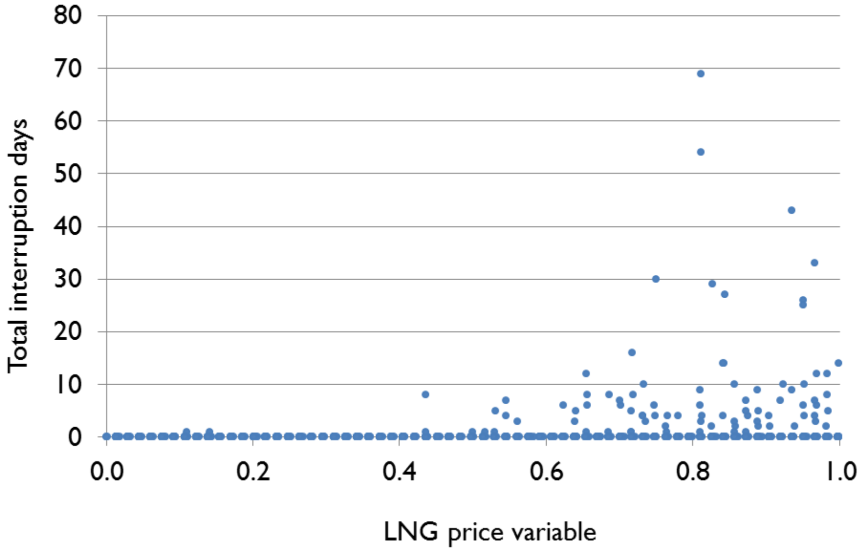


Figure 15[56] demonstrates that the risk to GB security of gas supply is generally higher when LNG price is high and driven by the JCC price[57]. The reason for this is that a low LNG price and thus high LNG imports into GB leave IUK and BBL to respond to shocks by bringing extra supplies into GB when 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 demand interruptions. 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 LNG cargoes.

Under this sensitivity, the LNG price is permanently driven by the JCC price. Table 15 shows interruption probabilities under the sensitivity and Section A.4.2 shows corresponding results under the Base case. In the sensitivity, the probability of interruptions on all tranches of gas and electricity demand is higher than under Base case assumptions. Table 15 shows that the probability of interruptions of gas and electricity demand is significantly lower under Options 1 and 2, which is consistent with results under Base case assumptions.

Table 15 Probability of at least one outage in a given year (Sensitivity 2016 & 2020)

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 25	1 in 83	1 in 81
NDM gas	1 in 83	1 in 100	1 in 100
Firm I&C electricity	1 in 10	1 in 24	1 in 23
Domestic & SME electricity	1 in 23	1 in 79	1 in 77

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

[57] The linear correlation coefficient between the two variables plotted in **Figure 15** is 0.17.

Unlike in the Base case, in this sensitivity, the probability of NDM interruptions is lower under both options relative to the Current arrangements. Since there are more NDM interruptions in this sensitivity than in the Base case, the likelihood of cash-out reform making a large enough difference to prevent NDM interruptions in at least one of the simulated years is greater.

Table 16 shows the expected unserved demand figures under the sensitivity and Section A.4.2 shows corresponding results under the Base case. The key trends are similar to those seen in the outage probability results. The impact of all types of interruptions is significantly higher in this sensitivity than in the Base case. Cash-out reform is effective at reducing the impact of all types of interruption. The effectiveness of Option 1 in this regard is very similar to Option 2.

Table 16 Unserved demand (Sensitivity 2016 & 2020)

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	0.528	0.050	0.051
NDM gas	1.462	0.982	0.982
Firm I&C electricity	0.345	0.082	0.085
Domestic & SME electricity	0.082	0.016	0.017

8.4.4 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. In this sensitivity, it is assumed that no new interruptible contracts are signed under Options 1 and 2.

Table 17 compares the current arrangements under the base case to the two options for reform under the sensitivity with respect to probability of interruption of different tranches of demand. The only difference between the current arrangements and the two options for reform here is that, under the reform options, the cash-out price rises to VoLL when firm gas customers are interrupted. The results show that allowing the cash-out price to rise to VoLL only makes a significant difference to the probability of interruption of CCGTs supplying domestic and SME electricity customers, although we note that this difference is relatively small[58]. This probability is reduced under both options for reform and to a greater extent under Option 2.

