GAS SCR – COST-BENEFIT ANALYSIS FOR A DEMAND-SIDE RESPONSE MECHANISM

A report to Ofgem

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Contact details

Name	Email	Telephone
Gareth Davies	gareth.davies@poyry.com	01865 722660
Richard Sarsfield-Hall	richard.sarsfield-hall@poyry.com	01865 722660

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Gas Significant Code Review (SCR) aims to reduce the likelihood and severity of a gas deficit emergency (GDE) by ensuring that market arrangements provide appropriate incentives on gas shippers to balance supply and demand, through the cash-out charges shippers face as a penalty for imbalance. As part of this reform, Ofgem is considering whether a centralised, system operator-led demand-side response (DSR) mechanism, through which major daily-metered gas consumers could indicate the true cost of interruptions to their gas supplies, would increase security of supply at an affordable cost.

The study has undertaken a cost-benefit analysis (CBA) on the relative merits of a demand-side response mechanism, using the designs proposed by Ofgem. The focus of the CBA is to provide confidence that the design of any chosen intervention package is robust, and will lead to improved outcomes for consumers.

DSR mechanism designs

Three straw man tender designs were originally laid out in Ofgem's Consultation[1] (Straw man 1, Strawman 2 (SM2), and Strawman 3 (SM3)). However consultation responses and stakeholder feedback led Ofgem to request that we assess SM2, SM3 and an alternative mechanism proposed by National Grid Gas (the NGG option) as part of the CBA. The key elements of each design is summarised in Table 1.

Modelling emergencies

We have utilised a fundamental approach to modelling the electricity and gas markets of Great Britain in gas years 2016/17, 2020/21 and 2030/31. Using Pöyry's BID3 and Pegasus electricity and gas market models respectively, we analysed supply against a 1-in-50 very cold weather demand (using an uplifted 2009/10 historical weather year).

Using the Future Energy Scenarios developed by National Grid, we have modelled the 'Gone Green' scenario as the base case, and then assessed an alternative 'High Demand' scenario using the demand from the Slow Progression scenario[2]. Within each scenario, we then modelled the effect of failure of key pieces of supply infrastructure which could result in a gas deficit emergency. Such an approach allows direct cause and effect to be evaluated.

Our modelling shows that the GB gas market is robust to all the supply failures we modelled under the Gone Green scenario. Under this scenario GB gas demand declines from current levels leaving the available infrastructure able to re-optimise flows to ensure supply can meet demand even in the event of key infrastructure failures.

However, our modelling of the High Demand scenario resulted in unserved energy under a number of supply failures; with small amounts in 2020 but in more significant volumes by 2030. In these cases, supply cannot be re-optimised through alternative supply routes, and as a consequence there are days when supply is insufficient to meet demand. The unserved energy from this High Demand scenario is summarised in Table 2.

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1 Ofgem Consultation on Gas Security of Supply Significant Code Review: Demand-Side Response Tender Consultation (Ref 130/13), 23 July 2013

2 www.gov.uk/government/uploads/system/uploads/attachment_data/file/236757/DECC_FI_Final_report_09072013.pdf

Table 1 – Modelled DSR mechanism design options

DSR mechanism	Strawman 2	Strawman 3	NGG option
Pay-as-clear vs. pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-bid
Exercise / Option fees	Exercise only	Exercise and variable option fee	Exercise only
Decision criteria	Volume cap (TBC, modelled at 70%)	Volume cap (TBC, modelled at 70%)	NGG decision on the day.
Contract duration	One year	One year	Real-time updating
Format	Sealed-bid tender	Sealed-bid tender	Real-time updating
Payments to unsuccessful bids	30 day SAP	30 day SAP	30 day SAP
Payments to ineligibles	Average of exercised DSR bids	Average of exercised DSR bids	Average of exercised DSR bids
Payments to don't participates	Zero	Zero	Zero
Gas-fired generation bidding	Electricity VoLL	Electricity VoLL	Scarcity
Gas-fired generation sensitivity (eligibility)	Included & Excluded	Included & Excluded	N/A

Table 2 – Unserved energy under High Demand scenario from supply disruptions

m therms	High Demand	High Demand Bacton	High Demand Milford Haven	High Demand Norway Rough	High Demand Qatar
2016	0	0	0	0	0
2020	0	92	0	27	0
2030	0	788	82	619	858

Demand-side response (DSR) participation

To determine the volumes and prices which could be offered by participants in a DSR mechanism, we utilised the gross value added figures calculated for each sector of the industrial and commercial users by London Economics in a previous study for Ofgem; combined with updated volumes from the 2012 DUKES data.

To understand how these consumers would then bid in a DSR mechanism, we split the consumers into tranches depending on their annual gas consumption. To split the data further, we disaggregated these volumes to reflect the different values that consumers would place on portions of their supply: backed-up (i.e. gas supply that can be replaced with distillate oil with no loss of opportunity cost other than the increased cost of fuel), non-backed up supplies which are dispensable, and non-backed supplies which are non-dispensable (plants which face critical damage to machinery, etc.). This approach resulted in a multi-layered approach to approximating the costs of interruption to different consumers.

Some of the potential designs are tested with gas-fired generators being eligible bidders, but others do not. Gas-fired generators are assumed to always have a route to market to sell their gas, but the cost of doing so will be reflective of the opportunity cost in the electricity market. For many periods in the future, when the electricity generation mix relies heavily on renewable and gas-fired generators, the cost of interrupting gas supplies to electricity producers is the value of lost load (VoLL) in the electricity market. Recent proposals for VoLL in the electricity market combined with the penalties under the Capacity Payment Mechanism introduced as part of Electricity Market Reform (EMR) mean that the cost of interrupting supplies to gas-fired generators translates to £118/therm of gas. Some generators can avoid this cost by switching to run on distillate, but there is currently a very limited number of CCGTs which retain this flexibility.

We then examined the design of each policy design to determine the volumes and prices which would be available under each one. This provides a supply curve which can be used to allocate unserved energy to those customers for whom this would result in the least cost, rather than the current 'largest first' approach, which would allocate unserved energy to the largest customers regardless of the cost that this would incur for those customers, and the wider economy.

Cost-benefit analysis

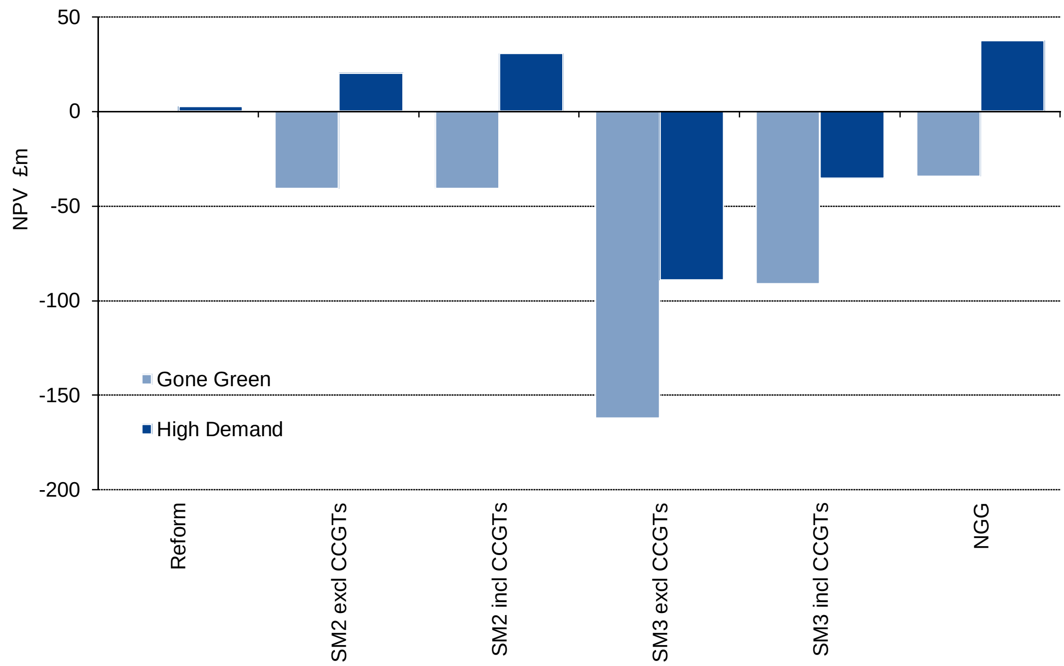
The improvement in the efficiency of allocating unserved energy results in a gross benefit in those cases where our fundamental market modelling showed that supply is insufficient to meet demand. Through calculating the cost of an emergency under each of the policy options, we can calculate the benefit that each policy would bring compared to the base case of the current arrangements. The benefits are reduced by the probability both of an extreme weather scenario and the probability of a supply failure. The benefits are then compared to the costs incurred to deliver the policy, and finally a net present value of the cost/benefit is calculated using a linear interpolation to fill the years between those which were modelled.

Reflecting the lack of unserved energy in the Gone Green scenario, none of the centralised DSR policies show a net benefit. However, under the High Demand scenario, we find that there are four policy designs which result in a positive NPV – a minor benefit from Cash-out Reform, both variants of Strawman 2 (including and excluding CCGTs) and the NGG option. The NGG option shows the greatest benefit under the High Demand scenario at £37.5m, reflecting its assumed lower participation costs. Although Strawman

3 provides a similar level of reduction in the cost of unserved energy to Strawman 2 it is adversely impacted by the annual charges from the option fees, which occur regardless of whether an emergency happens or not.

Our analysis is based on a set of assumptions and the actual results from any mechanism may vary from our results. Behavioural factors from participants, such as strategic bidding, may result in different outcomes from those we have shown.

Figure 1 – Net present value of benefits from each policy option compared to the current arrangements



Conclusion

Although the risks of a GDE are very low the impact would be enormous. Reductions in distillate backup at CCGTs and recent electricity reforms (cash-out and penalties for capacity mechanism non-performance), would see the cost of the current largest first curtailment reaching very inefficient levels. At the same time potential DSR market participants, which would face losing supply under a GDE, are not offering any interruption services, which could be addressed by providing a 'standardised' insurance product or marketplace.

Whilst the future supply and demand picture is by its nature uncertain, it seems prudent to assess the policies relating to security of supply in a risk-averse manner. Our analysis has shown that a low cost DSR mechanism that encourages maximum levels of I&C participation is an efficient and cost effective way of mitigating these risks.

Thus we recommend that either the option proposed by NGG or SM2 (either including CCGTs or preferably with a suitably high volume cap and participation incentives) is implemented. The NGG option has the highest NPV benefit (due to lower annual running costs plus provides transparent costs) whilst SM2 provides greater certainty around DSR volumes and costs. Adopting whichever scheme gains traction with the I&C community is more important than one having a greater benefit than the other.

1. INTRODUCTION AND SCOPE

1.1 Introduction

Gas is a vital part of Britain's energy mix, responsible for around 80% of domestic heating (and cooking) requirements and fuelling around a third of our power generation output.

The issue of security of gas supply is ever-present. The move from self-sufficiency to becoming dependent on imported gas, potentially tight LNG markets, high and volatile wholesale prices, and potentially limited market coverage for high impact low probability events all add to concerns about security of supply.

Key concerns around future gas security are linked to the changing nature and scale of risks associated with growing import dependence and the ability of the market to anticipate and respond appropriately. Over the last five years or so, GB has invested around £5bn in new import capacity to improve the diversity of supplies and entry points, to the extent that the GB market now has more than sufficient import capacity to meet its gas demands over the foreseeable future under normal circumstances.

Despite this, doubts persist over the ability of the current arrangements to ensure sufficient flexibility or spare capacity and whilst the GB gas market has delivered the infrastructure we need to date, even a fully functioning market can be undermined by factors beyond its control, such as major supply disruptions or extreme weather. There is a greater degree of uncertainty the further ahead we look into the future.

In January 2011 Ofgem began a Significant Code Review (SCR) into the gas cash-out arrangements. In November 2011 Ofgem published a draft policy decision to unfreeze the cash-out price in an emergency and allow it to rise to £20 per therm, which is the level estimated to be the Value of Lost Load (VoLL) to consumers.

Furthermore, the cash-out arrangements would be changed so that any consumers who were involuntarily disconnected (either through firm-load shedding or network isolation) would be paid for this service at the level of £20 per therm. The key principle being that the involuntary disconnection of firm consumers should be treated as a balancing action, and so incorporated into cash-out and remunerated accordingly. This decision was intended to provide an incentive for gas shippers to find means of mitigating the likelihood of involuntary interruptions. It is likely that a cost effective means for shippers to do this would be to enter into interruptible contracts with Daily Metered (DM) consumers who have a VoLL below £20/therm, so that, at times of system stress, their demand could be taken off and the likelihood of a Gas Deficit Emergency (GDE) significantly reduced. Ofgem's decision on the changes to the Gas SCR arrangements was reiterated in the 'Proposed Final Decision' (July 2012).

Industry stakeholders raised concerns regarding Ofgem's proposed final decision on the gas SCR. The principal concern centred around the administered estimate of VoLL for Daily Metered consumers acting as a target price. As an alternative to Ofgem's proposals Centrica raised a UNC modification proposal (UNC435) that suggests a demand-side response (DSR) auction or tender. As a result of these developments and following extensive engagement with stakeholders, Ofgem has made a number of changes to its proposed reforms:

- cash-out is to be unfrozen throughout an emergency subject to 'robustness criteria'. Ofgem no longer proposes capping cash-out at VoLL;

- the cost of network isolation is priced at the estimate of a domestic consumers VoLL which is revised to £14 per therm; and
- finally, Ofgem has agreed to explore further the possibility of having a demand-side response (DSR) mechanism for commercial customers (i.e. DMs). The outcomes from the DSR mechanism could then also be fed into the 'cash-out price' (both ahead of and during an emergency), in an attempt to produce a market-determined VoLL for DM consumers.

To take the latter forward Ofgem issued a consultation on whether or not to include a DSR mechanism in the arrangements and on the design options on the 23 July 2013.

1.2 Scope and approach of this study

The objective of this study is to undertake a cost-benefit analysis (CBA) considering the relative merits of a demand-side response mechanism, based on the designs proposed by Ofgem. The focus of the CBA is to provide confidence that the design of any chosen intervention package is robust, and will lead to improved outcomes for consumers.

To determine the elements needed to perform a cost-benefit analysis for a demand-side response mechanism we have separated the necessary analyses into the following parts:

- modelling of fundamental conditions in the gas and electricity gas markets;
- calculating the value of lost load (VoLL) in the relevant industrial and commercial segments of the gas market;
- analysis of the mechanism design and the participation in the mechanism which the design would incentivise; and
- analysis of the costs and benefits from the mechanism and cash-out reform.

Our approach to each part is explained in further detail with the report structured as follows:

- Section 2 – energy market modelling;
- Section 3 – potential participants in a demand-side response mechanism;
- Section 4 – demand-side response policy options;
- Section 5 – cost-benefit analysis; and
- Section 6 – sensitivity to the main cost-benefit analysis.

Thereafter are a number of annexes which contain supporting detail and analysis.

1.3 Conventions

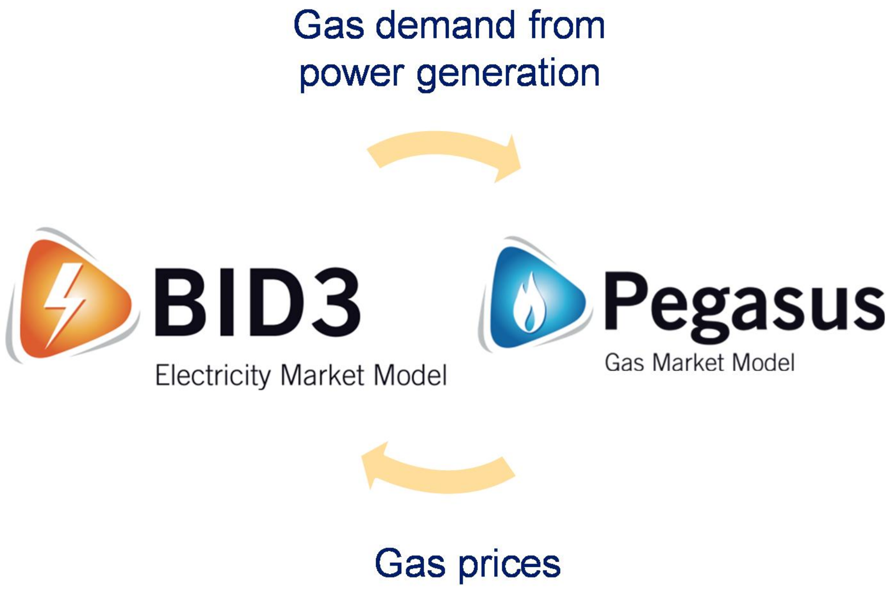
- All monetary values quoted in this report are in GB Pounds Sterling in real 2012 prices, unless otherwise stated.
- Annual data relates to gas years running from 1 October to 30 September, unless otherwise identified.
- Plant efficiencies throughout this report are defined at the Higher Heating Value (HHV) basis. Fuel prices are similarly quoted on a gross (HHV) basis.
- Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

2. ENERGY MARKET MODELLING

2.1 Introduction

Our analysis began by using our fundamental models of both the gas and electricity markets to ensure that the interactions between the gas and electricity markets were captured, as shown in Figure 2.

Figure 2 – Interaction between gas and electricity market models



For this study we have investigated two scenarios: Gone Green and High Demand. Within each of these scenarios we assessed supply disruptions which might result in a gas deficit emergency (GDE).

In each of the scenarios we looked at the price behaviour and the flows of gas to GB and the European continent; focusing in particular on unserved energy to calculate the cost of a GDE to the wider economy and how this cost is mitigated through a demand-side response mechanism as an input to the cost-benefit analysis.

2.2 Energy market modelling

Understanding of the electricity market is a key input into the gas market demand; especially considering the expected changes to the generation mix in Great Britain as coal plant close, renewable generation increases, and old nuclear capacity is replaced with new plant. Gas-fired generation will play a critical part within this mix and so the electricity sector has a strong impact on gas demand.

In addition, the proposed changes to electricity market cash-out and the introduction of the capacity mechanism as part of the electricity market reform change the financial incentives and penalties on gas-fired generation. With gas-fired power generation being such a significant part of the total gas demand understanding this new dynamic on the GDE will be an important part of the study.

2.2.1 Electricity market modelling

2.2.1.1 Electricity market modelling methodology

To consider in detail the impact that gas-fired generation will have, we have used our BID3 electricity market model. A full explanation of BID3 is included in Annex A, and a short summary of the key aspects is included below.

BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. We simulate all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year) and so ensure that weather conditions in the electricity market are consistent with those used to create daily demand in the gas market

2.2.1.2 Inputs

The major inputs to BID3 are demand, fuel prices, and the capacities of the plant available to meet demand.

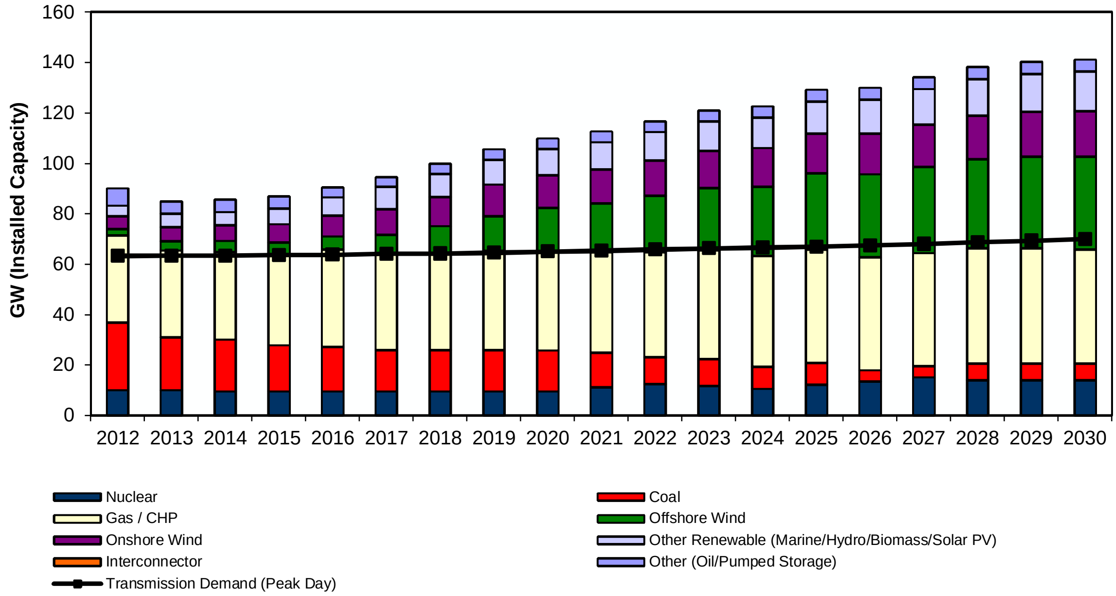
The demand and capacity assumptions used within this study were taken from National Grid's Future Energy Scenarios[3]. We assessed the electricity market using the assumptions for the Gone Green scenario, and an alternative scenario ('High Demand' scenario) using the installed capacities from the Slow Progression case from the same source. The capacities are shown in Figure 3 and Figure 4.

Minor adjustments have been made to the installed capacities to reflect recent plant closures (mothballing and permanent) and fuel conversions (for example coal to biomass). A more significant change was made to remove electricity interconnection capacity to the European continent. This change was made in order that the analysis is consistent with the assumptions made in Ofgem's 2013 Electricity Capacity Assessment Report. The assumptions within the assessment were in turn based on a previous Pöyry study which showed that under current market conditions, GB electricity interconnector flows may make the GB capacity margin situation better or worse and hence cannot be relied upon to support GB security of supply at times of GB system stress[4]. In reality, electricity interconnector flows may flow to or from GB and thus have a corresponding impact on gas-fired generation in GB.

3 http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Archive

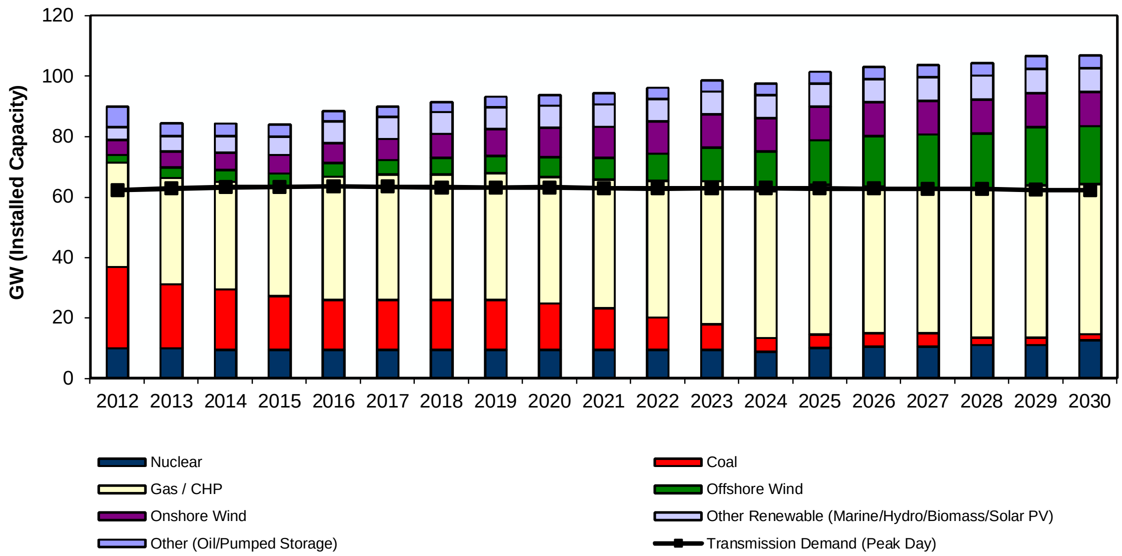
4 https://www.ofgem.gov.uk/ofgem-publications/75231/poyry-analysis-correlation-tight-periods-electricity-markets-gb-and-its-interconnected-systems.pdf

Figure 3 – Installed capacity from Gone Green scenario



Source: National Grid Future Energy Scenarios & Pöyry Management Consulting

Figure 4 – Installed capacity from High Demand scenario



Coal and oil prices are taken from the New Policies of the IEA World Energy Outlook for 2012[5]. The CO_2 prices applicable to the EU Emissions Trading Scheme (ETS) and a floor to these prices applicable in GB are taken from an update issued by the Department of

5 http://www.worldenergyoutlook.org/publications/weo-2012/

Energy and Climate Change (DECC)[6]. Gas prices are an output from our fundamental gas market modelling, and so are not defined input assumptions.

2.2.2 Gas market modelling

2.2.2.1 Gas market modelling methodology

To examine the potential for unserved energy following disruptions in the gas market, we have used our fundamental gas market model – Pegasus. Pegasus follows a similar approach to BID3 of dispatching all gas sources to minimise the cost of satisfying demand on a daily basis – also under a range of historical weather patterns. Through this approach, we capture the sensitivity of non-power gas demand to changes in effective temperature and the sensitivity of gas used in power generation to changes in wind and solar conditions, based on the same genuine weather data.

The optimisation of gas sources within Pegasus takes into account that market participants do not have perfect information about what weather conditions will occur throughout the year. Pegasus therefore schedules supplies based on good information about the weather conditions in the first few days[7], but based on imperfect information beyond this horizon. As a consequence, Pegasus has to minimise the cost of meeting demand including the uncertainty that it may face very high gas demand, caused by cold and still weather conditions, in the same way as traders and portfolio managers do in reality. Pegasus is explained in detail in Annex A including the optimisation under imperfect foresight.

2.2.2.2 Inputs

The key inputs relating to the GB market, including gas demand from the non-power sectors, were taken from the Gone Green National Grid Gas Future Energy Scenario. For the High Demand scenario, we used the non-power gas demand from the National Grid Slow Progression scenario. The gas demand from the power generation sector was taken from the relevant electricity market modelling scenario as described in Section 2.2.1 and so this approach provides two internally consistent scenarios.

To create a test for security of supply, we modelled gas demand using the weather profile from gas year 2009/10, which was much colder than seasonal normal and included the single highest historical day of gas demand. We then further adjusted the profile so that the demand matched that which would be expected in a 1 in 50 winter using data from the National Grid Gas scenarios. For the remaining countries of Europe, the demand was based solely on the 2009 weather data in order to be consistent that cold weather in GB is likely to be accompanied by cold weather in neighbouring European nations.

GB indigenous gas production and Norwegian production forecasts (shown in Figure 5) were also taken from the Gone Green Future Energy Scenarios. UK supplies have declined substantially in recent years, but are expected decline more slowly in future. Norwegian production is expected to decline steeply between 2020 and 2030, reaching less than 60bcm in 2030.

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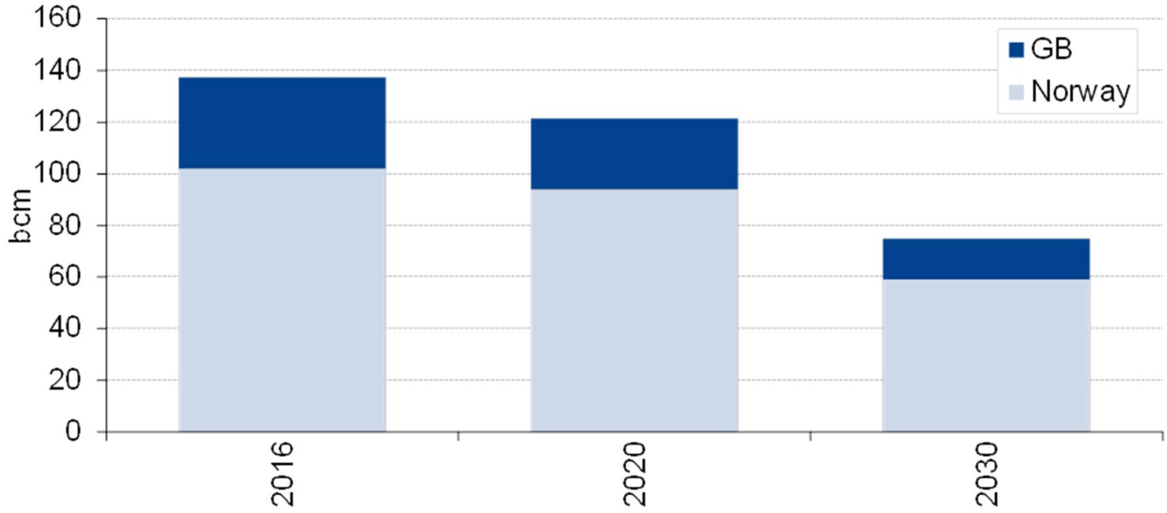
6 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/240099/short-term_traded_carbon_values_used_for_modelling_purposes_2013_URN.pdf

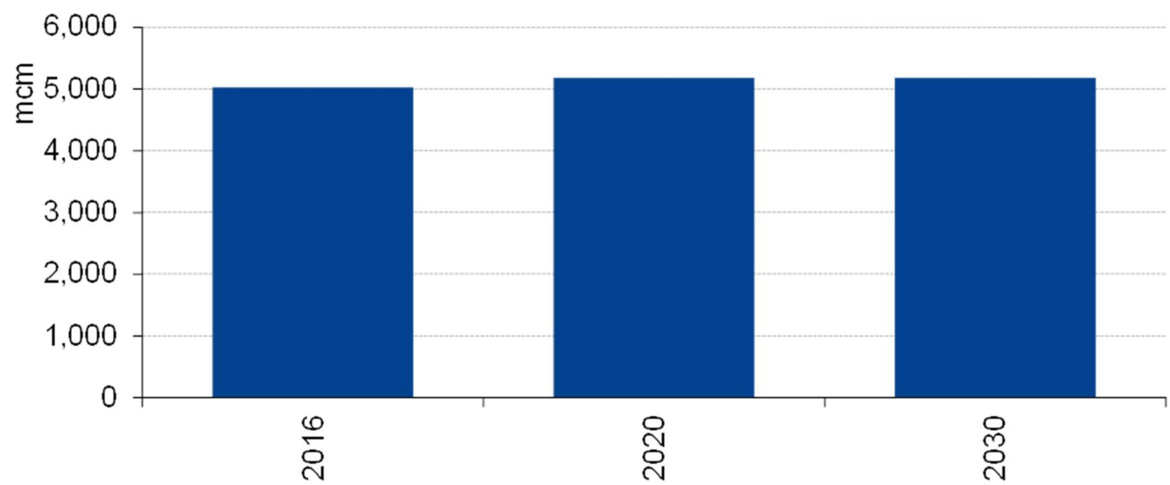
7 Akin to relying on an accurate weather forecast.

Figure 5 – GB and Norwegian gas production



Capacities of gas storage facilities in GB were taken from Pöyry's database, Central scenario (shown in Figure 6).

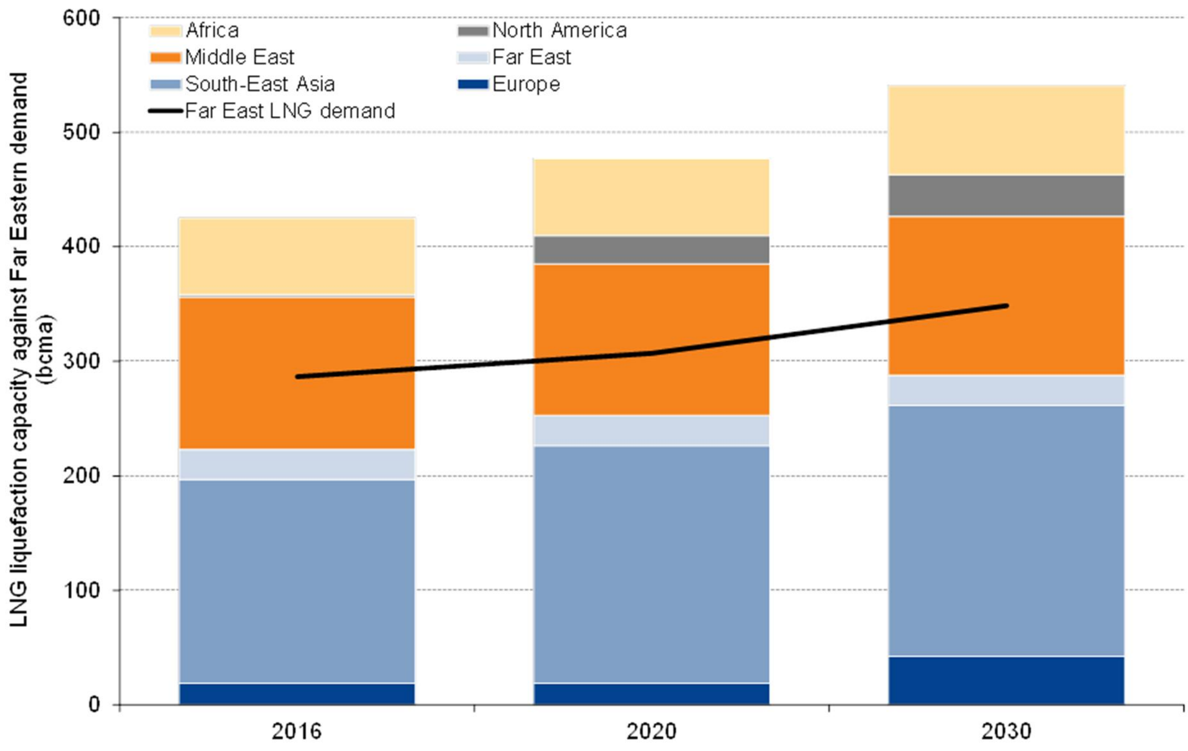
Figure 6 – GB gas storage working gas capacities



As Pegasus is a global gas model, we have also defined a number of assumptions outside GB for which the Future Energy Scenarios give no data. For these values we have used assumptions from Pöyry's Q3 2013 edition of our standard Central scenario, which covers Russian gas production, global LNG liquefaction, gas demand for countries outside GB (including in the Far-East, where we see demand for LNG rising by 22% by 2030). These assumptions are used consistently across scenarios and do not vary.

Figure 6 illustrates that there will be a considerable increase in LNG liquefaction capacity between 2016 and 2020. Much of this increase is from committed projects in Australia (and so included within the 'South East Asia' category) and a small volume of LNG available for export from North America. The increase in capacity outpaces the growth in LNG demand from the Far East; resulting in a well-supplied LNG market in 2020. After 2020, there is less certainty about the number and location of new projects; yet our expectation is that LNG liquefaction will continue to grow. Throughout this period, Qatari production remains approximately 100bcm/a and so it retains a significant market share despite growth from other LNG producing regions

Figure 7 – Global liquefaction capacity (Pöyry's Central scenario)



2.2.3 *Supply interruptions*

To understand events which could cause a gas deficit emergency, we have analysed a number of potential supply interruptions/shocks. Each 'supply shock' contains the immediate impact on supplies today/tomorrow, but the Pegasus model has no knowledge about how long the total outage will last or the future size of the supply shock. For consistency we model the supply shock for a predetermined duration. We refer to this combination of impact, outage perception and duration as a 'prognosis'.

We have selected a set of prognoses based on outages that have occurred in the market as well as those covered by the range of potential outcomes that have not, historically, been observed but nevertheless represent credible threats to security of supply.

Using predetermined prognoses in this way allows the capture of a range of potential outcomes based on supply/demand fundamentals. It also avoids being dependent on assumptions associated with a probability distribution method or whether a probability curve is correctly representing the supply disruption. Having flows and prices determined only by supply/demand fundamentals allows insights to be drawn on how the market would react to particular supply shocks without any unintended inconsistency in the assumptions.

The set of four prognoses agreed with Ofgem for investigation were:

- Milford Haven – a failure which prevents LNG being delivered from both the South Hook and Dragon regasification terminals in South Wales. The risk assessment required to satisfy EU regulation 994/2010 on gas security of supply requires that risks are assessed assuming that there is a failure of the largest piece of gas infrastructure ("N-1"). The November 2011 report compiled by DECC[8] states that the N-1 test would be the loss of both Milford Haven terminals from October 2012 onwards.
- Norway and Rough – a failure of the Norwegian transportation system at Sleipner field, which prevents deliveries of gas to GB through Langeled and through Zeepipe to Belgium, alongside a failure of the Rough gas storage. At a capacity of 70mcm/d (c. 25m therms/day), Langeled is an important route for Norwegian supplies to the GB market, and Langeled alone was close to fulfilling the N-1 criterion as the largest piece of gas infrastructure. The combined failure assumed in this case is akin to assuming a failure of the Easington terminal since both Rough and Langeled deliver into Easington (alongside smaller UKCS volumes).
- Bacton – a failure of the Bacton terminal which prevents deliveries of gas to the UK NTS of both indigenous gas landed at Bacton and gas through both IUK and BBL pipelines. The key intention of this case is to indicate robustness of security of supply in the event that no gas is available via interconnection to the continent. This could be caused by technical problems at Bacton, or market conditions on the continent preventing flows to GB.
- Qatar – a failure which prevents Qatar from exporting any gas. LNG is already a key source of gas to GB; as was shown in March/April 2013 when gas storage inventories were severely depleted when fewer cargoes than expected arrived in GB regasification terminals. Qatar has been, and is expected to remain, a key supplier to GB and a significant LNG producer on the global market.

For all failures, we assessed the impact of a 60 day outage commencing either on 15 December (for Bacton, Milford Haven, and Qatar) or 1 January (Rough & Sleipner).

2.2.4 Calculating unserved energy

Our Pegasus model matches supply to demand for each of the modelled zones and shows inflows and outflows of gas for a zone. Comparing supply and demand, the model can determine on a daily basis the amount of gas demand which remains unserved.

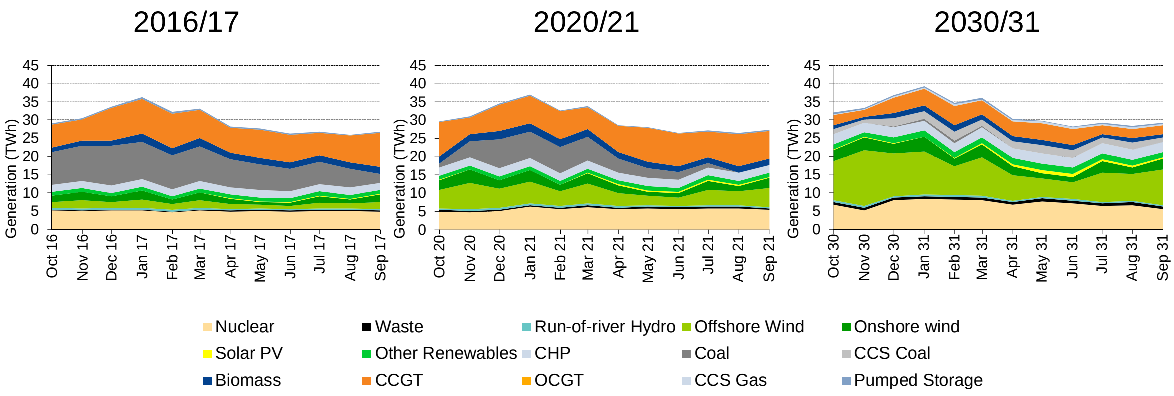
Supply disruption events, for example an outage of a critical piece of infrastructure (supply pipeline, gas storage facility, etc.), may result in supply being insufficient to meet demand. In this study we have identified the scenarios with unserved energy and conducted CBA on these scenarios.

8 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48224/3428-risk-assessment-eu-reg-sec-supply.pdf

2.3 Electricity modelling results

Using the installed capacities for the Gone Green scenarios, we arrive at the generation volumes shown in Figure 8.

Figure 8 – Generation from the Gone Green scenario



The most significant changes over the time period assessed are the reduction in coal capacity and generation, and the increase in the generation from renewable sources. This changes the reliance on CCGTs, since in 2016 gas is part of a more balanced portfolio alongside coal, with smaller contributions from nuclear and renewable sources. Therefore there is a relatively high demand for gas from the CCGTs in 2016 which diminishes by 2020, and by 2030 is clearly smaller than the generation from onshore and offshore wind. The reduction in gas demand from the power generation sector makes 2030 less challenging than 2016 from the perspective of gas security of supply.

Using the installed capacities for the Slow Progression scenarios gives the generation volumes shown in Figure 9. In the Slow Progression scenario, there is lower deployment of renewable resources, and so there is a more significant role for gas generators. 2016 shows a similar picture across both Gone Green and Slow Progression, but the role played by gas remains more stable into future periods. Coal generation declines, and renewable generation increases, but not to the same degree as in the Gone Green case. By 2030, this leaves GB heavily reliant on wind and gas generation, and thus particularly dependent on gas on days which are not windy.

The use of gas in the power generation sector in the Island of Ireland and GB is shown in Figure 10 reflecting the patterns of gas generation described above.

Figure 9 – Generation from the Slow Progression scenario

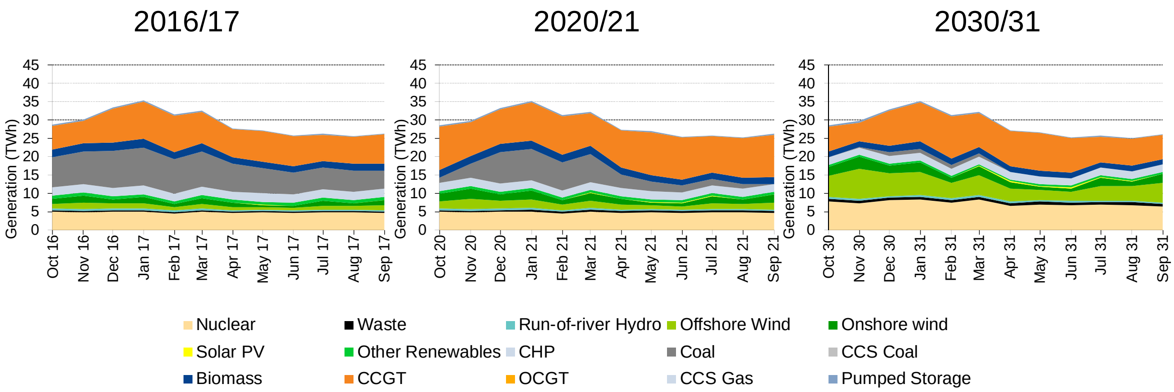
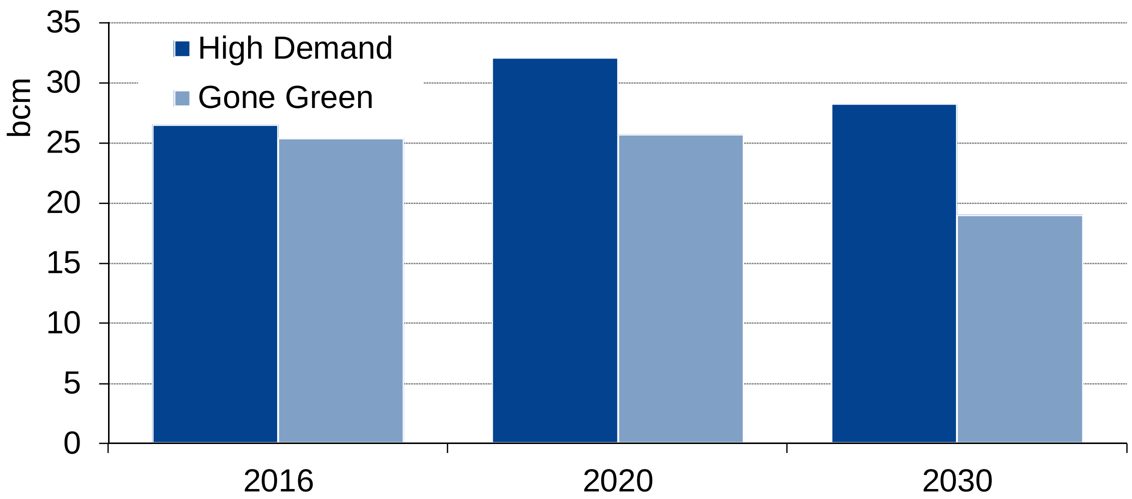


Figure 10 – Comparison of gas demand from the power generation sector for GB and Ireland

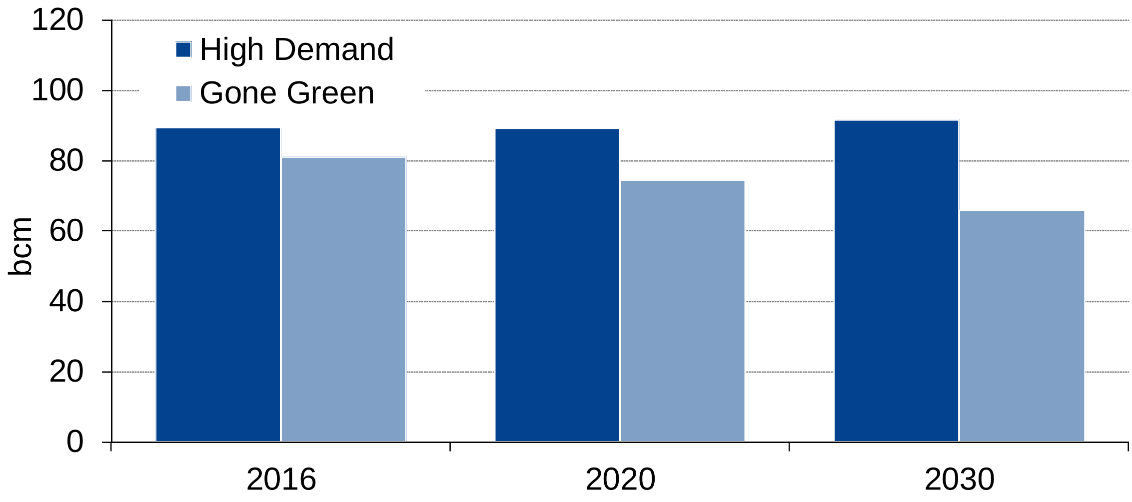


2.4 Gas market results

Total gas demand is determined by the combination of gas used in the power generation sector and the use in other sectors (industrial and commercial, small and medium enterprises and residential users). Gone Green shows a consistent reduction in total gas demand due to reductions in both the non-power sectors and the power generation sector. This has a significant impact on the later analysis, since the reduction in demand provides a much less challenging scenario from a security of supply perspective.

