Gas Charging Review (UNC621) – Analytical support

CLIENT: Ofgem

DATE: 20/12/2018

Version History

Version	Date	Description	Prepared by	Approved by
1.2	13/12/2018	Final	Vladimir Parail Manon Derelle	Duncan Sinclair

Contact

Duncan.Sinclair@baringa.com +44 203 327 4220

Vladimir.Parail@baringa.com +44 203 763 4813

Limitation Statement

Contents

1 Executive summary

Introduction

The European Network Code on harmonised transmission tariff structures for gas (TAR NC) is a set of harmonised gas transmission tariff structures that took effect in April 2017 and applies directly in all Member States. To implement the TAR NC in GB, National Grid Gas (NGG) raised UNC621 to modify the charging arrangements in the Uniform Network Code (UNC), and eleven proposals were made to replace the current charging methodology.

Baringa was asked by Ofgem to undertake quantitative and qualitative analysis of a number of tariff methodology options to inform its impact assessment of the potential options for gas transmission charging.

Methodology

Our methodology for the analysis is composed of the following elements:

1. **Gas tariff modelling**: calculation of tariffs under different gas transmission tariff methodology options and quantitative assessment of the distributional impact of changes in tariffs on different NTS users.
2. **Gas market modelling**: identification of changes in wholesale gas market flows and wholesale gas prices resulting from changes in the gas transmission tariff methodology options and consequent supply and demand response.
3. **Wider system impact analysis**: quantitative and qualitative assessment of potential impacts of changes in the tariff methodology on customer costs and other factors. This analysis draws on the outputs of tariff and gas market modelling.

Our assessment determines outcomes under different tariff methodology options, namely:

- Capacity Weighted Distance (CWD), based on Mod 621 as proposed by National Grid;
- CWD square root, using the square root of the distance in the CWD methodology;
- Postage stamp, dividing revenue recovery equally across Forecasted Contracted Capacity;
- CWD obligated capacity, using obligated capacity instead of Forecasted Contracted Capacity in the CWD methodology;
- CWD interconnector discount, applying a 50% discount to bi-directional interconnectors in the context of the CWD methodology;
- CWD storage discount, raising discount on storage facilities from 50% to 86% in the context of the CWD methodology; and
- Status quo, based on average historical tariffs, taking into account short-haul and other arrangements.

Gas tariff modelling and distributional analysis

Our distributional analysis assesses the tariff variation at each exit point under all options, by point category, and the variation in tariff bills for a set of Residential, Industrial and Commercial and Power station user archetypes. For Power stations and Industrial and Commercial users, we assume that the low archetype is connected to the distribution network while the high archetype is directly connected to the transmission system.

Tariff dispersion – Tariff modelling shows that tariff dispersion (the degree of variation in tariffs across locations) is higher under the Status quo methodology than under alternative tariff methodology options. Therefore, a move towards alternative options considered in this study reduces tariff dispersion. A comparison of the CWD option against other alternatives shows that CWD with storage and interconnector discounts are broadly aligned with the CWD option, and that tariff dispersion further reduces under CWD square root and CWD obligated capacity. Finally, tariff dispersion, by definition, is zero under the Postage stamp option.

Impact on bills for residential, industrial and commercial users and power stations – Tariff costs for demand calculated under alternative tariff methodology options are significantly different from Status quo tariffs. The options most different from the Status quo are Postage stamp and CWD obligated capacity. This is explained by the fact that Status quo has the highest tariff dispersion across different users and Postage stamp and CWD obligated capacity options have zero or low tariff dispersion.

Alternative tariff methodology options generally result in higher tariff bills for GDN-connected users and lower tariff bills for transmission-connected users.

Regional impact – Our analysis shows that regions in which Status quo tariffs are particularly low generally face tariff increases when moving to tariff methodology options in which tariffs are recovered more evenly across the system (e.g. Postage stamp and CWD obligated capacity). Additionally, regions that benefit from their relative proximity to large entry points under the CWD option face higher tariffs when the weighting assigned to distance from large entry points is lower as in the CWD square root and Postage stamp options.

Gas market modelling and wider system impacts

In order to assess the potential effects of changes in gas tariff methodology on consumer welfare and flows at different entry and exit points, we combine tariff modelling with modelling of the GB wholesale gas market. To test the robustness of our results to changes in key modelling assumptions, we compute outcomes for all tariff methodology options under a number of alternative wholesale market scenarios: the Baseline, Norwegian Continental Shelf (NCS) (high price responsiveness of NCS), Inelastic interconnector (increased competitiveness of LNG imports, reduced price responsiveness of interconnector imports), and Two degrees (lower gas demand, higher gas supply).

Our results indicate that changes in the total cost of gas consumed tend to account for the bulk of the estimated consumer welfare impact in the vast majority of modelled scenarios, years and tariff methodologies. The difference in estimated consumer welfare between the Status quo and alternative tariff methodology options varies to a significant degree depending on the modelled wholesale market scenario. This is due to the fact that, in our modelling, tariff changes on the marginal supply source flow into the wholesale price, and the identity of the marginal supply source can vary depending on the modelled wholesale market scenario. Hence, none of the modelled tariff methodologies are seen to achieve a clear improvement or deterioration in consumer welfare relative to the Status quo in all of the modelled scenarios.

Notwithstanding significant uncertainty around future conditions in the European and global gas markets, and the interactions of those conditions with the effect of differences in gas tariff methodologies on wholesale prices, a useful message from our modelling results is that levying higher charges on marginal supplies can have a significant impact on wholesale gas prices and therefore on consumer welfare.

Investment and closure analysis

Potential longer-term effects of changes in entry and exit tariffs include closure of existing gas infrastructure or change in location of new gas infrastructure. We analyse these potential effects for CCGTs, interconnectors, and gas storage.

CCGTs – We find that the choice of gas tariff methodology is unlikely to significantly influence the probability of retirement for existing CCGTs or the location of new CCGTs. The move towards full recovery of network revenue from capacity charges is expected to favour large-scale transmission-connected gas generation over smaller-scale distributed gas generation. However, the impact is likely to be small relative to the impact of Ofgem's ongoing reforms to electricity network charging.

Interconnectors – Our modelling does not suggest that changes in tariff methodology are likely to lead to closure of interconnectors while they are operational. Interconnectors' capacity to invest in additional infrastructure or refurbishment could potentially be influenced by the tariff methodology and the tariffs levied on interconnectors, although this also applies to other elements of gas infrastructure.

Storage – Our analysis finds that under a number of alternative tariff methodologies, storage facilities may face a significant reduction in revenues, although the effect of changes in gas transmission tariffs is small relative to the potential effects of changes in wider gas market conditions. If operating costs are sufficiently low, storage facilities are likely to remain open under any of the tariff methodology options analysed in this report. However, revenues may be insufficient to justify significant further investment, including refurbishment costs.

Qualitative analysis

Finally, we undertake a qualitative assessment of a number of questions related to our analysis, largely informed by economic theory and by the quantitative analysis we have done for this report.

Security of supply – Our analysis suggests that closure of existing interconnection, storage or gas generation capacity as a result of changes to the methodology for gas transmission charging is very unlikely in the shorter-term. However, there may be challenges with significant new capital investment for new projects, or for existing projects requiring significant refurbishment expenditure. Overall, our view based on the work we have done, is that it is not possible to say that a given tariff methodology is likely to be more favourable for security of gas supply than other tariff methodologies.

Impact of interruptible discounts – Discounts for interruptible capacity contracts are equivalent to charging lower tariffs for network access in periods of off-peak demand than in peak periods. The economic rationale for this is that the cost of the transmission network is determined by its peak capacity, and hence charges for network access should be proportional to peak usage. However, arguments for cost-reflective charging for network access are, in our view, less relevant when overall demand is declining and investment in network capacity expansion is unlikely to be required. Hence, the rationale for significant discounting of interruptible capacity is not strong.

Differentiation in long- and short-term capacity products – Our view is that offering a variety of capacity products in terms of product tenor is useful to ensure that the gas market functions efficiently and that users whose demand for network access does not fit the 'baseload' profile are not disadvantaged.

Appropriateness of proposed cost drivers – On the choice of Reference Price Methodology, our view is that the economic rationale for the CWD or CWD square root methodology is not necessarily stronger than for the Postage stamp methodology if gas network tariffs are viewed predominantly as cost recovery charges. On Forecasted Contracted Capacity, we see no economic rationale for basing tariff calculations on a historic measure of capacity (i.e. obligated capacity) that does not match expected future capacity bookings. Finally, the appropriate rationale for offering a higher tariff discount to storage is avoidance of double charging. For bi-directional interconnectors, the rationale for offering a tariff discount is flexibility, which can also be provided (arguably to a lesser extent) by other supply sources. Hence, in our view, the economic case for offering a tariff discount to bi-directional interconnectors is not the same as for storage.

Conclusion

Overall, the choice of gas transmission charging methodology is defined by the choice of how to allocate the cost of the transmission network among its users while minimising market distortions and significantly inequitable distributional outcomes. In this regard, distributional analysis of different tariff methodologies is as, or more, important than analysis of potential changes to consumer welfare.

2 Introduction

Ofgem launched the Gas Transmission Charging Review (GTCR) in June 2013 due to significant and ongoing changes to the patterns of gas flows in the National Transmission System (NTS) and the concurrent development of the European Network Code on harmonised transmission tariff structures for gas (TAR NC). In 15 November 2015, Ofgem concluded the GTCR by confirming its policy view and next steps (to prepare to implement the TAR NC).

The TAR NC[1] took effect in April 2017. It is the fourth European network code in the gas sector, supplementing and forming an integral part of the Gas Regulation and is one component of the Internal Energy Market. The TAR NC includes harmonised rules on cost allocation assessments, the application of a reference price methodology and calculation of reserve prices for standard capacity products. Developed under the Third Energy Package[2], with particular reference to Article 13, these common rules aim to foster greater market integration, enhance security of supply and promote greater interconnections between gas networks. In short, the TAR NC is a set of harmonised transmission tariff structures for gas that applies directly in all Member States.

The current approach to gas transmission charging in GB is based on the incremental cost of expanding the network at different locations. To implement the TAR NC in GB, National Grid Gas (NGG) raised UNC621 to modify the charging arrangements in the Uniform Network Code (UNC) with the aim of better meeting the relevant charging objectives and deliver compliance with TAR NC. Through discussions with the UNC Workgroup eleven different proposals were made to replace the current charging methodology.[3]

Ofgem requires analysis of the costs and benefits of the alternative proposals to provide evidence for its impact assessment. To inform this, Baringa has been asked to undertake quantitative and qualitative analysis of a number of tariff methodology options.

The rest of this document is structured as follows:

- In Section 3, we outline our methodology for the assessment;
- In Section 4, we present the results of our distributional analysis, wholesale gas market modelling and wider system impact assessment;
- In Section 5, we assess the potential impacts of different tariff options on the decisions of owners and developers of key infrastructure assets to close or to change the location in which they develop their assets; and
- In Section 6 we address a number of considerations that are not covered by our quantitative analysis.

[1] Regulation 460/2017.
[2] Directive 2009/73/EC and Regulation 715/2009.
[3] UNC621/A/B/C/D/E/F/H /J/K/L. We note UNC621G was later withdrawn by the Proposer.

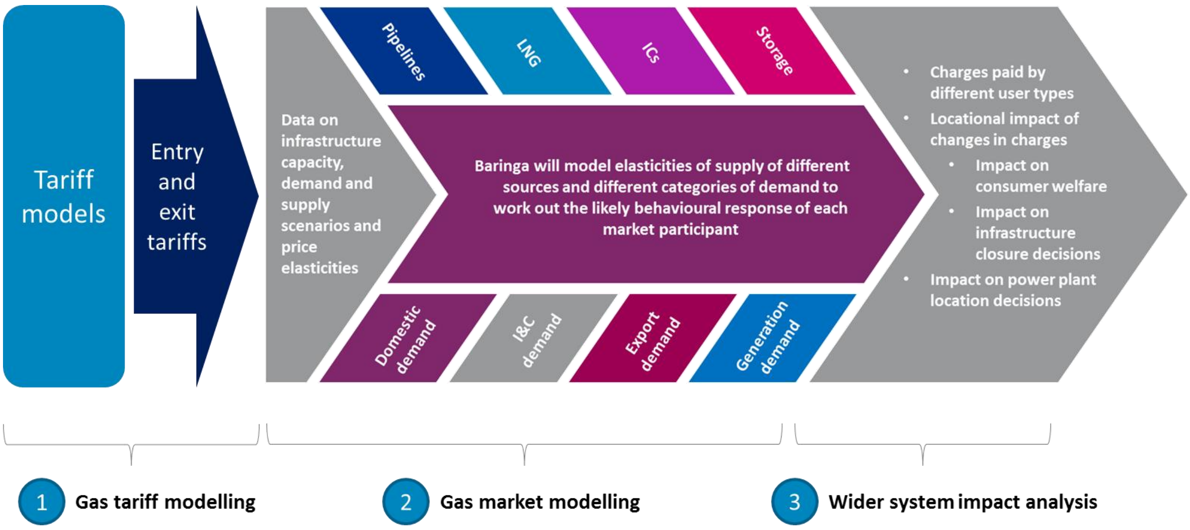
3 Methodology

3.1 Overview

Our methodology for the analysis is composed of three main steps and summarised in Figure 1:

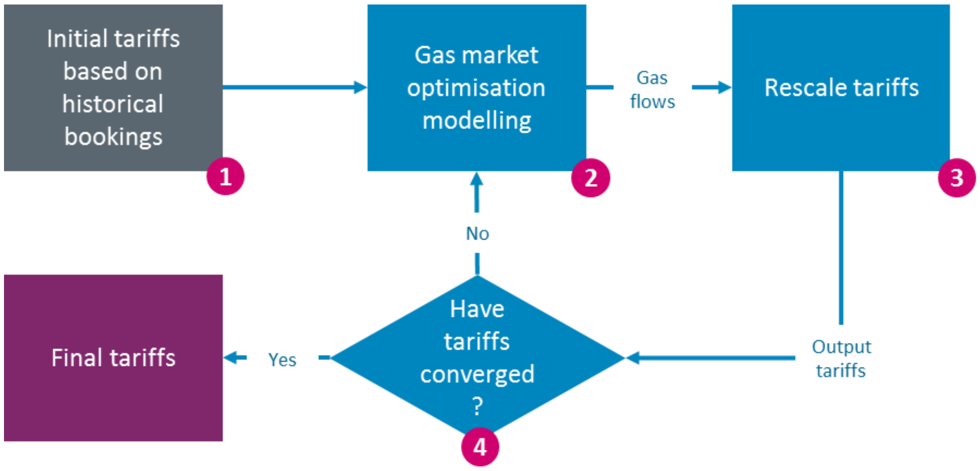
1. **Gas tariff modelling**: calculation of tariffs under different gas transmission tariff methodologies and a quantitative assessment of the distributional impact of changes in tariffs on different NTS users.
2. **Gas market modelling**: the identification of changes in wholesale gas market flows and wholesale gas prices resulting from changes in the gas transmission tariff methodology and consequent supply and demand response.
3. **Wider system impact analysis**: a quantitative and qualitative assessment of potential impacts of changes in the tariff methodology on customer costs and other factors. This analysis draws on the outputs of the tariff and gas market modelling.

Figure 1: Overview of Baringa's modelling methodology



Gas tariff and market modelling is undertaken on an iterative basis, as illustrated in Figure 2. This is done because of the two-way relationship between modelled tariffs and flows. Flows affect tariffs since they determine bookings and are the denominator in the calculation of tariffs. Tariffs affect flows since they determine the marginal cost of supply and demand and changes in tariffs can prompt supply and demand response.

Figure 2 Interaction of gas tariff and market modelling



1. Tariff model used to calculate an initial set of tariffs on the basis of historical bookings and flows. Tariffs are calculated on a flow basis using assumptions about the ratio of capacity bookings to commodity flows.
2. Tariffs for each entry and exit point are input into the wholesale market model to calculate wholesale gas market prices and gas flows at different entries and exits at a daily level. The market model calculates gas flows at every entry and exit point to the gas transmission system.
3. Gas flows from the wholesale market model are input back into the tariff model and an updated set of tariffs are calculated to recover the whole of the network allowed revenue.
4. The difference between old and new tariff is calculated to check for convergence. If new tariffs are noticeably different from tariffs calculated in the previous iteration – go to step 2 and feed new tariffs into the gas market model. If old and new tariffs have converged – record the tariffs and gas market model outputs as the final result.[4]

3.2 Gas tariff modelling

3.2.1 Overview of modelled tariff options

The purpose of our analysis is to compare the key features of different gas transmission charging methodologies. To better inform Ofgem's decision, we model Mod 621 as proposed by National Grid and options based on modifying one aspect of 621, such as the Reference Price Methodology (RPM), the discount for storage, or whether the Optional Commodity Charge is available in the transition period, in order to identify the impacts of that change in tariff model design on tariffs paid by different transmission system users, gas flows, consumer welfare, and broader gas market metrics. This approach enables the identification of key desirable features of a tariff methodology.

The variations of the tariff methodology considered in our assessment, which have been agreed with Ofgem, are set out in Table 1.

[4] If full convergence is not achieved, which happens in some cases, any remaining difference is accounted for in our CBA results.

Table 1 Modelled tariff methodology options

Option	RPM	Capacity used for tariff calculation	Storage discount	Bi-directional interconnector discount	Additional revenue recovery charges	Optional charge
CWD	Capacity Weighted Distance	Forecasted Contracted Capacity[5]	50%	0%	None	No
CWD square root	Capacity Weighted Square Root of Distance	Forecasted Contracted Capacity	50%	0%	None	No
Postage stamp	Postage stamp	Forecasted Contracted Capacity	50%[6]	0%	None	No
CWD obligated capacity	Capacity Weighted Distance	Obligated capacity	50%	0%	Commodity charge in transition period and capacity charge in enduring period[7]	No
CWD obligated capacity OCC	Capacity Weighted Distance	Obligated capacity	50%	0%		In transition period - limited to 60km
CWD interconnector discount	Capacity Weighted Distance	Forecasted Contracted Capacity	50%	50%	None	No
CWD storage discount	Capacity Weighted Distance	Forecasted Contracted Capacity	86%	0%	None	No
Status quo	Long-Run Marginal Cost	Capacity tariffs fixed at historical average rates	Storage exempt from commodity charges	0%	Commodity charge	Yes – not distance limited

[5] Forecasted Contracted Capacity is defined as the forecast of bookings at each entry and exit point that is used to calculate capacity tariffs.
[6] We note that the proposed modification that includes Postage stamp tariffs also specifies an 86% tariff discount for storage. We expect that incorporating a higher storage discount in the context of Postage stamp tariffs would have a similar effect to incorporating a higher storage discount in the context of CWD tariffs.
[7] The transition period is defined as gas years 2019/20 and 2020/21. The enduring period is defined as the period that follows the transition period. We note that UNC0621B has a commodity-based charge in the enduring period, which is different from the approach taken in our modelling.

3.2.2 Tariff models used for the assessment

Modelling of RPMs and RPM parameters using the National Grid model

For our modelling of gas tariffs and variants of the tariff methodology, we have used the MS Excel tariff models that have been created by National Grid as part of the process of documenting all of the proposed modifications to the gas transmission tariff methodology.[8] While the initial models were largely complete, a number of modifications were needed to make them suitable for deployment in our analysis. In order to have a master model enabling to test the various parameters of the assessment, we asked National Grid to use its 0621 model and integrate the following changes:

1. Modify such model to enable testing of the 3 different RPMs in the same model (i.e. CWD, CWD square root and Postage stamp), additional to more specific parameters such as Forecasted Contracted Capacity or capacity discounts;

2. Add the functionalities needed to undertake dynamic analysis, i.e. an iteration between the outputs of the tariff models described in this Section and Baringa's wholesale market model described in Section 3.3. More specifically, we have asked National Grid to enable tariffs to be determined on the basis of updated flows as calculated in Baringa's wholesale market model, whilst still ensuring revenue recovery.

Booking to flow ratio

In our approach to the analysis, the wholesale market model determines flows, whereas the tariff models determine tariffs on a bookings basis. This is described in Section 3.1. For the two models to work together, a relationship between bookings and flows needs to be defined.

In the context of modelling a forward-looking equilibrium in the alternative tariff methodology options, we assume that market participants' expectations are accurate and that they book exactly the capacity required for their demand and supply levels.[9] This assumption does not apply to GDNs, who interpret their licence as requiring them to book enough capacity to meet 1-in-20-year demand levels. For GDN exit points, we assume a booking to flow ratio of 2.88 based on historical data. It also does not apply to modelling of the Status quo, where we use alternative assumptions as set out below.

Modelling of CWD obligated capacity option

The CWD obligated capacity option requires additional revenue recovery charges because capacity tariffs are calculated on the basis of obligated capacity level but recovered on the basis of actual bookings, which are different and lower on average. In addition to capacity charges, a commodity revenue recovery charge is applicable during the transition period and an additional capacity revenue charge is applicable in the enduring period under this option. These are calculated on the basis of actual flows and Forecasted Contracted Capacity respectively.

[8] See https://www.gasgovernance.co.uk/0621/Models

[9] Differences between capacity bookings and commodity flows can be expected to occur when there is a mismatch between expectations and outturn. While we would expect such mismatches to happen frequently, we think it is reasonable to assume that they would average to zero in the long-run.

Treatment of existing contracts

Under all modelled scenarios, our modelling assumes that existing contracts are priced at their existing values and that holders of these contracts do not pay any additional capacity charges. Revenues associated with existing contracts are subtracted from the total revenue requirement, and the relevant capacity bookings are also subtracted from Forecasted Contracted Capacity in the calculation of capacity tariffs for users who are not in possession of existing capacity contracts. For the gas year 2020/21, existing entry contracts amount to 3.88 TWh/d and revenue of £60m.[10] For the gas year 2030/31, existing entry contracts amount to 0.67 TWh/d and revenue of £0.4m.