[58] We are satisfied that the slightly higher probability of firm DM gas interruptions under Option1 is a result of small differences in optimisation between the different options.

Table 17 Probability of at least one outage in a given year (2020)

	Current arrangements (Base case)	Option 1 (Sensitivity)	Option 2 (Sensitivity)
Firm DM gas	1 in 58	1 in 56	1 in 58
NDM gas	1 in 167	1 in 167	1 in 167
Firm I&C electricity	1 in 38	1 in 38	1 in 38
Domestic & SME electricity	1 in 94	1 in 100	1 in 107

Table 18 compares the current arrangements under the base case to the two options for reform under the sensitivity with respect to expected annual unserved demand for different tranches. It shows that the expected amount of unserved demand in firm DM gas and firm I&C electricity is lower when the cash-out price is allowed to rise to VoLL. This applies to both of the options for reform. Any difference for unserved demand in domestic and SME electricity is not significant to the third decimal place in million therms per year. Unserved NDM gas demand is the same in the Base case under current arrangements as under options 1 and 2 in the sensitivity. The same result holds in the Base case under cash-out reform for the 2020 spot year.

Table 18 Unserved demand (2020)

Million therms/year	Current arrangements (Base case)	Option 1 (Sensitivity)	Option 2 (Sensitivity)
Firm DM gas	0.237	0.219	0.217
NDM gas	0.395	0.395	0.395
Firm I&C electricity	0.077	0.067	0.067
Domestic & SME electricity	0.005	0.005	0.005

Overall, comparison of the results under this sensitivity to the results under the Base case demonstrates that, under our modelling assumptions, interruptible contracts play a more important role in improving security of supply than the ability to attract additional imported gas into GB in an emergency when the cash-out price is allowed to rise to VoLL.

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 as in this sensitivity, 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.

8.4.5 Old assumptions

This sensitivity tests the impact of rolling back all assumptions on fuel prices, as well as assumptions on demand, supply availability and power market parameters, taken from either NGG or Ofgem's internal analysis, to those used for modelling done for the Draft IA[59]. Hence it shows the effect of changes in those assumptions relative to the other changes to the model.

Table 19 shows probabilities of interruptions of different tranches of demand in the sensitivity and Section A.2.2 shows the corresponding results under the Base case. Probabilities of Firm DM gas and NDM gas interruptions are slightly higher under the sensitivity than under the Base case. However, the probability of CCGT interruption is significantly lower in the sensitivity than in the Base case. This is because the average margin of available non-CCGT generation capacity over peak electricity demand is higher under the old assumptions than under the revised Base case. Hence, when gas is rationed, electricity demand interruptions are less likely since there is more room for fuel switching from gas generation.

Table 19 Probability of at least one outage in a given year (Sensitivity 2020)

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 43	1 in 107	1 in 115
NDM gas	1 in 150	1 in 150	1 in 150
Firm I&C electricity	1 in 167	1 in 750	1 in 750
Domestic & SME electricity	Less than 1 in 1500	Less than 1 in 1500	Less than 1 in 1500

Table 20 shows the expected unserved demand figures under the sensitivity. Section A.2.2 shows the corresponding results under the Base case. The impact of firm DM gas interruptions is greater under the sensitivity than under the Base case. This is also the case for the impact of NDM outages, where the expected impact under the sensitivity is more than double that seen in the Base case. The impact of CCGT interruptions is much lower under the sensitivity than under the Base case.

Cash-out reform reduces the impact of all types of interruption in the sensitivity. The impact of NDM interruptions is marginally greater under Option 1 than under Option 2.