By contrast, demand in the High Demand scenario remains broadly stable over the assessed period; with reductions in non-power sector demands offset by the increases in the power generation sector as shown in Figure 11. The higher level of demand in the High Demand case means it is a more testing scenario when we assess the impact of interruptions to various supply sources which could result in a gas deficit emergency.

Figure 11 – Comparison of total demands for GB and Ireland



2.4.1 Gone Green scenario

The Gone Green scenario is based on the Gone Green National Grid Future Energy scenario in terms of power, non-power demand, indigenous and Norwegian production. We apply to this scenario a defined set of interruptions, described in Section 2.2.3. However, under the Gone Green scenario we see no unserved energy under any of the supply disruption cases, as shown in Table 3. A detailed description of the base case and each supply disruption can be found in Annex D.

Table 3 – Summary of Gone Green scenario infrastructure failure results

		Lost capacity (m th/d)	% of peak demand	Total unserved energy (m th)
Bacton	2016	43	25%	0
	2020	42	26%	0
	2030	37	26%	0
Milford Haven	2016	32	19%	0
	2020	32	20%	0
	2030	32	23%	0
Rough&Sleipner	2016	56	33%	0
	2020	56	35%	0
	2030	56	41%	0
Qatar*	2016	102	61%	0
	2020	102	64%	0
	2030	102	74%	0

* Qatar capacity relates to total Qatari production and so is only delivered to the GB market, but the percenatage of peak GB demand that this production represents has been presented here for consistency.

2.4.2 High Demand scenario

The following sections explain the detail within each interruption case, and the key findings are summarised in Table 4 for the High Demand scenario case, where the tighter supply and demand balance does result in unserved energy in 2020 and more in 2030.

Table 4 – Summary of High Demand scenario infrastructure failure results

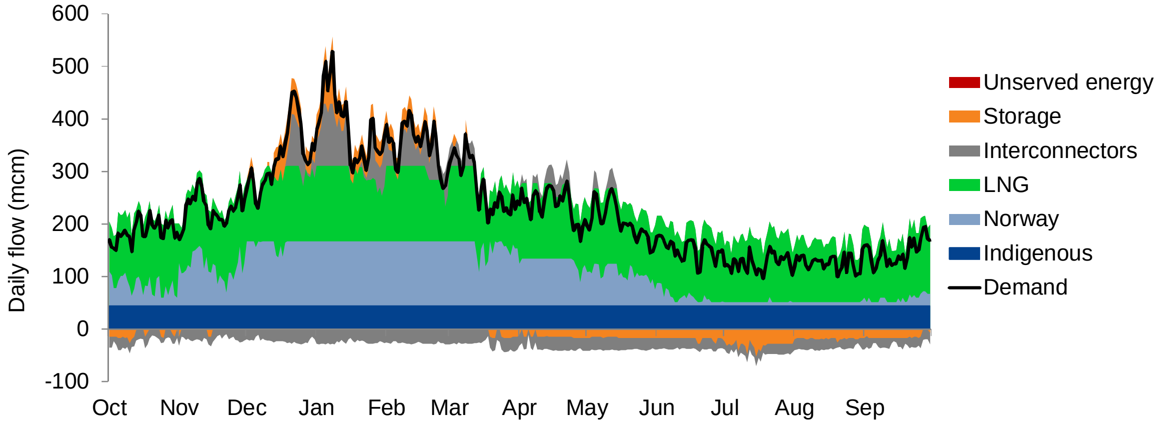
		Lost capacity (m th/d)	% of peak demand	Maximum daily unserved energy (m th/d)	No. days of unserved energy	Total unserved energy (m th)
Bacton	2016	43	22%	0	0	0
	2020	42	22%	15	13	92
	2030	37	19%	72	33	788
Milford Haven	2016	32	16%	0	0	0
	2020	32	16%	0	0	0
	2030	32	16%	19	10	82
Rough&Sleipner	2016	56	29%	0	0	0
	2020	56	29%	9	6	27
	2030	56	29%	34	40	619
Qatar	2016	102	53%	0	0	0
	2020	102	53%	0	0	0
	2030	102	53%	75	22	858

* Qatar capacity relates to total production and so is not solely connected to the GB market, but has been presented here for consistency

2.4.2.1 High Demand – Base case

This case does not assume any interruptions and the higher levels of demand in this scenario require greater imports of LNG and Norwegian gas than was shown in the Gone Green case. The higher demand also requires a greater use of interconnector flows, particularly during peak winter days, as shown in Figure 12. Under normal market conditions (i.e. no interruptions), there is no unserved energy, which would be shown in red.

Figure 12 – Sources of supply used to meet demand (High Demand with no failures 2030)



2.4.2.2 High Demand – Bacton

If the Bacton terminal were to fail, GB would lose supplies from both pipeline interconnectors to the continent (IUK from/to Belgium and BBL from the Netherlands) and so this presents a challenging case for the remaining gas supplies. In this case the indigenous production is not affected significantly, however on the days with relatively high demands, the flows from the continent cannot be fully replaced by LNG, flows from Norway or storage flows; resulting in unserved energy, as shown in Figure 13. In this case we observed several days when supply was not sufficient to meet demand - small amounts up to 15m therms/day in 2020, but much more significant levels exceeding 70m therms/day in 2030. The unserved energy occurs on the days of highest demand whilst the terminal is unavailable. This is shown in Figure 14.

Figure 13 – Sources of supply used to meet demand (High Demand with Bacton failure 2030)

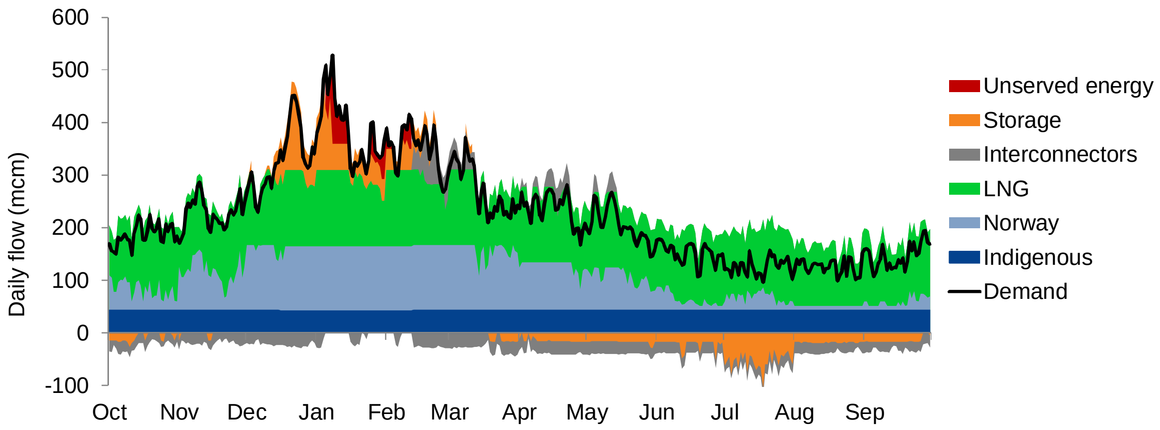
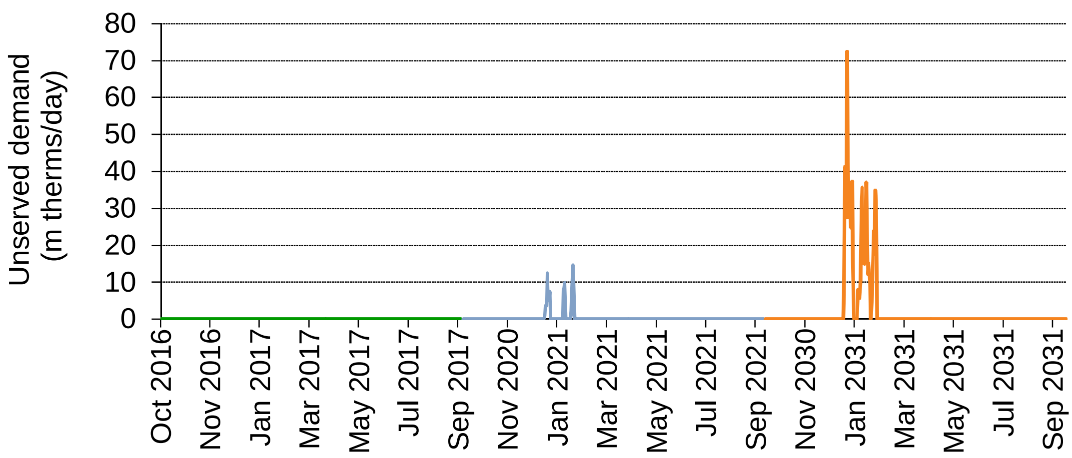


Figure 14 – Unserved energy (High Demand with Bacton failure)



2.4.2.3 High Demand – Milford Haven

If Milford Haven were to fail, GB would lose supplies from two LNG regasification terminals (South Hook and Dragon). GB would still be able to receive considerable LNG deliveries through the Isle of Grain terminal in Kent, but this is not sufficient to provide GB with all the gas required to serve demand in GB and Ireland, see Figure 15. In this case we observed a handful of days in 2030 when there was insufficient supply to meet demand. The unserved energy is not as significant as that which occurs in the Bacton failure, remaining below 20m therms/day in 2030. This is shown in Figure 16.

Figure 15 – Sources of supply used to meet demand (High Demand with Milford Haven failure 2030)

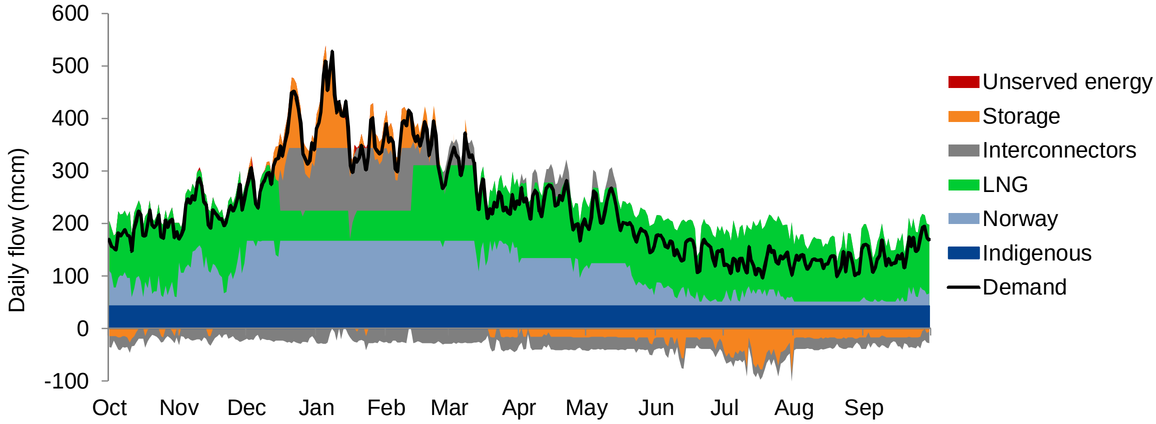
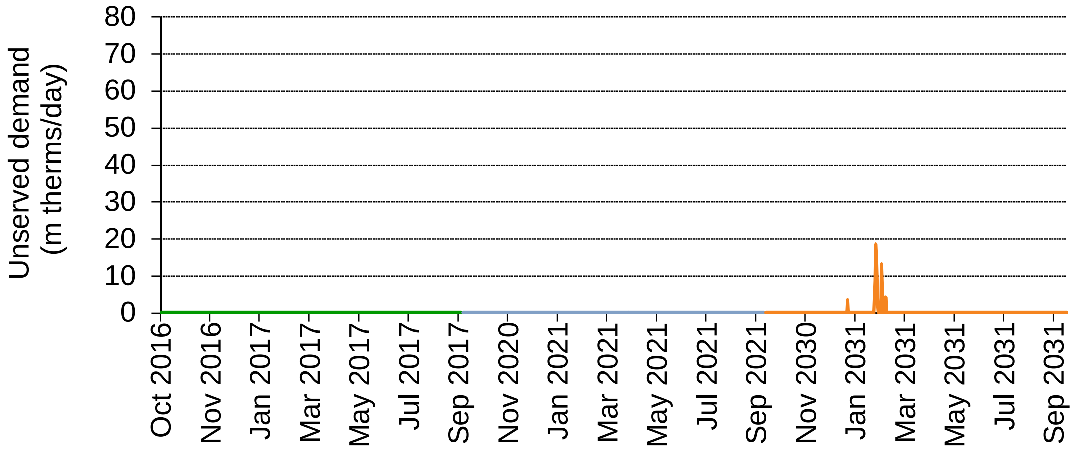


Figure 16 – Unserved energy (High Demand with Milford Haven failure)



2.4.2.4 High Demand – Sleipner and Rough

If Sleipner and Rough were to fail, GB would lose supplies from a significant Norwegian source (the Langeled pipeline) and from the largest gas storage facility. This compound failure would expose GB to heavy reliance on the global LNG market and also flows across the interconnectors from Belgium and the Netherlands as shown in Figure 17. Without Rough (which represents roughly two-thirds of GB working gas storage capacity), gas storage inventories are quickly exhausted at the start of the supply failure, and unserved energy occurs during days of high demand once storage withdrawals can no longer be maintained. In this case we observed six days in 2020 with unserved energy of less than 10m therms/day, but much higher levels of unserved energy in 2030 where there were 43 days with up to 35m therms/day of gas demand unserved. This is shown in Figure 18.

Figure 17 – Sources of supply used to meet demand (High Demand with Sleipner and Rough failure 2030)

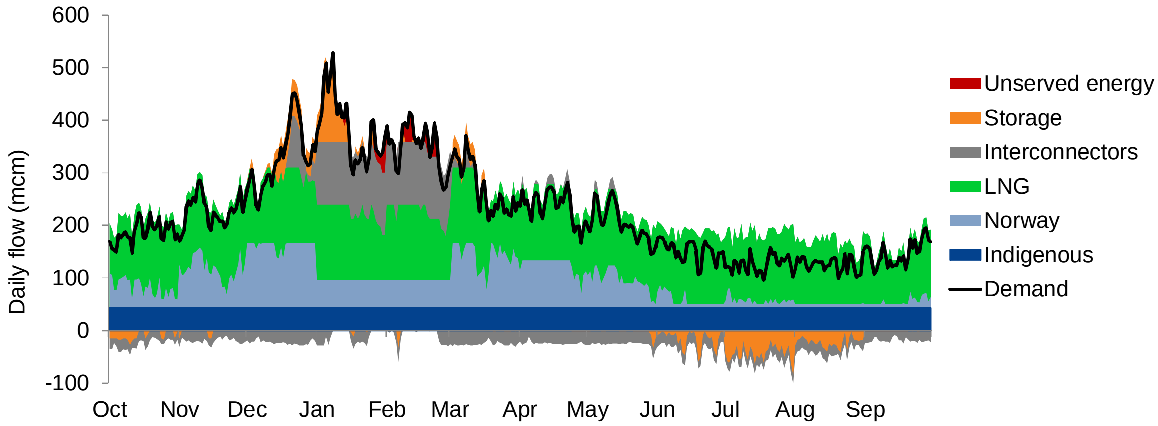
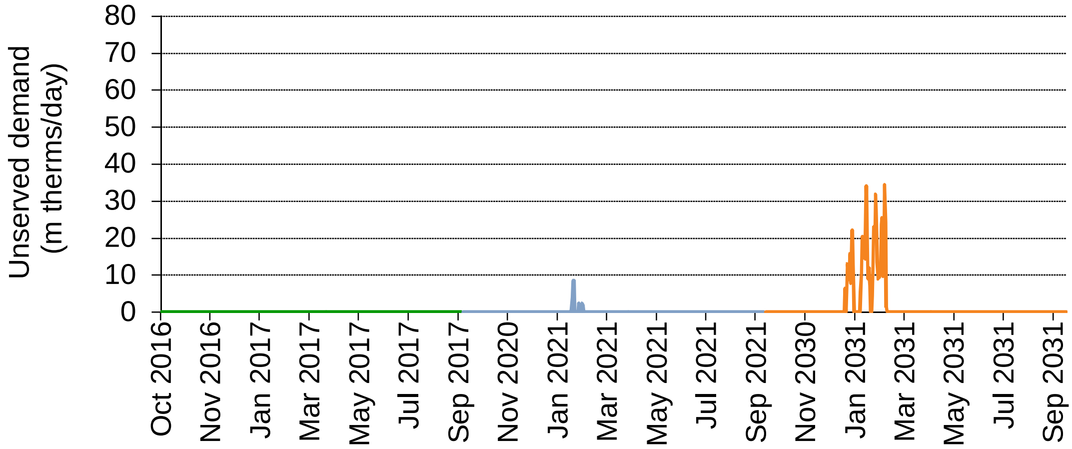


Figure 18 – Unserved energy (High Demand with Sleipner and Rough failure)



2.4.2.5 High Demand – Qatar

Qatar provides about 20% of global LNG production, and in the much tighter supply and demand position under the High Demand scenario, any such failure of its exports results in many European and Far-Eastern countries losing LNG supplies at the same time, with those in North-West Europe becoming heavily reliant on Norwegian gas and storage. During the periods of unserved energy in GB, the loss of Qatari LNG has affected also the supply/demand balance on the continent; to the extent that within 2030 there is also unserved energy in France, Belgium, and Germany. As a consequence there is high demand for pipeline supplies from Norway, and Norwegian supplies are insufficient to supply all markets with maximum volumes. The result is a noticeable dip in Norwegian supplies to GB during mid-February at a time when there is unserved energy. Diverting

Norwegian flows to the continent is not sufficient to prevent unserved energy in continental markets at the same time.

The result leaves insufficient Norwegian gas available to GB, combined with no volumes available for import via the interconnectors; resulting in unserved energy as shown in Figure 19. In this case we observed 22 days in 2030 with unserved energy. The Qatar failure results in the highest level of unserved energy seen in all of our cases; reaching a peak of 75m therms/day on one day. This is shown in Figure 20.

Figure 19 – Sources of supply used to meet demand (High Demand with Qatar failure 2030)

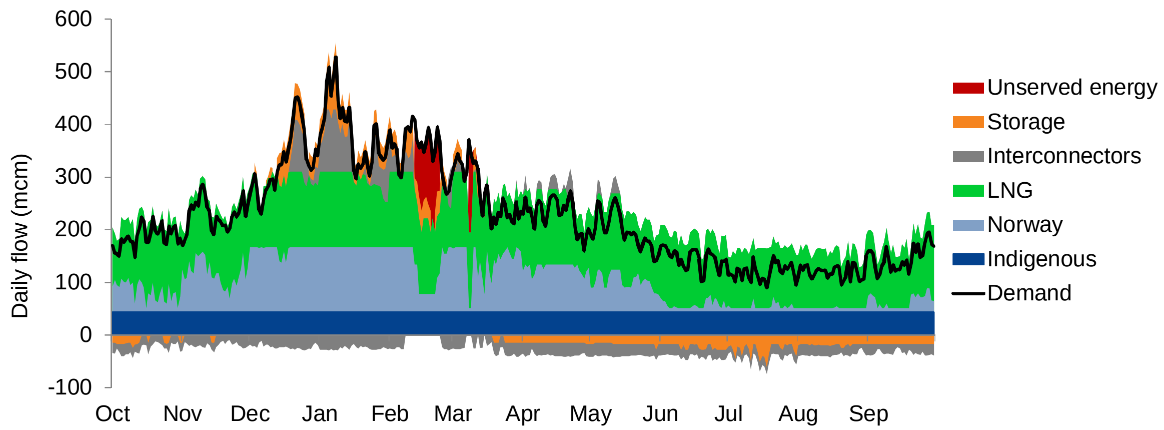
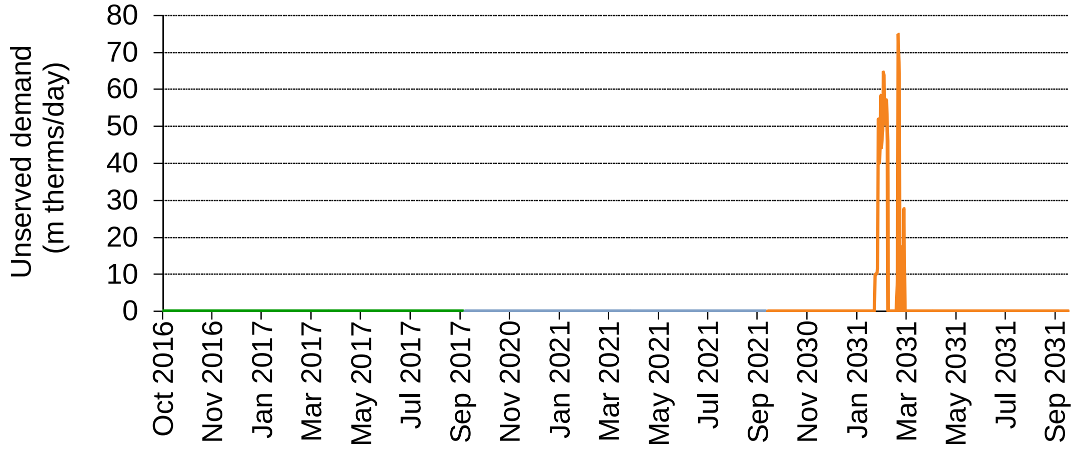


Figure 20 – Unserved energy (High Demand with Qatar failure)



2.4.2.6 Unserved energy in the High Demand scenario

The High Demand scenario had some amounts of unserved energy, depending on severity of interruption. Unserved energy in excess of 0.5bn therms was observed in Bacton, Norway and Qatari cases shown in Table 5.

Table 5 – Summary of unserved energy in the High Demand scenario

m therms	High Demand	High Demand Bacton	High Demand Milford Haven	High Demand Norway Rough	High Demand Qatar
2016	0	0	0	0	0
2020	0	92	0	27	0
2030	0	788	82	619	858

2.5 Probabilities of supply failures

In order to calculate an overall cost-benefit analysis from introducing a demand-side response mechanism into the GB gas market, it is necessary to estimate the probability of scenarios occurring which require demand-side response. The main difficulty with modelling outages is the lack of detailed or comprehensive information about outage events and whether historical data is a robust and reliable source for projecting future failures.

Pöyry undertook a previous 2010 study for DECC which included estimating the probability of supply outages[9], which itself built on a 2006 Pöyry study for the Department of Trade and Industry (DTI)[10]. In the 2006 study on security of gas supply, it proved to be very difficult to reach consensus on the probabilities of supply interruption. The outage probabilities were set on an empirical approach and the probability estimates were intended to broadly match observed historical events that have affected Britain's gas supply. The outage proportions assumed that an individual LNG source or pipeline could be completely curtailed.

Table 6 lists a number of notable events which have affected GB directly, and some events which had an impact on the European and global LNG markets; thus having a less direct impact on GB. From these incidents we observe that:

- in all cases the impact on UK supply was managed and the loss of supply was offset by additional supply from other sources (possibly including demand-side response);
- the risks that the GB market is exposed to are now more diverse than physical failures of a diversified portfolio of UKCS fields; and
- there are a number of physical and political risks which have affected production and transportation of gas, most notably the Rough gas storage fire in 2006 and the Russian/Ukraine transit disruption in 2009.

On the basis of the observations in the recent years we believe it would be unwise to change the probabilities of outages modelled on a limited data set of 'notable' outages[11]. Therefore it appears reasonable to adopt the empirical approach and probabilities that is consistent with the previous studies.

9 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47872/114-poyry-gb.pdf

10 http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file31788.pdf

11 Using the 'notable' outages in recent years on their own to form a view of probabilities could give a skewed picture as it does not include smaller potentially more frequent outages which were included in the earlier modelling.

Table 6 – Notable gas supply outages 2006 to 2009

Date	Location	Description and impact
Feb 2006	Rough storage	Fire on offshore platform results in all storage service from Rough being suspended. Stocks from other storage sites in UK drawn down and increased imports. GBA triggered on one day but no enforced curtailment. Injection restored at Rough in July 2006, and withdrawal restored in November 2006.
Jul 2007	CATS pipeline	Vessel dragged its anchor damaging pipeline resulting in a 10 week shutdown.
Feb 2008	Bacton Shell terminal	Fire at terminal interrupts flows from the Sean field. Flows restarted after 3 days.
Apr 2008	Grangemouth	48-hour strike at the oil refinery leads to Forties pipeline being closed down. Loss of gas production from Forties fields amounted to up to 70mcm.
Jan 2009	Ukraine transit	Dispute between Gazprom and Naftogaz leads to interruption to transit gas flows through the Ukraine, resulting in 20% reduction in Europe's gas supply for two weeks. UK supply not impacted. IUK increases exports to Europe during the dispute.
Jan 2010	Langeled	Severe one-day interruptions of Langeled flows, combined with cold weather resulted in National Grid issuing two GBAs. The amount of lost production was near 100mcm.
November 2010	Rough storage	A leak at Rough storage facility caused an outage lasting several days, causing a total loss of near 90mcm.
2011	Libya exports	Exports from Libya were interrupted due to civil unrest between March and October 2011 affecting more than 5bcm of gas supply.
March 2012	UKCS	Shutdown on Elgin/ Franklin field caused a loss of the full production, 15mcm/day for a day.
March 2012	Australia LNG	Production at Australian North West Shelf project was shut down due to a tropical cyclone.
March 2012	Yemen LNG	Yemen LNG facility lost four cargoes due to sabotage activities.
August 2012	St Fergus terminal	An outage on the Total St Fergus sub-terminal lasted several days and affected nearly 50mcm of gas supplies.
Spring 2013	Nigeria LNG	A leak on feed pipe resulted in Nigerian LNG announcing force majeure for half of the LNG supplies from its 22mtpa facility in April and March 2013.

Source: Pöyry Management Consulting

As the outage cases in this study are based on a 60 day outage period we have taken the conservative approach of using the likelihood of the previous 'balance of winter' event as the minimum probability[12] to be considered. Although the supply interruptions analysed here are not identical to those in the previous studies they are of such a similar nature (regardless of whether a technical or political cause) to mean we can adopt the same probabilities of 2% probability for all cases other than Rough and Sleipner, since this outage requires the simultaneous failure of two separate pieces of infrastructure and so has a lower probability of 1% assumed – see Table 7.

Table 7 – Outage events and probabilities

Failure case	Probability
Bacton	2.0%
Milford Haven	2.0%
Rough & Sleipner	1.0%
Qatar	2.0%

Source: Modification of Pöyry Energy Consulting 2010 and 2006.

2.6 Key insights

The two scenarios investigated (Gone Green and High Demand) show that whatever the situation, gas deficit emergencies are rare. If demand follows the reduction expected under the Gone Green scenario, then there is sufficient diversity in supply sources to prevent unserved energy even in the case of disruptions to a range of key supply sources.

If demand follows the High Demand scenario, then failure of import infrastructure is much more significant. Unserved energy emerges in small volumes in 2020 when GB cannot import gas via interconnectors from the continent, and in the case when pipeline supplies from Norway are severely disrupted at the same time as the failure of an important storage asset.

By 2030 unserved energy results from failure of several pieces of infrastructure, and in particularly large volumes if GB cannot import gas from the continent, and in the case where the failure of Qatar causes a widespread shortage of gas causing emergencies across Europe as well as in GB.

12 Balance of winter originally covered the an outage start date occurring at random between 1 October and 31 March, with any failure continuing for the remainder of the winter. The average outage period of a 'balance of winter' event is therefore 91 days and is therefore less likely to occur than the 60 day failure cases used within this study.

3. DEMAND-SIDE RESPONSE MECHANISM PARTICIPATION

3.1 Rationale for a demand-side response mechanism

The Gas SCR aims to reduce the likelihood and severity of gas deficit emergencies by ensuring that market arrangements provide appropriate incentives on gas shippers to balance supply and demand, through the cash-out charges shippers face as a penalty for imbalance.

The rationale for a DSR mechanism is that while demand-side actions may be the most cost effective means of addressing supply constraints, there is a material risk that a bilateral market for demand-side response will be slow to emerge (or may never emerge) and therefore demand-side participants will, in the initial phase, require a route to market for DSR services which were previously unremunerated. Doing so through a market-based mechanism creates an efficient disconnection order whereby those that have the least costly DSR are disconnected first, offering more protection to those which value their supplies more highly.

Moreover, the true cost of interruption for consumers would be revealed, and could then be incorporated in to the imbalance price; ensuring that the costs of balancing supply and demand are borne by those responsible for creating any imbalance.

Current arrangements and cash-out reform

Under current arrangements, cash-out prices are frozen if a GDE occurs, though Ofgem's updated final decision proposes to unfreeze the cash-out prices during an emergency. At present, National Grid Gas will take market balancing actions (MBA) as the residual balancer through the On-the-day Commodity Market (OCM) and over-the-counter (OTC) trading, throughout pre-emergency (issuance of a GDW (gas deficit warning) and emergency conditions (Stage 1 of a GDE). There are likely to be very limited volumes of DSR currently available through these routes, offered by the largest consumers (e.g. I&C and CCGTs) either commercially via their shippers or directly on the OCM.

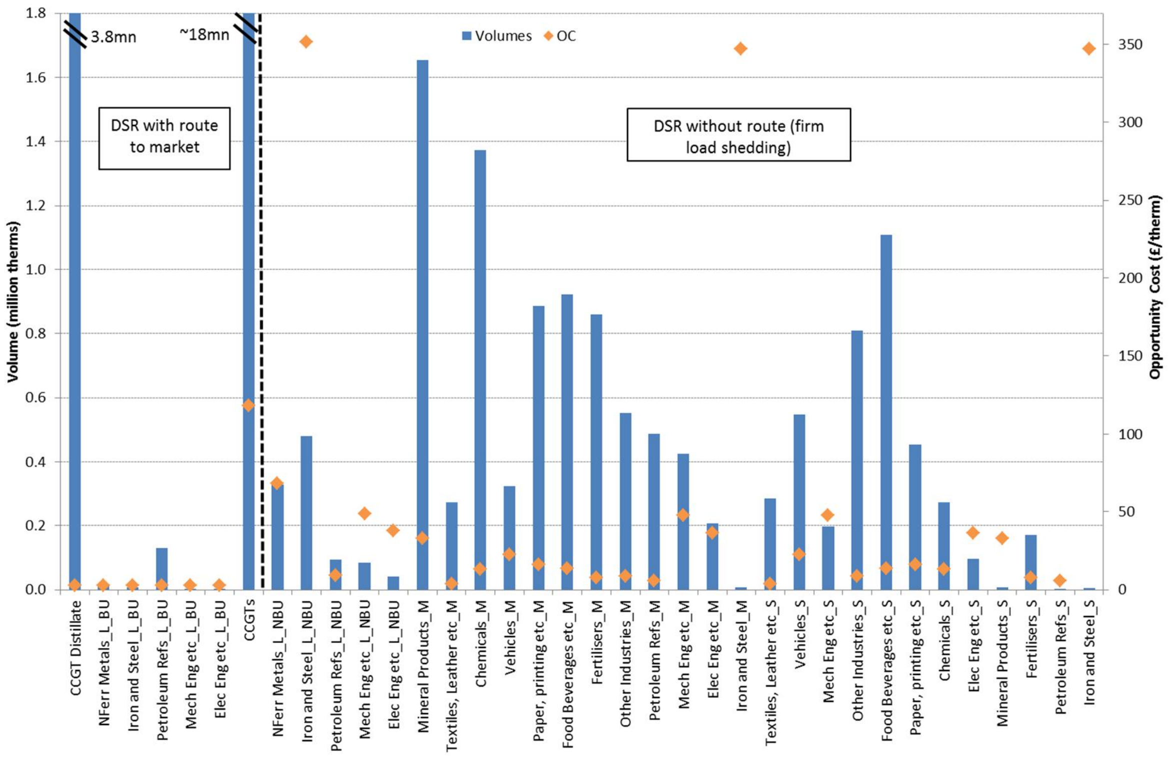
NGG will continue to take MBA in emergency conditions up to the point all possible options in the market in order to avoid firm load shedding have been exhausted. This signals Stage 2 of a GDE, where NGG ceases to take MBA and command and control is taken by the Network Emergency Coordinator (NEC). Firm load shedding is taken in order of load, largest first. This implies disconnecting gas-fired generators and large industrial and commercial gas consumers first (daily metered consumers), before invoking network isolation and therefore interrupting domestic consumers. This results in an inefficient disconnection order, as shown in Figure 21, whereby 18m therms of demand from CCGTs would be interrupted before 13m therms of demand from I&C customers.

The size classifications (Small, Medium, Large) in Figure 21 reflect that sectors are ordered according to average daily consumption per site to reflect the firm load shedding order. The opportunity cost is a volume weighted average of the costs of interruption of tranches within that sector (e.g. back-up, non-back-up dispensable and non-dispensable) and is based on the gross value added numbers supplied by London Economics to Ofgem. It also does not include I&C sectors and volumes with daily consumption below 4,000 th/day. The first in the disconnection order are those consumers which already have a route to market for DSR, which includes CCGTs/gas fired generators and some of the largest I&Cs with back-up. Note that CCGT volumes are likely to vary greatly on a daily basis, and although priced at electricity VoLL, this represents a maximum whereas in reality the OCM will allow them to bid at lower levels according to electricity market scarcity.

The proposal under the demand-side response tender consultation[13] is to unfreeze cash-out, incorporate a price of £14/therm for NDM interruptions and hold a centralised demand-side response mechanism, focused at large daily-metered consumers in the industrial and commercial sectors. DSR offered through the proposed mechanism would be exercisable from the issuance of a GDW by National Grid Gas.

As mentioned above, the benefit of a DSR mechanism is that it will allow a more efficient disconnection order to emerge in case of a GDE. The objective of this analysis is to understand what efficient disconnection curve looks like, and how alternative mechanism designs influence the volumes and costs of these bids.

Figure 21 – Example of inefficient disconnection order in 2030 under current arrangements



Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp = Dispensable, NDisp = Non-dispensable

3.2 DSR participation and pricing

Our approach to deriving the DSR mechanism supply curves consists of the following stages:

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13 Ofgem, 'Gas Security of Supply Significant Code Review – Demand-Side Response Tender Consultation', reference 130/13, 23 July 2013

- The GVA/VoLL data for I&C consumers calculated by London Economics[14] is used as a starting point. The opportunity cost as estimated by the forgone GVA per therm was maintained, but the volumes have been updated based on 2012 DUKES data.
- Our data analysis has disaggregated the volume data above on a sectoral basis for I&C consumers. At this stage we excluded those consumers which do not meet the 4,000therms per day minimum volume threshold for DSR participation. The data for each sector was split into tranches according to installation size (large, medium, small).
- We then disaggregated by relative dispensability of gas consumption (i.e. how the gas is used within each sector) into dispensable and non-dispensable tranches. Finally, we overlaid data on the availability of back-up, in order to obtain three tranches per industrial sector size class:
  - backed-up;
  - non-dispensable non-backed-up; and
  - dispensable non-backed-up.

  This approach is summarised in Figure 22 below.
- For the gas-fired generators, the volumes are generated by our Pegasus and BID3 modelling, and are contingent on the scenario and dates modelled. We do not disaggregate the generators' volumes into separate tranches.
- We then adjust the opportunity cost as provided by London Economics for each tranche in accordance to whether the tranche is (a) backed-up and (b) gas interruption would cause damage to plant integrity.
- Finally, these disaggregated DSR volumes and adjusted opportunity costs are used to construct DSR supply curves. At this stage, the effect of mechanism design on consumer participation and bidding levels will be taken into account.

3.3 Industrial and commercial consumers

Our assessment of the opportunity cost is based on the existing London Economics data set. This does not differentiate within sectors, and so we have disaggregated in the following way:

1. Volume disaggregation

- Step 1: disaggregation by consumer size using EU ETS database, eliminating ineligibles below the DSR volume threshold, and classifying into small, medium and large consumers.
- Step 2: disaggregate volumes by dispensability of consumption, assuming for simplicity that only 'High Temperature Processes' are non-dispensable.
- Step 3: define which volumes are backed-up, derived from auto-generation data and adjust by sector based on the reliance on gas / electricity.

This results in three tranches per sector size class: a backed-up tranche, a non-backed-up non-dispensable tranche and a non-backed-up dispensable tranche.

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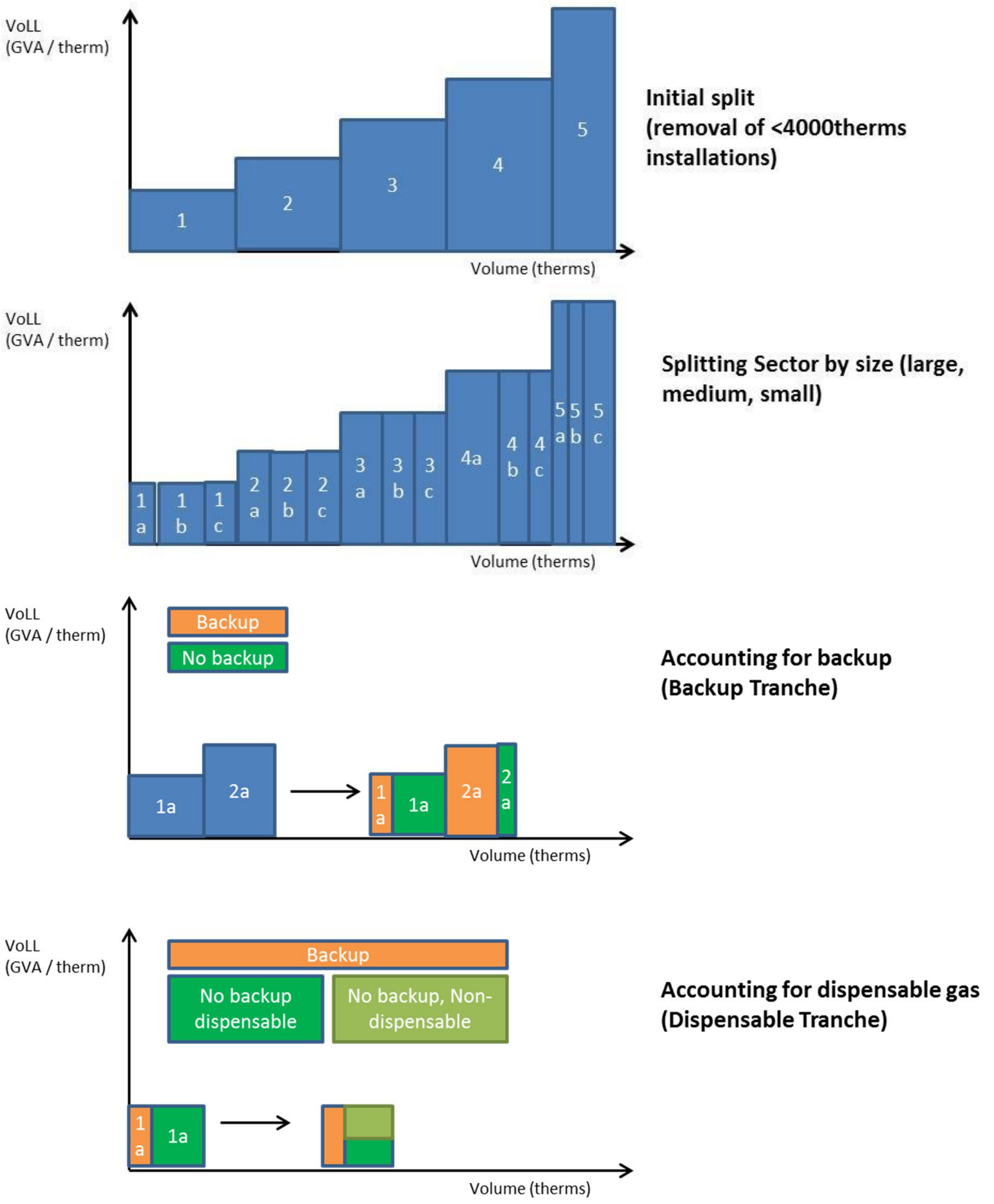
14 London Economics, 'Estimating Value of Lost Load (VoLL) – Final report to OFGEM', 5 July 2011

2. Cost of interruption

The previous step results in the three tranches per sector size category (small, medium, large), as indicated below. For each, we adjust the cost of interruption from the original London Economics GVA based opportunity cost (i.e. VoLL) to reflect the opportunity cost of interrupting that tranche.

Figure 22 – Approach to disaggregation



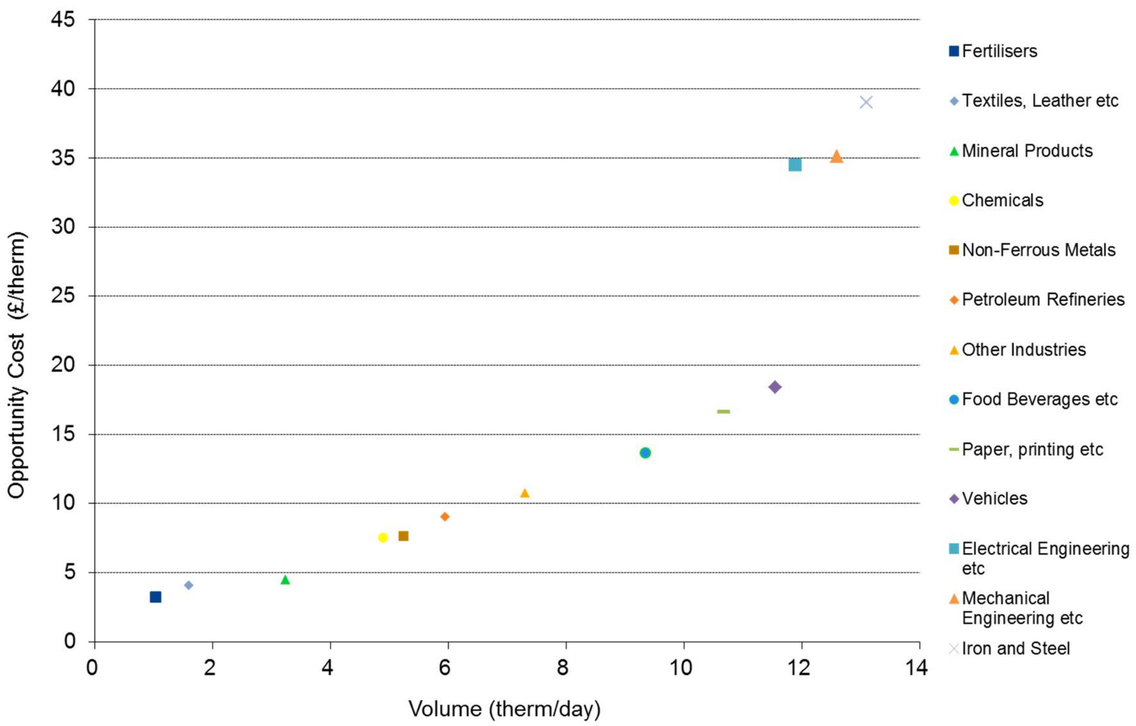
3.3.1 Original data

Table 8 summarises the total I&C volumes (using DUKES data) and opportunity costs (London Economics estimates) which form the basis of the analysis, with Figure 23 displaying this information graphically, in rising order of opportunity cost.