Being in possession of an existing capacity contract does not exempt a user from commodity charges. Hence, depending on the modelled tariff methodology and whether a significant proportion of the total revenue requirement is recovered through commodity charges, the average tariff payments by holders of existing contracts and by users without an existing contract can vary substantially. This is explored in more detail in Section 4.1.5.

Status quo modelling

In order to undertake analysis of potential changes in tariffs for different transmission system users, as well as potential changes in consumer welfare and broader wholesale gas market indicators, we have built a stylised dynamic model of the Status quo, such that tariffs are adjusted and revenue requirements are met under updated sets of flows. This allows us to make comparisons between the current tariff regime and alternative options on a like-for-like basis, under identical market conditions and tariffs set to recover the full network revenue requirement. The comparison includes analysis of tariffs paid by different user types, analysis of differences in consumer welfare, and analysis of changes in system gas flows, as a result of changes in gas tariff methodology.

We have based our modelling on point-specific Status quo tariff data provided by National Grid. For each entry and exit point, National Grid provided data on historical flows, historical firm and interruptible capacity bookings, together with capacity revenues. Our modelling of the Status quo assumes that capacity charges seen in 2017/18 are fixed for Status quo model runs for 2020/21 and subsequent years. Revenue recovery is achieved through a commodity charge.

The Status quo modelling steps are as follows:

1. Based on the data provided by National Grid, we derive (i) 2017/18 capacity tariffs, and (ii) ratios of historical bookings to flows.[11]
2. Using flows determined in our wholesale market model, we determine the level of bookings using the booking to flow ratio, which is derived as set out in point 1.(ii) above.
3. We multiply Status quo capacity tariffs (as calculated in point 1.(i) above) by capacity bookings to obtain total revenue recovered through capacity charges.

[10] Data provided by National Grid.

[11] These ratios differ from those used for modelling of alternative tariff methodology options because they are based on historical data bookings and flows under Status quo tariffs, whereas under the alternative options, bookings and flows are assumed to match for all users except DNOs on the assumption that, on average, Forecasted Contracted Capacity will match flows. The bookings taken into account in the calculation of the booking to flow ratios are firm bookings only, because interruptible bookings are free and therefore not informative. Capacity tariffs are derived by dividing total tariff revenue by total firm capacity bookings. This approach aggregates different types of firm capacity products.

4. We then compare this revenue to the revenue requirement, and recover any shortfall through a commodity charge.

The steps set out above lead to one set of capacity charges across all modelled years and all gas market scenarios. However, commodity tariffs will vary depending on flows and required network revenue to ensure that the total network revenue requirement is always met.

Our modelling also ensures that bookings and revenues associated with existing contracts are excluded from total bookings and revenue requirements. This applies to all capacity contracts as of 2017/18 which are recorded in the database provided to Baringa by National Grid. Finally, storage does not pay the commodity charge in our Status quo modelling as is the case under current arrangements.

NTS Optional Commodity Charge ('OCC') modelling

OCC, also known as the short-haul charge, is a charge that can be paid by NTS users as an alternative to the commodity charges (TO and SO commodity charges) under existing charging arrangements. When the OCC rate is cheaper than the corresponding commodity charge, eligible NTS users are likely to pay the OCC. Under the alternative tariff methodology options, OCC is only assumed to be available under the Obligated capacity option in the transition period as an alternative to the commodity revenue recovery charge, and is subject to a 60 km distance limit.

National Grid provided data to Baringa on historical OCC rates and flows for each relevant entry and exit point. To estimate whether users at a given entry or exit point would opt for the OCC instead of paying commodity charges, we compared the applicable OCC rates to the commodity charge for each possible pairing of entry and exit points, and assume that users would always choose the lower charge. As the next step, we calculate the revenue shortfall arising from users paying the OCC as opposed to the higher commodity or revenue recovery charge and uprate the charge paid by other users at entries and exits by the amount that ensures that revenue recovery is maintained.

3.3 Gas market modelling

Baringa's wholesale gas market model is built around an optimisation framework which mimics market operation. It minimises the cost of meeting gas demand in the UK given assumptions on the availability of supply and demand flexibility and the associated cost. Using inputs on demand and supply forecasts, together with estimates of price elasticity of various demand and supply sources, our model determines the clearing price and the balance of supply and demand at a daily level.

In our wholesale market model, we represent the different entry and exit point types though the categories summarised in Table 2. These categories match the categories represented in National Grid's tariff models.

Table 2: Demand and exit point types in the wholesale market model

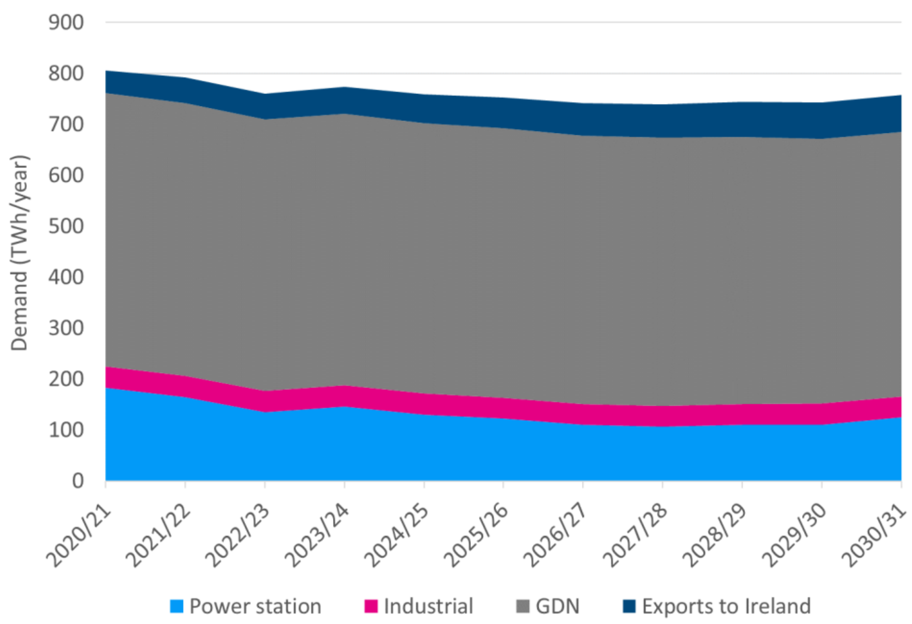
Demand (exit)	Supply (entry)
Transmission-connected Industrial and Commercial (I&C)	Beach terminals
Transmission-connected Power station	Onshore fields
Storage exit	LNG import
GDN	Storage entry
Interconnector exit	Interconnector entry

3.3.1 Demand and supply forecasts

Our demand assumptions are based on a blend of the National Grid Future Energy Scenarios (FES) 2018, which contains long-term demand scenarios by final user type (e.g. Residential, Industrial and Commercial, and Exports to Ireland), and the National Grid Gas Ten Year Statement (GTYS), which contains long-term demand forecasts by point type (as presented in Table 2). Where a timing difference occurs in the definition of years used in National Grid tariff models, FES, and GTYS, a year marked as 2020/21 is assumed to respond to 2020 calendar year.

Figure 3 shows our annual demand assumptions split by type of exit.

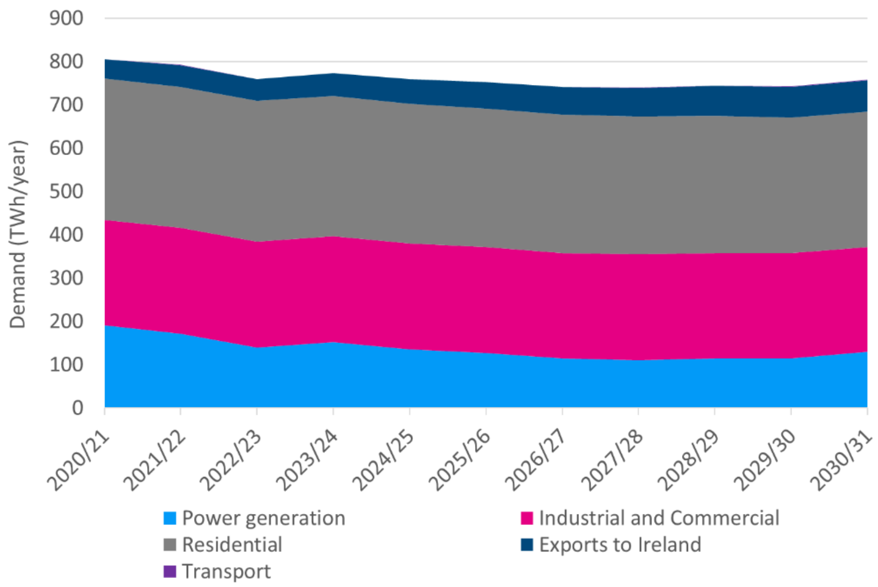
Figure 3 Annual demand by exit type



For the purposes of our gas market modelling, we also need to determine the composition of GDN demand between Residential, Industrial and Commercial, Power station and Transport because different types of users react differently to changes in price signals. We establish a mapping between FES and GTYS scenarios and identify the proportions of GDN demand attributable to different user categories. More specifically, mapping of latest historical demand figures involves the following steps: (i) demand from GDN-connected Industrial and Commercial users is identified by taking total Industrial and Commercial demand in FES and subtracting transmission-connected Industrial and Commercial demand in GTYS; [12] (ii) Residential and Transport demand is assumed to be distribution-connected , and (iii) demand from distribution-connected Power stations is the residual GDN demand once other components have been estimated. For future years, historical values for each demand component are assumed to grow proportionally with the corresponding category in the FES scenarios.

Figure 4 shows our annual demand assumptions split by user type. As an example of the effect of mapping GDN demand to different user types, Industrial and Commercial demand in Figure 4 is significantly greater than transmission-connected Industrial demand in Figure 3 because Figure 4 incorporates GDN-connected Industrial and Commercial demand.

Figure 4 Annual demand by user type



As in the distributional analysis framework, each exit point is represented in the wholesale market model, and associated final demand is mapped to those points. We attribute the demand forecasts to individual points based on their share of total demand in their exit point category in the gas year 2017-18, assuming these shares remain constant over time. For example, for Residential demand, we take total Residential demand and divide it up among the different GDN exits according to their historical share of total GDN gas exit flow.

[12] Total demand in FES and GTYS are scaled in order to avoid any discrepancy between sources.

Our Baseline long-term demand and supply assumptions are as defined in the Steady Progression scenario, but we run a scenario in which long term gas demand projections are based on the Two Degrees scenario.[13]

Baringa's supply forecasts are based on the GTYS statement, which provides point-level forecasts to 2039/40 for most entry points. This is the case for beach terminals, which we are able to use directly in our analysis on an annual level, applying historic seasonal variation to annual forecasts to derive daily flows. For onshore fields, the GTYS only provides forecasts for the category, which we then attribute to individual fields based on their share of historical production. [14]

Interconnector flows are capped at interconnector capacity and determined in our wholesale model based on the relation between system price calculated in our model and prices in interconnected markets. The methodology for determining supply pricing is set out in Section 3.3.2. When the system price is lower than the price in the interconnected markets, interconnectors are likely to export and vice versa.[15] The same methodology is applied to LNG import terminals but without the possibility to export.

Finally, storage flows are optimised within our model on the basis of minimising the cost of meeting demand over the course of the year and variable costs of storage injection and withdrawal, which include entry and exit tariffs. In order to make different model parameters comparable, storage in the model starts from the same level in every model run and must end the year at the same level.

3.3.2 Price elasticities and tranches of supply and demand

Each source of demand and supply also has an elasticity associated with it, such that changes in tariffs, as well as other wholesale market model dynamics, can change demand and supply at different exit and entry points. For demand, a degree of price elasticity reflects the fact that certain gas users would decide to turn down their demand as prices increase beyond their Value of Lost Load (VoLL), while other users would exhibit little responsiveness to price changes. Similarly, some supply sources would change production or deliveries in response to price changes, while others may not do so due to technical constraints, their cost structure, or existing contractual arrangements.

For supply, we determine price responsiveness based on analysis of historical data:

- Interconnector price elasticity is determined based on regression analysis of IUK flows against the NBP-ZEE price spread[16] using recent historical data.
- LNG price elasticity is determined based on the increase in LNG supply that occurred during a NBP price spike in early 2018.[17]

---

[13] Because demand and supply differences between are only noticeable in the long-run, we model this scenario for the gas year 2030/31.
[14] National Grid data with daily granularity, between 2013 and 2018. Available at http://mip-prod-web.azurewebsites.net/DataItemExplorer and extracted on 16 September 2018.
[15] BBL is assumed to have reverse flow capability by 2020/21.
[16] This is the price differential between gas traded at the British National Balancing Point (NBP) and Belgian Zeebrugge (ZEE) gas hubs.
[17] Since the price spike was caused by factors independent of LNG supply, this approach avoids the potential endogeneity bias from regressing changes in prices on changes in physical supply.

- Price elasticity for beach terminals is determined based on regression analysis of beach terminal flows against historical NBP prices.

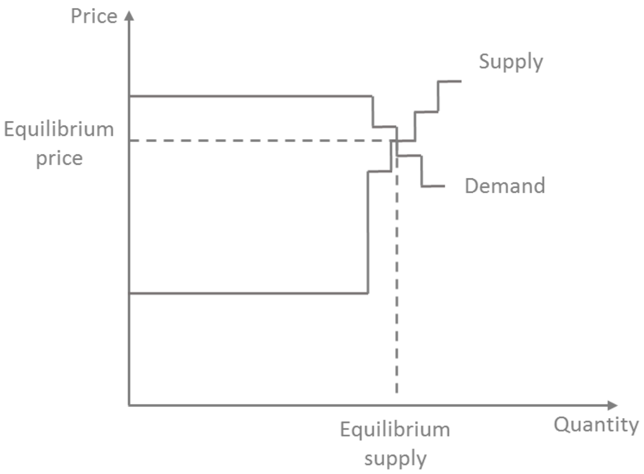
For demand, we determine price responsiveness based on published empirical studies and broader assumptions:

- Residential and Transport demand are assumed to be price insensitive. This means that they consume at their required level and do not provide demand response.
- Industrial and Commercial users provide demand-side response, and the demand from Power stations will fluctuate depending on the 'spark spread', relating to the relative gas and power prices. Assumptions on their respective price elasticities are taken from published studies. Gas demand for power is assumed to have a higher elasticity than Industrial and Commercial demand.[18]

Because GDN demand is composed of Residential, Transport, Industrial and Commercial and Power station demand, we apply the corresponding price elasticities to each component of GDN demand at each GDN exit point.

The attribution of price elasticity to different supply and demand sources allows continuous supply and demand functions. To enable these functions to be used in an optimisation framework, we determine step-wise demand and supply functions that approximate linear functions. Each demand and supply source, which is defined both by the underlying component of demand and supply as well as the relevant exit or entry point, is assumed to consist of four separate tranches with an associated quantity and price. In order to achieve a more granular representation of supply and demand functions in the region where the supply-demand balance is likely to be found, we generally define three small tranches that require relatively modest changes in the system gas price to come into play and one large tranche that requires a large change in the price to come into play. This is illustrated in Figure 5 and consistent with the elasticity values assumed in our analysis.

Figure 5 Illustration of model supply-demand balance



[18] Source: Vipin Arora, Estimates of the Price Elasticities of Natural Gas Supply and Demand in the United States, March 2014.

Finally, in order to derive full supply and demand functions for the purposes of modelling the wholesale gas market, demand and supply flexibility must be defined around some absolute level of demand and supply respectively. In absence of fundamental assumptions on the VoLL of different demand tranches and the cost of different supply tranches, supply and demand tranches are anchored to NBP price forecasts. On an annual level, these are based on Baringa assumptions, which are in turn informed by IEA projections.[19] Seasonal shape of NBP prices on a daily level is informed by historical seasonal variation in NBP prices.

3.4 Economic impact assessment

Using outputs from the tariff analysis and wholesale gas market model, we assess the wider system impacts of changes in tariff methodology. Our analysis focuses on changes in consumer welfare, but also allows us to estimate consequent changes in market shares of different supply sources and net revenues of gas storage. The assessment is carried out in the context of different scenarios in order to test whether the results are robust to changes in market conditions and certain key assumptions about supplier behaviour.

Our analysis of wider system impacts does not include estimating producer welfare. This is firstly because we are not in possession of reliable information on the costs of the different gas producers and importers and this is not the focus of our study. Secondly, a significant but uncertain proportion of producer surplus would be accrued by parties that are not GB-based. Nonetheless, it is important to note that consumer welfare and net social welfare are not synonymous and any consumer gains and losses are likely to be associated with equally significant producer losses and gains, unless there is a significant change in underlying resource costs.

The main way in which changes in gas transmission tariff methodology affect consumer welfare is through changes in wholesale gas prices. This manifests itself through changes in the price paid by consumers for gas.

The second component of consumer welfare estimated in our analysis is the change in the value of demand served. We consider that the value of demand served is captured by the VoLL, or in other words the maximum willingness to pay, of the corresponding demand tranche. Capturing differences in this value ensures that all differences in consumer surplus are captured in our analysis of consumer welfare.

Finally, our welfare analysis captures any residual differences between different tariff methodologies and modelled scenarios in tariff revenue raised by the transmission network. If one modelled tariff methodology option results in marginally higher tariff revenue being raised at the end of the last iteration, this tariff over-recovery is added to total consumer welfare for that option because it can offset revenue requirements for subsequent years. This puts welfare results from different model runs on a comparable basis to avoid penalising tariff methodologies that have not iterated to a full equilibrium and set marginally higher tariffs than the exact equilibrium level of tariffs.

[19] International Energy Agency (2018), 'World Energy Outlook 2018', and Baringa calculations.

4 Results

4.1 Distributional analysis

Our distributional analysis assesses the tariff variation at each entry and exit point under all options, by point category, and the variation in tariff bills for a set of Residential, Industrial and Commercial and Power station user archetypes. Tariff methodologies and parameters have a distributional impact because lower tariff revenue from one set of users must be compensated by higher tariffs from other users.

We have undertaken the distributional analysis for 2020-21, 2021-22 and 2030-31. Because similar patterns are observed across all years, we present outcomes for 2021-22 in this section, i.e. the first year of the enduring period. Results for other modelled years were provided to Ofgem in spreadsheet format.

4.1.1 User archetypes

We assess the effect of changes in tariffs on the yearly bills of Residential, Power station and Industrial and Commercial consumers. To undertake this assessment, we define typical consumer archetypes and calculate their tariff bill under all modelled scenarios.

- Residential consumers: We define consumer archetypes based on the Typical Domestic Consumption Values published by Ofgem.[20] Ofgem defines a typical Low consumption user as a Residential consumer with 8MWh annual gas consumption. Central and High values are 12 and 17MWh respectively.
- Industrial and Commercial users: We base Industrial and Commercial archetypes on BEIS gas consumption statistics for non-domestic users. For each local authority, BEIS publishes the distribution of gas consumption for non-domestic users (25th, 50th and 75th percentile). To have significant variation between our low and high archetypes, we define our low archetype as the lowest 25th percentile of gas use by Industrial and Commercial users across all regions in the UK (320MWh), and our high archetype as the largest 75th percentile of gas consumption by Industrial and Commercial users across all regions in the UK (970MWh).[21]
- Power station: We identify typical plant characteristics using the list of power plants and technical characteristics included in Baringa's GB Power Sector model, together with modelling outputs to identify efficiency and load factor. We define the low archetype as a GDN-connected Open Cycle Gas Turbine (OCGT) generator of 50MW with 32% efficiency and a load factor of 15%. For the high archetype, we model a large, high-efficiency Combined Cycle Gas Turbine (CCGT) generator such as those which could be built over the next couple of years. More specifically, the high archetype is a transmission-connected 700MW CCGT, with 56% efficiency and a load factor of 75% (similar to that of the most efficient plant currently operating).

For Industrial and Commercial users and for Power stations, we assume that the low archetype is connected to the gas distribution network and that the high archetype is connected to the gas

[20] https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values
[21] Based on Chart 14 of BEIS (2018), 'Sub-national electricity and gas consumption statistics' , January

transmission network. It follows that low users are liable for tariffs at GDN exit points, while high users are liable for tariffs at Industrial and Commercial / Power station exit points. We consider that this approach depicts how the each tariff scenario affects different types of points precisely because it does not mix point categories within a single archetype. Variation in tariff by exit point category would not be as clear if tariffs presented for a single archetype included tariffs at GDN exit points and at direct transmission points.

Due to the smaller number and the specificity of storage sites and interconnectors, it is more difficult to define a typical archetype for these user categories. For these sites, we simply assess the magnitude of changes in tariffs under different scenarios, as opposed to changes to a typical bill.

4.1.2 Pass-on of charges into consumer bills

As set out in Section 4.2.2, our wholesale market modelling assumes that entry charges are passed on into the wholesale market price of gas only if they apply to the marginal supply source. In terms of pass-on of exit tariffs into consumer bills, we note that these charges are generally paid by suppliers which are not subject to price regulation, and hence pass-on of these charges is at the supplier's discretion. However, changes in exit charges can be classified as a common cost shock because they would affect any supplier whose customer is located at the affected exit point. Economic theory would suggest that, in a competitive market, such cost changes would be passed on to customers in full.

We note that our distributional analysis presented in this section makes the assumption that entry tariffs are passed on to customers at different exit points on the basis of CWD weighting factors, where, for a given exit point, the extent of pass-on of entry charges is proportional to their respective capacities and distance from the said exit point. As set out in section 4.2.2, our wholesale market modelling assumes that entry charges are passed on only by the marginal producer via the wholesale price, which is paid by all demand. The resulting pass-on of entry charges for different supply sources in our wholesale market modelling is very sensitive to scenario assumptions and can be negative or greater than 100% due to the fact that changes in entry charges for supply sources that are not marginal do not affect the wholesale gas price. This is demonstrated in the results of our wholesale market modelling as set out in section 4.2. Hence, the assumption of 100% pass-on of changes in entry tariffs, distributed between end users at different exit points on the basis of CWD weighting factors, is a reasonable approximation of the pass-on that would be expected to occur via the wholesale price on average across a number of different wholesale market scenarios.