[59] Please see the "Update to assumptions" paragraph of section 7 for a list of the relevant assumptions. The new assumptions are described in detail in section 6. The corresponding old assumptions are described in section 6 of the Redpoint report that accompanied the Ofgem Draft IA (http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/Redpoint%20Energy,Gas%20Security%20of%20Supply%20Significant%20Code%20Review%20-%20Economic%20Modelling.pdf)

Table 20 Unserved demand (Sensitivity 2020)

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	0.313	0.035	0.035
NDM gas	1.022	0.838	0.818
Firm I&C electricity	0.006	0.001	0.001
Domestic & SME electricity	0.000	0.000	0.000

9 Conclusion

Overall, our analysis suggests that we would expect firm DM interruptions to occur once in 55 years and NDM interruptions to occur once in 167 years under the current arrangements. Security of gas supplies can be expected to be inversely proportional to the overall level of demand. Base case demand assumptions in our modelling are consistent with National Grid's Gone Green scenario, with 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. In one of the sensitivities modelled, the probabilities of firm DM and NDM interruptions respectively are as high as 1 in 21 and 1 in 54 years.

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.

Two options for reform are considered in this report. Our analysis indicates that allowing the cash-out price of gas to rise to domestic customer VoLL can reduce both the probability and impact of a GDE. This can happen first through more imported supplies being brought into GB in the course of an emergency regardless of whether the cash-out price is capped, and second through provisions being made by shippers in order to limit their exposure to very high cash-out prices. Whilst provisions in the form of new SRS investment are estimated to be uneconomic on the basis of our modelling results[60], other provisions, including changes in the way that gas in existing storage is managed and contracting for DSR, may prove to be welfare-enhancing for shippers facing potentially high cash-out prices.

In net welfare terms, it appears that allowing the cash-out price to rise to capped VoLL is the option for reform that would be likely to bring about the greatest improvement in social welfare. However, this is a direct result of our CBA assumptions, particularly the assumption that any extra gas brought into GB as a result of cash-out reform is paid for at the level of the cash-out price prevailing at the time. The underlying effect of options 1 and 2 on security of supply as estimated in our modelling is not significantly different. In both cases, a large part of the improvement in social welfare seen in our modelling is a result of the assumption that the primary response of market participants to cash-out reform incentivises is a significant increase in interruptible contracts. Such contracts enhance social welfare by ensuring that demand with the lowest VoLL is interrupted first. However, as noted above, there are many alternative measures that reduce the exposure of shippers to high cash-out prices and improve security of supply, including the holding of storage capacity and contractual provisions, among others. Should participant responses to heightened cash-out incentives not materialise to the extent assumed in our modelling with respect to interruptible contracts, the benefits of cash-out reform seen in our modelling would be reduced.

Our modelling does not account for the possibility of unintended consequences that may occur when prices are allowed to reach extremely high levels, potentially causing financial distress. If some kind of unintended consequences are 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 might not be better placed to either handle those costs or to make provisions in order to mitigate them.

[60] See Section 4.2 for details of how shipper response to high cash-out prices is estimated in our modelling. Notably, this analysis was based on the assumptions are risk-neutral with respect to the risk posed by potentially high cash-out prices. Risk aversion on the part of shippers could be expected to increase the benefit to shippers of a physical hedge against high cash-out prices.

A Modelling results

A.1 Summary

The results contained in this appendix supplement the results contained in Section 8. 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 for gas demand and Ofgem's Project Discovery for electricity demand. Average outage size is calculated conditional on an outage on the particular tranche of demand for which the result is shown.

A.2 Base case

A.2.1 Average results

Table 21 Cost of unserved demand

£m (real 2012)	Current arrangements	Option 1	Option 2
Firm DM gas	1.5	0.4	0.4
NDM gas	14.4	12.8	12.4
Firm I&C electricity	5.2	1.6	1.6
Domestic & SME electricity	1.0	0.2	0.2

Table 22 Average outage size[61]

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	13.9	3.5	3.5
NDM gas	116.2	104.1	101.2
Firm I&C electricity	2.8	1.9	1.9
Domestic & SME electricity	0.7	0.5	0.5

[61] Average outage size for each tranche represents average demand unserved in a year for a given tranche of demand, conditional on there being at least one outage on the corresponding tranche in a simulated year. This calculation is different from the one carried out for the Draft Impact Assessment. The change in approach has been made in order to avoid confusion in the interpretation of the results.