Table 8 – Summary of I&C sector volumes and opportunity costs

Sector	Opportunity Cost (£/therm/day)	Daily Consumption (million therms/day)
Agriculture	0.74	0.12
Fertilisers	3.22	1.03
Textiles, Leather etc.	4.06	0.56
Mineral Products	4.47	1.65
Construction	4.62	0.11
Chemicals	7.51	1.65
Non-Ferrous Metals	7.62	0.34
Petroleum Refineries	9.01	0.72
Other Industries	10.79	1.36
Food Beverages etc.	13.68	2.03
Paper, printing etc.	16.63	1.34
Vehicles	18.39	0.87
Electrical Engineering etc.	34.53	0.34
Mechanical Engineering etc.	35.13	0.71
Iron and Steel	39.03	0.50

Figure 23 – I&C volumes and opportunity costs of interruption



3.3.2 Volume disaggregation

Initially we updated the volume data used in the London Economics report to reflect changes within the sectors. Then as a second step we have split these sector volumes based on size, criticality of the gas and availability of backup generation

As we mentioned above, the first step was to update the London Economics gas consumption volume data based on the 2012 Digest of UK Energy Statistics (DUKES) data for 'Gas use in the UK Industry', combined with London Economics' auto-generation data to give a total annual consumption per sector (See Annex B). This change was made to reflect changes in the industrial consumption post the publication of the London Economics Paper.

The second stage was used to estimate the size breakdown of installations within the sectors. In order to estimate the size of installations within the sectors we have undertaken an analysis of the 2008 EU Emissions Trading Scheme Phase II National Allocation Plan[15] published by the government. Using this database we were able to estimate the size of installations within each of the sectors by converting the reported emissions data into consumption data. More details on this methodology are set out in Annex B.

3.3.2.1 Ineligible volumes

We initially removed those industries below the 4,000therm per day level as this is the threshold for participation in the demand-side response mechanisms. This corresponds to a total estimated demand of 0.5mtherms/day; approximately 3.7% of total DSR volumes. In addition the agriculture and construction sectors were removed from the analysis, as it is our understanding that the majority of the volumes associated with these sectors are not daily-metered and as a result are not eligible for participation in the DSR mechanisms.

3.3.2.2 Size classification

As we discussed above, in order to understand the distribution of DSR volumes we have disaggregated the sector level data according to individual consumer size. We have used the EU ETS data from 2008 to estimate the size of consumers within each sector

Based on discussion with Ofgem we have defined the small consumers as those with daily consumption below 25,000therms. Secondly we have defined the large installations as those installations which have gas use (in therms) comparable to the large electricity producers (e.g. CCGTs and OCGTs). The average daily consumption of the 'large electricity producers' sector (as calculated from the EU ETS data set), was used as a proxy. This defined large consumers as those who consume more than 944,962therms/day.

By applying these volume thresholds to the 2008 EU ETS data, we obtained an approximation of the proportion of total DSR volumes which fall within each size class (e.g. 30% small, 60% medium, and 10% large). Due to a lack of more recent data, we have had to assume that these proportions have remained constant since 2008, and applied these directly to the 2012 DUKES data. Table 9 below summarises the size disaggregation.

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15 2008 EU Emissions Trading Scheme Phase II National Allocation, final installation-level allocations 2008 - 2012

Table 9 – Disaggregation by size per sector (million therms/day)

Sectors	Small	Medium	Large	Total
Fertilisers	0.172	0.859	-	1.031
Textiles, Leather etc.	0.286	0.274	-	0.560
Mineral Products	0.019	1.633	-	1.652
Chemicals	0.274	1.372	-	1.646
Non-Ferrous Metals	-	-	0.344	0.344
Petroleum Refineries	0.003	0.488	0.224	0.715
Other Industries	0.809	0.553	-	1.361
Food Beverages etc.	1.108	0.923	-	2.030
Paper, printing etc.	0.453	0.886	-	1.339
Vehicles	0.548	0.324	-	0.872
Electrical Engineering etc.	0.095	0.206	0.041	0.342
Mechanical Engineering etc.	0.196	0.424	0.085	0.705
Iron and Steel	0.005	0.008	0.486	0.499
Total	3.966	7.950	1.181	13.097
Proportion of total	30%	61%	9%	100%

3.3.2.3 Dispensable consumption

To calculate the approximate level of dispensable and non-dispensable gas per industrial sector we have used fuel use data produced by DECC[16]. The data is split both by input fuel (Electricity, Natural Gas, Oil and Solid Fuel) and end use process.

Given the lack of alternative sources of data, we have assumed that tranches are considered non-dispensable where they correspond to 'High Temperature Processes'. This means that the gas which is used for alternative purposes, e.g. low temperature processes, is assumed to be dispensable. This arguably underestimates the impact of disconnecting a dispensable tranche; however a simplifying assumption was necessary for this analysis. From this data we have calculated the percentages set out in Table 10.

16 DECC, *Energy Consumption in the UK,* 2012, secondary analysis of data from the Office for National Statistics and Building Research Establishment. Table 4.05: Industrial energy consumption by end use (different processes), https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/energy-consumption-in-the-uk

Table 10 – Percentage of total gas used considered 'High Process Heat'

I&C Sector	Percentage of total gas used considered 'High Process Heat'
Petroleum Refineries	0%
Fertilisers	15%
Iron and Steel	89%
Other Industries	9%
Paper, printing etc.	0%
Chemicals	15%
Non-Ferrous Metals	89%
Food Beverages etc.	0%
Vehicles	3%
Textiles, Leather etc.	0%
Mechanical Engineering etc.	6%
Electrical Engineering etc.	5%
Mineral Products	79%

3.3.2.4 Backed-up tranches

The proportion of gas use which is backed-up has been estimated by combining the London Economics level of auto-generation by industry, and assumptions regarding whether the auto-generation is being used for electricity based processes, for heat based processes. The percentage of auto-generation (of total gas use) per sector has been adjusted by the reliance each industry has on electricity generation, to obtain the assumed back-up per industry, as per Annex B. The results are in Table 11.

The assumptions regarding back-up volumes have been sense-checked with past data on back-up volumes. In 2006 Global Insights produced a report which suggested 54% of industrial volumes were backed up. However, since the publication of this report there have been significant changes across industrial as a result of increases in back-up fuel costs and changes to industry rules and regulations. These changes have led to significant decline in back-up volumes. The risk of such a decline was highlighted in a report by Pöyry in 2010 for DECC which identified the decommissioning of back-up as a key impact of the Mod 90/195AV changes[17].

[17] Global Insight; Report for DTI and Ofgem, estimation of Industrial Buyers Potential Demand Response to Short Periods of High Gas and Electricity Prices, Table 6-4, 20 May 2005, http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file33152.pdf

Table 11 – Total assumed back-up per sector (million therms/day)

Sectors	Backed-up volume	Proportion of total sector consumption
Fertilisers	-	0%
Textiles, Leather etc.	0.052	9%
Mineral Products	0.134	8%
Chemicals	0.108	7%
Non-Ferrous Metals	0.014	4%
Petroleum Refineries	0.413	58%
Other Industries	0.328	24%
Food Beverages etc.	0.024	1%
Paper, printing etc.	0.043	3%
Vehicles	0.008	1%
Electrical Engineering etc.	0.012	4%
Mechanical Engineering etc.	0.015	2%
Iron and Steel	0.007	1%
Total (proportion of total)	**1.158**	**9%**

3.3.2.5 Defining the tranche volumes

Where back-up exists, we assume it "protects" non-dispensable gas consumption first, and is netted off against this tranche. If the volume of back-up in an industry exceeds the non-dispensable gas consumption, it is then netted off the dispensable gas consumption as well. This creates the back-up tranche (a). The remaining tranches (even for sectors without back-up) are either (b) dispensable non-backed-up or (c) non-dispensable non-backed-up tranches. These estimated volumes have been summarised in Table 12 which shows that 9% of eligible demand is backed-up, 18% is considered non-dispensable, and 73% is dispensable, but not backed up[18].

18 Note that all I&C volumes are assumed to remain constant into the future

Table 12 – Summary of the estimated volumes disaggregation by tranche (million therms/day)

	Back-up tranches			Non-back-up, non-dispensable tranches			Non-back-up, dispensable tranches		
	Small	Medium	Large	Small	Medium	Large	Small	Medium	Large
Petroleum Refineries	0.0015	0.2823	0.1295	-	-	-	0.0011	0.2062	0.0946
Fertilisers	-	-	-	0.0261	0.1306	-	0.1454	0.7289	-
Iron and Steel	0.0001	0.0001	0.0066	0.0042	0.0073	0.4268	0.0005	0.0009	0.0530
Other Industries	0.1947	0.1331	-	-	-	-	0.6139	0.4196	-
Paper, printing etc.	0.0146	0.0286	-	-	-	-	0.4382	0.8573	-
Chemicals	0.0180	0.0902	-	0.0236	0.1183	-	0.2322	1.1638	-
Non-Ferrous Metals	-	-	0.0141	-	-	0.2922	-	-	0.0374
Food Beverages etc.	0.0134	0.0111	-	-	-	-	1.0944	0.9114	-
Vehicles	0.0053	0.0031	-	0.0133	0.0079	-	0.5294	0.3128	-
Textiles, Leather etc.	0.0267	0.0256	-	-	-	-	0.2591	0.2484	-
Mechanical Eng etc.	0.0042	0.0091	0.0018	0.0082	0.0178	0.0036	0.1837	0.3969	0.0799
Electrical Eng etc.	0.0034	0.0073	0.0015	0.0009	0.0020	0.0004	0.0909	0.1963	0.0395
Mineral Products	0.0016	0.1328	-	0.0135	1.1511	-	0.0041	0.3490	-
Tranche total	0.2835	0.7234	0.1535	0.0898	1.4349	0.7229	3.5929	5.7916	0.3044
Tranche as a proportion overall	2%	6%	1%	1%	11%	6%	27%	44%	2%

3.3.3 Cost of interruption

To calculate the VoLL for large gas users London Economics used a value-at-risk methodology, whereby the VoLL for each sector (based on SIC codes) is estimated using the following equation:

VoLL = Gross value added / gas use (therms per year) * 100pence/therm

This implies that a loss of gas supply would result in loss of production in each sector equal to the GVA for that sector. Therefore to provide more differentiation between the sectors, London Economics added additional detail on the criticality of the gas:

- identifying the percentage of GVA that might be lost in a gas disruption for each subsector; and
- adjusting the GVA to account for gas used to generate electricity on site.

For this study we start from the GVA/therm (i.e. VoLL) opportunity costs calculated by London Economics, with the adjustments described below.

3.3.3.1 Backed-up tranche

For both the I&C and the generators, the cost of interruption is assumed equal to the fixed and variable costs which gas-fired generators incur in switching to distillate fuel described in Section 3.4.1.3. Arguably, this underestimates the I&C switching point, since most I&C are not expected to use back-up on a commercial basis, as is the case with gas-fired generators. In 2016, costs are estimated to be 190p/therm, but this value increases with fuel and carbon costs: 230p/therm in 2020, and 290p/therm in 2030.

Note that unlike gas generators which operate on a commercial basis, we are not assuming that autogeneration units operate on a commercial basis in the electricity market, since they are principally used for on-site production on a back-up basis. This means that we do not consider that autogeneration units would be exposed to cash-out penalties in the same way as generators.

3.3.3.2 Non-backed-up, non-dispensable tranche

In most cases, the cost of this tranche is equal to the opportunity cost estimated by London Economics (£GVA/therm). However, there are some sectors which are expected to incur damage to plant integrity if they are interrupted.

We begin by identifying sectors in which consumers might incur damage to plant integrity if their gas supply is interrupted: ceramics, brick and lime (cement), steel, agrochemicals, mechanical and electrical engineering, chemicals and glass industries, aluminium, chlor alkali, chemicals, plastics, vehicles sectors, mechanical and electrical engineering (more details on this classification can be found in Annex E).

Since these sectors risk damage to plant integrity, we assume that they are likely to differentiate their bids for the tranches which are “responsible” for that damage if it were interrupted. Again, due to a lack of data, we made the simplifying assumption that it is the non-dispensable tranche which would be “responsible” for this damage if interrupted.

Coincidentally, almost all sectors which incur damage are those which have high-heat processes, and are thereby defined as having a non-dispensable tranche as per our analysis in Section 3.3.2.3. The only sector for which this is not true is “other industries”.

In order to define the premium applied to the non-dispensable tranche in a sector which incurs some form of damage, we arbitrarily chose a factor of ten times the OC as defined by London Economics (e.g. Iron and Steel sector's non-dispensable tranche is priced at £39.03/therm*10 = £390.33). Only the non-dispensable tranche of "Other industries" remains at the original OC. i.e. GVA/therm estimated by London Economics.

It is important to note that applying this premium to non-dispensable tranches with damage is intended only to reflect the additional cost of interruption due to damage to plant integrity. They are not intended to reflect any form of strategic bidding. Moreover, the premium was arbitrarily chosen due to a lack of data, and may not reflect the actual cost of interrupting this tranche.

3.3.3.3 Non-backed-up, dispensable tranches

This will also be priced at the OC in GVA/therm. Again, this is based on the assumption that the GVA is equally dependent on the dispensable and non-dispensable tranches of consumption. This arguably overestimates the OC of interrupting a "dispensable" tranches, but is a necessary simplification given data restrictions.

Table 13 summarises the costs of interruption (which remain equal across size classification) by tranche type, using 2016 as an example. Note that with the exception of the back-up tranche, OC is assumed to remain constant in real terms into the future.

Table 13 – Opportunity cost of interruption by tranche type (2016 example, £/therm/day)

	Backed-up	Non-dispensable, non-backed-up	Dispensable, non-backed-up
Fertilisers	1.9	32.18	3.22
Textiles, Leather etc.	1.9	4.06	4.06
Mineral Products	1.9	44.75	4.47
Chemicals	1.9	75.13	7.51
Non-Ferrous Metals	1.9	76.22	7.62
Petroleum Refineries	1.9	9.01	9.01
Other Industries	1.9	10.79	10.79
Food Beverages etc.	1.9	13.68	13.68
Paper, printing etc.	1.9	16.63	16.63
Vehicles	1.9	183.93	18.39
Electrical Engineering etc.	1.9	345.29	34.53
Mechanical Engineering etc.	1.9	351.28	35.13
Iron and Steel	1.9	390.33	39.03

3.3.3.4 Limitations to the opportunity cost analysis

In the previous section we estimated the opportunity cost of interruption as the value of foregone production for a single day. This takes the output per sector on an annual basis, and divides it by the gas consumption on an annual basis. To estimate daily amounts, we assume this production is evenly spread throughout the year. However there are reasons to believe that this measure may under- or over-estimate the value of foregone production:

- As mentioned above, some sites will incur damage through participation, which will not be reflected in the OC hence the adjustment described above. We have also assumed that damage would result from any interruption to demand for high-heat processes in the relevant industries. It may be possible to prevent plant damage if only a proportion of the demand is met, though due to lack of information relating to volumes of gas required, we made the simplifying assumption that damage will be incurred with any interruption to this tranche.
- Certain sectors require a number of days to restart once their processes are interrupted.
- There may be seasonal variations in the OC which are not captured by the average.
- There may be liquidated damages payable if contracts are breached, and these amounts may exceed OC.
- OC may change as a function of the amount of time that a consumer is interrupted. In the food industry, raw materials may expire if the interruption goes on for too long;
- There may be knock on effects of an interruption, so that OC is not only the foregone production and revenue, but also reflects interruptions to downstream customers and upstream suppliers and, in the longer term, loss of market share, plant closures and job losses if an interruption lasts for sufficient time (1week+).
- OC is assumed to remain constant into the future in real terms (i.e. 2016, 2020, and 2030).

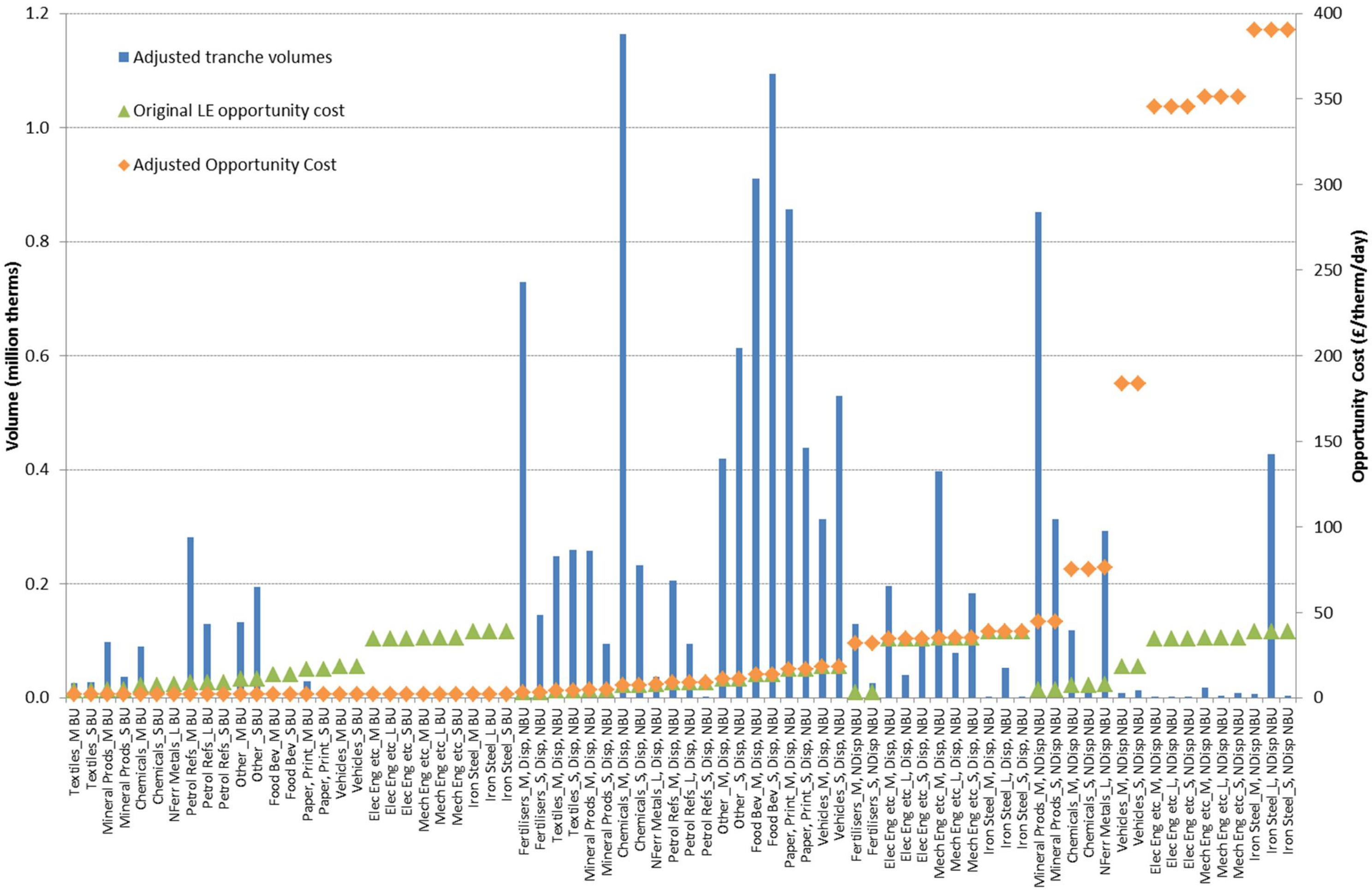
3.3.4 Implied efficient I&C DSR disconnection curve

Combining the volume disaggregation and the cost of interruption analysis, we obtain results in Figure 24, the efficient disconnection order of the I&C sectors, with volumes disaggregated into respective tranches and costs of interruption adjusted from the London Economics original. In particular:

- The adjusted costs of the tranches on the left-hand side of the chart are lower than the original London Economics cost estimates reflecting the volume of gas that has back-up, and as a result this gas is priced at the cost of the distillate alternative.
- The tranches in the centre represent gas that is not backed-up but is dispensable and so is priced at the level consistent with the London Economics study.
- The adjusted costs of the tranches on the right-hand side of the chart represent the non-dispensable gas tranche that is not backed-up in sectors which would incur critical plant damage and so priced at 10 times the level of the original estimates.

(Note the figure key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp = Dispensable, NDisp = Non-dispensable).

Figure 24 – Adjusted I&C DSR disconnection order, 2016 example



3.4 Gas-fired generators

The power generation sector offers an important source of demand-side response. For example some gas-fired power stations (CCGTs) can switch to distillate (or another alternative fuel such as naphtha) in order to continue generating without using gas. Alternatively, portfolio generators can use other fuel sources of power generation to reduce usage of gas where market prices incentivise this.

In assessing how and whether CCGTs can or should contribute to the DSR mechanisms we first look at the current capability of power generation with distillate back-up and the drivers that may influence provision of distillate capability from a practical perspective.

We then address the future market challenges from the forthcoming Electricity Market Reform (EMR) and consider how these might impact on interest and bidding behaviour in any gas DSR mechanism process from CCGTs. These reforms have a critical impact on our results since the penalties faced by CCGTs will certainly drive bidding behaviour, and since CCGTs provide such a large proportion of the potential DSR. However, our energy market modelling showed that in future, there are seldom any alternative sources of generation to CCGTs, and so interruption to gas-fired generators will very often lead to a pass through of the electricity VoLL to the gas market, whether that takes the form of the current proposed arrangements in the electricity markets or not.

3.4.1 Backed-up capacity at power generation sites

3.4.1.1 Current distillate back-up capacity at power stations

Table 14 below shows the gas-fired power generation stations that have distillate back-up and typical levels of on-site storage. The total capacity of distillate back-up at CCGTs is 10mcm/d. There is an additional 5mcm/d of this capacity in a mothballed state, but it is our expectation that this capacity will not be re-commissioned.

Table 14 – Existing CCGT distillate back-up in GB

Name	Capacity (MW)	Estimated gas use (mcm/day)	Gas connection	Days oil storage capacity	Status
Fawley	155	1	DNO	2	Open
Immingham	1190	5	NTS / Theddlethorpe	14	Open
Little Barford	665	3	NTS	4	Open
Sellafield	155	1	NTS	14	Open
Derwent	228	-	NTS	-	Mothballed
Keadby	730	-	NTS	-	Mothballed
Teeside	1876	-	NTS / Teesside	-	Decommissioning

Source: Pöyry

3.4.1.2 Future distillate back-up at power stations

Table 15 below shows that of the two committed CCGTs under development in GB neither are currently proposing distillate back-up.

Table 15 – Proposed CCGT distillate back-up in GB

Name	Capacity (MW)	Gase use (mcm/day)	Gas connection	Oil backup
Carrington	856	4	NTS	No
Abernedd	470	-	-	No

Source: Pöyry

3.4.1.3 Distillate cost

Ofgem has emphasised that the DSR mechanism is not designed with the aim of incentivising investment i.e. subsidising investment in backup capacity. Notably, there are still strong incentives being placed on gas-fired generators to invest in backup irrespective of any DSR mechanism (e.g. the electricity market penalties).

Therefore, of concern for this analysis are the fixed and variable costs of maintaining a back-up facility. These costs will cover provision of ditstillate, tanks, bunds, delivery facilities and fire protection, estimates of which are provided in Annex C.

This gives a cost of £642/tonne, equivalent to around 148p/therm. We then factor in the carbon costs, reduced efficiency, shut down time to switch between the fuels and the increased maintenance costs of running on distillate, which means that it would only be worth switching when the gas price is in excess of approximately 190p/therm in 2016.

3.4.2 Future policy impacts on gas-fired generation

This section provides an overview of the how obligations on gas-fired generation in the electricity market may impact on the involvement in the gas DSR mechanisms. We have identified what we believe to be the key drivers on this interaction for current and future gas-fired generation in the electricity market.

3.4.2.1 Capacity Payment Mechanism

The introduction of a Capacity Payment Mechanism is a key component of the Government’s EMR proposals. With significant amounts of capacity due to close in the next decade, and the desired increase in renewable (and therefore intermittent) generation by 2020 potentially reducing the operating hours of mid-merit plant, its introduction is intended to ensure that there are sufficient incentives on capacity providers in order to maintain an adequate security of supply.

The aim of the Capacity Payment Mechanism is to deliver generation adequacy. It offers capacity providers a capacity payment revenue stream, in return for which they commit to deliver energy in periods of system stress or face exposure to penalties if they fail to deliver.

Capacity contracts are allocated to providers though auctions intended to secure a capacity requirement needed to meet a reliability standard defined by government. The auction clearing price forms the basis of the capacity payment to successful auction participants. The first auction is expected to run in 2014 for delivery of capacity from 1 October 2018 to 30 September 2019, subject to state aid clearance. In addition, auctions will be held one year ahead of delivery for demand-side response (including embedded generation and smaller storage), with the first auction taking place in 2015.

3.4.2.1.1 Penalty arrangements

Capacity agreements require their holders to deliver energy in line with the underlying capacity obligation in system stress periods. Failure to deliver will result in a penalty.

Penalty payments will be set equal to the value of lost load (VoLL) minus the prevailing System Buy Price (SBP i.e. cash-out). VoLL is the theoretical cost of lost load to consumers and so represents the value placed on avoiding blackouts, estimated at £17,000/MWh. The SBP adjustment is made to reflect that if a capacity provider is not delivering energy in the system stress period, it is also likely to be facing imbalance price exposure for failing to fulfil an energy contract position. The proposed penalty, therefore, reflects the value of avoiding blackouts adjusted to take account of the impact of imbalance cash-out on overall exposure.

Ofgem's Electricity Balancing SCR set a single cash-out price of £6,000/MWh in the event of either voltage reduction or consumer interruptions. DECC's latest proposal[19] however applies an adjustment "penalty scaling factor" to allow for a level of performance incentives that is appropriately strong but that is not overly punitive and so does not significantly increase the financing costs for new investment which would deter independent investors from entering the market. The factor is set at 0.475, resulting in a penalty of (0.475* £17,000/MWh) – £6,000/MWh = £2,075/MWh.

3.4.3 DSR contribution from gas-fired generators

3.4.3.1 Distillate back-up volumes

Using the data provided above, the total CCGT distillate volume is shown below.

Table 16 – CCGT Distillate back-up volumes

Site	Capacity (MW)	Estimated gas use (mcm/day)	Million therms/day
Fawley	155	0.89	0.33
Immingham	1190	5.4	1.99
Little Barford	665	3.25	1.20
Sellafield	155	0.89	0.33

Source: Pöyry Management Consulting

3.4.3.2 Non-backed-up volumes

The volumes available for DSR vary with the electricity market and whether these consumers are generating at the time of interruption. For this reason, the volumes available vary significantly across scenarios and years (obtained from our BID3/Pegasus modelling) and represent the market activity of generators who may already be providing DSR through the OCM.

For the purposes of modelling bids into the DSR mechanism, we took the consumption from representative peak winter periods and averaged this within each of the modelled gas years as a proxy for the running patterns that gas-fired generators might expect. Table 17 summarises these volumes, which are used to calculate the volumes that CCGTs might offer into a DSR mechanism (note that in Section 3.4.3.2 we present reasons why volumes may differ by mechanism design from those set out below).

3.4.3.3 Back-up costs of interruption

As per Section 3.4.1.3, using the distillate switching point we estimate a cost in 2016 for the distillate tranche of 190p/therm. As carbon and fuel costs increase, this cost is estimated to rise to 230p/therm in 2020 and 290p/therm in 2030.

19 DECC, 'Electricity Market Reform: Consultation on Proposals for Implementation', October 2013, pp.185-7

Table 17 – Gas-fired generator volumes (million therms/day)

Gas year	Daily consumption
2016	17.6
2020	22.8
2030	18.4

3.4.3.4 Non-back-up cost of interruption

The non-backed-up volumes of generators' consumption will be priced either according to electricity market scarcity or at the maximum penalty level under the capacity mechanism.

3.4.3.5 Scarcity pricing

This assumes generators bid according to the prevailing conditions in the electricity market at the time of a gas emergency. If there are alternative means of generation at that time, the opportunity cost of interruption is equal to the price needed to incentivise equivalent generation from a more expensive source of on the electricity market, divided by the gas usage saved.

3.4.3.6 Capacity mechanism penalty pricing

If there are no alternative generation means in the electricity market, generators will face a penalty equal to the cash-out plus the penalty under the capacity mechanism, as shown in Section 3.4.2.1.1: £6,000 + £2.075 = £8,075/MWh, i.e. electricity VoLL. This converts to approximately £118/therm[20]. Our approach assumes that all gas-fired generators will be participating in the capacity market.

3.5 Summary

The rationale for a DSR mechanism is that a market-based mechanism can improve the efficiency of the disconnection order under the current arrangements whereby those that have the largest demand are interrupted first, regardless of the cost to the wider economy. Under current arrangements, CCGTs are very early in the disconnection order, yet under the proposed electricity cash out reforms and capacity payments regimes, they will face high penalties if they cannot honour their commitments in the electricity market.

Our analysis, building on the London Economics data, shows that there are a large number of I&C customers which could offer DSR at better value than the CCGTs and thus improve the efficiency of the GDE arrangements. Whether the improvement in efficiency can be realised will depend upon the policy design and the incentives that the chosen policy places on eligible participants.

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20 Assuming the level of efficiency of 50% (1MWh of lost gas curtails 0.5MWh of electricity generation), the CM penalty + cash-out at £8,075/MWh is then converted at a factor of 34.121 from MWh to therms.

4. DSR POLICY REFORM OPTIONS

The objective of this section is to demonstrate how different policy options impact the levels of voluntary DSR provided by I&Cs and electricity generators.

Three straw man tender designs were originally laid out in Ofgem's Consultation[21] (Straw man 1, Strawman 2 (SM2), and Strawman 3 (SM3)). However consultation responses and stakeholder feedback led Ofgem to request that we assess SM2, SM3 and an alternative mechanism design proposed by NGG as part of the consultation process (i.e. the NGG option) within the CBA. These mechanism designs are described in more detail below. We present here the volumes of DSR and costs of interruption expected under each policy option.

4.1 Current arrangements and cash-out reform

Whilst gas-fired generators always have a route to market for their DSR through the OCM, we expect that very limited amounts of I&C volumes currently have a route to market for DSR, whether commercially via their shippers or directly on the OCM.

We expect that cash-out reform (unfreezing the cash-out prices in an emergency) will perhaps encourage more volumes to come forward. However, there is insufficient data as to the amount of I&C customers currently providing DSR, and what volumes could be expected under cash-out reform (See Annex B.4).

In light of this, our conservative assumption is that only large I&C tranches with back-up provide DSR at present under current arrangements. Under cash-out reform, we assume that large I&C tranches with back-up, and non-back-up dispensable, will provide DSR.

4.1.1 Current arrangements

A summary of the I&C DSR volumes with a route to market under the 'current arrangements' policy option (backed-up tranches of large I&C consumers) and those without is presented in Table 18. These values are assumed to remain constant in the future. Note that for volumes "without route" only eligible DSR participants are considered. Note that the disconnection order is the same as that presented in Figure 21.

Table 18 – I&C DSR volumes under current arrangements

	With route to market	Without route
Daily consumption (m th/day)	0.153	12.95
Proportion of total daily consumption	1.2%	98.8%

4.1.2 Cash-out reform

A summary of the I&C DSR volumes with a route to market under the 'cash-out reform' policy option (backed-up tranches and non-backed, dispensable tranches of large I&C consumers) and those without is presented in Table 19. These values are assumed to remain constant in the future.

21 Ofgem Consultation on Gas Security of Supply Significant Code Review: Demand-Side Response Tender Consultation (Ref 130/13), 23 July 2013

Table 19 – DSR volumes under cash-out reform

	With route to market	Without route
Daily consumption (m th/day)	0.458	12.65
Proportion of total daily consumption	3.5%	96.5%

4.2 DSR mechanism policy options

Ofgem is considering the range of DSR mechanism policies which could be introduced alongside cash-out reform.

4.2.1 Overarching principles of mechanism design

Regardless of the precise design of the DSR mechanism, there are some key principles assumed for modelling purposes:

- The product offered is the provision of daily demand-side response with no limit on the number of times the response may be exercised or duration once exercised, with a notice period of 4-6 hours.
- Eligible participants are defined as gas consumers with daily metering capacity (daily metered (DM) consumers and those directly connected to the national transmission system) which can choose whether or not to participate and the volume and price they bid (subject to the minimum threshold of 4,000 th/day).
- Accepted bids will form a DSR supply curve, detailing the costs and volumes of DSR which NGG can procure, in rising order of cost.
- If a consumer bids in more than one tranche, each tranche will be treated as a separate bid, and only accepted tranches will be remunerated.

4.3 Actions around a GDE

In the run up to a GDE, I&C consumers and gas-fired generators with an existing route to market for their DSR will be able to supply this through the OCM.

The first, pre-emergency, stage of a GDE commences upon the declaration of a Gas Deficit Warning. At this stage NGG will take market balancing actions in price order, through the OCM/OTC and the DSR mechanism offers. NGG is obliged to operate the system in an efficient, economic and co-ordinated manner.

When balancing the system, the minimum size MBA that NGG considers will have a discernible impact on the system is 3GWh (~0.3mcm). The minimum size for a trade is 100,000KWh (~4,000therms) and an MBA may be made up of many such trades.

We have assumed that during the GDW, the cash-out price charged to shippers will be equal to the most expensive balancing action taken by NGG on that day – whether this is the cost of exercising DSR bids, or interventions in the OCM market.

As the emergency progresses, there is no hard cap on the costs of actions that NGG may take in its role as residual balancer, but it is still obliged to act in an economic and efficient manner. On the cusp of Stage 2 emergency, (i.e. when involuntary firm load shedding begins) NGG must assure the National Emergency Coordinator that it has exhausted all possible options in the market that could have averted firm-load shedding. As such, NGG could potentially take an action on the cusp of Stage 2 at almost any price if the action represents a material volume that is of sufficient size to avert the need to go into firm-load shedding. In principle this means NGG may deem a very high priced action to be justified as efficient if that action could save the system and avert firm-load shedding.

4.3.1 GDE Stage 2 assumptions under current arrangements, new cash out, SM2 and SM3

The second stage of a GDE will be reached if the required curtailment goes beyond the volumes offered by these accepted bids from the DSR mechanism. In Stage 2 firm-load shedding is initiated, and any consumers that National Grid interrupts will be interrupted purely on the basis of load size.

In the case of SM2 and SM3, among consumers disconnected in Stage 2 are three categories:

1. Eligible consumers which participated and submitted unsuccessful bids. They will be remunerated at the 30-day System Average Price (SAP) based on the 30 days prior to the emergency event[22].
2. Ineligible consumers which did not meet the minimum eligibility standards (the minimum volume threshold) to participate in the DSR mechanism. They will be remunerated at the volume weighted average of exercised DSR bids during stage 1[23].
3. Eligible consumers which chose not to participate, who will not be remunerated for the DSR provided.

4.3.2 GDE Stage 2 assumptions under the NGG option

Under the NGG option design, there is no cap on accepted bids.

From a modelling perspective we assume that all bids up to the cost of NDM network isolation could be justified by NGG as being ‘economic and efficient’. However, when NGG is close to exhausting all market actions (i.e. it is close to entering involuntary interruptions as part of Stage 2 firm-load shedding) it will become increasingly concerned with the materiality of offers, and so will consider the likelihood of a given action averting firm-load shedding. This means they will not exercise the most expensive bids unless they are sufficient to avoid firm load shedding.

In all policy options, consumers will be treated as a complete site in the firm load shedding Stage 2, and will not be able to shed in tranches. For the purposes of modelling, we assume loads are instructed to shed on the basis of site size, not remaining unshed volume.

Note for the purposes of modelling, we assume that the cash-out charge that shippers will face in the Stage 2 (including both sub-stages) is equal to the price of the highest exercised bid in Stage 1.

To re-iterate, the disconnection order in Stage 1 is economically efficient in ascending order of opportunity cost. Stage 2 is economically inefficient in comparison, with

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22 This assumption has been made for modelling purposes, and is still subject to final decision.

23 This assumption has been made for modelling purposes, and is still subject to final decision.

interruptions occurring in descending order of consumer volume, irrespective of opportunity costs.

4.3.3 GDE Stage 3

The third stage of a GDE is reached if required curtailment goes beyond the volumes offered by Stages 1 and 2. The third stage is network isolation and involves the interruption of NDM consumers. In order to limit the risks imposed on shippers, the cash-out charge will be limited to the cost of the first day of network isolation. NDM consumers have a VoLL of £14/therm for a one day outage. Any NDM disconnection would involve isolating a network and our working assumption has been that this would entail any affected consumers being offline for 14 days. This means the marginal cost of NDM network isolation is actually 14x14 = £196/therm.

4.4 Straw man mechanism designs

A summary of the DSR mechanism designs is presented in Table 20.

For each of the DSR mechanism designs, the outcomes vary with each modelled gas year (2016, 2020 and 2030) and two sensitivities per year – one including gas-fired generators within the mechanism, and one excluding them. It should be noted however that even when generators are excluded, they can still provide DSR through the OCM route to market.

4.4.1 I&C participation

Consumers have strong incentives to participate because of the opportunity to hedge the costs of interruption, and are better off through participation than they would otherwise have been in the event of a GDE through the payments which they would receive whether successful or not. The benefit that a consumer derives from participation is a function of their dependency on gas consumption for production. Sectors with higher dependency have more to gain from hedging this risk than the remainder.

Nonetheless, consumers also face barriers to participation through an increased likelihood of disconnection through participation, transaction costs for formulating and submitting a bid, and other annual costs (contractual and health and safety arrangements).

4.4.1.1 Increased likelihood of disconnection

The current disconnection order is economically inefficient, based on the principle of shedding the largest load first, as seen in Section 3.1. At the front of the order are gas-fired generators and the largest industrial and commercial consumers of comparable size.

Successful participation in the DSR mechanism necessarily involves increasing one's probability of disconnection, since a consumer will move forward in the disconnection queue. Since smaller consumers would be located at the end of the largest first disconnection order, they incur the greatest increase in probability of disconnection through participation, whereas the largest consumers incur the least change.

This increased probability of disconnection is a cost incurred on an annual basis through participation, equal to an increase in the present value of the OC of interruption, as this event becomes more likely. Since this cost increases inversely with consumer size, the smaller the consumer the higher this economic barrier to participation. However, large consumers already face a high probability of disconnection in the inefficient disconnection order, and so the change in probability through participation is less significant, particularly for those of comparable size to a gas generator. Notably, this cost can only be recovered through an option fee.

Table 20 – Modelled DSR mechanism design options

DSR mechanism policy option	Strawman 2	Strawman 3	NGG option
Pay-as-clear vs. pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-bid
Exercise / Option fees	Exercise only	Exercise and variable option fee	Exercise only
Decision criteria	Volume cap (TBC, modelled at 70%)	Volume cap (TBC, modelled at 70%)	NGG decision on the day.
Contract duration	One year	One year	Real-time updating
Format	Sealed-bid tender	Sealed-bid tender	Real-time updating
Payments to unsuccessful bids	30 day SAP	30 day SAP	30 day SAP
Payments to ineligibles	Average of exercised DSR bids	Average of exercised DSR bids	Average of exercised DSR bids
Payments to don't participates	Zero	Zero	Zero
Gas-fired generation bidding	Electricity VoLL	Electricity VoLL	Scarcity
Gas-fired generation sensitivity (eligibility)	Included & Excluded	Included & Excluded	N/A

4.4.1.2 Transaction and other annual costs

In addition, these other costs of participation (such as transaction costs) are both higher for smaller consumers (since larger consumers benefit from economies of scale) and are less affordable, since consumer size can be used as a proxy for access to financial resources.

It is important to note however that although these barriers seem higher for small consumers, they must be weighed against the benefits of participation. A consumer with a higher dependency on gas will have more to gain from hedging this risk to their consumption through participation than one who is less dependent, i.e. the benefit of participation is greater, and is a function of a consumers' dependency, not their size.

4.4.1.3 I&C volumes bid by straw man

If the costs outlined above are not considered significant, a consumer will have a strong incentive to participate in the DSR mechanism.

Larger consumers already face a high probability of disconnection in the current order, incur smaller costs of participation and these are more affordable. The benefit of participation is clear for these consumers, enabling them to hedge a risk and receive a payment in the event of interruption. This is true even if they are unsuccessful, obtaining a reduced payment (the 30-day System Average Price (SAP) based on the 30 days prior to the emergency event).

Small consumers however, face proportionately higher costs – due to reduced scale and significantly increased probability of interruption – and are less able to afford these, unless they are paid through an option fee. This means we consider that small consumers do not participate in mechanisms where there are no option fees (i.e. SM2 and NGG proposal).

Nonetheless, we assume in all cases that the backed-up tranches do participate in the mechanism (even those assigned to small consumers). Since their production is already protected by back-up in this tranche, the opportunity cost of interrupting this tranche is much smaller, and the cost associated with the increased likelihood of using this is negligible.

4.4.1.4 I&C exercise fee bids by straw man

We typically assume that consumers bid in a manner which is representative of their true opportunity cost (OC) of interruption on the basis of economic rationality. However, we did not take into account the fact that participants may choose to bid strategically (e.g. adding a premium to their OC) in order to maximise payments or load protection. The data underpinning this section of the analysis was not sufficiently granular to allow for this level of detail on bidding behaviour. Nonetheless, the subject of the relative merits of each mechanism design, and the effect on bidding behaviour are important factors to take into consideration when designing these mechanisms, and will be expanded upon in the subsequent section.

4.4.2 Gas-fired generator participation

For each mechanism design, there will be a sensitivity including and excluding the participation of generators from the mechanism. Nonetheless, in all cases we assume that generators can still provide a route to market through the OCM. These bids reflect distillate switching, scarcity rent or electricity market penalties under the capacity mechanism.

4.4.2.1 Generator volumes bid by straw man

We make a distinction between SM2/NGG and SM3. In the former two, there are no penalties for self-interruption (i.e. when called, a consumers does not have to provide a net response if already self-curtailed). However, SM3 necessitates the provision of a guaranteed response (i.e. when called, a consumer has to provide a net response so there is a penalty for self-interruption).

Therefore we consider that generators will be more conservative about the volumes they bid under SM3, and will not be able to participate in the OCM with the volumes offered under the tender. For SM2 and NGG, we will assume generators offer peak volumes into the DSR but they will use the OCM if the opportunity allows. In essence, there is no penalty for overestimating, and so peak consumption can be offered without fear that the CCGT won't be running at the time of the interruption. The difference between SM2 and NGG is that in the former, generators must commit to the volumes through the annual tender, whereas the NGG option allows them to do so in real time through the market platform.

For SM3, we analysed the minimum levels of running, and assumed that CCGTs would be prepared to take a small amount of risk; assuming that they would offer a volume which could be delivered 80% of the time in our two scenarios. We did not take the absolute minimum since the option fee should incentivise bidders to take part and assume a low level of risk. The absolute minimum is very close to zero and so would give a negligible difference from the case where CCGTs were excluded. The distillate volumes remain the same throughout the period.

Table 21 – CCGT volumes by straw man (million therms)

	Daily consumption		
Gas year	SM2	SM3	NGG
2016	17.6	12.3	Volumes available on the day
2020	22.8	13.3	
2030	18.4	5.5	

4.4.2.2 Generator exercise fee bids by straw man

Prices for the non-backed-up tranches are as follows:

- SM2 and SM3: given that generators will only be allowed to bid on an annual basis, they cannot bid in real time according to the prevailing conditions in the electricity market at the time of a gas emergency. We assume that they bid in a risk averse manner, at electricity VoLL equal to the level of the cash-out plus the penalty under the capacity mechanism, as shown in Section 3.4.2.1.1: £6,000+ £2.075 = £8,075/MWh. This converts to approximately £118/therm.[24] This approach assumes that all gas-fired generators will participate in the capacity market.
- NGG option: given that generators are able to bid in real time under this option, we assume that they bid according to electricity market scarcity.

Backed-up tranche pricing does not vary by straw man, in line with Section 3.4.3.3.

This methodology assumes that bidding in a risk averse manner is equivalent to bidding at electricity VoLL, and effectively assumes that the only mitigation for the risk of disconnection due to a GDE would be through the OCM or a DSR mechanism.

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24 Assuming the level of efficiency of 50% (1MWh of lost electricity is equivalent to 1/2MWh of lost gas), the CM penalty + cash-out at £8,075/MWh is then converted at a factor of 34.121 from MWh to therms.