Finally, in the context of our distributional and wider system impact analysis, we need to consider whether a move from charging on the basis of commodity flows to charging on the basis of capacity contracts is likely to change the extent of pass-on of changes in transmission charges at different entry and exit points. A simple argument might be that commodity charges are a marginal cost of supply, varying proportionally with the quantity supplied, and hence would be passed on by the marginal supplier. Capacity contracts could on the other hand be seen as a fixed cost which does not vary directly with quantity supplied, and hence would not necessarily be passed on to final customers equally in all periods, although it would be expected to be passed on in the long-run.

Without going into detail on the pass-on of fixed costs into prices paid by consumers, it is sufficient to note that capacity contracts can generally be booked at different levels of granularity. While the question of what types of contracts may be available under future transmission charging arrangements is outside of the scope of this study, if those products include short-term (e.g. daily) capacity products, it is likely that market participants will be able to shape their capacity bookings to their expected commodity flows, making the cost of capacity bookings effectively a marginal cost and removing much of the difference between capacity- and commodity-based charges for the purposes of determining pass-on of cost changes into consumer bills.

4.1.3 Comparison of total transportation tariffs

We evaluate total transportation tariffs at each exit point, assuming that entry tariffs are passed on in their entirety. To determine total tariffs, we apportion entry tariffs to exit points using a weight similar to the capacity weighted distance methodology. Under this assumption, exit points will be liable for entry tariffs of points that are relatively close and relatively large.

Tariff dispersion

The current Status quo methodology is based on the incremental cost of expanding the network at different locations. Under the existing methodology, tariffs are higher where it would be more expensive to build new pipelines, and there is a significant degree of geographical differentiation.

With the exception of the Postage stamp methodology, all options are based on the capacity weighted distance approach. Under the CWD regime, points which are relatively large and relatively distant from other entry or exit points are liable for a larger share of revenue recovery. This also implies a degree of geographical differentiation. It is difficult to predict whether this methodology will create more or less tariff differentiation than under the Status quo. As indicated in Figure 6, Figure 7 and Figure 8, our results show that tariff dispersion is higher under the Status quo methodology than under the CWD options. This means that users who are currently paying high tariff rates may (on average) see their tariff costs fall if the tariff methodology changes to CWD, whereas those users who are currently paying low tariff rates may (on average) see their tariff costs increase.

Options with interconnector and storage discounts can be expected to be relatively similar to CWD. Any difference would come in the form of discounted tariffs being lower than under the CWD option and other tariffs being slightly higher. Hence discounts would be expected to have a significant effect on tariffs paid by a small number of directly affected users and only a limited impact on the larger body of other users.

Under the CWD square root option, tariff differentiation is lower than under the CWD option because the effect of distance when determining tariffs is diminished. This would correspond to lower geographic variation in tariffs, with demand at more remote locations paying less. In the extreme case of Postage stamp, all entry and exit points pay a single unit rate (in absence of any discounts) and tariff dispersion disappears completely.

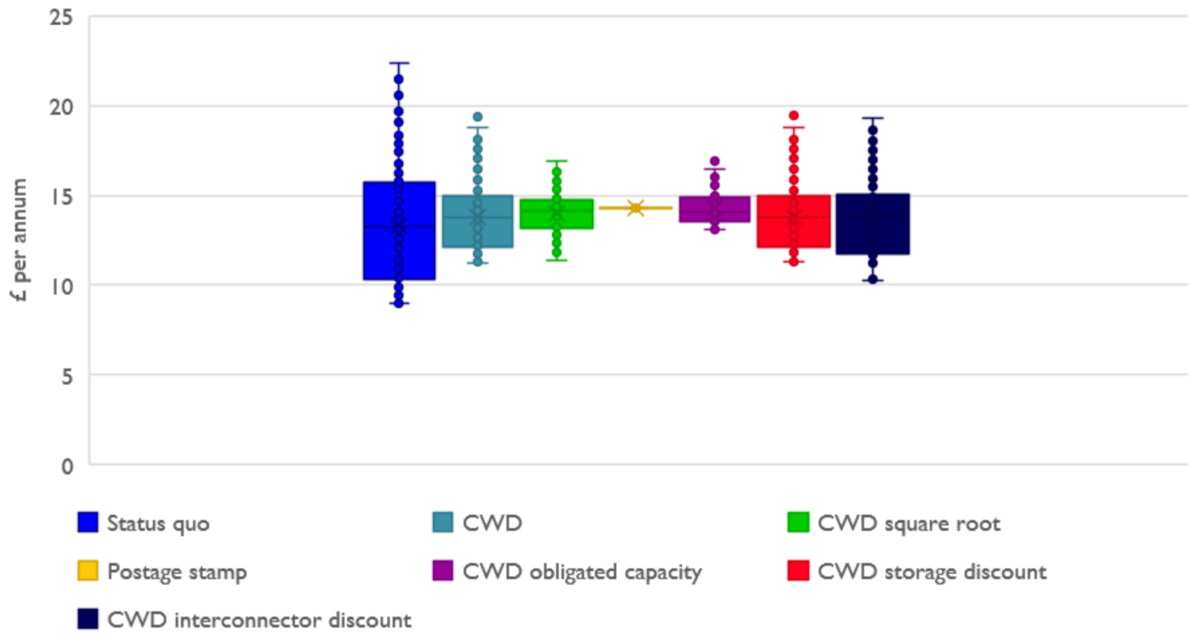
Finally, outcomes under the CWD obligated capacity option are largely dependent on differences between forecasted and obligated capacity. Obligated capacity tends to be larger and more evenly distributed than forecasted capacity. Because capacity revenue recovery is based on actual capacity bookings rather than obligated capacity, there is significant revenue under-recovery under this tariff option. This is recovered through an additional revenue recovery charge on all users that smears the residual cost of the network across all users. For these reasons, calculating capacity charges on the basis of Obligated capacity results in lower dispersion of tariffs than under the CWD option.

For the 2020/21 transition year, we also model the option of Obligated capacity where users can choose short-haul tariffs as opposed to the revenue recovery charge. Results with short-haul are largely aligned to those under Obligated capacity without short-haul.

Figure 6, Figure 7 and Figure 8 show the distribution of annual tariff bills by user category. The total tariff bill is calculated at each exit point and comprises entry and exit charges. Entry charges are allocated to exit points using weighting factors based on booked capacity and distance as in the CWD methodology.[22] The boxes in the charts represent the 25th to 75th percentile range, the line in the middle of the box represents the 50th percentile, and dots represent tariffs at individual exit points.

The analysis behind these charts assumes that entry and exit charges are passed on to final consumers in their entirety. We consider the assumption of full pass-on of entry tariffs to final users to be a conservative one. As discussed further in Section 4.2.3, our wholesale market modelling assumes that only the marginal supply source is able to pass changes in entry tariffs into prices. Hence, at least in the short-run, pass-on of changes in entry tariffs into final user bills may not be complete.

Figure 6 Total entry and exit gas tariff bills for the central Residential consumer archetype



[22] See section 4.1.2 for an explanation of the rationale behind this assumption.

Figure 7 Total entry and exit gas tariff bills for the high Industrial and Commercial archetype

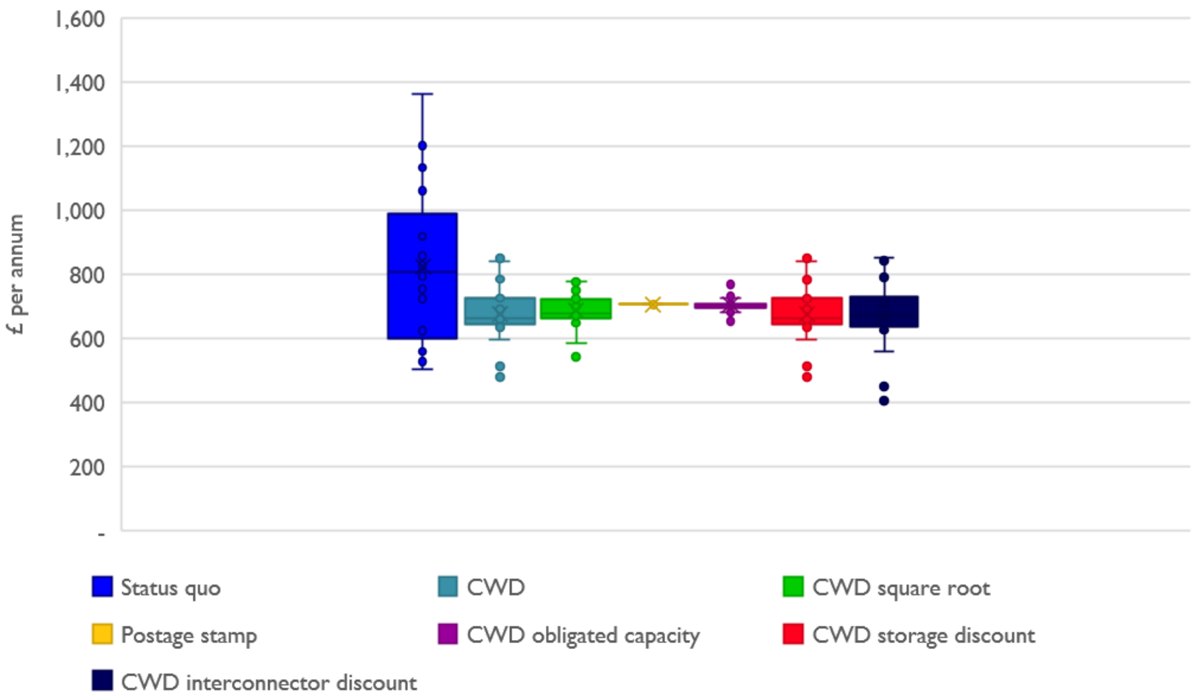
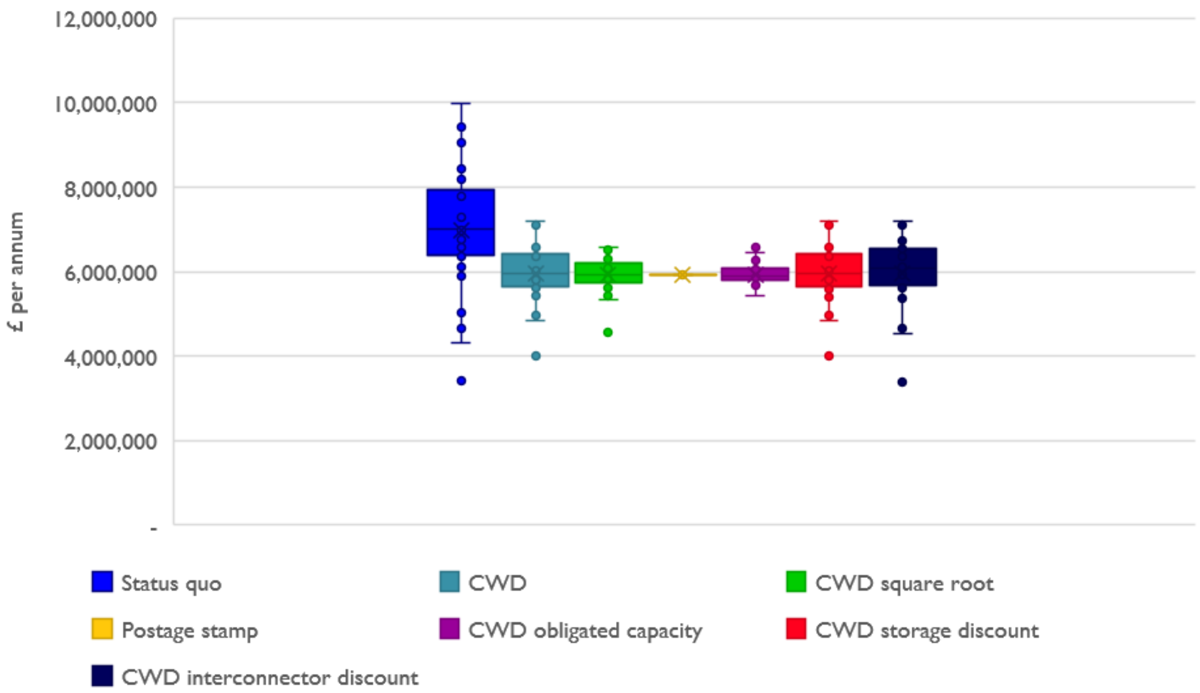


Figure 8 Total entry and exit gas tariff bills for the high Power station archetype

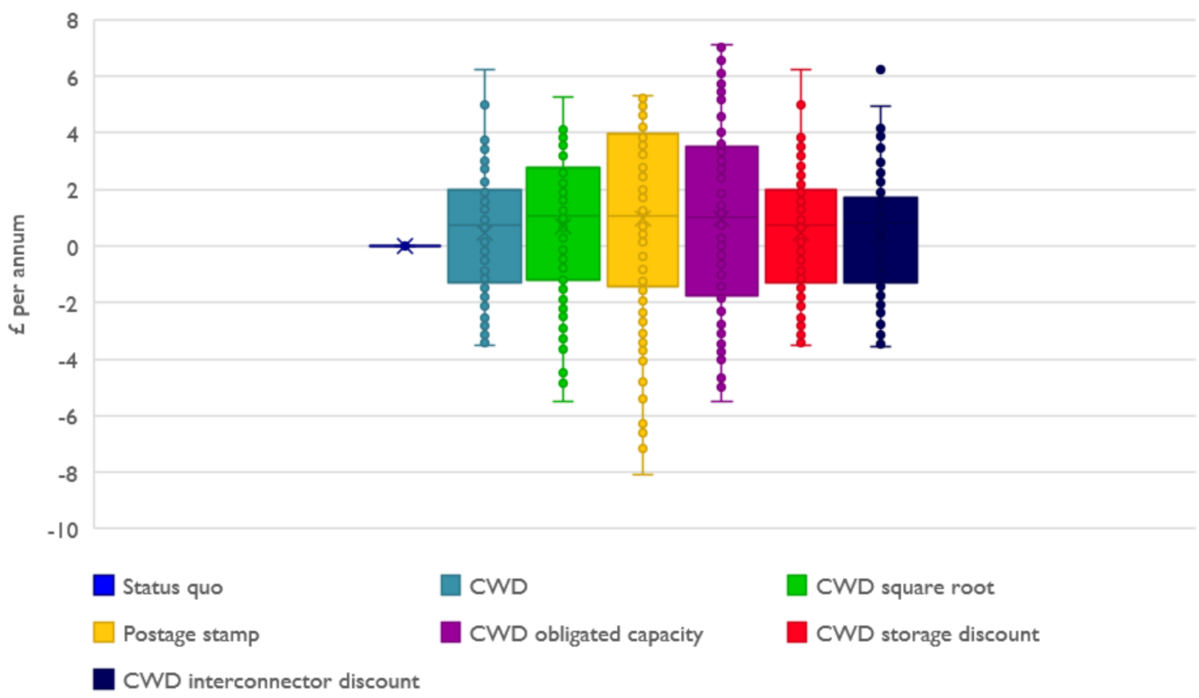


Comparison of all options against the Status quo

Figure 9, Figure 10 and Figure 11 show the magnitude of the differences in tariffs paid by different types of user at different exit points under the alternative tariff methodology options compared to the Status quo. A difference of zero indicates that tariffs are the same across options. A negative difference indicates a reduction in tariffs, and a positive difference indicates an increase in tariffs. Differences between the Status quo and new options vary at each point due to distributional effects. This means that a given methodology does not result in the same changes across all points. Rather, points of different categories and in different locations are affected differently.

All alternative methodologies considered result in significant changes in the tariffs paid by each point as compared to the Status quo. For GDN-connected users, differences are centred around zero, but there is significant point-specific variation. For example, in the case of CWD, the largest bill reduction for the central Residential archetype is around £4 per annum and the largest bill increase is around £6 per annum. The options most different from the Status quo are Postage stamp and Obligated capacity. This is consistent with the fact that Status quo has the highest tariff variation and that Postage stamp and Obligated capacity have zero and low tariff variation respectively.

Figure 9 Differences in total entry and exit gas tariff bills between all options and the Status quo - Residential central archetype



The fact that tariffs under Postage stamp and Obligated capacity options are most different from Status quo can also be observed for transmission-connected Industrial and Commercial users and Power stations.

Figure 10 Differences in total entry and exit gas tariff bills between all options and the Status quo – Industrial and Commercial high archetype

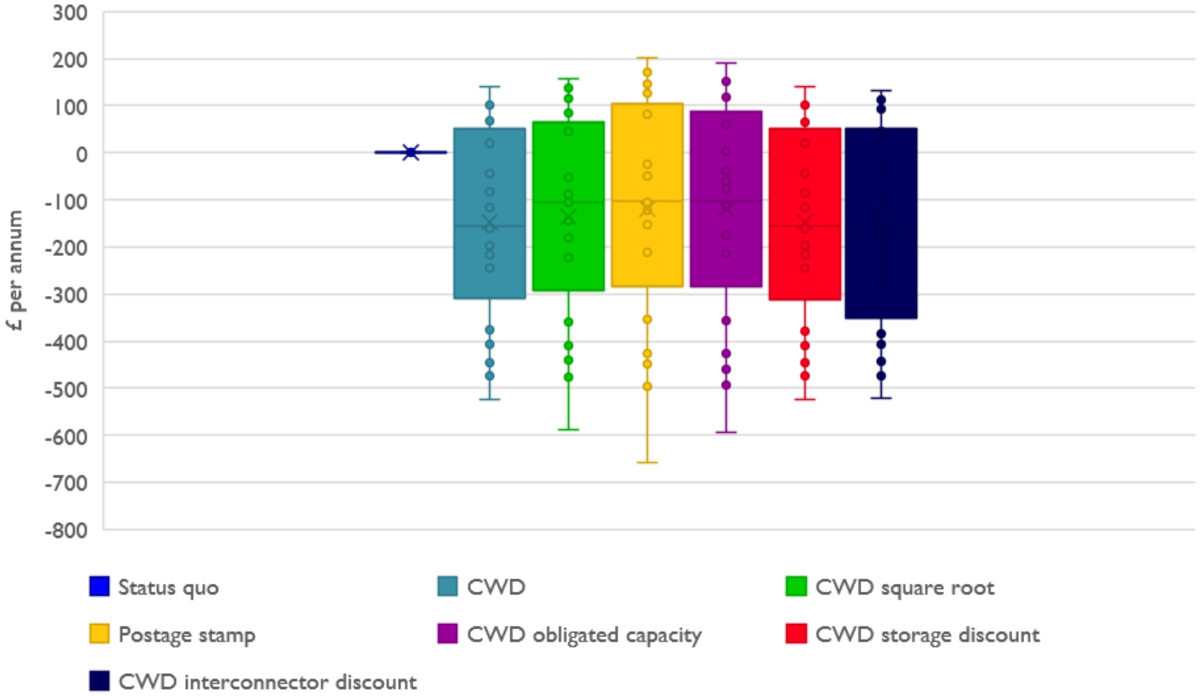
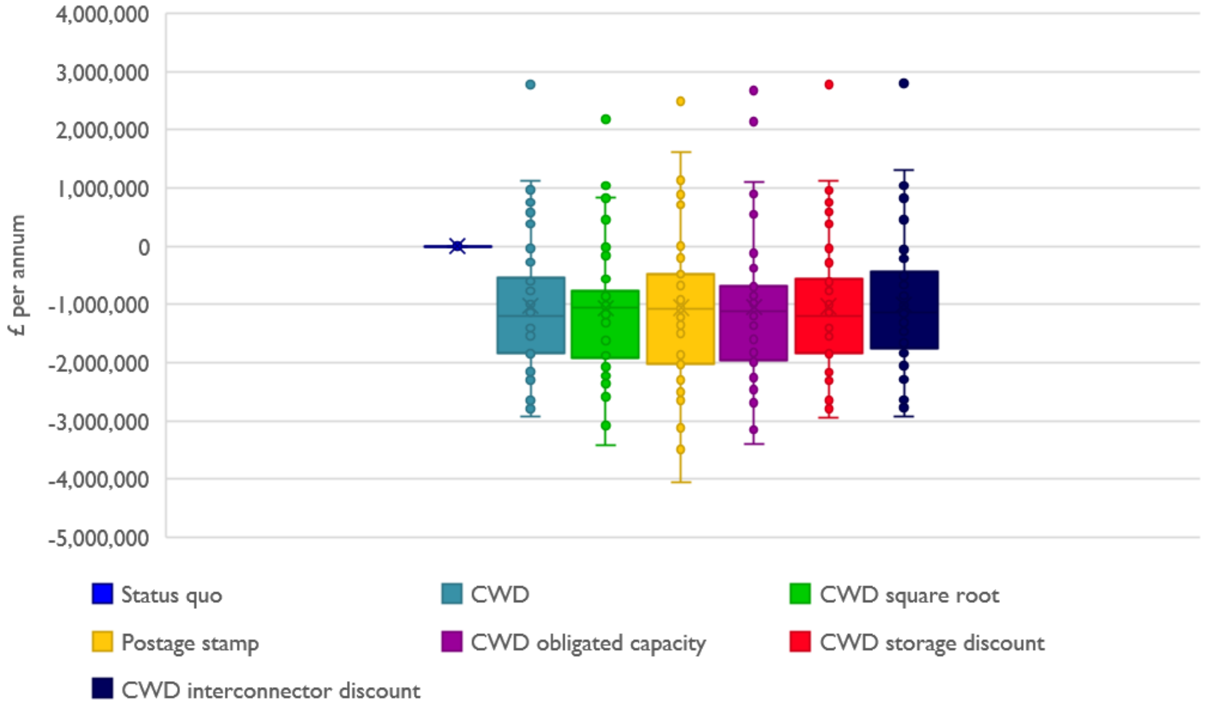


Figure 11 Differences in total entry and exit gas tariff bills between all options and the Status quo – Power station high archetype



Since tariffs shown in the charts are not demand-weighted, small differences in average tariffs can occur between options as a result of different distributions of tariffs across different exit points, even though the total revenue raised by each tariff methodology is the same. Notwithstanding this, a noticeable pattern is that all alternative tariff methodologies result in higher average tariff bills for GDN-connected users and lower average tariff bills for transmission-connected users. The reason for this is that GDNs are assumed to be under obligation to book capacity for 1-in-20 demand.[23] Under the Status quo, a large proportion of total tariff revenue is recovered from commodity charges, which are based on actual gas flows at each point. Hence, moving to a tariff methodology where all revenue is recovered from capacity charges would have the effect of increasing tariff bills for users who are subject to overbooking of capacity and reducing them for other users.