A.2.2 Annual results

Table 23 Probability of at least one outage in a given year (current arrangements)

	2012	2016	2020	2030
Firm DM gas	1 in 54	1 in 65	1 in 58	1 in 47
NDM gas	1 in 167	1 in 214	1 in 167	1 in 136
Firm I&C electricity	1 in 39	1 in 23	1 in 38	1 in 43
Domestic & SME electricity	1 in 136	1 in 42	1 in 94	1 in 500

Table 24 Probability of at least one outage in a given year (Option 1)

	2012	2016	2020	2030
Firm DM gas	1 in 136	1 in 214	1 in 125	1 in 88
NDM gas	1 in 167	1 in 214	1 in 167	1 in 136
Firm I&C electricity	1 in 75	1 in 56	1 in 75	1 in 107
Domestic & SME electricity	1 in 500	1 in 150	1 in 300	Less than 1 in 1500

Table 25 Probability of at least one outage in a given year (Option 2)

	2012	2016	2020	2030
Firm DM gas	1 in 136	1 in 214	1 in 125	1 in 88
NDM gas	1 in 167	1 in 214	1 in 167	1 in 136
Firm I&C electricity	1 in 75	1 in 58	1 in 71	1 in 115
Domestic & SME electricity	1 in 500	1 in 150	1 in 300	Less than 1 in 1500

Table 26 Unserved demand (current arrangements)

Million therms/year	2012	2016	2020	2030
Firm DM gas	0.290	0.189	0.237	0.300
NDM gas	0.832	0.436	0.395	1.224
Firm I&C electricity	0.086	0.154	0.077	0.034
Domestic & SME electricity	0.002	0.047	0.005	0.000

Table 27 Unserved demand (Option 1)

Million therms/year	2012	2016	2020	2030
Firm DM gas	0.026	0.019	0.025	0.035
NDM gas	0.723	0.418	0.395	1.030
Firm I&C electricity	0.028	0.045	0.024	0.011
Domestic & SME electricity	0.000	0.010	0.001	0.000

Table 28 Unserved demand (Option 2)

Million therms/year	2012	2016	2020	2030
Firm DM gas	0.026	0.020	0.025	0.033
NDM gas	0.723	0.436	0.395	0.916
Firm I&C electricity	0.028	0.044	0.025	0.010
Domestic & SME electricity	0.000	0.010	0.001	0.000

Table 29 Cost of unserved demand (current arrangements)

£m (real 2012)	2012	2016	2020	2030
Firm DM gas	1.8	1.1	1.4	1.8
NDM gas	16.6	8.7	7.9	24.5
Firm I&C electricity	5.1	9.2	4.6	2.0
Domestic & SME electricity	0.1	3.5	0.4	0.0

Table 30 Cost of unserved demand (Option 1)

£m (real 2012)	2012	2016	2020	2030
Firm DM gas	0.4	0.3	0.4	0.6
NDM gas	14.5	8.4	7.9	20.6
Firm I&C electricity	1.7	2.7	1.4	0.6
Domestic & SME electricity	0.1	3.5	0.4	0.0

Table 31 Cost of unserved demand (Option 2)

£m (real 2012)	2012	2016	2020	2030
Firm DM gas	0.4	0.3	0.4	0.5
NDM gas	14.5	8.7	7.9	18.3
Firm I&C electricity	1.7	2.7	1.5	0.6
Domestic & SME electricity	0.0	0.8	0.1	0.0

Table 32 Average outage size (current arrangements)

Million therms	2012	2016	2020	2030
Firm DM gas	15.5	12.3	13.7	14.0
NDM gas	138.7	93.3	65.9	166.9
Firm I&C electricity	3.4	3.5	2.9	1.5
Domestic & SME electricity	0.3	1.9	0.5	0.2

Table 33 Average outage size (Option 1)

Million therms	2012	2016	2020	2030
Firm DM gas	3.6	4.0	3.2	3.1
NDM gas	120.5	89.5	65.9	140.5
Firm I&C electricity	2.1	2.5	1.8	1.1
Domestic & SME electricity	0.1	1.5	0.4	0.0

Table 34 Average outage size (Option 2)

Million therms	2012	2016	2020	2030
Firm DM gas	3.6	4.2	3.2	2.9
NDM gas	120.5	93.3	65.9	124.9
Firm I&C electricity	2.1	2.6	1.8	1.1
Domestic & SME electricity	0.1	1.6	0.4	0.0