However, this approach is a simplification, and there may be reasons why generators do not act in this manner. Generators cannot be certain that any bids at £118/therm will be accepted by NGG, as was explained in Section 4.3. NGG may deem such a high-priced action to be inefficient, or unable to avert firm load shedding. This approach also disregards alternative mitigation strategies, such as investing in back-up.

4.4.3 Derivation of variable option fees

Under SM3, participants are allowed to bid in both an exercise and option fee. For both I&C consumers and gas-fired generators, we use a sum of parts approach to estimating the option fee they will bid into the mechanism. These should only include costs which are incurred on an annual basis by participating in the tender. At a minimum, these are the costs the option fee should cover:

- cost of increased probability of disconnection;
- transaction costs; and
- other annual costs.

Stakeholders have indicated the desire to cover the costs of maintaining back-up through the option fee. Strictly speaking however, this cost should only be priced into the option fee if it is incurred through participation in the mechanism. Those which would have maintained their back-up irrespective of the DSR mechanism should not include this cost into their bids. However, we consider that an annual mechanism, at which success is not guaranteed on one or consecutive years, provides insufficient incentive to maintain back-up which would otherwise be decommissioned. For that reason, it is not included in the analysis.

4.4.3.1 Cost of increased probability of disconnection

The cost of increased probability of disconnection varies on a sectorial basis, according the opportunity cost per therm of interruption. We have taken a very simplistic approach to estimating this cost, using data which is already in the public domain.

I&C non-backed-up tranches

We have used the probabilities estimated in a report for Ofgem[25] which calculates the probabilities of interruption of firm DM consumers under current arrangements (1/55 years), and the probability of interruption of a firm electricity interruption (1/34 years). The current disconnection order is on the basis of largest first, and in theory, if I&C consumers participate they will be taking the place of generators in that disconnection order. Consumers will have access to this public data, and although they may have difficulty estimating their exact probability of interruption and how this is altered through participation, this will provide them with a rough estimate.

In fact, this cost should be differentiated according to consumer size, but given the scarcity of data we have been unable to do so. This cost is likely to be underestimated for the smaller players, who are at the end of the current firm load shed disconnection order, with the opposite being true of larger consumers.

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25 Redpoint Energy, Gas security of supply Significant Code Review: Economic modelling or Ofgem's proposed final decision, July 2012, https://www.ofgem.gov.uk/ofgem-publications/40922/120731gasscrrp.pdf

Table 22 below summarises the costs based on the exercise fees of different sectors. A distinction is made between the non-backed-up tranches which do not incur damage, and those which do incur damage, with the cost rising tenfold in the latter.

Table 22 – Estimate costs of increased probability of disconnection per sector (£/therm/day)

	Sector	Cost (£/therm/day)
Non-backed tranches without damage to plant	Fertilisers	0.036
	Textiles, Leather etc.	0.046
	Mineral Products	0.050
	Non-Ferrous Metals	0.086
	Petroleum Refineries	0.101
	Other Industries	0.121
	Chemicals	0.084
	Food Beverages etc.	0.154
	Vehicles	0.207
	Paper, printing etc.	0.187
	Mechanical Engineering etc.	0.394
	Electrical Engineering etc.	0.388
	Iron and Steel	0.438
Non-backed tranches with damage to plant	Mineral Products	0.503
	Chemicals	0.844
	Non-Ferrous Metals	0.856
	Vehicles	2.065
	Electrical Engineering etc.	3.878
	Mechanical Engineering etc.	3.945
	Iron and Steel	4.383

I&C and generators back-up tranches

The differences in these probabilities are applied to the OC of interruption per therm in each sector. This cost reflects an increase in the present value of the OC of interruption through participation in the mechanism, on the basis of foregone production. This cost is therefore not applied to the backed-up tranches, since production is already protected in these tranches.

Gas-fired generation DSR tranches

Similarly, these costs are not applied to the gas-fired generator's option fees. This is because their bids at the price of electricity cash-out costs (£118/therm) is likely to make their bid unsuccessful, and their chances of disconnection have actually improved (decreased) through participation. This would allow them to bid a negative or zero option fee, in theory. However, we assume that they bid at a minimum level equal to their transaction costs.

4.4.3.2 Transaction costs

These include the costs of formulating and submitting a bid: estimating one's own OC, that of your competitors to understand positioning in the disconnection order, chances of success through relative positioning in the OC based merit order. As we have mentioned, estimating one's opportunity cost is complex - estimates are uncertain at best, and can vary with the business cycle.

Larger consumers may benefit from economies of scale which reduce these transaction costs. For instance, larger consumers may already have an energy manager who only requires a few extra hours to elaborate and submit a bid, whereas smaller consumers may have to rely on the financial manager or external help.

4.4.3.3 Other annual costs

Other costs include contractual and legal arrangements to be made with suppliers, who remain the intermediaries between the NGG and the consumer. This is a one off cost which is probably similar irrespective of participant size. Finally, there are also health and safety costs relating to the training of staff such that they know how/what to partially interrupt to ensure they are compliant with the terms of their DSR bid (i.e. 4-6hr response time). These costs increase with consumer size.

Table 23 – Estimated transaction and other annual costs of participation (£000s)

Consumer	Trans action costs	Contractual and legal arrangements	Health and safety protocols	Total £/yr.
I&C Small	7.5	10	2.5	20
I&C Medium	5	10	5	20
I&C Large	0	10	7.5	17.5
Gas-fired generators	0	10	0	10

There is great uncertainty surrounding the costs and so the above estimates were agreed by Ofgem and Pöyry. It may be the costs of participation for certain consumers are above or below those listed here.

Although option fees are intended to be a fixed fee, compensated on an annual basis, in order to enable a comparison and creating a ranking of the option fees, the fees are converted into a £/therm/day metric, seen below. For each participant type, we indicate what the range of option fees on a therm/day basis would be using the upper and lower bounds of consumed volumes in that category.

Table 24 – Estimated transaction and other annual costs of participation

Participant	Total £000s/yr.	Lower	Upper	Lower	Upper	Average
		000s th/day		£/therm/day		
I&C Small	20	4	9	5.00	2.22	**3.61**
I&C Medium	20	9	94	2.22	0.21	**1.22**
I&C Large	17.5	94	5,500	0.19	0.00	**0.09**
Gas-fired generators	10	94	5,500	0.11	0.00	**0.05**

In summary, these are the costs considered for the option fees of these tranches:

Non-backed-up (with or without risk of damage):

- I&C: annual costs (transaction, contractual, health and safety) + costs of increased probability of participation; and
- Gas-fired generators: annual costs excluding health and safety costs only.

Backed-up tranches:

- I&C: annual costs only; and
- Gas-fired generators: annual costs excluding health and safety costs only.

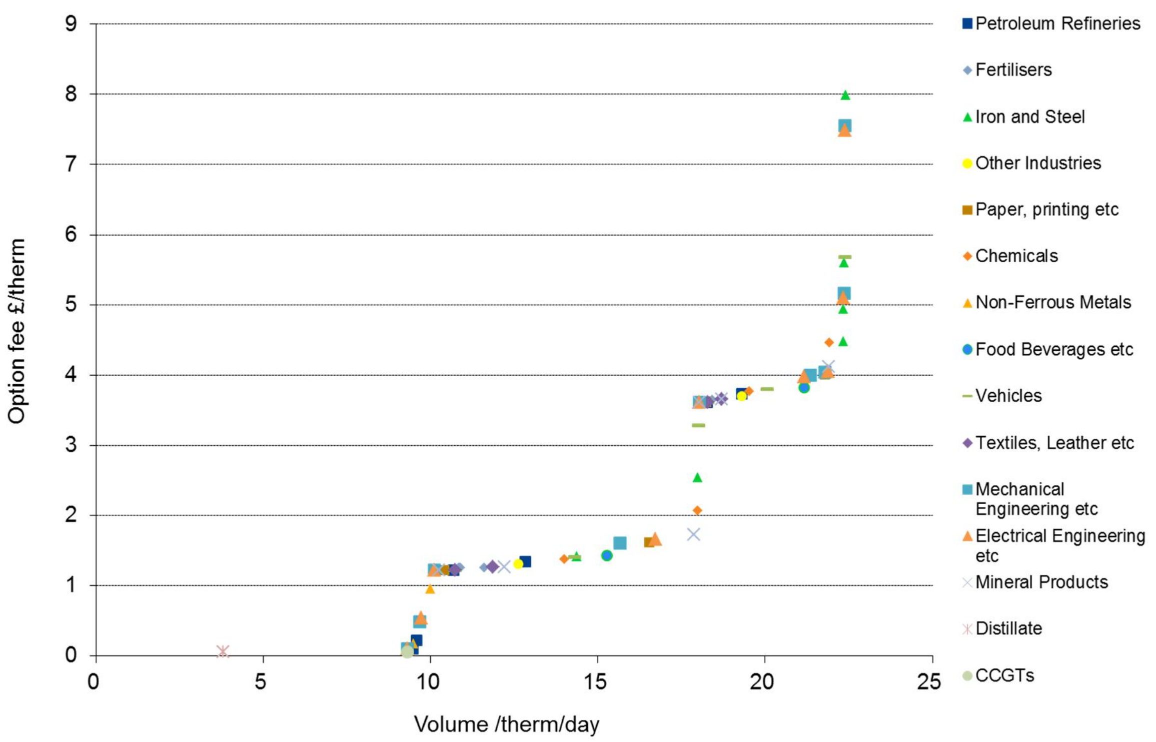
Under this approach, the option fees for the generator plants (backed-up and not) have the same price. There is reason to believe that the non-backed-up tranches for generators will be bid at some risk premium level to the back-up tranche. Without a robust means of estimating this, we assume that gas-fired generation tranche with back-up are ahead of non-backed-up tranches, when ranking bids to determine those which are successful.

The option fees are summarised in Table 25, and an option fee based DSR supply curve (i.e. ordered by option fee merit) is shown in Figure 25.

Table 25 – Total option fees (£/therm/day)

	Small			Medium			Large		
	Back up	**Non back up, no damage**	**Non back up, damage**	**Back up**	**Non back up, no damage**	**Non back up, damage**	**Back up**	**Non back up, no damage**	**Non back up, damage**
Fertilisers	3.61	3.65	-	1.22	1.25	-	0.09	0.13	-
Textiles, Leather etc	3.61	3.66	-	1.22	1.26	-	0.09	0.14	-
Mineral Products	3.61	3.66	4.11	1.22	1.27	1.72	0.09	0.14	0.60
Non-Ferrous Metals	3.61	3.70	4.47	1.22	1.30	2.07	0.09	0.18	0.95
Petroleum Refineries	3.61	3.73	-	1.22	1.34	-	0.09	0.22	-
Other Industries	3.61	3.70	-	1.22	1.30	-	0.09	0.18	-
Chemicals	3.61	3.76	4.45	1.22	1.37	2.06	0.09	0.25	0.94
Food Beverages etc	3.61	3.82	-	1.22	1.42	-	0.09	0.30	-
Vehicles	3.61	3.80	5.68	1.22	1.40	3.28	0.09	0.28	2.16
Paper, printing etc	3.61	4.01	-	1.22	1.61	-	0.09	0.49	-
Mechanical Engineering etc	3.61	4.00	7.56	1.22	1.61	5.16	0.09	0.48	4.04
Electrical Engineering etc	3.61	4.05	7.49	1.22	1.66	5.10	0.09	0.53	3.97
Iron and Steel	3.61	4.94	7.99	1.22	2.54	5.60	0.09	1.42	4.48
Gas fired generators	-	-	-	-	-	-	0.05	0.05	-

Figure 25 – Option fee based DSR supply curve



This methodology gives the resulting ranking of option fees:

1. Gas-fired generators no back-up;
2. Gas-fired generators back-up;
3. Large I&C back-up;
4. Large I&C no back-up, no damage;
5. Large I&C no back-up, damage;
6. Medium I&C back-up;
7. Medium I&C no back-up, no damage;
8. Medium I&C no back-up, damage;
9. Small I&C back-up;
10. Small I&C no back-up, no damage; and
11. Small I&C no back-up, damage.

Our estimates result in many tranches having the same option fee (the back-up tranches). When this occurs, we rank them second in order of exercise fees, and third in order of volumes.

4.4.3.4 Comparison of estimated option fees to transportation discount under previous network code arrangements

It was important to sense check that the option fee was at an appropriate level. The intention of the option fee was that it should be provide a more efficient outcome than the costs associated with the transportation discount that was received by interruptible customers under the previous transportation regime. To verify whether this was the case we completed a high level assessment of the value of the interruptible transportation discount under current market conditions.

As a proxy for this calculation, we estimated the interruptible discount using the current LDZ Transportation Charges for Northern Gas Network and applied this price to the gas consumption volumes assumed under SM3. This gave an estimated cost for the interruptible contracts of approximately £18million for all tranches, and £12million for the accepted volumes[26]. This is broadly in line with expectations[27].

4.4.4 Inefficient disconnection order and pricing

Under the current arrangements and cash out reform policy options, the inefficient disconnection order is made up of daily metered consumers without a route to market for DSR (i.e. the medium and small tranches), which are disconnected in firm load shed order according to site size rather than volume of remaining connected tranches. Within the size classes, the volumes of these tranches from the same sector were grouped, and priced at a volume weighted average of the OC previously shown. Consumers with loads

26 We only used the Northern Gas Network charges and obviously these will vary across the country and even to customers with different consumption levels within the Northern Gas Network. In addition we assumed all consumption has the same unit rate.

27 See Table 28 for the estimation of option fees under each policy design.

below the minimum volume threshold are next, priced at an average of the OC of all sectors.

Following these are the non-daily metered consumers, including the construction and agricultural sectors which were assumed to be NDM. Their volumes represent the residual demand on any given day, and are priced at the OC of network isolation, (i.e. estimated at £14/therm* 14 days = £196/therm, reflecting the number of days to reconnect domestic consumers once isolated.)

Under the straw men DSR mechanism designs, there are four categories of consumer in the inefficient disconnection order. Tranches belonging to eligible consumers which were unsuccessful through the DSR mechanism and eligible consumers which chose not to participate in the mechanism, are grouped by sector and size as above, and organised in firm load shed order.

The remaining categories, ineligible non-participants (i.e. below the volume threshold) and the non-daily metered consumers are the final two tranches in the order, price and volumes described above. Note that under SM3, we assume there are no eligible non-participants. Further, under NGG despite not having a decision criterion, we have considered unsuccessful any bidders with OC above £196/therm and those with bids below £196/therm where acceptance of their bid would not avert a GDE.

4.5 Implied DSR mechanism supply curves

In this section we review the disconnection order and volumes of accepted and unaccepted volumes under each of the three DSR mechanism policy options. The volumes will be presented for each modelled gas year, and the impact of gas-fired generators' participation analysed.

4.5.1 Strawman 2

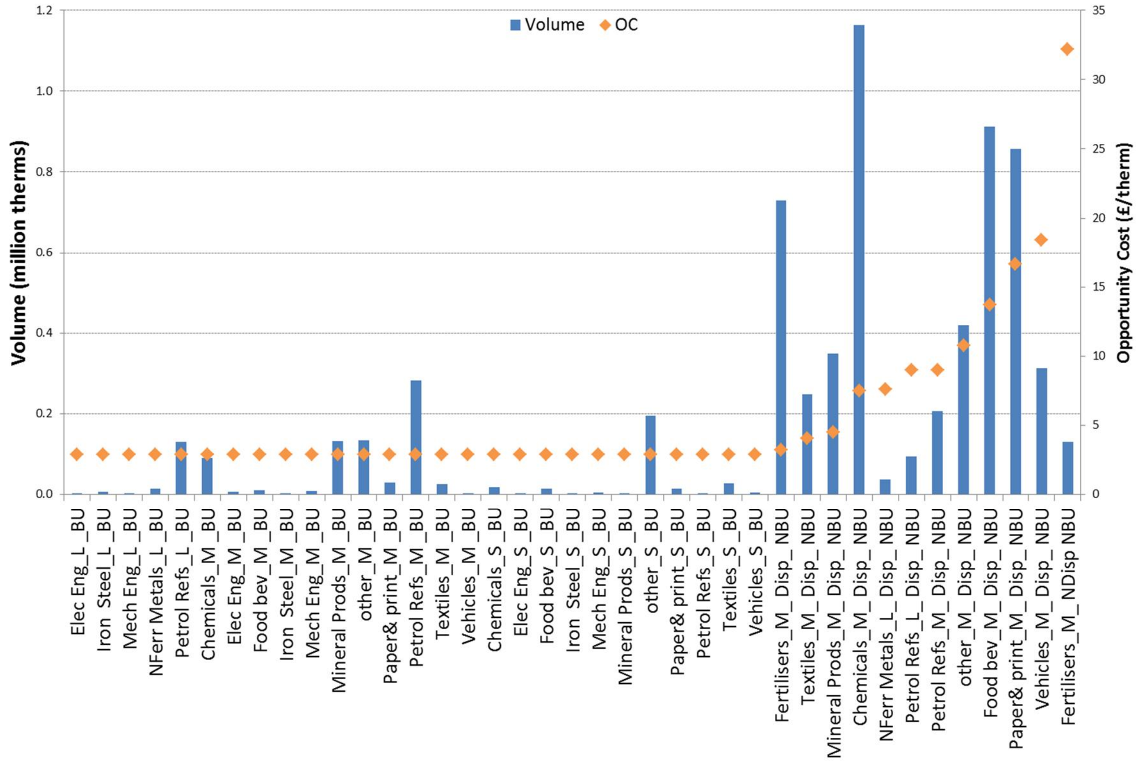
4.5.1.1 Strawman 2, excluding gas-fired generators

To reiterate, these volumes have been included for all modelled gas years:

- All I&C back-up priced with varying costs by year;
- Medium and large I&C dispensable and non-dispensable tranches, priced at London Economics estimates of OC; and
- The non-dispensable non-backed-up tranches of sectors with damage priced at 10x their OC.

All small non-backed-up tranches have been excluded (dispensable and non-dispensable). Figure 26 shows the disconnection order of accepted bids in 2030.

Figure 26 – Disconnection order of accepted bids under SM2 in 2030, excluding generators



Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp= dispensable, NDisp = Non-dispensable

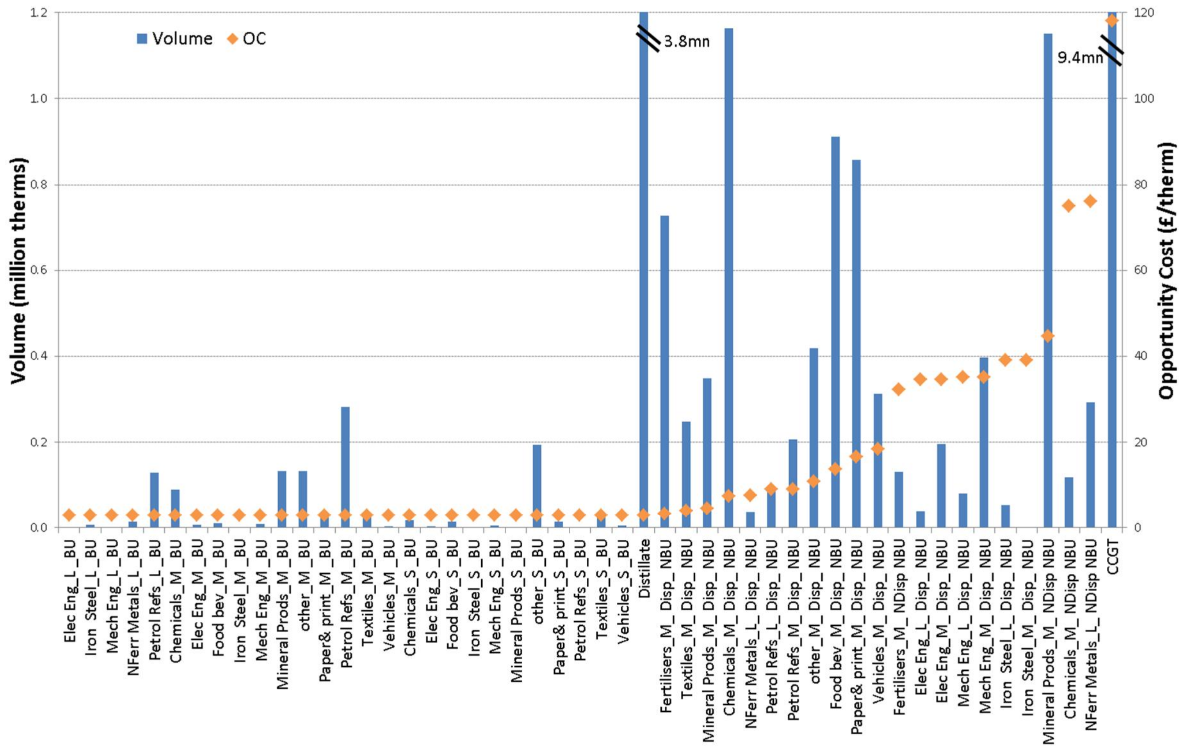
4.5.1.2 Strawman 2, including gas-fired generators

To reiterate, these volumes have been included for all modelled gas years:

- All I&C and generator back-up priced with varying costs by year;
- Medium and large I&C dispensable and non-dispensable tranches, priced at London Economics estimates of OC;
- The non-dispensable non-backed-up tranches of sectors with damage priced at 10x their OC; and
- All generators non-backed tranches priced at electricity VoLL

Once again excluding all small non-backed-up tranches (dispensable and non-dispensable). Figure 27 shows the disconnection order of accepted bids in 2030.

Figure 27 – Disconnection order of accepted bids under SM2 in 2030, including generators



Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp= dispensable, NDisp = Non-dispensable

4.5.1.3 Impact of gas-fired generator participation in SM2

Table 26 summarises the effect of generators participation on the volumes accepted and rejected at the SM2 tender. Note that the volumes of non-participants do not change. However, the impact of generator participation is to significantly increase the proportion of I&C bids which are accepted (by 17%).

Finally, Figure 28 displays the impact of generator participation on the volumes and prices of the SM2 tender.

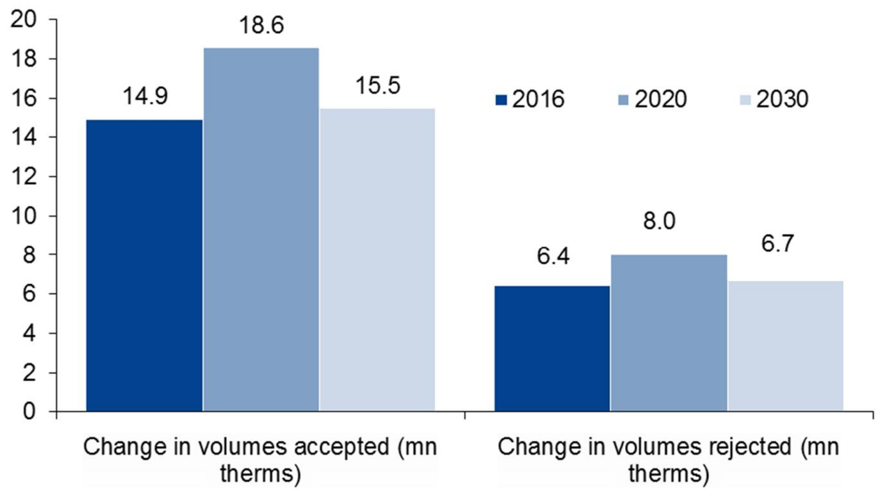
When included, generators increase the accepted volumes by 14.9-18.6mtherms/day in the three years. The effects are most noticeable in 2020, since the volumes of generator bidding are the highest in this gas year. Equally, they increase the volumes rejected by 6.4-8.0m therms/day.

Nonetheless, generators are more expensive than 96% of the total I&C volumes, and their total volumes represent approximately 60% of total DSR volumes in SM2, varying by year. Since generators are relatively expensive and represent the largest volumes, they will always be the marginal bidder if there is a relative volume cap methodology. When they are included, an additional 17% of I&C volumes are included.

Table 26 – SM2 volume results including and excluding generators (mth/day)

	Gas year	Total volumes accepted	Proportion of total I&C accepted	Total volumes rejected	Eligible non participants
Excluding Generators	All years	6.62	51%	2.79	3.68
Including generators	2016	21.56	68%	9.25	3.68
	2020	25.21	68%	10.80	3.68
	2030	22.13	68%	9.48	3.68

Figure 28 – Impact of generator participation on volumes



4.5.2 Strawman 3

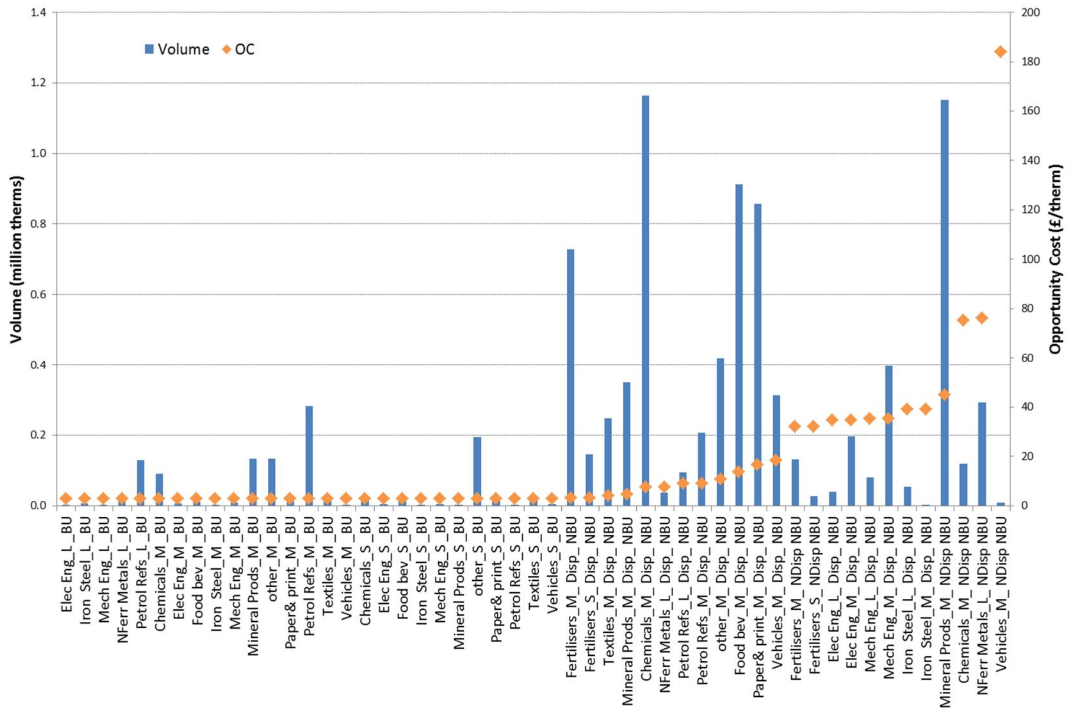
4.5.2.1 Strawman 3, excluding gas-fired generators

In SM3, all consumers are expected to participate, including the small tranches. Tranches have been ordered according to the option fees, and the cheapest 70% of volumes are successful. Figure 29 shows the exercise fees accepted on the basis of option fee merit which are exactly the same as those in SM2, excluding gas-fired generators.

4.5.2.2 Strawman 3, including gas-fired generators

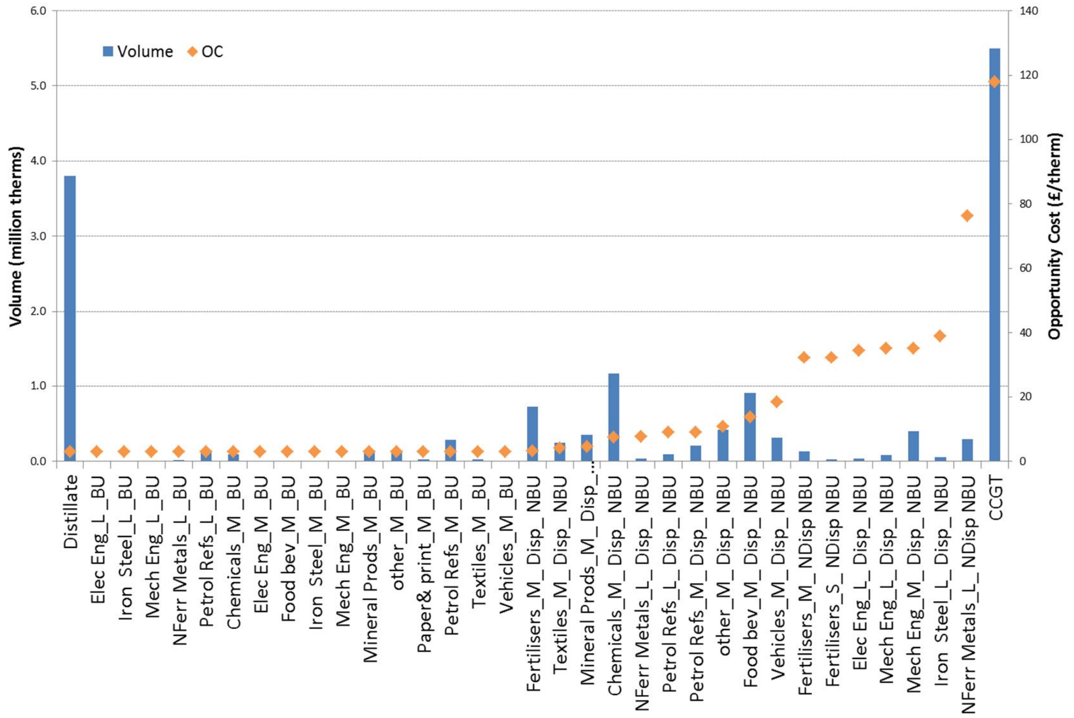
In SM3, all consumers are expected to participate, including the small tranches. Tranches have been ordered according to the option fees, and the cheapest 70% of volumes are successful. Figure 30 shows the accepted exercise fees on the basis of option fee order.

Figure 29 – Disconnection order of accepted bids under SM3 in 2030, excluding generators



Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp= dispensable, NDisp = Non-dispensable

Figure 30 – Disconnection order of accepted bids under SM3 in 2030, including generators



Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp= dispensable, NDisp = Non-dispensable

Table 27 summarises the effect of generators participation on the volumes accepted and rejected at the SM2 tender. Note that there are no non-participants.

As we can see, a much larger proportion of I&C volumes are accepted when generators are excluded (70%). This drops to 36% in 2016 and 2020 where they are included; meaning generators displace 34% of I&C volumes. In 2030, this increases again to 49% because of the significant reduction in generator volumes bid into the tender reflecting the growth of renewable electricity generation (total generator bidding falls to 5.5m therms in 2030 from 12.3m in 2020).

Table 27 – SM3 volume results including and excluding generators (mth/day)

	Gas year	Total volumes accepted	Proportion of total I&C accepted	Total volumes rejected	Eligible non-participants
Excluding Generators	All years	9.13	70%	3.97	0
Including generators	2016	20.79	36%	8.40	0
	2020	21.79	36%	8.40	0
	2030	15.67	49%	6.73	0

Table 28 summarises the effect of generator participation on total cost of option fees.

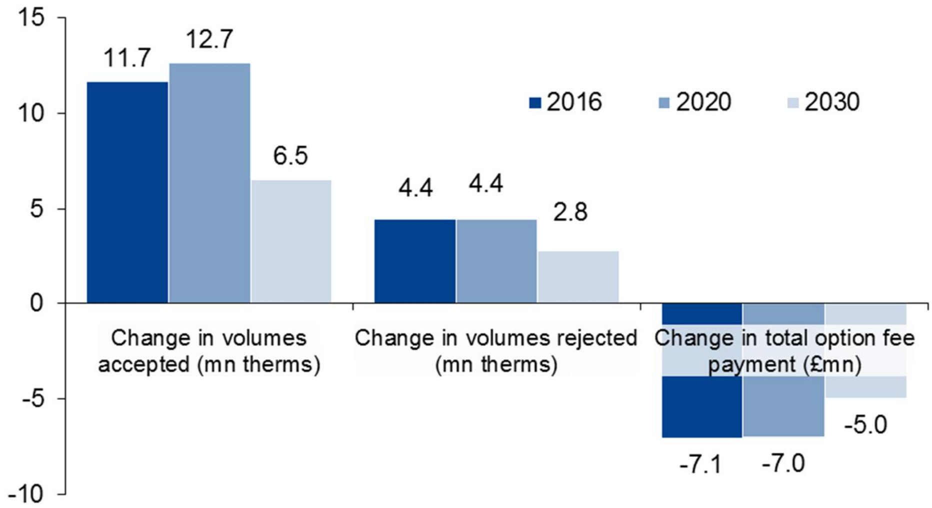
Table 28 – SM3 total cost of option fees (£mn)

Gas year	Excluding Generators (£m)	Including Generators (£m)
2016	13.5	6.4
2020	13.5	6.5
2030	13.5	8.5

As we can see, the impact of generator participation is to significantly decrease the total option fees in 2016 and 2020, to approximately half the value where they are excluded. This is because generators are the largest consumers, and their option fees per therm are very low. The option fees rise again in 2030, where a higher proportion of more expensive option fee I&C volumes accepted, as bidding levels of generators decrease into the future.

Finally, Figure 31 displays the impact of generator participation on the volumes and total option fees under SM3 tender. Generators increase the accepted volumes by 6.5-11.7m therms, which is less than under SM2. Further, they also increase the volumes rejected, and displace between 21-34% of I&C volumes as seen in Table 27. Interestingly, their effect is also to approximately half the total option fee pay out, due to their relatively cheap option fees in 2016 and 2020, but this effect is reduced in 2030 as lower volumes are offered.

Figure 31 – Impact of generator participation on volumes and total option fees under Strawman 3



4.5.3 NGG option

Under the NGG design, the bids are updated in real time, and used as required in an emergency.

In order to model NGG's approach to firm load shedding, only economically efficient bids, sufficiently material to avert firm load shedding were assumed to be accepted. In practice, we began by accepting only the bids which are below the cost of network isolation (£196/therm). In order to satisfy the materiality requirement, i.e. that a bid will only be exercised if it is assumed to be sufficiently large to avoid firm load shedding, we assumed that as the emergency approaches Stage 2, a bid would only be exercised if it is above the minimum size action that could have a discernible impact on the system (3GWh), as set out in 4.3.

In price order, the last tranches (below £196/therm) are generators tranches (at £118/therm, assuming electricity market scarcity does not permit them to bid below this level) and the medium, critical, non-backed-up tranche of the Vehicles sector (£183.93/therm). Since the latter represents a negligible volume (0.01mtherms), it was assumed to be immaterial and rejected in all cases, whereas the generator volumes are assumed to always be material, and accepted if needed. This approach is clearly a simplification of the decision-making process that NGG would employ in the event of a GDE.

Table 29 summarises the resulting volumes. The volumes provided by CCGTs will vary according to the period (rather than being fixed through a yearly tender). CCGTs can provide DSR through either participating on the OCM, or submitting bids through the new NGG platform. For modelling purposes, this distinction is not important – since we are concerned only with the volumes and prices which come to market rather than the route –

but this distinction may be more important from a policy perspective[28]. For this policy option, we have once again assumed that no small consumers participate, other than with their back-up tranches.

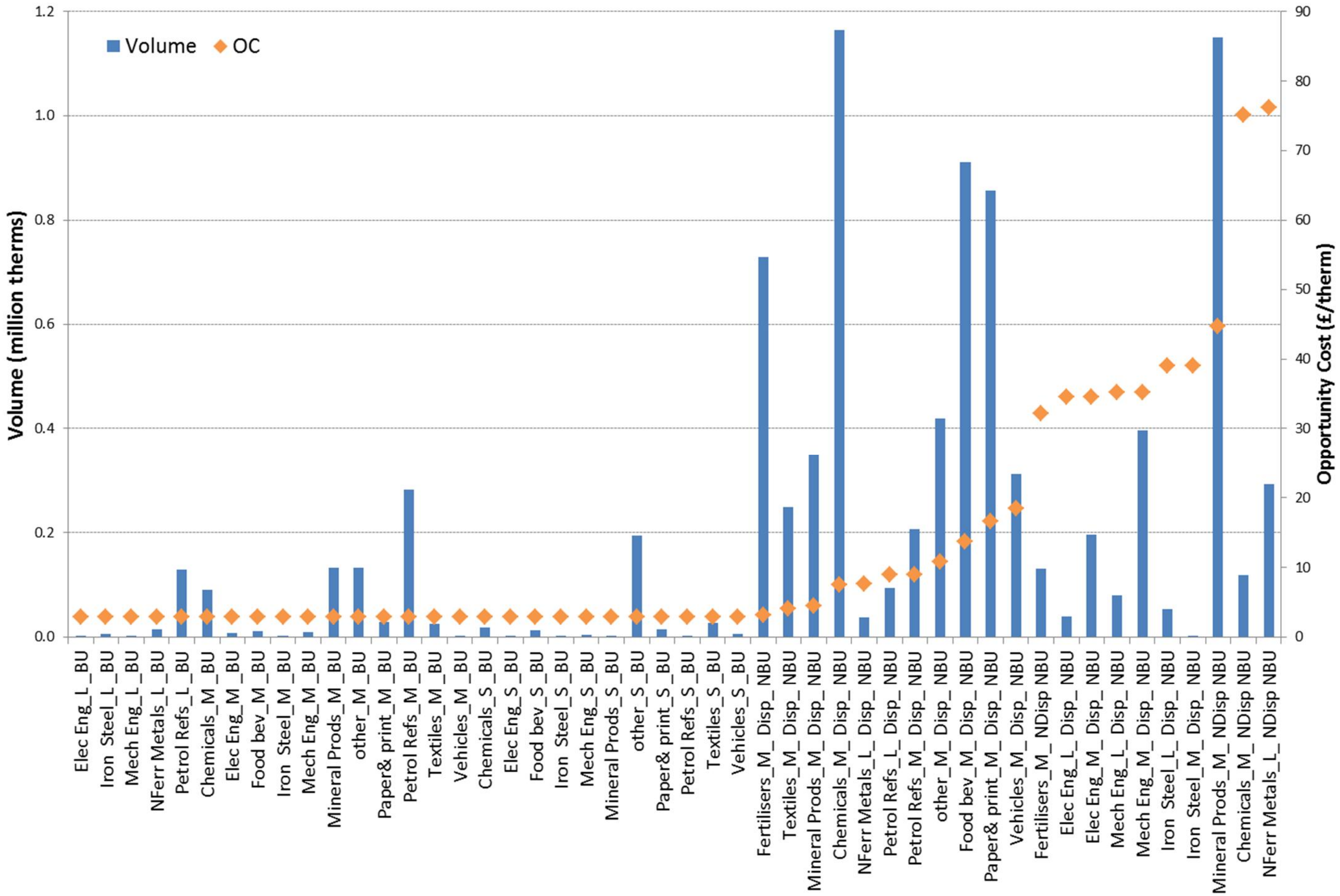
Table 29 – NGG volume results (million th/day)

	Gas year	Total volumes accepted	Proportion of total I&C accepted	Total volumes rejected	Eligible non participants
I&C	All years	8.95	68%	0.47	3.68

Figure 32 shows the disconnection order with generators excluded. (Note, figure key: Key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp= dispensable, NDisp = Non-dispensable).

28 For example if the inclusion of CCGTs will discourage other participants, or the effect that the inclusion of CCGTs could have on any calculation of the volume weighted average prices paid to ineligible participants.

Figure 32 – Disconnection order of accepted bids under NGG in 2030, excluding generators



4.6 Effect of altering the volume cap

The effect of altering the volume cap will vary according to tender design and inclusion/exclusion of generators. This is not relevant for the NGG option however.

Bearing in mind the objective of increasing the accepted I&C volumes, in design options which exclude generators, the higher the volume cap the higher the resulting I&C volumes accepted. However, in scenarios where generators are included, this is not necessarily the case. Table 30 below presents the proportion of total volumes which generators account for under each design.

Table 30 – Proportion of total DSR volumes represented by generators per DSR mechanism design

	Daily consumption	
Gas year	**SM2 & NGG**	**SM3**
2016	57%	48%
2020	64%	50%
2030	58%	30%

In SM2, generators will fall behind the vast majority of I&C volumes in an exercise fee based merit order (their bid at £118/therm is more expensive than 96% of all I&C volumes). Moreover, they represent two-thirds of the total volumes. This means that as long as the volume cap is not set at below a 30% level, the outcome is efficient since all but the most expensive I&C bids are accepted (i.e. all but those above £118/therm).

In SM3, generators come first in the option fee-based merit order. If the volume cap were below 48% in 2016, 50% in 2020, and 30% 2030, no I&C volumes would be accepted. I&C volumes will only be accepted if the cap is above this level and the higher the volume cap, the greater the amounts of I&C volumes accepted.

4.7 DSR mechanism summary

In terms of the CBA analysis the mechanism that incentivises the most I&C participation will result in the greatest gross benefit[29], since it reorganises the current inefficient disconnection order, where the largest are disconnected first. The largest gas users are gas fired generators, which in our assumptions have bids more expensive than 96% of the total I&C DSR volumes. By providing more efficient forms of I&C DSR with a route to market, the costs of interruption in the event of an emergency decrease substantially.

Table 31 summarises the resulting volumes available under each DSR mechanism design option, with a focus on the effect of including or excluding CCGTs, and the proportion of total I&C volumes accepted.

29 i.e. before the costs of the auction are considered.

Table 31 – DSR volumes under three policy options (mth/day)

	Generator participation	Gas year	Total volumes accepted	Proportion of total I&C accepted	Total volumes rejected	Eligible non participants
SM2	Excluded	All years	6.62	51%	2.79	3.68
	Included	2016	21.56	68%	9.25	3.68
		2020	25.21	68%	10.8	3.68
		2030	22.13	68%	9.48	3.68
SM3	Excluded	All years	9.13	70%	3.97	-
	Included	2016	20.79	36%	8.4	-
		2020	21.79	36%	8.4	-
		2030	15.67	49%	6.73	-
NGG	N/A (only I&C volumes shown)	All years	8.95	68%	0.47	3.68

Note: 'Proportion of total I&C accepted' refers to the proportion of total eligible I&C volumes.

- In SM2, the exercise fee-based merit order and a relative 70% acceptance criterion, means that more I&C volumes are accepted when generators participate than when they do not. Since the generators are the last accepted bid, they do not displace I&C consumers when they participate. SM2 including generators results in the equal 2nd highest proportion of I&C volumes accepted.
- In SM3, with an option fee-based merit order, less I&C volumes are accepted when CCGTs participate than when they do not since CCGTs submit the most competitive bids. In effect, generators displace I&C volumes in SM3. However, there is a greater proportion of I&C participating than in SM2 because the small consumers are encouraged to participate. SM3 excluding generators results in the highest proportion of I&C volumes accepted.
- In the NGG option, generators do not "displace" I&C volumes since there are no rejected bids. This means that the total volumes available through the DSR mechanism are the highest of all three straw men. This results in the equal 2nd highest proportion of I&C volumes accepted, along with SM2, including generators.

In comparison to the base case, the benefit of the mechanisms will come through the reorganisation of the current inefficient disconnection order, so that those with lower OC of interruption are interrupted first and most often. However, the costs of the setting up and running the mechanism, both for participants (whether compensated through option fees or not) and regulators/NGG, will be the main cost component compared to the base case.

4.8 Risks and strategic bidding

Our approach to modelling the bidding behaviour of participants in the previous section does not account for strategic bidding. This is due to a lack of data to support and form an understanding of different forms of bidding behaviour. In this section we expand upon how certain consumer characteristics and mechanism design may influence bidding behaviour, and so lead participants to bid in a different manner than that specified above.

4.8.1 Consumer bidding behaviour

A consumers' risk aversion will be an important determinant of their bidding behaviour. The provision of gas DSR services is not the core business of these consumers, and imposes significant costs and risks. Price risk in bidding for the non-backed-up tranches arises from uncertainty regarding the possible timing of provision in the business cycle (high or low season) and the frequency and length of provision. There is also uncertainty about knock on effects, such as loss of market share. The combination of these significant uncertainties may lead consumers to bid conservatively.

Generally speaking, a conservative bid is one which protects a consumers' load by placing them at the end of the disconnection order, achieved through bidding above "true" OC. A consumer's risk aversion can be said to vary with these characteristics:

- **Gas dependency**: consumers with a greater proportion of their output dependent on gas consumption, whether as a raw material or as form of energy, will value their gas consumption more than those with low dependency. Those with high dependence on gas will be more willing to protect their load, more risk averse.
- **Access to bidding resources**: a consumer with greater bidding or financial resources will be better placed to understand auction rules, estimate their OC, formulate and submit a bid through the DSR mechanism. In order to bid strategically, they will also need to understand the bids of competitors. Generally speaking, a consumer's size may be a proxy for financial resources, with risk aversion increasing inversely with consumer size. In order to even the playing field, Ofgem has responded to stakeholder feedback placing value on simplicity, and has endeavoured where possible to simplify the mechanism design, e.g. having a single round, sealed bid mechanism as opposed to an iterative dynamic auction.
- **Positioning in the current firm load shed disconnection order**: as we have seen in the previous section, participation in the DSR mechanism necessarily implies increasing the risk of disconnection, by increasing the probability of this occurrence. The increase in probability increases inversely with consumer size: smaller consumers are currently at the end of the firm load shed disconnection order, and could theoretically place themselves at the beginning of the disconnection through participation. Again, risk aversion would increase inversely with consumer size.