4.1.4 Impact of exit tariffs on different consumer archetypes

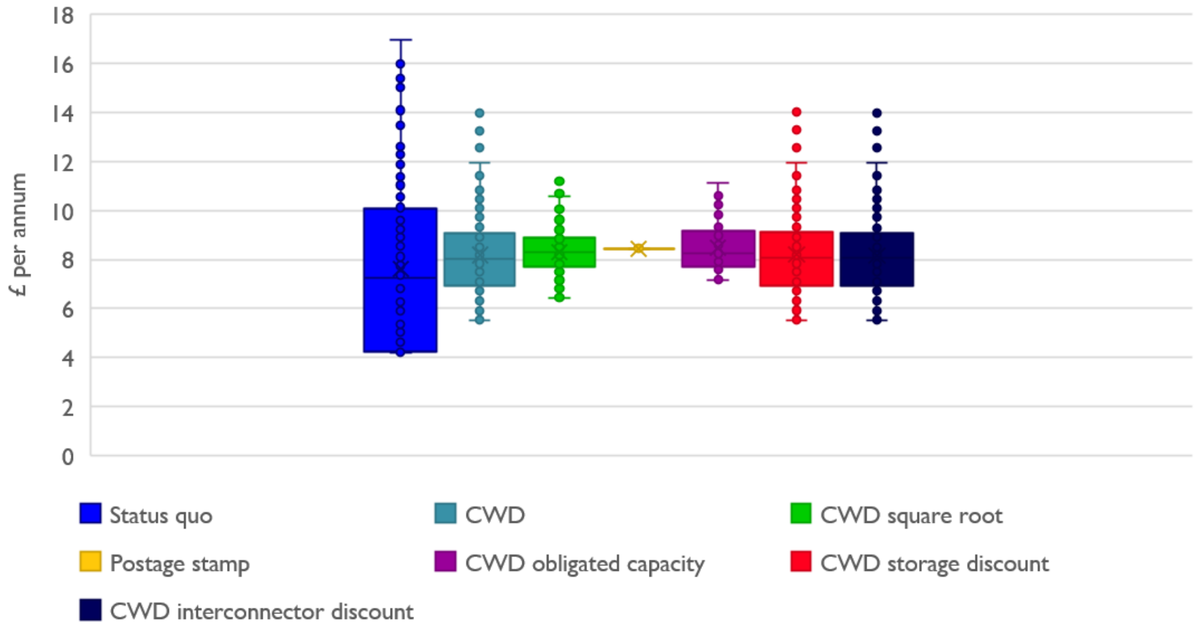
As explained in section 4.1.2, the treatment of entry tariffs in the distributional results presented in section 4.1.3 is an approximation. In practice, we would expect the pass-on of changes in entry tariffs to consumers to be sensitive to the particular conditions prevailing in the gas market in the future, which are difficult to predict. These figures are therefore subject to a degree of uncertainty. Exit tariffs are determined by charges in the gas tariff framework, and are therefore subject to less uncertainty. In this section, we present our distributional analysis based only on changes in exit tariffs under different tariff methodologies.

Residential consumers

We find that exit tariffs for Residential consumers are broadly aligned across different tariff methodologies, and the average tariff cost for the central Residential archetype is around £8 per annum. We observe the variation patterns described in Section 4.1.2, namely that CWD reduces tariff variation as compared to Status quo. Similar patterns are observed for the low and high archetypes, where annual tariff costs centre around £5 and £11 for the low and high archetypes respectively.

[23] National Grid has informed Baringa that a degree of overbooking of capacity occurs as a result of GDN's interpretation of their obligations under their standard licence conditions.

Figure 12 Exit gas transportation tariff bill – Residential central archetype



Industrial and Commercial users

For Industrial and Commercial users, tariff variation is greatest under the Status quo, reducing under CWD and disappearing under Postage stamp.

As for combined entry and exit tariffs, tariff costs are higher under alternative tariff methodologies than under the Status quo for GDN-connected Industrial and Commercial users, and lower for transmission-connected users. The reason why tariff bills are similar for the low and high Industrial and Commercial archetypes is that (i) GDN bookings are subject to an overbooking ratio of around 3, which increases tariffs paid by distribution-connected users under capacity-based tariff methodology options, and (ii) there is no overbooking of capacity by the high archetype but gas consumption is incidentally around 3 times as high as that for the low archetype.

Figure 13 Exit gas transportation tariff bill – Industrial and Commercial low archetype

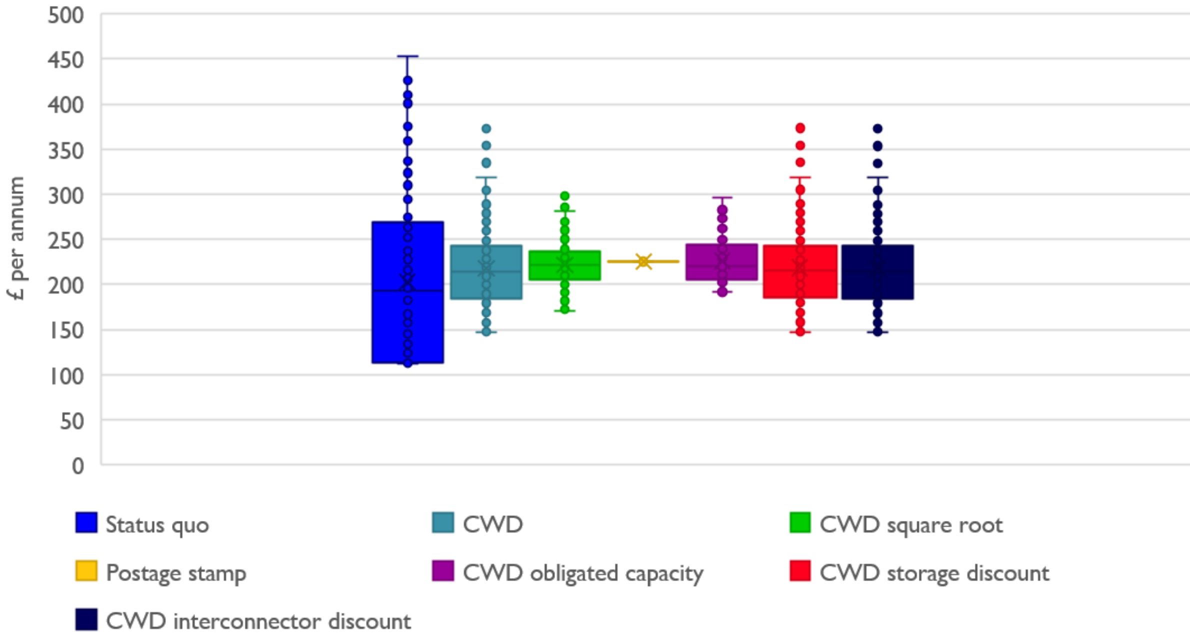
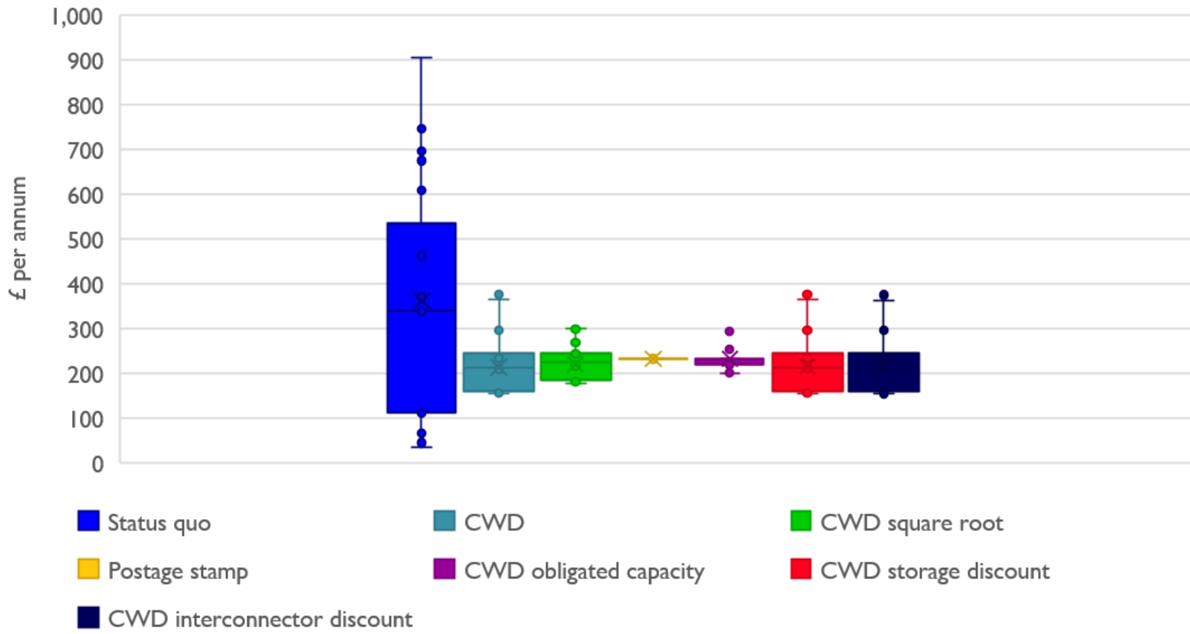


Figure 14 Exit gas transportation tariff bill – Industrial and Commercial high archetype



Power stations

For Power stations, we find that bills are likely to increase slightly for the low archetype (small GDN-connected OCGT) while bills are likely to significantly decrease from the Status quo for large transmission-connected CCGTs. As discussed above for other user types, the reason for this is the tendency for tariff methodologies based on recovering all tariff revenue from capacity charges to result in higher tariff cost for GDN-connected users, which are subject to capacity overbooking, and lower tariff cost for transmission-connected users.

Figure 15 Exit gas transportation tariff bill – Power station low archetype

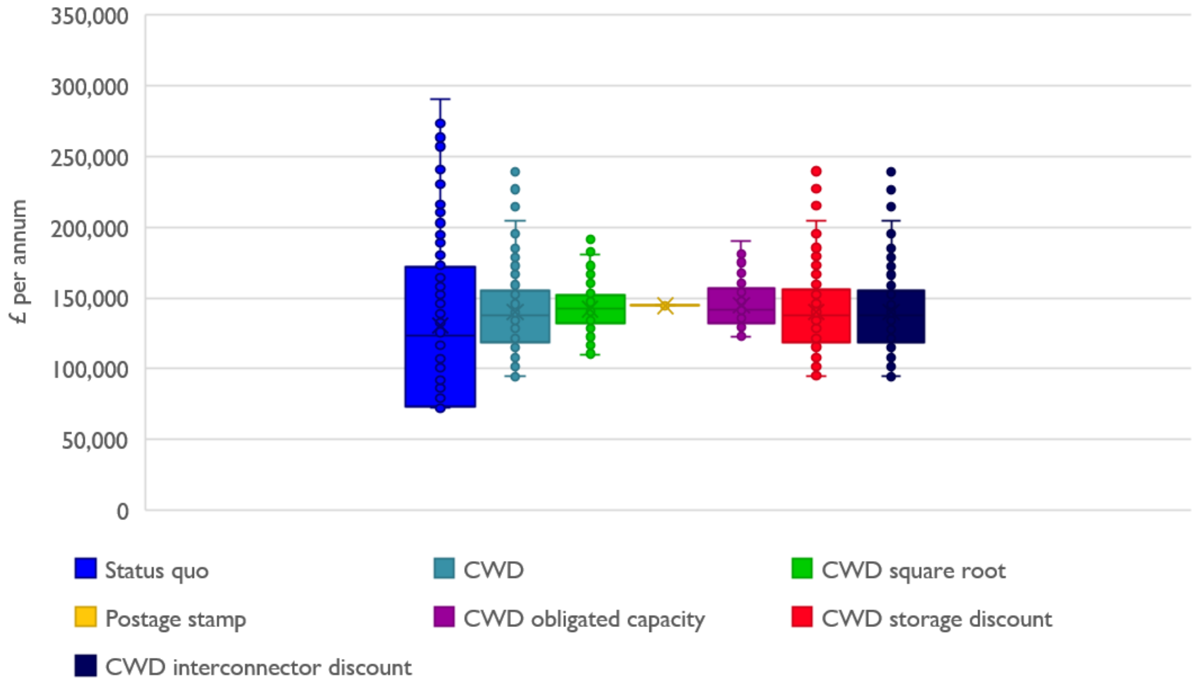
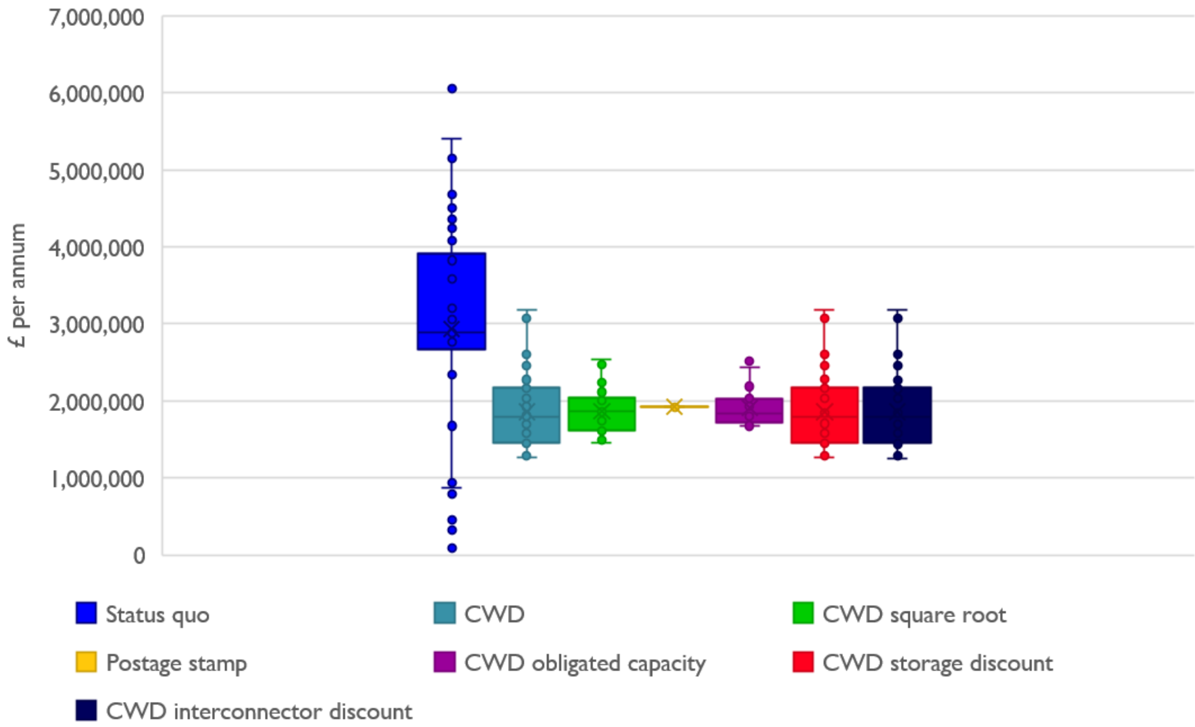


Figure 16 Exit gas transportation tariff bill – Power station high archetype



Potential impacts of changes in gas tariff methodology on existing CCGT retirement and new CCGT location are explored in Section 5.2. In terms of the potential impacts of a move to full recovery of network revenue from capacity charges, this change would be expected to favour large-scale centralised gas generation over smaller-scale distributed gas generation. Recent years have seen a considerable amount of investment in distributed generation and little investment in centralised gas generation. Moving to a tariff methodology based on full recovery of network revenue from capacity charges would be expected to counteract this trend to some degree. However, we note that the impact is likely to be small relative to the impact of Ofgem's reforms to electricity network charging, both in terms of reforms to embedded benefits that are progressing at the time of writing, and potential future reforms as part of the Targeted Charging Review and review of network access and forward-looking charging.

Storage facilities

For storage facilities, we compare the sum of unit entry and exit tariffs paid under each option. This is based on weighted average tariffs, where the tariff at each entry and exit point is weighted by corresponding flows. We sum entry and exit tariffs because gas exiting storage must have paid the entry charge at some stage and hence it is the sum of entry and exit charges that would be expected to affect storage behaviour.

Figure 17 Weighted average entry and exit tariffs for storage facilities (2021/22)[24]

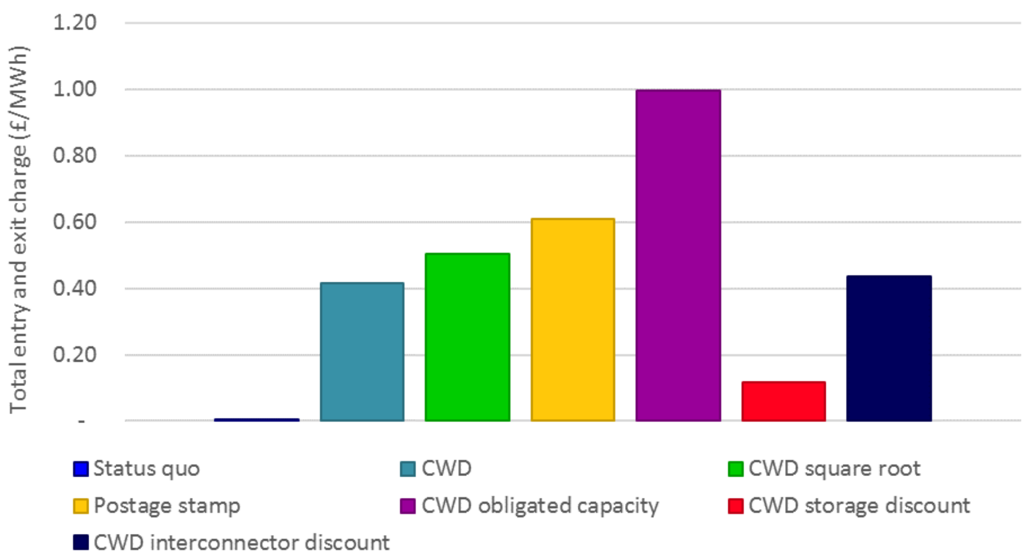


Figure 17 shows that, under the Status quo, storage is liable for the lowest exit tariff. This is mainly due to the fact that a large part of the total network revenue requirement is currently recovered from commodity charges, and storage is exempted from paying these charges. Of the alternative tariff methodology options considered in our study, total tariffs for storage facilities are lowest under the CWD storage discount option, where storage gets an 86% discount, but these are still

[24] The mapping of storage entry and exit points respectively that we have used is as follows: (i) Hatfield Moor (storage) - Hatfield Moor Max Refill; (ii) Barton Stacey - Barton Stacey Max Refill (Humbly Grove); (iii) Hornsea - Hornsea Max Refill; (iv) Cheshire – Holford; (v) Garton - Garton Max Refill (Aldbrough); (vi) Hole House Farm - Hill Top Farm (Hole House Farm); (vii) Cheshire - Stublach (Cheshire); (iix) Avonmouth - Avonmouth Max Refill

substantially higher than under the Status quo. We note that the proposed modification that includes Postage stamp tariffs also specifies an 86% tariff discount for storage. We would expect that that incorporating a higher storage discount in the context of Postage stamp tariffs would have a similar impact on the Postage stamp results above as it does on CWD results in the CWD storage discount option.

Storage exit tariffs under CWD and the CWD interconnector discount option are broadly similar. Tariffs are higher under the CWD square root option and the Postage stamp option. This is due to the geographic location of storage facilities relative to other entry and exit points having less impact under the CWD square root option and no impact under the Postage stamp option. Storage tariffs are highest under the CWD obligated capacity option. This is mostly due to the fact that revenue under-recovery under this option necessitates an additional capacity revenue recovery charge, on which storage does not get a discount. We note that if the revenue recovery charge in the enduring regime of the CWD obligated capacity option was a commodity charge and storage benefitted from similar exemptions to those applicable in the transition period, tariffs for storage under the CWD obligated capacity option would be significantly lower.