A.3 Infrastructure outages sensitivity

Table 35 Cost of unserved demand (Sensitivity 2020)

£m (real 2012)	Current arrangements	Option 1	Option 2
Firm DM gas	6.5	1.7	1.8
NDM gas	50.9	25.7	28.8
Firm I&C electricity	17.7	5.1	5.0
Domestic & SME electricity	2.3	0.4	0.4

Table 36 Average outage size (Sensitivity 2020)

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	22.1	4.7	5.2
NDM gas	136.4	80.4	86.3
Firm I&C electricity	3.9	2.4	2.3
Domestic & SME electricity	0.7	0.7	0.7

A.4 LNG price sensitivity

A.4.1 Sensitivity results

Table 37 Cost of unserved demand (Sensitivity 2016 & 2020)

£m (real 2012)	Current arrangements	Option 1	Option 2
Firm DM gas	3.2	0.8	0.8
NDM gas	29.2	19.6	19.6
Firm I&C electricity	20.6	4.9	5.1
Domestic & SME electricity	6.1	1.2	1.3

Table 38 Average outage size (Sensitivity 2016 & 2020)

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	13.3	4.2	4.1
NDM gas	118.2	97.3	97.3
Firm I&C electricity	3.3	1.9	1.9
Domestic & SME electricity	1.5	1.1	1.1

A.4.2 Corresponding Base case results

Table 39 Probability of at least one outage in a given year (Base case 2016 & 2020)

	Current arrangements	Option 1	Option 2
Firm DM gas	1 in 61	1 in 158	1 in 158
NDM gas	1 in 188	1 in 188	1 in 188
Firm I&C electricity	1 in 28	1 in 64	1 in 64
Domestic & SME electricity	1 in 58	1 in 200	1 in 200

Table 40 Unserved demand (Base case 2016 & 2020)

Million therms/year	Current arrangements	Option 1	Option 2
Firm DM gas	0.213	0.022	0.023
NDM gas	0.415	0.407	0.415
Firm I&C electricity	0.115	0.035	0.035
Domestic & SME electricity	0.026	0.006	0.006

Table 41 Cost of unserved demand (Base case 2016 & 2020)

£m (real 2012)	Current arrangements	Option 1	Option 2
Firm DM gas	1.2	0.4	0.4
NDM gas	8.3	8.1	8.3
Firm I&C electricity	6.9	2.1	2.1
Domestic & SME electricity	1.9	0.4	0.4

Table 42 Average outage size (Base case 2016 & 2020)

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	13.0	3.6	3.7
NDM gas	79.6	77.7	79.6
Firm I&C electricity	3.2	2.2	2.2
Domestic & SME electricity	1.2	0.9	1.0

A.5 Demand side response sensitivity

Table 43 Cost of unserved demand (2020)

£m (real 2012)	Current arrangements (Base case)	Option 1	Option 2
Firm DM gas	1.4	1.3	1.3
NDM gas	7.9	7.9	7.9
Firm I&C electricity	4.6	4.0	4.0
Domestic & SME electricity	0.4	0.4	0.3

Table 44 Average outage size (2020)

Million therms	Current arrangements (Base case)	Option 1	Option 2
Firm DM gas	13.7	12.2	12.5
NDM gas	65.9	65.9	65.9
Firm I&C electricity	2.9	2.6	2.5
Domestic & SME electricity	0.5	0.5	0.5

A.6 Old assumptions sensitivity

Table 45 Cost of unserved demand (Sensitivity 2020)

£m (real 2012)	Current arrangements	Option 1	Option 2
Firm DM gas	1.9	0.6	0.6
NDM gas	20.4	16.8	16.4
Firm I&C electricity	0.3	0.0	0.0
Domestic & SME electricity	0.0	0.0	0.0

Table 46 Average outage size (Sensitivity 2020)

Million therms	Current arrangements	Option 1	Option 2
Firm DM gas	13.4	3.8	4.0
NDM gas	153.2	125.6	122.7
Firm I&C electricity	0.9	0.4	0.4
Domestic & SME electricity	0.0	0.0	0.0