A consumer's risk aversion will inform both their decision to participate and their bidding behaviour.

4.8.2 Participation

How participation varies with dependence on gas consumption is not clear. On one hand, a highly dependent consumer may emphasise the benefit of participation through the ability to hedge the OC of an interruption. On the other hand, they may emphasise the need to protect their load from disconnection, and non-participation would allow them to do so.

Consumer size is also an important determining factor: the smaller the consumer, the more successful a strategy to protect their consumption through non-participation becomes, since they are able to remain at the end of the firm load shed disconnection order. A large consumer, particularly one of comparable size to a gas-fired generator, may take the view that due to their size, they have a high likelihood of being among the first to be disconnected in the firm load shed, so their preference would be to participate and obtain the benefit of participation.

As for the remaining consumers, those who consider the barriers (financial and DSR mechanism complexity) to participation too high would have less incentive to participate. This also applies to the increased probability of disconnection, which is also a function of size.

A final point is that a consumers' willingness to participate will also depend on their perceived ability to submit a successful bid. For this reason, it may be that a consumer with a relatively high OC would choose not to participate because they deem their chances of success too low.

4.8.3 Impact of mechanism design

The key elements of a DSR mechanism design which will have an impact on bidding behaviour, both in terms of the decision to participate and the level at which to bid, are:

- the pricing regime: exercise and option fees;
- the decision criteria method and level;
- inclusion/exclusion of gas-fired generators;
- payments to unsuccessful participants;
- format;
- payment regime;
- payment to non-participants;
- penalties for non-compliance; and
- contract duration.

To a lesser extent, these elements will also influence bidding behaviour: the payment regime (pay as bid or pay as clear), the payment to non-participants, and the contract duration.

Taking each of these elements in turn, it is possible to compare the impact on bidding behaviour under each of the proposed mechanism designs: SM2, SM3, and the NGG option.

4.8.3.1 Pricing regime

As previously mentioned, due to economic barriers to participation, (transaction costs, contractual arrangements, health and safety costs and cost of increased probability of disconnection) some participants may only be incentivised to participate if these upfront annual costs of participation can be remunerated through an option fee. This is the case with the smaller consumers who we assume do not participate in the SM2 and NGG option.

4.8.3.2 Decision criteria and level

The decision criteria under SM2 and SM3 is a relative volume cap (i.e. accept 70% of bids). Participants know that in order to be accepted, they must be among the cheapest

70% of DSR volumes. No decisions have yet been made by Ofgem regarding the decision criteria, and so this level was used purely for modelling purposes.

Under SM2, bids will be accepted in ascending order of exercise fees. The combination of an unknown volume cap and limited understanding about participation rates and relative positioning on an efficient disconnection curve increases the uncertainty facing consumers over whether they will be successful at the tender, especially when compared to a price cap. This should encourage more competitive bidding at true OC of interruption, and this effect should increase as the volume cap level decreases. However, it does not preclude consumers taking a conservative approach to bidding as mentioned above. It may also discourage those with a high absolute OC from participating, if they perceive their chances of success as being too low, and the costs (increased probability of disconnection) outweigh the benefit (payments for unsuccessful participants, i.e. 30 day SAP).

Under SM3, bids will be accepted in ascending order of option fees; however they will be exercised in order of exercise fees. This encourages competitive option fee bids, given that this will be a certain annual payment. The opposite is true for exercise fees however, as there is no direct incentive to bid competitively in SM3.

The relevant metric for comparing bids is the option fee/therm of DSR obtained. This implies that if consumers have broadly similar costs of participating in the tender (£10-20k/year), the most competitive bids will be those of largest players, as these fees are spread over a significantly larger volume. This will place small players at the end of the option fee stack, and may discourage their participation, if costs outweigh benefits as seen above.

The NGG option does not have a volume cap. As specified in Section 4.2.1, NGG must act in an economically efficient manner, and our modelling assumption that virtually all bids below £196/therm will be accepted is a simplification. The limit will depend on NGG's market balancing actions on the day, and the nature of the emergency itself; for NGG must make a judgment as to whether exercising remaining bids are sufficient to avert firm load shedding.

Uncertainty around the level of bids which NGG will ultimately accept should also encourage more competitive bidding, in order to ensure a successful bid. However, participants with small volumes which are at the end of the disconnection order may be discouraged from participating if unable to meet the materiality requirement.

4.8.3.3 Inclusion or exclusion of gas-fired generators

Generators have been assumed to bid in a simplistic risk averse manner (i.e. electricity VoLL) under SM2 and SM3, due to the necessity of bidding yearly in advance under a DSR tender. It is worth noting that electricity cash-out is volatile and this represents their maximum possible exposure, and may be an inefficient outcome in some cases. However, if generators are able to offer their volumes through the OCM at lower levels, this should not matter (for example in SM2), but this will not be the case for SM3 because of the penalty for self-curtailment.

The inclusion of gas-fired generators would have very significant implications on bidding behaviour, varying with the DSR mechanism.

Under SM2, with exercise fees only, gas-fired generators will bid both a distillate tranche, and the remainder at electricity cash-out and penalties under the capacity mechanism

(£118/therm). Due to the existence of a relative volume cap at 70%, and with the assumption that our estimates of OC are roughly accurate, the marginal bid is always a gas-fired generator. Despite the common perception that generators will crowd out the I&C DSR, this is only true of the cheap backed-up tranches. As long as I&C consumers bid below the CCGT level, they will be successful. This would have a similar effect of an unofficial price cap.

In the case of SM3, generators bids would be the most competitive on an option fee/ therm level, and they can be expected to crowd out the I&C bids. This would encourage greater competition on an option fee level. Perversely, the generators also represent one of the most expensive exercise fees. The effect mentioned above of discouraging smaller players would be even more extreme.

In the case of the NGG option, there is no reason to believe that the participation of generators will have any obvious impact on I&C bidding. Responding to real-time market signals, generators may be able to offer more competitive bids than some I&C consumers if electricity market scarcity allows this. However, our modelling has shown that this is very rarely the case, and non-backed-up generator volumes should not crowd out I&C consumers.

4.8.3.4 Payment to unsuccessful participants

At present the policy behind all the mechanism designs is to pay unsuccessful bidders the 30 day SAP for the 30 days preceding the emergency. Although the value of this payment will vary with the market conditions, it is likely to be substantially lower than the OC of I&C participants. Although the incentive to participate weakens as a consumer's absolute OC increases, it is still preferable to receiving no payment in the event of interruption.

The advantage of setting this payment at a low level prevents those with OC below this level from acting perversely, such as submitting a sleeper bid in order to obtain some form of payment, while being able to remain at the end of the disconnection order in firm load shedding.

4.8.3.5 Format

SM2 and SM3 are designed as sealed bid tenders. The NGG option incorporates real-time updating, and may have the format of an open iterative auction (to be confirmed). Whilst dependent on the design of the mechanism open bidding auctions provide bidders with information about the relative competitiveness of their bid and their position in the stack. It also allows participants to increase their confidence in their valuations by comparing with competitors.

This reduces uncertainty around both (a) ability to submit a successful bid and (b) the appropriate valuation of the opportunity cost of interruption. Consequently, increased transparency around the chances of being successful may encourage more participants. Further, greater understanding of relative valuations may encourage more confident or aggressive bidding, for instance reducing the uncertainty premium on some bids.

However, there is also the risk that consumers react to the likelihood of being interrupted by either increasing their bids in real-time or removing offers at a time when it is needed. A sealed bid approach provides more certainty on the volumes and costs being offered. In addition, there is the concern that open bidding increases the potential for strategic bidding as partipants can react to where they are in the biding stack, although if there are sufficient participants then such a risk is significantly reduced.

4.8.3.6 Payment regime

Ofgem had originally proposed to adopt a variant of the pay-as-clear payment regime, whereby all exercised DSR bids will be paid the price of the highest exercised bid, as per the marginal DSR bid scheduled that day of the emergency. However, all mechanism designs as modelled here currently adopt a pay-as-bid regime for the exercise fees.

General auction theory stipulates that bidders have a greater incentive to bid at "true" opportunity cost under pay-as-clear, unlike pay-as-bid where the incentive is to predict the clearing price. Under a DSR mechanism therefore, pay-as-bid could potential imply guessing the clearing price in order to be successful and obtain the maximum possible remuneration.

The quantitative modelling assumed that all consumers bid at true opportunity cost, despite all the modelled designs being paid-as-bid. As already noted, this assumption was necessary due to a lack of information with which to make informed estimates of how consumers may bid strategically (e.g. guess the clearing price). Importantly, this means we have been unable to assess quantitatively the key potential benefit of pay-as-clear compared to pay-as-bid (i.e. incentivising bidding at true cost). We therefore assess the merits of pay-as-clear qualitatively.

Firstly, we would note that whilst theory suggests that pay-as-bid may incentivise consumers to guess the clearing price, this is clearly an extremely uncertain exercise which depends on the shape of the DSR supply curve and the demand on any given emergency day. The effect of the uncertainty of the clearing price on bidding behaviour is uncertain but likely to vary with a consumers' risk aversion profile. It is possible that some will chose not to gues the clearing price and bid at true opportunity cost (an efficient outcome). However, it is also possible that others may try to guess this, leading to erratic and inefficient bids, and yet others may decide not to participate because they cannot guarantee a successful bid.

Furthermore, even if a pay-as-clear system were adopted, because of the variant suggested (i.e. based on the highest exercised bid rather than the highest accepted bid), it may still be insufficient to encourage bidding at true OC if bidders were interested only in maximising the potential pay-offs. This is because the daily clearing level is not the maximum accepted bid of the DSR mechanism round but the marginal accepted bid.

Thus, any motivation for strategic bidding still exists irrespective of payment regime. All things equal therefore, the benefit of having a pay-as-bid is a reduced overall pay out to DSR participants when bids are exercised, although this is limited to some extent by the pay-as-clear variant based on daily exercised bids.

Finally, it is worth reminding all that a consumers' "true" cost of interruption will in itself be a simplification or estimate. Imperfect information means OC varies with the context of the interruption (timing, length and frequency) which are not known in advance. Moreover, it is hard to calculate precisely, since there are primary (e.g. loss of GVA, risk of damage to equipment) and secondary impacts (such as up/downstream knock on effects, loss of market share, reputation etc.). As mentioned, this implies a range of possible OC, for which the payment regime will only have a limited impact.

4.8.3.7 Payment to non-participants

Consumers that do not participate will not receive any payment in the event of an interruption. The strength of this as an incentive to participate varies with the probability of disconnection: large consumers with high probability under current arrangements have a stronger incentive than small consumers. Further, other factors mentioned above are also key to the participation decision: economic barriers, perceived chances of success, etc.

4.8.3.8 Penalties for non-compliance

In the case of exercise fee only straw men (SM2 and NGG), the proposed penalty for non-compliance is the exercise fee based payment the consumer would have received, as this is the cost of balancing the system at that time. Additionally, in the case of SM3 although the penalty design has not yet been finalised, Ofgem expects that some proportion of the option fee will be clawed back. These penalties seem appropriately high to ensure compliance. Indeed, we can expect that consumers with less predictable loads (e.g. gas-fired generators and those in highly cyclical industries) will be more conservative in the volumes they offer in order to ensure that they comply, more so under SM3 where the penalties are accordingly higher.

4.8.3.9 Contract duration

The contract duration is one year under SM2 and SM3, and real time updating under the NGG option.

Year-ahead contracts result are more likely to result in conservative bidding since consumers are uncertain of the circumstances they will face in the interruption, for instance, bidding at the top end of the OC range (e.g. CCGTs bidding at £118/therm).

However, the benefit of bidding in real-time is that consumers can more accurately reflect the cost of interruption rather than bidding at the maximum, which in certain circumstance could reduce the total pay-out (e.g. CCGTs bidding according to electricity market scarcity, if there are alternative sources of generation available). However, CCGTs can already provide real-time offers through the OCM so the benefit of a more flexible approach will be if it encourages more DSR bids from I&C consumers.

5. COST-BENEFIT ANALYSIS

The analysis undertaken thus far now provides the data required to calculate a full cost-benefit analysis of the proposed policy options by comparing the benefits which the policies would bring compared to the base case of maintaining the current arrangements.

This section outlines the results under each of the proposed policy options and analyses the important messages which can be drawn from the study.

5.1 Approach to the cost-benefit analysis

This cost-benefit assessment methodology has been designed to help to inform the development of the policy decision for the implementation of demand-side mechanism in the GB gas market in the event of a Gas Deficit Emergency.

The assessment methodology is essential to ensure a robust assessment of the proposed structures for the DSR mechanisms, and their development.

As part of the cost-benefit analysis we have identified the following requirements:

- identify the problem/reason for intervention;
- agree objectives;
- define a robust baseline;
- describe the modelled scenarios; and
- develop a robust methodology.

Identify the problem/reason for intervention

The current disconnection curve for gas customers in the event of a gas deficit emergency is considered inefficient. This is because customers are disconnected on size order and not according to price (VoLL), and customers may have a limited ability to send appropriate price signals for the value they place upon their supply at times of system stress.

Overall objective

The objective of any policy change is to provide a route to market for demand-side response in order to reduce the likelihood, severity and duration of a gas deficit emergency. This would be achieved through a more efficient disconnection of gas customers in the event of, or immediately before, a gas deficit emergency. This 'efficiency' assumes disconnections will take place on a least cost basis. This study looks at seven alternative policy options and compares the relative costs and benefits of each one against the baseline and against each other.

Definition of a robust baseline

A robust baseline is vital for an accurate assessment. In this case we have set the baseline to be the expected participation in demand-side reduction under the current arrangements.

Describe the modelled scenarios

The modelling options have been designed to test a wide-ranging set of potential mechanism designs to deliver demand-side response, in the event of a gas deficit emergency. These scenarios are set out in detail in Section 2.

Develop a robust methodology

The methodology set out below has been identified to allow the best possible comparison of the modelled scenarios against the base case and each other.

5.1.1 Overview of the methodology

This final stage of the analysis brings together the results of each individual mechanism design to provide a quantification of the net benefit of each of policy option relative to the baseline counterfactual (which is the expected cost of an emergency under the current arrangements). For this analysis the costs and benefits of the assessment will be represented at a societal level.

The analysis will compare the costs of undertaking demand-side reductions in each of our policy options against the costs under the current arrangement. The expected benefit will occur because the mechanisms are designed to deliver a more efficient least cost methodology for dealing with periods of gas scarcity. This is compared to the current arrangements, in which disconnection occurs in size order and is not linked to the cost of delivering the DSR.

Against these expected benefits we will assess the additional costs of implementing and operating the mechanism; plus the costs associated with the additional administrative burden faced by consumers incurred as a result of taking part in the mechanisms. The costs impact both on the consumer and the mechanism operator (in this case assumed to be National Grid Gas). These costs will include:

- the costs incurred by National Grid Gas to set up the necessary system to allow the mechanism to take place;
- the annual running costs to maintain the mechanism process; and
- an additional cost (incurred on an annual basis) to reflect the 'administrative burden' faced by all customers to identify whether or not they wish to take part in the DSR mechanism process. This cost reflects the transaction and search costs incurred by all eligible industrial and commercial installations independent of whether they ultimately decide to bid into the mechanism.

Each of these scenarios has been modelling for three sample gas years 2016, 2020 and 2030. All costs/benefits will be discounted in accordance with the approach set out in the HM Treasury Green Book.

We have also undertaken a qualitative assessment of the risks or unintended consequences that have not been captured directly in the modelling or that could not be adequately quantified. These are presented in the discussion of the options in Section 3. As such the remainder of this Section focusses on just the quantitative assessment

5.1.2 Policy options

In the section below we have identified the mechanism design packages to be assessed as part of this study. More details on each of the mechanism designs are given in Section

3. The key distinctions between the straw men mechanism design packages lie with the defined payment and pricing regimes and the decision criteria, repeated here for clarity:

1. **Current arrangements**: this scenario is based on expectations of DSR which is currently available and does not require any change to policy to gain a route to market. In this case, only gas-fired generators and the large industrial tranches with back-up will provide DSR on a least cost basis. **This will be the base case for our assessment**. Once these volumes are exhausted NGG will resort to calling DSR disconnections based on the current inefficient size order basis.
2. **Cash-out Reform**: Under this scenario we model the impact of reformed cash-out arrangements on the provision of DSR in the absence of a centrally-administered scheme. It is our view that participation will remain limited and as such only gas-fired generators, the large industrial tranches with back-up tranche and the large industrial non-dispensable, non-backed-up tranches will take part on a least cost basis. Once these volumes are exhausted NGG will resort to calling DSR disconnections on the current inefficient size order basis.
3. **Cash-out Reform + Strawman 2 (SM2)**: a pay-as-bid payment regime, an exercise fee only pricing regime, and a volume cap decision criteria. After the accepted volumes contracted under the volume cap have been exhausted NGG will resort to calling DSR disconnections on the current inefficient size order basis. This includes two variants; one with CCGTs included and one without.
4. **Cash-out Reform + Strawman 3 (SM3)**: a pay-as-bid payment regime, an option fee plus exercise fee pricing regime, and a volume cap or budget cap. After the accepted volumes contracted under the volume cap have been exhausted NGG will resort to calling DSR disconnections on the current inefficient size order basis. This includes two variants, one with CCGTs included and one without.
5. **Cash-out Reform + NGG option**: a pay-as-bid payment regime, an exercise fee only pricing regime, and bids will be accepted in order of cost and at the discretion of NGG when considering whether the acceptance of a bid will materially avert firm-load shedding.

For each DSR policy design, we identify whether the cost of meeting the disruption is greater or less than the cost incurred within our base case and thus there is an economic benefit to the wider economy.

5.1.3 Calculating the costs and benefits

We have used a relatively straightforward methodology for calculating the costs and benefits of these DSR mechanisms. This methodology is set out below:

- Stage 1 – calculating the level of unserved energy: Based on our gas supply scenarios highlighted above we have calculated a level of unserved energy which might occur in the gas market in the event of a gas deficit emergency.
- Stage 2 – calculating the 'inefficient' disconnection (base case): We have applied our base case disconnection to the unserved energy in each of our gas supply scenarios. This gives a total cost of meeting the unserved energy from curtailing gas supply across industry under the base case assumptions.
- Stage 3 – calculating the cost of the 'efficient' disconnection: Again based on the unserved energy calculated for each of the gas supply scenarios we have calculated the cost of meeting this unserved energy through the interruption of industrial and commercial load (and CCGTs) under the various reform policies. This provides a set

of costs for disconnection that can compared against the 'inefficient' base case disconnection.

- Stage 4 – comparison of inefficient and efficient curves: We have compared the cost of meeting the unserved energy under the base case with each of our policy design proposals. For each of these comparisons we have calculated the cost or benefit to society of a particular policy design approach. We then multiplied the benefit which would result from the change in policy by the probability of an interruption occurring within the market in any given year, and by the probability of weather scenario occurring. By finding the probability-weighted benefit we identify the true cost or benefit of the mechanism over the assessed period.
- Stage 5 – applying the additional costs: We apply the additional costs of implementing and operating the mechanism plus the costs associated with the additional administrative burden faced by consumers incurred as a result of taking part in the mechanisms. These costs are annualised and then deducted from any benefits accrued through the improvement in the efficiency of disconnection.
- Stage 6 – comparison of results: Finally we compare the costs and benefits of each of the alternative policy options against the baseline and each other. Based on this comparison we identify, based on the quantitative assessment, the policy option which delivers the greatest benefit.

We then review these quantitative results alongside the qualitative impacts of the mechanism design to identify a preferred DSR mechanism approach.

5.2 Costs of DSR mechanism

The costs of implementing a demand-side response mechanism include:

- the costs incurred by National Grid Gas to set up the necessary system to allow the mechanism to take place;
- the annual running costs to maintain the auction process;
- if relevant, the cost of option fees payable under the mechanism (i.e. in SM3); and
- the additional cost of the 'administrative burden' faced by all customers as a result of increasing regulatory requirements from government.

To estimate these costs, we have compared the policy proposals to similar processes which are known.

The initial set up costs for the Capacity Payment Mechanism were estimated at £13m in DECC's impact assessment. We predict that the DSR mechanism will be simpler to set up than the CPM, and so we have estimated an initial set up cost of £1m incurred in 2014 for SM2, SM3 and the NGG option.

The annual running costs for the Capacity Payment Mechanism were estimated at £2m p.a. in DECC's impact assessment. Our understanding of the Operating Margins tender which is run on an annual basis by National Grid Gas is that NGG incurs an administrative cost of roughly £1,000 per contract entered. On the basis of high level assumption of 600 customers being eligible would give an equivalent cost of £600k p.a. Comparing this figure with the £2m for the CPM process which is expected to be more complex but include fewer parties, we have estimated an annual running cost of £1m per year for SM2, SM3. We have assumed a lower annual cost for the NGG option of £400k p.a., since the structure of this design would require no new contracts to be put in place, and so results in substantial savings in administrative costs, and to reflect there will still be remaining costs required to cover maintaining IT systems, employee time, and any amendments that need to be made to the contracts between shippers and their customers.

The payments due through option fees were calculated through our assessment of the bids at the auction and the successful volumes as shown in Section 4.4.3.

The administrative burden placed on all bidders (successful or otherwise) in the time and effort spent understanding the mechanism design and submitting a bid is also estimated at £2.6m per year for SM2 and the NGG option. The cost estimate is based on the same analysis for the derivation of the admin costs included in the option fees for SM3. This fee is not included within the SM3 policy option itself since the option fees include an estimate of these costs which the participants would seek to recover through the fee (albeit that unsuccessful bidders will also incur the costs and will not be recompensed) and so to include the cost again would be double-counting.

5.3 Benefits from the DSR mechanism policy designs

The analysis will compare the costs of undertaking demand-side reductions in each of our policy options against the costs under the current arrangement. The expected benefit will occur because the mechanisms are designed to deliver a more efficient least cost methodology for dealing with periods of gas scarcity. This is compared to the current arrangements, in which disconnection occurs in size order and is not linked to the cost of delivering the DSR.

In each case, the unserved energy is taken from the results presented in Section 2.4 and the supply of DSR is as described in Section 4.5. Note that this section describes only the cost of meeting unserved energy under the policy options, and does not consider yet the other costs associated with each mechanism which will be used for the CBA.

5.3.1 Comparison of the policy options under a Bacton failure, High Demand scenario

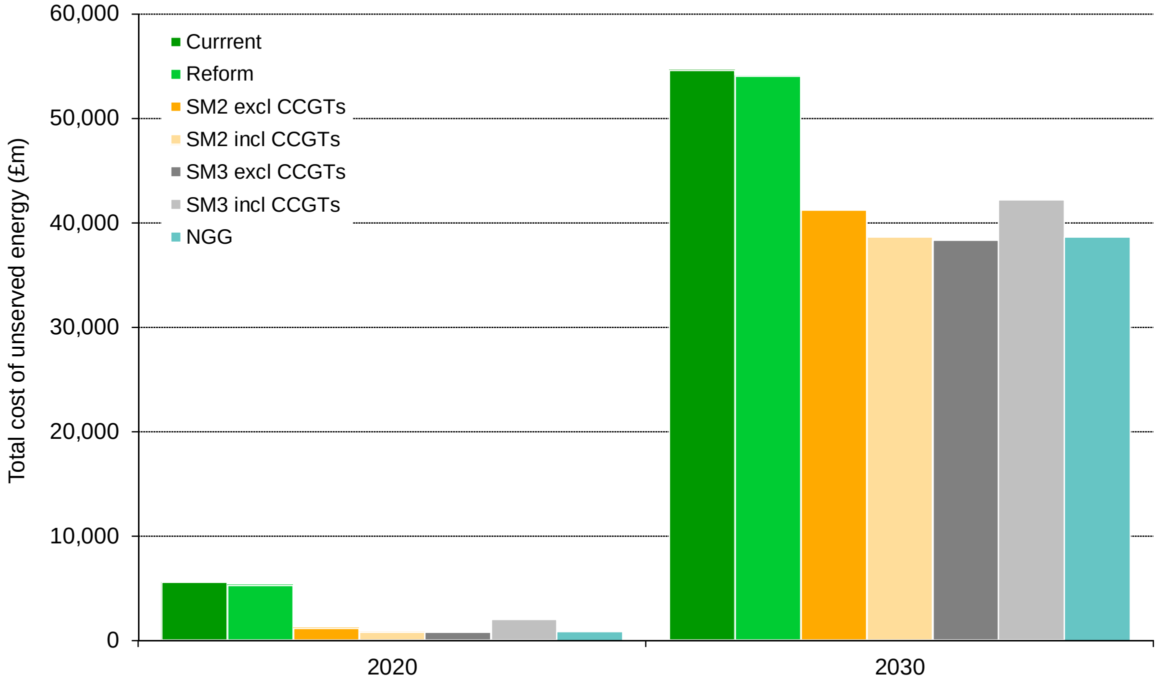
Figure 33 below illustrates the cost of meeting the unserved energy from the case when Bacton is assumed to fail. The chart illustrates clearly that the most expensive way to allocate the unserved energy is through the current arrangements; since this utilises the largest-first methodology regardless of the cost to the economy of interrupting these users apart from a small amount of DSR which will be provided by large users with back-up supplies. Our analysis shows that since there is only a small amount of voluntary DSR which is incentivised under the current arrangements, it is CCGTs which are asked to deliver a large proportion of the unserved energy. By 2030, there are few other sources of electricity generation available in the power market, and so the cost of interrupting the gas supplies to a CCGT is very high (£118/therm as detailed in Section 3.4.3.6). The inefficient interruption order means that the total cost to the economy of the unserved energy in 2030 exceeds £50bn.

Under the Reform case, there is a minor improvement over the current arrangements, but only a small amount of new DSR is incentivised to come forward. Thereafter, the case reverts to utilising the inefficient largest first methodology which again incurs a large cost through the use of CCGTs.

Compared to the first two cases, all five of the remaining policy options perform well in bringing forward an increasingly efficient disconnection order, and thus show substantial benefits compared to the current arrangements.

Strawman 2 including CCGTs performs better than the corresponding Strawman 2 excluding CCGTs. This is due to the 70% acceptance cap. The inclusion of a large volume of CCGTs also allows the acceptance of more bids from I&C customer. Since these bids typically contain lower exercise fees than the CCGTs, their inclusion brings further benefits. The CCGTs are typically the final bid accepted to meet the 70% limit.

Figure 33 – Cost of unserved energy in the Bacton failure case, High Demand scenario



By contrast, Strawman 3 excluding CCGTs performs better than its counterpart including CCGTs. This is because under SM3, the accepted bids are chosen according to the lowest option fees. CCGTs are therefore accepted under the tender since they have low option fees; but at the expense of non-CCGTs which contain lower exercise fees. This results in SM3 excluding CCGTs performing better than the case where CCGTs are included.

The NGG option has the one of the lowest costs of unserved energy from all the policy options assessed; which at £39bn in 2030 represents a 30% reduction on the cost of the current arrangements. This is because no volumes are crowded out by the inclusion of the CCGTs and so virtually all bids below £196/therm are accepted

The benefits under SM2 including CCGTs and SM3 excluding CCGTs and the NGG option are very similar.

As an illustration of how unserved energy is allocated differently under the different policy options, Figure 34 and Figure 35 show the unserved energy from the Bacton case for January 2031. The comparison shows the effect of encouraging I&C customers to submit bids where the cost they would incur through the loss of their gas supply is lower than the costs that CCGTs would incur. In both cases it proves necessary to interrupt non-daily metered customers, but the re-allocation of the unserved energy on days when this is not required delivers the substantial reductions in savings shown in Figure 33.

Through the comparison of Figure 34 and Figure 35, it is possible to see an example on 25 January of a day when the DSR mechanism prevents a GDE. Under the current arrangements on this day there is a substantial degree of firm-load shedding (visible as coloured layers above the CCGT volume). On the same day, the NGG mechanism is sufficient to bring forward enough voluntary DSR to mean that no firm-load shedding occurs.

Figure 34 – Allocation of unserved energy under current arrangements

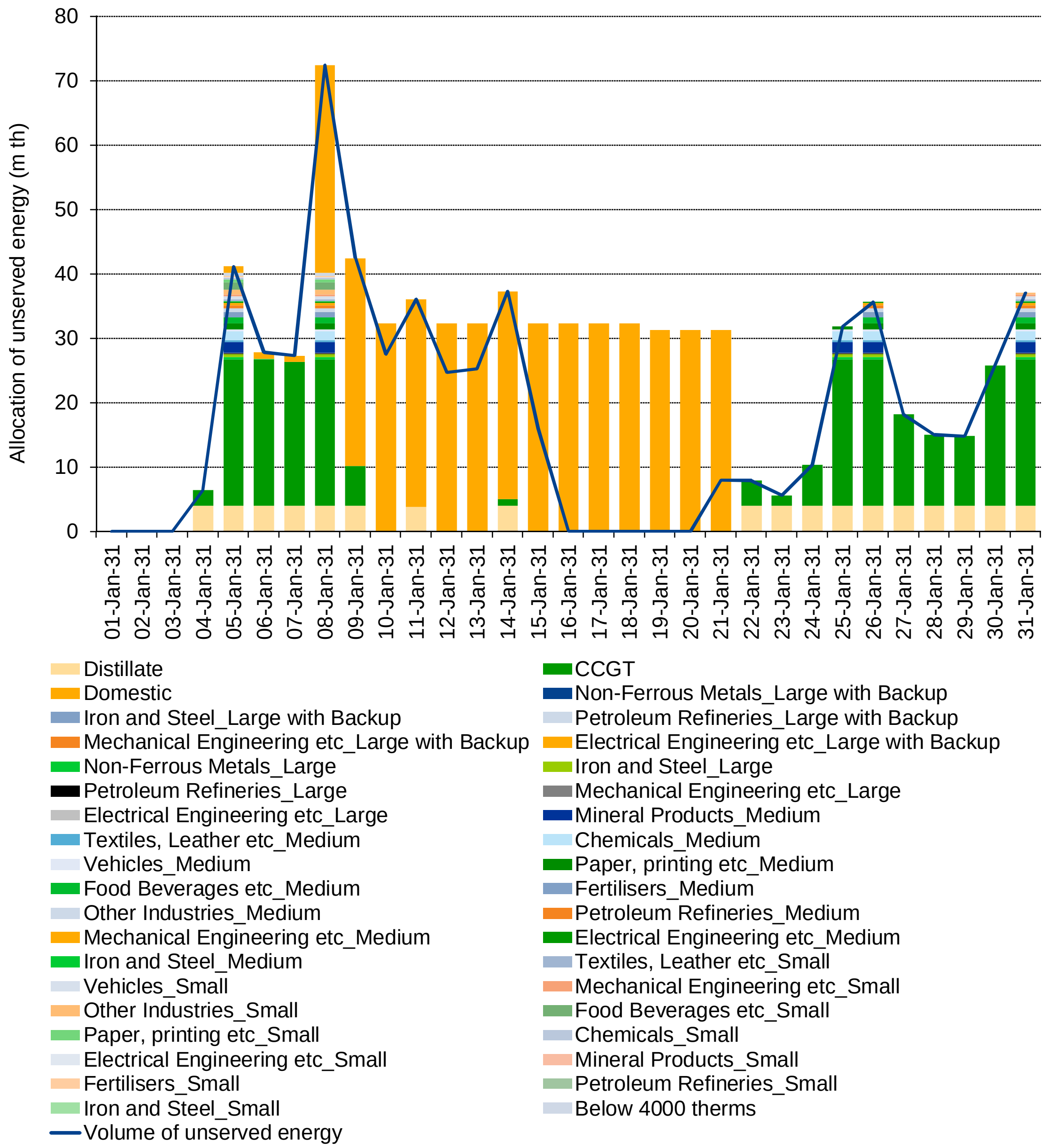
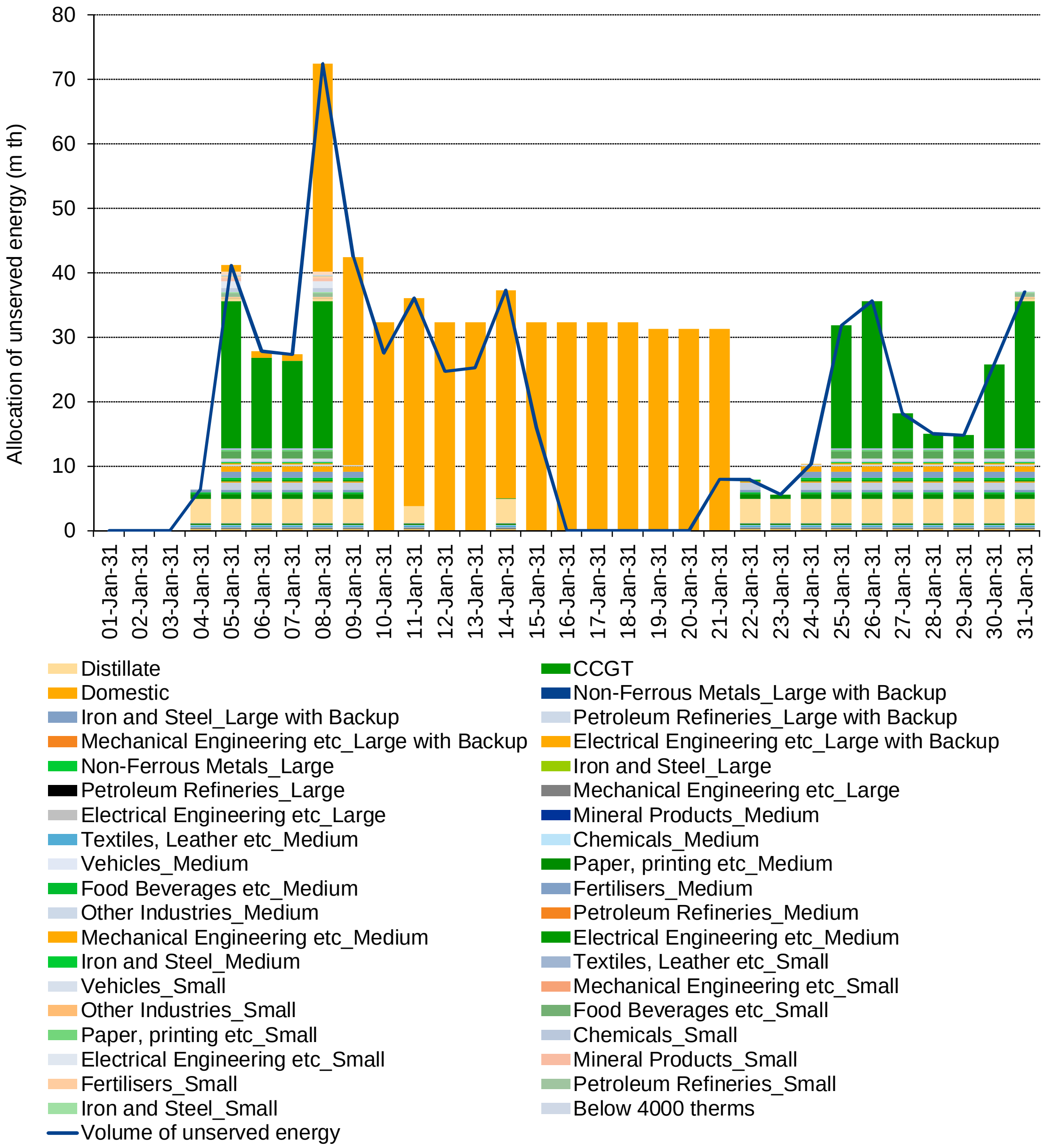


Figure 35 – Allocation of unserved energy under the NGG option

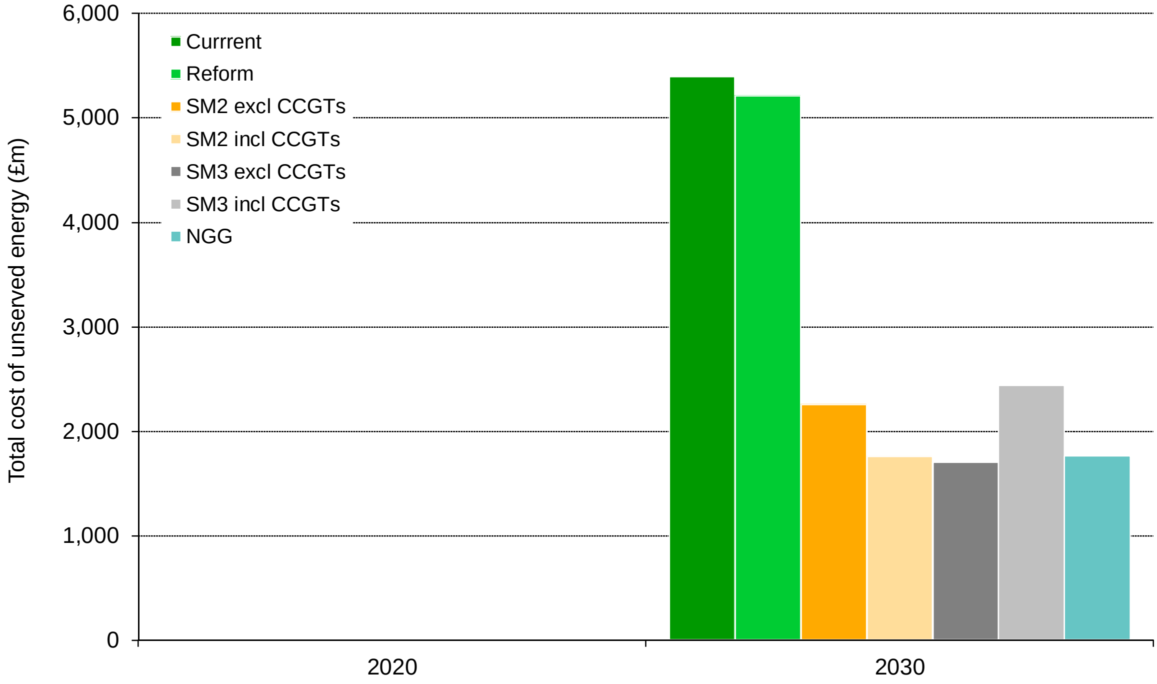


5.3.2 Comparison of the policy options under a Milford Haven failure, High Demand scenario

Figure 36 below illustrates the cost of meeting the unserved energy from the case when Milford Haven is assumed to fail.

The Milford Haven case shows a similar pattern of results to those in the Bacton case – though notably there is no unserved energy in 2020, and the cost of the unserved energy in 2030 is on a different scale from the Bacton case. The current arrangements would incur a cost of over £5bn in 2030 which is cut to less than £2bn by SM2 including CCGTs, SM3 excluding CCGTs and the NGG option.

Figure 36 – Cost of unserved energy in the Milford Haven failure case, High Demand scenario

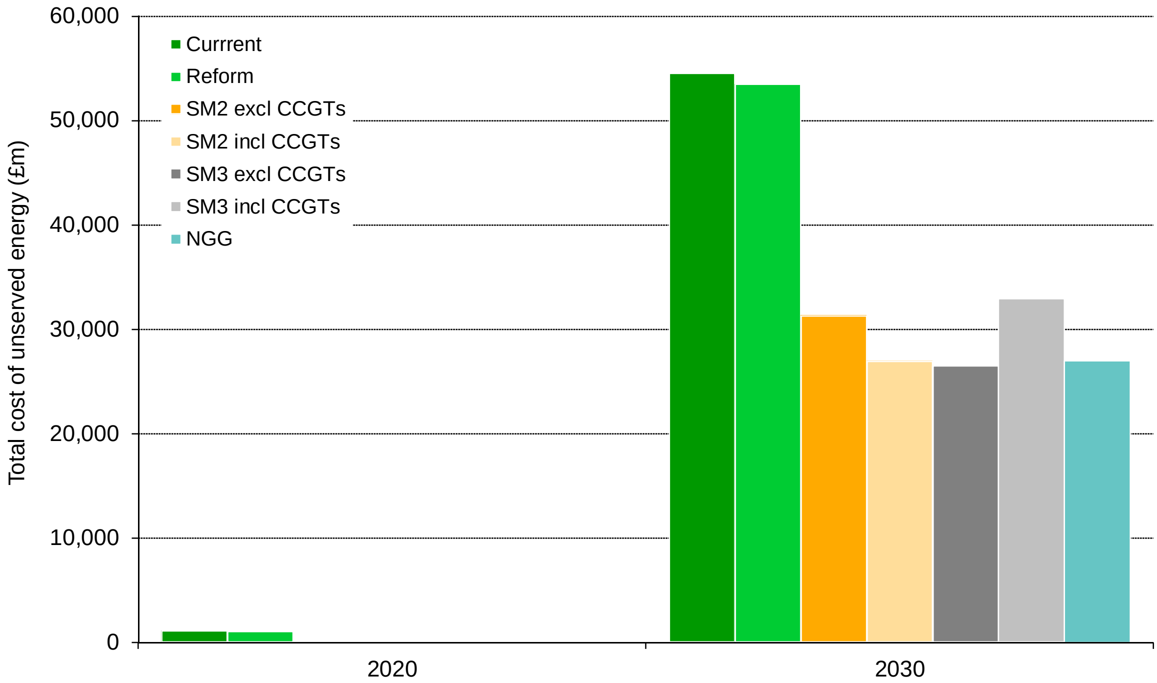


5.3.3 *Comparison of the policy options under Rough and Sleipner failure*

Figure 37 below illustrates the cost of meeting the unserved energy from the case when Rough and Sleipner are assumed to fail.

The failure of Rough and Sleipner shows that in 2020 all DSR mechanism designs would reduce the cost of unserved energy to approximately £100m from the £1bn in the current arrangements. 2030 shows the greatest saving in the cost of unserved energy; with SM2 including CCGTs, SM3 excluding CCGTs and the NGG option reducing the costs from £55bn to less than £30bn.

Figure 37 – Cost of unserved energy in the Rough and Sleipner failure case

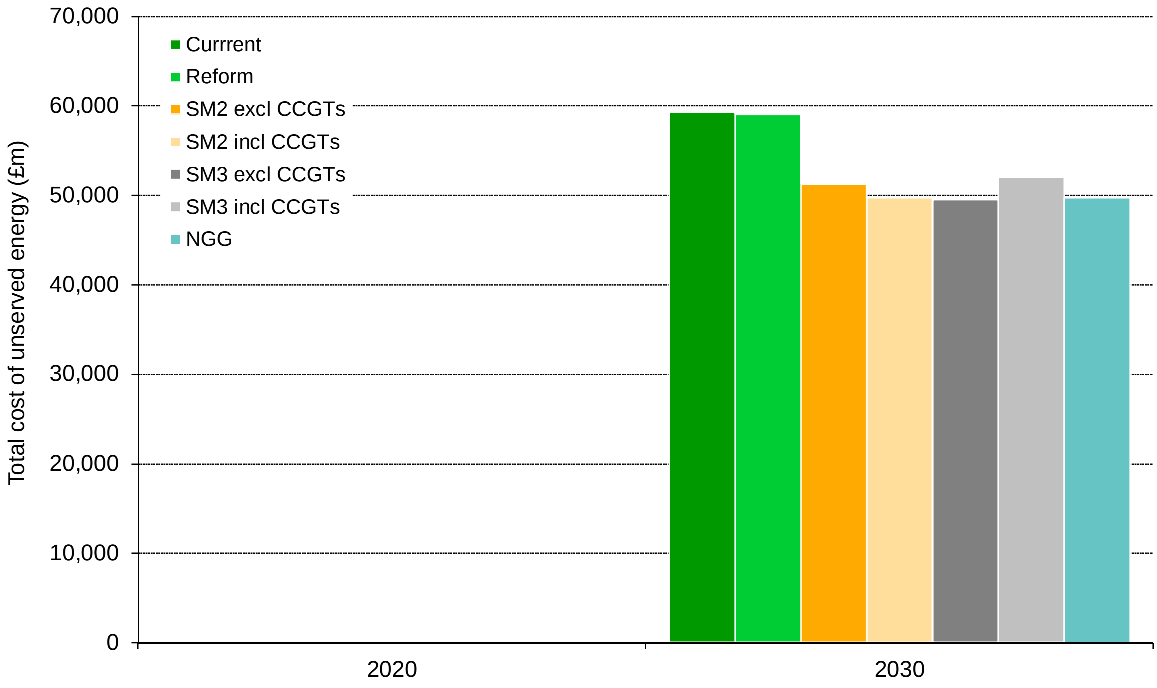


5.3.4 Comparison of the policy options under Qatar failure, High Demand scenario

Figure 38 below illustrates the cost of meeting the unserved energy from the case when supplies from Qatar are assumed to fail.