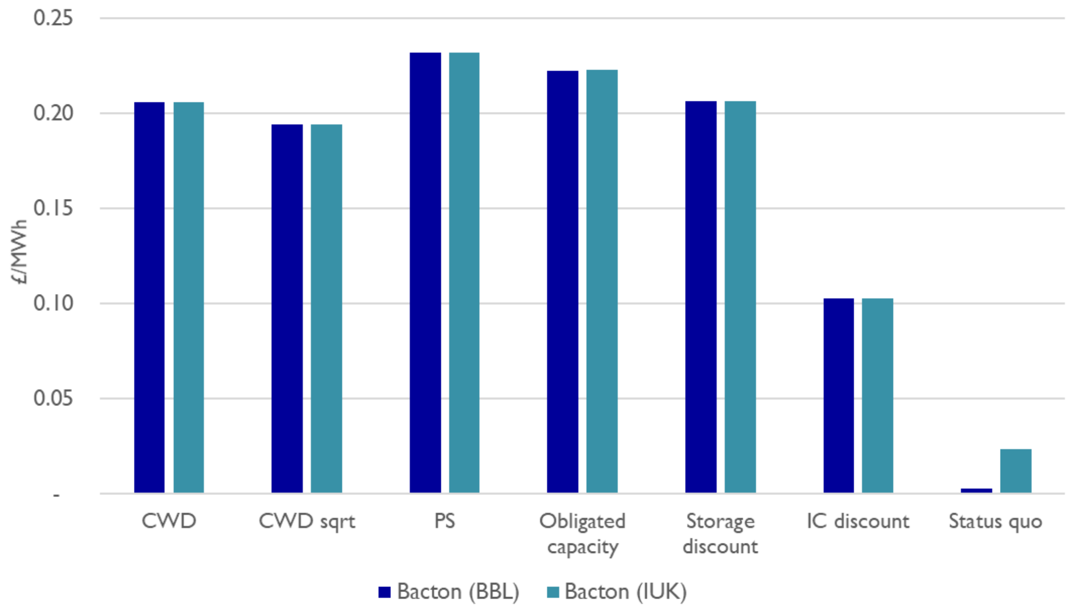
The potential impacts of differences in storage tariffs between different tariff methodologies are discussed in Sections 4.2.2, 4.2.4 and 5.4.

Interconnectors

We report exit tariffs at the two interconnection points under all options in Figure 18, noting that our analysis assumes that BBL will become bi-directional by the time the new enduring regime is in place. First, the significant tariff differential between different interconnector exit points, which is observable under the Status quo, is largely absent under the alternative tariff methodology options. This is largely due to extensive use of interruptible contracts and short-haul tariffs for BBL and Interconnector UK in the Status quo.

Second, we find that interconnector exit tariffs are significantly lower under the Status quo than under the alternative tariff methodology options. The reasons for this are the same as the reasons for significant tariff differential between different interconnector exit points. Under the interconnector discount option, tariffs are around half as high as tariffs under other options because interconnector bookings receive a 50% discount. Exit tariffs for interconnectors are similar across the other tariff methodology options.

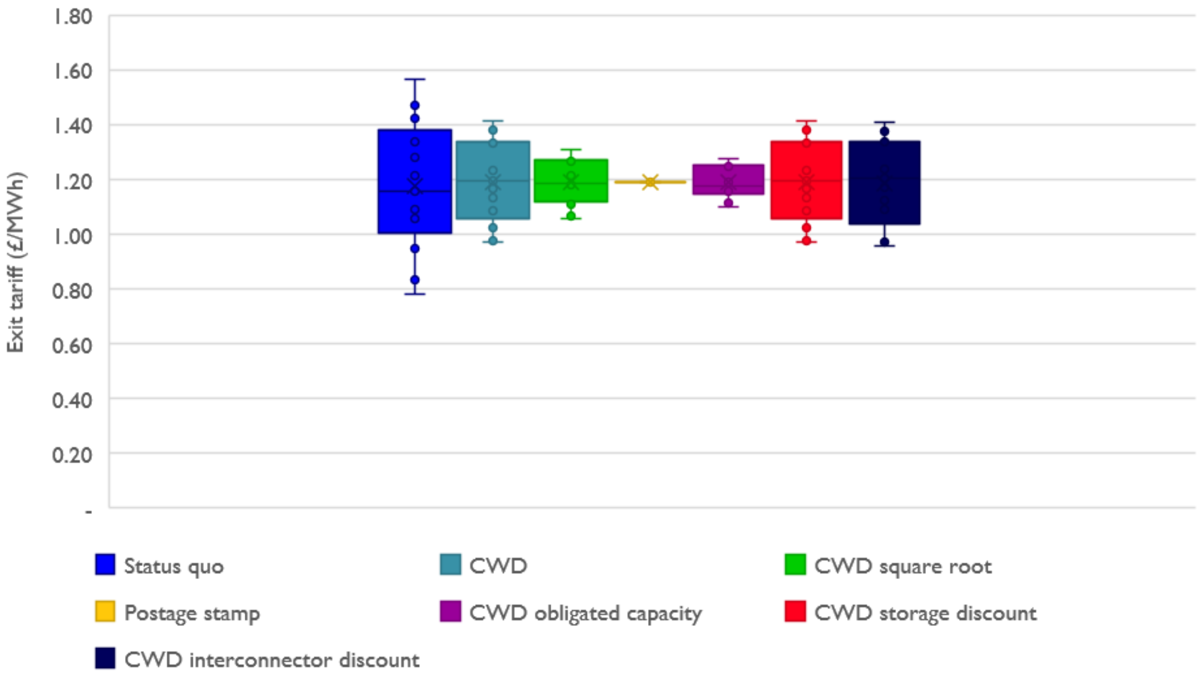
Figure 18 Exit tariffs for interconnection points (2021/22)



Regional outcomes for residential consumers

Tariff dispersion across different regions, as defined by GDN zones, is consistent with dispersion observed in total tariff bills for residential consumers presented in Figure 12. More specifically, variation across regions is significant under the Status quo and reduces under CWD. CWD variants with storage and interconnector discounts are broadly aligned with the CWD base case. Finally, tariff dispersion falls under CWD square root and CWD obligated capacity, and is zero, by definition, under the Postage stamp option. This is summarised in Figure 21 below.

Figure 19 Regional variation in exit tariffs for GDNs (2021/22)



Different tariff methodology options impact regional exit tariffs differently depending on the criteria underpinning the allocation of revenue requirements between points. Table 3 summarises the average exit tariff, weighted by demand, that is applicable in each GDN region under all scenarios. For each region, we identify the tariff methodology option under which tariffs are highest (in red) and lowest (in green). Figure 20 shows weighted average exit tariffs for GDNs grouped under wider regions (Central, North, Scotland, South and South West &Wales) under all tariff methodology options. [25]

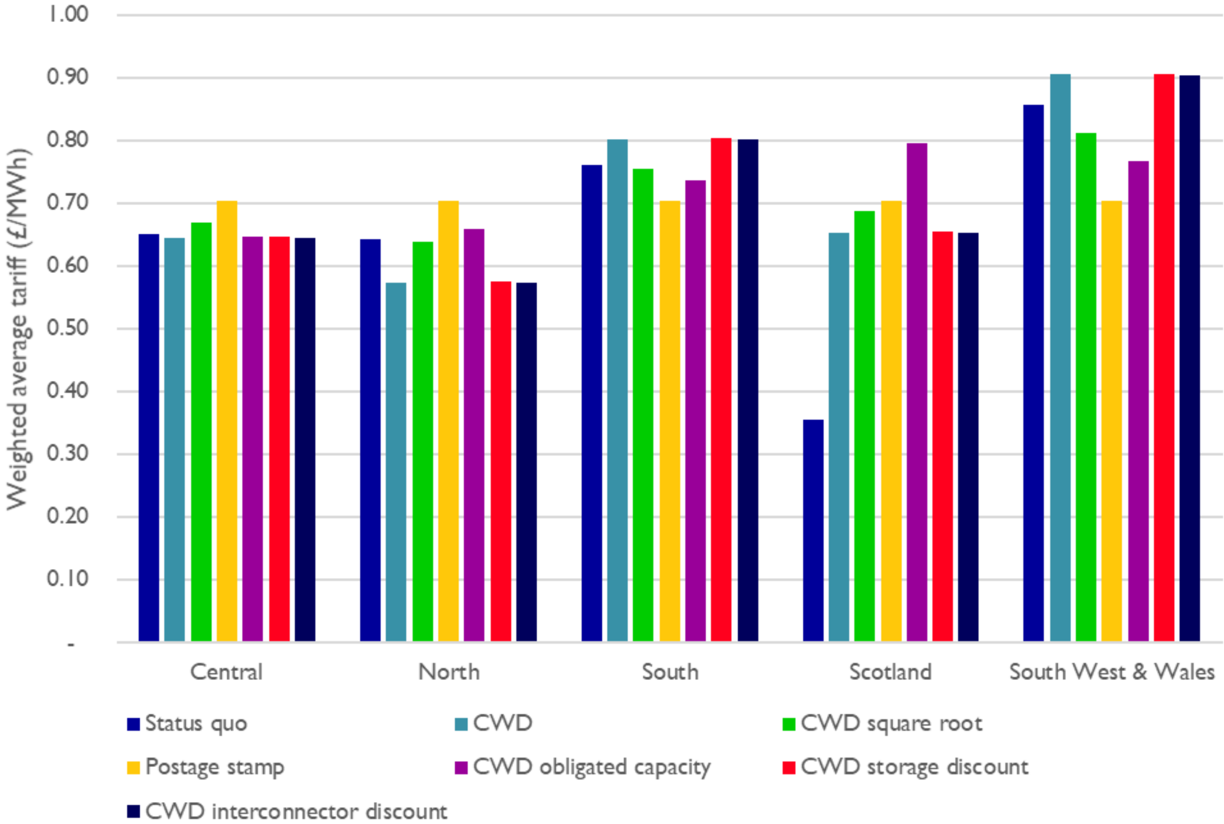
[25] East Anglia, East Midlands and West Midlands are grouped under 'Central'; North East, Northern and North West are grouped under 'North'; Scotland is the only GDN under 'Scotland'; North Thames, South East and Southern are grouped under 'South'; and South West, North Wales and South Wales are grouped under 'South West & Wales'.

Table 3 Weighted average exit tariffs by GDN in £/MWh (2021/22)

Region	Status quo	CWD	CWD square root	Postage stamp	CWD obligated capacity	CWD storage discount	CWD interconnector discount
EA	0.56	0.69	0.69	0.70	0.68	0.69	0.69
EM	0.61	0.59	0.63	0.70	0.62	0.59	0.59
NE	0.46	0.47	0.57	0.70	0.61	0.47	0.47
NO	0.37	0.51	0.59	0.70	0.67	0.51	0.51
NT	0.66	0.73	0.72	0.70	0.70	0.73	0.73
NW	0.88	0.66	0.70	0.70	0.68	0.66	0.66
SC	0.35	0.65	0.69	0.70	0.80	0.65	0.65
SE	0.73	0.85	0.78	0.70	0.76	0.85	0.85
SO	0.95	0.86	0.79	0.70	0.76	0.86	0.86
SW	1.10	0.94	0.83	0.70	0.79	0.94	0.94
WM	0.79	0.68	0.70	0.70	0.65	0.68	0.68
WN	1.01	0.73	0.74	0.70	0.69	0.73	0.73
WS	0.60	0.91	0.81	0.70	0.76	0.91	0.91

Note: The weight used to compute a regional tariff is the modelled exit flow at each point under the corresponding tariff methodology option. Hence, regional tariffs presented in the table place a higher weight on tariffs applicable at large exit points.

Figure 20 Weighted average exit tariffs by region in £/MWh (2021/22)



Note: The weight used to compute a regional tariff is the modelled exit flow at each point under the corresponding tariff methodology option. Hence, regional tariffs presented in the figure place a higher weight on tariffs applicable at large exit points.

Regions in which Status quo tariffs are particularly low – reflecting a low cost of network reinforcement at the margin – generally face significant tariff increases when moving to alternative tariff methodology options which spread network cost more evenly across exit points, such as Postage stamp and CWD obligated capacity. For example, significant increases occur in East Anglia (EA), North East (NE) and Northern (NO) regions when moving from Status quo to a Postage stamp methodology. Conversely, regions where Status quo tariffs are high benefit from the move to a methodology that reduces tariff dispersion across the system. For example, significant tariff reductions occur in Southern (SO) and South West (SW) regions when moving to Postage stamp, and in West Midlands (WM) and Wales North (WN) when moving towards CWD obligated capacity. This reflects the effect of reduction in tariff differentiation. Changes between Status quo and CWD are more modest since some of the main factors that influence tariffs under the Status quo are a function of capacity and distance, which are the determinants of tariffs under the CWD tariff methodology.

Second, we find that tariffs under the CWD, CWD storage discount and CWD interconnector discount options are very similar. It follows that storage and interconnector discounts do not lead to significant distributional differences on exit tariffs across regions as compared to the CWD base case. More significant distributional differences occur when comparing CWD to CWD square root, Postage stamp and CWD obligated capacity.

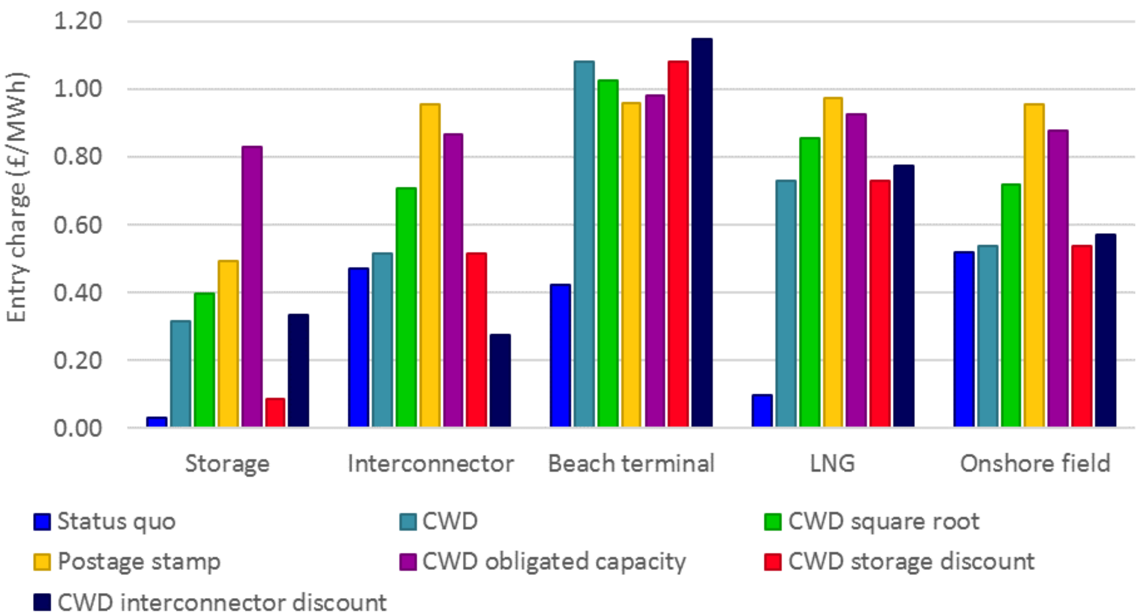
Third, we find that regions with relatively low tariffs under CWD, which benefit from their relative proximity to large entry points, face higher tariffs when the weighting on distance falls as in CWD square root and Postage stamp options. This is the case for North East (NE) due to the presence of the Easington terminal, for Scotland (SC) due to the presence of the St Fergus terminal, and more generally for other regions in the East of the country. Conversely, regions in the South[26] and in the West,[27] more remote from large entry points, benefit from tariff methodology options placing a lower weighting on distance to large entry points.

Finally, tariff differences and distributional impacts between CWD and CWD obligated capacity options stem from differences in the relative shares of each region in total obligated capacity and in forecasted bookings. Regions in which CWD obligated capacity tariffs are higher than under the CWD case tend to have a higher share of obligated capacity than of actual bookings. Conversely, regions in which CWD tariffs are higher tend to have a higher share of forecasted bookings than of obligated capacity.

4.1.5 Comparison of entry tariffs

The estimated distribution of charges for new bookings across different types of entry point is shown in Figure 21 for the Status quo and the modelled alternative tariff methodologies.

Figure 21 Average unit entry charges for new contracts weighted by entry flows (2021/22)[28]



Overall, while the distribution of tariffs between different entry points varies significantly across different tariff methodologies, there are two factors that cut across these distributional differences.

---

[26] South East (SE), Southern (SO), and South West (SW).

[27] West Midlands (WM), Wales North (WN) and Wales South (WS).

[28] Tariffs at different entry points are weighted by the corresponding flows at those points. Hence, if any entry point has zero flows under a given tariff option, the tariff at that point does not contribute to the average. The figure shows charges for new capacity contracts.

First, because determination of tariffs broadly involves dividing up the revenue requirement by bookings or flows, methodologies that result in greater exports from GB via interconnectors will result in lower entry and exit charges since the same revenue amounts are spread across a greater quantity of bookings and flows. In our modelling, the Postage stamp methodology is estimated to result in the lowest level of interconnector exports on average across the different modelled scenarios and years, whereas the CWD with interconnector discount option results in highest interconnector export flows.

Second, the Status quo has a lower level of entry tariffs for new contracts than alternative tariff methodology options when calculated on a flow basis.[29] The reasons for this are subtle and worth setting out clearly. Each tariff methodology option, including the Status quo, assumes that historical capacity contracts would be kept whole. This means that holders of existing contracts would pay capacity charges as defined in their existing contracts as opposed to capacity charges calculated under the new regime i.e. without any increase in capacity charges relating to their existing contracts to account for revenue recovery. They would also be subject to commodity charges if such charges form part of the charging regime. Because a large proportion of revenues are recovered from commodity charges under the Status quo, recovery of the remaining revenue requirement once capacity charges for existing and new contracts have been paid falls on all contracts (existing and new).[30] Under alternatives to the Status quo in the enduring period, there is no commodity charge, and new capacity bookings have to pay for all remaining revenue requirement after revenue from existing contracts has been taken into account. Tariffs for new capacity bookings under alternative tariff methodology options are therefore more expensive than new capacity bookings under the Status quo.[31] This is a temporary effect that would only hold in the years covered by historical contracts, although some contracts extend well into the period of the enduring regime.

More detailed observations are set out below.

Storage

Under the Status quo, storage facilities pay very low tariffs due to the fact that they are exempt from commodity charges and interruptible capacity is free. The exemption from commodity charges extends into the transition period under the modelled options, but not the enduring period as shown in Figure 21. Storage faces the lowest entry tariffs when there is a specific storage discount, and the highest tariffs under the CWD obligated capacity option. The reasons for this are set out in Section 4.1.4.

---

[29] For the Status quo, entry tariffs presented in Figure 21 are the sum of capacity and commodity charges. For alternative options, entry tariffs presented in Figure 21 correspond to capacity charges only (which includes the capacity-based residual charge in the case of CWD obligated capacity). There is no commodity-based charge in any of the alternative tariff methodology options. All values are expressed in £/MWh of flow terms.

[30] To put this effect into context, for 2021/22 in our modelling, after revenue from historical entry capacity contracts is taken into account, nearly 90% of the remaining revenue from entry is recovered from commodity charges in the Status quo. This gives a sense of the scale of the implied discount to existing capacity contract owners as a result of moving to a tariff methodology that is based on recovering revenue exclusively from capacity contracts and keeps historical contracts whole.

[31] Note that we calculate entry capacity tariffs for new capacity bookings. This is based on the principle that market prices are based on the marginal cost of transactions rather than average cost. Hence, prices paid for historical capacity contracts only affect entry tariffs through their effect on the residual network revenue requirement.

Interconnectors

We project that interconnector entry tariffs are lowest under the CWD interconnector discount option, and highest under the Postage stamp option. The difference in tariffs between these two options is a factor of three. Much of this difference is explained by the 50% tariff discount granted to interconnector tariffs under the CWD interconnector discount option. The rest of the difference is explained by the relative proximity of interconnector entries to demand, which makes tariffs derived using the CWD methodology lower than the flat tariff under the Postage stamp option, and by the fact that Postage stamp sees the lowest exports of all the tariff options, which means that entry tariffs must be smeared over a smaller amount of bookings and are hence higher on a unit basis.

Beach terminals

Our analysis shows that average entry tariffs for beach terminals are likely to be similar under the proposed alternatives. All of them are likely to be higher than under the Status quo given historical booking behaviour, tariffs, and availability of the short-haul option under the Status quo.

LNG

LNG import terminals are estimated to face similar charges under the proposed alternative options, which are all higher than under the Status quo. LNG faces slightly higher charges under the Postage stamp, CWD square root, and CWD obligated capacity options. This is because LNG entries are closer to demand in relative terms than the average for other entry points, and hence methodologies that penalise distance from demand less heavily than CWD (e.g. CWD square root or Postage stamp) result in higher tariffs at LNG entry points.

4.2 Wider system impact analysis

4.2.1 Overview

This section sets out the results of our assessment of the wider system impacts of changing the gas transmission charging methodology. The assessment is based on a combination of tariff modelling carried out using adapted National Grid tariff models and wholesale gas market modelling using Baringa's gas market model, and using the process described in Section 3.1. The summary of the wholesale scenarios used in our modelling is presented at Appendix B. We also evaluate certain aspects of gas tariff methodologies on a qualitative basis.