The failure of Qatar in 2030 shows the, now familiar, pattern with all mechanism designs showing a considerable saving in the cost of unserved energy. The Qatar failure case has costs under the current arrangements and the reform case at almost £60bn whilst SM2 including CCGTs, SM3 excluding CCGTs and the NGG option all reduce this cost to somewhere close to £50bn.

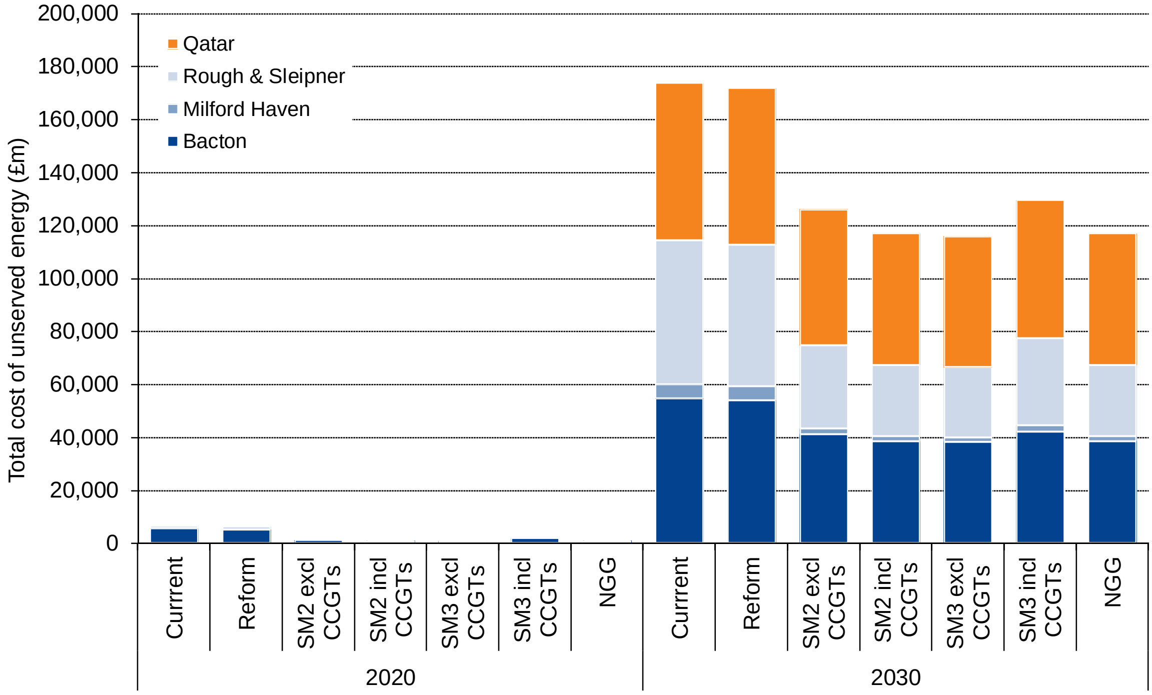
Figure 38 – Cost of unserved energy in the Qatar failure case



5.3.5 Comparison of the policy options under all cases

Figure 39 illustrates the aggregate savings that would be made across all of the failure cases considered in order to demonstrate the relative size of the savings in each case. The chart shows that the savings under the Bacton and Qatar failures exceed the other two by some distance.

Figure 39 – Cost of unserved energy in all failure cases



5.4 Probability-weighted benefits

To conduct the full CBA, we need to adjust the raw results for the probability of each case occurring. To do so, the following probabilities, as described in Section 2.5, were used.

Figure 40 – Probabilities of each failure

Failure case	Probability
Bacton	2.0%
Milford Haven	2.0%
Rough & Sleipner	1.0%
Qatar	2.0%

The benefits were also reduced for the probability of the weather scenario occurring. We have modelled a 1 in 50 winter, and so the probability weighted benefits after the probability of the infrastructure failure are then multiplied by 2% to represent the chance of the infrastructure failure coinciding with a cold winter.

The result of probabilities to reflect two factors results in a combined probability of 0.14% of the benefits we show being included in the CBA[30]. We believe this is overall a

30 By comparison, Redpoint's previous study for Ofgem (November 2012) found a probability of 1 in 34 (2.9%) of interruptions to the electricity sector, and a probability of 1 in 167 (0.6%) of interruptions to non-daily metered customers.

conservative approach to estimating the benefits resulting from the DSR mechanism for two reasons:

- we have not modelled an exhaustive list of all infrastructure failures which could result in a gas deficit emergency; and
- it is is also possible that weather events which are more common than a 1 in 50 winter would also result in unserved energy in the High Demand scenario; albeit lower volumes than would result from the 1 in 50 case.

5.5 Consolidated results

5.5.1 Quantitative results

To perform the CBA, we compare the probability-weighted benefits with the known costs. We then calculate an NPV (to 2030) of the expected benefit from adopting each policy option compared to the base case of the current arrangement, using a real discount rate of 3.5% (as per the Green book). The results are summarised in Table 32 and illustrated in Figure 41.

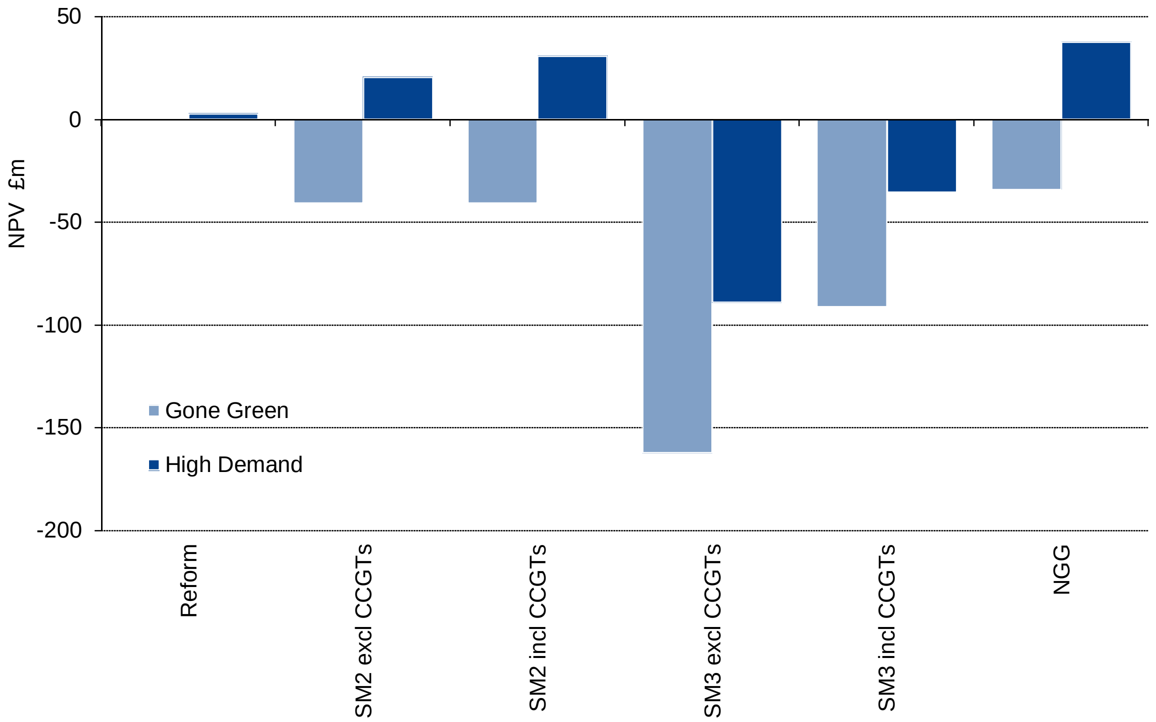
Under the Gone Green scenario, all policy options have a zero or negative NPV because there is no unserved energy and so the NPV represents only the current value of the future costs of implementing the policy option.

The NGG option shows the greatest benefit under the High Demand scenario at £37.5m. SM2 including CCGTs also has a significant positive NPV since it delivers the same benefit from the improvement in the efficiency of the disconnection order, but has higher annual costs than NGG which reduces the NPV. Despite providing a similar level of reduction in the cost of unserved energy to SM2 including CCGTs, SM3 excluding CCGTs performs less well once the annual costs of the option fees are taken into account since these costs will be incurred every year regardless of whether there is an emergency or not.

Table 32 – CBA NPV for assessed policy options

£m	Reform	SM2 excl CCGTs	SM2 incl CCGTs	SM3 excl CCGTs	SM3 incl CCGTs	NGG
Gone Green	£0.0	-£41.0	-£41.0	-£162.3	-£91.3	-£34.3
High Demand	£2.7	£20.5	£30.8	-£89.3	-£35.5	£37.5

Figure 41 – Net present value of benefits from each policy option compared to the current arrangements



5.5.2 Risks relating to quantitative results

5.5.2.1 Risks relating to modelled results

When comparing the relative merits of the DSR mechanisms, it is important to bear in mind that these CBA results are driven by key assumptions with varying degrees of certainty. While the assumptions behind the costs of running the DSR mechanism are relatively uncontentious, the relative benefits of each design are driven entirely by our assumptions on the volumes and cost of I&C DSR. In terms of volume, the main risk is whether we have overestimated the levels of participation in the DSR mechanism. In terms of cost, the risk is that bid prices have been underestimated, especially relative to the maximum bidding price assumed for CCGTs (i.e. £118/therm), since it is the CCGT bidding level which is a key driver of these results.

Table 33 below summarises the main risks in the assumptions we have made which may affect the relative merits of the DSR mechanism designs, in terms of the volume and price risk.

Table 33 – Key assumptions affecting relative benefits of DSR mechanisms

		SM2		SM3		NGG*
		Excluding (CCGTs)	**Including CCGTs**	**Excluding (CCGTs)**	**Including CCGTs**	
Volume risk	**Barriers to participation**	Volumes may be overestimated across most policy designs, particularly if barriers to participation are higher				Insofar as the barriers to participation are reduced (formulating one's own valuation becomes easier in an open bid auction, and reduced contractual costs); may increase participation
	Perceived bid success	Lower levels of participation may be driven by fear of being unsuccessful				Lack of decision criterion** reassures consumers that their bid will be successful; may increase participation
	CCGT participation		CCGT participation may create the perception of crowding out I&C volumes; may reduce participation		CCGT participation may create the perception of crowding out I&C volumes; may reduce participation	
Price risk	**Premiums: load protection**	Incentive to inflate bids in order to increase load protection (move down the curve) may be underestimated across all policy options				In addition, real time updating may exacerbate this allowing "load protectors" to increase prices steeply as GDE approaches
	Premiums: uncertainty in calculating OC	Sealed bid tender and uncertainty regarding how to estimate true OC may lead to bidding at a premium				Iterative, open bid tender increases transparency and allows for relative valuation, increasing confidence in one's valuation.
	Option fee acceptance criteria			Perverse incentive created by "option-fee only" acceptance criteria; may lead to particularly high exercise fees		
	CCGT bidding levels		Volumes of accepted I&C highly dependent on the relative valuation of I&C vs CCGT bids. If CCGTs were to bid at lower levels, less I&Cs would be accepted		Volumes of accepted I&C highly dependent on the relative valuation of I&C vs CCGT bids. If CCGTs were to bid at lower levels, less I&Cs would be accepted	As above, prices may increase steeply as GDE approaches**

* Assumes NGG formatted as an open, iterative tender (TBC). ** Subject to NGG's decision in the event of an emergency.
Source: L:\OFGEM\41X177951_Ofgem_GasSCR_DSR_CBA\ClientDeliverables\Drafts\CDE\RisksDSRtender.xlsx

These risks should be borne in mind when comparing the DSR mechanism designs.

5.5.2.2 Limitations of the CBA

Ofgem considers there to be three likely impacts from the various reforms options that have been assessed:

- more efficient utilisation of DSR;

- more efficient price signals; and
- transfer of risks resulting in new costs of a GDE on shippers.

The CBA results presented here represent those benefits which accrue from the more efficient utilisation of DSR. Our modelling assumes efficient pricing across the globe, and so only results in unserved energy when there is no possible commercial solution which results in a more efficient allocation of gas. In a GDE GB may be able to attract more gas from neighbouring markets through paying a higher price (if there is available gas in neighbouring markets), but this is not necessarily a more efficient outcome for the gas markets of Europe as a whole, particularly if it swaps unserved energy in one country for unserved energy in another.

Our analysis does not consider whether the increase in risks faced by gas shippers through the extra payments which will be made to interrupted customers will incentivise them to take additional steps to better secure their supplies due to any increase in the expected cost of a GDE. Examples of these steps could include infrastructure development (for example CCGTs investing in distillate back-up or new gas storage infrastructure becoming commercially viable), diversification of supply portfolio, and greater efforts to contract commercially for DSR.

5.5.3 Impact on consumer bills

Any DSR mechanism will have costs which would need to be funded ultimately by consumers – assuming a competitive market where retailers make only normal profits. The costs to be covered include the annual cost of running an auction and the payments which would be due to consumers which are involuntarily interrupted. The payments to consumers involuntarily interrupted under each of the policies is summarised in Table 34.

Table 34 – Payments to consumers under firm-load shedding

	Unsuccessful participant	Eligible non-participant	Ineligible participant	NDM consumers
Currrent	N/A	N/A	N/A	No payment
Cash-out reform	All DM customers paid 30 day SAP			£14/therm
SM2 excl CCGTs	30 day SAP	No payment	VWA	£14/therm
SM2 incl CCGTs	30 day SAP	No payment	VWA	£14/therm
SM3 excl CCGTs	30 day SAP	No payment	VWA	£14/therm
SM3 incl CCGTs	30 day SAP	No payment	VWA	£14/therm
NGG	30 day SAP	No payment	VWA	£14/therm

NB. VWA = Volume weighted average of the bids accepted under the DSR mechanism. NDM consumers will be paid for the first day of interruption only.

To estimate the impact that the DSR mechanisms could have on consumer bills we have taken the following approach:

- calculate the payments due to each type of consumer (adjusted for the probability of the payments being necessary); and
- include the annual costs of the DSR mechanism.

The total cost is then divided between the non-power gas consumers, and is presented in Table 35 as the impact on an average annual consumer bill.

This approach leads to a 'worst-case' impact on consumer bills, since they are assumed to bear the full expected cost of the payments, but even this methodology results in very modest increases to the average bill. The costs of the DSR mechanism are expected to be very small compared to the number of gas customers and the expected payments under the policy are small due to the unlikely nature of an emergency occurring which would necessitate payments.

Table 35 – Impact on annual average consumer gas bills

£/a	Firm load shedding	Fixed costs	Total
Currrent	0.000	0.00	0.00
Cash-out reform	0.006	0.00	0.01
SM2 excl CCGTs	0.004	0.07	0.08
SM2 incl CCGTs	0.004	0.07	0.08
SM3 excl CCGTs	0.004	0.29	0.30
SM3 incl CCGTs	0.005	0.17	0.17
NGG	0.005	0.06	0.07

Under the current arrangements there are no payments to customers under firm load shedding and so all alternative policy options are compared to this position. With cash-out reform there is a very small fee of less than 1pence per annum, which would be required to cover the expected cost of payments to customers compensated for loss of their firm load. This cost remains very small under all of the DSR mechanisms which are being considered alongside cash-out reform; though the cost does come down very slightly in all the DSR cases since the policy results in more consumers being interrupted on an efficient basis rather than falling into an inefficient largest first firm-load shedding.

In the cases with a DSR mechanism, the costs of the mechanism will also need to be passed through to gas consumers. This fee is the lowest in the case of the NGG option as this has assumed lower annual costs, though SM2 also has a similar impact on consumer bills. SM3 has a greater impact on consumer bills since the option fees payable under this scheme increase the annual costs.

Overall, the impact of the cheapest policy option including a DSR mechanism is the NGG option at 7 pence per annum, and the most expensive is SM3 excluding CCGTs at 30 pence per annum.

5.6 CBA conclusion

We have seen that the current arrangements of largest site first in disconnection results in a very inefficient disconnection process should there be insufficient gas supply to meet demand. The cost of this process is significantly more than previous studies have revealed due to the impact of the charges gas-fired generation are expected to face. The reforms to the electricity cash-out reform and penalties for not meeting the obligations under the capacity payment mechanism result in CCGTs having a VoLL of £118/therm. Any change in the level of costs faced by the CCGTs (for example through changes to the proposed electricity cash-out reforms and capacity mechanism penalties) can be expected to result in different results to our analysis.

It is also clear from the consultation responses associated with this policy consideration and the lack of bids in recent DNO DSR auctions that potential participants have not yet seen any value or need to offer DSR. This reflects the difficulties in addressing the risks associated with these low probabilities but very high impact events.

The CBA shows that there is expected to be a worthwhile benefit if a suitable DSR design is adopted and so improve the efficiency of allocating unserved energy amongst gas consumers in GB in cases where a GDE ensues. Ensuring lower cost disconnections before the now very expensive CCGTs has a major benefit to consumers and the economy as a whole in reducing the impact of supply shocks that result in unserved energy. However, such a benefit is reduced to a significant degree by the fact that the events which would lead to a gas deficit emergency are also very unlikely.

The CBA illustrates that there would be a benefit from a suitable DSR mechanism in a high demand world (the High Demand scenario) but a net cost in a low demand world (the Gone Green scenario). In our view, policies relating to security of supply should be assessed with sufficient awareness of the risks from an uncertain future, and so it would be unwise to base a decision only on the results from the Gone Green scenario. A suitable DSR mechanism represents a relatively low cost option for improving market efficiency in the unlikely event of a gas deficit emergency – which in our view seems a sensible insurance product for the gas market to adopt.

Although most DSR mechanism designs would provide a net cost to GB, of those evaluated the NGG option and SM2 including CCGTs (as this encourages acceptance of higher I&C volumes) result in the greatest net benefit. Whilst the former provides an easier access to the market for DSR the latter has the advantage of providing known volumes and costs each year.

It would also seem likely those similar benefits could be achieved if a higher volume cap was adopted under SM2 excluding CCGTs, especially if strong incentives to participate are provided e.g. non-payment to non-participants or even compulsory participation at the extreme.

SM3 excluding CCGTs delivers a similar level of reduction in cost in the event of an emergency, but cannot provide a net benefit due to the costs incurred in paying option fees to all participants for services which are unlikely to be required other than in extreme circumstances.

6. CBA SENSITIVITY

The level of demand-side response which will come forward under both the current arrangements and cash-out reform policy options is not known with great certainty. To take into account a base-case where there is a greater level of DSR which finds a route to market without a centralised DSR mechanism, Ofgem requested that we undertake a sensitivity to the CBA as set out in Section 5.

6.1 Rationale

There is historical data which shows that industrial and commercial users, as well as gas-fired generators have reduced their consumption due to commercial reasons when gas prices are high. However, there are several factors which mean that current and future DSR is likely to differ from historically witnessed levels; including modifications to the Uniform Network Code[31], changes to the GB economy resulting in lower levels of gas usage, and changes in the electricity generation sector (for example closure of coal-fired plant) which mean that there are fewer alternatives to gas within the electricity generation mix.

Within this sensitivity, we have considered the possibility that a more significant number of industrial and commercial customers would look to manage their commercial risks through putting in place interruptible or flexible contracts with their suppliers which would allow the customer to respond to high prices through reducing their consumption. The sensitivity does not affect the volumes and prices of DSR from CCGTs.

A recent report published by Datamonitor illustrated that 21.2% of major gas users are on a fully flexible gas contract as shown in Figure 42. As gas markets have become liquid, major gas consumers now have a range of ways of pricing their gas supplies; including indexation to spot market (day-ahead and month-ahead) products alongside more traditional annual fixed priced deals. Those customers which have indexation to day-ahead pricing would have a commercial incentive to respond to high spot prices if the gas cost were to exceed the gross value-added of their final product. In these cases, Ofgem expects consumers may come to a commercial agreement with their shipper to reduce their demand during periods of high price without the need for a centralised DSR process.

There are three potential issues with utilising the Datamonitor figures. The first issue is that the volume requirement for ‘major energy users’ is well below the 4,000 th/day eligibility criteria for participation. However, we consider that larger consumers are likely to be more familiar with gas trading, and so should be at least as likely as a group containing smaller users to have market indexation within their contracts. The second issue is that many consumers within the ‘at least partly flexible’ group may also have sufficient market indexation to encourage demand-side response as prices reach high levels. The third issue is that even though customers may be on market reflective pricing, they may not respond quickly to very high gas prices, and industry response to the Ofgem consultation on DSR mechanisms indicates that few parties are interested in providing DSR on a voluntary basis. This lack of engagement is supported by the lack of

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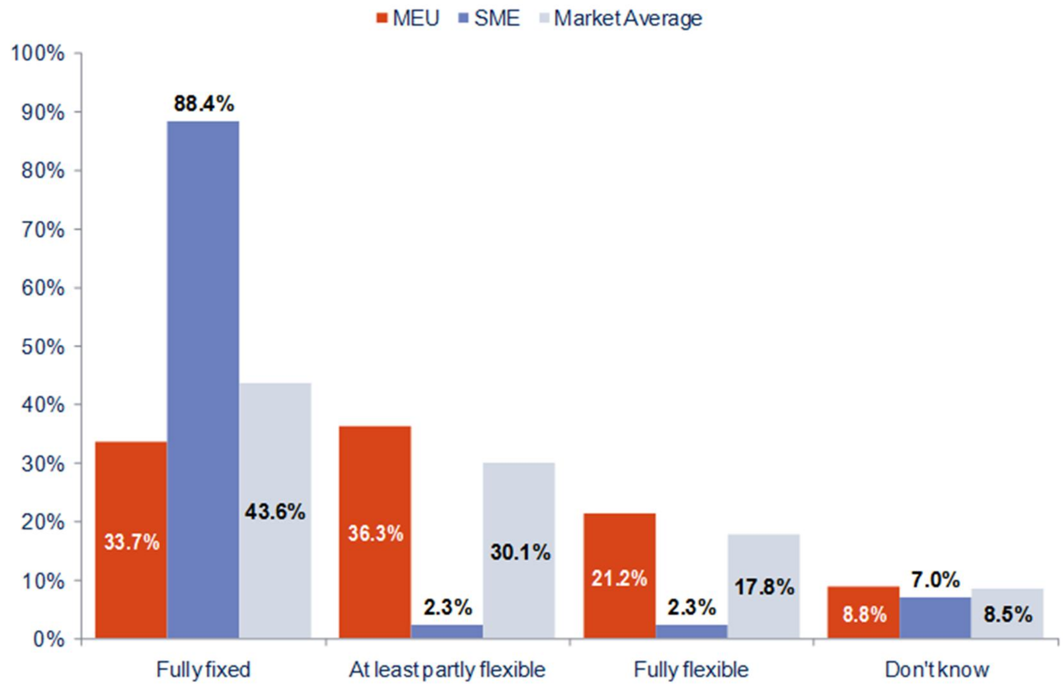
31 For example Modification 0090 which allowed gas distribution networks (GDNs) to determine the amount of interruptible contracts that they purchase from consumers, and removed the standard charging methodology of allowing a flat use of system capacity discount and Modification 0116AV which reformed the NTS exit capacity regime including amending interruptible NTS capacity (amongst many other aspects).

interruption bids offered to DNOs as part of implementation of Mod90 (see Annex D for more details).

Figure 42 – Contract pricing mechanisms of major energy users[32]



Source: Datamonitor B2B Energy Buyer Research, 2012

6.2 Participation

For the current arrangements and cash-out reform sensitivities, we have increased the range of I&C customers that would provide voluntary DSR under these two cases. We have not altered our approach to the participation of CCGTs since the CCGTs are assumed to have a route to market through the OCM in the original analysis.

6.2.1 'Current arrangements' sensitivity

Within the 'Current Arrangements' sensitivity, we re-examined the I&C participation to match as closely as possible the number of customers which Datamonitor indicates have fully flexible contracts. We followed a consistent approach to the volume disaggregation as described in Section 3.3.2. We included in the order below:

- large customers with back-up supplies;
- large dispensable, non-backed-up;
- medium customers with back-up supplies; and
- a portion of medium customers with dispensable non-backed-up supplies.

32 Ofgem have provided results from a 2012 Datamonitor survey on gas and power usage among major energy users: Datamonitor, *MEU H1 2012, B2B Energy Buyer Research*.

The rationale behind the selection of tranches was that the largest customers are more likely to provide DSR presently, and would be more willing to do so for their backed-up and dispensable tranches. In order to select the portion of medium sizes customers with dispensable, non-backed-up supplies, we organised the tranches in firm load shed order, and included the first three tranches (taking us to 22.5% of the total DSR volumes – the closest approximation to 21.2% that we could get using our dataset).

A summary of the I&C DSR volumes with a route to market under the 'current arrangements sensitivity' policy option and those without is presented in Table 18. These values are assumed to remain constant in the future. Note that for volumes "without route" only eligible participants are considered.

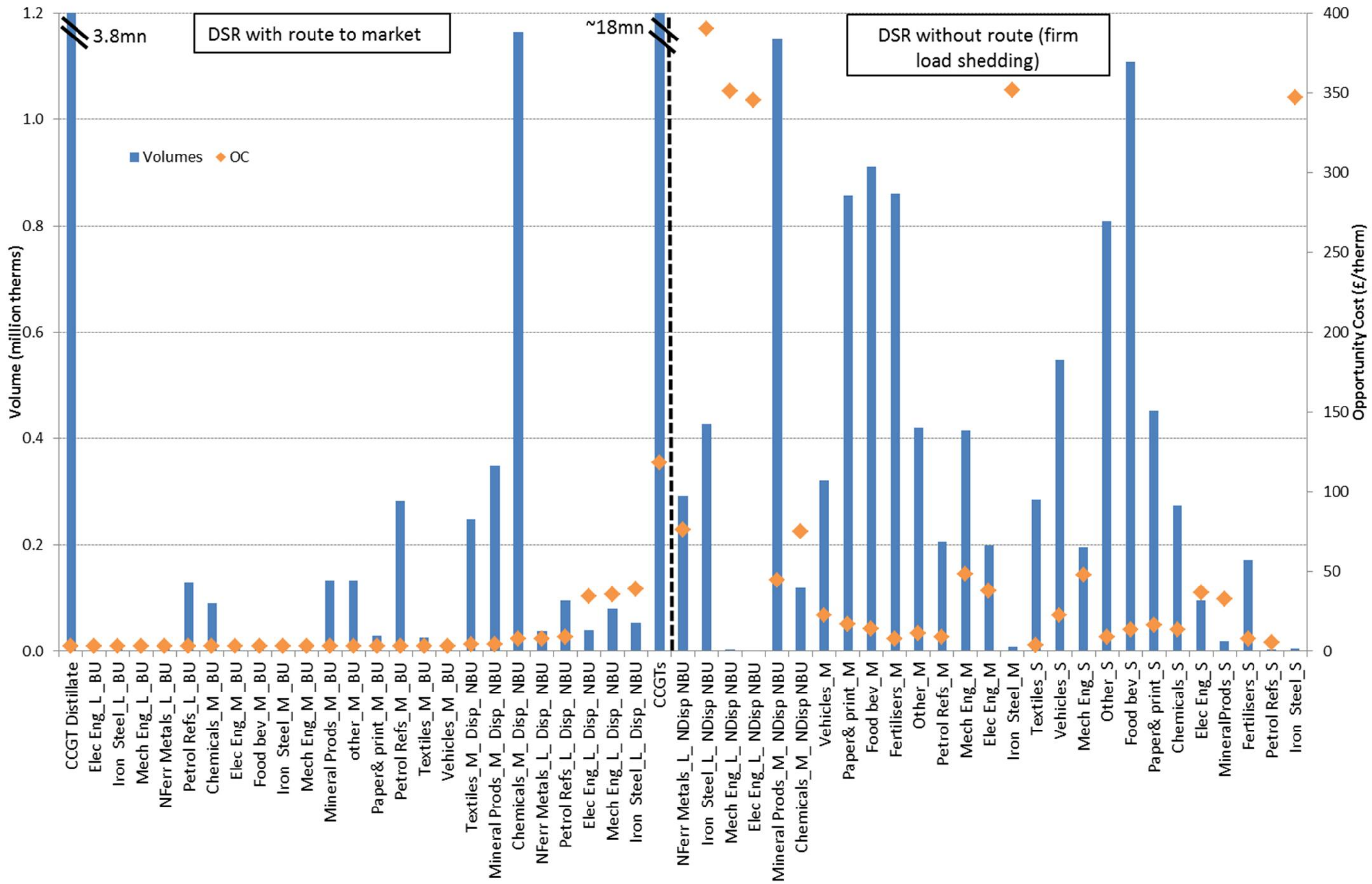
Table 36 – I&C DSR volumes under current arrangements sensitivity

	With route to market	Without route
Daily consumption (m th/day)	2.94	10.2
Proportion of total daily consumption	22.5%	77.5%

Figure 43 shows the resulting DSR disconnection order for 2030, again showing only eligible I&C participants' volumes (excluding ineligibles based on volume, and non-daily metered). While gas fired generator volumes have been included, these volumes vary greatly day by day, and while they are priced at the maximum electricity VoLL, in reality they would bid through the OCM according to electricity market scarcity possibly at lower levels.

(key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp = Dispensable, NDisp = Non-dispensable).

Figure 43 – Disconnection order under Current Arrangements sensitivity in 2030



6.2.2 'Cash-out reform' sensitivity

Within the 'Cash-out reform' sensitivity, we included the volumes from the 'Current arrangements' sensitivity, and one additional I&C tranche in order to reflect a small increase in the voluntary DSR which would emerge under the reform sensitivity, due to sharper price signals. The difference in volumes between the current arrangements and cash-out reform sensitivities correspond to the difference between these policy options in the original analysis.

A summary of the I&C DSR volumes with a route to market under the 'cash-out reform sensitivity' policy option and those without is presented in Table 37. These values are assumed to remain constant in the future. Note that for volumes "without route" only eligible participants are considered.

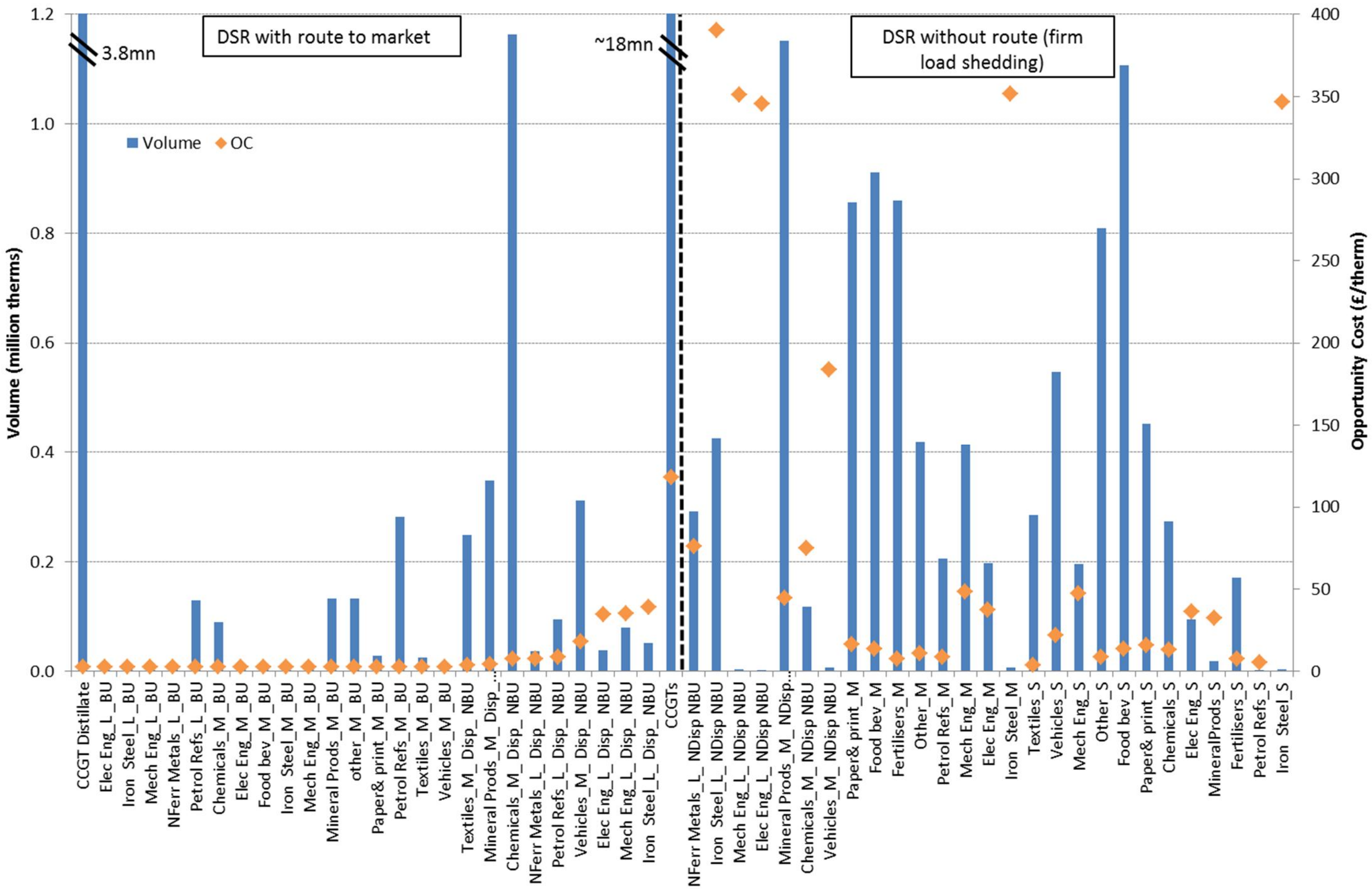
Table 37 – I&C DSR volumes under cash-out reform sensitivity

	With route to market	Without route
Daily consumption (m th/day)	3.26	9.84
Proportion of total daily consumption	24.9%	75.1%

Figure 44 shows the resulting DSR disconnection order for 2030, again showing only eligible I&C volumes. Same caveats apply to the gas fired generator volumes shown.

(key: S= Small, M= Medium, L= Large, BU= Backed-up, NBU= Non-backed-up, Disp = Dispensable, NDisp = Non-dispensable).

Figure 44 – Disconnection order under 'Cash-out reform' sensitivity in 2030

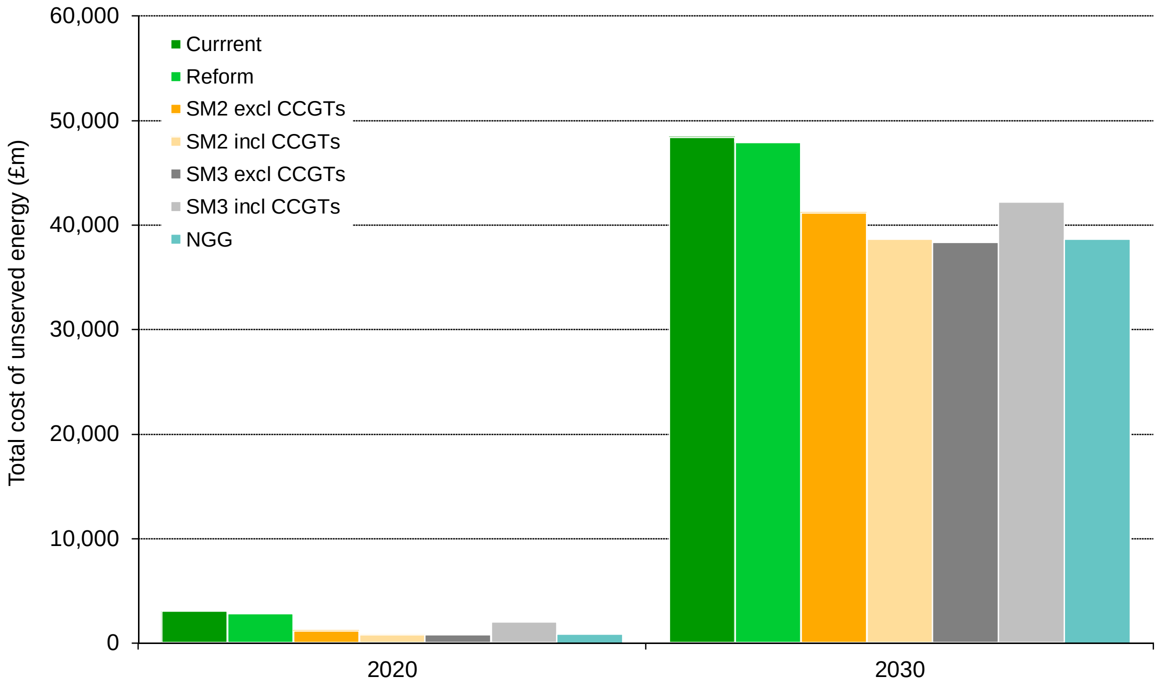


6.3 Benefits from the DSR mechanism policy designs

Utilising the increased DSR which is assumed to be available under the 'Current arrangements' and 'Cash-out reform' sensitivities outlined above, reduces the cost of allocating unserved energy in the High Demand scenario. As a result, the benefits shown by the introduction of a centralised DSR process are reduced, since the gap between the DSR which can already access the market and those that require the centralised process to provide this route is reduced; and hence the incremental benefit is smaller.

This point is illustrated in Figure 45 below.

Figure 45 – Cost of unserved energy in the Bacton, High Demand scenario, Current arrangements and Cash-out reform sensitivities



Comparing the results shown in Figure 45 with the equivalent values from Figure 33 shows that the cost of unserved energy has reduced from £55bn in 2030 in the base case scenario to £48bn in the sensitivity above. The costs under the remaining policy options are the same as shown previously, and therefore the gap between the current arrangements and cash-out reform cases and the new policy options has narrowed.

This situation is also true for the other failure cases, as shown in Figure 46, Figure 47 and Figure 48.

Figure 46 – Cost of unserved energy in the Milford Haven, High Demand scenario, Current arrangements and Cash-out reform sensitivities

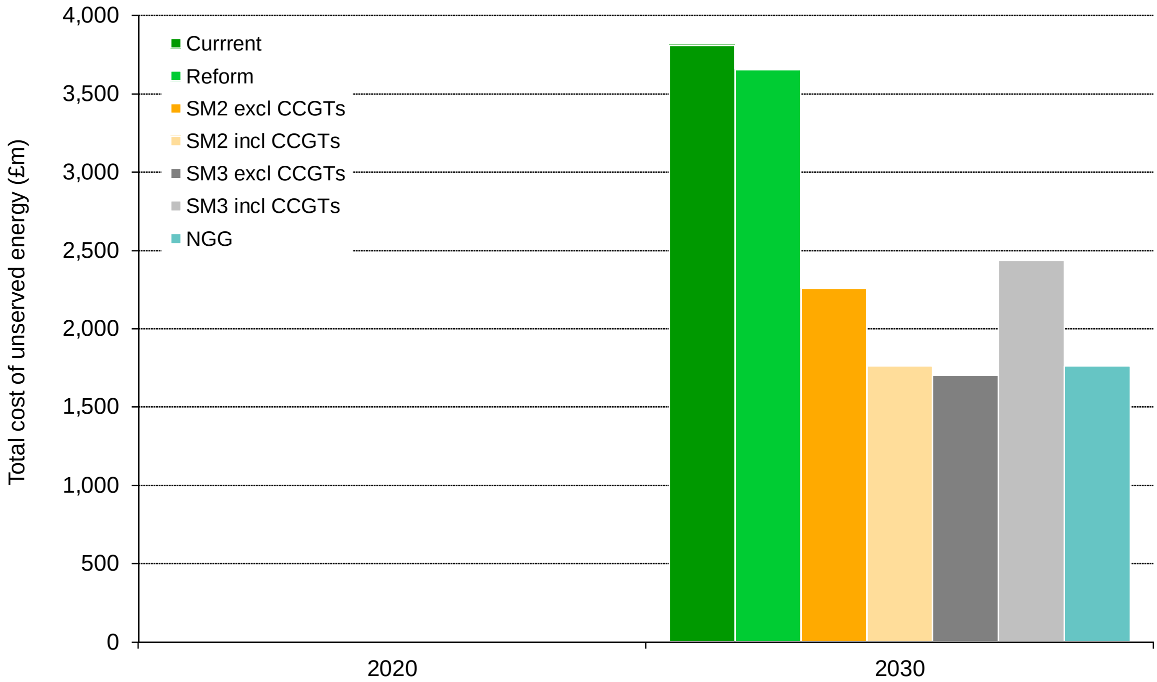


Figure 47 – Cost of unserved energy in the Rough and Sleipner, High Demand scenario, Current arrangements and Cash-out reform sensitivities

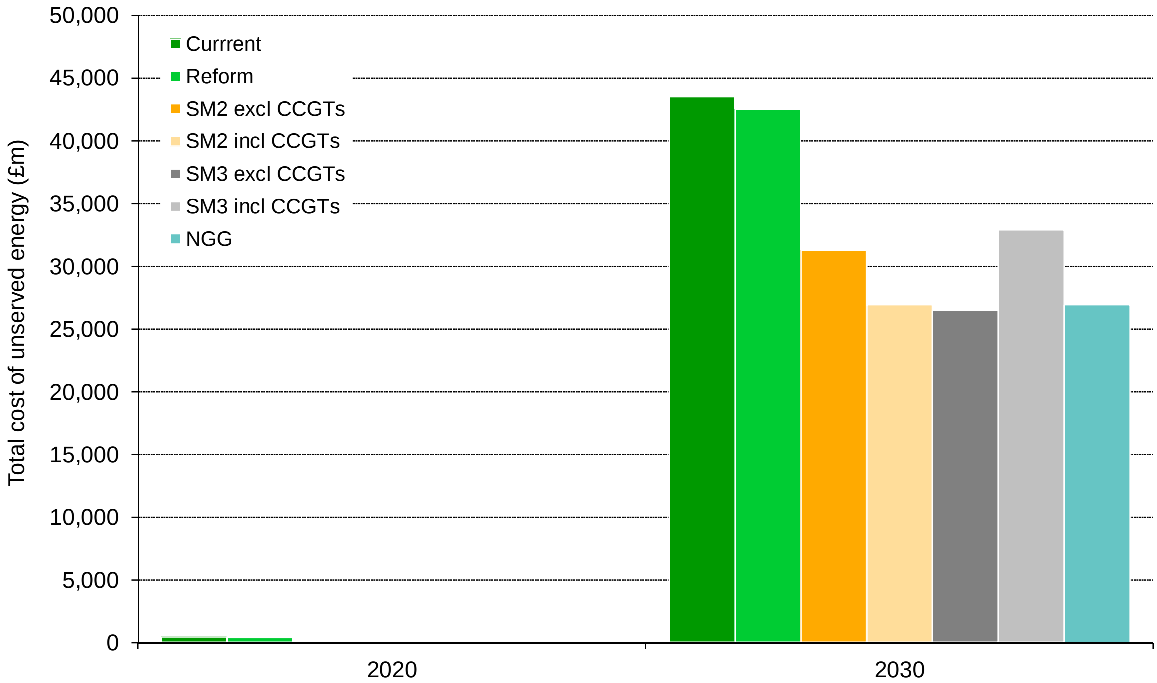
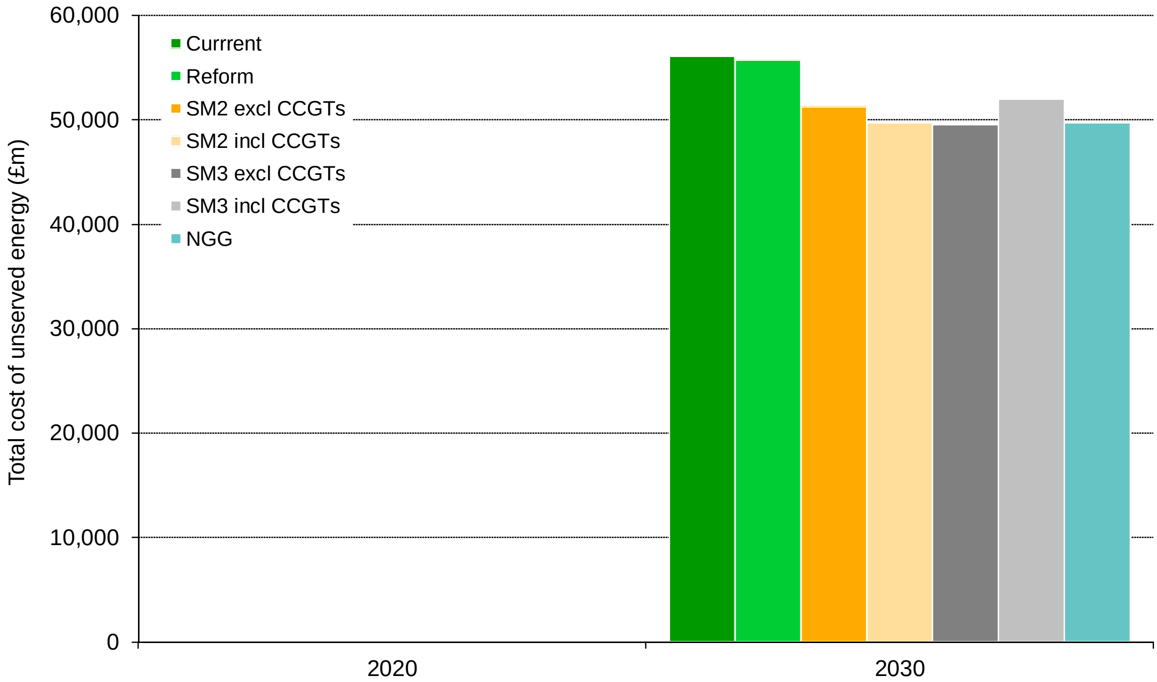


Figure 48 – Cost of unserved energy in the Qatar, High Demand scenario, Current arrangements and Cash-out reform sensitivities



6.4 CBA results

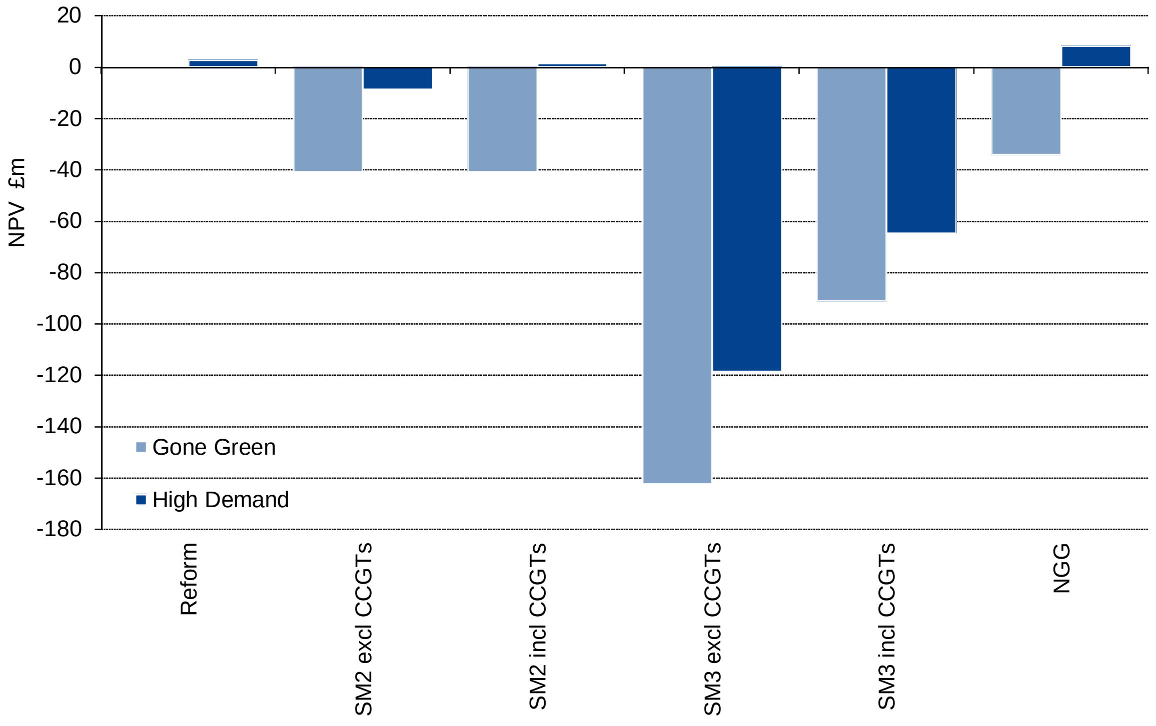
The charts above show that increasing the amount of DSR available under the current arrangements and Cash-out reform cases causes a corresponding reduction in the cost of allocating unserved energy. If this were the case, introducing a centralised process to encourage DSR is not as beneficial as our base case; since there is already a degree of efficiency to the interruption order.

This situation is shown in Table 38 and Figure 49 where all policy options under the Gone Green scenario are negative. There is a small benefit from SM2 including CCGTs and the NGG design under the High Demand scenario, but this is much reduced from the base case.

Table 38 – CBA NPV of DSR policy options

£m	Reform	SM2 excl CCGTs	SM2 incl CCGTs	SM3 excl CCGTs	SM3 incl CCGTs	NGG
Gone Green	£0.0	-£41.0	-£41.0	-£162.3	-£91.3	-£34.3
High Demand	£2.7	-£8.8	£1.5	-£118.6	-£64.8	£8.2

Figure 49 – Net present value of benefits from each policy option compared to the current arrangements sensitivity



ANNEX A – ENERGY MARKET MODELS

A.1 Pegasus gas model

Pegasus is a gas market fundamentals model, which aims to optimise flows of gas across the world in a way that replicates market behaviour. Pegasus has been developed to assess daily flows of gas in a world where gas demand is highly variable and uncertain. For this study, the model looks at the core geographic zones of GB, Ireland, France, Belgium the Netherlands, Germany and Spain at a detailed level, and at the Rest of Europe and Rest of the World at lower resolution.

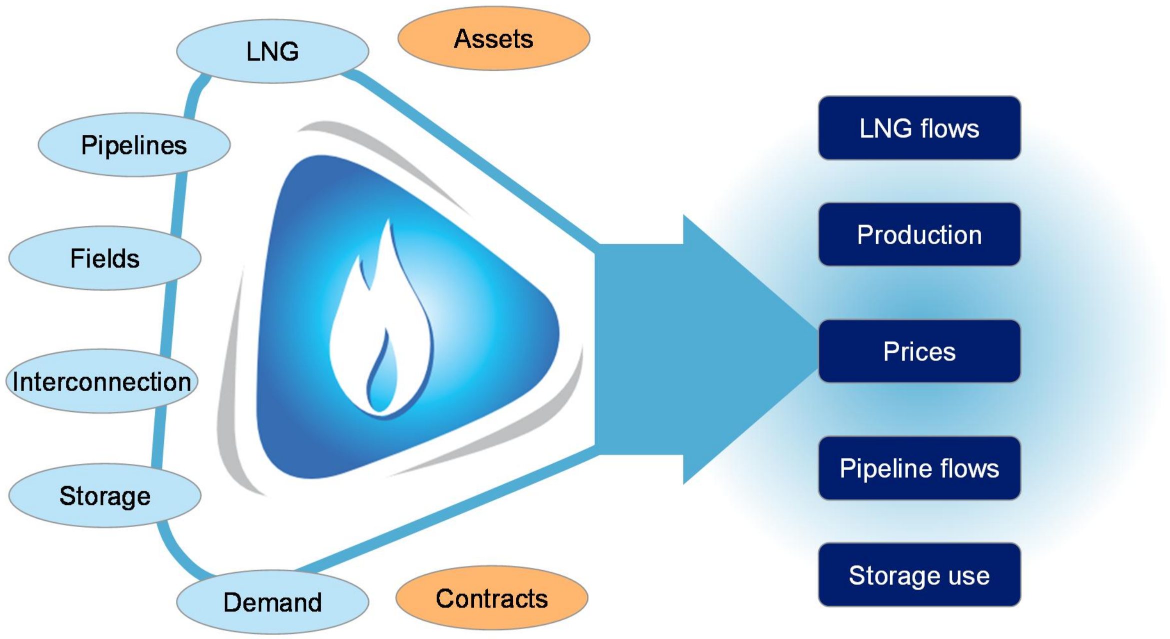
Pegasus optimises flows of gas from the major import pipelines, LNG terminals, indigenous production and gas storage.

The founding modelling principle of Pegasus is to optimise flows of gas in order to minimise the annual cost of meeting daily demand in every zone.

In addition to meeting daily demand, the model takes into account a number of constraints that represent the physical constraints and contractual obligations of the market. Pegasus holds a database of capacities and costs for all the major pieces of infrastructure like LNG terminals, production fields at an aggregated level, gas storage volumes and dynamic capabilities.

An overview of the major inputs and outputs is shown in Figure 50.

Figure 50 – Overview of Pegasus



Pegasus has two optimisation techniques which are used for different purposes:

- Perfect foresight – using this optimisation technique Pegasus has perfect foresight of 365 days of each year and will minimise cost based on seasonal normal demand.

This mode is suitable for assessing trends in long-term prices as changes in supply and demand can be assessed for a large number of countries across the globe.

- Rolling tree optimisation – this optimisation technique has been developed to represent a realistic 'limited foresight' of future events. This has been implemented by the 'rolling tree' methodology created by Pöyry and further explained in the following sections. This technique is suitable for assessing detailed flows and prices as they respond to changing demand on a daily basis taking into account variations in weather conditions.

For this project, the rolling tree version was utilised to take into account that gas market players will not have perfect foresight; especially when considering events which could result in a gas deficit emergency. For completeness, both techniques are now explained in further detail, though only rolling tree optimisation was used for this project.

A.1.1 Model structure

Gas prices are projected using our pan-European and US gas model, *Pegasus* ('Pan-European GAS + US'). The model examines the interaction of supply and demand worldwide on a daily basis. Pipeline imports and interconnections between the UK, NW Europe, Spain, Italy, Central and South East Europe and Turkey, and the interactions with Norwegian and Russian supplies are modelled in detail, alongside all existing and proposed LNG terminals, and their interaction with the global LNG market.

Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine cold spells, weekday/weekend differences, flows through the interconnectors and gas flows in and out of storage in detail.

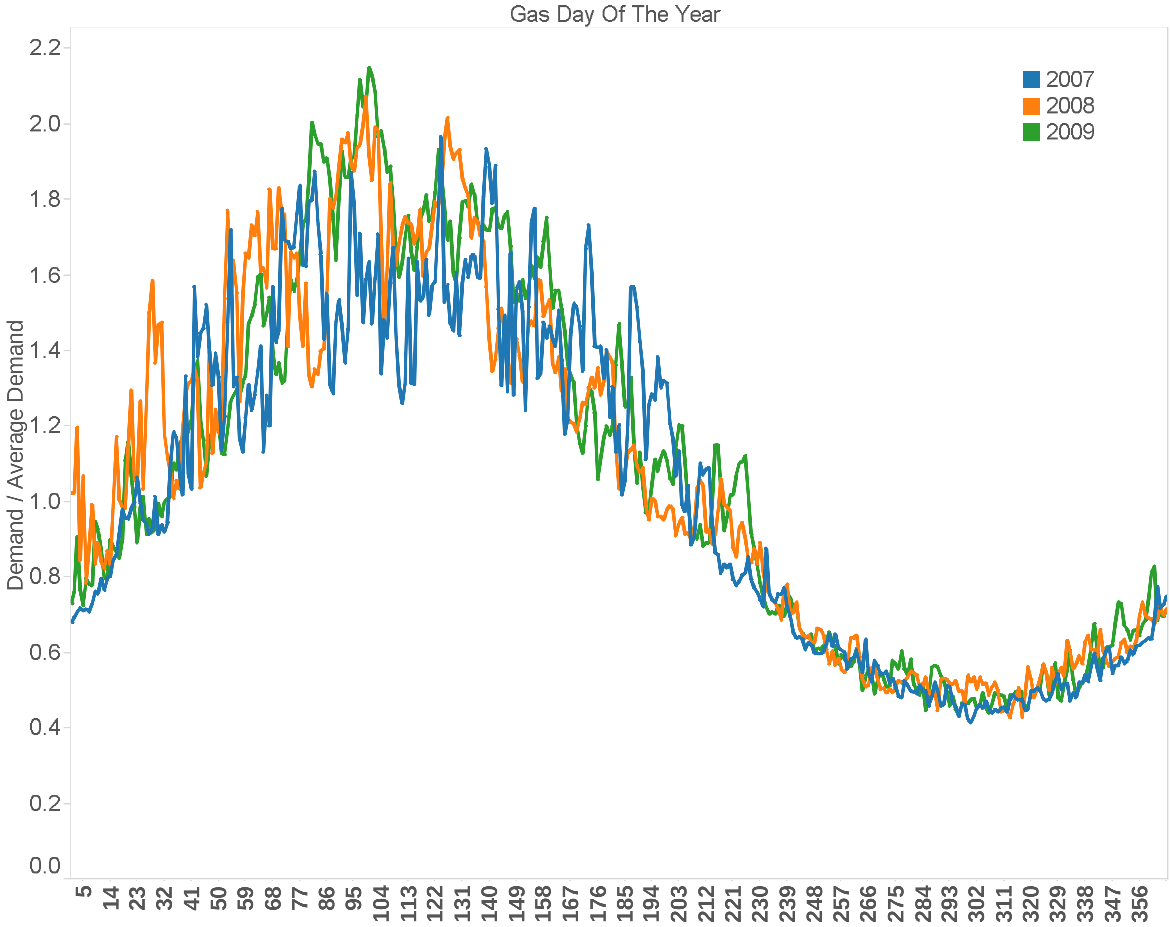
Pegasus itself is comprised of a series of modules. The main solving module is based in XPressMP, a Linear Programming (LP) package, which optimises to find a least-cost solution to supply gas to 23 zones over a gas year. Figure 51 shows 22 of the zones and the remaining 'Rest of the World zone' includes all the other LNG terminals. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions.

Figure 51 – Geographic coverage of Pegasus

A.1.2 Gas demand

Gas demand for non-power generation use has a daily profile calculated based on the historical weather patterns in each country, combined with analysis of how historical gas demand is correlated to weather. In this way, we can capture the important dynamic between weather (particularly cold periods) and gas demand. The resulting gas demand profile is then a realistic representation of genuine weather conditions, and hence the demand, that the supply will be required to satisfy. The daily gas demand takes into account the difference in demand between weekdays, weekends, and the Christmas holiday period, again based on historical patterns.

Figure 52 – Sample demand profiles for replicating historical weather patterns



Gas demand for power generation directly comes from our Poyry's electricity model BID3 on a daily resolution.

A.1.3 Indigenous sources

Conventionally produced indigenous gas is often the cheapest source of gas available to a country. Pegasus includes annual, monthly and daily constraints of indigenous production to ensure realistic production patterns. Seasonal swing patterns are included where indigenous production has historically produced in this manner, although decline over time to reflect lower production volumes and reduced future potential from smaller gas reservoirs.

A.1.4 Pipelines and interconnections

Pipeline imports and interconnections between the European demand zones are modelled in detail, alongside existing and proposed LNG terminals and their interaction with the global LNG market. We differentiate between a gas source (e.g. a field or group of fields) and a delivery point (e.g. a pipeline) to include flow constraints from both of these aspects within the model.

The interconnections between zones means that during certain periods, gas flows can switch back and forth between import and export based on costs. Flexibility can be transferred between markets if there is a surplus in one and a shortage in another alongside sufficient interconnection capacity.

A.1.5 LNG

Pegasus also models the worldwide LNG market. All existing, under construction, proposed and conceptual LNG liquefaction projects worldwide are taken into consideration in our scenarios. Similarly, all LNG re-gasification terminals are modelled. In Europe and the US each terminal is identified separately, except in the longer term when unspecified LNG terminal capacity may be included. The terminal capacity in the Far East, Canada and South America, and the rest of the world is grouped within zones.

Each LNG source can deliver to any LNG terminal, whilst gas fields can deliver via one or a few pipelines. As a result, LNG can be delivered to different destinations depending on which market is most profitable – for example, LNG will deliver preferentially to Montoir (France) or Zeebrugge (Belgium) when prices are higher in those markets than in GB. Thus European gas markets are linked not just through the interconnectors but also via LNG arbitrage. The interaction with the US and the rest of the world means that gas markets worldwide are linked based upon supply and demand for LNG.

A.1.6 Storage

Modelling storage accurately is important to understanding price formation, as it affects both summer and winter prices, along with weekday/weekend prices. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality.

In Pegasus, storage facilities are grouped into tranches per country based on their withdrawal and injection rates. This level of detail is sufficient to arrive at a realistic result of the use of European storage, but for the GB market, each storage facility has been modelled individually. In Italy and Hungary we take account of the fact that some storage is designated as ‘strategic’ and in other countries at least some gas storage is more difficult to access, which increases its cost.

A.1.7 Gas pricing and oil-indexation

Oil has traditionally acted as a major driver of European and worldwide gas prices through the practice of indexing gas prices to the price of oil in the preceding 3 to 9 months. However, the continued liberalisation of European energy markets and the creation of relatively liquid hubs in North-West Europe, coupled with the situation of oversupply has, at times, weakened the link between oil and spot gas prices. The longevity of this pricing mechanism and the extent to which it may apply in the future remains uncertain and is explored in our scenarios.

We maintain a database with details of long-term contracts which are used in the model to set prices along certain routes based on the level of oil indexation. Price levels in the receiving markets are then set by the marginal sources, whether it is the LRMC or oil-indexed contract, depending on the take-or-pay commitments, available uncommitted supplies and transportation capacity.

A.1.8 Feedback with power generation

As a core part of our modelling, we carry out iterations with our electricity model to understand how the demand for gas used in power generation will vary at different gas price levels. Iterating between the two models ensures that our assumptions on gas prices and gas demand remain realistic and reflects the elasticity of gas demand across a range of gas prices.

A.1.9 'Rolling-tree' optimisation

In order to model gas flows at a daily resolution, we developed a 'rolling-tree' optimisation approach[33]. The principle is to combine the advantages of Linear Programming (LP) with the real-world uncertainty that gas market players face when making scheduling decisions.

Standard optimisation using Linear Programming assumes perfect foresight – the model perfectly knows the demand on every day into the future, and the availability of all supplies. As a result, a pure optimisation approach misrepresents real-world gas markets – in particular for the use of gas storage and take-or pay constraints.

The approach we have chosen is to repeat the LP every day for the rest of the year being modelled with uncertain future demand. The 'rolling tree' approach is a combination of:

- 'Rolling optimisation': the day-ahead flows are calculated with an expectation of future demand which can (and will) be different from the demand which outturns. The model has to take scheduling decisions restricted by the sub-optimal decisions made in the past under a different expectation of demand.
- 'Tree based approach': the model considers different simultaneous paths of future demand. We believe that gas market participants are risk averse and will consider the possibility of high demand in the future when making scheduling decisions today. The model is therefore required to optimise flow decisions based on the probability-weighted costs of having either normal or extreme demand.

In Figure 53 below, this methodology is illustrated for the uncertainty of demand. On day 1, the model is simultaneously solving the 365 days for two paths of future demand – representing a 'typical' weather pattern and a more extreme cold winter. The results for the first day are kept, and the model then rolls forward to day two and solves 364 days for two future demand paths. The results for day two are kept and the process is repeated until all the year is solved.

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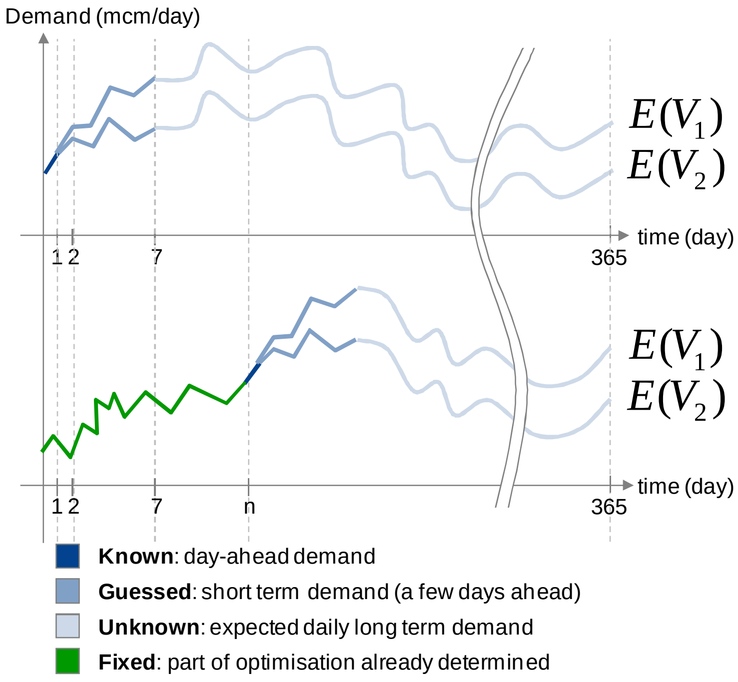
[33] Also called stochastic programming. We use the term 'rolling tree' as it is more descriptive.

Figure 53 – Overview of the 'rolling tree' approach



$$minimise\ \{D = 1..365\}:$$
$$E = \alpha_1.E(V_1) + \alpha_2.E(V_2)$$

$$minimise\ \{D = n..365\}:$$
$$E = \alpha_1.E(V_1) + \alpha_2.E(V_2)$$

Where:
D is day
E is total costs
α_2 is probability of branch 1 occurring
α_2 is probability of branch 2 occurring

Note that the 'supply curve' created through the demand-side response tenders was calculated outside the Pegasus models, and so these costs did not form part of the rolling-tree optimisation. The rolling-tree optimisation is incentivised to utilise the available sources of gas to meet demand, and so the DSR supply curves were applied to days when supply could only match demand if demand were reduced.

A.2 BID3 electricity market model

A.2.1 Evolution of Pöyry market models

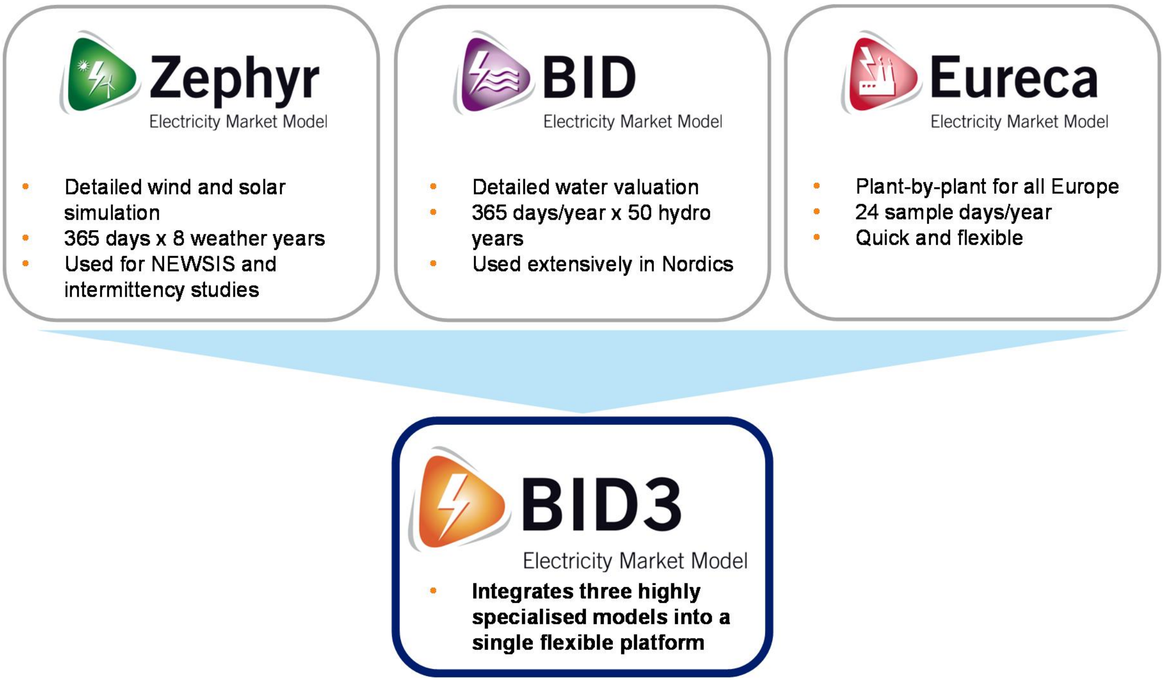
BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. We simulate all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

As illustrated in Figure 54 we have developed ***BID3*** out of our previous power market models: BID 2.4 which has sophisticated treatment of hydro dispatch, using Stochastic Dynamic Programing to calculate the option value of stored water; and Zephyr, which has underpinned our ground-breaking studies quantifying the impacts of intermittency in European electricity markets and the role flexibility could play in meeting the challenges of intermittent generation. ***BID3*** is highly flexible to use and incorporates the best aspects of our previous models. Since ***BID3*** is based upon the same underlying dispatch algorithm as Zephyr, there is no fundamental basis shift in projections when moving between the two. ***BID3*** is:

- the modelling platform used for Pöyry's *Electricity Market Quarterly Analysis* reports, giving European power price projections used by major banks, utilities, governments and developers;

- used for bespoke projects for a wide range of clients; and
- available to purchase – deployed in-house by Energinet, Fingrid, Hydro, NVE, Statnett, and Svenska Krafnät.

Figure 54 – Evolution of Pöyry electricity market models



A.2.2 Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

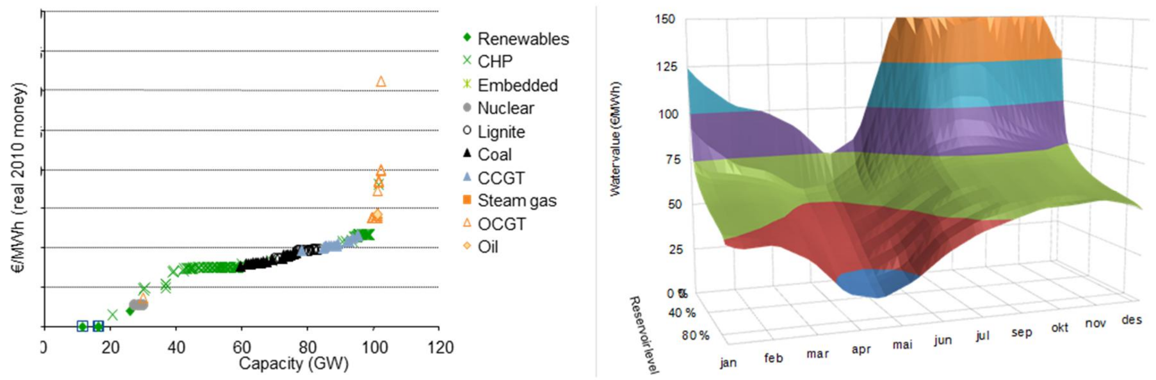
A.2.3 Producing the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order bases – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 55 below shows an example merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - a simple perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way; or

- the water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Figure 55 below shows an example water value curve, and section A.2.7 presents this methodology in more detail.

- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

Figure 55 – Thermal plant merit-order and water value curve



A.2.4 Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost.** The SRMC is the extra cost of one additional unit of power consumption. It is the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.

- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market. Where a capacity mechanism exists this reduces the level of scarcity rent required from the wholesale market and is reflected in our assumptions and modelling.

A.2.5 Input data

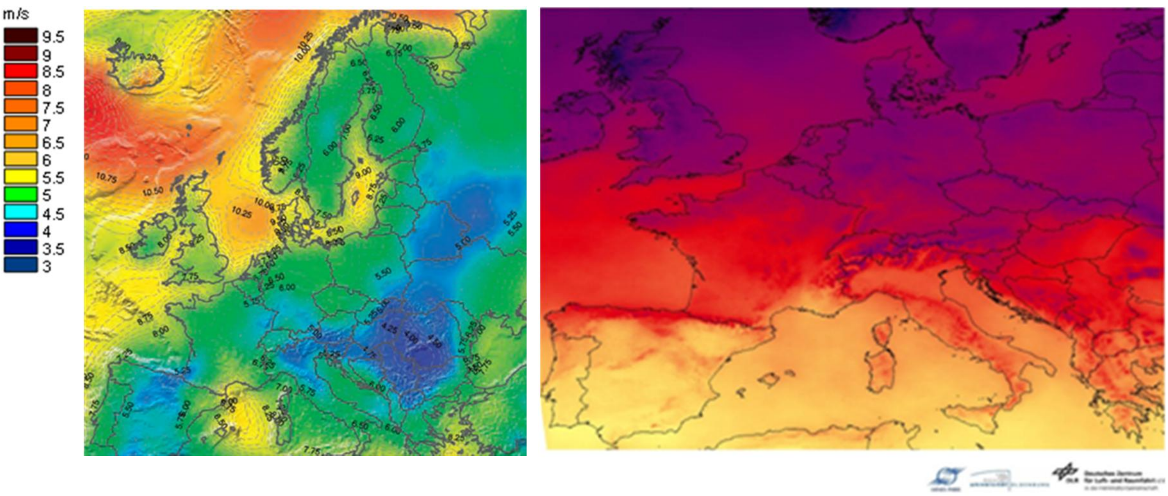
Pöyry's power market modelling is based on Pöyry's plant-by-plant database of the European power market. The database is updated each quarter by Pöyry's country experts as part of our *Electricity Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles –

for each future year that is modelled we use demand profiles from a range of historical years.

- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year). This means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.
  - Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 56 below shows average wind speeds based on this data. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.
  - The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country. Figure 56 below shows average solar radiation based on this data.
- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.

Figure 56 – Average wind speeds and solar radiation in Europe



Source: Anemos, data resolution 20km by 20km Source: Transvalor, data resolution 2km by 2km

A.2.6 Model results

BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. As selection of model results is show below in Figure 57 and Figure 58.

Figure 57 – Hourly dispatch and related metrics

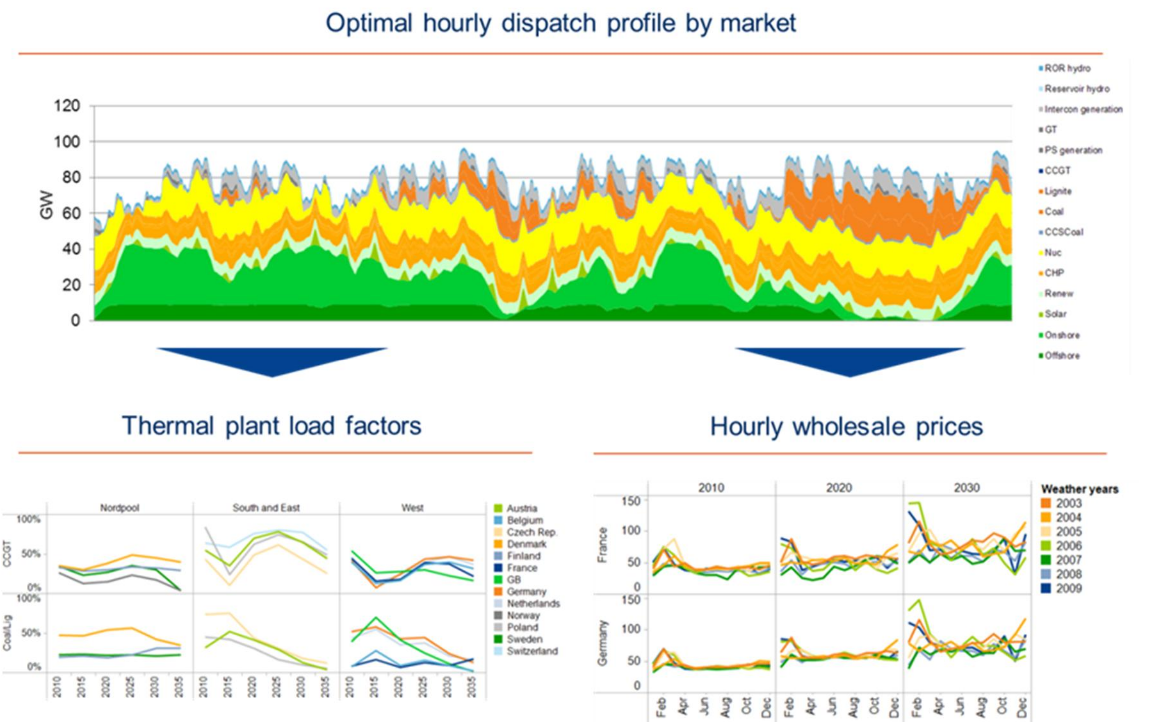
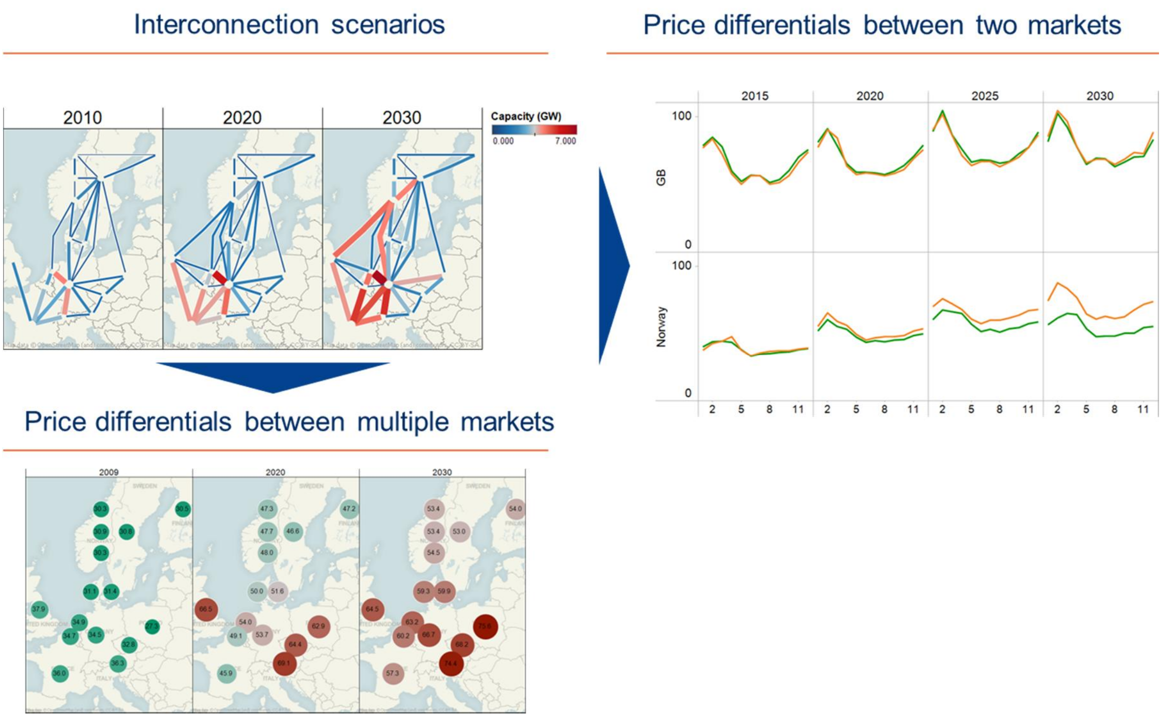


Figure 58 – Interconnector value assessment



A.2.7 Description of the hydro dispatch optimisation

Pöyry has implemented a Stochastic Dynamic Optimisation (SDP) methodology to optimise reservoir hydro dispatch under uncertainty of future inflows. In the hydro-dominated areas like the Nordic region it is critical to use such a technique, as the uncertainty of future inflows greatly affects the pricing of electricity on the spot market. If all players knew their future inflows, they would price their water much more aggressively and would not hesitate to go down to very low reservoir levels. In reality, market players are conservative in their use of water, to ensure that they can always meet the demand from their customers even in very dry years. This optimisation methodology is used by most market players in the Nordics as one of the steps to determine their bidding price into the market.

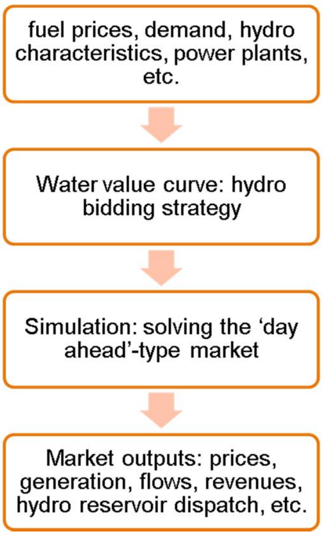
The principle of the methodology implemented in BID3 is described in Figure 59 .

The water value represents the cost increase in electricity supply that the region would face if it had one less MWh of water in the reservoir. This opportunity cost is the value at which a hydro market player offers production into the market.

Figure 60 shows a simplified water value curve, where all assets in the scope are assumed to have the same reservoir level. Each week, the model determines a new bidding price for reservoir hydro depending on the reservoirs' level at the end of the previous week.

Figure 61 shows example of applications of this water value curve. The left-hand side picture shows the impact of hydrology on annual prices – the more inflow, the lower the price. The right-hand side picture shows monthly price results across twenty consecutive hydro inflow patterns, all other inputs being equal. Note that this picture does not represent the full range of weather-related price variations: dry years are often cold in the Nordics, which could create periods of price peaks in winter.

Figure 59 – Optimisation sequence

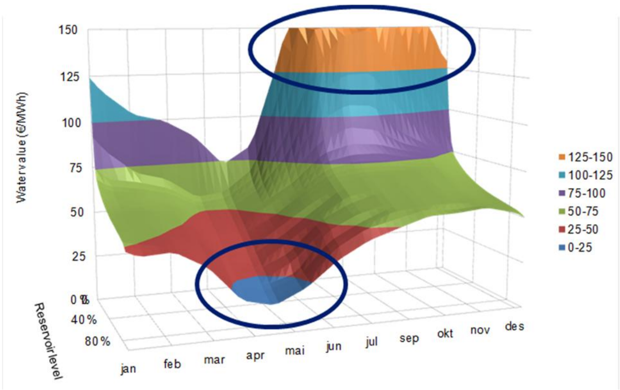


BID3 creates a 'bidding strategy' for reservoir hydro assets called 'Water Value Curve', whereby the dispatch decisions of reservoir hydro at any point in time are robust to a variety of future inflow situations.

This takes the form of a bidding price for an asset, called 'water value', determined according to several parameters: the hydro reservoir level for the asset considered, the reservoir level in other assets, and the time of the year.

This bidding price is then used in the Market Simulation like a 'fuel price' for the use of water.

Figure 60 – Example water value curve

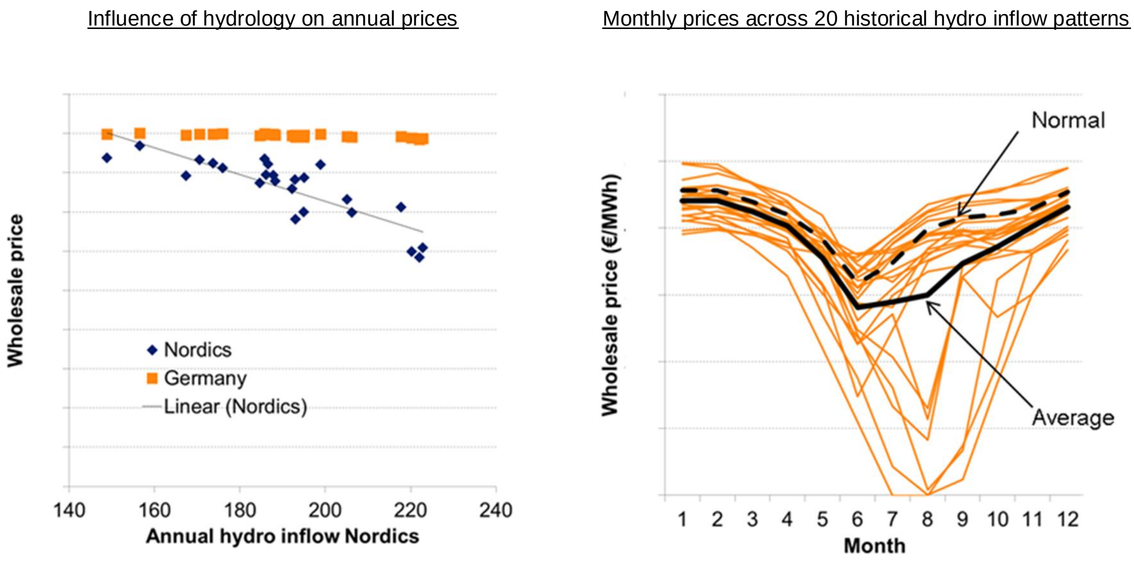


The two circled areas show interesting periods:

- When reservoirs are nearly empty before winter period water is expensive, the hydro players are only willing to produce when the power prices is very high; and
- when reservoirs are nearly full near the snow melting period water is cheap, hydro players want to undercut other generation to avoid spilling in case of high inflow.

Source: Pöyry BID3 power market model

Figure 61 – Influence of hydrology on power prices



Source: Pöyry BID3 analysis

A.2.8 Purchase of BID3

BID3 is available to purchase, and has been used by many organisations (Figure 62). If you are interested in obtaining BID3 or power plant datasets for your organisation please email BID3@poyry.com.

Figure 62 – BID3 clients

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ANNEX B – GAS CONSUMPTION VOLUME DISAGGREGATION & CURRENT I&C DSR

B.1 Annual gas consumption

We have combined the 2012 Digest of UK Energy Statistics (DUKES) data for 'Gas use in the UK Industry' with London Economics autogeneration data to give a total annual consumption per sector. This data is presented in Table 39 below.

Table 39 – Annual gas consumption per sector (million therms)

I&C Sector	Direct gas use	Auto generation	Total gas use
Petroleum Refineries	149	112	261
Fertilisers	51	329	380
Iron and Steel	17	166	182
Other Industries	298	220	518
Paper, printing etc.	77	422	499
Chemicals	102	505	607
Non-Ferrous Metals	30	96	125
Food Beverages etc.	60	731	791
Vehicles	24	321	345
Textiles, Leather etc.	44	169	214
Mechanical Engineering etc.	37	227	264
Electrical Engineering etc.	31	97	128
Mineral Products	108	516	624

B.2 Converting emissions

The first stage involved converting the relevant emission data from the EU ETS allocations into gas consumption[34]. For this it was important to ensure that we used the appropriate breakdown of fossil fuels currently used in each industry, as this impacts on the calculation of heat loads from the relevant emissions and ultimately the gas consumption in therms. Therefore to determine the gas used we:

- used the breakdown of fossil fuels used by industry, as presented in the Digest of UK Energy Statistics (DUKES); and

34 2008 EU Emissions Trading Scheme Phase II National Allocation, final installation-level allocations 2008-2012

- applied standard emission factors and heat production efficiencies based on DUKES data and Pöyry Management Consulting modelling.

This allowed us to estimate gas consumption for each industrial site. These were then checked against data from NGG on DM SOQs (i.e. peak DM consumption values).

B.3 Auto-generation and back-up

To calculate the assumed level of back-up generation within each industry we have used a two stage approach. In stage one we have compared the levels of auto-generation used within each industry (as calculated by London Economics / Ofgem) to the total gas consumed by each industry. The total gas consumption figures have been sourced from DECC's DUKES publication. This results in a percentage of auto-generation per industry. These results are set out in Table 40.

In stage two we have assessed whether the auto-generation (calculated by London Economics) is being used primarily for electricity based processes or heat based processes. To calculate this we have used the percentage of total electricity use in industry (taken from DECC DUKES publication) and identified what percentage is auto-generation.

This distinction between those sectors where processes are heat driven, and those sectors where processes are electricity driven, should help us to make assumptions on the likelihood of back-up generation being available. For example, an industry with a higher percentage of electricity from auto-generation, is likely to be more dependent on electricity for its processes (than heat). As a result it is less likely to have on site back-up, as these installations dependent on electricity will use the electricity network as back-up rather than distillate generators. These results are set out in Table 40.

Table 40 – Auto-generation and back-up assumptions

I&C Sector	Percentage of auto-generation as a percentage of gas use	Percentage of electricity use which is auto-generation	Assumed proportion of total consumption as back-up
Petroleum Refineries	57%	100%	57%
Fertilisers	n/a data	n/a	0
Iron and Steel	9%	15%	1%
Other Industries	57%	42%	24%
Paper, printing etc.	15%	21%	3%
Chemicals	17%	26%	7%
Non-Ferrous Metals	24%	17%	4%
Food Beverages etc.	8%	16%	1%
Vehicles	7%	14%	1%
Textiles, Leather etc.	21%	45%	9%
Mechanical Engineering	14%	15%	2%
Electrical Engineering	24%	15%	4%
Mineral Products	17%	47%	8%

B.4 Current levels of I&C DSR

A National Grid report[35] subsequent to Winter 2005/6 indicated that there was as much as 16mcm of non-power station gas demand which responded to the high prices witnessed in that year. However, there are reasons to believe that the market conditions are very different at present:

- First there were still many I&C interruptible contracts in 2005 (c.1500). Whilst many of these had clauses added so that they could only be interrupted if Transco called a transportation restriction some still had the old supplier right to call an interruption for its own supply/demand balancing. For example, it is understood that the British Gas LTI contracts still had this term and as the contracts were in the money to the consumer this term was never revised. Thus we are not sure 2005 is a good representation of the present commercial position.
- Second the volume of I&C demand is significantly lower now than in 2005 - 25% lower according to DUKES - (2005 = 5.2bn therms, 2012 = 3.9bn therms). So the maximum that could be suggested based on 2005 is 1.5mcmd.