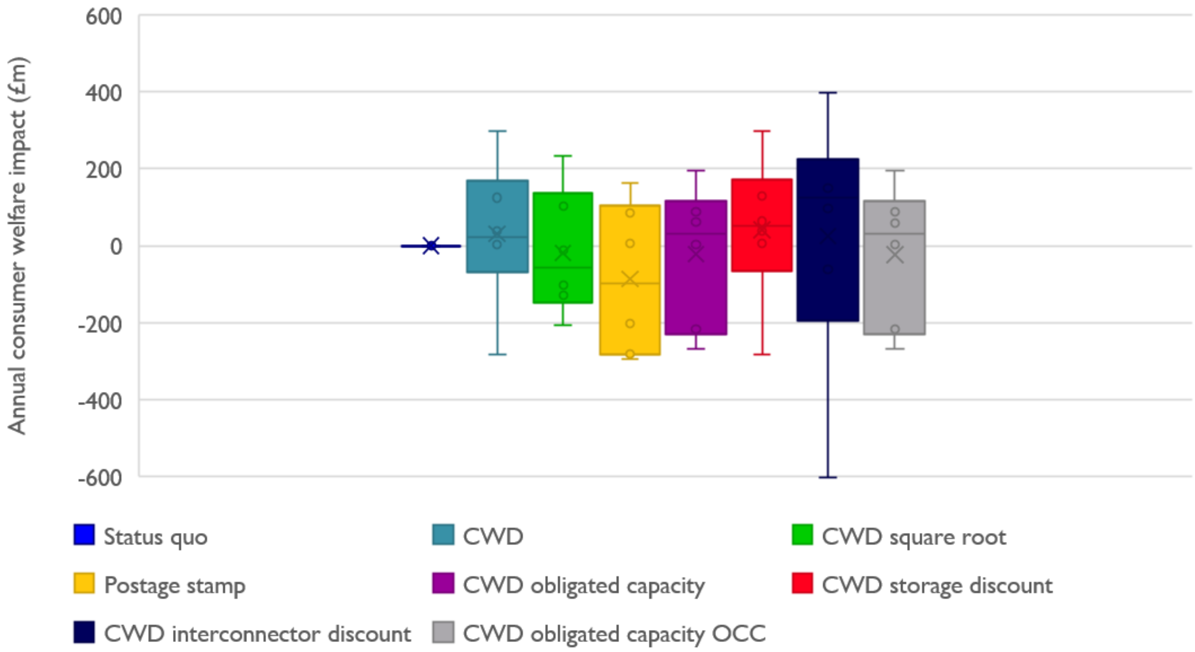
The impact of a change in the tariff charging methodology is assessed by comparing key market indicators and welfare metrics obtained from two model runs that are based on identical assumptions with the exception of those pertaining to the gas tariff methodology. Differences between these model runs arise from differences in tariffs payable at different entry and exit points and the dynamic price response of the supply and demand behind those points, including storage, as captured by our gas market model.

Analysis of wider system impacts is undertaken in the context of several gas market scenarios. The underlying assumptions and key market metrics for those scenarios are described in Appendix B. This is done in order to test the dependency between the scenario assumptions and results of the wider system impacts analysis and to test the robustness of those results. Analysis is undertaken for the years 2020/21, 2021/22 and 2030/31 in order to test the effect of changes in tariff methodology across periods covering the transitional arrangements, the beginning of the new enduring regime, and the enduring regime in a more distant future period.

4.2.2 Consumer welfare results

Figure 22 shows a summary of estimated annual differences in consumer welfare relative to the Status quo across seven different tariff methodologies (as listed in the legend of Figure 22), three modelled years (2020/21, 2021/22 and 2030/31) and four market scenarios (Baseline, NCS, Inelastic interconnector, and Two Degrees).[32] Each bar corresponds to a given tariff methodology that is evaluated relative to the Status quo. The range of values covered by each bar corresponds to the range of estimated consumer welfare impacts across the different combinations of modelled market scenarios and spot years. The results are given in table format in Table 11 of Appendix A.

Figure 22 Summary of consumer welfare analysis – comparison against Status quo



The major components of consumer welfare that make up the total consumer welfare impact are the change in the cost of gas consumed and the change in the value of demand served. Of these two components, changes in the total cost of gas consumed tend to account for the bulk of the estimated welfare impacts in the vast majority of modelled scenarios, years and tariff methodologies.

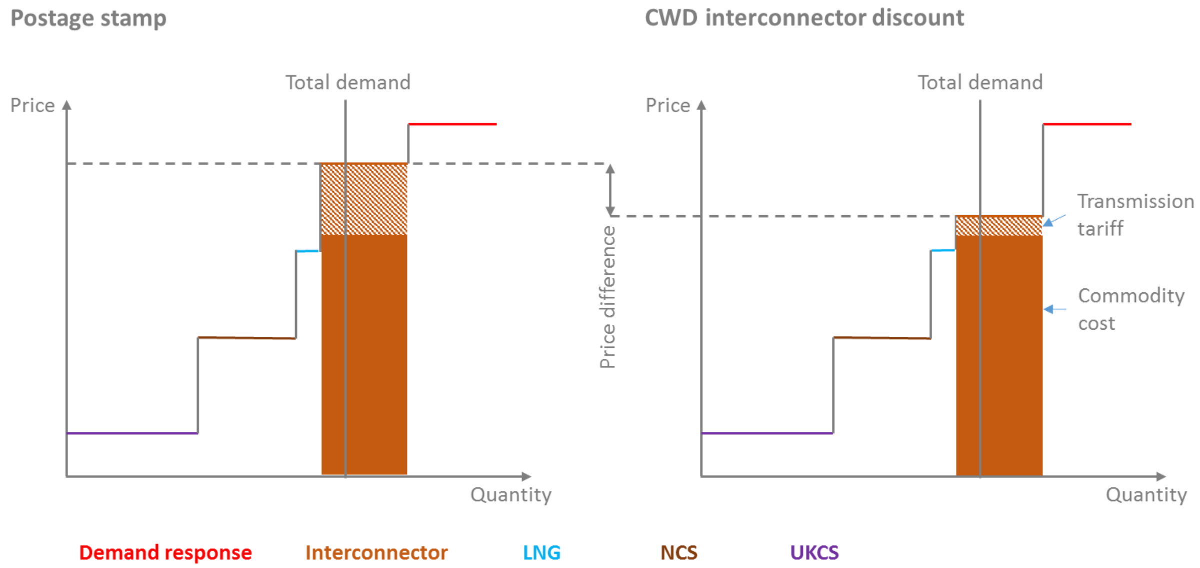
In order to understand the results, it is important to consider the mechanism by which the greatest component of the welfare impact – change in the cost of gas consumed – is estimated in the model. The system cost of gas is determined in the optimisation model on a daily basis as the cost of accommodating one additional unit of demand. This is generally the cost of an incremental increase in supply or reduction in other demand. Gas entry tariffs are a component of cost of every supply source. The gas market model works on the assumption that the gas market is a uniform price

[32] Only the Baseline scenario is modelled for year 2020/21, whereas Baseline, NCS and Inelastic interconnector scenarios are modelled for 2021/22, and Baseline and Two degrees scenarios are modelled for 2030/31.

market and the system price is determined by the marginal cost of the highest cost supply source that is required to clear the market. Hence, when the tariff paid by the marginal supply source changes, this will flow directly into the price paid by all demand unless the marginal supply sources changes as a result of the tariff change.

Figure 23 illustrates the dynamic described above.

Figure 23 Illustration of the model price formation process



In our modelling, using 2021/22 as an example, entry tariffs for Bacton IP are 2.80 p/th and 0.80 p/th on a flow basis under the Postage stamp and CWD interconnector discount tariff methodologies respectively. This difference implies that if Bacton IP remains the marginal supply source throughout the modelled year, the annual cost of gas would be around £561m lower in 2021/22 under the CWD interconnector discount tariff methodology than under the Postage stamp methodology. In our modelling, the estimated difference in the total annual cost of gas between the Postage stamp and CWD interconnector discount methodologies for 2021/22 under the Baseline scenario is in fact £400m, since although our tests of modelling results suggest that Bacton IP is indeed the marginal supply source for much of the modelled year in those model runs, that is not always the case. This can be seen in Figure 26 in Appendix B, which presents gas flows and prices under the Baseline scenario and shows that interconnector imports flow during the warmer months but are pushed out of the merit order during the winter months.[33]

In order for different model runs to be comparable for the purposes of welfare analysis, the total tariff revenue in each run equals the total revenue requirement. This is achieved by iterating the gas market and tariff models as described in Section 3.1. The implication of this is that lower tariffs for one entry point must mean higher entry tariffs for other entry points. It follows that in a scenario where Bacton IP is not the marginal supply source, granting a discount to interconnector entries

[33] For 2030/31 under Baseline scenario assumptions, Bacton IP entry sees the highest unit entry tariff under the Status quo. Accordingly, Status quo is estimated to result in lower consumer welfare than all of the alternative tariff methodology options.

would increase the tariff on the marginal supply source and thus increase the system price for all demand.

The relationship between entry tariffs and wholesale price projections described above explains the reason why estimates of the difference in consumer welfare between the Status quo and alternative tariff methodologies vary to such a significant degree between different modelled scenarios. Changes in market scenario assumptions often change the supply source that sets the system price. Because of the 'waterbed' effect by which decreases in some tariffs must be accompanied by increases in other tariffs, a change in the marginal supply source can turn a positive consumer welfare effect of a tariff change into a negative one. Because such changes affect all consumers, the magnitude of the consequent changes in consumer welfare can be very large.

Overall, none of the modelled tariff methodologies are seen to achieve a clear improvement or deterioration in consumer welfare relative to the Status quo under a broad range of modelled scenarios. Depending on the modelled market scenario or spot year, any change in the tariff methodology from the Status quo can result in an estimated improvement or deterioration in consumer welfare. CWD square root option appears to have the lowest variation in results while CWD with interconnector discount has the highest level of variation. It is not possible to conclude with any degree of certainty from these results alone which of the alternative tariff methodologies under consideration are more likely to lead to an improvement in consumer welfare.

Additionally, we note that the ranges of consumer welfare changes from the Status quo, as shown in Figure 22, do not necessarily provide firm guidance on what may be the least risky choice of tariff methodology from the perspective of consumers. For example, CWD appears to have a relatively narrow range of outcomes compared to Postage stamp. However, this is likely to be due to the fact that tariffs under the Status quo and CWD tariff methodologies are more similar than tariffs under the Status quo and Postage stamp tariff methodologies. In absolute terms, flat Postage stamp tariffs are less likely to accentuate any effect of changes in market conditions on consumer prices than other tariff methodologies. This is because any change in the marginal supply source as a result of changes in market conditions would not result in a change in tariffs being paid by the marginal supply source. This would not be the case for tariff methodologies characterised by tariff differentiation, where a change in the marginal supply source as a result of changes in market conditions may result in the tariff paid by the marginal supply also being higher or lower than the tariff being paid by the supply source that was marginal previously. Postage stamp could therefore be expected to produce more stable outcomes for consumers across different sets of gas market conditions.

Finally, it must also be noted that changes in prices paid by consumers are matched by changes to prices received by producers. In particular, if the system gas price falls due to a reduction in the entry tariff paid by the marginal supply source, this change is profit-neutral for the marginal supply source. However, infra-marginal suppliers, defined as suppliers whose marginal cost is below that of the marginal supply source, experience a decrease in revenue with no corresponding decrease in cost. The welfare benefit experienced by consumers in this case is a transfer of producer benefit rather than a gain in net welfare. Hence, in a system where there is no change in infrastructure investment or retirement as a result of changes in the tariff methodology, the overall net welfare effect of changes in gas tariff methodology is not expected to be significantly different from zero, with the majority of any gains and losses for consumers under a given scenario expected to be matched by corresponding losses and gains for producers. Once changes in infrastructure investment and retirement are taken into account over the longer-run, changes in gas tariff methodology may generate larger net welfare gain or losses as tariffs influence the overall efficiency of the gas system.

4.2.3 Interpretation of consumer welfare results

The results of Baringa's wider system analysis show that the expected consumer welfare impact of alternative gas tariff methodologies is highly dependent on which entry point represents the marginal price-setting supply source. This is inherently uncertain as our exploration of different scenarios demonstrates, and therefore the interpretation of the results needs to recognise this.

Notwithstanding the fact that it is not possible to predict the future of the European and global gas markets with confidence, it is possible to extract useful messages from the modelling results. A marginal supplier in our modelling framework is one that is likely to have a relatively high elasticity of supply. That is, a relatively small change in the system gas price can make the difference between that supply source flowing and not flowing. Our results show that levying higher charges on such suppliers is likely to be detrimental to consumer welfare. Notably, this corresponds to guidance from economic theory, and in particular the concept of Ramsey pricing, which suggests that the most efficient way to allocate revenue recovery charges is in inverse proportion to elasticity of supply. This is based on the principle that revenue recovery charges should have minimal economic incentive effects.[34]

Considerations of which supply sources are more likely to be marginal include the following points.

- **Interconnectors** undertake arbitrage between connected markets and can generally be expected to be price-elastic if the markets they connect are similar. However, they can also be used as part of an overall transit route by producers whose marginal cost of production is much lower than the NBP gas price. Hence, different parts of interconnector entry flow may have quite different elasticities of supply.
- **UKCS** supply can generally be expected to be less price-elastic in the short-term as it is largely captive to the GB market. However, with UKCS production in decline, many UKCS suppliers may be operating on thin margins, which would make their supply price-elastic in the medium and longer-term if it results in field closures.
- **NCS** supply can be expected to be more price-elastic than UKCS supply given that it has a greater degree of discretion over the market which it enters. Potentially, this discretion could mean that price elasticity of NCS supply may be similar to that of an interconnector as noted above. However, network constraints could also limit this discretion to a significant degree.
- **LNG** supply can be expected to have a significant degree of discretion over which market to enter, particularly at times of tight supply-demand balance.
- **Storage** supply elasticity can be expected to vary with market conditions and the amount of gas in storage relative to the seasonal average.

Overall, apart from supply sources that are clearly captive to the GB market, it is difficult to predict which ones are likely to have consistently higher or lower supply elasticity than the average. Hence,

[34] We note that incentive effects of network charges may be desirable to signal appropriate economic decisions by network users where those decisions can affect network costs. However, with gas demand declining and expansionary investment in network capacity unlikely, such signals are unlikely to be required.

considerations of pass-on of entry charges and the effect on consumer welfare do not provide clear guidance for the choice of gas transmission tariff methodology.

4.2.4 Effect of tariff methodologies on entry flows

Sections B.2 to B.5 of Appendix B set out the effect of scenario assumptions on gas flows in the GB energy market. Our wholesale market modelling also enables us to estimate the effect of differences in entry tariffs on the distribution of flows across different entry points. In this section we explore key trends in changes of entry flows across different tariff model options. While this does not constitute full analysis of consumer welfare, it does nonetheless allow for some conjecture on which tariff models are likely to be favourable or detrimental to certain supply sources.

This section should be read in conjunction with Section 4.1.5, which compares entry tariffs across the different tariff methodology options.

Table 4 shows changes in UKCS and NCS supply under different scenarios and tariff methodologies relative to the Status quo. Since alternatives to the Status quo see higher entry charges for beach terminals, they generally see lower entry flows from beach terminals. This is especially pronounced under the NCS scenario where price elasticity of entry flows on Easington and St Fergus terminals is equivalent to that of the interconnectors. A discount for bi-directional interconnectors accentuates this pattern further.

Table 4 Changes in UKCS and NCS supply compared to Status Quo (mcm/year)

Change in GB and Norway supply (mcm)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	9	12	-152	-5,225	0	-35
CWD	-31	-41	-109	-6,881	0	-35
CWD square root	-8	-16	-134	-3,148	0	-35
CWD obligated capacity	-76	38	-144	-2,803	0	-37
CWD obligated capacity OCC	-30	38	-144	-2,803	0	-37
CWD interconnector discount	-58	-74	-92	-17,628	-53	-15
CWD storage discount	-49	-70	-110	-6,894	0	-35

As with entry flows from beach terminals, Table 5 shows that higher entry tariffs for LNG see lower LNG flows under all alternative tariff methodologies. This is most pronounced under the Inelastic interconnector scenario, which sees higher price elasticity of LNG import flows.

Table 5 Changes in LNG supply (mcm/year)

Change in LNG supply (mcm)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	-170	-473	-1,767	-78	-500	-229
CWD	-167	-482	-1,102	-846	-785	-229
CWD square root	-183	-482	-1,334	-777	-719	-229
CWD obligated capacity	-183	-482	-1,721	-793	-523	-229
CWD obligated capacity OCC	-57	-482	-1,721	-793	-523	-229
CWD interconnector discount	-183	-482	-941	-1,002	-740	-229
CWD storage discount	-183	-482	-1,124	-843	-785	-229

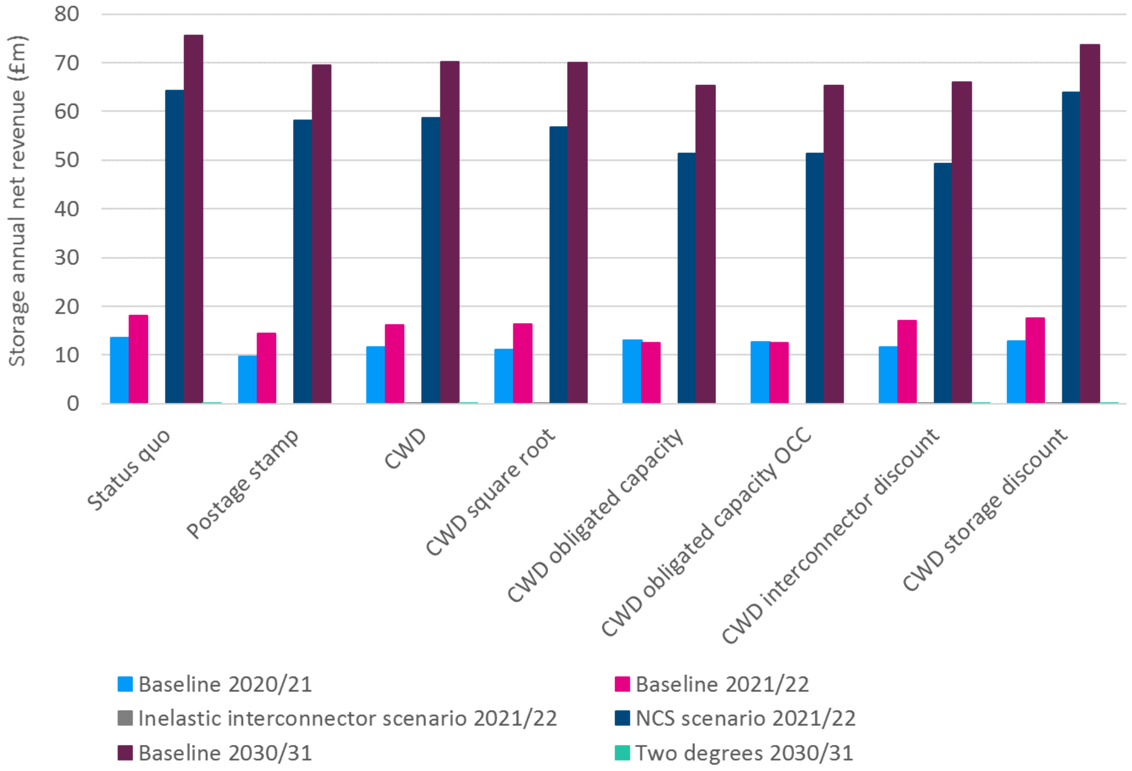
Table 6 shows that greater interconnector imports offset lower entry flows from other sources under the alternative tariff methodologies. This is especially pronounced under the NCS scenario where price elasticity of entry flows on Easington and St Fergus terminals is equivalent to that of the interconnectors. A discount for bi-directional interconnectors accentuates this pattern further.

Table 6 Changes in interconnector supply (mcm/year)

Change in interconnector supply (mcm)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	-7	325	0	5,259	539	1,181
CWD	247	550	0	7,627	1,001	2,946
CWD square root	138	462	0	3,860	767	2,203
CWD obligated capacity	294	360	0	3,540	567	1,446
CWD obligated capacity OCC	123	360	0	3,540	567	1,446
CWD interconnector discount	338	651	0	18,408	2,208	4,574
CWD storage discount	287	619	0	7,638	1,000	2,909

Finally, Figure 24 shows modelled net storage revenues under different combinations of scenario assumptions and tariff methodology assumptions. Broadly, they show that the Status quo is the most favourable scenario for storage, with CWD incorporating a higher discount for storage being only marginally less favourable. The estimates also show that broader gas market conditions have a much greater degree of influence on storage net revenues than variations in gas tariff methodology.

Figure 24 Storage net revenues



5 Investment and closure analysis

5.1 Overview

The potential longer-term dynamic effects of changes in entry and exit tariffs is closure of existing infrastructure or change in location of new infrastructure that is part of the gas value chain. We have undertaken a separate assessment of how changes in gas transmission network charges could affect the location or closure decisions of CCGTs, gas interconnectors, and gas storage facilities.

We have not undertaken a review of closure and location decisions of LNG terminals since we do not expect the tariff costs at LNG entries to be material relative to the other variable costs of the LNG transport and regasification process. Likewise, we have not undertaken analysis of closure decisions by offshore gas fields since assessing the economics of individual fields was outside the scope of this study.

5.2 CCGT generators

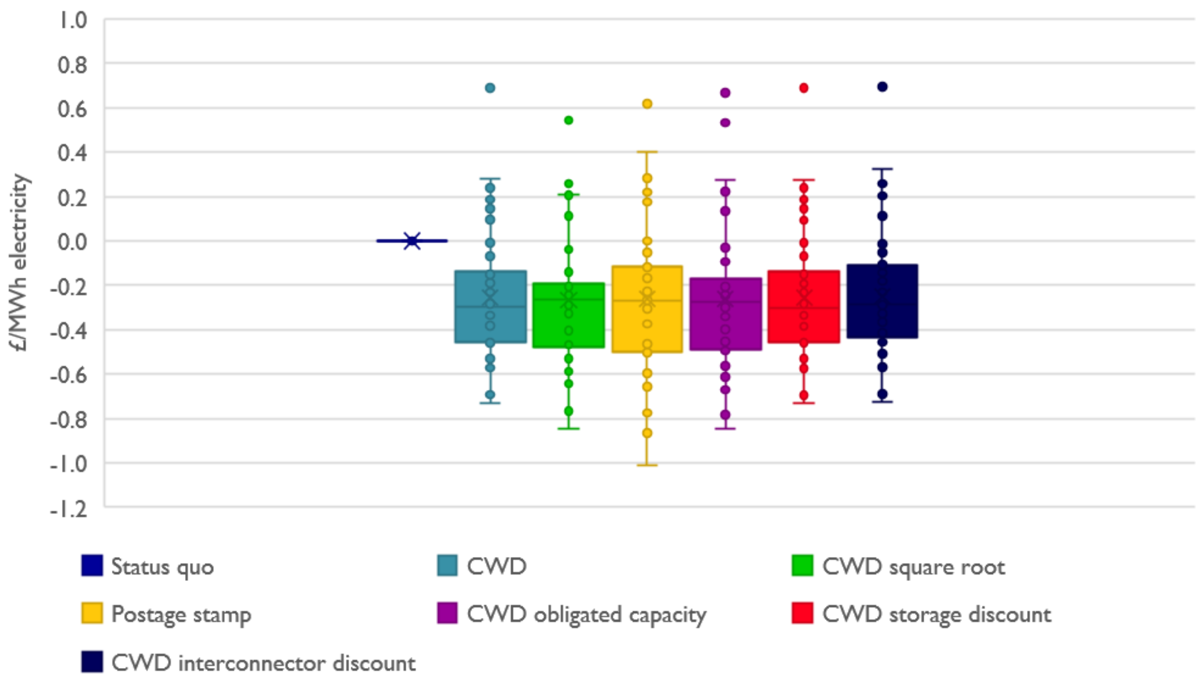
5.2.1 Impact on plant closure

To determine whether the likelihood of closure for a mid-merit CCGT could be significantly different under different tariff methodologies, we compare differences in exit charges to estimates of the clean spark spread (gross profit margin) for such generators. The comparison is carried out in units of £/MWh of electricity rather than gas in order to compare changes in gas tariff cost to benchmark gross profit margins and Transmission Network Use of System (TNUoS) charges. We note that existing generators act as price takers in the capacity auction, and hence the only potential change in their bidding strategy is whether they bid or not.

We find that median tariffs for transmission-connected Power stations fall by about £0.2/MWh of electricity in the alternative tariff methodologies compared to the Status quo. This is driven by the change to recovery of tariff revenues exclusively through capacity charges, which reduces charges for users that are not subject to overbooking of exit capacity. Variation in charges is relatively small, between around £ -1 to £+0.5/MWh electricity.[35] This is shown in Figure 25 below, which plots the change in tariffs (minimum, 25th percentile, median, 75th percentile and maximum) relative to the Status quo, per MWh of electricity. Negative values indicate a reduction in exit tariffs, and positive values indicate an increase in exit tariffs.

[35] This compares to average electricity prices of around £44/MWh in 2017.

Figure 25: Changes in tariffs for a transmission-connected Power station (49% efficiency, 2021-22)



In comparison, Baringa's wholesale electricity market modelling estimates the clean spark spread for a 49% gas-fired power plant at around £4.7/MWh in 2021 and £3.2/MWh in 2022.

Overall, changes in gas transmission tariffs are likely to have a limited impact on gross profits of a mid-merit CCGT. Even in the most extreme cases, the impact of changes in gas tariffs is likely to amount to less than one third of the gross margin. In the majority of cases, the impact is likely to be much less material. Also, our analysis suggests that for transmission-connected CCGTs, the impact of changes in the gas tariff methodology is more likely to lead to lower tariffs. Although it is possible that some power plants that are only marginally profitable under Status quo tariffs may be tipped into closure by a change in gas tariffs, this does not appear likely given the potential magnitude of tariff changes. It is also no less likely that the opposite is the case and change in tariffs leads to delayed closure.

5.2.2 Impact on plant location

In order to assess whether changes in transmission tariffs could have a significant impact on the location choices of CCGT developers, we carry out the following two tests:

1. Compare the materiality of locational variation in transmission tariffs across different tariff methodologies, including the Status quo, to the variation in TNUoS observable across GB. If locational variation in transmission tariffs across different tariff methodologies, including the Status quo, is large relative to the variation in TNUoS observable across GB, the choice of tariff methodology may influence the decisions of CCGT developers on where to locate their power plants.

2. Compare the materiality of the maximum difference in transmission tariffs between the Status quo and other tariff methodologies, to the variation in TNUoS observable across GB. If the change in gas transmission tariffs from the Status quo to alternative tariff methodologies for a given generator is large relative to differences in TNUoS charges in different locations, this may indicate that gas tariff reform is likely to influence the decisions of CCGT developers on where to locate their power plants.

The first approach tests the underlying locational signal that is present in different gas tariff methodologies. The second approach tests the extent to which this signal would change compared to the Status quo, which may affect the investment case of power plants that are currently in the planning stage.

Under test (1) described above, we calculate the difference between the highest and lowest tariff under each option, for a new CCGT with an indicative efficiency of 56%.

Table 7 Tariff differentials under the options studied (2021-22)

Difference between the highest and lowest tariff (£/MWh of electricity)	Embedded	Transmission-connected
Status quo	£2.00	£1.42
CWD	£1.21	£0.69
CWD square root	£0.82	£0.44
Postage stamp	£0.00	£0.00
CWD obligated capacity	£0.57	£0.25
CWD storage discount	£1.21	£0.69
CWD interconnector discount	£1.35	£0.83

As Table 7 indicates, tariff variation significantly falls under all alternative tariff methodologies as compared to the Status quo. This means that incentives for a plant to choose a particular location to benefit from lower transmission tariffs are likely to be lower under all new tariff options considered than under the Status quo, with no locational incentives under the Postage stamp option.

Results of test (2) described above are shown in Table 8.

Table 8 Absolute changes in tariffs from the Status quo (2021-22)

Maximum absolute change in tariffs compared to Status quo (£/MWh of electricity)	Embedded	Transmission-connected
CWD	£1.63	£0.73
CWD square root	£1.44	£0.85
Postage stamp	£2.11	£1.01
CWD obligated capacity	£1.85	£0.85
CWD storage discount	£1.62	£0.73
CWD interconnector discount	£1.62	£0.73

The greatest possible absolute change in tariff cost for a CCGT generator between the Status quo and alternative tariff methodologies is £2.11 per MWh of electricity for a GDN-connected power station and £1.01 per MWh of electricity for a NTS-connected power station. Both of these figures are based on the comparison between Postage stamp and Status quo tariffs since the Postage stamp tariff methodology represents the greatest change in tariffs for the majority of users.

Considering variation in TNUoS, for 2021-22, and assuming a load factor of 75%, we find that the difference between zones with the highest and lowest TNUoS tariffs respectively is around £7/MWh[36]. This difference increases for lower load factors, so would expected to be greater for lower efficiency power plants.

Generator TNUoS, which is designed to provide locational signals to power plants, causes a significant variation in the cost base of generators depending on their location. In comparison, variation in gas transmission charges under alternative tariff methodologies, and the maximum change in tariffs relative to the Status quo, is significantly smaller.[37] Hence, changes in gas tariffs are highly unlikely to play a significant role in the location decisions of power plant developers unless that decision is a marginal one.

Another aspect of plant location that can be influenced by changes in transmission tariffs is the decision on whether to locate on the gas distribution or the gas transmission network. This question is addressed in Section 4.1.4. The move to full recovery of network revenue from capacity charges would be expected to favour large-scale NTS-connected gas generation over smaller-scale GDN-connected gas generation. This means that incentives for generation to locate on the gas distribution network are likely to be reduced at the margin.

[36] National Grid (2018), 'Final TNUoS Tariffs for 2018/19', January and Baringa calculations.
[37] Note that the maximum change in tariffs relative to the Status quo (£1.01 per MWh of electricity for a transmission-connected CCGT) occurs under the Postage stamp methodology and the greatest difference between the highest and lowest tariff (£1.42 per MWh of electricity for a transmission-connected CCGT) occurs under the Status quo.

5.3 Bi-directional interconnector

It is difficult to assess potential changes in profitability of interconnectors as a result of changes in tariff methodology because data on their cost structure, and in particular the breakdown between fixed and variable costs of gas imports and exports, is not readily available. Our modelling therefore cannot directly compute changes in interconnector profits as a result of changes in tariffs.

We are able to measure changes in interconnector flows occurring as a result of changes in transmission tariffs. Table 9 shows the change in total interconnector flows (including imports and exports) under the alternative tariff methodologies relative to the Status quo.

Table 9 Change in total interconnector flows relative to the Status quo[38]

Change in total interconnector flows relative to the Status quo	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	2.5%	3.3%	10.3%	18.6%	3.3%	20.3%
CWD	5.0%	5.5%	6.3%	24.8%	6.9%	40.6%
CWD square root	3.9%	4.7%	7.7%	14.3%	4.6%	33.4%
CWD obligated capacity	5.4%	3.7%	10.0%	13.3%	3.5%	24.2%
CWD obligated capacity OCC	3.7%	3.7%	10.0%	13.3%	3.5%	24.2%
CWD interconnector discount	5.9%	6.5%	5.3%	44.4%	18.4%	51.9%
CWD storage discount	5.4%	6.2%	6.4%	24.9%	6.9%	40.2%

The results of our analysis indicate that all alternative tariff methodologies are likely to lead to higher interconnector flows than under the Status quo.[39] This trend is significantly more pronounced in the NCS scenario where interconnectors and NCS supply compete directly and have the same supply elasticity, and also in the Two Degrees scenario, where interconnector imports and exports are fairly balanced and change from a much lower base. Highest interconnector flows are, unsurprisingly, generally seen under the CWD interconnector discount option.

Overall, our analysis suggests that alternative tariff methodologies are likely to be more favourable to interconnectors than the Status quo if interconnector welfare is measured in terms of market share. This does not account for any effect of changes in tariff methodology on price spreads on the interconnected borders, which is highly uncertain, or the specifics of the capacity contract arrangements for BBL and Interconnector UK.

More broadly, we consider that, as with other elements of gas infrastructure, interconnectors are unlikely to shut down unless they are unable to recover their ongoing costs. In the case of Interconnector UK, published financial statements for the financial year ending 31 December 2017 state that operating expenses made up just 38% of total revenue. Further, around 40% of total operating expenses was made up of depreciation of property, plant and equipment. Since

[38] Numbers include the effect on flows on the IUK, BBL and Moffat interconnectors.

[39] We note that our analysis is based on the assumption that BBL acquires reverse flow capability from 2020/21. If this assumption is not used, we would expect the effect of increasing flows under alternative tariff methodologies to be focussed more on Interconnector UK.

depreciation refers to accounting recognition of sunk costs, inability to recover depreciation costs in full would not be expected to lead to closure.

Overall, the evidence we have available to us does not suggest that changes in tariff methodology are likely to lead to closure of interconnectors while they are operational. However, investment in additional infrastructure, such as would be required for BBL to obtain reverse flow capability, or when significant refurbishment of interconnection infrastructure is required, may potentially be influenced by the tariff methodology and the charges levied on interconnectors.

5.4 Storage facilities

Given that data on the full cost structure of storage facilities, including capex and other fixed costs, is not available to us, our assessment of the potential impact of changes in gas transmission tariffs is based on estimated changes in net storage revenues after accounting for variable costs of storage. We assess changes in net revenues between the Status quo and the alternative tariff methodologies, as computed in Baringa's wholesale market modelling. This assessment takes into account changes in storage behaviour in response to changes in tariffs.

Our analysis suggests that net revenues of storage facilities are likely to be lower under all alternative tariff methodologies compared to the Status quo. Depending on the modelled tariff methodology, the extent of the difference varies between around -3% (CWD storage discount) and -31% (CWD obligated capacity), using results for 2020/21 under the Baseline scenario. This can be seen in Table 10.

Table 10 Evolution in net revenues of storage facilities vs Status quo (Baseline scenario)

Change in net revenues	2020-21	2021-22
CWD	-14%	-10%
CWD square root	-18%	-9%
Postage stamp	-28%	-20%
CWD obligated capacity	-4%	-31%
CWD interconnector discount	-14%	-6%
CWD storage discount	-5%	-3%

The Status quo is estimated to be the most favourable tariff methodology for gas storage. This is driven by the fact that storage is exempted from commodity charges and interruptible capacity can be obtained for free. The maximum estimated extent of variation in net revenue (31% reduction) appears to be significant. The lowest loss of storage net revenues as compared to the Status quo occurs under the CWD storage discount option. More generally, we would expect that the combination of a higher storage discount with any of the above tariff methodology options would mitigate the loss of storage net revenue relative to the Status quo.[40]

The above estimates must be put into context of potential variation in net revenues due to changes in broader market conditions and their effect on the seasonal spread in the gas price. Figure 24 of Section 4.2.4 shows that changes in net revenues of gas storage in response to changes in gas tariff methodology are very small in comparison to changes in net revenues as a result of differences between different modelled market scenarios. However, we also note that storage operators are likely to be accustomed to changes in market conditions and spreads, and regular changes in market conditions mean that the impact of such changes averages out over time. The impact of changes in the tariff methodology would be seen as permanent and would therefore not be assessed in the same way.

To continue operating, revenues of storage facilities need to be sufficiently high to cover all ongoing costs. Although we are not in possession of good estimates of fixed operating costs of gas storage, we consider it unlikely that they would amount to more than 69% of net revenues after variable costs have been netted off.[41]

Although the largest share of costs of storage facilities relate to CAPEX and is therefore sunk, a reduction in net revenues of 20-30% or more would significantly impact the profitability of storage facilities. If operating costs are sufficiently low, storage facilities are likely to remain open but revenues may not be sufficiently high to justify any significant further investment, including refurbishment costs. Hence, under a number of alternative tariff methodologies, storage facilities may encounter challenges in continuing operations in the medium- to longer-run.

[40] Although we have not modelled this scenario, we note that the Postage stamp mod includes an 86% discount for storage rather than the 50% discount assumed in our modelling of the Postage stamp option. A higher storage discount would likely reduce the change in net revenues reported in Table 10 for the Postage stamp option.

[41] This is the estimated residual proportion of Status quo net storage revenues under the least favourable tariff methodology for storage.

6 Qualitative analysis

6.1 Security of supply

Our quantitative modelling is undertaken on a deterministic basis, which means that it does not account for any unexpected demand- or supply-side shocks. Any analysis of security of supply would need to consider the possibility of deviations from a central view of supply and demand. Therefore, we consider the potential effects of adverse demand and supply shocks on a qualitative basis.

Our quantitative analysis of the effect of changes in gas tariff methodology under a variety of gas market scenarios suggests that differences in gas transmission tariff methodology would have little effect on gas flows at different entry and exit points in comparison to the effect of changes in underlying gas market conditions. Hence, any positive or adverse effects of changes in gas tariff methodology on security of gas supply would likely be linked directly to changes in gas infrastructure investment and retirement.

Section 5 undertakes the relevant analysis of gas infrastructure investment and closure decisions. Overall, our analysis suggests that closure of existing interconnection, storage or gas generation capacity is very unlikely in the shorter-term. However, there may be challenges with significant new capital investment for new projects, or for existing projects requiring significant refurbishment expenditure.

Finally, we note that a discount on tariffs for any kind of gas infrastructure creates the need to raise tariffs for other gas infrastructure. Hence, improving the prospects of a given type of infrastructure remaining operational invariably comes at a price of diminishing such prospects for other infrastructure types. The arguments set out in this section apply to all types of infrastructure reviewed in section 5. Although we did not undertake closure analysis for LNG import terminals and offshore gas fields, we would expect similar logic to apply to these types of infrastructure also. Hence, we do not believe that it is possible to say definitively that a given tariff methodology is likely to be more favourable for security of gas supply than other tariff methodologies – rather the impact associated with a new tariff methodology is likely to be very small relative to the effect of changes in underlying gas market conditions.

6.2 Impact of interruptible discounts

Discounts for interruptible capacity contracts are equivalent to charging lower tariffs for network access in periods of off-peak demand than in peak periods. The economic rationale for this is that the cost of the transmission network is determined by its peak capacity, and hence charges for network access should be proportional to peak usage. However, arguments for cost-reflective charging for network access are, in our view, less relevant when demand is declining and investment in network capacity expansion is unlikely to be required.

Given the existence of significant amounts of spare capacity, changes in gas flows as a result of changes in gas network tariffs are unlikely to trigger the need for additional network investment.[42]

[42] We note we have not considered the possible role of a forward-looking component of charges in the (unlikely) situation of an unexpected investment requirement.

Therefore, the economic rationale for cost-reflective network charges is significantly weakened since changing the behaviour of system users through such charges is unlikely to affect the total cost of the network. Overall, gas transmission network charges are best characterised as cost recovery charges. Under this characterisation, the rationale for significant discounting of interruptible capacity is not strong. However, we must note that we have not undertaken full constraint modelling of the GB gas transmission network, and therefore we cannot be certain that removal of discounts for interruptible capacity would not create constraints on the network where there are none currently.

6.3 Differentiation in long- and short-term capacity products

Our analysis considered a single tariff for each entry and exit point on the system and abstracted from differences between products of different tenor. Our analysis also assumed that capacity bookings can be matched exactly to commodity flows by users who wish to do so. In combination, these assumptions imply that capacity products are available down to the daily level to enable users to profile their demand for capacity to the underlying shape of their intended usage of the network.

Our view is that offering a variety of capacity products in terms of product tenor is useful to ensure that the gas market functions efficiently and that users whose demand for network access does not fit the 'baseload' profile are not disadvantaged.

With regard to the question of whether there should be price differentiation between long- and short-term capacity products, we note that this should not make any material difference from the perspective of the transmission network operator since it would not affect the total revenue raised or the risk associated with that revenue. From the perspective of transmission system users, it is not clear whether there would be any impact on their welfare overall, although significant distributional effects may be seen depending on the extent to which different users are able to forecast their future demand for capacity.

Finally, from the perspective of overall economic efficiency, demand elasticity for shorter-term products is likely to be lower given that making adjustments to demand is more difficult in the short-term. However, the principle that an efficient charging mechanism would apply higher charges to products for which demand is less elastic is unlikely to be applicable in this case since differential pricing would mostly prompt substitution between shorter- and longer-term capacity products, with no obvious gain in economic efficiency.

6.4 Appropriateness of proposed cost drivers

The major cost drivers in the alternative tariff methodology options covered in our analysis are Reference Price Methodology (CWD, CWD square root and Postage stamp), Forecasted Contracted Capacity definition (obligated capacity or forecast capacity bookings), and discounts for storage and bi-directional interconnectors. We examine each of these in turn.

Reference Price Methodology

The rationale for weighting of gas network tariffs by capacity and distance is cost-reflectivity. Building infrastructure to deliver larger quantities of gas and to deliver gas to more remote locations is likely to impose a higher cost on the network. However, barring certain exceptions such as installing new compressors, our understanding is that significant new investment in transmission network capacity is unlikely. Hence, as argued in section 6.2, in our view gas network tariffs are best viewed as cost recovery charges. In this context, the economic rationale for the CWD or CWD square root methodology is not necessarily stronger than for the Postage stamp methodology.

Forecasted Contracted Capacity

The options covered by our analysis are based on calculating capacity charges either on the basis of forecast capacity bookings or obligated capacity. In the absence of a published methodology to calculate forecast capacity bookings for the alternative tariff methodologies, we have assumed in our analysis that forecast bookings match actual usage for all users barring GDNs, who over-book capacity. This is a reasonable long-term assumption as over time we would expect errors to net to zero. Our analysis suggests that calculating capacity charges on the basis of obligated capacity is likely to result in significant under-recovery of network revenue and the need for a further revenue recovery charge.

Discounts for storage and bi-directional interconnectors

Our understanding is that the economic rationale for granting a tariff discount to storage is avoidance of double-charging. Gas that enters and subsequently exits storage will have paid an entry charge and will eventually pay an exit charge. We understand further that the main rationale for the discount for storage being less than 100% is that gas that takes a ‘detour’ via storage on its way to the final consumer makes more extensive use of the gas transmission network than gas that goes to the final consumer directly. While we have not carried out a detailed study of gas flows around the network and the extent to which storage affects this, we see a rationale for offering tariff discounts to storage.

With regard to discounting tariffs for bi-directional interconnectors, our understanding is that the main rationale for this is the flexibility that they can offer in terms of exporting gas from GB in times of surplus supply and importing gas in times of shortage. The argument might be that the behaviour of bi-directional interconnectors is akin to storage. However, unlike the case of storage, it is unlikely that the gas entering GB via interconnectors in times of shortage is the same gas that exited GB in times of surplus, hence the avoidance of double-charging argument is not directly applicable to bi-directional interconnectors. With regard to offering broader flexibility, we note that many uni-directional entries into GB such as LNG and beach terminals can also offer a significant degree of flexibility, although not necessarily to the same degree as bi-directional interconnectors. Overall, in our view the case for offering a tariff discount to bi-directional interconnectors is weaker than for storage.

Appendix A Detailed modelling results

Table 11 Summary of consumer welfare results

Net consumer welfare relative to Status quo (£m)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	-280.7	-293.3	6.6	-201.6	164.5	85.6
CWD	38.5	7.7	3.1	-283.0	297.2	125.2
CWD square root	-102.3	-128.2	-12.3	-205.9	232.6	103.7
CWD obligated capacity	62.3	-269.1	2.4	-215.7	195.5	89.2
CWD obligated capacity OCC	58.6	-269.1	2.4	-215.7	195.5	89.2
CWD interconnector discount	168.3	150.7	-61.2	-601.3	397.9	97.1
CWD storage discount	63.1	39.4	6.2	-283.9	296.7	128.6

Table 12 Summary of demand response

Difference in value of demand served (£m)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	-31.3	-25.9	-0.3	-8.7	9.7	0.2
CWD	8.8	5.0	0.2	-19.3	14.2	0.2
CWD square root	-10.1	-6.9	0.1	-12.9	11.7	0.2
CWD obligated capacity	6.5	-16.2	-0.3	-10.9	10.8	-0.1
CWD obligated capacity OCC	6.6	-16.2	-0.3	-10.9	10.8	-0.1
CWD interconnector discount	17.7	17.9	-0.1	-42.7	19.4	0.1
CWD storage discount	10.1	12.7	0.2	-19.3	13.9	0.2

Table 13 Change in cost of demand served (effect of changes in the gas wholesale price)

Difference in cost of demand served relative to Status quo (£m)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Postage stamp	-249.9	-267.9	6.4	-193.4	154.2	84.9
CWD	29.2	2.1	2.4	-264.3	282.4	124.5
CWD square root	-92.7	-121.9	-13.0	-193.5	220.3	103.0
CWD obligated capacity	55.3	-253.5	2.2	-205.3	184.1	88.8
CWD obligated capacity OCC	52.0	-253.5	2.2	-205.3	184.1	88.8
CWD interconnector discount	150.1	132.3	-61.6	-559.2	377.9	96.4
CWD storage discount	52.4	26.2	5.5	-265.2	282.2	127.9

Table 14 Summary of storage net revenues

Storage net revenue (£m)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Status quo	13.5	18.1	0.0	64.2	75.7	0.0
Postage stamp	9.7	14.5	0.0	58.2	69.6	0.0
CWD	11.5	16.2	0.0	58.7	70.3	0.0
CWD square root	11.1	16.4	0.0	56.7	70.0	0.0
CWD obligated capacity	13.0	12.5	0.0	51.4	65.4	0.0
CWD obligated capacity OCC	12.7	12.5	0.0	51.4	65.4	0.0
CWD interconnector discount	11.7	17.1	0.0	49.3	66.1	0.0
CWD storage discount	12.8	17.6	0.0	63.9	73.7	0.0

Table 15 UKCS and NCS supply

GB and Norway supply (mcm/year)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Status quo	65,988	63,309	62,805	48,733	50,889	49,757
Postage stamp	65,998	63,321	62,653	43,508	50,889	49,722
CWD	65,957	63,268	62,696	41,853	50,889	49,721
CWD square root	65,981	63,293	62,671	45,585	50,889	49,722
CWD obligated capacity	65,913	63,347	62,661	45,930	50,889	49,720
CWD obligated capacity OCC	65,959	63,347	62,661	45,930	50,889	49,720
CWD interconnector discount	65,930	63,235	62,713	31,106	50,836	49,742
CWD storage discount	65,940	63,239	62,695	41,839	50,889	49,721

Table 16 LNG supply

LNG supply (mcm/year)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Status quo	2,379	2,672	11,563	3,192	2,975	2,419
Postage stamp	2,209	2,200	9,796	3,114	2,475	2,190
CWD	2,212	2,190	10,461	2,346	2,190	2,190
CWD square root	2,196	2,190	10,229	2,415	2,256	2,190
CWD obligated capacity	2,196	2,190	9,843	2,399	2,452	2,190
CWD obligated capacity OCC	2,322	2,190	9,843	2,399	2,452	2,190
CWD interconnector discount	2,196	2,190	10,623	2,190	2,235	2,190
CWD storage discount	2,196	2,190	10,439	2,349	2,190	2,190

Table 17 Interconnector supply

Interconnector supply (mcm/year)	2020/21	2021/22			2030/31	
	Baseline	Baseline	Inelastic interconnector scenario	NCS scenario	Baseline	Two degrees
Status quo	9,254	9,401	10,985	23,086	15,748	3,696
Postage stamp	9,247	9,726	10,985	28,344	16,287	4,877
CWD	9,501	9,952	10,985	30,713	16,749	6,641
CWD square root	9,392	9,864	10,985	26,945	16,514	5,899
CWD obligated capacity	9,548	9,762	10,985	26,626	16,315	5,142
CWD obligated capacity OCC	9,377	9,762	10,985	26,626	16,315	5,142
CWD interconnector discount	9,592	10,052	10,985	41,493	17,956	8,270
CWD storage discount	9,541	10,020	10,985	30,723	16,748	6,605

Appendix B Wholesale market scenarios

B.1 Overview

In order to test the sensitivity of our results to changes in key modelling assumptions, we compute outcomes for all tariff options under a number of alternative scenarios. This section sets out a summary of the scenarios used in our modelling. It shows some of the possible conditions that may prevail in the gas market in the near future.

The results presented in this section allow for an informed interpretation of the results of wider system impact analysis. For example, the effect of granting a higher tariff discount to storage on consumer welfare is likely to depend on the extent to which storage plays an active role in balancing supply and demand in different seasons. As can be seen from the results presented in this section, some scenarios see relatively flat gas prices across different seasons and storage playing only a limited role in balancing supply and demand, and hence discounted storage tariffs may have little effect on wholesale prices and consumer welfare in these scenarios. Hence, it is important to keep in mind the market conditions that prevail under different scenarios, as shown in this section, when considering the results of wider system impacts analysis set out in Section 4.2.

The detailed results of wholesale market modelling presented in this section are also used to produce the flow and capacity booking projections for all entry and exit points that are used in our distributional analysis as set out in Section 4.1.

Finally, we note that we model each scenario for an entire year, but that market conditions that each scenario represents may prevail for parts of any given year and market conditions can change at any time.

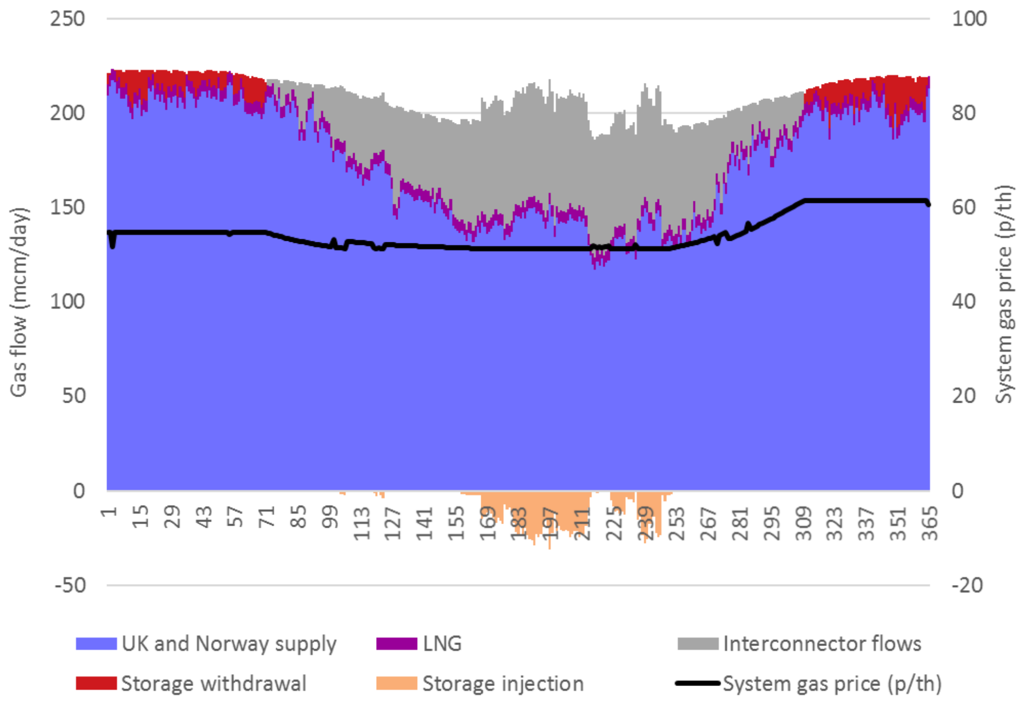
B.2 Baseline scenario

The Baseline scenario is based on a calibration of supply and demand as described in Section 3.3. It represents one possible set of gas market conditions that could prevail in the next few years.

Figure 26 shows some key market metrics for the Baseline scenario, for a calendar year starting on 1 January. This convention is applied to wholesale market modelling results throughout the report. Gas flows from different sources are measured against the left-hand vertical axis and the system gas price against the right-hand axis. Flows above the x-axis represent entry of gas into the transmission system. Flows below the x-axis represent exit of gas from the transmission system that are not directly serving domestic demand, such as interconnector exports and injection into storage.

The purpose of this chart is to illustrate the prevailing wholesale market conditions, including the mix of supply sources serving GB demand, and to demonstrate the interaction between the system gas price and flows on the gas transmission system.

Figure 26 Gas flows and prices (Baseline scenario - 2021)



Under the Baseline scenario, the system gas price shows some seasonal variation but actions of storage injecting in the summer months and withdrawing in the winter months flatten the seasonal price shape significantly in the peak winter and off-peak summer months. Storage plays a material role in meeting winter demand.

Being the most price-responsive supply source in the Baseline scenario, interconnector imports are the marginal supply point for much of the year, ramping up in the summer months to supply gas for injection into storage. St Fergus and storage become marginal supply sources in other periods.

In the winter months, supply from beach terminals and storage displaces interconnector imports. Contracted LNG imports at Milford Haven play only a small role in the overall supply mix.

B.3 Norwegian Continental Shelf (NCS) scenario

This scenario tests the theory that Norwegian Continental Shelf (NCS) flows have a choice of whether to supply gas to the UK or continental Europe, and that they also have a choice of entry point into the GB gas system. It seeks to answer the question of how wholesale market dynamics and the evaluation of the different gas transmission tariff methodologies would be affected by NCS flows being as responsive to price changes as bi-directional interconnectors.

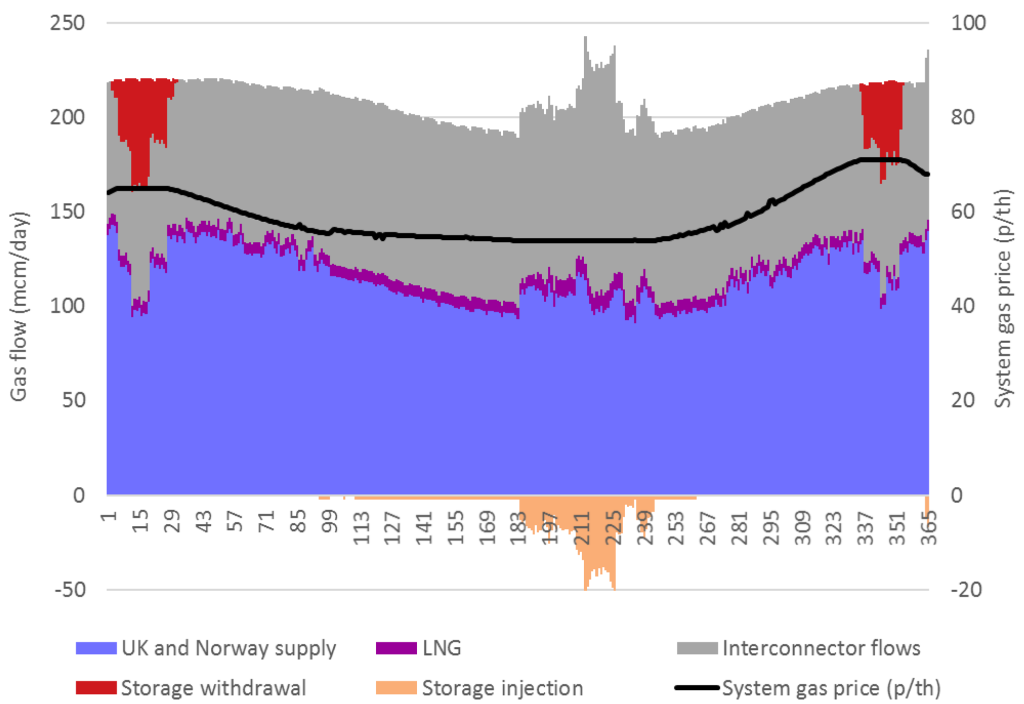
This is modelled as price elasticity of supply at the Easington and St Fergus entry points being the same as for Bacton IP under the Baseline scenario.[43] Under this scenario, flows on Easington and St

[43] Under the Baseline scenario, Easington and St Fergus are less price-responsive than Bacton IP.

Fergus terminals would be expected to be more responsive to changes in tariffs on those entry points, as well as to broader wholesale gas market dynamics.

Figure 27 shows the key market metrics for the NCS scenario, in which supply from Easington and St. Fergus terminals is assumed to be as price-responsive as interconnector imports.

Figure 27 Gas flows and prices (NCS scenario - 2021)



The system gas price shows a greater amount of seasonal variation than under the Baseline scenario, with higher prices in winter required to attract Norwegian gas supply into GB. Actions of storage flatten the seasonal price shape only to a limited extent. Storage capacity is utilised fully and within a relatively short period at the peak of winter. A significantly greater share of demand is supplied by interconnector imports.

B.4 Inelastic interconnector scenario

In our Baseline scenario, interconnector imports are generally cheaper than LNG and therefore have a more competitive position in the merit order. The Inelastic interconnector scenario sees lower priced LNG than the Baseline scenario, with LNG supply also being more responsive to changes in the GB gas price. Interconnector imports, rather than being price responsive as in the Baseline scenario, are characterised by a baseload of contracted flows and low price elasticity of supply for additional capacity.

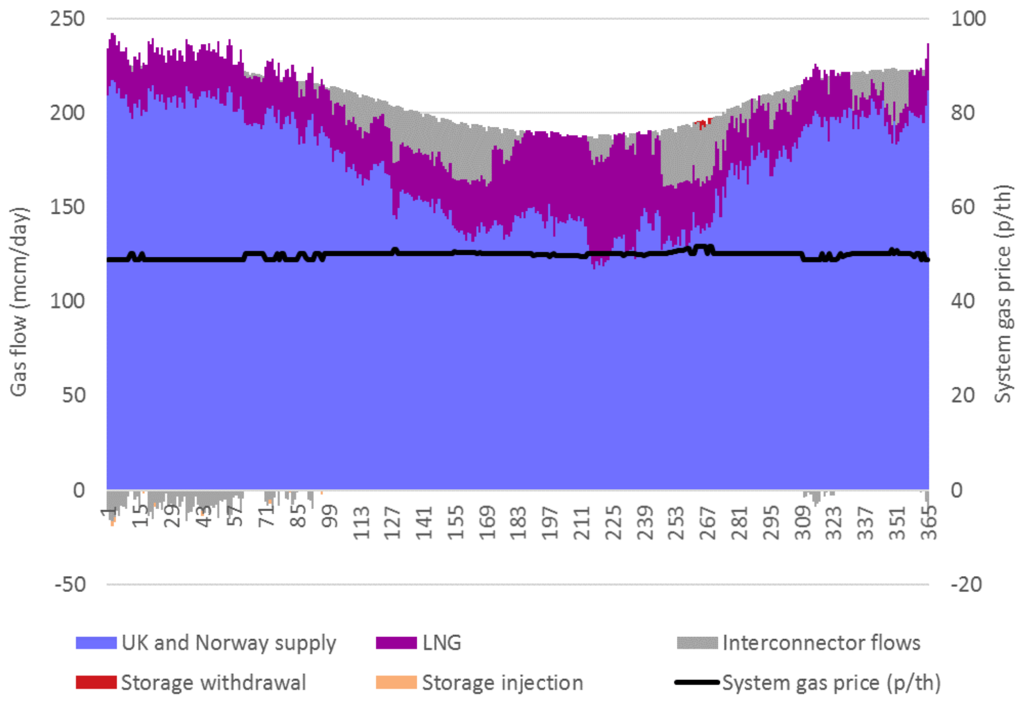
The Inelastic interconnector scenario seeks to answer the following questions:

1. How do market dynamics in terms of gas flows, storage utilisation and wholesale prices change if LNG becomes cheaper and interconnector flows become less responsive to changes in the GB wholesale price?
2. How does this change affect the relative evaluation of the different gas transmission tariff methodologies?

Figure 28 shows the key market metrics for the Inelastic interconnector scenario. Greater abundance of LNG and a tranche of price-insensitive contracted supply from interconnectors ensures that the gas price is low and stable throughout the year. This means that storage is utilised to only a very limited extent. There is also an increase in demand where the power sector increases its use of gas relative to the Baseline scenario.

Although LNG imports take a significantly greater share of the market than under the Baseline scenario, UK and Norwegian gas supplies still account for the bulk of the market. Interconnector flows are more balanced, with some exports in the winter months.

Figure 28 Gas flows and prices (Inelastic interconnector scenario - 2021)



B.5 Two Degrees scenario

This scenario seeks to answer the question of whether significantly lower gas demand, coupled with abundant gas supply from multiple sources, is likely to affect the relative evaluation of the different gas transmission tariff methodologies. It sees lower demand for gas by 2030, particularly from the power sector. It changes the demand-supply balance in favour of demand and sees supply sources having to compete more intensively for market share.

Since differences in demand growth between scenarios take a number of years to be felt, we evaluate differences between the Baseline and Two Degrees scenarios for 2030. To enable this comparison, we present wholesale market modelling results for both scenarios below.

Figure 29 shows the key market metrics for the Baseline scenario in 2030. Lower margin of available supply over demand than in 2021 means that there is more seasonality in the shape of the system gas price and storage is utilised to a greater extent. A significant decline in UKCS gas production means that the market share of interconnector imports is greater than in 2021.

Figure 29 Gas flows and prices (Baseline scenario - 2030)

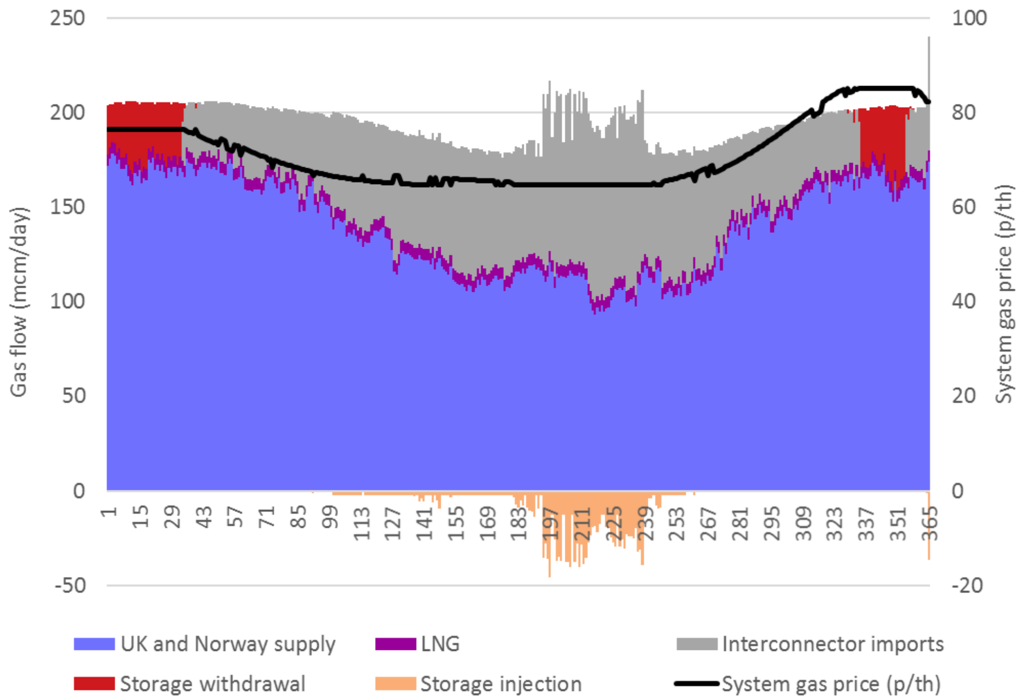
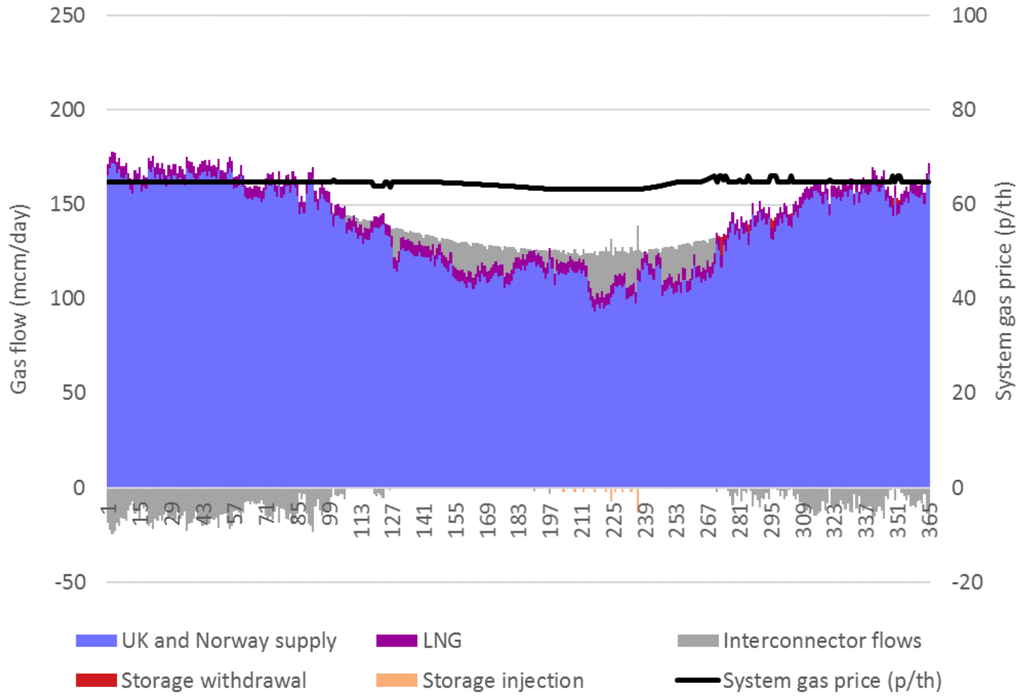


Figure 30 shows the key market metrics for the Two degrees scenario in 2030.

Figure 30 Gas flows and prices (Two degrees scenario – 2030)



A higher margin of available supply over demand than in the Baseline scenario in the same year means that there is less seasonality in the shape of the system gas price and storage is utilised to a much lesser extent.

The reduction in demand for gas relative to the Baseline scenario is largely accommodated by a reduction in supply from interconnectors, which are assumed to be the most price-responsive supply source. This occurs particularly in the winter months, when interconnectors export gas from the GB market.