Moreover, there has been recent evidence of the complete lack of involvement of I&C consumers into DN interruptible tenders.

The annual interruption capacity auctions introduced by Mod 90 have been run since 2008, with the latest results being published in July this year for the 2013 process. In 2008, there had been about 1200 sites nationally with interruptible transportation, and of these about 200 participated in the first year, but only 27 bids were accepted. The result of the 2008 auctions for 2011/12 was a stated DN interruption requirement of 252GWh/d (23mcm/d) but only some 13GWh/d (1.2mcm/d) was contracted. The 2009 auctions stated a DN interruption requirement of 77.6GWh/d (7.2mcm/d) for 2012/13 but with only 7.1GWh/d (0.66mcm/d) contracted. The consequence of this has been a commitment from the DNOs to make new reinforcement investments to remove transportation constraints before the new regime started in 2011.

This in turn has meant that in subsequent years, the volume of interruption capacity being submitted into the annual auction process has been reducing, and in turn the number of bids being submitted has dwindled to almost zero.

As an example, the Scotia gas networks published results for both the 2012 and 2013 auctions have stated: 'due to the low number of interruptible tenders and inability to acquire sufficient interruptible capacity, no DN Interruptible Summary Reports will be published by Scotia Gas networks'.

This has in effect meant that due to the low interest in the tender process from customers, and the low volume of tenders accepted by the DNs, the annual tender process has effectively ceased to provide any material interruptible capacity. In turn, this has resulted in the DNOs investing in additional pipeline capacity, and most of the sites that have historically had interruptible transportation moving to firm transportation in the new regime. We believe that this in turn has meant that the vast majority of these sites have consequently decommissioned their back-up fuel systems, and therefore back-up

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35 http://webarchive.nationalarchives.gov.uk/20130402174434/http:/ofgem.gov.uk/Markets/WhlMkts/CustandIndustry/WO2006/Documents1/14222-CM_NG_Final%202.pdf

capability at the DN level has effectively ceased to exist. We also believe that having been decommissioned, it will be very difficult for the capability to be reinstalled without significant capital expenditure.

ANNEX C – CCGT DISTILLATE INFORMATION

C.1 CCGTs without distillate back-up capacity

Table 41 shows the remaining CCGTs which do not have distillate back-up.

Table 41 – CCGTs without distillate back-up in GB

Name	Capacity (MW)	Estimated gas use (mcm/day)	Gas connection	Days oil storage capacity	Status
Barking	1000	5	NTS	-	Open
Baglan Bay	525	2	NTS	-	Open
Connahs Quay	1380	7	NTS/Pt of Ary	-	Open
Coryton	800	3	NTS	-	Open
Damhead Creek	805	4	NTS	-	Open
Deeside	505	2	NTS	-	Open
Didcot B	1430	7	NTS	-	Open
Enfield	408	N/A	NTS	-	Open
Grain	1275	6	NTS	-	Open
Grangemouth	144	1	NTS	-	Open
Great Yarmouth	420	2	NTS	-	Open
Humber	1280	6	NTS	-	Open
Langage	880	4	NTS	-	Open
Marchwood	880	4	NTS	-	Open
Pembroke	2000	9	NTS	-	Open
Peterhead	1524	4	NTS	-	Open
Rocksavage	810	3	NTS	-	Open
Rye House	715	4	NTS	-	Open
Saltend	1140	5	NTS	-	Open
Seabank	830	5	NTS	-	Open
Severn Power	850	3	NTS	-	Open
Shoreham	420	2	DNO	-	Open
Spalding	880	4	NTS	-	Open
Staythorpe	1600	7	NTS	-	Open
Sutton Bridge	800	4	NTS	-	Open
West Burton CCGT	1200	5	NTS	-	Open
Barry	240	1	DNO	-	Open / Conversion to flexible operation
Brigg	260	1	NTS	-	Open / Conversion to flexible operation
Corby	401	2	NTS	-	Open / Conversion to flexible operation
Cottam Development Centre	395	2	NTS	-	Open / Conversion to flexible operation
Killingholme _Centrica	665	3	NTS / Theddlethorpe	-	Open / Conversion to flexible operation
Killingholme _EON	900	4	NTS / Theddlethorpe	-	Open / Conversion to flexible operation
Medway	700	3	NTS	-	Open / Conversion to flexible operation
Peterborough	395	2	NTS	-	Open / Conversion to flexible operation
Kings Lynn	340	4	NTS	-	Mothballed
Roosecote	229	1	NTS	-	Mothballed

Source: Pöyry Management Consulting

C.2 CCGT distillate back-up investment drivers

The drivers for investing in distillate back-up will vary depending on whether this is being considered for new plant or as retrofitting at an existing station. In this section we consider both situations.

C.2.1 New gas-fired power station

The issues for a new gas-fired CCGT when considering whether to install distillate back-up capability can be divided into the following:

C.2.1.1 Cost of installation

The cost of a new distillate back-up facility for a CCGT will comprise both the cost of the storage facility itself, plus the initial cost of filling it.

We have assessed costs for a 10,000 m3 'module' of distillate storage, including foundations, tanks, bunding and fire protection, with a single rail delivery siding adjacent to a Network Rail line. We have then multiplied this up to give indicative costs for higher volumes of storage. Clearly this is a simplified approach, since there will be economies of scale for both bunding and tanks. However, bearing in mind the fact that the costs will also be dependent on site conditions, contracting market conditions and other site-specific issues, we still believe that they are a reasonable approximation of the cost of distillate back-up. A 400MW 'F' class CCGT module (i.e. a single gas turbine and single steam turbine/HRSG combination) that is often used in GB will burn approximately 1500 tonnes per day at 50% efficiency.

The cost of the distillate includes three main elements, the wholesale price, the cost of delivery and duty. The current price of distillate (otherwise known as gasoil or diesel) is about $900/tonne[36] CIF North West Europe for prompt delivery, and futures prices are approximately flat for the next year. Current Brent crude prices are about $108/barrel, and gasoil prices broadly follow crude prices, although of course there is some variation depending on local refinery capacity and design. For an assumed future Brent crude price of $120/barrel, this would mean a future assumed gasoil or distillate price of about $1000/tonne. At a current exchange rate of about £1 = $1.6, and an assumed distillate price of $1000/tonne, this means an assumed GB cost of about £630/tonne. To this must be added transport and duty costs, and we estimate that transport by rail from a refinery to be in the order of £12/tonne. With regard to duty, on 1 December 2005 the government announced a 100% rebate on distillate used for power generation, such that the duty is now zero. The total delivered cost to fill two 5000 m^3 tanks (or 8,400 tonnes) is therefore in the region of £5.4 million.

Taking all of the above into account the total distillate back-up installation costs have been estimated in Table 42 below.

Table 42 – Distillate Back-up Costs for a 400MW CCGT

Oil Storage (m^3)	Days of Storage	Tanks/Bunding/Siding Costs	Distillate Cost	Total (millions)
10,000	0	£2,000,000	Zero	£2.0
10,000	6	£2,000,000	£5,400,000	£7.4
50,000	30	£8,500,000	£27,000,000	£35.5

C.2.1.2 Transportation issues

Historically, when considering distillate as a form of gas security of supply during a severe supply disruption it has been recognised that replenishing stocks at power stations could be a significant logistical exercise and the volumes required might place a substantial strain on the existing distillate production capacity and distribution network.

Using figures from DUKES[37], UK production of distillate is about 25 million tonnes a year, with another 11 million tonnes imported, and about 8 million tonnes exported, leaving a net UK capacity of about 28 million tonnes. Current stock levels are about 3 million tonnes.

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36 Source: Reuters ICE GAS OIL Futures

37 Diary of UK Energy Statistics, DECC

Of this 28 million tonnes, about 21 million tonnes is used in motor vehicles as diesel (DERV), about 3 million tonnes in industry (including power generation), and the rest for other uses including domestic heating, railways etc.

A key practical problem is the white/red issue, with motor duty exempt distillate dyed red, which means that generally tankers are used for one or the other, but not both, as it is a very difficult job to clean out a distillate tanker for use as a DERV tanker.

However, as shown in Table 14 and Table 16 above, there is now only about 2.2GW of generation capacity in GB with operational distillate backup capability. Of this, some 1.4GW is located at refineries, so that clearly distillate transportation issues are not relevant. This means that only the remaining 800MW of capacity will need to utilise distillate transport capacity. As mentioned above, we estimate that a 400MW CCGT module will consume about 1500 tonnes a day at full load, so with only about 2.2GW of plant with distillate back-up, this will require about 3,000 tonnes a day to refill, which compares to the current supply of red distillate of about 8,000 tonnes a day, and the total supply of distillate/DERV combined of about 70,000 tonnes a day. In our opinion, this could be managed within the existing distillate transportation infrastructure. This volume also needs to be seen in the context of the total volume of UK consumption of distillate of about 28 million tonnes a year, and also in the context that there is a highly liquid market for this product at the North West Europe, Amsterdam/Rotterdam/Antwerp (ARA) hub. UK prices are in fact NWE ARA prices, and in effect distillate is sourced as a product in a Europe wide market of about 200 million tonnes per year. As an example of the liquidity of this market, the ICE futures market for NWE ARA distillate trades about 100,000 tonnes a day for prompt delivery. In our opinion therefore, this additional volume of distillate could be sourced without difficulty in the current distillate market.

An additional issue for generators is caused by distillate (and DERV) being supplied in the winter months with an additive which prevents waxing, or freezing, in cold weather. Since distillate is not generally treated with these chemicals in the summer, it is therefore very risky for a generator to buy at this time since if it is not burnt before the winter, it will freeze in the tanks when the temperature gets low and when it is needed. Alternatively it will need to pay the additional costs associated with adding the anti-waxing chemicals on site.

C.2.1.3 Gas/Distillate arbitrage

The installation of distillate capability clearly enables the operator to benefit when gas prices are higher than equivalent distillate prices, and there is still a positive clean electricity/fuel spread. This will also depend on the accounting system used by the operator to price the distillate, and the level of storage. This is because the price of distillate will tend to be linked to that of gas, and if the distillate is priced at replacement cost, rather than actual cost, then the electricity/fuel spread value will of course be reduced. This effect is limited the greater the storage level, and therefore the greater the flexibility the operator has to choose the time (and hence price) at which the tanks are refilled.

This is further affected by the fact that distillate is supplied in bulk either in ‘winter grade’ or ‘summer grade’ depending on the time of year that it is produced and delivered as explained above. This in turn means that the ability of a station to refill the tanks in the summer, when prices are generally lowest is limited due to the risk of ‘waxing’ in the winter.

Historically, there have been very few days over the past 10 years or more that gas has been more expensive than distillate, so this would not normally be a key factor in deciding to build distillate tanks.

C.2.1.4 Reduced efficiency

All CCGTs in GB are designed to fire on natural gas as the primary fuel. This means that the Heat Recovery Steam Generators (HRSGs) are optimised for gas firing such that the design exhaust temperature from the HRSG into the stack is minimised, while maintaining sufficient stack buoyancy. When firing on distillate, there is a risk that the flue products will condense in the stack leading to corrosion as a result of the fact that distillate contains sulphur, such that it is usual practice to run the HRSG with the final feed heater (or economiser) section isolated. This therefore increases the exhaust temperature from the HRSG to minimise condensation risk, but at the penalty of reduced HRSG efficiency. This reduction is in the order of 2% of overall cycle efficiency. Clearly this reduction will need to be taken into account in the calculation of any potential gas/distillate arbitrage upside above.

C.2.1.5 Technical Issues

It is our understanding that there is very little world wide experience of sustained operation on distillate for the latest ‘F’ class (or the later ‘G’ or ‘H’ class, although there is only one of these machines operating in the GB market) gas turbines. The difference in these classes of gas turbine is the firing temperature, with the later letters referring to higher firing temperatures. Clearly the higher the firing temperature of the turbine, the more efficient it will be, but this also means much more complex burner systems, blade cooling systems, and control systems. This inevitably means that the quid pro quo of higher efficiency is that it is more difficulty to optimise the turbine for both gas and distillate operation. It is very important to note that these later turbines are designed primarily for gas firing, and although they may well have been tested for alternative distillate operation, we are not aware of any plants anywhere in the word with any significant experience of this type of operation.

Conversely, the less efficient (and lower firing temperature) ‘E’ class machines are routinely operated on distillate in many locations around the world. However, many of the GB stations operating this class of machinery have either closed or mothballed over the past few years, due to the very low clean spark spreads available in the market. We are aware of one GB CHP CCGT plant in particular which had back-up capability due to a requirement to supply secure heat to an adjacent industrial facility. In order to ensure the reliable operation of the back-up capability, they tested the changeover to distillate on a monthly basis, but of course this posed significant extra costs.

Therefore, we believe that the reliability of the higher efficiency ‘F’ class machines will be much lower on distillate than on gas due to limited experience of firing distillate and the difficulties of optimising the burners on this fuel. This means that there is likely to be a higher tripping risk, and therefore a higher risk of both imbalance and capacity mechanism penalties. Bearing in mind that distillate is likely to be burned when both the gas and electricity systems are under stress, we believe that these risks are very significant.

In addition, we understand that there will be an additional maintenance penalty for running on distillate, which will mean that fewer fired hours will be allowed before maintenance inspections are required. A further technical issue is that we also understand that water injection may be required for NOx control while running on distillate (whereas on gas firing Dry Low NOx, or DLN systems are used), and this will require significant volumes of demineralised water which may not be available without appropriate water treatment plant and storage.

C.2.1.6 Practical issues

The primary practical issues to tackle are to ensure that there is sufficient land available for the distillate tankage and bunding, and there is a suitable delivery mechanism. The land issues can be very significant if large volumes of distillate are envisaged to provide a prolonged back-up capability prior to further deliveries being organised. It is our view that road tanker delivery is impractical in most circumstances, due to the inability to source large numbers of tankers and drivers in the event of a prolonged distillate requirement as explained above. This means that the site must be adjacent to: a large distillate facility, such as a refinery or storage depot; a rail line or siding; or a suitable river, canal or coastal facility. The number of site available with this type of infrastructure is likely to be very limited.

C.2.1.7 Environmental Issues

There are significant regulatory and environmental issues involved with the storage and burning of distillate. The Control of Major Accident Hazards Regulations 1999 (as amended by the Control of Major Accident Hazards (Amendment) Regulations 2005) (COMAH) lay out the safety systems required for large hazardous industrial sites. Although it applies mainly to the chemical industry, it also applies to other industries where certain threshold quantities of dangerous substances are stored. It therefore applies to power station sites that store distillate in quantities in excess of 2500 tonnes, which therefore includes virtually all oil back-up facilities at CCGTs. Another important feature of COMAH is that it lays out two levels of hazard management systems required, depending on the amount of the hazardous substance stored, 'lower tier (LT)' and 'top tier (TT)'. The regulatory requirements for top tier are obviously much more onerous than for lower tier, and are triggered at storage levels above 25,000 tonnes. Although all CCGT sites with oil back-up are caught by the regulations, they will be in lower tier, since we are not aware that any CCGT site in GB stores more than 25,000 tonnes of distillate. However, if there is to be a significant expansion of storage to meet prolonged gas interruptions, then the site will become top tier, with a significantly increased regulatory and hence cost burden on the site.

A further environmental consenting issue relates to the distillate delivery system. We think it very likely that if a back-up facility is installed, the permitting authority will have concerns about the road traffic implications of road delivery of distillate, which means that notwithstanding the practical difficulties mentioned above, road delivery may be prevented under the planning consent issued.

C.2.2 Existing Plant Retrofit Issues

Of the issues raised above, the key ones for the retrofit of a back-up capability to an existing plant are likely to be the following:

C.2.2.1 Space

A new site is very likely to have additional space available adjacent to the site for the station itself, since it is unlikely to be constrained precisely to that required. However, an existing site is much less likely to have additional space available for the installation of the tankage and bunding required. Clearly, if the space is not available, then the installation of back-up will not be possible.

C.2.2.2 Access to delivery mechanism

Again, a new site will have some flexibility as to its precise location, and hence its proximity to a pipeline connection, a rail connection or a barge terminal. However, this will clearly not be the case for an existing site, and if there are no such connection possibilities, then the installation of distillate back-up is in our view impractical due to the difficulties identified above with road delivery. For example, the nearest distillate supply for a CCGT power station in Devon is in Southampton, making road delivery and even rail deliveries not feasible because of the distance and poor transport connections.

C.2.2.3 Technical Issues

An existing station is likely to have a lower risk profile for the installation of distillate back-up than a new station. This is because it is likelier to have older gas turbine technology, which will have been proven over a number of years, and is also likely to have some form of experience running on distillate somewhere in the world. However, there would be significant down time to re-configure the fuel and burner systems.

Indeed, the Institute of Mechanical Engineers has stated that most older ‘E’ class CCGTs could be retrofitted to run on distillate[38]. They in fact have recommended pursuing this strategy in preference to any obligation to install dual firing to new CCGT units. The suggestion is that retrofitted old CCGTs could form a standing reserve similar to that provided by current oil firing plants such as Grain and Littlebrook. However, as noted above there would be many financial and practical barriers to be overcome in order to achieve such a retrofit.

C.2.2.4 Consents

Any change from gas to duel firing would require a change in the environmental and planning permits for the plant, plus of course COMAH compliance. This is likely to be challenging due to the perceived hazards of the storage of large volumes of distillate, plus concerns about transportation issues mentioned above.

C.2.2.5 Financial

The key difficulty for an existing CCGT contemplating the retrofit of back-up capacity is of course a financial one. With recent market conditions for the older and less efficient CCGTs having been very challenging due to low or negative clean spark spreads, many of these have been closed or mothballed. It is very difficult to see that they would now contemplate further capital investment without a strong financial incentive from a DSR mechanism.

C.2.3 Gas DSR mechanism and electricity market interface

C.2.3.1 Interaction with the demand-side response mechanisms

The Capacity Payment Mechanism is intended to be technology neutral across generation, storage and demand-side providers and to allow new entrants and existing capacity to participate. However it is expected that the majority of the volume in the Capacity Payment Mechanism will be gas based generation. The consequence of these

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[38] Institution of Mechanical Engineers, response to consultation into effectiveness of current gas security of supply arrangements, January 2007.

proposals is that it is unlikely that these gas generators would be willing to be exposed to the Capacity Payment Mechanism penalty to participate in the gas DSR process. As a result it is likely that any bids in the DSR mechanism will be at least equal to this level.

C.2.3.2 Reserve and response (key ancillary services for CCGTs)

Contracts for the provision of reserve and response to National Grid are an increasingly important revenue stream for CCGTs and OCGTs. This is likely to increase over time as the requirements increase in response to:

- **Demand forecast errors**: Most end users of electricity do not need to provide any statement of their intended usage and so electricity demand is uncertain and actual demand is often quite different to forecast even quite close to real time.
- **Unexpected loss of thermal generation**: Large generator units are required to notify their intended output to National Grid. However, problems can occur and unexpected trips can lead to a short notice requirement for additional generation.
- **Variable wind generation**: Output from wind capacity is inherently variable and unpredictable even close to real time. Therefore reserve is required to deal with situations where wind generation is lower than expected.

As a result it is important to understand the possible impact, this responsibility will have on a gas generators' decision to bide into the demand-side response mechanisms.

C.2.3.2.1 Short Term Operating Reserve

Short Term Operating Reserve is National Grid's key Balancing Service used to manage short term uncertainties in the GB wholesale electricity market. The STOR service retains spare generation capacity on stand-by during certain hours of the day (typically periods when demand is changing rapidly). STOR is essentially capacity that National Grid retains on stand-by that can be called on to generate within four hours of instruction.

C.2.3.2.2 Fast reserve

Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid. This service operates in quicker timeframes than STOR and requires a 50MW minimum capacity.

Fast Reserve is used in addition to other energy balancing services, to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand.

C.2.3.2.3 Frequency response

Frequency Response is the automatic provision of increased generation or demand reduction in response to a drop in system frequency. It is a service that maintains the system frequency at 50Hz, and restores the frequency to 50Hz in the event of an outage or change in demand, by generators increasing or decreasing their output on a second-by-second basis.

C.2.3.2.4 Interaction with the demand-side response mechanisms

Penalties exist for providers unable to deliver contracted services to National Grid. The short term penalty imposed by National Grid of availability payments being withheld may not as extreme as those proposed under the Capacity Payment Mechanism. However, the long term impacts of being contracted and trusted by National Grid to deliver the services may be damaged resulting in reduced revenues in the electricity market. This revenue will also become increasingly important for CCGTs on an intermittent system as their load factors (and income for the wholesale energy market) declines.

C.2.4 Electricity Balancing – Significant Code review on cash-out

The proposed arrangements on the future rules for electricity cash-out are designed to fix perceived inefficiencies in the current arrangements. Ofgem published its draft policy decision on the 30 July 2013. The draft decision outlines the following changes to the cash-out regime:

- Making cash-out prices marginal by calculating them using the single most expensive action the System Operator takes to balance the system.
- Including a cost for disconnections and voltage control into the cash-out price calculations based on the Value of Lost Load (VoLL) to consumers. Ofgem proposes to introduce this cost gradually; starting with £3,000/MWh and increasing to £6,000/MWh. They also propose to pay domestic consumers and small businesses at £5 and £10 per hour of disconnection, respectively, in recognition that they effectively provide involuntary demand-side response services to the System Operator.
- Improving the way reserve costs are priced by reflecting the value reserve provides to consumers at times of system stress. To achieve this, Ofgem proposes the introduction of a Reserve Scarcity Pricing function that prices reserve when it is used based on the prevailing scarcity on the system.
- Moving to a single cash-out price for each settlement period to simplify the arrangements and reduce unnecessary imbalance costs.

The changes to the balancing market will affect the cost of imbalances for all generators out of balance (i.e. including wind generators and flexible capacity providers).

C.2.4.1 Interaction with the demand-side response mechanisms

The most recent proposals will result in electricity cash-out prices that are more volatile and sharper than under the current arrangements. As a result, in the case of a gas emergency the proposed cash-out arrangements are to likely incentivise a CCGT / OCGT to balance in the electricity market ahead of participating in the gas DSR mechanisms.

These proposals further shift the incentives on gas generation to ensure their electricity market obligations are met ahead of obligation / opportunities in the gas market[39].

C.2.5 Black Start capability

In general, all power stations need an electrical supply to start up. Under normal operation this supply would come from the transmission or distribution system, however under emergency conditions Black Start stations receive this electrical supply from on-site GTs.

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[39] From a commercial, not a safety perspective.

Black Start will be procured on a bilateral basis to meet the requirements of National Grid's Black Start strategy. In addition National Grid will also indicate its potential requirement for a new Black Start service at a new generator during the connection application process, prior to construction.

No details are provided by National Grid on the number or identity of current black start providers. However it is our understanding that historically around 12 stations have been contracted by National Grid for black start and these have tended to be the coal fired stations. As a result of the on-going closure of coal stations in the GB market, National Grid will be seeking to contract new black start capability. Over the next 8 years National Grid has stated that 'it would need to sign contracts with a number of new black start providers as it expected a number of stations which currently provide black start services to close'.

National Grid will pay availability payments, exercise price and in some case it will pay a contribution to building new black start facilities or refurbishments at existing plants.

C.2.5.1 Interaction with the demand-side response mechanisms

As the existing coal plants close, CCGTs will become increasingly important in the delivery of black start capability for National Grid. This will mean that those plants contracted by National Grid will be required to hold Back-up fuel supplies (e.g. distillate fuel), to enable the power station to run for a minimum duration, of between 3 to 7 days, following a Black Start instruction.

While this does indicate the possibility that gas will be available in a gas emergency, it is unlikely that these stations would be able to use this back-up fuel in any situation other than black start. While the contracts between parties are bilateral and not publically available it would be realistic to assume that they include heavy penalties if the provider is unable to provide black start when requested.

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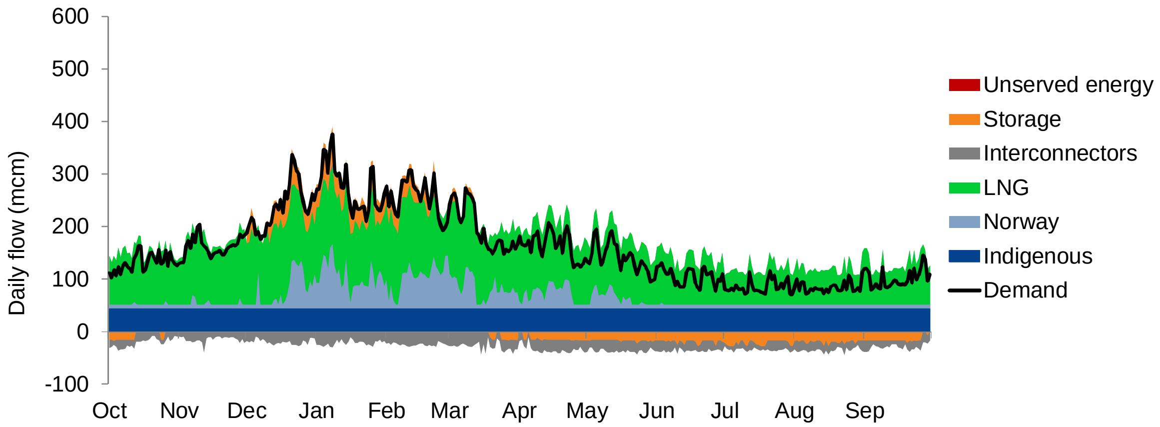
ANNEX D – GONE GREEN SUPPLY FAILURE ANALYSIS

D.1 Gone Green – Base case

In the Gone Green scenario where we do not assume any interruptions, LNG makes up a large proportion of GB supplies by 2030, as indigenous and Norwegian production decline. Norwegian supplies are still providing key gas supplies during the winter period, but the annual volume is much less significant than LNG, as shown in Figure 63.

By 2030, there are no contractual flows via either IUK and BBL, and our modelling shows that it is rarely optimal for GB to import gas via these routes; instead LNG and direct pipeline imports from Norway are preferred. The interconnector exports shown are primarily to Ireland. Due to relatively low demand, this case does not have any unserved energy, which would be shown in red.

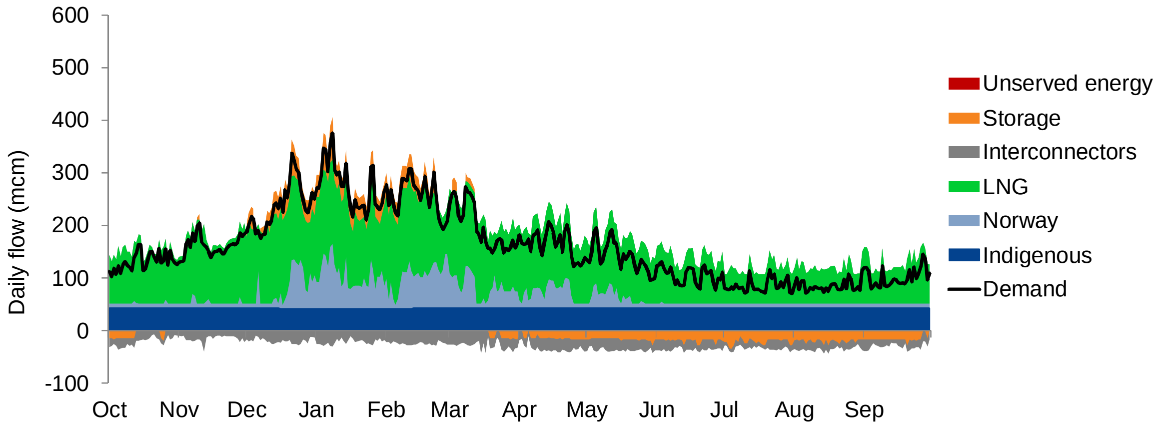
Figure 63 – Sources of supply used to meet demand (Gone Green with no failures 2030)



D.2 Gone Green – Bacton

In this case the receiving terminal for indigenous production and imports from the continent at Bacton is interrupted. However this decreases overall indigenous supply by only a small amount and GB is able to manage the outage of the interconnectors through LNG and Norwegian deliveries as shown in Figure 64. Due to relatively low demand, the infrastructure failure in this case does not result in any unserved energy, which would be shown in red.

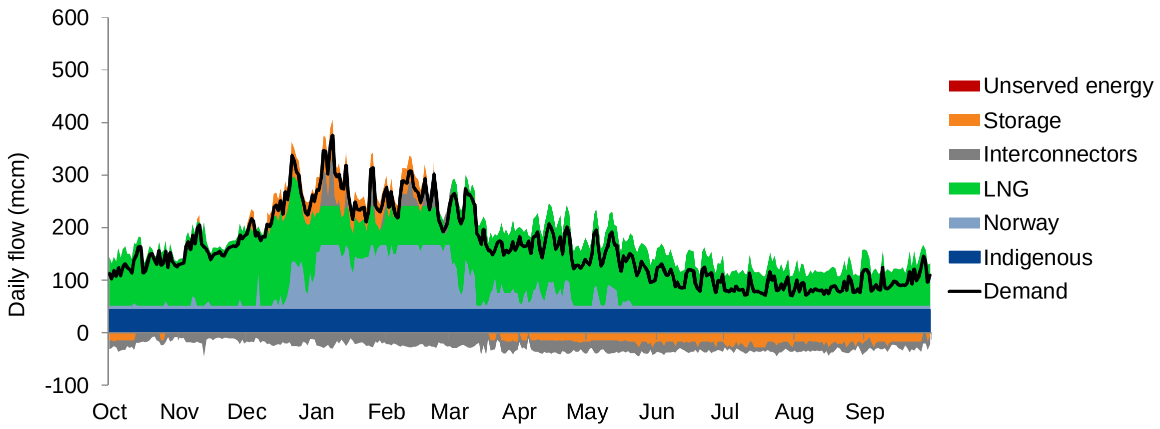
Figure 64 – Sources of supply used to meet demand (Gone Green with Bacton failure 2030)



D.3 Gone Green – Milford Haven

In the Gone Green case when two large LNG regasification terminals at Milford Haven are interrupted, the reduced LNG supply is replaced by gas from Norway and the continent, as shown in Figure 65. Due to relatively low demand, the infrastructure failure in this case does not result in any unserved energy, which would be shown in red.

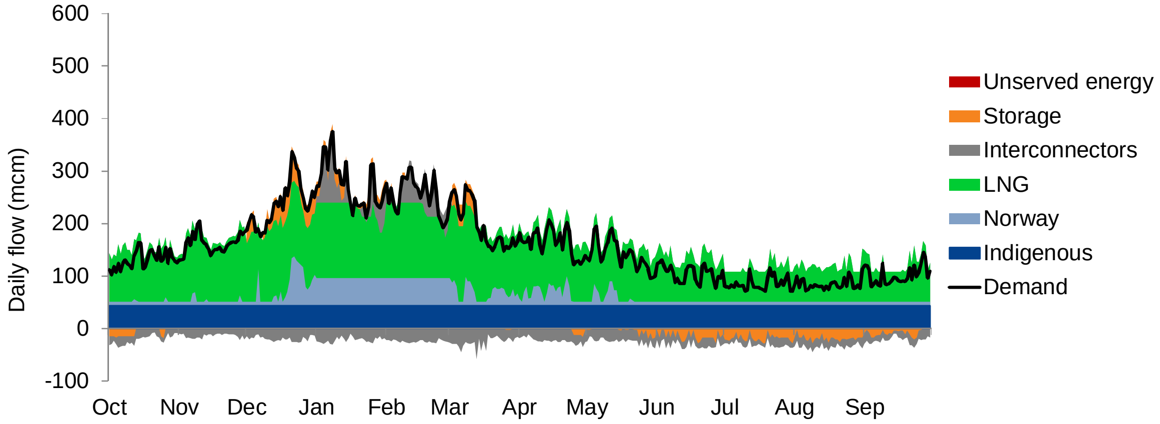
Figure 65 – Sources of supply used to meet demand (Gone Green with Milford Haven failure 2030)



D.4 Gone Green – Sleipner and Rough

In the Gone Green case with failures affecting Norwegian flows at Sleipner (preventing the use of Langeled), and the storage facility at Rough, the reduced supply is replaced by LNG and gas from the continent, as shown in Figure 66. Due to relatively low demand, the infrastructure failure in this case does not result in any unserved energy, which would be shown in red.

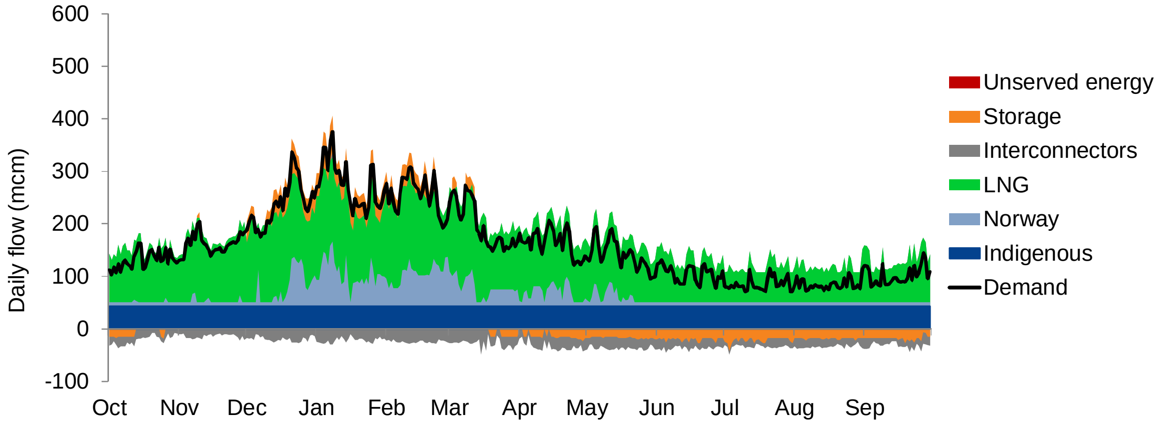
Figure 66 – Sources of supply used to meet demand (Gone Green with Sleipner and Rough failure 2030)



D.5 Gone Green – Qatar

The interruption of all LNG production in Qatar does not change the overall composition of supply sources to GB; LNG is still able to provide sufficient supply, as the lost LNG is replaced by LNG from other sources (such as Australia and the US), as shown in Figure 67. Due to relatively low demand, the infrastructure failure in this case does not result in any unserved energy, which would be shown in red.

Figure 67 – Sources of supply used to meet demand (Gone Green with Qatar failure 2030)



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ANNEX E – EVIDENCE OF PLANT DAMAGE THROUGH INTERRUPTION

We have drawn on this evidence of site damage to indicate which sectors would have barriers to participation in the DSR mechanism.

E.1 Evidence from the 2006 Ilex study

The 2006 Ilex study on the economic implications of gas interruptions to UK industry[40] provides the following evidence on site damage in the event of a gas supply interruption, on pages 15 and 21:

Table 43 – Site damage if there is a one-day interruption to the gas supply

Sector	Site damage?
Aluminium	Freezing of the primary pots - 4 hours critical.
Steel	Freezing
Glass	Cracking of furnace – 1 hour critical
Refineries	
Ammonia manufacture	
Bricks	
Lime (Cement)	
Chlor-alkali	Freezing of product within pipelines
Industrial gases	
Other chemicals	Freezing of product within pipelines
Plastics	Freezing of product within pipelines
Paper	
Heavy Food Manufacturing	

Blanks mean that no significant damage to plant was identified. Source: interviews with industry.

… This excludes the damage that could accrue from water freezing. All manufacturing processes that require water heating are susceptible to frost damage (burst pipes, etc.) if cessation to production coincides with cold weather. Such damage is potentially significant: one respondent reported damage of £500k from a single on-site frost protection failure.

Page 21:

"*Sectors that would suffer physical damage to plant – if they are not able to retain at least some of their gas supplies – are listed in*

For these sites there will be a requirement to rebuild the plant before production can restart. At some of these sites it is likely that the capital will not be spent and the sites will close permanently. From our interviews the permanent closure of some sites is seen as inevitable in the Aluminium and Glass sectors. It is also likely at sites in the Brick and Lime sectors where permanent damage to kilns would require the kilns to be rebuilt before production could restart.

40 Ilex Energy, "Economic implications of a gas supply interruption to UK industry- a report to DTI", January 2006

In other sectors where the damage is freezing of the plant there may be significant time and money spent to repair damage on the site. In the Chlor-alkali sector the site would have to wait till warmer temperatures in spring to begin thawing and repairing plant. At some sites in the Plastics sector it could take weeks to bring back production and to achieve a quality of product that is saleable.

In manufacturing industry damage to boiler plant would have to be repaired before production could restart."

Further evidence from the interviews with industry in the annexes to the same Ilex study[41] highlights damage which could occur through the freezing of raw materials:

- *Chlor-alkali sector, "Interview with Andy Waring, Ineos Chlor, 29 Nov 05: 1 day interruption would cease production. In cold weather if the plant freezes (caustic solidifies between 6 and 12 Celsius), Ineos estimate that it would cost £80 million to repair damage, but does not include the cost of lost production in this figure. If the site freezes in winter it would take 2 to 4 months to recover, and 6 to 9 months to become fully operational again…"*[42]
- *Similarly, under the "other chemicals" sector representatives reinforced the need to keep from prevent the raw materials freezing.*
- *Plastics: If plant freezes then cost to repair £250,000 to £500,000, and could take 3 to 4 weeks to restore production at sales quality.*[43]

Other evidence from the interviews with industry evidences some difficulty in safely interrupting on short notice in other sectors:

Steel industry:

Melting Shop (SMACC)

1.239 We could manage a one-day interruption (maybe up to 3 days) and recover from it - although it will be very difficult on the current production pattern. A notification period of at least 8 hours would be required for us to safely process the steel in the system. A total loss of gas supply could result in damage to plant depending on the ambient temperature.

Billet Rolling Unit (Alloy Steel Rods)

1.255 This unit is currently viable. It takes its feedstock mainly from the melting shop. If the melting shop ceased output for any significant period of time ASR would have to try to find alternative suppliers. This would be difficult and costly. Again a period of notice would be necessary to allow the safe shut down of furnaces and equipment. A total loss of gas supply could result in damage to plant depending on the ambient temperature.

Precision Strip Unit (Sheffield Special Steels)

1.260 …Some annealing cycles are very long and so warning of a total loss of supply would have to be 2 days.

Agrochemicals industry:

Peter Johnson, Bayer Crop Science, by email 21 Nov 05

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41 Ilex Energy, Industry Information

42 Page 12, paragraph 1.60

43 Page 33, paragraph 1.207

1.109 Without heating during cold weather the disruption is significant. Emptying all lines and vessels of materials which could solidify. The problem is where do you empty them to at relatively short notice. Then the restart can be a lengthy process. We had a problem one Xmas and it took about 2 weeks to clean up and restart

E.2 Evidence from responses to Ofgem's consultation

Responses to the consultation[44] from the Ceramics industry indicate that unsafe cooling of the kilns could result in serious, survival threatening damage, and that many continuous manufacturing processes would not be able to offer reduction in gas consumption on a short notice.

This view of being unable to respond on short notice is repeated in other responses:

- *Chemical industry: "many of our companies run large continuous processes and therefore do not have the ability to switch off or down at short notice."*
- *Glass: (in response to tender Question 8: What is your preferred length of time and/or frequency with which NGG may exercise a DSR contract? Do you have a preferred minimum response time if a DSR contract were to include one?) "The maximum is likely to be seven days and the preferred minimum time would be 24 hours. Shorter time periods may be available but these would need to be negotiated on a case by case basis."*

E.3 Non-participation due to technical barriers

Based on this evidence we can identify two technical barriers to participation: difficulty in safely responding to a short notice period (4-6hrs) and the necessity to maintain a minimal load at all times to prevent the freezing of furnaces or raw materials.

Response time

Regarding the difficulty to respond in a short period i.e. that continuous processes cannot be interrupted in a short period without significant damage, we can differentiate between those which will threaten plant closure if interrupted without sufficient notice: kiln based processes, such as ceramics, brick and lime (cement), and where damage is not survival threatening: steel, agrochemicals, chemicals and glass industries.

Freezing damage

Of those sectors that need to maintain a minimal amount of load in order to prevent freezing of furnaces or raw materials, the former is expected to incur more critical damage than the latter. This is the case in the Aluminium, Glass and Vehicles sectors, if unable to keep a minimal amount of heating this could cause damage which risks plant closure. Freezing of raw materials would cause less critical damage these sectors: chlor alkali, other chemicals, and plastics.

Most of these sectors which fall into this second freezing damage category have already been accounted for above, with the exception of the plastics and the aluminium industry.

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44 Response to Ofgem Consultation on Gas Security of Supply Significant Code Review: Demand-Side Response Tender Consultation (Ref 130/13)

E.3.1 Limitations to damage evidence

While we consider that these industries are not likely to have changed from a technical perspective since 2006, it is likely that industry responses about the damage they would incur through interruption may have been tempered by the existence of back-up, which we know to be higher in the past. This means that this damage could potentially be underestimated in the 2006 responses.

Furthermore, another form of damage mentioned above is that of frost damage, which presumably affects all sectors, who in theory would not offer this very minimal tranche to ensure that this damage did not occur. Since this is considered negligible to most industries, we are ignoring it.

E.3.2 Limitation to VOLL analysis

Restart time

Finally, evidence from industry information in the Ilex study also indicates that in many cases, interruption for one day should actually be priced at more than one day's foregone production, because most sites would take a greater amount of time to restart following an interruption. In not accounting for this, we are underestimating the actual opportunity costs of interruption.

From the Ilex study industry information annexe, this is the evidence on restart times. (Where there is more than one response from a participant in the same sector, this is separated by a comma):

Table 44 – Sector Restart Time

	Time to restart	Page
Ammonia	3 days, 2 weeks	4, 16
Industrial gases	1 week – 1 month (assuming no freezing)	12
Other chemicals	3-4 days, 5-7 days	13, 15
Glass	3-5 days , 2 weeks	18, 21
Steel	3 weeks, 24 hours	37, 35
Aluminium	1 week	2
Manufacturing vehicles	Not a problem restarting.	41

E.4 Treatment of Mechanical and Electrical Engineering

The study by Ilex did not explicitly consider the sectors of Manufacturing and Electrical Engineering. However based on our interpretation of the SIC data, the companies identified as Mechanical and Electrical Engineering in the previous London Economics assessment would be implicitly included as 'sub-sectors' to the high level sector discussed in this Ilex study (e.g. there will be mechanical and electrical engineering companies operating in sectors such as Iron and Steel, Aluminium etc.).

Based on a review of the Mechanical and Electrical Engineering 'sub-sectors', it is also our view that many of the companies in this sector will provide a service which will be dependent on a constant gas supply to prevent damage to the plant equipment (i.e. these industries will require gas to maintain the non-dispensable, non-backed-up elements of their demand, such as preventing freezing of boiler equipment). As a result we have made the assumption that Mechanical and Electrical Engineering will be similar in their reliance on gas to the sectors of Aluminium, Glass and the Vehicle production that are all included in the Ilex report. Consequently it was decided to treat these sectors in the same way in regard to the pricing of the non-dispensable, non-backed-up tranche of the gas demand.

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ANNEX F – ILEX ENERGY REPORTS

Pöyry produces the renowned ILEX Energy Reports. ILEX Energy Reports provide detailed descriptions of European energy markets coupled with market-leading price projections for wholesale electricity, gas, carbon and green certificates. ILEX Energy Reports and price projections are currently available for the:

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  - Cyprus
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  - Greece
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  - Italy
  - the Netherlands
  - Poland
  - Romania
  - South East Europe
  - Spain
  - Switzerland
  - Turkey
- renewables markets in:
  - Italy
  - Poland
  - Romania
  - Spain
  - United Kingdom
- the biofuels market in Europe.

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Pöyry Management Consulting
King Charles House
Park End Street
Oxford, OX1 1JD
UK
Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.poyry.co.uk
E-mail: consulting.energy.uk@poyry.com

PÖYRY

Pöyry Management Consulting (UK) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK